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BEFORE THE ARIZONA CORPORATION C...

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816
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	DOCKET NO. E-01345A-05-0826
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INITIAL POST-HEARING BRIEF
OF
ARIZONA PUBLIC SERVICE COMPANY

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816
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I.
INTRODUCTION

On November 4, 2005, Arizona Public Service Company ("APS" or the "Company") filed an application with the Arizona Corporation Commission ("ACC" or "Commission") for a rate increase and to amend Decision No. 67744 (April 7, 2005). On November 9, 2005, the Commission opened a docket to investigate outages at the Palo Verde Nuclear Power Generating Station ("Palo Verde") during 2005, and also opened a docket to audit the fuel and purchased power practices and costs of APS. On January 31, 2006, and at the request of Commission staff ("Staff"), the Company filed an amended application for a rate increase using an updated Test Year. By Procedural Order issued September 18, 2006, all three dockets were consolidated. Hearings were conducted on these matters between October 10, 2006 and December 15, 2006 before the Commission's Chief Administrative Law Judge ("ALJ"), with various members of the Commission in attendance.

II.
SUMMARY OF POSITION

A. Overview.

APS is requesting an increase of $434,639,000, or 20.43 percent, over adjusted test period revenues. *See,* Initial Post-Hearing Brief of Arizona Public Service Company ("Initial Brief") Exhibit 1.[1] Of this, approximately $314,400,000 (72.3 percent) represents an increase in fuel costs. (APS Exhibit No. 18 at 2 [Ewen]). The balance of the increase is composed of increased non-fuel costs, both operating and capital, that like fuel, are driven by both price increases in components ranging from copper wire to steel to concrete to pensions to equity capital and, perhaps to a greater extent, by the continued rapid growth of the Company's customers – a growth that demonstrably does **not** "pay for itself." (*Id.* at 2, 4; APS Exhibit No. 5 at 9-10 [Brandt]; *id.* at Attachment DEB-1RB; Tr. Vol. IV at 782-85; APS Exhibit No. 59). Because the Interim Power Supply Adjustor ("PSA"), will continue until rates in this proceeding

[1] APS Initial Brief Exhibit 1 is the first page of APS hearing Exhibit No. 53.

become effective, but was not considered in the calculation of adjusted test period revenues, the incremental increase over rate levels currently in effect is $249,046,000, or 11.7 percent.

The rate relief sought by APS is necessary and appropriate because the Company's current rates substantially under-collect the legitimate costs of providing electric service (particularly fuel and purchased power costs), do not adequately reflect certain non-fuel costs, and do not provide APS an opportunity to earn a reasonable rate of return on its invested equity ("ROE"). Although timely recovery of fuel and purchased power costs will be addressed in significant part if the Commission adopts the modifications to the PSA proposed by Staff and APS, no refinements to the PSA can be sufficient by themselves to address the non-fuel cost recovery and ROE issues that APS has raised in this proceeding. And it is these issues that have led to chronic under-earning by APS and have driven the Company and its customers to the very brink of "junk" credit status, with the attendant problems of even higher costs and limited access to critically needed capital to meet the growing demands of this State.

APS continues to suffer from a severe cash flow problem that began in 2005 and that was discussed in great detail in the emergency rate case[2] last spring. As APS's customer base grows, the need for cash to fund capital expenditures to meet that growth increases, as does the required return on such investment. At the same time, as costs of service (including, but not limited to, fuel and purchased power costs) continue to rise; APS's cash flow needs increase proportionately. This cash flow pressure from both the operating and new construction perspectives, coupled with the regulatory lag associated with recovery of billions of dollars of capital expenditures and the resulting inability of APS to earn anything close to a reasonable current rate of return on its invested equity, has left APS in a perilous credit-rating position that threatens to plunge APS into "junk" credit status for the first time in its more than 100-year history.

At present, APS has a Standard & Poor's ("S&P") credit rating of BBB-minus (just one notch above "junk" status) and a negative outlook from Moody's Investors Service ("Moody's"). Those credit rating agencies, as well as the broader investment community, have made it clear

[2] Docket No. E-01345A-06-0009.

that they are looking at this rate proceeding for an indication as to whether APS is likely to obtain the rate relief and further regulatory support that will be required for APS to fully recover its costs in a timely manner, earn a reasonable ROE, and improve its lagging credit metrics.

As they did in the emergency rate case, Staff and The Residential Utility Consumer Office ("RUCO") downplay the seriousness of APS's cost recovery and ROE needs, and essentially ask APS customers to take the risk that APS can get by with less than it has requested – indeed, substantially less under both the Staff and RUCO proposals, which actually would **reduce** APS rates exclusive of fuel and purchased power costs. And although APS disputes a number of Staff and RUCO adjustments to the test period, the largest conceptual difference between the Company and these Parties is the latter's refusal to consider whether their proposals actually would produce rates that are just and reasonable **during the period they would be in effect,** rather than simply during some hypothetical historical period.

But the Staff and RUCO proposals not only entail substantial financial risk to APS and its customers that would stem from a downgrade to "junk" status, those proposals also effectively ignore the constitutional and regulatory mandate that APS be permitted to recover its prudently incurred costs of service and be afforded an opportunity to earn a reasonable ROE. Indeed, under both the Staff and RUCO proposals, APS's Funds From Operation ("FFO")/Debt ratio – the most important credit metric – would remain well below investment grade and would almost certainly result in APS being downgraded by the rating agencies to "junk" credit status.

The consequences of such a downgrade would be financially disastrous for the Company, its customers and its shareholders and would adversely impact the economy of the State. Among other things, such a downgrade to "junk" status would saddle the Company's customers with as much as $1.3 billion in **additional** financing costs over the next decade.

Contrary to the protestations of Staff and RUCO, both of whom have proposed **decreases** in the non-fuel related rates charged by APS, the impact of the Commission's decision in this case on APS's projected financial condition and on future customer rates not only **can** be considered by the Commission, but **must** be considered by the Commission in order to ensure that the rate relief granted by the Commission is adequate **at the time it becomes effective** and, thus, is consistent with applicable constitutional and regulatory principles.

> [T]he 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.**

Scates v. Arizona Corporation Comm'n, 118 Ariz. 531, 533-34, 578 P.2d 612, 614-15 (Ariz. App. 1978).

The inability of APS to recover its costs of service and earn a reasonable ROE in the last several years, coupled with the strong evidence that these shortfalls will continue to increase in the future unless the Commission grants the rate relief requested by the Company, cannot and should not be ignored by the Commission in this case.

The Commission has been given, in this proceeding, several alternative and innovative options for addressing the cost recovery and ROE needs of the Company, including the options to include Construction Work in Progress ("CWIP") in rate base, allow recovery of accelerated depreciation, and/or include an attrition allowance to address the predicted (and undisputed) result that APS will continue to under-earn its allowed ROE because of the Company's huge capital expenditure obligations in coming years. The Commission could also authorize a return on "fair value" rate base in excess of APS's cost of capital. Whatever mechanisms the Commission chooses to use, however, the end result should achieve the full cost recovery, reasonable ROE, and improved financial metrics that APS seeks in this proceeding.

For more than ten years – from the early 1990s until March 2005 – APS went without any rate increase whatsoever and even reduced rates several times during that period. This provided cumulative benefits to APS customers of $1.74 **billion**. (APS Exhibit No. 1 at 3 [Wheeler]). Now, circumstances have changed. And although APS recognizes that the rate increase it seeks is not insignificant, APS believes that its rate increase request is both fair to customers and amply justified by increasing costs and other financial circumstances.

B. Calculation Of Requested Increase.

The test year used by the Company to determine operating income (test year ended September 30, 2005 ("Test Year")), when adjusted as proposed by the Company, produces adjusted jurisdictional operating revenues of $2,545,020,000. (APS Exhibit No. 53 at 2). Adjusted jurisdictional operating expense for the same period is $2,415,481,000.[3] (*Id.*). Therefore, the Company's jurisdictional Test Year operating income is $129,539,000. (*Id.* at 1). This produces just a 2.91 percent rate of return for APS – well below that found reasonable in Decision No. 67744 and below any of the recommendations in this case. (APS Exhibit 53 at 1).

The Company has proposed an adjusted jurisdictional original cost rate base ("OCRB") of $4,456,937,000. (*Id.*). Correspondingly, the Company's adjusted jurisdictional reconstruction cost new – depreciated rate base ("RCND") is $7,765,052,000. (*Id.*). The Commission has traditionally defined "fair value" rate base ("FVRB") as the average of OCRB and RCND, although there is no Commission rule or case law that would prevent a different weighting.

The Company's proposed weighted cost of capital is 8.73 percent (consisting of a cost of debt of 5.41 percent and a cost of equity of 11.50 percent).[4] (*Id.*) Based on the foregoing, the operating income required to realize this return is $389,091,000 (OCRB of $4,456,937,000 x 0.0873). (*Id.*). Therefore, as the adjusted jurisdictional operating income is only $129,539,000, the Company's operating income deficiency for the Test Year is $259,552,000. (*Id.*). When the revenue conversion factor is applied (to include the incremental impact of federal and state income taxes), an increase in base revenue of $425,847,000 is required. (*Id.*).

The Company is also proposing a new adjustment clause, the Environmental Improvement Charge ("EIC"), and is proposing to increase funding of its Environmental Portfolio Standard ("EPS"), which respectively adds $4,542,000 and $4,250,000 to the annual increase in revenue, increasing the Company's proposed required base revenue to $434,639,000. (*Id.*).

III.
RATE OF RETURN AND APS's FINANCIAL INTEGRITY

A. APS's Current Credit Ratings And Related Cash Flow Problems Are The Result Of Inadequate Rates.

As the Commission knows, APS's rates decreased for more than a decade from the early

[3] This is the sum of line 2, purchase power and fuel costs, and line 9, the total.
[4] *See,* Standard Filing Requirement Schedule D-1, page 1 of 2, filed January 31, 2006.

1990s until April 2005 when the Commission approved a small rate increase in Decision No. 67744. Since early in this decade, the Company's costs have been steadily increasing faster than its revenues, causing the Company to consistently under-earn its allowed rate of return. The Company's financial metrics (particularly its all important FFO/Debt ratio) began to slide downward. Although the rate increase in Decision No. 67744 helped to slow the Company's financial slide, the rapidly increasing costs of service in 2005 and 2006, coupled with the increasing expenditures necessary to meet the needs of the nation's second fastest growing customer base, have far exceeded the rates that APS charged its customers and have caused substantial deterioration of the Company's credit metrics and other financial criteria.

On December 21, 2005, in the wake of mounting unrecovered costs and the perception that Arizona regulators would not provide timely and adequate rate relief for the Company, S&P downgraded the Company's credit rating to BBB-minus – just one small step away from non-investment "junk bond" credit rating status. In doing so, S&P highlighted the deterioration of APS's credit metrics, and noted: "The need for continued timely processing of APS's rate applications and reasonable rate relief will be critical to producing consolidated long-term financial gain." (APS Exhibit No. 4 at 13-14 [Brandt]). Since then, S&P has recognized what it called the "generally constructive" decisions by the Commission to accelerate the start of the PSA in January 2006 and to grant the 7 mill interim PSA adjuster effective May 1, 2006. (*Id.* at 14). Nevertheless, S&P has twice since the downgrade reaffirmed the Company's low credit rating and has recently made it clear that "APS's 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." (APS Exhibit No. 5, Attachment DEB-5RB [Brandt]).

The other principal credit rating agency, Moody's, likewise took steps during the past year to downgrade APS. On January 10, 2006, Moody's placed APS "under review for downgrade" for the same reasons cited by S&P. (APS Exhibit No. 4 at 14 [Brandt]). Then, on May 9, 2006 – **after** the Commission's action in January 2006 to accelerate the PSA and after implementation on May 1 of the 7 mill interim PSA adjuster – Moody's downgraded APS from

Baa1 to Baa2 and assigned a "Negative" outlook to APS. (APS Exhibit No. 5, Attachment DEB-6RB at 1 [Brandt]). In doing so, Moody's stated that "the company's weak regulatory position reflects below average assurance of timely recovery of costs and investments." (*Id.* at 2). Moody's also stated: "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." (*Id.*). And Moody's went on to observe that the Company's critical FFO/Debt ratio was "in the mid-teens and expected to remain there" unless "regulatory treatment is supportive of timely cost recovery." (*Id.*).

Plainly, both S&P and Moody's have serious concerns about APS's weak credit metrics and realize that only strong cash flow recovery in this proceeding will allow APS's metrics to improve. APS is expected to have an FFO/Debt ratio at year-end 2006 near the minimum for investment grade metrics under the S&P criteria. But the marginal year-end 2006 FFO/Debt ratio weakens and declines in 2007 without the rate relief requested by the Company. The current rates, even with an improved and forward-looking PSA, as proposed by Staff, are not enough to prevent a credit metric decline in 2007 and an even more precipitous drop in 2008. Indeed, current rates, **even with a forward-looking PSA**, would result in the Company having an FFO/Debt ratio at year-end 2007 of 16.4 percent and at year-end 2008 of 15.1 percent. (APS Exhibit No. 5, Attachment DEB-2RB [Brandt]). As Mr. Brandt explained and as Mr. Fetter confirmed, such FFO/Debt ratios are insufficient from a quantitative standpoint to maintain an investment grade credit rating and will negate any qualitative rating benefits that the rating agencies may have taken into account based on the Commission's interim rate orders in 2006.

Nor is it correct to assume that APS's current cash flow woes and earnings shortfall are the result solely of increased fuel and purchased power costs. Although such fuel and purchased power costs are about 70 percent of the revenue requirements of the Company's current rate request, they account for only about 32 percent of APS's total revenue requirements. (APS Exhibit No. 80). Other costs, such as operating and maintenance costs, taxes, and interest expense also drive the need for added cost recovery. Indeed, the huge capital expenditures that APS has been making in recent years and expects to make during coming years – an average of

$900 million a year – to meet rapid customer growth in its service territory not only adversely impact the Company's ability to earn its allowed ROE, but also exacerbate the Company's cash flow needs. If only the increases in fuel and purchased power costs are dealt with in this rate case, the increases in the other revenue requirements due to the large capital expenditure outlays will lead to ongoing under-earning and non-investment grade financial metrics.

Simply stated, the Company's current rate level, even with an improved, forward-looking PSA, is insufficient to allow the Company to recover its costs and to maintain, let alone improve, its current credit rating. From both a quantitative as well as a qualitative standpoint, the outcome of this rate proceeding will determine whether APS remains an investment-grade company or plunges to "junk" credit status for the first time in its more than 100 year history – a status that would put APS in the company of only five other investor-owned electric utilities in the United States. (Tr. Vol. II at 465-66 [Brandt]).

B. <u>The Company's Credit Metrics And Other Financial Indicators Are Important And Relevant Factors For The Commission To Consider.</u>

Staff and RUCO would have the Commission believe that financial projections regarding the impact of various rate proposals can and should be disregarded by the Commission in reaching a decision in this proceeding. In fact, although the Company's direct testimony and, to a greater extent, its rebuttal testimony discussed in detail the Company's current financial condition, including its credit standing and credit metrics and the impact of various rate proposals on those metrics (*see, e.g.*, APS Exhibit No. 4 at 3-18 [Brandt]; APS Exhibit No. 5 at 6-30 [Brandt]; APS Exhibit No. 23 at 8-34 [Fetter]), no Staff or RUCO witness even bothered to address those issues (except in passing), let alone attempt to rebut them. Indeed, at the outset of this case, RUCO's counsel argued that the Company's discussion of "projected financial results" and the Company's "prefiled testimony . . . about Wall Street rating agencies and their potential reactions to actions of this Commission" were a "novel approach to setting rates" that the Commission should not accept. (Tr. Vol. I at 57-58 [Wakefield]). And Staff counsel similarly argued that the Company's emphasis on "financial forecasts" and "projected financial data" amounts to an "end results analysis" that the Commission has not undertaken in past rate cases and should not engage in now. (Tr. Vol. I at 75, 84 [Kempley]).

The Company disagrees with those contentions by Staff and RUCO. Projected financial information and projected credit rating information are important and relevant indicators for the Commission to consider in assessing the adequacy and reasonableness of a rate increase. Indeed, the Company is required by Commission regulations to provide projected financial information as part of its rate filing, and the Company did so in its original Standard Filing Requirement ("SFR") Schedule F. (Tr. Vol. I at 113-14 [Wheeler]). Moreover, the consideration of such projected financial information by the Commission is not only appropriate, but also constitutionally mandated in order to ensure that rates are just and reasonable under all the facts and circumstances.

As Staff's and RUCO's own witnesses acknowledged, the concept of just and reasonable rates can be achieved through a variety of different approaches (Tr. Vol. I at 75), but all of those different approaches must comport with certain underlying constitutional principles that were articulated by the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1942). (Staff Exhibit No. 8 at 5-7 [Parcell]; RUCO Exhibit No. 11 at 4-5 [Hill]). In the *Bluefield* case, the Supreme Court stated:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, **having regard to all relevant facts**. . . . The return should be reasonably sufficient to assure confidence in **the financial soundness of the utility**, and should be adequate, under efficient and economical management, to **maintain and support its credit** and enable it to raise the money necessary for the proper discharge of its public duties.

262 U.S. at 692-93 (emphasis added). The Court reaffirmed these fundamental principles in the *Hope* case by stating:

> The rate-making process . . . , i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and consumer interests. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be **sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.**

320 U.S. at 603 (emphasis added).

It is obvious that these constitutionally-mandated principles of ratemaking cannot be adequately addressed without consideration of the projected impact of a rate decision on a regulated utility's financial criteria, including its ability to "maintain and support its credit" and to "raise the money" necessary for the further operation of its business. In fact, the law requires that rates be just and reasonable when they are in effect, which necessitates some forward looking and not just rigid adherence to a hypothetical and stale Test Year that has been demonstrated to be unrepresentative of present conditions. *See, Scates v. Arizona Corporation Comm'n*, 118 Ariz. 531, 578 P.2d 612 (Ariz. App. 1978). Perhaps it is true, as Staff and RUCO suggest, that the Commission has not dwelled on these aspects of ratemaking in the past. The Company submits, however, that that was due to the fact that the Company previously was not repeatedly under-earning its allowed ROE, and the Company's cash flow, credit rating and credit metrics have rarely required a detailed analysis of the Company's projected financial data before now to ensure that a ratemaking decision satisfies the underlying constitutional principles. But that does not mean that those fundamental principles should now be ignored.

Indeed, other regulatory commissions often take into consideration the projected impact of a rate decision on a company's financial indicators, particularly the company's credit standing with the major credit rating agencies. (*See, e.g.*, Tr. Vol. XXIV at 4577-78 [Brandt] (citing Tom McGhee, *State Oks Xcel rate hike*, Denver Post, Nov. 21, 2006. Responding to questions about an Xcel Energy settlement agreement (Decision No. C06-1379) that increased rates, PUC Chairman Gregory Sopkin "said a smaller rate increase could damage Xcel's credit rating and increase its borrowing costs."); APS Exhibit No. 23 at 25 [Fetter] (referring to Missouri Public Service Commission ("MPSC") Case No. EO-2005-0329 at 14-15, where the MPSC decided that in making rate decisions for the next several years for Kansas City Power & Light ("KCPL") it will rely on "S&P's publicly-disseminated credit ratio guidelines to ensure that KCPL's key financial measures would remain at levels adequate for its 'BBB' credit ratings."); *see, also,* Tr. Vol. VI at 1284-86 [Fetter]; APS Exhibit No. 23 at 27-28 [Fetter] (noting that last year the Colorado Public Service Commission approved a comprehensive settlement agreement (Decision

No. C06-1379) allowing the Public Service Company of Colorado to peg certain rate increases to that company's "credit quality" rating.); *see, also, e.g., In re Public Service Co. of Indiana*, 72 P.U.R. 4th 660, 677 (Mar. 7, 1986); Cause No. 37414 (taking into consideration the company's S&P and Moody's ratings and the company's need to "have reasonable access to the capital markets to provide for its future capital needs…."); *see, also, In re Commonwealth Edison Co.*, 49 P.U.R. 4th 62, 76 (May 6, 1982); Decision No. 82-0026 (recognizing that a "further downgrading of Edison's credit ratings, particularly as to commercial paper, would immediately restrict Edison's day-to-day financing of all expenditures…."); *see, also, Public Serv. Co. of Colorado v. Publ. Utilities Comm'n of Colorado*, 653 P.2d 1117, 1122-23 (1982)(upholding rate increase where evidence showed that the company's "ability to raise capital was seriously impaired due to decreased earnings and a downgrading of [the company's] rating by both Moody's and Standard & Poors [sic].")).

Simply stated, projected financial information as to the impact of the various rate proposals in this case on the Company's credit ratings and other financial indicators is highly relevant to the Commission's decision and cannot be ignored.

C. <u>There Is A Substantial Risk That APS Will Be Downgraded To "Junk Bond" Credit Status If The Full Rate Increase It Has Requested Is Not Granted.</u>

Recognizing as it must that the Company's projected financial information should be considered at least to the extent of assessing the impact of a rate decision on the Company's ability to "maintain its credit and to attract capital" (*Hope Natural Gas Co.*, 320 U.S. at 603), the Commission must then assess the extent to which the evidence in this proceeding bears on that issue. In this regard, the evidence presented by the Company is substantial and is essentially unrefuted.

In his Direct Testimony, Mr. Brandt (the Company's Chief Financial Officer) explained the current and projected cash flow needs of the Company, the Company's current credit ratings, the extent to which those credit ratings and related credit metrics have declined during the past twelve to twenty-four months, the precarious nature of the Company's current credit ratings, the importance of maintaining and eventually improving the Company's investment-grade credit rating, and the projected credit metrics and other financial indicators under the Company's rate increase proposal. (APS Exhibit No. 4 at 3-31 [Brandt]; *Id.* at Attachments DEB-1 through DEB-4 [Brandt]). Among other things, Mr. Brandt explained that the Company's current rates have not adequately covered all costs of service, that the Company's cash flow and ROE have been impacted significantly by the Company's need to fund a large capital expenditure program averaging $900 million a year for the foreseeable future, and that the Company's rate proposal would only modestly improve the Company's credit metrics over the next few years. (*See, also,* Tr. Vol. IV at 783-84.)

In his Rebuttal and Rejoinder Testimony, Mr. Brandt reinforced the points made in his Direct Testimony and pointed out that the Staff and RUCO rate proposals, if accepted by the Commission, would almost certainly result in APS having its credit rating downgraded to "junk bond" status. (APS Exhibit No. 5 at 3-15 [Brandt]; APS Exhibit No. 6 at 2-14 [Brandt]). As he did in the emergency rate case, Mr. Brandt called upon his more than 22 years of experience dealing with credit rating agencies to estimate for the Commission the risk of a credit rating downgrade under the Company proposal as well as the Staff and RUCO proposals, estimating the risk of a downgrade to junk at about 95 percent for the RUCO proposal, about 85 percent for the Staff proposal (notwithstanding Staff's improved and forward-looking PSA proposal), and even about 15 percent under the Company's proposal. (APS Exhibit No. 5 at 3 [Brandt], *see,* Arizona Public Service Company Risk of Credit Rating Downgrade to Junk, attached hereto as "APS Initial Brief Exhibit 2"). As Mr. Brandt explained, he based these estimates on financial forecasts that he prepared using the same forecasting methodology that the Company uses in the ordinary course of business and in its regular dealings with rating agencies and financial analysts. (Tr. Vol. IV at 769-72).

The financial forecasts for the Company's proposal, Staff's proposal (with projected PSA), and RUCO's proposal were summarized in attachments to Mr. Brandt's Rebuttal Testimony (DEB-1RB through DEB-3RB respectively), and the principal financial assumptions on which those forecasts were based were contained in Exhibits APS-10 and RUCO-2. (Tr. Vol. IV at 770-74). Mr. Brandt explained that, under the Company's proposal, APS's FFO/Debt ratio would be 19.2 percent at year-end 2007, but then trend down to 17.5 percent at year-end 2008 due largely to one undeniable fact: **near-term costs of customer growth are greater than the increased revenues generated by that growth by about $86,000,000 per year at present.** (APS Exhibit No. 5 at 9-10 [Brandt]; *Id.* at Attachment DEB-1RB; Tr. Vol. IV at 782-85; APS Exhibit No. 77.) Similarly, Mr. Brandt explained that, under the Staff proposal (with projected PSA), the Company's FFO/Debt ratio would be 16.4 percent at year-end 2007 and 15.1 percent at year-end 2008; and under the RUCO proposal, the Company's FFO/Debt ratio would be 15.1 percent at year-end 2007 and a mere 12.9 percent at year-end 2008. (APS Exhibit No. 5 at 9-10 [Brandt]; *Id.* at Attachments DEB-2RB and DEB-3RB.) Those forecasted FFO/Debt ratios under the Staff and RUCO proposals (which were never refuted by any Staff or RUCO witness) are well below the 18 percent minimum for APS to maintain an investment grade credit rating under the S&P criteria and the comparable Moody's criteria. And as Mr. Brandt pointed out, both S&P and Moody's have implied that the credit metrics produced by the Staff and RUCO proposals would not be well received from a credit ratings standpoint. (APS Exhibit No. 5 at 13-15 [Brandt]).[5]

Mr. Fetter, a former rating agency executive and a former Chairman of the Michigan Public Service Commission, testified in his Direct Testimony that the uncertainty and unprecedented events in the energy industry during recent years have caused credit rating agencies and the financial community generally to pay even closer attention to a regulated utility's credit metrics and other financial indicators. (APS Exhibit No. 23 at 16-19 [Fetter]). Mr. Fetter went on to explain that regulatory commissions need to engage in "proactive regulatory behavior" (*Id.* at 31-32) to ensure that the closer scrutiny now being given to a regulated utility's financial criteria by rating agencies and the financial community does not result in dire financial consequences for both the utility and its customers – which are exactly the

[5] As Moody's said in its release of May 9, 2006, in which the agency assigned to APS a "negative outlook":

> In light of the 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 Exhibit No. at 14 [Brandt]). (Emphasis added.).

consequences that Nevada Power Company ("Nevada Power") and its customers have had to endure as a result of that company's downgrade to "junk bond" credit rating status several years ago.

More importantly, Mr. Fetter testified in his rebuttal that he independently analyzed APS's financial forecasts for 2006 through 2008, including the forecasts based upon the Staff and RUCO rate proposals. (APS Exhibit No. 24 at 11 [Fetter]). He went on to explain that those forecasts are similar to ones that he has used and relied upon as a regulator and as a ratings agency official. (*Id.*). He then explained that he "utilized the S&P methodology and the [Company's] forecast data" to determine for himself what he described as "the likely credit 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." (*Id.*). His conclusions, similar to those of Mr. Brandt, were: (1) "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;" and (2) "The results under the RUCO case would cause an even more severe negative impact on APS's credit profile, thus also likely driving the Company into below investment-grade or 'junk bond' status." (*Id.* at 12-13). Mr. Fetter then summarized his analysis and findings by stating: "If the Commission were to adopt either the Commission Staff position or the RUCO case, APS's credit ratings would likely suffer a rating downgrade to below investment-grade level." (*Id.* at 14).

Mr. Fetter reinforced his opinions about the likelihood of a downgrade if the Commission accepted either the Staff or the RUCO proposals (or anything close to them) by underscoring the fact that APS currently is rated by S&P at the lowest level of investment grade credit, leaving no margin for slippage given APS's credit metrics remain on the brink of non-investment grade if some other event causes APS's financial metrics or cash flow requirements to change. (APS Exhibit No. 24 at 10 [Fetter]). As Mr. Fetter put it, "BBB-minus is a very dangerous place to be," and he cautioned that APS should not be permitted to "linger" with such a credit rating for very long. (Tr. Vol. VI at 1278). In fact, Mr. Fetter went on to opine that he thought it would be a "close call" for APS to maintain its current investment-grade credit rating even under the

Company's own rate increase proposal:

> I also noted in my testimony and my live answers today that APS's modified position is not an overwhelmingly strong position as shown by this chart, and I believe that APS would be able to maintain its investment grade status. It would be a close call, and I believe that the company, if it survives that close call, will endeavor, hopefully with support from regulators, to improve its credit rating over time higher into the BBB category where, which I view is the minimum level that any utility should operate in within today's current environment.

(Tr. Vol. VI at 1277-78).

This testimony by Mr. Brandt and Mr. Fetter – the two most experienced and knowledgeable witnesses on these issues in this proceeding – is strong evidence that there is a substantial risk that anything less than the rate increase proposed by the Company (and certainly the Staff and RUCO proposals) will result in a credit rating downgrade for APS – a downgrade to non-investment "junk bond" credit rating status.

D. __Quality Of Regulation Is Also A Factor Being Closely Watched In This Proceeding.__

The foregoing discussion of APS's credit metrics and other financial indicators addresses what the rating agencies consider to be the "quantitative" aspects of their credit rating criteria, but those agencies also consider several "qualitative" factors to assess the financial and business risks of a regulated utility and its debt offerings. (APS Exhibit No. 4 at 11-18 [Brandt]; APS Exhibit No. 24 at 3 [Fetter]). One of the most important qualitative factors is regulation. (*Id.*). S&P itself has recently explained the importance of supportive regulation as a factor in affixing a company's credit rating:

> 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.

(*Id.* at 5-6 [Fetter Rebuttal], quoting S&P Research: "New York Regulators' Consistency Supports Electric Utility Credit Quality," August 15, 2005).

Indeed, the importance of regulatory environment in the context of changes to a company's credit rating was underscored last year when S&P downgraded Central Vermont Public Service ("Central Vermont") from BBB to "junk" status based primarily on a single unfavorable rate order by the Vermont Public Service Board. (APS Exhibit No. 42 at 7 [Avera]). In doing so, S&P stated:

> 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.

(*Id.*, quoting Business Wire, *S&P Downgrades CVPS Corporate Credit Rating*, June 14, 2005).

There can be no doubt that the rating agencies are closely and carefully assessing the extent of regulatory support and the consistency of treatment that will be provided to the Company by the Commission in this proceeding. Indeed, the rating agencies have said so. For the most part, the rating agencies viewed the Commission's actions in 2006 (including the acceleration of the 4 mill PSA in January and the added 7 mill interim PSA adjustor in May) to be "generally constructive" and supportive of the Company. (APS Exhibit No. 4 at 14). Nevertheless, S&P cautioned just a few months ago that:

> 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. . . . 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 rates are brought more in line with current costs.

(APS Exhibit No. 5 at 13-14 [Brandt], quoting S&P release dated August 31, 2006, entitled *Summary: Arizona Public Service Co.*).

Moody's has similarly cautioned that its current negative outlook for APS reflects "the potential for downward pressure on ratings if [among other things] outcomes in still pending rate proceedings are not supportive of relatively timely recovery of increased costs." (APS Exhibit No. 5 at 14 [Brandt], quoting Moody's release dated May 9, 2006, entitled *Credit Opinion:*

Arizona Public Service Company).[6]

The Company agrees that the Commission's actions in the past twelve months have been constructive from a ratings standpoint and reasonably supportive of the Company's financial needs. Indeed, the Company has no doubt that the Company's credit rating would be in the "junk bond" category today, but for the actions of the Commission in the past twelve months. But the Company is far from safe from having its credit rating slip into "junk" status if the Commission were to reverse course in this proceeding and reject the Company's rate proposal in favor of something more closely approximating the Staff or RUCO proposals. Such action by the Commission would demonstrate a lack of regulatory support and would produce the very sort of regulatory uncertainty that the rating agencies have said would carry negative rating implications for APS, even apart from APS's quantitative credit metrics.

As Mr. Fetter has said, "nothing should be taken for granted in the current investing environment" (APS Exhibit No. 23 at 24 [Fetter]), particularly where, as here, APS is already in the precarious position of having a near-junk BBB-minus credit rating from S&P and a negative outlook from Moody's. Thus, from a qualitative as well as a quantitative standpoint, the Commission should strive in this proceeding to ensure that APS has rates going forward that are sufficient for the Company to maintain and eventually improve its credit rating.

E. <u>A Downgrade To "Junk Bond" Credit Rating Status Would Be Extremely Detrimental To APS And Even More So To Its Customers.</u>

The adverse consequences of APS having its credit rating downgraded to "junk bond" status would be severe and long term. In his Direct and Rebuttal Testimony, Mr. Brandt cataloged the significant adverse financial impact that such a downgrade would have on APS and its customers, including added financing costs of as much as $1.3 billion over the next ten years, limitations on access to daily liquidity instruments, increased interest rates on the Company's

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[6] It should be obvious that the rating agencies will re-evaluate their ratings and outlooks for APS promptly after the Order in this case is issued by the Commission. As Mr. Fetter has pointed out:

> 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.

(APS Exhibit No. 24 at 15 [Fetter]).

debt, and restricted access to the capital markets due to the inability or unwillingness of many institutional investors to invest in "junk" rated bonds that would potentially prevent APS from raising needed funds for capital expansion and improvement. (APS Exhibit No. 4 at 19-23 [Brandt]; APS Exhibit No. 5 at 15-17 [Brandt]). Mr. Brandt also discussed the impact that a "junk bond" credit rating would have on the Company's energy trading business and its contracts with power suppliers, pointing out that APS would be required to provide collateral or other security for such purchases and might be precluded from obtaining some contracts altogether. (APS Exhibit No. 4 at 22-23 [Brandt]; APS Exhibit No. 5 at 16-27 [Brandt]). All of these consequences of a "junk bond" credit rating were confirmed by Mr. Fetter in his testimony. (APS Exhibit No. 23 at 23 [Fetter]).

These consequences of a downgrade are neither speculative nor overstated. Both Mr. Brandt and Mr. Fetter discussed the examples of Nevada Power and Central Vermont (among others) which, as a result of their slide into "junk" credit status, have been saddled with hundreds of millions of dollars of added costs and significant restrictions on their ability to borrow. (Tr. Vol. VI at 1285-89 [Fetter]; Tr. Vol. IV at 744-45 [Brandt]). In fact, Mr. Brandt testified that recent reports have indicated that the increased financing costs to Nevada Power over just the last five years have already exceeded $1 billion. (*Id.* at 744). In short, everything that Mr. Brandt has said will happen to APS if it were to slip to "junk" credit status has already happened to Nevada Power and the other electric utilities now rated "junk." (Tr. Vol. VI at 1285-89 [Fetter]).

Moreover, recovery from a "junk" credit rating is difficult and slow. Citing again to the examples of Nevada Power and Central Vermont, Mr. Fetter explained:

> [O]nce a company goes below investment grade, it's not like turning on a dime, and the Commission by itself cannot divine decisions that return investment grade immediately. Even if all the parties in this room are in agreement, it could not bring APS back from the fall off the cliff within a day or a month or a week. It's a long process. And Nevada Power is now about three or four years into being below investment grade. Central Vermont Public Service accepts that even with [a] positive regulatory agreement, if approved by the commission, that they are looking at a two to three-year time period to get back. And so it . . . cannot be underemphasized the danger of going below investment grade.

(Tr. Vol. VI at 1288-89; *see, also,* APS Exhibit No. 23 at 24 [Fetter]).

These dangers and the dire consequences of a slide to "junk" credit status were cavalierly dismissed by Staff and RUCO witnesses. RUCO witness Stephen Hill stated that such a result is just "a situation we will deal with when we get there. . . . it's certainly not insurmountable" (Tr. Vol. X at 2130), and Staff witness David Parcell opined that APS's BBB-minus credit rating is "still BBB" and that S&P's "stable" outlook for APS suggests that a downgrade is not in the offing (Tr. Vol. XVII at 3286) (ignoring that APS had a "stable" outlook in December 2005 when S&P downgraded APS from BBB to BBB-minus). Not surprisingly, neither of those witnesses has any experience in dealing with rating agencies and neither did an analysis of the likelihood or the impact of a slide to "junk" status before rendering their unsupported opinions. Thus, the only credible evidence in the record is that a slide to "junk" credit status by APS would be extremely costly and detrimental to APS and its customers, would not be quickly remedied, and would potentially impede APS's ability to finance its huge capital expenditure requirements. As the Commissions in Missouri, Colorado and elsewhere have recently done, this Commission should be proactive and should not disregard the significant adverse implication of a downgrade to "junk" credit status for APS. Simply put, the cost recovery and the ROE that APS seeks as part of its rate request are intertwined with and directly related to the cash flow woes and the under-earnings in recent years that have brought APS to the brink of a "junk bond" credit rating. The Commission should recognize that its rate decision in this proceeding must be sensitive to and address those issues.

F. <u>The 11.5 Percent ROE And The Debt/Equity Ratio Requested By The Company In This Proceeding Are Fair And Reasonable Under All The Facts And Circumstances.</u>

To comport with the constitutional principles articulated in *Bluefield* and *Hope* – and to avoid a downgrade to junk bond status – APS must be authorized a fair rate of return on equity, taking into account the economic requirements necessary to support continuous access to capital, as well as the specific risks and potential challenges for APS. Moreover, the Company's overall return must be calculated based on a reasonable capital structure.

1. An ROE Of 11.5 Percent Is Fair And Reasonable.

In his Direct Testimony, Dr. William Avera recommended that APS be authorized an 11.5 percent ROE. Dr. Avera discussed the relationship between ROE and the preservation of the Company's financial integrity and ability to attract capital, explaining that an inadequate ROE in this proceeding "would further pressure APS's financial flexibility and credit standing." (APS Exhibit No. 41 at 62 [Avera]). Ultimately, he concluded that, based on "capital market expectations, the potential exposures faced by APS, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances," an 11.5 percent ROE would be fair and reasonable for APS at this time. (*Id.* at 74; Tr. Vol. IX at 1859-63 [Avera]).

a. Dr. Avera Used A Comprehensive Methodology To Determine A Fair And Reasonable Recommended ROE Of 11.5 Percent.

To arrive at his 11.5 percent ROE recommendation, Dr. Avera applied the Discounted Cash Flow ("DCF") model, risk premium methods, and the comparable earnings method to a proxy group of other electric utilities operating in the Western United States. Dr. Avera concluded that a fair and reasonable cost of equity range was 10.8 percent to 11.8 percent. (APS Exhibit No. 41 at 56 [Avera]). Dr. Avera incorporated a 20 basis-point allowance for equity flotation costs, resulting in a range of 11.0 - 12.0 percent, and concluded that the midpoint of 11.5 percent represented a reasonable rate of return on common equity for APS. (*Id.* at 56-61).

Under Dr. Avera's analysis, the DCF model implied a cost of equity of 9.0 percent. Dr. Avera identified the limitations of the DCF model, however, noting that it would be unreasonable to establish an ROE based on the DCF approach alone because "it is a blunt tool" and does not necessarily capture long-term expectations for the industry. (*Id.* at 42).

Given the limitations of the DCF model, Dr. Avera also used the risk premium method, which "directly estimates investors' required rate of return by adding an equity risk premium to observable bond yields," in contrast to DCF models, "which directly impute the cost of equity." (*Id.* at 43-53). Dr. Avera also evaluated the cost of equity using the comparable earnings method, which refers to rates of return available from alternative investments of comparable risk.

(*Id.* at 53-55). Both of these methods implied a fair rate of return on equity far higher than the DCF model, ranging from 11.0 percent - 12.6 percent. (*Id.* at 53, 55). Given that the DCF result was out of line with the preponderance of estimates produced by these other methods, Dr. Avera concluded that the appropriate range was 10.8 - 11.8 percent, with an additional 0.2 percent for flotation costs.

b. The Staff's Recommended ROE Of 10.25 Percent And RUCO's Recommended ROE Of 9.25 Percent Are Downward-Biased And Based On Technically Flawed Analyses.

Despite the fact that the Staff and RUCO agree with APS that a utility's ability to attract capital must be considered in establishing a fair rate of return, the Staff recommends a downward-biased ROE of 10.25 percent and RUCO recommends an untenable ROE of 9.25 percent.

Various benchmarks show that both of these recommendations fail to pass the threshold test of reasonableness required by established regulatory and economic standards governing a fair rate of return on equity. (APS Exhibit No. 42 at 2-11 [Avera]). First, the rates of return on common equity authorized electric utilities by regulatory commissions were 10.69 percent for electric utilities in the second quarter of 2006 and 10.57 percent for the year as of September 15, 2006. (*Id.* at 8). Using the groups of firms identified as most comparable to APS by Mr. Hill and Mr. Parcell, the two groups of firms were authorized an average ROE of 10.89 percent and 10.91 percent respectively. (*Id.* at 9; *Id.* at WEA-1RB). Second, Value Line reported as of September 1, 2006, that electric utilities as a whole are anticipated to earn a return of at least 10.5 percent from 2007 through 2011. (APS Exhibit No. 42 at 9 [Avera]). And Lehman Brothers projected that in 2007 the electric utility industry would be granted allowed rates of return that averaged 11.3 percent in order to keep pace with the market as a whole. (AUIA Exhibit No. 1 at 28 [Cannell]).[7]

In addition to recommending returns below the average that other commissions have been

[7] Along these lines, the Commission can take administrative notice that, on December 21, 2006, the Missouri Public Service Commission issued its order in the Kansas City Power & Light rate case (Great Plains Energy) allowing a rate of return of 11.25 percent (on an equity ratio of 54 percent), notwithstanding testimony of staff witnesses who recommended an ROE range of 9.32-9.42 percent. (*See,* Credit Suisse Release: *Great Plains Energy*, December 22, 2006, attached hereto as "APS Initial Brief Exhibit 3").

allowing utilities in recent months and are expected to allow in 2007, the Staff and RUCO witnesses based their ROE's on flawed analyses. Staff witness David Parcell based his results on his application of the constant growth DCF model, Capital Asset Pricing Model ("CAPM"), and comparable earnings approaches. (APS Exhibit No. 42 at 11 [Avera]). Dr. Avera identified many errors in Mr. Parcell's analysis, including problems with the following: the criteria Mr. Parcell used to define the proxy group in his analysis; his biased application of the DCF model; and his use of historical (rather than projected) rates of return and geometric (rather than arithmetic) means in applying the risk premium approach. (*Id.* at 11-31).

Indeed, Dr. Avera noted – and no other witness disputed – that based on the methodologies recently applied by ACC Staff witness Dennis Rogers in his January 16, 2006 testimony in Docket No. W-01303A-05-0405 and adopted by the Commission in its July 28, 2006 decision, the average cost of equity for Mr. Parcell's reference group is 11.20 percent before consideration of flotation costs. (*Id.* at 19-28; APS Exhibit No. 43 at 8 [Avera]). Thus, once the errors in Mr. Parcell's analysis are corrected, the average cost of equity falls squarely within the 11.0 - 12.0 percent range recommended by Dr. Avera.

While the Staff's recommended ROE of 10.25 percent is downward-biased because of the flaws discussed above, RUCO's recommended ROE of 9.25 percent is "completely outside a reasonable range and is entirely inconsistent with mainstream benchmarks." (APS Exhibit No. 42 at 23 [Avera]). RUCO witness Stephen Hill relied solely on a constant growth DCF model, which has been recognized as fallible and misleading by regulators across the country, including Texas, Florida, Pennsylvania, Iowa, Alaska, and the Federal Communications Commission. (*Id.* at 46-48.) Moreover, applying the multi-stage DCF model that recently was adopted by the Commission results in an average cost of equity of 10.7 percent for Mr. Hill's same reference group, showing that his application of the DCF model produces downwardly biased and even illogical results. (*Id.* at 48; *Id.* at Attachment WEA-15RB.) These errors, among others, resulted in a single-digit ROE – which Mr. Hill admits is low (RUCO Exhibit No. 11 at 7 [Hill]) – that falls completely outside of a fair and reasonable range. Indeed, Mr. Hill admitted that he could not identify a single instance in the last year and a half in which any regulatory commission anywhere in the country had allowed a rate of return as low as his recommended 9.25 percent in this case. (Tr. Vol. IX at 2035 [Hill]).

2. APS's Proposed Rates Support A Capital Structure – Including A 46/54 Debt/Equity Ratio – Necessary To Maintain An Investment Grade Rating.

APS must maintain a strong financial profile to ensure access to the capital markets as the Company finances the capital expenditures required to meet the growing energy needs of its customers and to avoid a downgrade to junk status. As explained above, APS's proposal supports the capital structure necessary to keep the Company's financial metrics sufficiently strong to maintain an investment grade credit rating. In contrast, when viewed in the aggregate, APS's financial metrics would fall far below the minimum levels required to maintain investment grade ratings under either the proposed rates of the Staff and RUCO.

Mr. Brandt explained that to maintain an investment-grade credit rating, S&P requires a company like APS to maintain a Debt/Capital ratio of 48 – 58 percent. (APS Exhibit No. 5 at 9 [Brandt]). Under APS's proposal, APS's Debt/Capital ratio would move from 54.6 percent at year-end 2006 to 52.1 percent by 2007. (*Id.* at 6; *Id.* at Attachment DEB-1RB [Brandt]) While Staff witness Parcell accepted APS's recommendation for a 46/54 Debt/Equity ratio, RUCO witness Hill opined that a 50/50 Debt/Equity ratio for the Company would suffice. (Tr. Vol. X at 2127 [Hill]; Tr. Vol. XVII at 3272-3[Parcell]).

Mr. Hill's "phantom capital structure" ignores APS's current reality. (APS Exhibit No. 42 at 2 [Avera]). First, Mr. Hill contends that APS's requested capital structure is different than its historical capitalization (which is not true). But historical ratios do not provide a basis for determining a reasonable capitalization for APS going forward given the Company's weakened credit ratings and the challenges of raising the capital necessary to support its capital expenditure requirements. (*Id.* at 64-65; APS Exhibit No. 6 at 19 [Brandt]). Second, Mr. Hill contends that APS's requested capitalization is not consistent with industry benchmarks. As Dr. Avera testified, Mr. Hill's analysis of industry capitalization ratios erroneously includes short-term debt and also includes the financial ratios of utilities with junk ratings, severely distorting his results. (APS Exhibit No. 42 at 66-69 [Avera]).

As Dr. Avera explained in his rebuttal, the decision by S&P and Fitch Ratings ("Fitch") to downgrade Central Vermont to below investment grade highlights the importance of maintaining sufficient common equity to preserve a utility's creditworthiness. Although Central Vermont's equity ratio exceeded 60 percent, the ratings agencies determined that the company's financial position was inadequate to support an investment grade rating. (APS Exhibit No. 42 at 68-69 [Avera]).

In today's capital environment and in APS's current growth cycle, a 50/50 Debt/Equity ratio would result in a financially weaker APS and would undoubtedly reduce the Company's credit metrics to non-investment grade. (APS Exhibit No. 6 at 19 [Brandt]). A 46/54 Debt/Equity ratio, as proposed by APS and as accepted by Staff, is more appropriate and more consistent with APS's current financial situation.

G. <u>APS Is Being Deprived Of A Reasonable Opportunity To Earn Its Allowed ROE Because Of Attrition Of Earnings Stemming From The Lag In Recovering Capital Expenditures.</u>

APS has demonstrated that it has substantially under-earned its allowed ROE for the last several years. (*See,* Arizona Public Service Company Return on Equity Twelve-Month Period Ended March 31, 2003 to June 30, 2006, attached hereto as "APS Initial Brief Exhibit 4"; *see, also,* APS Exhibit No 5, Attachment DEB-10RB [Brandt]). Indeed, the evidence shows that, over the more than three year period from March 31, 2003 to June 30, 2006, APS consistently under-earned its allowed rate of return by as much as half, resulting in a $134,000,000 **annual** earnings deficit as of June 30, 2006, relative to APS's current allowed rate of return of 10.25 percent. (*Id.*). Over this period, APS's actual ROE eroded from 8.4 percent for the twelve months ended March 31, 2003, to 5.7 percent for the twelve months ended June 30, 2006. (*Id.*).

The reasons for this earnings shortfall are both obvious and undisputed – the need for APS to fund a huge capital expenditure program in recent years, coupled with the regulatory lag in recovering those expenses as part of rate base, has prevented APS from maintaining a level of earnings commensurate with its allowed ROE. (APS Exhibit No. 4 at 29-31 [Brandt]). Even Staff and RUCO witnesses agreed (or at least could not deny) that this "attrition" of earnings resulting from the lag in recovering capital expenditures was causing APS to under-earn its allowed rate of return. As Staff witness David Parcell testified:

> Q. Do you have any reason to believe that APS is not going to continue to under earn the way it has [as shown] on this [Don Brandt] ROE chart . . .?
>
> A. I have no reason to believe that APS would necessarily earn its authorized rate of return. . . .

(Tr. Vol. XVII at 3267 [Parcell]).

Similarly, RUCO witness Stephen Hill testified:

> Q. You do not deny, do you, sir, that the phenomenon of attrition prevents APS from earning its authorized rate of return under current circumstance, correct?
>
> A. Well, I think I said yesterday that I haven't confirmed Mr. Brandt's projections, so I really can't confirm or deny that. But we will certainly agree with you that that could be the case.

(Tr. Vol. X at 2090-91[Hill]).

Under these circumstances, the constitutional requirement that APS be given a reasonable opportunity to earn a fair return on its invested equity is undermined. *See, Bluefield,* 262 U.S. at 692 ("A public utility is entitled to such rates as will permit it to earn a return on the value of property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties"). Knowing that the regulatory process in Arizona can entail at least a year or two before a new rate order is implemented, it is not enough to suggest that APS need only file another rate case in order to timely recover capital expenditures and thereby avoid the effects of earnings attrition. In the wake of compelling evidence in this proceeding that APS has consistently under-earned its allowed ROE and will continue to do so for the foreseeable future because of the attrition of earnings resulting from huge capital expenditures, the Company submits that the Commission should take appropriate measure to limit the impact of such earnings attrition and thereby afford the Company a reasonable opportunity to earn its allowed ROE.

H. The Commission Should Consider The Rate Adjustment Mechanisms Proposed By The Company, Including CWIP In Rate Base, Accelerated Depreciation, An Attrition Allowance And/Or A Higher Return On Fair Value Rate Base.

Within the constitutional framework that requires that APS be allowed to recover its costs of service and be given a reasonable opportunity to earn a fair rate of return on its invested equity, the Commission certainly has broad discretion to determine how to achieve those goals. In his letter to the Company dated July 21, 2006 (APS Exhibit No. 5, Attachment DEB-11RB [Brandt]), Chairman Hatch-Miller seemed to recognize that point by requesting that the Company provide the Commission with testimony "on what measures the Commission could take" to help APS "gradually improve its creditworthiness" and ensure that the Company and its customers are not saddled with the added financing costs and possible capital expenditure ("CAPEX") disruptions that would result from a downgrade of APS to "junk" credit status.

In response to that letter from the Chairman, APS submitted with its Rebuttal Testimony of Mr. Wheeler, Mr. Brandt and Dr. Avera several measures for the Commission to consider (apart from the Company's rate proposal itself) that would address the Company's ongoing cash flow problems and the earnings attrition that result from the delay in recovering large capital expenditures. These measures included: (1) inclusion of construction work in progress ("CWIP") in rate base; (2) allowance of accelerated depreciation; (3) an attrition allowance to give the Company an opportunity to earn its allowed ROE, and (4) an increased return on "fair value" rate base. The Company submits that the Commission, consistent with the purpose and intent of the Chairman's July 21 letter, and in any event, should consider implementation of each of these measures in this case, not as additions to the rate increase requested by the Company, but rather as alternatives (in the event that any portion of the Company's rate request is not granted) to ensure that the Company's cash flow and permitted earnings do not continue to lag far behind that to which the Company needs and is constitutionally entitled.[8]

[8] The benefits of these suggested measures were well summarized by Mr. Fetter:

1. CWIP In Rate Base.

As of June 30, 2006, the Company's CWIP accounts included $261 million of generation and distribution plant expenditures. (APS Exhibit No. 24 at 17-18 [Fetter]). By placing these amounts in rate base, the Company would obtain cash flow to pay the financing costs it currently incurs on these existing expenditures. (APS Exhibit 5 at 25 [Brandt]). Specifically, inclusion of $261 million of CWIP in rate base would increase APS's annual revenue by $33 million. (*Id.* at 25-26). This additional $33 million in annual revenue would generate for the Company after taxes a total of $20 million in positive cash flow annually. (*Id.*). As a result, the Company's FFO/Debt ratio would improve by an additional one-half percent in each of the next several years. (*Id.* at 27). Moreover, the inclusion of CWIP in rate base would not only improve the Company's credit metrics but would also reduce future revenue requirements from customers. (*Id.*).

Including CWIP in rate base does **not** increase the Company's earnings. (APS Exhibit No. 5 at 26 [Brandt]). As Mr. Brandt explained, because the Company would stop accruing Allowance for Funds Used During Construction ("AFUDC") on the CWIP investments that are placed in rate base, the loss of AFUDC would offset the earnings from the additional revenue generated by the CWIP inclusion. (*Id.*). In other words, inclusion of CWIP in rate base improves the Company's cash flow and credit metrics without increasing the Company's earnings.

Inclusion of CWIP in rate base is not a new concept. It has been utilized by this Commission in the past (Tr. Vol. I at 106 [Wheeler]; APS Exhibit No. 5 at 25 [Brandt]) and by other regulatory commissions when, as here, large capital expenditure obligations have the effect of eroding a company's current cash flow and, thereby, negatively impacting the company's

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> 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. . . . Arizona is competing with other jurisdictions all the time [for investment funds]. Competitiveness in this context is measured by fair returns and timely processes.

(APS Exhibit No. 24 at 17-18 [Fetter]).

FFO/Debt ratio. For example, Mr. Fetter discussed the decision last year by the Colorado Public Utility Commission to allow Public Service Company of Colorado (Decision No. CO6-1379) to include CWIP in rate base and the decision just a few months ago by the Missouri Commission (Case No. EO 2005-0329) to allow KCPL to include CWIP in rate base – both for the stated purpose of improving current cash flow and related credit metrics of those companies while they undertake much smaller capital expenditure programs than APS must undertake. (APS Exhibit No. 23 at 25-28 [Fetter]). Commenting on this CWIP decision by the Colorado Commission, S&P applauded the forward thinking of the Colorado Commission, and went on to state:

> This is a major step forward in eliminating the tug-of-war over cost recovery that, in the past, has plagued the credit of so many utilities when the time comes to build again.

(APS Exhibit No. 23 at 28 [Fetter Direct], citing *S&P Research: PS Colorado Garners Support for Credit Quality Up-Front; a Viable Model for the Electric Industry*, March 29, 2005).

Given the extraordinary circumstances in which the Company now finds itself – a credit rating on the brink of "junk" status due to lingering cash flow and earnings shortfalls – the inclusion of CWIP in rate base is a sensible (albeit limited) step by the Commission to protect the creditworthiness of the Company and prevent needless added financing costs for the Company's customers. No party to this proceeding has presented any contrary evidence or arguments.

2. Accelerated Depreciation.

Like the inclusion of CWIP in rate base, an allowance for accelerated depreciation is a sensible regulatory measure to help improve the Company's cash flow, and, therefore, the Company's creditworthiness, without increasing the Company's earnings as a result.

Total Company depreciation expense in the September 30, 2005 Test Year was approximately $350,000,000 per year after pro forma adjustments. (APS Exhibit No. 5 at 24 [Brandt]). With projected capital spending of about $900,000,000 per year for the next three to five years, the imbalance between expenditure and recovery – averaging about $550 million per year – contributes dramatically to the financial strain on the Company's creditworthiness because the Company must finance this "gap" in the capital markets. (*Id.*). Accelerating some of this depreciation expense has the beneficial impact of increasing cash flow, thereby increasing FFO. (*Id.*). For example, an allowance of $50,000,000 per year in accelerated depreciation would generate about $30,000,000, after income taxes, of additional positive cash flow, which would have the effect of improving the Company's FFO/Debt ratio by about seven-tenths of a percent in each of those years. (*Id.* at 25).

Even Staff witness Dittmer seemed to acknowledge the benefits of an allowance for accelerated depreciation as a means of improving cash flow without simultaneously increasing the Company's earnings:

> Because there would be an increase in the recording of depreciation expense that would be equivalent to the increase in revenues being collected, the Company would not experience any reduction in earnings attrition. However, depreciation is a "non-cash" expense. Accordingly, the recovery of depreciation expense on an accelerated basis **would improve the Company's cash flow metrics**.

(Staff Exhibit No. 37 at 16 [Dittmer]). (Emphasis added).

In short, APS's earnings would remain the same with an allowance for accelerated depreciation, but the Company's cash flow and credit metrics would improve. (APS Exhibit No. 6 at 16 [Brandt]). As such, an allowance for accelerated depreciation – like the inclusion of CWIP in rate base – is a sound regulatory measure for helping to improve APS's creditworthiness while also potentially saving money for customers if its use helps to avoid a slide by APS into "junk bond" credit status.

3. Attrition Allowance.

As discussed above, APS has consistently and substantially under-earned its allowed ROE over at least the last three to four years, and the reason is the lag between the Company's need to expend huge sums for expansion of plant and equipment to meet the needs of a rapidly growing customer base and the eventual recovery of those sums in future rate base adjustments approved by the Commission. (*See, also,* APS Exhibit No. 5 at 28 [Brandt]). This so-called "regulatory lag" (APS Exhibit No. 2 at 13-14 [Wheeler]; Tr. Vol. I at 105) is particularly detrimental to earnings where, as here, current rates are based on a historical Test Year even though substantial capital expenditures are projected for the years when the rates will be in effect. (APS Exhibit No. 2 at 14-16 [Wheeler]).

As a preliminary matter, it should not be assumed that a company's level of earnings is not related to its creditworthiness and its perceived business risk among investors in debt securities. As both Mr. Brandt and Mr. Fetter explained, a company that consistently under-earns its allowed ROE is perceived to be riskier from a debt-security standpoint because there is added cash flow pressure and less margin available for payment of principal and interest on debt obligations if the company runs into financial difficulties. (APS Exhibit No. 6 at 33 [Brandt]; APS Exhibit No. 24 at 9 [Fetter]). As Mr. Fetter put it:

> 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.

(*Id.* at 9).[9]

Having established – without dispute by any party – that the lag in recovering large capital expenditures has caused APS to substantially under-earn its allowed ROE in recent years and that such earnings attrition will continue into future years as the Company's capital expenditure obligations increase, an attrition allowance added to the Company's revenue requirements in this proceeding is both fair and appropriate. Indeed, with undisputed evidence in the record that the Company will not actually earn the allowed ROE set by the Commission in this proceeding, it raises serious constitutional issues for the Commission to ignore an attrition allowance under these circumstances. As the Arizona courts have stated:

> [T]he 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.**

[9] In this regard, RUCO witness Stephen Hill was just flat wrong when he testified that a company's allowed ROE or actual equity earnings do not influence the decisions of credit rating agencies. As recently as September 2006, S&P made it clear that its credit determination:

> . . . focuses on the willingness and ability of regulation to provide cash flow and earnings quality adequate to meet investment needs, **earnings stability** through timely recognition of volatile cost components such as fuel, **and satisfactory returns of invested capital and equity**.

(APS Exhibit No. 6 at 13-14 [Brandt], quoting S&P Research: *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*, September 14, 2006).

Scates v. Arizona Corporation Comm'n, 118 Ariz. 531, 533-34, 578 P.2d 612, 614-15 (Ariz. App. 1978).

Certainly, setting an allegedly "reasonable" ROE that the Commission knows (or reasonably should know) cannot actually be earned under present circumstances fails the constitutionally-mandated "reasonableness" standard.[10]

In this instance, the Company has proposed an earnings attrition allowance of 1.7 percent to 4.1 percent, to be added to the Company's allowed ROE, depending on the amount of the rate increase granted by the Commission. (Tr. Vol. II at 407-412 [Brandt]). This proposed range of attrition allowances was calculated based on the expected percentage amount by which the Company will under-earn its allowed ROE in years 2007 and 2008 due to the above-described regulatory lag associated with the Company's planned capital expenditures during those years. (*Id.*). In other words, simple math determines that, under present circumstances, APS will not have an opportunity to earn its allowed ROE unless the Commission adds the attrition allowances discussed above. Moreover, adding such an attrition allowance does not increase the Company's earned ROE to a level higher than the cost of capital, as found by the Commission, but rather allows the Company the opportunity to earn the cost of capital to which it is entitled.

4. Adjustment to Return on Fair Value.

If the Commission is unwilling to address the Company's critical need for its requested additional revenues through one or more of the above techniques, there remains one other avenue of relief. The Commission has historically set the return on "fair value" rate base to produce the utility's weighted cost of capital. However, the Commission has likewise made it clear that such a return on "fair value" is the minimum reasonable return under Arizona's Constitution, thus clearly allowing the Commission to establish a higher return if such is necessary to produce "just and reasonable" rates. (Decision No. 53537 [April 27 1983]; APS Exhibit No. 2 at 19 [Wheeler]).

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[10] The downward trend of the Company under-earning its allowed ROE over the last five years, even apart from the attrition projections for future years, is strong evidence that the Company does not have a reasonable opportunity to earn its allowed ROE because of large capital expenditure commitments. *See* the chart at page 71 of DEB-10RB which discloses that the Company's adjusted ROE has fallen from 15.1 percent in 2001 (a year in which the Company lowered rates pursuant to an ACC Order) to 7.2 percent in 2003 and then to 5.7 percent as of June 2006. (*Id.* at 4).

IV.
BASE FUEL COST AND POWER SUPPLY ADJUSTOR

It is important to note what is NOT at issue in this matter. First, no party has suggested, let alone recommended, that the PSA be eliminated or weakened. Second, ALL the parties submitting testimony relative to the PSA have either proposed or supported changes to the mechanism to enhance the timely and full recovery by APS of prudent fuel and purchased power costs. And third, ALL such parties have recommended a significant increase in the Base Fuel Cost used to determine the level of fuel cost deferrals authorized under the PSA.

The Company itself has proposed several structural changes to the existing PSA, both as originally approved in Decision No. 67744 and as modified by Decision No. 68437 (February 2, 2006). These are set forth at page 22 of the Direct Testimony of Donald G. Robinson (APS Exhibit No. 7) and include:

1) Elimination of the Total Fuel Cost Recovery Cap of $776.2 million established by Decision No. 67744 (and which has been effectively suspended by Decision Nos. 68437 and 68685 pending the resolution of this case);

2) Elimination of the four mill cumulative "lifetime" cap on the Annual PSA Adjustor and its replacement with a four mill annual cap;

3) Elimination of the 90/10 cost sharing mechanism established by Decision No. 67744 for the following elements of fuel and purchased power costs:

    a. the costs of renewable energy acquired from third parties and not otherwise recoverable under the Environmental Portfolio Standard/Renewable Energy Standard; and

    b. the demand component of any long-term purchased power agreement acquired via a competitive procurement process;

4) Removal of 10 percent of hedging gain/losses from the 90/10 sharing, thus effectively increasing the sharing of such gains/losses to 80/20; and

5) Elimination of the requirement for mandatory PSA surcharge applications whenever the level of deferrals reaches $100,000,000.

In addition to these structural changes to the PSA, APS seeks to increase the Base Fuel Cost to 3.2491¢/kWh to reflect estimated 2007 fuel and purchased power costs. (APS Exhibit No. 18 at 2 [Ewen]). APS is further asking to add the Federal Energy Regulatory Commission

("FERC") Fuel Account No. 557 (Broker Fees) to the costs recoverable through the PSA. (APS Exhibit No. 16 at 10-11 [Ewen]; Tr. Vol. XXIII at 4438-39 [Ewen]). Such broker costs were excluded from the PSA in Decision No. 68437 for reasons that do not exist in this proceeding, as will be discussed below, and their continued exclusion from the PSA would result in the complete disallowance of what no party has contested is not a prudent and reasonable cost of acquiring fuel and purchased power.

A. Base Fuel Cost.

APS has calculated its proposed Base Fuel Cost using the methodology suggested by Staff witness Antonuk for determining 2007 fuel and purchased power costs. (APS Exhibit No. 18 at 4-5 [Ewen]). In his Supplemental Testimony, Mr. Antonuk agreed that the 3.2491¢/kWh figure was a reasonable estimate of 2007 fuel and purchased power costs. (Staff Exhibit No. 30 at 23 [Antonuk]). Unlike the Base Fuel Cost proposals in the Company's Direct and Rebuttal testimonies APS has not annualized price changes scheduled to take effect in 2007 nor has it annualized generation levels for end of year customers. Both these omissions reduced the 2007 Base Fuel Cost compared to the methodology used by APS in its prior testimony and used by the Commission in establishing the Base Fuel Cost in Decision No. 67744. For this reason, APS believes a Base Fuel Cost of 3.2491¢/kWh is a very reasonable, even conservative, estimate of what fuel costs will be in 2007.

Moreover, the 3.2491¢ figure is an annual average cost that includes the lower fuel and purchased power costs generally incurred by APS during the non-summer months of the year. (APS Exhibit No. 105 at 5). As shown in APS Exhibit No. 105, costs during the peak use months of 2007 would be 3.6915¢/kWh. (*Id.*). Assuming the Company's proposed Base Fuel Cost was adopted effective May 1, 2007, APS still projects an unrecovered balance of 2007 fuel and purchased power costs of $58 million.

RUCO, AECC and Staff have all proposed lower Base Fuel Costs. In part, the differences reflect the use of staler prices (November 30, 2005, in the case of RUCO and February 28, 2006, in the case of AECC), but a more significant distinction is that they reflected estimates of costs for 2006 rather than the period rates established in this proceeding which will actually become effective.[11] If these lower Base Fuel Costs are adopted without simultaneous adoption of the Staff's proposed prospective adjustor, annual PSA deferrals at 2007 levels would increase by roughly $30 million for every mill that the Base Fuel Cost is set below 3.2491¢/kWh. The required adjustments to the PSA in 2008 would be increased by the same amounts.

Under Staff's recommendation, the problem of massive under-collections of 2007 fuel and purchased power costs, estimated at approximately $130 million, is addressed by simultaneously implementing a forward-looking PSA adjustor equal to the difference between Staff's Base Fuel Cost of 2.7975¢ and the 2007 figure of 3.2491¢ – the APS Rejoinder recommendation to which Mr. Antonuk agreed in his Supplemental Testimony. (APS Exhibit No. 17 at 7 [Ewen]; Tr. Vol. XXIII at 4441-4442 [Ewen]; Staff Exhibit No. 30 at 23 [Antonuk]). Although mathematically identical to the Company's proposal, APS sees no purpose served by deliberately understating the Base Fuel Cost. Even if Staff's entire PSA structure is to be adopted, there was some continued lack of clarity concerning the procedural details of how the so-called "forward element" of the Staff PSA would be established for 2008. Using the Company's Base Fuel Cost of 3.2491¢/kWh would obviate the need for setting a "forward component" to the PSA in 2007, or more precisely, that "forward component" could be set at zero. (Tr. Vol. V at 109 [Ewen]). Between the time a decision is made in this proceeding and the Fall of 2007, the procedural details of implementing the Staff's PSA proposal going forward can be fleshed out prior to any filing for a PSA "forward component" to be applicable in 2008.[12]

The RUCO proposal of 3.1202¢/kWh is the same as the Company's originally recommended Base Fuel Cost of 3.1904¢, adjusted for the withdrawal of the APS proposal to increase the sharing of hedging gains and losses. (RUCO Exhibit No. 21 at 1 [Hornby]). Although relatively close to the Company position, RUCO's Base Fuel Cost would still result in

[11] The Staff calculation of Base Fuel Costs for 2006 has other inaccuracies, such as the inclusion of non-recurring revenues that have already been credited to the 2006 PSA deferral accounts and its reflection of the reduced fuel costs attributable to the Company's approved DSM programs, while at the same time other Staff witnesses were rejecting the corresponding revenue adjustment.

[12] As of the filing of this Initial Post-Hearing Brief, Staff has not filed a revised Plan of Administration ("POA") to implement its PSA proposal as amended by the testimony of Staff withness Antonuk. However, with the changes suggested in this Section of the Company's Initial Post-Hearing Brief, APS believes the Commission can and should approve either the Staff POA or the Company's POA to with no Party has expressed any exception to other than the substantive dispute between APS and AECC over proposed changes to the 90/10 penalty provision.

many millions of dollars in unnecessary PSA deferrals in 2007, with additional interest, all of which would then be passed on to customers in 2008.

The AECC position on Base Fuel Cost (2.9419¢/kWh) is premised on using the estimates of 2006 fuel costs presented during the emergency rate case proceeding. (AECC Exhibit No. 4 at 6 [Higgins]). Although there has been significant price volatility since the February 28, 2006 date used for the emergency rate case estimate, the primary reason the AECC proposal so significantly understates 2007 fuel and purchased power costs is that, like Staff's Base Fuel Cost, it is mired in 2006 data that ignores the higher utilization of gas generation and purchased power in 2007, including the recently executed contracts resulting from the RFP referenced in the 2004 APS Settlement and Decision No. 67744, as well as other contractual price changes in 2007. (*See, Id.* at 6; APS Exhibit No. 17 at 8-9 [Ewen]).

B. <u>PSA.</u>

1. 90/10 Sharing.

The need to establish an accurate Base Fuel Cost is heightened to the extent the Commission retains significant elements of the present 90/10 sharing. In practice, the 90/10 sharing feature has served as a penalty provision that automatically denies APS's recovery of 10 percent of its increased fuel and purchased power costs. (APS Exhibit No. 8 at 7 [Robinson]). Mr. Antonuk, the Staff's consultant on PSA issues, agreed that the 90/10 sharing feature would result in the non-recovery of costs APS would reasonably expect to occur. (Tr. Vol. XXII at 4149 [Antonuk]).

Staff's PSA proposal would completely eliminate the 90/10 penalty provision. Mr. Antonuk described it as a "blunt instrument" at best with regard to providing an incentive, and he suggested that the Commission focus in on the "drivers" of fuel cost. (Tr. Vol. XXI at 3896). APS believes Staff has made a valid point and that, rather than attempt to modify the 90/10 provision to alleviate some of its most obvious inequities, eliminating it is appropriate, especially in view of the findings by Liberty Consulting and R.W. Beck concerning the overall prudence and effectiveness of the Company's fuel procurement and hedging practices. (Staff Exhibit No. 33 at 6-7 [Fuel Audit]; APS Exhibit No. 72 at 5-1 through 5-4 [R.W. Beck]).

Although the APS proposed changes to the PSA did not eliminate this penalty feature, it would somewhat ameliorate its punitive impact both through the establishment of a realistic Base Fuel Cost and the exclusion from the sharing mechanism of two specific categories of purchased power costs. The most significant of these is the fixed or demand element of long-term Purchase Power Agreements ("PPAs") acquired through competitive procurement. (APS Exhibit No. 7 at 25 [Robinson]). APS is also asking that renewable energy purchases not otherwise recoverable through the EPS/RES be excluded. (*Id.* at 24-25).[13]

The rationale for excluding the former category of purchased power costs is simple. APS has, through the competitive procurement process, already received the best deal available. Although the variable portion of a PPA (which would remain subject to 90/10 sharing) can be affected, at least marginally, by APS dispatch and gas procurement policies, the demand component is fixed. Thus, there can be no further action by APS to reduce that cost component. Clearly, in such instances, the application of any manner of sharing mechanism is no more than a penalty for entering into PPAs with demand cost components, irrespective of their overall economics for APS customers. (*Id.* at 8).

Renewable resources have been and should continue to be encouraged by the Commission as a matter of public policy. These resources are generally higher cost than so-called conventional resources, and, thus, it is patently unfair to penalize the Company for 10 percent of such additional costs. (*Id.* at 24-25).

RUCO supports this change to the PSA. (RUCO Exhibit No. 26 at 17-18 [Diaz Cortez]). Staff has suggested that the entire 90/10 sharing arrangement be abandoned; thus, APS would assume that Staff would also support the Company's position on this issue even if other elements of its PSA proposal were not adopted by the Commission.

AECC opposes any modification of the 90/10 sharing on the grounds that no exceptions were made in the original 2004 APS Settlement. (AECC Exhibit No. 4 at 15-16 [Higgins]). AECC does not contend that the 90/10 provision, at least as applied to these two categories of PPA costs, is an effective "incentive" to APS for further cost containment. Neither does AECC

[13] Obviously, both these proposals are moot if the 90/10 penalty provision is removed, as has been suggested by Staff.

dispute the testimony by APS that both cost elements have become significantly larger components of overall fuel and purchased power costs as a direct result of other elements to the 2004 APS Settlement and Decision No. 67744. (APS Exhibit No. 8 at 7-8 [Robinson]). Finally, AECC itself has suggested changes to the rate design agreed to in the Settlement (as is its right) and, thus, its contention that the 90/10 penalty provision to the PSA is somehow sacrosanct rings particularly hollow. (*Id.*).

2. Broker Fees.

APS and each of the other parties[14] have included approximately $200,000 in broker fees in their calculation of Base Fuel Cost. (Tr. Vol. XXIII at 4438 [Ewen]). It is undisputed that such fees are a legitimate cost of acquiring fuel and purchased power for the benefit of APS customers. (Tr. Vol. XXI at 4010 [Antonuk]). Staff has proposed that such costs nevertheless be excluded from the costs recoverable through the PSA. (Staff Exhibit No. 30 at 8 [Staff PSA Plan of Administration]; Tr. Vol. XXI at 4010 [Antonuk]). This has the effect of not only denying to the Company any recovery of cost increases attributable to such fees, but also effectively denies recovery of even the amount included in the Base Fuel Cost. (Tr. Vol. XXI at 4010 [Antonuk]).

In Decision No. 68437, the Commission denied recovery of broker fees through the PSA because it believed that they had been excluded from the Base Fuel Cost established in Decision No. 67744, and that such exclusion might result in double-recovery of such fees. (Decision No. 68437 at 25). Whether either the assertion in Decision No. 68437 about the calculation of Base Fuel Cost in Decision No. 67744 or the potential for over-recovery were accurate in the first instance is beside the point. There is no disagreement that they are included in Base Fuel Costs in this proceeding, that they are legitimate and necessary costs of fuel and purchased power procurement, and that their exclusion from the PSA would result in a complete disallowance of such costs.

3. Four Mill Cap / Total Fuel Cost Recovery Cap / Mandatory Surcharge Application / Hedging Gains And Losses.

There is no disagreement by any of the parties with the Company's position on the first

[14] The RUCO, Staff and AECC Base Fuel Cost recommendations are all variants of the original Base Fuel Cost proposed by APS and, thus, implicity reflect the level of broker fees included by APS.

three of these proposed changes to the PSA. The Company has since withdrawn the fourth proposal and would treat hedging gains and losses just like other fuel and purchased power costs, which is the position explicitly taken by RUCO and AECC and not inconsistent with the Staff's position, which would eliminate the 90/10 sharing provision in its entirety.

4. Plan Of Administration ("POA").

Both APS and Staff submitted POAs to implement their respective recommendations relative to the PSA. (APS Exhibit No. 70, Attachment DJR-5RB [Rumolo]; Staff Exhibit No. 30 at Staff's Proposed Plan of Administration [Antonuk]; Staff Exhibit No. 31 at Staff's Irrata to Plan of Administration [Antonuk]). With the exception of the substantive disputes over the level of Base Fuel Cost and application of the 90/10 penalty provision, there were no reservations expressed by the Parties concerning the Company's PSA POA.

As to Staff's POA, Mr. Antonuk made several oral revisions to that POA during his testimony at hearing. (Tr. Vol. XXI at 3870-75 [Antonuk]; Tr. Vol. XXII at 4123-32 [Antonuk]). Most were ministerial, but the more significant change was to permit those PSA charges in effect at the time the Commission adopts Staff's PSA to run their course rather than being swept into some "Transition Component" of the PSA. These could include (depending on the timing of a final order in this proceeding) the: Step 1 surcharge (ends of its own terms on May 1, 2007); Step 2 surcharge (would begin coincident with rates in this proceeding, and per the recommendations of both Staff and APS, extend for twelve months); 2007 annual PSA Adjustor (would run from February 1, 2007 through January 31, 2008); and the Interim PSA Adjustor (ends coincident with an order in this proceeding). If these changes were made and the Base Fuel Cost be set at $.032491 and the POA be amended to include broker fees, APS can support adoption of the Staff's POA. (Tr. Vol. XXIII at 4314-16 [Rumolo]; Tr. Vol. XXIII at 4437-40 [Ewen]).

All parties expressing an opinion on the issue urged the Commission to approve a POA in its order in this proceeding. (Tr. Vol. XIV at 2948 [Rumolo]); Tr. Vol. XVIII at 3401 [Diaz Cortez]). APS believes this to be imperative so that whatever changes to the PSA are authorized in this docket can be implemented immediately and without controversy. Either the Company

POA or the Staff's POA, with the changes discussed herein, provides an adequate framework for implementing their respective PSA proposals.

V.
OPERATING INCOME AND RATE BASE ADJUSTMENTS

A. Jurisdictional Allocation Of Rate Base And Operating Income Adjustments.

Although APS and certain other parties disagreed over the propriety and calculation of a number of rate base and operating income adjustments, there was no issue concerning the Company's allocation of rate base and operating income adjustments as between the ACC jurisdiction and that of other bodies. Thus, in the discussion of these issues, APS will use ACC jurisdictional amounts, which may at times vary slightly from the amounts referenced in some of its witnesses' testimonies. *See,* Consolidated Standard Filing Requirements Final APS Position,[15] attached hereto as "APS Initial Brief Exhibit 5".

B. Pro Forma Adjustments Affecting Rate Base.

1. Uncontested Rate Base Adjustments.

a. Sundance Units

The Company is seeking the Commission's determination that the acquisition of the Sundance Units was prudent,[16] that the assets are "used and useful", and that APS be accorded full cost recovery under traditional cost-of-service principles in this rate case. The Sundance Units were acquired on May 13, 2005 for $189,500,000. (APS Exhibit No. 56 at 16 [Rockenberger]). APS is seeking to include this amount as part of its rate base in this rate case. (*Id.*). Both Staff and RUCO affirmatively stated that the acquisition of the Sundance Units was prudent. (Staff Exhibit No. 34 at 95 [Dittmer]; RUCO Exhibit No 29 at 3 [Schlissel]). No other party to this proceeding has suggested otherwise.

b. Spent Fuel Storage.

There is no dispute to the Company's final adjustment to reduce rate base in the amount

[15] The Company has prepared Consolidated Schedules by adding the pro forma adjustments from its Direct, Rebuttal and Rejoinder positions to show the complete impact of the Company's request. These Consolidated Schedules are attached hereto as APS Initial Brief Exhibit No. 5.

[16] FERC issued a Letter Order on May 6, 2005, approving the acquisition of Sundance from PP&L Sundance Energy, LLC ("PPL"). (APS Exhibit No. 46 at 3 [Dinkel]; *Id.* at Attachment PD-2). The sale and purchase transaction closed on May 13, 2005. (APS Exhibit No. 46 at 3 [Dinkel]).

of $5,775,000,[17] which represents the Company's ACC Jurisdictional portion of current on-going and future activities to transfer spent nuclear fuel to an interim Spent Fuel Storage facility. *See,* APS Initial Brief Exhibit 5, Schedule B-2, Column 3.

c. Palo Verde Unit 1 Steam Generators.

There is no dispute to the Company's final adjustment to increase rate base in the amount of $ 81,941,000,[18] which represents the Company's ACC Jurisdictional portion of the costs associated with the replacement and retirement of steam generators and related equipment for Unit 1 that occurred in 2005. *See,* APS Initial Brief Exhibit 5, Schedule B-2, Column 4.

d. Long Term Disability (SFAS 112).

There is no dispute to the Company's final adjustment to reduce rate base in the amount of $ 3,661,000,[19] which represents the Company's ACC Jurisdictional portion of deferred credits for long term disability (SFAS 112) related to expenses for employees on long-term disability. *See,* APS Initial Brief Exhibit 5, Schedule B-2, Column 6.

e. Regulatory Disallowance Of West Phoenix Unit 4.

There is no dispute to the Company's final adjustment to reduce rate base in the amount of $11,155,000, which represents both the Total Company and ACC Jurisdictional regulatory disallowance required by Decision No. 67744 for one of the generating units, West Phoenix Unit 4, that was not reflected on the Company's books per GAAP, and as adjusted for the actual transfer date from Pinnacle West Energy Company ("PWEC") to APS. (APS Exhibit No. 56, Attachment LLR1-2 [Rockenberger]). *See,* APS Initial Brief Exhibit 5, Schedule B-2, Column 2.

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[17] In this case, the Company's testimony referenced an amount of $5,869,000, which represents the Total Company figure. (APS Exhibit No. 56 at Attachment LLR 1-3 [Rockenberger]).

[18] In this case, the Company's testimony referenced an amount of $82,896,000, which represents the Total Company figure. (*Id.* at Attachment LLR 1-4). After the Company's January filing, RUCO identified an error in the Company's rate base pro forma related to the retirement of turbine rotors associated with the original Unit 1 steam generators and proposed a rate base adjustment to reflect that retirement. The Company agreed with RUCO's recommendation to record retirement of original steam generators by decreasing plant assets and accumulated depreciation by $36,684,000. (APS Exhibit No. 57 at 11 [Rockenberger]). This had no effect on rate base, but it did have an impact on depreciation expense.

[19] In this case, the Company's testimony referenced an amount of $3,886,000, which represents the Total Company figure. (APS Exhibit 49, Attachment CNF-5RB [Froggatt]).

2. Contested Rate Base Adjustments.

a. Allowance for Working Capital.

Working capital consists of four basic components: fuel inventories; materials and supplies; prepayments; and, cash working capital. There is no dispute as to the first three of these elements. The issue of cash working capital is another matter, and there the Parties are in significant disagreement. APS's position is that it has an overall jurisdictional working capital requirement of $148,089,000, consisting of $76,849,000 for fuel inventories; $95,836,000 for materials and supplies; $4,968,000 for prepayments; and a negative cash working capital requirement (which partially offsets the other three components) of $29,565,000.[20] The difference between the Company's allowance for working capital in its original filing and the Company's revised rebuttal allowance for working capital of $148,089,000 results in a net reduction of cash working capital of $4,344,000[21] as reflected on APS Initial Brief Exhibit 5, Schedule B-2, Column 7.

According to *Accounting for Public Utilities*:

> Working capital is the average amount of capital provided by investors in the company, over and above the investment in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service.

ROBERT L. HAHNE & GREGORY E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES 5-2 (1990).

Unlike other rate base elements, which can be taken directly from the Company's balance sheet with or without adjustments, cash working capital is a calculated number that identifies the additional cash investment made in the Company in order to operate and maintain its electric system on a daily basis. Simply put, if cash revenues are received after an expense has been incurred and reflected on the Company's income statement or balance sheet, investors have to provide funds to bridge that gap. If cash is received prior to that expense being incurred, the opposite is true, *i.e.*, customers are providing that bridge and should receive credit in the form of an offset to the utility's rate base.

In this instance, the primary dispute relative to cash working capital is not in the

[20] APS Exhibit No. 69, Attachment DJR-1, Schedule GJ, p. 1 Column (1) [Rumolo].
[21] APS Initial Brief Exhibit 5, Schedule B-3, Column 7(N).

calculation of lead/lag days, but the elements of cost of service that ought to be reflected in the calculation. APS believes that both depreciation and deferred taxes generate additional investment needs that must be reflected in rate base as part of the Allowance for Cash Working Capital, while Staff and RUCO do not. (APS Exhibit No. 66 at 2-3 [Balluff]). Staff and RUCO also use the lag in the payment of interest expense to further reduce cash working capital while ignoring the more than offsetting lag in the receipt of equity returns. (*Id.*). Finally, Staff has excluded the amortized expense of pre-paid insurance costs and nuclear fuel from its lead-lag study. (Staff Exhibit No. 34, Attachment JRD-A; APS Exhibit No. 66 at 10 [Balluff]).

It is indisputable that the construction of depreciable utility plant, which gives rise to both depreciation and deferred taxes, involves a cash investment. It is equally clear that the utility is entitled to a return on that investment until it has been recovered from customers in the form of cash receipts. When depreciation expense is recorded and deferred income tax charges are recorded, accumulated depreciation and deferred income tax credits are recorded. The reserve for accumulated depreciation and the accumulated balance of deferred taxes offset the investment in plant for ratemaking purposes. (*Id.* at 3-4 [Balluff]). Those two reserves, which reduce rate base, are credited (increased) monthly based on the depreciation and deferred tax expense recorded for the month. The corresponding cash receipts will not be received until the following billing month. Because the Company's rate base is reduced by the **recorded** level of accumulated depreciation and deferred taxes (rather than the **received** level of actual cash recovery), there is a gap between when customers are credited (through a rate base deduction) for their payment of depreciation expense and deferred tax expense and the time they actual pay for these items. (APS Exhibit No. 65 at 10-11 [Balluff]). This gap represents additional investment by the Company that must either be reflected in the calculation of cash working capital or recognized as direct adjustments to the depreciation and deferred tax reserves. Exclusion of depreciation expense alone prevents APS from earning a return on over $32,000,000 of unrecovered invested capital. (APS Exhibit No. 66 at 3 [Balluff]). Excluding deferred tax expense leads to another understatement of rate base of $7,872,000. (APS Exhibit No. 65 at Attachment FB-1 [Balluff]).

APS is aware that the Commission has rejected the inclusion of depreciation and deferred taxes in prior decisions. As the arguments on this issue have become focused, an increasing number of jurisdictions have taken a new look and have concluded that one or both of these costs are appropriate elements of cash working capital. A few examples of states that have included depreciation and deferred income taxes in lead lag studies are: South Carolina, where these items must be included in a lead lag to reflect the delay in the collection of these components of revenue;[22] Connecticut, where the Department of Public Utility Control agreed that no-cash expenses such as depreciation, amortization, and deferred income taxes create a working capital requirement;[23] and California, which includes both depreciation expense and deferred taxes at zero lag days because of the reduction of rate base by accumulated depreciation and deferred income taxes.[24]

The Commission has previously taken conflicting positions on the use of interest expense, adopting it in Decision No. 55931 (April 1, 1988), while admitting in that same Decision that it had previously rejected the concept. (Decision No. 55931 at 67). The testimony in this case is that the lag in paying interest, a non-operating expense, is an inherent part of the return to equity investors, *i.e.*, part of the "leverage" provided by debt capital to equity. 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 rate base (including the weighted cost of debt) in the calculation of working capital. (APS Exhibit No. 66 at 11 [Balluff]). To use it to reduce rate base is tantamount to making equity investors use a component of their rightful return to finance plant used to serve APS customers. Moreover, as Mr. Balluff pointed out, there is also a lag in the receipt by equity investors of their return. If one form of investment (*i.e.*, debt) is to be factored in the calculation of cash working capital, then all other forms should be in play, which would have increased the Company's overall cash working capital allowance from that requested. *(Id.)*.

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[22] In re Application of South Carolina Electric & Gas Company for Adjustments in the Company's Electric Rate Schedule and Tariffs, Docket No. 88-681-E – Order No. 89-588 at 37 (July 3, 1989).

[23] DPUC Review of the United Illuminating Company's Rate Filing and Rate Plan Proposal, Docket No. 01-10-10 at 44 (Sept. 26, 2002).

[24] *See, generally,* Water Division, California Public Utilities Commission, Standard Practice U-16-W, Determination of Working Cash Allowance (May 16, 2002).

Although the impacts of excluding the amortization of prepaid insurance costs ($500,000) and nuclear fuel amortization ($3,500,000) from the Staff lead-lag study are relatively small, Staff has simply provided no explanation for this departure from normal practice other than to declare the expense "non-cash." RUCO, which supported Staff on the other cash working capital issues, did not propose a similar insurance adjustment. (APS Exhibit No. 66 at 10 [Balluff]).

b. Bark Beetle Regulatory Asset.

In Decision No. 67744, the Commission authorized APS to defer the reasonable and prudent costs of bark beetle remediation that exceeded 2002 Test Year levels of tree and brush control. The Company began deferring costs in 2005 to ensure that the allowable deferred costs were properly calculated. (APS Exhibit No. 57 at 13 [Rockenberger]). The Company has estimated a Total Company deferral of distribution-related bark beetle remediation costs of $11,622,000 at December 31, 2006, which adds $4,360,000 to APS's rate base. *See,* APS Initial Brief Exhibit 5, Schedule B-2, Column 5.[25]

The only disputes related to the bark beetle remediation costs is the time period for which the Company can recovery its remediation expenditures, as discussed in detail in section V.C.2(a), below. The required rate base adjustment is, of course, dependent upon the Commission's resolution of that "time period" issue.

c. Investment Tax Credit

Prior to 1987, federal ITCs that were related to the construction and acquisition of utility plant had been available to corporate utility taxpayers. The Tax Reform Act of 1986 generally eliminated the ITC for tax years beginning in 1987, concurrent with implementation of a lower corporate federal income tax rate. (Staff Exhibit No. 34 at 100 [Dittmer]). The ITCs at issue in this rate case were realized by APS as a result of the Company's recent claim requesting additional credits for a specific transition period (1986 – 1990) that was permitted after repeal of

[25] The Company's rate base calculation was reduced from its original filing of $6,115,000 (APS Exhibit No. 56, Attachment LLR-1-5 [Rockenberger]) by $1,755,000, which includes a reduction of $2,793,000 for accumulated deferred income taxes, partially offset by a $1,038,000 rate base increase comprised of a $705,000 addition to correct the calculation for the actual September 30, 2005, deferred bark beetle remediation costs, and a $333,000 addition to increase the projected bark beetle remediation cost deferrals through December 31, 2006. (APS Exhibit No. 57 at 13-14 [Rockenberger]).

the ITCs. (APS Exhibit No. 49 at 9-10 [Froggatt]). As with the out of period tax consulting fee discussed above, these related tax credits are non-recurring and clearly unrelated to the Test Year and should, therefore, not be included in the regulated cost of service, independent of the issues of their permitted ratemaking treatment under federal tax law and the prior decisions of this Commission. (*Id.* at 8).

Staff has recommended an offset to rate base by 100% of the unamortized balance of the ITC (1986 through 1990) for plant that was not fully depreciated as of the Test Year, less the fees paid to Deloitte and Touche to obtain these additional ITCs.[26] (Staff Exhibit No. 37 at 43 [Dittmer]). The ITCs in question relate to plant constructed during the years 1986 through 1990, which was 15 to 20 years ago. (APS Exhibit No. 50 at 2 [Froggatt]).

Staff's assertion that it is difficult to speculate upon how such ITCs may have been treated in regulatory proceedings had they been claimed and known at a much earlier date is both unfounded and contradicted by their own testimony. (Staff Exhibit No. 34 at 105 [Dittmer]). Pursuant to Decision No. 58644, which adopted a 1994 Settlement Agreement, the remaining (as of 1994) unamortized ITCs from all of the years prior to 1991 were to be fully amortized below-the-line over five years. (Decision No. 58644 at 7; Staff Exhibit No. 34 at 105 [Dittmer]). Thus, customers have not further claim to any such ITCs.

Staff has presented no reason to disregard the clear language of Decision No. 58644. Staff has agreed that the ITCs at issue in this case were for tax years prior to 1994. (Tr. Vol. XXII at 4214 [Dittmer]). Staff also agreed that the five-year below-the-line amortization period would have expired well before the beginning of the test period in this case. (*Id.*). For all of these reasons, as well as those discussed at the beginning of this section, Staff's proposal should be rejected.

RUCO did not propose any sharing of the benefit of the ITCs or use of the ITCs as a rate

[26] In its direct testimony, Staff had recommended a 50/50 sharing between ratepayers and shareholders of net savings resulting from the ITCs. (Staff Exhibit No. 34 at 104 [Dittmer]). That Staff proposal would violate the Internal Revenue Code, constituting an IRS normalization violation. (APS Exhibit No. 49 at 9 [Froggatt]). The result of this proposal would be disastrous to the Company and its customers, with the loss of tens of millions of dollars of previously-claimed ITCs that would have to be refunded to the IRS. (Staff Exhibit No. 37 at 42 [Dittmer]). Staff withdrew their first proposal, deciding that based on reading Private Letter Rulings issued by the IRS, the ITC rate base adjustment as originally proposed would be an Internal Revenue Code normalization violation. (*Id.* at 44 [Dittmer]). Subsequently, Staff recommended the approach discussed above.

base reduction. No other Party made recommendations regarding the additional tax credits.

C. Pro Forma Adjustments Affecting Operating Income.

1. Uncontested Operating Income Adjustments.

a. Spent Fuel Storage.

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax operating income in the amount of $10,653,000,[27] which represents the Company's ongoing ACC Jurisdictional costs for interim storage of spent nuclear fuel from Palo Verde and an amortized portion of deferred amounts. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 14. Consistent with the treatment in Decision No. 67744, the Company is specifically requesting that the Commission include the "Schedule of Amounts to Be Deposited in the Decommission Trusts" to its final Decision in this case. (*See,* Appendix I, Decision No. 67744; APS Exhibit No. 56 at Attachment LLR-3 [Rockenberger]).

b. Nuclear Decommissioning

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax operating income in the amount of $3,820,000,[28] which represents the Company's ACC Jurisdictional qualified funding levels annualized to $19,211,000, as approved in Decision No. 67744 at 171-177. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 13. The Company is requesting that the Commission's Decision in this case also specifically provide for approval of the $19,211,000 annual level of decommissioning funding and that the Commission Decision include Attachment LLR-3 from APS Exhibit No. 56 [Rockenberger].

c. Four Corners Coal Reclamation.

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax operating income in the amount of $1,284,000,[29] which represents the Company's ACC Jurisdictional annual expense of reclamation costs based upon the 2004 Marston study. *See,*

[27] In this case, the Company reduced pre-tax operating income by $10,828,000, which represents the Total Company figure. (APS Exhibit No. 56 at 9 [Rockenberger]; *Id.* at Attachments LLR 2-2; APS Exhibit No. 57 at 17 [Rockenberger]; *Id.* at Attachment LLR-4-3RB).

[28] In this case, the Company reduced pre-tax operating income by $3,883,000, which represents the Total Company figure. (APS Exhibit No. 56 at Attachments LLR 2-7 [Rockenberger]).

[29] In this case, the Company reduced pre-tax operating income by $1,305,000, which represents the Total Company figure. (APS Exhibit No. 56 at 19-20 [Rockenberger]; *Id.* at Attachment LLR-2-8).

APS Initial Brief Exhibit 5, Schedule C-2, Column 17.

d. Annualize Payroll.

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax operating income in the amount of $8,717,000,[30] which represents the Company's ACC Jurisdictional annualized payroll, benefits, and payroll tax expense to December 2005 employee levels; December 2005 wage levels for performance review employees; and April 2006 wage levels for union employees. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 20.

e. Regulatory Disallowance For West Phoenix Unit 4.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income in the amount of $227,000,[31] which represents the Company's ACC Jurisdictional adjustment to reflect an annual reduction in depreciation expense associated with the write-off discussed in the Uncontested Rate Base Adjustments portion of this brief. *See,* APS Initial Brief Exhibit 4, Schedule C-2, Column 10.

f. Regulatory Assessments And Franchise Fees.

There is no dispute to the Company's final adjustment to Test Year pre-tax operating income of $0, which represents the Company's ACC Jurisdictional pro forma adjustment that removes assessments and franchise fees in the amount of $15,723,000[32] from both operating revenues and expenses in the Test Year. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 1. Pursuant to Decision No. 67744, both items are treated as "add-ons" to customers' bills, similar to sales tax.

g. Base Rate Component For EPS.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income in the amount of $779,000, which represents both the Total Company and the ACC Jurisdictional pro forma adjustment that reflects the Company's accounting for the

[30] In this case, the Company reduced pre-tax operating income by $9,239,000, which represents the Total Company figure. (APS Exhibit No. 56 at 24 [Rockenberger]; *Id.* at Attachments LLR 2-14).

[31] In this case, the Company increased pre-tax operating income by $230,000, which represents the Total Company figure. (APS Exhibit No. 56 at 7 [Rockenberger]; *Id.* at Attachments LLR 2-1).

[32] In this case, the Company reduced operating revenues and expenses by $15,947,000, which represents the Total Company figure. (APS Exhibit No. 28 at 11 [Froggatt]; *Id.* at Attachment CNF 1-1).

$6,000,000 authorized System Benefits Charge ("SBC") to fund the EPS.[33] (APS Exhibit No. 48 at 12 [Froggatt]; *Id.* at Attachment CNF 1-2). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 2.

h. Interest On Customer Deposits.

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax operating income in the amount of $2,400,000, which represents both the Total Company and the ACC Jurisdictional pro forma adjustment that reflects annualized interest costs associated with customer deposits (interest expense). (APS Exhibit No. 49 at 5 [Froggatt]; *Id.* at Attachment CNF 6RB). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 4.

i. Amortization Of Regulatory Assets.

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax operating income in the amount of $381,000, which represents the Company's ACC Jurisdictional pro forma adjustment that reflects the amortization of the Palo Verde Unit 2 Sale/Leaseback rent levelization regulatory asset over the remaining life of the lease. This adjustment is consistent with both the Settlement Agreement adopted in Decision No. 67744 and the Commission's original authorization of this transaction in Decision No. 55120 (July 24, 1986). (APS Exhibit No. 48 at 13 [Froggatt]; *Id.* at Attachment CNF 1-5). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 5.

j. PWEC Loan.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income in the amount of $3,292,000,[34] which represents the Company's ACC Jurisdictional pro forma adjustment to amortize over five years deferred net interest income from the APS loan to PWEC, which was repaid in full on April 11, 2005. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 6.

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[33] Revenue of $6,779,000 was reclassified from Contribution-in-Aid-of-Construction. Because the costs were charged to Construction Work in Process rather than an Operation and Maintenance account, they are not reflected in the Test Year operating results. The pro forma adjustment is needed to properly reflect, for ratemaking treatment, revenue of $6,779,000 and an expense of $6,000,000, the allowed portion of expenses related to the base rate portion of the SBC used to fund the EPS. (APS Exhibit No. 48 at 12 [Froggatt]; *Id.* at Attachment CNF 1-2).

[34] In this case, the Company increased pre-tax operating income by $3,330,000, which represents the Total Company figure. (APS Exhibit No. 48 at 14 [Froggatt]; *Id.* at Attachment CNF 1-6).

k. Tax Consulting Fees.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income in the amount of $2,746,000,[35] which represents the Company's ACC Jurisdictional pro forma adjustment that reflects the elimination of non-recurring tax research consulting fees that was recorded during the historic Test Year, but was incurred prior to the beginning of the Test Year and is not an on-going expense. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 32.

l. Out Of Period Income Tax Adjustments.

There is no dispute to the Company's final adjustment to increase Test Year operating income in the amount of $243,000[36] that represents ACC Jurisdictional figure, which added income tax true-up items that related to the Test Year period, and removed income tax expense recorded during the Test Year period related to non-recurring income tax items. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 7.

m. Miscellaneous Adjustments.

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax operating income in the amount of $1,720,000,[37] which represents the Company's ACC Jurisdictional pro forma adjustment that reflects the elimination of non-recurring or out-of-period expenses or credits from the Test Year, including financial data warehouse costs, Four Corners severance reserve true-up, FERC audit reserve, APS corporate offices rent expense, and bill estimation refund. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 23.

n. Pension Expense.

There is no dispute to the Company's final adjustment to decrease pre-tax operating income by $2,119,000,[38] which represents the Company's ACC Jurisdictional pre-tax adjustment

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[35] In this case, the Company increased pre-tax operating income by $2,778,000, which represents the Total Company figure. (APS Exhibit No. 49 at 7-8 [Froggatt]; *Id.* at Attachment CNF-9RB).

[36] In this case, the Company increased operating income by $1,287,000, which represents Total Company figure. (APS Exhibit No. 48 at 14-15 [Froggatt]; *Id.* at Attachment CNF 1-7).

[37] In this case, the Company reduced pre-tax operating income by $3,876,000, which represents the Total Company figure. (APS Exhibit No. 56 at 26-27 [Rockenberger]; *Id.* at Attachment LLR-2-17).

[38] In this case, the Company decreased pre-tax operating income by $2,249,000, which represents the Total Company figure. (APS Exhibit No. 57 at 22 (Rockenberger); *Id.* at Attachment LLR-4-5RB.)

to reflect actual 2006 pension expense. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 36.

o. Post Retirement Medical Benefits.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income by $3,006,000,[39] which represents the Company's ACC Jurisdictional pro forma adjustment reflecting updated actuarial information related to post-retirement medical benefits.[40] *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 37.

p. Administrative And General.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating expenses by $8,422,000,[41] which represents the Company's ACC Jurisdictional pro forma adjustment that reflects out-of-period costs related to depreciation and rent expense, including out-of-period adjustments for the PWEC Units and legal costs properly chargeable to PWEC and related to the sale of Silverhawk. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 35.

q. Unregulated APS Marketing And Trading Activity.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income by $14,917,000,[42] which represents the Company's ACC Jurisdictional adjustment related to the exclusion of calculations related to revenue and expenses associated with transactions that are not related to serving APS native load during the Test Year. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 33.

r. Palo Verde Unit 1 Steam Generators Depreciation

There is no dispute to the Company's final adjustment to reduce Test Year pre-tax

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[39] In this case, the Company increased pre-tax operating income by $3,191,000, which represents the Total Company figure. (APS Exhibit No. 57 at 23 [Rockenberger]; *Id.* at Attachment LLR-4-6RB).

[40] Staff recommended an increase in operating expenses of $2,038,000, which was based on the actuarial estimates that the Company was relying on to record 2006 post-retirement benefit costs in excess of the level of costs recorded in the Test Year. (Staff Exhibit No. 35, Schedule C-7). Subsequently, the Company updated that adjustment with final 2006 actuarial information, and Staff had no disagreement with that number. (Staff Exhibit No. 37 at 24 [Dittmer].

[41] In this case, the Company increased pre-tax operating income by $8,520,000, which represents the Total Company figure. (APS Exhibit No. 57 at 25-26 [Rockenberger]).

[42] In this case, the Company increased pre-tax operating income by $15,149,000, which represents the Total Company figure. (APS Exhibit No. 49 at 4 [Froggatt]; *Id.* at Attachment CNF-3RB).

operating income by $1,764,000,[43] which represents the Company's ACC Jurisdictional adjusted depreciation expense to include one full year of depreciation on the new Unit 1 steam generators and to exclude the actual Test Year depreciation on the replaced steam generators. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 15.[44]

s. Normalize Non-Nuclear Maintenance Expense.

Except as discussed in the Contested Operating Income Adjustments section V.C.2(b) and (c) below regarding the Sundance and PWEC Units, there is no dispute to the Company's final adjustment to decrease Test Year pre-tax operating income by $1,435,000,[45] which represents the Company's ACC Jurisdictional adjustment to Test Year operations to reflect the normalization of fossil production maintenance expense and to include operation and maintenance ("O&M") costs of renewable generation acquired in compliance with the EPS. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 25.

t. Normalize Nuclear Maintenance Expense.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income by $718,000,[46] which represents the Company's ACC Jurisdictional adjustment to Test Year operations to reflect the normalization of nuclear production maintenance expense. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 26.

u. Annualize Customer Levels To Year End 2004.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income by $28,318,000, which represents the both the Total Company and ACC Jurisdictional adjustment to Test Year operations to reflect the annualization of customer counts at December 31, 2004. (APS Exhibit No. 16, Attachment PME-19 [Ewen]). *See,* APS Initial

[43] In this case, the Company reduced pre-tax operating income by $1,785,000, which represents the Total Company figure. (APS Exhibit No. 59 at 12 [Rockenberger]; *Id.* at Attachment LLR-4-1RB).

[44] As noted in the Uncontested Rate Base Adjustments portion of this brief, APS and RUCO originally had a dispute over the exclusion of depreciation on the retired steam generator and associated equipment. This was resolved and was reflected in APS Exhibit No. 57 at 11 [Rockenberger], as well as in the Company's final proposed depreciation expense.

[45] In this case, the Company reduced pre-tax operating income by $1,456,000, which represents the Total Company figure. (APS Exhibit No. 16 [Ewen] at Attachment PME-15).

[46] In this case, the Company increased pre-tax operating income by $729,000, which represents the Total Company figure. (*Id.*).

Brief Exhibit 5, Schedule C-2, Column 27.

v. Normalize Weather Conditions.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income by $5,967,000, which represents both the Total Company and ACC Jurisdictional adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2004. (APS Exhibit No. 16, Attachment PME-18 [Ewen]). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 28.

w. Annualize 4/1/05 ACC Rate Levels.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income by $17,136,000, which represents both the Total Company and ACC Jurisdictional adjustment to Test Year operations to reflect the annualization of ACC rate levels for the April 1, 2005 rate increase that was authorized in Decision No. 67744. (APS Exhibit No. 69, Attachment DJR-5 [Rumolo]). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 29.

x. E-3/E-4 Promotional Expense.

There is no dispute to the Company's final adjustment to decrease Test Year pre-tax operating income by $62,000, which represents both the Total Company and ACC Jurisdictional adjustment to Test Year operations to reflect the increased promotional expense for low income rate options that were required by Decision No. 67744. (APS Exhibit No. 69, Attachment DJR-7 [Rumolo]; APS Exhibit No. 70 at 5 [Rumolo]). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 30.

y. Schedule 1 Changes.

There is no dispute to the Company's final adjustment to increase Test Year pre-tax operating income by $165,000, which represents both the Total Company and ACC Jurisdictional adjustment to Test Year operations to reflect revenue-related changes to the Company's Rate Schedule 1 that were authorized by Decision No. 67744. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 31.

z. Federal And State Income Tax

There is no dispute between APS and Staff as to the Company's additional adjustment to the Company's original cost of service income tax expense to reflect a top-down tax calculation including permanent tax items to reduce Test Year income tax expense by $4,588,000[47], which represents the Company's ACC Jurisdictional adjustment. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 34.

2. Contested Operating Income Adjustments.

a. Bark Beetle Remediation.

Based upon APS's proposed three-year amortization, the Company has proposed a pro forma adjustment to increase Test Year costs, and, thus, reducing pre-tax operating income by $1,548,000 to reflect that annual expense level. (APS Exhibit No. 57 at 14 [Rockenberger]; *Id.* at Attachment LLR-4-2RB). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 16.

There is no dispute among the Company, Staff and RUCO that Decision No. 67744 provided for recovery of deferred bark beetle remediation costs and subsequent amortization of such costs, and each accepted the three-year amortization period proposed by the Company. (APS Exhibit No. 57 at 12 [Rockenberger]; Staff Exhibit No. 34 at 23 [Dittmer]; RUCO Exhibit No. 22 at 11 [Rigsby]). Rather, the disputes related to these remediation costs involve the time period for which the Company can collect the expenditures in this proceeding.

It is Staff's position that the Company did not have the authority to defer remediation costs prior to April 2005, because Decision No. 67744, which authorized such a deferral, did not go into effect until April 2005. As a result, Staff has proposed an adjustment to APS's proposed rate base addition and amortization expense for bark beetle costs incurred from January 1, 2005 through March 31, 2005.

This interpretation is contrary to the plain reading of Decision No. 67744 and the Settlement Agreement (adopted by that Decision), which states, "APS is authorized to defer for

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[47] In this case, the Company reduced test year income tax expense by $4,838,000, which represents the Total Company figure. (APS Exhibit No. 49 at 4 [Froggatt]; *Id.* at Attachment CFN-4RB). The impacts of interest synchronization and the Generation Production Income Tax deduction are incremental to the $4,588,000, but this number remains the same.

later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the *test year* levels of tree and brush control." (Emphasis added). (Decision No. 67744 at 31; Settlement Agreement, ¶¶ 110-111). Clearly, the language indicates that a full year of cost recovery was intended. (APS Exhibit No. 57 at 13 [Rockenberger]). Otherwise, it would make no sense to compare expenditures from April 1, 2005 through December 31, 2005 to an annual figure (*i.e.*, the 2002 Test Year used for purposes of Decision No. 67744), as is required by that Decision. An alternative computation would be to take the nine months of bark beetle costs in 2005 that occurred after Decision No. 67744's effective date and then annualize them (*i.e.*, multiply them by 133 percent) prior to making the calculation referenced in the above passage of the Decision. However, that result would essentially be the same position as under the Company's proposal, which simply uses the actual calendar year 2005 costs. Therefore, it is the Company's position that the Settlement Agreement intended, and Decision No. 67744 authorized, that deferrals would include the entire calendar year in which the deferral became effective. (*Id.* at 12-13).

RUCO, on the other hand, has not taken issue with bark beetle deferrals beginning in January 2005, but objected to the Company's calculation of deferred costs through 2006, and asserted that the adjustment in this case should only reflect direct costs that were recorded at the end of the Test Year. RUCO has proposed a reduction to the Company's pro forma rate base calculation of $6,115,000 and a corresponding reduction to amortization expense of $2,273,000 associated with bark beetle remediation. RUCO did acknowledge that amounts deferred by APS subsequent to September 30, 2005, and prior to rates going into effect as a result of this proceeding, would be recovered by APS in a subsequent rate proceeding. (Tr. Vol. XVIII at 3363-65 [Diaz-Cortez]).

It is APS's contention that it is appropriate to use estimated costs for the period of time from September 30, 2005 (the end of the Test Year) through December 31, 2006, to ensure that the rates in effect for 2007 provide for the amortization for the actual costs incurred by year end 2006. (APS Exhibit No. 57 at 16 [Rockenberger]). There is little purpose served in prohibiting current recovery of prudently incurred costs and burdening future rate proceedings with the recovery of costs that were already incurred in 2006 to serve the Company's customers. Therefore, APS does not accept RUCO'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. (*Id.* at 14-15).

b. Sundance Units.

The Company has reduced its pre-tax operating income by a pro forma adjustment of $4,804,000,[48] which represents the Company's ACC Jurisdictional adjustment and includes non-fuel operations and maintenance expenses of the Sundance Units, necessary to annualize the Test Year expense. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 12.

The Company is seeking an annualized O&M expense of $6,410,000, which includes $3,660,000 (one full year of routine O&M expense) and $2,750,000 (overhaul maintenance costs). (APS Exhibit No. 56 at 16 [Rockenberger]). The routine O&M expense was estimated based on the projected information provided by PP&L, the former owners of the Sundance Units, as adjusted for the expected level of Company operation. (*Id.* at 16-17). The Total Company $4,860,000 pro forma adjustment reflects the difference between the $6,410,000 annualized costs and the Test Year actual costs of $1,550,000, which is about five months of actual costs. (*Id. at* 17).

Although Staff has determined that the acquisition of the Sundance Units was prudent, Staff has recommended that the non-routine (overhaul) O&M expense normalization for the Company's Sundance Units be excluded, despite the fact that the Company has followed the same methodology for the Sundance Units as it has for its other generating facilities. (APS Exhibit No. 17 at 12 [Ewen]). This is the same methodology that has historically been accepted by the Commission. (*Id.*). Although it appears that Staff is concerned that the adjustment for Sundance plant overhauls could potentially lead to a double-recovery of such costs at a future date, in fact, the converse is true. (*Id.*).

The method traditionally followed by the Commission in setting rates for such items is to

[48] In this case, the Company reduced pre-tax operating income by $4,860,000, which represents the Total Company figure. (APS Exhibit No. 56 at 16 [Rockenberger]; *Id.* at Attachment LLR-2-6).

average the expenses over generating plant overhaul cycles so that payments in one year do not lead to an overstatement of the Company's rates. (APS Exhibit No. 18 at 11 [Ewen]). For example, if overhauls are conducted every five years, the cost is recovered by charging one-fifth of the cost each year. That way, the fact that an overhaul might occur in a particular test period (thus inflating that year's non-routine maintenance costs) does not lead to over-recovery of the total cost of the overhaul. Conversely, the fact that an overhaul of a particular unit did **not** occur in a test period does not result in the cost being ignored and going unrecovered. Because the Sundance Units major overhaul cycle is twelve years (the same as the former PWEC units, to which Staff has **not** objected (Tr. Vol. XXII at 4221-22 [Dittmer]), the Company has requested essentially that one-twelfth of its expenses be recovered in each year. (APS Exhibit No. 18 at 11 [Ewen]). This way, APS neither over nor under recovers these costs depending on whether the overhaul occurs during a test period.

Under the Staff recommendation, the Company does not begin to recover these costs until some indeterminate time in the future. (*Id.*). If and when that occurs, the Company may be able to recover its costs, but customers in the future will be left to pay for costs attributable to customers in the present and in the recent past. (*Id.*). Staff has cited no reason to depart from long-accepted Arizona regulatory practice in this specific instance.

Although RUCO has also determined that the acquisition of the Sundance Units was prudent and did not support Staff's adjustment to non-routine O&M, RUCO is requesting that the Sundance Plant routine O&M be adjusted – more specifically the variable component of that O&M. RUCO's proposed adjustment, which is premised on lower operating levels at Sundance, is inconsistent with the findings of Staff's consultants, who after an extensive and thorough audit, found that "O&M expenditure patterns [were] … consistent with system operational requirements." (Staff Exhibit No. 28 at 92 [Antonuck]; Staff Exhibit No. 33 at 92 [Fuel Audit]). Moreover, Staff made no similar adjustment to routine O&M costs of Sundance. (*Id.*).

c. PWEC Units.

The Company reduced pre-tax operating income by $53,021,000,[49] which represents the Company's ACC Jurisdictional annualized operating expense for the PWEC Units. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 11. The adjustment included a reduction of $1,125,000, which was associated with auxiliary power purchased by PWEC from APS that was no longer applicable because the PWEC Units are now owned by APS. The adjustment also includes an Administrative and General ("A&G") expense and an annualized depreciation and amortization expense, as well as an annualized property tax expense. (APS Exhibit No. 56 at 14-16 [Rockenberger]).

The Commission authorized the transfer of the PWEC Units to APS in Decision No. 67744, and they were formally transferred to APS on July 29, 2005. (Decision No. 67744 at 8-9). Because these units transferred to APS during the Test Year, they were already included in the Test Year rate base; however, an operating income pro forma adjustment was necessary to annualize the PWEC Units operating expenses.

The annualized routine operations maintenance expense of $26,204,000 reflected the actual 2004 expenditures for the PWEC Units, adjusted for the expected increase in average projected operating megawatt hours for 2006 through 2011. (APS Exhibit No. 56 at 14-15 [Rockenberger]). Because the PWEC Units had only recently been placed in service, the Company had no historical cost basis for calculating overhaul costs. (*Id.* at 15). For that reason, the Company estimated a $10 million normalized overhaul maintenance expense using a projected 12-year average, restated in 2004 dollars. (*Id.*).

Neither Staff nor RUCO took exception to the non-routine (overhaul) O&M expense for the PWEC Units.[50] RUCO proposed a reduction in the variable component of routine O&M for the PWEC units. The reason given for such adjustment was the same as for the Sundance Units, and it should be rejected for the same reasons as discussed above.

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[49] In this case, the Company reduced pre-tax operating income by $53,644,000, which represents the Total Company figure. (APS Exhibit No. 56 at 14 [Rockenberger]).

[50] The inconsistency of Staff's position on this issue as between Sundance and the other APS generating units, including but not limited to, the PWEC units was discussed above.

d. Advertising And Business Meals.

The evidence in this case supports the Company's final adjustment to increase its pre-tax Test Year operating income in the amount of $6,264,000,[51] which represents the Company's ACC Jurisdictional pre-tax adjustment to advertising and other expenses. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 22.

The Company does not oppose the removal of Staff's marketing and sponsorship costs from expense totaling $437,000. This adjustment is included in the $6,264,000 figure discussed above. (APS Exhibit No. 57 at 24 [Rockenberger]).

RUCO proposed an adjustment of $566,000 for sponsorships and other expenses, and an adjustment of $4,625 to remove what RUCO categorized as promotional advertising. Although APS has not opposed RUCO's $4,625 adjustment nor some $66,000 of its "sponsorship and other expenses" adjustment (also already included in the $6,264,000 figure cited above), APS opposes the remaining $500,000 of that adjustment. (APS Exhibit No. 57 at 24 [Rockenberger]).

RUCO's proposed adjustment includes $100,000 for the Dodge Theater expense that Staff has already included in its adjustment, to which APS agreed and already included. To allow RUCO's adjustment would result in reducing advertising twice for the same $100,000 expense. (*Id.*).

The remaining piece of RUCO's advertising adjustment, $400,000, is for business lunches, which the Company believes are legitimate business expenses that provide APS the benefit of additional productive non-interrupted, non-paid work time from its employees. (*Id.*). Neither Staff nor any other Party other than RUCO has proposed the elimination of meal expenses for employees that work through lunch at the Company's request. APS is not aware of such an adjustment ever having been proposed in prior APS rate proceedings even though the provision of employee meals under the circumstances cited by Ms. Rockenberger is a long-standing Company practice. (Tr. Vol. XIII at 2687-89 [Rockenberger]). RUCO provided **no** evidence that either the amount claimed was excessive or that such meals did not serve valid

[51] In this case, the Company increased pre-tax operating income by $6,648,000, which represents the Total Company figure. (APS Exhibit No. 56 at 25 [Rockenberger]; *Id.* at Attachment LLR-2-16); See also APS Exhibit No. 57 at 24 [Rockenberger]; *Id.* at Attachment LLR-4-7RB).

business purposes. RUCO's assertion that there are other less expensive ways to incent employees to "go above and beyond the call of duty" lacks both evidentiary basis and, in any event, does not refute the Company's contention that customers are well-served by allowing APS to continue to conduct business during what would otherwise be time allotted for employees to take their lunch break. (Tr. Vol. XVIII at 3432 [Diaz-Cortez]).

e. Underfunded Pension Liability.

The evidence in this case supports the Company's final adjustment to decrease its pre-tax Test Year operating income in the amount of $41,166,000,[52] which represents the Company's ACC Jurisdictional pre-tax adjustment to its underfunded pension account. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 21.

APS, like companies in all industries across the nation, is faced with an underfunded pension obligation. APS firmly believes that the Company and the Commission should begin to address this under funding issue now.

APS (through its parent company, Pinnacle West Capital Corporation) has a pension plan that covers all of its employees. (APS Exhibit No. 56 at 24-25 [Rockenberger]). As of December 31, 2004, the projected benefit obligation of the pension plan was approximately $1,371,000,000 and the fair value of the plan's assets was approximately $982,000,000. (*Id.* at 25). The difference between these two amounts represents the underfunded pension liability of the plan. (*Id.*).

To address this, the Company has proposed an adjustment that would accelerate the recovery of the Company's underfunded pension liability over a five-year period, beginning in 2007. (*Id.*). The annual increase to pension expense proposed by the Company would be approximately $44,000,000. (*Id.*; *Id.* at Attachment LLR-2-15 [Rockenberger]). Because this would be an accelerated recovery, the Company has proposed creating a regulatory liability that would be later amortized as a reduction to pension expense over ten years (beginning in 2012). (APS Exhibit No. 56 at 25 [Rockenberger]). Such amortization would reduce future costs by approximately $22,000,000 per year for ten years, thus entirely offsetting the accelerated

[52] In this case, the Company decreased pre-tax operating income by $43,695,000, which represents the Total Company figure. (APS Exhibit No. 56 at 24-24 [Rockenberger]; *Id.* at Attachment LLR-2-15).

recovery sought in this proceeding. (*Id.*). In addition, the accelerated recovery of the current under funding would itself reduce future pension costs independent of the creation of the aforementioned regulatory liability, thus providing additional benefits to APS customers in the future. The accelerated pension funding will also provide an ongoing benefit to customers by an estimated $10,000,000 per year in perpetuity, as a result of the higher fund balance at the end of the 15-year program. (Tr. Vol. XXIV at 4547 [Brandt]).

During the time that the Company "holds" any funds as a result of this accelerated pension funding, customers receive a "rate base return" on the outstanding balance because the balance is recorded as regulatory liability, which is a reduction to rate base. (*Id.*; APS Exhibit No. 6 at 24 [Brandt]). As a result, customers are fairly compensated for their up front funding of the Company's pension program, both by receiving that funding back over ten years **with** a full return and the lowering of revenue requirements in the future, all of which will have a stabilizing effect on rates in future years. (APS Exhibit No. 6 at 24 [Brandt]); APS Exhibit No. 5 at 57-58 [Brandt]).

There are several other reasons for the Commission to approve what the Company has proposed. First, this is a liability that exists now, and it, therefore, stands to reason that this liability should be reflected in current rates and not deferred to a later date to be paid by future customers. Second, there is no reason to believe that this under funding in the plan over the last several years will go away or be reversed on its own. Indeed, the APS pension plan did not "under perform" relative to the market (APS Exhibit No. 5 at 56 [Brandt]); in fact, it outperformed the peer group and the S&P 500 index during the period in question. (*Id.*). The under funding is mostly the result of the lower than "normal" interest rates used for purposes of discounting the pension obligation (and therefore determine the pension plan contribution). (*Id.*; *Id.* at Attachment DEB-16RB). Third, APS must now account on a current basis for the projected benefit obligation ("PBO") rather than the smaller accumulated benefit obligation ("ABO") and must reflect on its year-end balance sheet a liability for any unfunded PBO-based pension obligation. (Tr. Vol. IV at 776-77 [Brandt]; APS Exhibit No. 6 at 26 [Brandt]).[53] As Mr. Brandt explained, the new accounting standard for pension accounting (Financial Accounting Standard 158), that requires companies to reflect on their financial statements the PBO rather than the ABO, was prompted by the many highly-publicized instances in the last few years in which large corporations disclosed that their employee pension plans were substantially underfunded. (Tr. Vol. IV at 776-77 [Brandt]). And finally, as noted above, the Company's pension funding proposal has substantial long-term financial benefits for customers and a levelizing impact on rates.

Another benefit of the Company's pension funding proposal, which is not directly reflected in the discussion above, is the positive impact that it has on the Company's overall cash flow and its FFO/Debt ratio. (APS Exhibit No. 6 at 25-26 [Brandt]). The credit rating agencies now look very closely at the unfunded pension obligations that a company has, and the rating agencies use the PBO (rather than the ABO) when calculating a company's credit metrics. (*Id.* at 25). Thus, accelerated contributions to the pension plan would substantially reduce the need for future pension fund contributions (as well as lowering the pension expense borne by APS customers), thereby improving the Company's FFO/Debt ratio and assisting the Company to maintain its bond ratings. (*Id.*).

The objections of Staff, RUCO and AECC to this pension funding proposal by APS essentially amount to a "wait-and-see" approach – *i.e.*, let's wait and see what happens in future years. But as Mr. Brandt explained, such an approach merely defers the problem, and likely causes it to grow; it does nothing to deal with the underfunding that already exists. (APS Exhibit No. 5 at 56-59 [Brandt]; APS Exhibit No. 6 at 23 [Brandt]). Implementing the Company's pension funding proposal now is not only consistent with the new PBO accounting requirement (Tr. Vol. IV. at 778 [Brandt]), but also has the benefit of requiring current customers to fund a liability that has already been incurred rather than deferring that liability to future customers.

[53] The PBO measures the full pension liability, whereas the ABO is a partial measure (*i.e.*, a subset of the PBO). The ABO is based on current pay levels for employees and assumes that employees do not receive pay increases between the measurement date and their retirement dates. (APS Exhibit No. 5 at 61-62 [Brandt]). The PBO assumes that employees continue to receive pay increases until they retire. (*Id.*). Because the ABO does not consider future pay increases that affect future pension obligations, the ABO yields a smaller pension liability than the PBO. (*Id.*).

(APS Exhibit No. 5 at 58 [Brandt]).

In short, it is both fair to customers and fiscally prudent for the Company and the Commission to deal with this pension under funding issue now rather than deferring the problem to a later date.

f. Annualize Property Tax Expense.

The evidence in this case supports the Company's adjustment to reduce its pre-tax Test Year operating income in the amount of $15,031,000,[54] which represents Company's ACC Jurisdictional revised calculation of annualized property tax expense. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 19.

In its filing, the Company adjusted its operating expenses to include amounts to annualize the PWEC Units' property taxes, one full year of property taxes for the Sundance Units, estimated taxes for the full Maricopa Community College Bond and account for an automatic 2007 increase in property taxes resulting from the PWEC Units "phase-in" period provided by statute[55] through 2009 (APS Exhibit No. 56 at 23 [Rockenberger]). The 2005 tax year APS composite tax rate, which includes the PWEC Units, was calculated based on tax rates provided by the County Treasurer in each of the counties where APS has property. In addition to the APS composite tax rate, the actual 2005 tax rate for the Sundance Units was used. Finally, the Company took into account the reduction in assessment ratio provided by House Bill 2779, which was passed during the 2005 legislative session. (*Id.*).

In its January 2005 filing, the Company calculated its property tax expense, which was based on the December 31, 2004 property values provided by ADOR. (APS Exhibit No. 57 at 20-21 [Rockenberger]). During the course of this proceeding, however, the Company received more current assessment valuation information from ADOR based on actual plant values at December 31, 2005 that provides a more precise calculation of the property taxes that the Company will be accruing and paying as property tax expense in 2007, the time period when rates from this case will be in effect. (*Id.*). ADOR has also recently approved the Company's

[54] In this case, the Company decreased pre-tax operating income by $15,159,000, which represents the Total Company figure. (APS Exhibit No. 56 at 23 [Rockenberger]; *Id.* at Attachment LLR-2-12-13; *see also* APS Exhibit No. 57 at 20 [Rockenberger]; *Id.* at Attachment LLR-4-4RB).

[55] A.R.S. § 42-14156.

request to reduce the assessed value for the PWEC Units regulatory disallowance that is reflected in Company records. These are known and measurable net increases in the 2005 assessed value and should appropriately be taken into consideration in the calculation of property taxes. (*Id.*).

APS opposes RUCO's stand-alone adjustment to reduce property taxes by $5,977,000, which is based on a temporary suspension of the county education tax rate.[56] (*Id.*). This legislation was passed during the 2006 legislative session, and signed into law June 21, 2006. RUCO is proposing the use of a tax rate enacted outside the Test Year that reduces property taxes, but fails to take into consideration other significant factors that occur outside the Test Year that increase property taxes.

Property taxes are comprised of two key components: the level of plant-in-service; and, the property tax rate. As plant-in-service increases, property taxes increase, and as property tax rates decrease, property taxes decrease. In this case, although the property tax rate is decreasing, the Company's total tax bill is actually increasing because the amount of facilities that APS has added to its electric system has increased. (Tr. Vol. XII at 2616 [Rockenberger]). One component of property tax cannot be implemented in isolation; both the increase in plant-in-service through the end of 2005 and its impact on the property tax calculation, as well as the reduction in the tax rate, have to be considered. (Tr. Vol. XIII at 2683 [Rockenberger]).

The rates that are approved in this proceeding will go into effect in 2007. The matching principle requires that APS match the recovery in rates with the actual expense to ensure that the Company will have the cash flow to pay the property tax bill. (Tr. Vol. XIII at 2685 [Rockenberger]).

The Company's projected 2007 property tax expense is anticipated to be $128,000,000, based upon December 31, 2005 general ledger balances and inclusive of all property tax deductions. (Tr. Vol. XII at 2616 [Rockenberger]). RUCO's calculation only considered the 2006 level of property tax expense, which was based upon December 31, 2004 general ledger balances. (Tr. Vol. XII at 2618 [Rockenberger]). That level of plant-in-service is nine months prior to the end of Test Year and, thus, fails to reflect even the property taxes due on Test Year

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[56] A.R.S. § 41-1276 (I).

end plant levels. It is 18 months prior to enactment of the new tax rate and more than two years prior to any new rates going into effect from this proceeding. RUCO's proposed adjustment would result in recovery of, at most, $124,000,000 in property tax expense in the first year that the rates in this case will be in effect; calendar 2007 property tax expense is already at least $128,000,000. This will result in a shortfall of $4,000,000 in revenues. (Tr. Vol. XIII at 2686 [Rockenberger]).

APS proposes that the Test Year property tax expense be based on year-end 2005 plant to ensure that the regulated rates provide for a larger share of the Company's actual 2007 property tax expense. (APS Exhibit No. 58 at 3-4 [Rockenberger]). APS's proposal recognizes both the post-Test Year change in the rate and the post-Test Year changes to the level of plant to which that rate would apply. (Tr. Vol. XXIII at 2640-41 [Rockenberger]). This proposal provides customers the full benefit of the suspension of the county education tax rate, while also recognizing the full cash value of plant-in-service that is known and measurable at this time. (*Id.* at 2683, 2686 [Rockenberger]).

Staff has 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. (Staff Exhibit No. 35, Schedule C-17). APS agrees with Staff's recommendation which provides for a Test Year operating expense of $128,600,000. This amount most nearly approximates the Company's 2007 estimated $128,000,000 property tax expense, with is the level of property tax expense that the Company believes is appropriate to recover. It should be noted that the Company does not agree with the elimination of the 2007 statutory phase-in, but rather, the Staff adjustment provides for the recovery of expected property tax expense.

g. Annualized Depreciation And Amortization.

The evidence in this case supports the Company's final adjustment to decrease its pre-tax Test Year operating income in the amount of $ 20,276,000,[57] which represents the Company's

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[57] In this case, the Company decreased pre-tax operating income by $22,498,000 which represents the Total Company reduction. (APS Exhibit No. 56 at 20-22 [Rockenberger]; *Id.* at Attachment LLR-2-9).

ACC Jurisdictional pre-tax adjustment to depreciation and amortization expense based upon the technical update to the depreciation rates authorized in Decision No. 67744. *See,* APS Initial Brief Exhibit 4, Schedule C-2, Column 18.

(1) Depreciation.

Consistent with Decision No. 67744, as of April 1, 2005, APS implemented the depreciation rates ordered by the Commission. For this filing, Dr. Ronald White performed depreciation studies as of December 31, 2004. Based upon the results of the technical update, depreciation and amortization expense increased by $23,055,000.[58] (APS Exhibit No. 56 at 21 [Rockenberger]; *Id.* at Attachments LLR-2-9 and LLR-2-10).

Staff and RUCO have agreed with the depreciation rates proposed by APS. Staff found that the depreciation rates proposed by the Company were developed in a manner that was consistent with the Commission's rules for depreciation rates and were consistent with a "technical update" approach to the depreciation rates that the Commission approved in Decision 67744. (Staff Exhibit No. 18 at 34-35 [R. Smith]). The Staff had recommended that APS clearly specify the new depreciation rates as a service life rate or a net salvage rate, similar to the rates shown in Appendix A to Decision No. 67744, and the Company does not object. APS does not agree with Staff's proposal to modify the Commission's rules regarding net salvage. Staff's approach would only serve to further jeopardize the Company's already inadequate cash flow and to burden future customers with the cost of retiring or decommissioning plants that are serving current customers. No other Party opposed APS's proposal.

(2) Amortization.

The Company has not requested any change to the amortization rates authorized in Decision No. 67744, although the Company is requesting approval for two new rates to provide for the amortization of leased vehicles that are purchased by the Company at the end of the lease

[58] The depreciation study does not include allocation of shared services depreciation expense. In accordance with the Code of Conduct and the Company's Affiliate Accounting policies, an operating revenue adjustment of $480,000 was made by APS to reflect the amounts received from affiliates for their allocation of shared services depreciation expenses. (APS Exhibit No. 56 at 22 [Rockenberger]; *Id.* at Attachment LLR-2-9). In addition, amortization of the gain associated with the sale of the Glen Canyon 230 kV line further reduces depreciation and amortization expenses by $77,000. (*Id.*).

term. (APS Exhibit No. 56 at 22-23 [Rockenberger]). No party has opposed the new amortization rates.

RUCO, however, has taken issue with the Company's overall amortization expense even though it was calculated based on current authorized amortization rates. Instead, RUCO has proposed a $6,991,000 reduction in amortization expense based on its use of a composite amortization rate. RUCO calculated an increase in amortization expense by multiplying the total increase in intangible and general plant balances by a composite amortization rate of 10.38 percent. This approach ignores the differences in the ACC-approved amortization rates for various intangible plant accounts and is contrary to the long-standing, Commission-approved method of amortization of intangibles and general plant assets that APS has been operating under for many years and was used by Staff in this proceeding.

In contrast to the RUCO methodology, the Amortization Rate Summary provided by APS clearly shows that the actual amortization rates vary according to the type of asset group and are, in many instances, specific to the individual asset. (APS Exhibit No. 56, Attachment LLR-2-11 [Rockenberger]). For example, amortization of computer software is at 20 percent annually, while amortization of a lease is over the life of the particular lease. APS's calculation was based on the actual individual asset costs and lives at September 30, 2005, multiplied by the actual ACC-approved amortization rates for each individual asset account. (APS Exhibit No. 57 at 19 [Rockenberger]).

RUCO did not dispute the asset balances of the intangibles or general plant account balances. In fact, Ms. Diaz Cortez stated in her testimony that she analyzed the asset balances at December 31, 2004, and at September 30, 2005, and noted the assets increased by approximately 5.5 percent. (RUCO Exhibit No. 24 at 28 [Diaz Cortez]). RUCO did not dispute any of the account balances that it analyzed. RUCO also agreed that different asset accounts with the same total balance amortized over different service lives result in different amortization expense. (Tr. Vol. XVIII at 3427 [Diaz Cortez]). RUCO concurred that the overall asset balance can remain the same, yet there can still be a significant change in amortization expense. The adoption of one composite rate, as RUCO has proposed, would disregard the method of amortizing intangible and general plant account balances that has been the long-standing method accepted and approved method by this Commission specifically for APS, and to its knowledge, for other major utilities in this state.

h. Demand Side Management.

The Company proposed a final adjustment to decrease Test Year pre-tax operating income by $7,896,000, which represents both the Total Company and ACC Jurisdictional DSM pro forma adjustment to the Test Year operating costs. (APS Exhibit No. 48 at 12 [Froggatt]; *id.* at Attachment CNF 1-3). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 3. The DSM pro forma adjustment increases Test Year operating costs by the $2,989,000 (for program costs) and recognizes the corresponding reduction in revenue as a result of Commission approved DSM programs, which is expected to be $4,907,000. (*Id.*). These numbers are additive.

Both Staff and RUCO dispute APS's pro-forma $4,907,000 revenue adjustment, which reflect a conservation adjustment.[59] Staff contended that the conservation adjustment, unlike the performance incentive, is based upon estimated costs. (Staff Exhibit No. 16 at 9 [Anderson]).[60] RUCO concurred in this objection, arguing that the conservation adjustment is based upon "estimated lost revenues and expenses that have not actually been realized." (RUCO Exhibit No. 24 at 15 [Diaz Cortez]). Since the program is in its early stages, RUCO believes estimates of future consumption and losses in revenue based upon DSM programs should not be taken into account until they have occurred in some historical period. (*Id.*).

RUCO argued that the Settlement Agreement specifically precludes the Company from making the conservation adjustment.[61] (RUCO Exhibit No. 24 at 15 [Diaz Cortez]). However,

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[59] The term "conservation adjustment" has been used interchangeably with "net lost revenues". To avoid confusion with the "net lost revenues" or "uncollected fixed costs" that have been discussed related to the Company's net metering program, the term "conservation adjustment" is used in this discussion.

[60] Staff's argument that reflecting the conservation adjustment to test period sales is somehow duplicative of the performance incentive is addressed in section VII.D.3(a) of the Company's Initial Post-Hearing Brief.

[61] The Settlement Agreement from APS' previous rate case provides:

> This Agreement does not provide for the recovery of net lost revenues. *Except* to the extent reflected in a test year used to establish APS rates in future rate proceedings, or unless otherwise authorized by the Commission in a separate non-rate case proceeding, APS shall not recover or seek to recover net lost revenues on a going-forward basis. In no event will APS recover or seek to recover net lost revenues incurred in periods prior to such test year or for periods prior to the Commission's authorization of net lost revenue recovery in a separate non-rate case proceeding ....

Decision No. 67744 at 10 ¶ 46 (2005) (emphasis added).

RUCO later modified its argument, recognizing that the Settlement Agreement did allow APS to make a request for the conservation adjustment as part of a general rate case – precisely what APS is doing. (Tr. Vol. XVIII at 3420 [Diaz Cortez]). Although RUCO attempted to qualify its position by arguing that the Settlement Agreement contemplated three years of uninterrupted DSM policy, no Settlement Agreement language or evidence was entered to that effect, nor does the Company's request for a relatively routine type of pro forma adjustment to test period revenue affect the three-year commitment to DSM required by Decision No. 67744.

RUCO also argued that the conservation adjustment violates the "matching principle" alleging that it accounts for post-Test Year losses in revenue without accounting for "post-test-year gains in revenue from customer growth." (RUCO Exhibit No. 24 at 15 [Diaz Cortez]). The Company disagrees in that its adjustment merely captures the impact of DSM expenditures made during the Test Year and in 2006.

Although Staff agreed with the Company that the conservation adjustment may be pursued as part of a general rate case (Tr. Vol. XIX at 3639 [Anderson]), Staff argues that the conservation adjustment is limited by the Test Year, and since the conservation adjustment requested by the Company was provided as a pro forma adjustment, it should not be allowed. (*Id.* at 3640 [Anderson]). Yet, the revenue pro forma adjustment made by the Company is simply a normalization adjustment for the "known and measurable" effect of the recently approved DSM programs based on expenditures in 2005-2006. (APS Exhibit No. 17 at 10 [Ewen]).

Although both Staff and RUCO contend that the conservation adjustment, unlike the performance incentive, is based upon estimated costs and should not be allowed, (Staff Exhibit No. 16 at 9 [Anderson]; RUCO Exhibit No. 24 at 15 [Diaz Cortez]), the Company submits that it is appropriate to set rates on conditions that will be present when the new rates go into effect. (APS Exhibit No. 17 at 10 [Ewen]). Consistent with standard ratemaking policy, the Company proposes a conservation adjustment to base rates predicated upon known and measurable conditions as set forth in Decision No. 67744. (*Id.*). The Company even modified its request, basing the conservation adjustment on "actual spending … and the amounts planned to be spent in the 4th quarter of this year." (APS Exhibit No. 18 at 9 [Ewen]). Most of that spending was for programs such as the compact fluorescent light program, for which the savings per bulb are completely predictable. (Tr. Vol. VII at 1404 [Orlick]. As such, the Company's calculations are not estimates, but "known and measurable" adjustments to the Test Year. (Tr. Vol. V at 1095 [Ewen]). The failure to allow APS to recover its lost revenues from DSM programs by reflecting such revenue losses in general rate proceedings will simply prevent the Company from currently recovering its full cost of service. (APS Exhibit No. 17 at 10 [Ewen]).

i. Base Fuel And Purchased Power (Including Off-System Sales).

Fuel and purchased power expenses were discussed in a previous section of APS's Initial Post-Initial Brief. The pro forma adjustment necessary to reflect the Company's proposed Base Fuel Cost is shown on APS Initial Brief Exhibit 5, Schedule C-2, Column 24. The evidence in this case supports the Company's adjustment to reduce its operating income in the amount of \$259,512,000,[62] which represents the Company's ACC Jurisdictional adjustment to the Company's original pro-forma to include 2007 base fuel and purchased power expense and off-system revenues, as expressed in cents/kWh, at adjusted Test Year levels.

j. "Lobbying" Costs.

(1) Company's Request.

The Company is requesting inclusion of \$1,763,994 of prudently incurred expenses for efforts by its Federal Affairs and Public Affairs Departments that benefit customers and utility operations in its cost of service for which Staff seeks elimination. (Staff Exhibit No. 35 at Schedule C-15). The Company itself already allocated certain costs between "below-the-line" lobbying activities for which the Company is not seeking recovery and "above-the-line" Public Affairs activities that directly benefited regulated operations and, as a result, nearly two-thirds of the Company's Public Affairs Department budget had already been allocated to the shareholders "below-the-line." (APS Exhibit No. 2 at 23-24 [Wheeler]).

[62] This amount is calculated as follows: \$243,824,000 (SFR Schedule C-2, filed January 31, 2006, column (VV)), plus \$32,305,000 (APS Exhibit No. 49, Attachment CNF-2RB Page 6 of 7, column 16 [Froggatt]), minus \$16,617,000. (APS Exhibit 53, Rejoinder C-1, Page 2 of 2, column (e)).

Examples of customer benefits that arose from the activities of two APS departments include: obtaining a waiver of the tariff importation fees for the Palo Verde replacement steam generator, which resulted in savings of approximately $10 million; support of provisions in the Energy Transportation Act of 2005 on tax incentives for new transmission investment, which resulted in an estimated savings of $1.4 million per $50 million of eligible new transmission; support of the Production Tax Credit provisions of the American Jobs Creation Act that produced a $3 million benefit, which is already reflected in this rate case; and support of state property tax legislation, which resulted in annual property tax savings of $1.7 million – also reflected in this proceeding. (APS Exhibit No. 2 at 24 [Wheeler]).

Evidence presented relating to utility and customer savings associated with lobbying efforts has not been controverted. RUCO recognized that some of APS's requested lobbying expenses have a public benefit to customers and has recommended that the Commission allow 50 percent recovery of such costs. (RUCO Exhibit No. 26 at 15 [Diaz Cortez]). Staff acknowledged that not all lobbying efforts by utility companies are detrimental to customers and that "it is virtually impossible to know at what 'cost' the achievement of even the 'pro-consumer' legislation was accomplished" by such efforts. (Staff Exhibit No. 34 at 116 [Dittmer]). Staff, while admitting that some lobbying expenses are beneficial to customers, did not specifically analyze APS's lobbying expenses to determine whether such lobbying efforts benefited customers in this case. (Tr. Vol. XXII at 4231-4233 [Dittmer]).

The Commission itself has seemingly recognized the legitimacy and even necessity of efforts by utilities to influence public policy and its role in benefiting utility customers. At the hearing in this case, in conjunction with the discussion of the utilization of hook-up fees, both Commissioner Mayes and Mundell specifically inquired as to whether APS has "lobbied" Congress for tax changes related to the requirement that a utility include in gross taxable income contributions in aid of construction. (Tr. Vol. IV at 752-753[Brandt]; Tr. Vol. XXVI at 4836 [Robinson]). In addition, one of the Commissioners suggested that APS "lobby" the legislature for additional funding so the Commission could acquire additional staff. (Tr. Vol. XX 3754; Tr. Vol. XXII at 4233 [Dittmer]).

(2) Precedent In Recovery Of Lobbying Expenses

The Commission may allow recovery of lobbying expenses. Despite Staff's contention to the contrary, there are a number of jurisdictions, including Arizona and FERC, which have allowed recovery of lobbying expenses as long as the utility can demonstrate the benefits of such activities to customers and not just to shareholders.[63]

In 1994, Tucson Electric Power Company ("TEP") requested the Commission include $152,000 for membership dues in the Edison Electric Institute ("EEI"). *Decision No. 58497,* 149 P.U.R. 4th 251 (January 12, 1994). Although the Commission disallowed $40,000 of the dues directly attributable to lobbying expenses, it was not because it was somehow "per se" improper for a utility to attempt to influence legislation, rather the Company did not clearly demonstrate the benefits that lobbying activities would have for customers. The clear implication is that if the company had demonstrated that the lobbying activities were beneficial to customers, the Commission would have allowed such recovery.

In 1986, APS sought to recover trade industry dues. *Decision No. 55228,* 77 P.U.R. 4th 542 (October 9, 1986). Although the Commission did disallow a portion of the dues associated with advertising and government affairs expenses, it was again an alleged failure of proof rather than some arbitrary policy against "lobbying" that prompted the outcome. The Commission stated in its Decision that "[o]nly expenditures which primarily or exclusively benefit shareholders which have no significant direct benefit to ratepayers should be disallowed." (*Id.*). Here again, the inescapable conclusion is that "lobbying" expenditures that benefit customers would be allowed.

Most recently, FERC issued a decision that involved a determination as to whether certain expenses associated with ISO New England's "external affairs" and "corporate communications" were just and reasonable and properly recoverable from customers or whether they should be classified as "lobbying" activities in Account No. 426.4. *ISO New England Inc.*, 117 F.E.R.C. P61,070; 2006 FERC Lexis 2338, *Docket Nos. ER06-94-001, ER06-94-003, EL06-77-000, EL06-77-002* (October 19, 2006). In permitting recovery of these expenses, FERC made

[63] At the Hearing, Commissioner Mayes requested that APS brief this issue of recovery of lobbying expenses. (Tr. Vol. II at 291-295 [Wheeler]).

the following determination:

> 47. Our precedent has not always been clear when it comes to the classification and recovery of informational expenditures. On a number of occasions the Commission has found "lobbying" expenses of any type to be non-recoverable, while on other occasions the Commission has determined that even if the costs are related to lobbying and should be recorded in Account **426.4**, they are appropriately recoverable from ratepayers upon sufficient showing that they were undertaken for the benefit of ratepayers. . . .
>
> 48. Based on the above-stated principles, the Commission will permit recovery of ISO-NE's "external affairs" and "corporate communications" expenses as detailed in ISO-NE's July 17 filing. *We find that because ISO-NE has shown that its informational activities were directly related to existing or proposed core operations and undertaken to benefit its ratepayers, it may recover the costs associated with those activities.* (Emphasis added.)

(*Id.* at 43-44).

There are other jurisdictions that have allowed or have implied that they would allow recovery of some or all of lobbying-type expenses to the extent such activities benefited customers, including Georgia,[64] Idaho,[65] Indiana,[66] Missouri,[67] Nevada,[68] Florida,[69] and Rhode Island.[70]

The Commission has previously indicated that it would consider allowing the recovery of lobbying expenses to the extent a utility has met its burden of demonstrating customer benefits. Because APS has provided uncontroverted evidence demonstrating the benefits of its lobbying activities to customers, the Commission should reject the adjustments proposed by Staff and RUCO.

k. Incentive Compensation.

APS's annual variable incentive plans and its long-term incentive plans are designed consistently with the competitive market practices, and are integral in providing a reasonable,

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[64] *Re GA. Power Co.*, 120 P.U.R. 4th 621, Georgia Public Service Commission, Docket No. 3840-U (Sept. 28, 1989).
[65] *Re Intermountain Gas Co.,* 30 P.U.R. 4th 231, Idaho Public Utilities Commission, Order No. 14859 (Aug. 17, 1979).
[66] *Re Hoosier Energy Rural Elec. Coop., Inc.*, 62 P.U.R. 4th 134, Indiana Public Service Commission, Cause No. 37294 (June 29, 1984); *Re Ind.-Am. Water Co., Inc.*, 169 P.U.R. 4th 252, Indiana Utility Regulatory Commission Cause No. 40103 (May 30, 1996).
[67] *Re Kan. City Power and Light Co.*, 55 P.U.R. 4th 468 (July 8, 1983).
[68] *Re Sierra Pac. Power Co.*, 129 P.U.R. 4th 470 (Jan. 31, 1992).
[69] *Re Florida Power Corporation,* 138 P.U.R. 4th 472, Florida Public Service Commission, Order No. PSC-92-1197-FOF-EI (October 22, 1992).
[70] *Providence Gas Company v. Edward Burman et. al.*, 22 P.U.R. 4th 103, 119 R.I. 78, 376 A.2d 687 (1977).

competitive "total" compensation program at all levels of the organization. (APS Exhibit No. 51 at 4 [Gordon]). The elimination of any of these programs would significantly impair APS's ability to attract and retain employees critical to its successful ongoing operation. (*Id.*). In addition, the variable incentive plan is effective in aligning employees with its business objectives and reinforcing a high performance culture. (*Id.* at 4-5).

There is an important distinction between a mere "bonus" payment and an "incentive" program. (*Id.* at 7). A bonus is often viewed as an *ad hoc* and wholly discretionary "add on" to base pay, with the award size arbitrarily determined at the end of the year based on the generosity of management. (*Id.*). In sharp contrast, an annual incentive or "at risk" pay program is an integral part of annual cash compensation where a portion of the employee pay is put at risk and establishes an expectation for the participant at the beginning of the year that if certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual award earned is variable based on actual results relative to the pre-set goals. (*Id.*).

The philosophy and strategic reasons behind the introduction of variable incentive plans include to:

- Link pay with business performance and personal contribution to results.
- Motivate participants to achieve higher levels of performance.
- Communicate and focus on critical success measures.
- Reinforce desired business behaviors, as well as results.
- Reinforce an employee ownership culture.

(*Id.* at 8).

APS's incentive program benefit customers in a number of ways, including helping to attract, motivate and retain key employees, a key factor in driving high performance. (*Id.* at 16). It has also produced measurable results in cost-containment and service improvement. (*Id.* at 18.)

(1) Staff's Disallowance Of Stock-Based Incentive Compensation

APS is seeking approval of $4.8 million in operating expenses related to its employee stock incentive program, which is also part of the compensation package for eligible APS employees. Staff has proposed to eliminate this amount in its entirety. RUCO has not specifically objected to the Company's proposal.

Although proposing no disallowance of **cash** incentive pay, Staff has drawn an arbitrary distinction in the case of incentives paid in Company stock. APS's stock incentive component, or "long-term" incentive, is integral in attracting and retaining high quality management personnel. (APS Exhibit No. 50 at 19-20 [Gordon]). The program benefits APS customers by:

- Minimizing costs associated with high turnover at the executive level, including recruiting, productivity reductions and continuity of leadership.
- Minimizing the need for additional base pay or other fixed benefits to provide competitive compensation levels.
- Providing focus and accountability for the executive and management team to develop and implement effective business strategies that span multiple year periods.
- Long-term financial health provides stability and allows the Company to continue to invest in the business operations, grow its asset base and continue to improve operating efficiencies through economy of scale and upgrades in technology and infrastructure which directly benefit customers through maintaining a low cost generation and delivery structure.

(*Id.* at 21-22).

Staff has attempted to justify the exclusion of approximately $4.8 million of stock-based incentive compensation by alleging that stock-based incentives are entirely or primarily driven by Pinnacle West earnings achievements or total return to shareholders that only indirectly benefits consumers. First of all, the issue is whether APS employee compensation, including cash and stock incentives, is reasonable and **not** how that compensation is determined or whether that compensation is comprised of base salary, incentive pay, benefits or stock. (APS Exhibit 2 at 22 [Wheeler]). There has been no allegation, let alone evidence, that overall APS employee compensation is excessive or unreasonable. (APS Exhibit No. 2 at 21-22 [Wheeler]).

Moreover, the Staff disallowance of the plan is based upon the faulty belief that the interests of investors and consumers are in fundamental conflict over the issue of financial performance. 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. (*Id.*) In a sense, their stake may be higher than that of investors and the employees receiving stock incentives. The former can take their capital and their services elsewhere if they do not receive fair compensation. Consumers cannot as easily avoid the problems associated with a utility in financial trouble or which cannot attract and retain qualified management employees.

The stock incentive plan is an additional component of employee compensation that the Company offers which is consistent with similar programs of other companies. (*Id.* at 22). Again, the only relevant ratemaking issue is whether APS employee compensation taken as a whole is reasonable, and not whether the compensation is base salary, benefits, cash incentive pay or stock. Not only has there been no evidence presented in this case that suggests that overall APS compensation is unreasonable, the evidence presented is to the contrary. (*Id.* at 21-22). On cross-examination, when asked whether he made any determination as to the reasonableness of the compensation received by the Company's officers and senior management, the Staff witness responded "no" and that the basis for his recommendation was "conceptual". (Tr. Vol. XXII at 4229 [Dittmer]). Staff did not find the stock incentive plan unreasonable or imprudent – indeed Staff did not even allege as much. Therefore, APS should be permitted recovery of such costs. (APS Exhibit No. 2 at 22 [Wheeler]).

(2) RUCO's Overall 20 Percent Reduction In Incentive Pay

As noted above, Staff did not oppose APS's Employee Cash Incentive Program in which APS is seeking approval of approximately $17,800,000 in operating expenses related to its employee cash incentive program and concluded that the cash incentive payments were reasonable and found that the Company proposed level of Test Year cash incentives are **tied primarily to performance measures that directly benefit APS customers as they included the achievement of customer oriented goals such as lowering costs, increasing reliability or improving service and satisfaction.** (Emphasis added.) (Staff Exhibit No. 34 at 110, 112 [Dittmer]).

In contrast, RUCO has proposed a reduction of approximately 20 percent ($4,563,000) to the Company's employee cash incentive program, without providing **any** supporting analysis

(RUCO Exhibit No. 23 at 9, 12 [Rigsby]), or making any assertion that APS's incentive program was not in line with other firms. Furthermore, in making this recommendation, RUCO failed to: 1) analyze the potential impacts that a reduction in incentive compensation would have on APS's ability to retain or attract qualified employees; 2) analyze the reasonableness of the total compensation package of APS employees; 3) determine how many APS employees were also APS residential customers and take into consideration that such employees would realize a reduction in compensation, as well as a rate increase; or 4) analyze the potential effects such a reduction would have on investors, rating agencies, or Wall Street analysts. (Tr. Vol. XVIII at 3330-3336 [Rigsby]). RUCO's sole justification was that APS customers should not have to shoulder the burden of higher electric rates when APS employees are given an opportunity to earn more pay that could mitigate or eliminate the impact of the rate increase, and that APS employees should "share the same pain and hardship" that the rate increase would have on their customers. (RUCO Exhibit No. 22 at 13-15 [Rigsby]).

The RUCO proposal to reduce incentive compensation to even rank and file APS employees is simply arbitrary and ill-conceived and should not be adopted. The suggested "share the pain" approach implies that APS employees that directly and substantially contribute to the provision of an essential utility service should subsidize the cost of providing electricity to the Company's customers. It penalizes APS employees by requiring them to shoulder the burden of cost increases attributable to economic forces outside of their control, such as increased fuel costs and a rapidly growing service territory. Moreover, in the case of APS employees who also happen to be APS customers, the RUCO proposal would, in effect, require such employees to pay twice for the increase. Finally, it also sends the wrong message to a highly skilled and trained workforce regarding how their efforts are viewed and could potentially inhibit the Company's ability to attract and retain such employees in a very competitive environment.

The Company presented evidence that it had already eliminated **all** officer cash incentive payments (approximately $3,890,000) from its Test Year period and included officer salaries at the 2004 (as opposed to the higher Test Year) level. (APS Exhibit No. 2 at 21 [Wheeler]; APS Exhibit No. 3 at 10 [Wheeler]. Moreover, whereas RUCO again presented no evidence that the

APS compensation was unreasonable, the Company provided uncontroverted testimony as to the reasonableness of the employee compensation programs. (APS Exhibit No. 2 at 21-22 [Wheeler]).

3. Adjustments Where The Need For And The Means Of Calculations Are Uncontested, But Where Final Adjustments Differ.

While there is no disagreement among Parties regarding the need for the following adjustments or the mechanics as to how they are calculated, the outcomes of the calculations differ because the amounts that are input into the calculations depend on other factors, as described below.

a. Income Tax / Interest Synchronization.

There is no dispute as to the methodology used in the Company's final adjustment to reduced Test Year operating income in the amount of $2,523,000,[71] which represents ACC Jurisdictional figure that reflected the synchronization of interest expense using the adjusted September 30, 2005 capital structure and the cost of long-term debt, as well as the use of the statutory income tax rate. *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 9. However, the level of synchronized interest and its associated income tax effect does depend on the final level of jurisdictional (original cost) rate base found appropriate by the Commission and the weighted cost of debt. (RUCO Exhibit No. 23 at 17 [Rigsby]).

b. Generation Production Income Tax Deduction

APS had determined the deduction for the Test Year ended September 30, 2005 reduced income tax expense by $1,862,000. (APS Exhibit No. 48 at 15-16 [Froggatt]; *id.* at Attachment CNF 1-8). Subsequent to the filing of APS's direct case, final Treasury Regulations were issued. (Staff Exhibit No. 34 at 127 [Dittmer]). Staff's proposed adjustment takes into account the final Treasury Regulations that were not available to APS when it filed its direct case and synchronizes the calculation for Staff's proposed return recommendation. APS agrees in principle with the changes resulting from the issuance of the final regulations, but opposes

[71] In this case, the Company reduced operating income by $3,009,000, which represents Total Company figure. (APS Exhibit No. 48 at 16 [Froggatt]; *Id.* at Attachment CNF 1-9; *see also* APS Exhibit No. 49 at 7 [Froggatt]; *Id.* at Attachment CNF-8RB).

calculating the adjustment based on Staff's proposed weighted cost of common equity. This adjustment should ultimately reflect the cost of capital used by the Commission to establish rates in its final Order. (APS Exhibit No. 49 at 6 [Froggatt]). The Company's revised estimate results in a reduction of ACC Jurisdictional income tax expense of $3,054,000.[72] [*Id*; *Id* at Attachment CNF-7RB). *See,* APS Initial Brief Exhibit 5, Schedule C-2, Column 8. The revised estimate was based upon the final Treasury Regulations and the APS proposed cost of common equity of 6.27 percent. For every tenth-point reduction (from 6.27 percent) in the weighted cost of common equity used by the Commission to establish rates in its final Order, the income tax expense increases by approximately $42,600.[73]

D. Other Revenue Requirement Issues.

1. Environmental Improvement Charge

The Company proposes a final adjustment to increase Test Year pre-tax operating income by $4,542,000, which represents the Company's ACC Jurisdictional pro forma adjustment increase to Test Year operating costs. (APS Exhibit No. 53 [Rejoinder A-1]). (A detailed analysis of justification for the EIC adjustment is discussed later in this Initial Post-Hearing Brief.)

2. Addition Of Incremental EPS Surcharge

Decision No. 68668 required APS to set aside $4,250,000 for additional funding for the EPS Uniform Credit Purchase Program ("UCPP"). Staff recommends that the EPS adjustor rate and caps be increased to recover an additional $4,250,000 through the Company's Adjustment Schedule EPS-1. (APS Staff Exhibit No. 12 at 4 [Keene]; APS Exhibit No. 38, Attachment GAD-2RB [DeLizio]). APS notes that the actual level of expenditures for the UCPP during 2006 was unknown as of the time of the hearing and, thus, it may be appropriate to allow for some manner of "true-up" such that under/over spending of the additional $4,250,000 would be carried forward as a regulatory asset/liability that could be reconciled in future rate proceedings

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[72] In this case, the Company reduced income tax expense by $3,089,000, which represents the Total Company figure. (APS Exhibit No. 49 at 6 [Froggatt]; *Id.* at Attachment CNF-7-RB).

[73] *E.g.*, Staff's proposed weighted cost of common equity is 5.59%. 6.27%-5.59% = 0.68%. (0.68%/.1) x $42.6K = $290K. $3,089K - $290K = $2,799K, which is the Staff proposed reduction of income tax expense.

or, in the case of a regulatory liability, used to finance additional credit purchases in 2007 and succeeding years.

VI.
FUEL AUDIT

Commission Staff retained The Liberty Consulting Group ("Liberty") to conduct an examination and analysis of the management and operations of fuel and purchased power functions at APS (the "Fuel Audit" [Staff Exhibit No. 33]), focusing on April through December 2005, during which the PSA applied. As part of its review, Liberty examined the Company's organization structure, responsibilities, and Staff; policies, procedures, systems, and tools; and procurement approach, methods, and decisions. (Staff Exhibit No. 28 at 7 [Antonuk]). Liberty conducted a comprehensive audit examining fuel and purchase-power procurement policy, strategy and transactions, as well as fuel and purchased-power costs in the Company's PSA. As a part of its audit, Liberty issued over 200 data requests, conducted on-site interviews, and did on-site inspections of fuel handling, quality control, performance monitoring and maintenance at the Company's generating stations. (Staff Exhibit No. 33 at 4-5 [Fuel Audit]). Liberty reviewed the simulation models used to develop fuel and purchased power forecasts and analyzed the models used by traders to determine the correct dispatch of resources, as well as reviewing the Company's hedging, off-system sales and fuel and purchased power contracts. (Staff Exhibit No. 28 at 7-8 [Antonuk]).

The Fuel Audit verified that APS handled fuel and energy procurement and management in a manner that produced appropriate costs during the audit period. (Staff Exhibit No. 28 at 4 [Antonuk]). Liberty concluded that there were no indications of imprudently incurred fuel and purchased power costs for 2005. Liberty specifically noted that most of the changes Liberty had recommended as a result of the Fuel Audit seek to move APS in the direction of utilizing best practices in terms of procedures and analytical methods, and that these changes would be incremental improvements to overall management that is already effective. (*Id.* at 21).

Regarding the Company's **organization and staffing**, Liberty found that the personnel in the fuel and power procurement organizations have solid analytical skills and sound experience;

that communication within and among these organizations was satisfactory, as was the Company's program for training and cross training individuals. (Staff Exhibit No. 33 at 6 [Fuel Audit]). Liberty concluded that APS used adequate procedures and decision processes, documented decisions sufficiently, operated under established procurement approval limits, and underwent regular internal auditing. Liberty recommended improvements in procedures for fuel contract management and administration and in procedures for accepting gas-supply offers. (*Id.* at 6-7).

In response to these recommendations, the Company has agreed to review its procedures for fuel contract management and administration and, as appropriate, incorporate additional detail to reflect the processes used. (APS Exhibit No. 45 at 3 [Denman]). The Company has also improved its acceptance of gas supply offers by expanding the review process to compare 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 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. (APS Exhibit No. 25 at 14-15 [Carlson]).

With regard to **fuel management**, Liberty found that APS had effectively managed coal inventory levels, administered coal contracts, carried out sampling processes, and made economical use of coal combustion by-products. (Staff Exhibit No. 28 at 13 [Antonuk]). Liberty also concluded that APS's approach to gas-supply management had been effective. (*Id.*) Liberty made recommendations to streamline the procedures for handling information on coal weights and revising the inventory for the coal at the Cholla Station. (*Id.*). Liberty has also stated concerns about the change in APS's full-requirements arrangement with El Paso Natural Gas pipeline, in that FERC's interests in unbundled services and pricing has brought changes to El Paso's rates that will result in enormous increases in El Paso's charges to APS. (*Id.*; Staff Exhibit No. 33 at 53 [Fuel Audit]). Liberty recommended that APS examine its alternatives for reducing future pipeline-transportation costs and report the results of this analysis to the Commission within one year. (Staff Exhibit No. 28 at 13-14 [Antonuk]).

In response to Liberty's recommendations, APS will work with Cholla Power Plant management to review the coal inventory target and adjust it to reflect the appropriate inventory practice. With respect to the increases in El Paso's charges, the Company has investigated and will continue to investigate alternatives to gas transportation and will continue to work with Kinder Morgan and TransWestern Pipeline to encourage the construction of new pipelines to serve Arizona. (APS Exhibit No. 45 at 4 [Denman]). Lastly, the Company will conduct the recommended analysis of gas purchasing and management under El Paso's revised rate structure and submit a confidential report within one year of the Commission's decision in this docket. (*Id.* at 4-5).

With regard to the Company's **fuel contracts**, Liberty concluded that APS's long-term and short-term coal supply agreements were appropriate and effective and that APS used a sound process to contract for gas commodity. In addition, Liberty found that the Company's contracting process for fuel oils was effective. (Staff Exhibit No. 28 at 14 [Antonuk]).

With regard to **nuclear fuel**, Liberty found that APS conducts nuclear fuel procurement and management through an effective organization and has developed and used effective procedures for procuring nuclear fuel. In addition, Liberty found that APS used an appropriate basis to account for its nuclear fuel costs for ratemaking purposes. (Staff Exhibit No. 33 at 12 [Fuel Audit]).

In addressing APS's **purchased power**, Liberty found the Company based its marketing and trading activities on sound hedging policies and procedures, conducted electricity sales and purchases consistently with least-cost dispatch guidelines, produced economic transactions, and traded with diverse counterparties. Liberty concluded that APS was using appropriate tools and documentation to conduct power trading to achieve least-cost total dispatch. (Staff Exhibit No. 28 at 14 [Antonuk]). In the area of fuel and energy management, Liberty's principal concern was the physical location of the Company's utility and non-utility trading activities. (*Id.* at 15). In response to this concern, APS would like to point out that its recent revisions to the Code of

Conduct, which were adopted by the Commission and postdate Liberty's audit, include new policies and procedures that prohibit traders who handle APS's system from providing trading services for APS energy affiliates. (APS Exhibit No. 5 at 48 [Brandt]). Although Liberty's audit discovered no indications of any deliberate favoritism to any party, including any APS affiliate, APS has started implementing additional physical separation and controls, which should be completed in the immediate future. (*Id.* at 48-49).

Liberty also voiced a concern about PWCC's use of a utility transmission corridor that had generated positive margins of approximately four million dollars during a five month period. Liberty did note that APS had discovered this issue itself, and had made corrections. APS received a full credit for the $4.2 million noted above, which credit was passed along to APS customers through the PSA. (Staff Exhibit No. 28 at 16 [Antonuk]).

In analyzing APS's **off-system sales**, Liberty acknowledged that APS does not have excess coal and nuclear generation available for substantial portions of the year because its system load has grown past the Company's coal and nuclear resources. Thus, its sales opportunities and its margins from off-system sales are constrained. (*Id.* at 17).

Liberty found that APS designed and operated a sound **hedging** program, and that it has been successful in meeting its primary objective to promote price stability. (*Id.* at 17-18). To promote a common understanding of the hedging program and to verify that it is meeting the needs and expectations of customers, Liberty encouraged the Company, stakeholders and the Commission to have a dialogue on what goals a hedging program should have and the extent to which it should produce hedged prices. (*Id.* at 18). APS generally agrees with this suggestion. (APS Exhibit No. 5 at 45 [Brandt]). A dialogue 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. (*Id.* at 45-46). However, APS ultimately must 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. (*Id.* at 45).

Liberty was not the only third party that has reviewed the Company's hedging practices.

As a result of Decision No. 68685, APS was ordered to engage in a benchmarking study of their fuel costs and hedging practices. The consulting firm, R.W. Beck, performed that review. Their report, the Arizona Pubic Service Company Fuel Hedging Program Benchmarking Assessment (November 1, 2006) ("R.W. Beck Report"), was entered into evidence as APS Exhibit No. 72. The R.W. Beck Report concluded that "APS has a high-quality energy risk management and hedging program," that it was "consistent with leading industry practices." (*Id.* at 5-1).

Liberty had no recommendations regarding the Company's **forecasting and modeling**. Liberty found that APS used sufficiently accurate modeling to predict fuel and purchased power volume and cost; had taken appropriate actions to ensure that it achieves least-cost total dispatch; had utilized outside reviews appropriately to improve management and operations; and had maintained adequate documentation to support regulatory oversight and review. (Staff Exhibit No. 33 at 9 [Fuel Audit]).

In regard to **plant operations**, Liberty found that the performance metrics of the Company's base-loaded coal units demonstrated effective operation, as did the performance metrics of the large natural gas units. Liberty noted that the performance metrics of the natural gas units have been adversely affected since the former merchant units were inserted as part of the APS dispatch order, and that the Company is appropriately dealing with these issues. Liberty found that capital and O&M expenditure patterns for the APS generating fleet and its individual units have been consistent with current operational requirements and that APS times and layers it unit outage schedules effectively, and conducts scheduled outages within reasonable durations. (Staff Exhibit No. 28 at 18-19 [Antonuk]).

Liberty recommended that APS focus on optimizing the performance of the new natural gas units and improving its economic evaluations related to a minimization of outage time. (*Id.* at 19). Liberty also recommends that APS evaluate the replacement of boiler sections in some of its coal plants, and conduct a centralized review of operator and maintenance errors at the coal plants. (*Id.*). To improve the availability of West Phoenix Unit No. 5, Liberty recommended that root-cause analysis be undertaken when generation is lost at this facility. (*Id.* at 19-20). Liberty also recommended that APS analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix Load Pocket.

In response to these recommendations, APS believes it continually works to optimize performance of its natural gas units and minimize outages. APS has addressed operational and start-up issues with its natural gas units, Redhawk and West Phoenix CC5. (Staff Exhibit No. 45 at 6 [Denman]). With respect to Redhawk, APS has replaced several by-pass valves and added additional generator endturn blocking and larger start-up drains. With respect to West Phoenix CC5, APS has replaced several by-pass and feedwater regulating valves, redesigned the rotor air cooler system, and plans to redesign and replace the heater retubing and low pressure steam turbine last stage blades. These efforts allowed Redhawk to operate at a combined equivalent availability factor ("EAF") of 96.5 percent for 2006 and West Phoenix CC5 to operate at 91.6 percent EAF for 2006. (*Id.*). As to minimizing outage time, APS has a process in place. APS schedules required planned outages using a production cost model, which produces the least cost replacement power for the system. (APS Exhibit No. 45 at 6-7 [Denman]). All scheduled outages are planned to minimize outage time and replacement power cost and to also ensure that scheduled work is performed at the least cost. (*Id.*). Forced outages are scheduled based on value to the system, replacement power cost at the time of the outage, and forecasted near term anticipated dispatch of the unit. (*Id.*). With respect to duration, APS ensures that the appropriate resources (labor, tools, parts, contract support) are available so the outage is as short as possible. (*Id.*).

As to evaluating the replacement of boiler sections at Four Corners and Navajo Generating Station, APS has proactively responded to this recommendation through its boiler tube leak reduction program. (APS Exhibit No. 45 at 8 [Denman]). The program includes inspection and testing to anticipate leaks, procedures to determine the root cause of leaks, ensure that repairs are performed properly, require the development of short and long-term corrective action plans, and monitor implementation of corrective action plans to assure timely completion. (*Id.* at 8-9).

In addition, APS routinely investigates the root causes of all operator and maintenance errors at its coal plants, including West Phoenix CC5, and at the Navajo Generating Station, which is operated by Salt River Project ("SRP"). (*Id.* at 9, 11). APS regularly reviews reports on all APS plant operation, lost generation, and plant performance. (*Id.*). APS then conducts regular operational assessments at each of the base-load and intermediate load plants to assure that operators are knowledgeable and following good operational practices. (*Id.*). As to the Navajo Generating Station, SRP provides daily status and monthly lost generation reports to APS management. (*Id.* at 10). APS representatives also attend quarterly meetings where SRP provides detailed information about Navajo's operations, including lost generation events, and identifies corrective actions that it has taken or plans to take. (*Id.*).

In using its root cause policy, APS has determined that there is no unusual pattern of operator errors at Four Corners and Navajo Generating Station. There were seven human performance errors reported at Four Corners Unit 3 in 2005 – one maintenance and six operations. Of the six operations errors, five were related to one event – a faulty check valve. The Company did not correct the historical 2005 data to reflect that these five reported errors were, in fact, **not** operator errors. The six human performance errors at Navajo Unit 3 in 2005 were related to unit start up and operator experience. Each of these events were investigated and appropriate action taken by SRP to help insure that human performance errors are kept to the lowest possible level. (APS Exhibit No. 45 at 10 [Denman]).

Lastly, the Company has prepared and analyzed the impacts of "90/10" load forecasts in the past as part of the Company's routine sensitivity analysis. While the risks of exceeding the 50/50 load forecast are fairly well understood in the Company, the Company will seek ways to incorporate these forecasts more formally. (APS Exhibit No. 17 at 26 [Ewen]).

In its **financial audit of PSA costs**, Liberty concluded that APS's accounting systems were adequate and reasonably maintained to provide the necessary collection, reporting and auditing of the PSA filings and that the monthly filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate. Liberty found the supporting information for the PSA data to be well documented and reasonably consistent with the values reported. (Staff Exhibit No. 28 at 20 [Antonuk]). Liberty did recommend a number of minor improvements in the process.

In response to those recommendations, the Company has been and will continue to closely review and approve adjustments to fuel costs to ensure that supplemental charges and refunds are recorded properly and that they will flow through the PSA within 30 days of the adjustment. (APS Exhibit No. 57 at 27-28 [Rockenberger]).

VII.
RATE DESIGN AND COST OF SERVICE

A. Overview.

Topics with general agreement:

- Jurisdictional Cost of Service study.
- Service schedule modifications proposed by APS.
- Phase-out of frozen rates.
- Recovery of transmission costs.
- Rate design concepts.
- Hook-up fees should be examined in a workshop.
- Transmission/primary discounts.

Topics in dispute:

- Overall rate levels
- Class Cost of Service Demand allocation factor

The starting point in the rate design process is the cost of service study, which allocates the costs of providing service to each of the major classes of customers, as well as various sub-classes and rate schedules. (APS Exhibit No. 69 at 13 [Rumolo]). Yet, the cost of service study is not the only determinant for setting rates. (*Id.*).

Many other considerations were taken into account in designing the proposed rates, including rate stability and continuity. (APS Exhibit No. 69 at 14 [Rumolo]). For this reason, under APS's proposed rate design, the major classes of customers – Residential, General Service, Irrigation, Street Lighting, and Dusk to Dawn – would each receive a percentage increase that is approximately the same as the overall requested increase, even though strict adherence to the results of the cost-of-service study would indicate higher increases are supportable. (*Id.*). In addition, the individual rate schedules have been designed to depart from strict cost-of-service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated to the extent APS believes reasonable. (*Id.*). Additional considerations in developing the proposed rate schedules were customer understandability and ease of administration. (*Id.*).

1. Proposed Changes To Residential Rate Schedules.

APS is proposing the following:

- Each residential rate schedule has been designed to improve cost tracking.
- Rate Schedule EC-1 will be eliminated in accordance with Decision No. 67744, and customers will select another rate option or, in the absence of such a new selection, be transferred to Rate Schedule ECT-1R by default, as meters are exchanged. The interim rate that will be applied during the transition will be an increase comparable to the increase the typical EC-1 customers will experience when moved to Rate Schedule ECT-1R.
- Rate Schedule E-10 will also be eliminated in accordance with Decision No. 67744. Customers will have the option to choose another rate, or will be transferred to Schedule E-12 by default if no choice is made.
- Rate Schedules E-12, ET-1, ECT-1R, ET-2 and ECT-2 will be increased to reflect increased revenue requirements.
- The discounts available under the low income and medical equipment rates, Rate Schedules E-3 and E-4 respectively, will remain unchanged from the levels found in Decision No. 67744.

(APS Exhibit No. 69 at 24 [Rumolo]).

APS is also modifying the winter-summer rate differentials to better reflect the higher energy costs APS faces in the summer months. (*Id.* at 21). The proposed base rate increase for the residential customer class is approximately 21.1 percent. (*Id.*). On a rate schedule basis, the proposed increases for Schedules ET-1, ECT-1R, and E-12 are 24.5 percent, 19.7 percent and 15.6 percent[74] respectively, excluding customers who are transferring to these schedules from cancelled schedules. (*Id.*). These increases are computed based on total schedule results excluding the EIC. (*Id.*).

[74] Percentage based on APS's original requested increase of 21.34 percent. The Company's current requested increase of 20.43 percent would decrease percentages proportionally.

2. **Proposed Changes To General Service Rate Schedules.**

APS is proposing the following:

- All rate schedules have increased charges to reflect increased revenue requirements. The majority of the increases is due to increased fuel and purchased power expenses and is reflected in the power supply component of the unbundled rates. Rates were developed with consideration of the impacts on energy sales due to energy efficiency demand side management programs.
- TOU Rate Schedules E-21, E-22, E-23, and E-24 will be eliminated and customers transferred to E-32TOU.
- Rate Schedule E-32 will be increased to reflect increased revenue requirements, especially higher energy costs.
- Rate Schedules E-34 and E-35 will be increased to reflect cost of service and increased fuel and purchased power expenses.
- Rate Schedules E-38 and E-38-8T will be eliminated and customers transferred to Rate Schedule E-221 in accordance with Decision No. 67744.
- The basis for computing the energy portion of Rate Schedule E-36 will change from system incremental cost to an index-based cost that is consistent with the computation of energy imbalance charges under the APS open access transmission tariff ("OATT").

(APS Exhibit No. 69 at 30-31 [Rumolo]).

3. **Additional Rate Schedule Changes.**

APS is seeking authority to eliminate Schedule EPR-3, Solar 1, and the direct access rate schedules that were put in effect as a result of the 1999 Settlement Agreement.[75] APS is also seeking to freeze the Solar Partners program. (*See,* Decision No. 67744; APS Exhibit No. 69 at 31 [Rumolo]).

4. **Service Schedules.**

APS has proposed modifications to its Service Schedules that comprise the non-rate elements of the Company's Electric Tariff. The proposed changes include revision of the Company's line extension policy (Schedule 3) to a policy that is generally based on equipment allowances and refinements to clarify other aspects of the extension policy. Except for minor language changes, the parties do not oppose APS's proposed Service Schedule changes and APS

[75] No customers are served under these direct access rates, so there is no revenue impact resulting from the elimination of those rate schedules.

has filed revised language for such Schedules in response to Staff's suggestions. (APS Exhibit No. 70, Attachments DJR-2RB, DJR-3RB).

5. AECC, Kroger, FEA and DEAA's Rate Design Proposals.

AECC recommended the use of an hourly allocation factor for the fuel and purchased power element of base rates. AECC raised concerns that APS over-allocated transmission costs to general service customers based on energy. The current "across the board" energy-based charge is consistent with the rate designs that were part of the Settlement Agreement that was incorporated in Decision No. 67744. (APS Exhibit No. 71 at 3 [Rumolo]). APS made no changes to that method in this case, *i.e.* the transmission element costs were allocated based on energy. (*Id.*). Transmission costs are incurred by APS for retail sales based on charges found in the OATT, and are not the result of any allocation method in a retail rate case. (*Id.*). Under the OATT, each service schedule has a list of charges that are applicable to retail classes of service based on usage. (*Id.*). OATT charges for residential service and general service customers without demand meters are based on energy. (*Id.*). The OATT charges for customers with demand meters are based on the customers' billing demands each month. (*Id.*). Therefore "allocation" of OATT charges by applying a demand allocator, such as the 4CP allocator, does not reflect an accurate representation of how the costs are incurred to provide transmission service and is, therefore, inappropriate. (*Id.*).

APS opposes AECC's recommendation that there be an exception for partial requirements customers using demand for transmission cost recovery, even if transmission costs are otherwise assessed by the Commission based on demand, as proposed by AECC. (*Id.* at 4-5 [Rumolo]). Partial requirements customers require adequate "wire" capacity for stand-by and other services and, under the OATT and for general service customers over 20 kW, APS would pay for transmission service based on the partial requirements customer's demand. (*Id.* at 5). Therefore, the retail rate should also be demand based, if the transmission service for full requirement customers is demand based. (*Id.*).

AECC, Kroger and FEA all recommended larger increases to residential customers as compared with general service customers.

DEAA opposed demand rates and cost-based ratemaking for general services customers and proposed a general service rate that it contended is more similar to the one used by Salt River Project ("SRP"). APS has approximately 108,000 general service customers, and approximately 86,000 of those customers have loads under 20 kW. (APS Exhibit No. 70 at 12 [Rumolo]). Rate Schedule E-32, as approved in the Settlement Agreement, provides that customers under 20 kW are billed on the basis of energy with capacity costs recovered in the energy charges.[76] (*Id.*). APS also offers a time-of-use companion rate that has a similar rate design, *i.e.* no explicit demand charge for customers under 20 kW.[77] (*Id.*). The remaining (larger) general service customers are fully capable of understanding and responding to demand charges. In addition, the 67,000 residential customers who are served on demand/energy rates have opted for those rates voluntarily, understand capacity charges, and will likely adopt measures to reduce demand. (*Id.* at 13).

B. <u>Cost Of Service.</u>

APS prepared an embedded class and fully allocated cost-of-service study, with the twelve-month period ending September 30, 2005 as the test period, when designing its proposed rates. (APS Exhibit No. 69 at 4 [Rumolo]). The purpose of a class cost-of-service analysis is an attempt to evaluate the specific costs to serve each type of customer or each customer class for which APS provides service. (Tr. Vol. XIV at 2778 [Rumolo]). A class cost of service analysis takes each cost element, whether its production demand or fuel or wires, and through a series of calculations, assigns the dollars that APS incurs to provide service to each customer class. (*Id.*). The Test Year data provides the most recent calendar year financial and operational information and is, therefore, consistent with the Company's revenue requirements. (APS Exhibit No. 69 at 4 [Rumolo]). The Company's analysis includes a number of pro forma adjustments to the Test Year to reflect known changes and to better match the costs and revenues with the period in

[76] This is the exact concept that Mr. Murphy espouses, and APS applies it to 80 percent of our general service customers. (APS Exhibit No. 70 at 12 [Rumolo]).

[77] Mr. Murphy discusses the SRP Time of Use rates in detail but he neglects to inform the Commission that the majority of SRP's general service customers are served under SRP Schedule E-36, which is a demand/energy rate for all customers and is very similar to the APS rate design prior to Decision No. 67744. (*Id.*).

which the proposed rates will be in effect, as well as other adjustments to normalize[78] the test period. (*Id.*).

Because production-related and transmission-related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August, and September ("4CP"). (*Id.* at 7). Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class' peak load, which may or may not be coincident with the system peak load, so allocations of costs related to distribution substations and primary distribution lines are made on the basis of non-coincident peak loads ("NCP"). (*Id.*). Allocations of costs related to distribution transformers and secondary distribution lines are made on the basis of the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP"). (*Id.*).

1. Staff Proposes The Use Of A "Peak And Average" Method That Allocates A Portion Of Production Capacity Costs Based On Contribution To Peak Demand And A Portion Based On Average Demand.

Staff proposed the use of a "peak and average" method that allocates a portion of production capacity costs based on contribution to peak demand and a portion based on average demand. (Staff Exhibit No. 7 at 8 [Brosch]). Specifically, Staff has suggested that APS continue to use 4CP for the jurisdictional split, but within the retail segment, use the average and peak methodology ("4-CP&A"). (Tr. Vol. XIV at 2770 [Rumolo]).

In contrast, APS's use of the 4CP method in this case is consistent with its use in previous APS retail rate cases and is consistent with the method that APS was directed to use by FERC in previous federal rate case litigation. (APS Exhibit No. 70 at 3 [Rumolo]). Because of the magnitude of the requested revenue increase in this case, APS was concerned that adopting an alternative demand allocation method for customer class allocations could introduce a higher degree of rate shock to some customers. (*Id.*). When comparing the results of the cost of service

[78] Normalization refers to eliminating the effect of conditions or situations that would not ordinarily occur or be expected to occur in a normal test year, or that recur periodically, but should be averaged out over a period of years. The purpose of normalization is to produce a test year that will be more representative of conditions that will exist during the period in which the proposed rates will be in effect. (APS Exhibit No. 69 at 5 [Rumolo]).

study under the 4CP method and 4-CP&A, the retail cost allocations shifted between customer classes when 4-CP&A was used, with more costs being shifted to general service, irrigation and lighting service customers and reduced cost allocation to residential customers. (*Id.* at 4). Staff's methodology shifts some of the production cost to an energy base through the averaging effect instead of just a peak contribution. (Tr. Vol. XIV at 2773 [Rumolo]). The 4-CP&A methodology would allocate more demand related production costs to higher load factor classes, compared to 4CP. (*Id.* at 2774).

In contrast, the 4CP is strictly a demand allocator and is based strictly on the contribution to peak. (*Id.* at 2773-2774). That is important because APS's system requirements are especially peak driven because of the summer air conditioning load in the heat of Arizona. (*Id.* at 2774). Based upon the system capacity, the demand that APS has to build to meet that load is driven by that peak. (*Id.*).

2. Although AECC Agrees With APS's Use Of 4CP For Allocating Fixed Production And Transmission Costs, AECC Proposes Using 4CP With Fuel Allocated On Hourly Energy Costs.

AECC proposed using 4CP with fuel allocated on hourly energy costs. (AECC Exhibit No. 5 at 8 [Higgins]). Although AECC agreed with APS's use of 4CP for allocating fixed production and transmission costs ("demand") (*Id.* at 3), AECC opposed APS's allocation of fuel and purchased power costs ("energy costs") based upon the annual number of kilowatt-hours each customer class consumes. (*Id.* at 8). It is AECC's position that seasonal and time-of-use information should be used in determining the allocation of energy costs to customer classes. (*Id.* at 9). APS does not oppose this adjustment to its cost of service study. (Tr. Vol. XIV at 2803, 2805 [Rumolo]).

3. Although FEA Supports APS's Use Of The 4CP Demand Allocation, FEA Recommends Increasing The Discounts For Primary And Transmission Voltage Level Customers Under Rates E-34.

Like AECC, FEA supported APS's use of the 4CP. FEA recommended increasing the discounts for primary and transmission voltage level customers under Rates E-34. (FEA Exhibit No. 3 at 17 [Goins]). APS does not disagree with FEA's recommendation, which is consistent with the results of the APS cost-of-service, but it must be recognized that this recommendation results in slightly higher bills to customers who are not eligible for the discount. (APS Exhibit No. 70 at 11 [Rumolo]). As long as the changes are strictly within E-34, it would not affect other rate schedules. (Tr. Vol. XIV at 2777 [Rumolo]). FEA's proposal would basically shift dollars from customers who receive the discount within E-34 to customers who do not receive that discount. (*Id.*).

C. Specific Rate Schedule Issues.

1. Schedule Modifications.

a. Schedule 1 – General Terms And Conditions.

APS is proposing modifications to this service schedule to address situations where it may not be appropriate to bill a Service Establishment Charge, and to add clarifying language that better reflects APS's envisioned business practices. (APS Exhibit No. 37 at 13 [DeLizio], Attachment GAD-6). The modifications are as follows:

> Section 2.2.4: APS is proposing clarifying language to Section 2.2.4. The special services discussed in this section are performed outside of normal work hours, and usually require a crew with more than one person. The language clarifies that the $75.00 charge is per crew person, per hour.[79] (APS Exhibit No. 37 at 13 [DeLizio]).
>
> Section 2.2.5: APS is proposing that the Company have the right to waive the Service Establishment Charge in instances where either 1) a name change is requested, but no field trip is necessary, or 2) where the Company has an active Landlord Agreement in place. The request for a name change typically results when a surviving spouse requests that the service be placed in their name after the death of the customer of record, or a name has changed as a result of a divorce. (*Id.*).

The Company is also proposing to reduce the Service Establishment Charge in those instances where multiple connect requests are made for the same location, such as a trailer park that has seasonal visitors. APS is proposing to charge only one Service Establishment Charge for every two requests for service connects made during the same site visit and placed in the same name, at the same address, for the same class of service. (APS Exhibit No. 37 at 14

[79] The Company is proposing to clarify that the $75 charge is per crew person, per hour. Staff witness Ms. Andreasen recommends that the charge remain at $75 per hour, regardless of how many workers are required. The Company believes that Staff's recommendation will not appropriately recover the Company's costs and, therefore, will shift those costs to other customers. In addition, Staff's proposal will not send the proper price signal to customers as to the true costs of requesting after-hours work. (APS Exhibit No. 38 at 29 [DeLizio]).

[DeLizio]).

Sections 4.3.3 & 4.3.4: APS is proposing to eliminate these sections that permit the Company to offer incentives for customers who elect to pay electronically and customers who elect to not receive a paper copy of their bill. (*Id.*).

Section 6.6: In Section 6.6, APS is proposing language regarding master metering to clarify situations where prohibiting master metering is not applicable, such as a high rise residential unit where units are privately owned and the building is served by centralized heating (6.6.3), or senior care centers that provide packaged services such as housing, meals and nursing care (6.6.2). (*Id.* at 15).

b. Schedule 4 – Totalizing.

Schedule 4 addresses the Company's practice relative to totalizing of meter readings. It is applied when customers at a single premise receive service through multiple service points. APS is proposing language to address the emergence of new metering technology that allows for electronically totalized demand and energy, in addition to physical wire interconnections. (APS Exhibit No. 37 at 15 [DeLizio]; *id.* at Attachment GAD-7).

c. Schedule EPS-1 Environmental Portfolio Standard.

Decision No. 68668 required APS to set aside $4.25 million for additional funding for the Environmental Portfolio Standard ("EPS") Uniform Credit Purchase Program. Staff recommends that the EPS adjustor rate and caps be increased to recover an additional $4.25 million through the Company's Adjustment Schedule EPS-1. (Staff Exhibit No. 12 at 4 [Keene]; APS Exhibit No. 38 [DeLizio], Attachment GAD-2RB). As discussed earlier, APS believes that some manner of reconciliation provision should be provided so "true-up" this $4.25 million with actual UCPP costs for 2006 or that there be authorization to carry-forward any unspent funds from 2006 to subsequent years.

Currently, there is $6,000,000 for renewables in the System Benefits Charge. Staff recommends that the amount continue to be $6,000,000. (Staff Exhibit No. 12 at 3 [Keene]).

2. Partial Service Offerings.

a. Proposed Modifications.

APS is proposing to: (1) eliminate existing rate schedules EPR-3,[80] EQF-S, EQF-M, and E-52,[81] which are currently frozen and, therefore, not available to new customers. (APS Exhibit No. 38 at 24 [DeLizio]).

> EPR-3 is applicable to qualified solar/photovoltaic small power production facilities 10 kW and less and is similar to rate schedule EPR-2 with a few exceptions. Under EPR-3, there are no monthly service charges based on the type of service and the customer is not charged for the installation of bi-directional metering. EPR-3 also offers a simultaneous buy/sell metering arrangement where the customer can elect to have APS provide 100 percent of their electric requirements while selling 100 percent of the output of the generator to APS. This rate is frozen to new customers. (*Id.*).
>
> EQF-S is applicable to qualified cogeneration and small power production facilities 100 kW and less capable of producing firm power. This rate offers quantities of standby power to a customer who is not taking full requirements service from the Company and who desires a permanent electric connection as standby power source. The Company currently has no customers being served under Schedule EQF-S. (*Id.* at 23).
>
> EQF-M is applicable to qualified cogeneration and small power production facilities 100 kW and less capable of producing firm power. This rate offers quantities of contracted maintenance capacity, taken during scheduled periods, to a customer who is not taking full requirements service from the Company and who desires a permanent electric connection as maintenance power source. The Company currently has no customers being served under Schedule EQF-M. (*Id.*).
>
> E-52 is a partial requirements service available to customers with an aggregate partial requirements service load less than 3,000 kW. It contains per day basic service and generation meter charges, supplemental service charges provided in accordance with the rate levels contained in rate schedule E-32, Standby Service charges based on the amount of capacity reserved by the customer, and maintenance service charges applicable when the customer's generator is down for scheduled maintenance. The Company currently has no customers being served under Schedule E-52. (*Id.* at 22).

The Company is also proposing to close (freeze) existing rate schedules E-32R, and E-55 to new customers and eliminate them in the next rate case.[82] (*Id.* at 24).

E-32-R is applicable to general service customers who are also served under Schedule E-

[80] The Company believes that the proposed net metering rate EPR-5 and the rate EPR-2, with the proposed changes, are better options for customers compared with Schedule EPR-3, which currently has no customers on the rate. (APS Exhibit No. 38 at 25 [DeLizio]).

[81] Schedules E-52, EQF-S, and EQF-M are being replaced by the revised Schedules EPR-2, E-56 and E-57. There are currently no customers being served under these rates. (*Id.*).

[82] APS's proposed new Partial Requirements Rates Schedules E-56 and E-57 will replace schedules E-32R and E-55. The Company is currently serving three customers under E-32R and one customer under E-55. (APS Exhibit No. 38 at 26 [DeLizio]).

32. All billing is in accordance with Schedule E-32 with one exception: the customer's billing kW is the greater of: 1) the average kW supplied during the 15-minute period for maximum use during the month; 2) 80 percent of the average of the highest kW measured during each of the six (6) summer billing months; or 3) the minimum kW specified in the agreement for service or individual customer contract. The Company currently has three customers being served under Schedule E-32R. (*Id.* at 21-22).

> E-55 is a partial requirements service available to customers with an aggregate partial requirements service load of 3,000 kW and above. It contains per day basic service and generation meter charges, supplemental service charges provided in accordance with the rate levels contained in rate schedule E-34, Standby Service charges based on the amount of capacity reserved by the customer, and maintenance service charges. The Company currently has one customer being served under Schedule E-55. (*Id.* at 22-23).

The Company is further proposing to eliminate schedule E-51, which is currently frozen, in the Company's next rate case.[83] (*Id.* at 24).

> E-51 is an optional electric service for qualified facilities over 100 kW. It contains a daily basic service and generation meter charges, supplemental service charges provided in accordance with the rate levels contained in rate schedule E-32 or E-34, Standby Service charges based on the amount of capacity reserved by the customer, and maintenance service charges applicable when the customer's generator is down for scheduled maintenance. This rate schedule is frozen to new customers. The Company currently has two customers being served under Schedule E-51. (*Id.* at 22).

Finally, the Company proposes to consolidate Schedule EPR-4 into the revised Schedule EPR-2.[84] (*Id.* at 23).

> EPR-2 would be applicable to qualified cogeneration and small power production facilities under 100 kW. This rate schedule offers monthly purchase rates for energy the customer does not use that is delivered to the Company. The customer is responsible for the additional costs associated with the installation of bi-directional metering in addition to monthly service charge based on the type of service (e.g. single- or three-phase) provided. All other provisions of the customer's otherwise applicable rates schedule will continue to apply. (*Id.* at 21).

> EPR-4 was applicable to qualified small power production facilities 10 kW or less utilizing renewable resource technologies and is similar to EPR-2 with two exceptions. Under EPR-4 there are no monthly service charges based on the type of service and the customer is not charged for the installation of bi-directional metering. (*Id.*).

The Company is also proposing modifications to the existing EPR-2 rate schedule by updating the buyback rate to incorporate the avoided costs filing of June 30, 2006, which was

[83] E-51 will be replaced by the proposed rate E-56. APS currently has two customers served under Schedule E-51. (*Id.*).

[84] The Company's proposed revisions to Schedule EPR-2 make the provisions of service identical to the existing Schedule EPR-4. The Company is currently serving 249 customers under the EPR-4 rate. (*Id.* at 25).

required by Decision No. 52345 (July 27, 1981). (*Id.* at 25; *id.* at Attachment GAD-7RB). In addition, the Company made minor wording changes to be able to use these schedules with the new residential time-of-use rates ET-2 and ECT-2; eliminated the monthly service charge which was dependant on the customer's type of service; changed the summer and winter billing cycle months to match APS's other rate schedules; eliminated the requirement for the Customer to share in the cost of bi-directional metering; and removed a provision that allowed the customer to pay the incremental metering costs over a five year period. (*Id.*).

b. Proposed New Offerings.

The Company is proposing two additional partial requirements rate schedules (E-56 and E-57). (*Id.* at 26).

E-56 would be applicable to general service customers having distributed generating equipment 100 kW or greater capable of supplying all or a portion of its power requirements. (APS Exhibit No. 38 [DeLizio], Attachment GAD-8RB). The main components of the rate schedule include:

(1) A Basic Service component which is comprised of the unbundled monthly Basic Service and Revenue Cycle Service charges included in the customer's applicable General Service rate schedule;

(2) Supplemental Service is defined as the demand and energy needs contracted by the customer to augment the power and energy generated by the customers' generation facility. Supplemental Service will be provided in accordance with the monthly rate levels contained in the customer's applicable General Service rate schedule excluding the monthly Basic Service and Revenue Cycle Service Charges (these are already included in the above-mentioned Basic Service component); and,

(3) Standby and Maintenance Service, which is the sum of demand and energy charges, derived as follows:

Demand Charge: The Demand Charge is the unbundled transmission charge, if applicable, contained in the Customer's General Service rate schedule, plus the unbundled delivery charge contained in the Customer's General Service rate schedule. This summation is then multiplied by the amount of Contract Standby Capacity. Contract Standby Capacity is defined as the greater of, a) the measured kW output of each customer self-generation unit at the time of start-up testing; or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed the Customer's actual load.

> Energy Charge: Defined as the electric energy supplied by the Company to replace power normally supplied by the Customer's generator(s) during unscheduled full outages, unscheduled partial outages, and scheduled maintenance periods. The unbundled transmission charge, if applicable, contained in the Customer's General Service rate schedule plus the per kWh monthly firm power purchase rates shown in rate schedule EPR-2.

(*Id.* at 26-27).

E-57 would applicable to general service customers having solar/photovoltaic generating equipment greater than 100 kW but less than 1,000 kW capable of supplying all or a portion of its power requirements. The main components of the rate schedule include:

(1) A basic service component that is comprised of the unbundled monthly Basic Service and Revenue Cycle Service charges included in the customer's applicable General Service rates schedule;

(2) Supplemental Service is defined as the demand and energy needs contracted by the customer to augment the power and energy generated by the customers' generation facility. Supplemental Service, to include 100 percent of the customer's energy requirements, will be provided in accordance with the monthly rate levels contained in the customer's applicable General Service rate schedule excluding the monthly Basic Service and Revenue Cycle Service Charges (these are already included in the abovementioned Basic Service component);

(3) A monthly Standby Service component is derived by multiplying the unbundled delivery charge contained in the Customer's applicable General Service rate schedule by the 15 minute integrated kW measured on the customer's generator meter(s) during the customer's monthly peak demand, and

(4) The Company will pay the customer for any excess energy produced by the distributed generator at the purchase rates specified in the Schedule EPR-2 that are based on the Company's avoided cost.

(*Id.* at 27-28).

The Company will install, at the customer's expense, a generator meter(s) at the point (s) of output from each of the customer's generators. This allows the Company to accurately meter customers taking service under this rate schedule. (*Id.* at Attachment GAD-9RB).

c. Party Opposition.

APS disputes DEAA's general rate design philosophy as being fundamentally flawed and its proposed partial requirements rate design philosophy has no basis in cost causation. (*Id.* at 24). Furthermore, DEAA presented no evidence to support its claim that APS's demand and energy rate schedule components are not cost-based. (*Id.*). In response to DEAA's claims that the Company's partial requirements rates are complicated and not easy to understand, the Company is proposing several changes to the partial requirement rate schedules and proposes to combine several of its partial requirements rates in order to make it easier for a customer with distributed generation to select the best option. (*Id.*).

D. <u>Line Extension Policy.</u>

APS is proposing to change its line extension tariff, which currently provides residential customers a 1,000 foot free footage allowance up to a $5,000 construction allowance for individual customer extensions and a construction allowance based method for subdivisions/developments.[85] Both changes will reduce the Company's investment in line extensions and be easier to administer. (Tr. Vol. XIV at 2812 [Rumolo]). Neither Staff nor RUCO have objected to proposed changes.

No party objected to APS's proposal to change its current line extension policy or has supported an alternative approach. However, at the hearing, Commissioner Mayes asked the Company to prepare an analysis of the impact of alternative equipment allowances. (Tr. Vol. XXIII at 4348-4350 [Mayes]). In response to the request, on December 19, 2006, the Company filed a letter in the docket that contained an Appendix A which calculated the impact of variations to its proposed $5,000 equipment allowance in increments of $500. (APS Exhibit No. 105). This calculation was made for both individual customer connections and new subdivisions.

VIII.
<u>MISCELLANEOUS</u>

A. <u>Environmental.</u>

1. Environmental Improvement Charge.

a. Overview.

To remain successful in the future, APS must address the ongoing challenge of meeting Arizona's growing energy demands efficiently, with limited rate impacts, while minimizing the

[85] Also referred to herein and at the hearing as "equipment" allowance. A.A.C. R14-2-207(c) requires APS to provide either a maximum footage allowance or an equipment allowance at no charge.

environmental impact of its generating plants. (APS Exhibit No. 34 at 3 [Fox]). To provide reliable electric service to its customers, APS has several generation plants, including three coal-burning plants[86] that provide a significant part of APS's generation capacity. (*Id.*). The three coal plants are located near one or more large national parks and wilderness areas designated as mandatory "Class I Areas" under the Clean Air Act. (*Id.* at 3-4). APS proactively works with the environmental community and regulators to reduce emissions from its coal-burning plants and improve the Company's environmental profile in other ways. (*Id.* at 7-8, 10). Due to the extensive capital required to reduce emissions, the Company must recover the costs of these capital projects on an annual basis, as the costs are incurred. (*Id.* at 8). Unlike other capital expenditures, environmental expenditures do not produce revenue that can be used to offset the cost of the improved facilities. (*Id.* at 9). Regulatory lag compounds the problem with the inevitable delay between the Company's environmental expenditures and the issuance of a rate order that allows for the recovery of these expenditures. (APS Exhibit No. 37 at 3 [DeLizio]). Delayed recovery of these substantial costs adversely affects APS's earnings, which impacts the Company's financial ability to fund environmental improvements. (APS Exhibit No. 34 at 9 [Fox]; APS Exhibit 37 at 3 [DeLizio]).

b. The Company's EIC Proposal.

As a solution to these problems, APS has proposed the EIC, an adjustor mechanism that would allow for the timely recovery of investments in environmental improvements on an annual basis. (APS Exhibit No. 37 at 7 [DeLizio]; *Id.* at Attachments GAD-1, GAD-2).

(1) Costs That Would Qualify For Recovery Under The EIC.

The EIC is designed to collect the expected return, associated tax, depreciation, and other carrying costs associated with the proposed environmental projects. (Tr. Vol. VII at 1669 [Berry]; Tr. Vol. XII at 2488, 2565 [DeLizio]). It would **not** require customers to pay for the investment in these projects on a current basis, i.e., this would not be contribution in aid of construction ("CIAC") but more analogous to CWIP. APS's initial EIC proposal included costs

[86] APS's coal-burning generation plants include the Cholla Power Plant located near Joseph City, Arizona; the Four Corners Power Plant located in the Navajo Nation in northwestern New Mexico; and the Navajo Power Plant located in northern Arizona. (APS Exhibit No. 34 at 3 [Fox]).

associated with environmental improvements that would reduce emissions from the Company's Cholla Power Plant, which would cost approximately $243 million over the next five years.[87] (APS Exhibit No. 34 at 8 [Fox]; APS Exhibit No. 35, Attachments EZF-3RB, EZF-4RB). Specifically, the Company plans to retrofit baghouses on Cholla Units 1-3, upgrade sulfur dioxide ("SO_2") controls on Unit 1, retrofit SO_2 controls on Unit 3, retrofit low nitrogen oxide ("NO_x") burners and carbon injection on Units 1-3, install a lime-slaking project, as well as construct a slurry disposal project. (*Id.*). The proposed improvements are considered "traditional" pollution controls that have proven to be effective in reducing emissions and have been used by many utilities across the country. (Tr. Vol. VII at 1482-81 [Fox]). Benefits from these projects include significant reductions of SO_2, NO_x, particulate matter, and mercury emissions.[88] (APS Exhibit No. 35 at 12-13 [Fox]).

Although the Company's initial request only included costs associated with Cholla Power Plant improvements, the EIC, as proposed, could be used for the recovery of costs associated with the reduction of pollutant emissions for APS's other coal-fired plants, reduction of carbon emissions to quell climate change, and other environmental improvements that the Company anticipates. (APS Exhibit No. 34 at 8 [Fox]).

(2) Calculation Of The EIC.

APS has proposed an initial request of $243,000,000[89] for environmental improvements to the Cholla Power Plant for the next five years to be recovered through the EIC. Customers would be billed the carrying costs on the portion of this capital cost expended by a particular year within the five-year period referred above, $243,000,000 that is to be up front. (Tr. Vol. VII at 1515 [Fox]; Tr. Vol. VII at 1669 [Berry]; Tr. Vol. XII at 2482, 2488, 2565 [DeLizio]). These costs would be recovered from customers on a monthly basis. (Tr. Vol. XII at 2566 [DeLizio]). To determine the monthly charge, APS used both the actual and forecasted expenditures required

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[87] APS has forecasted a five-year period for the initial EIC for the sole purpose of allowing the Commission to understand what APS plans to do in the first five years of the EIC's implementation. (Tr. Vol. XII at 2481-82 [DeLizio]).

[88] For example, SO_2 emissions will be reduced from 32,475 tons in 2007 to 5,148 tons in 2010 and beyond. (APS Exhibit No. 35 at 12-13 [Fox]).

[89] This figure includes six additional projects included in Mr. Fox's Rebuttal Testimony as well as the seven identified in APS's original filing. (APS Exhibit No. 35 at 14-15 [Fox]; *Id.* at Attachment EZF-4RB).

for the proposed environmental improvement projects. (*Id.*). Using that forecasted amount, APS then determined how much the environmental improvement projects would cost on an annual basis and then averaged over 12 months. (*Id.* at 2473, 2566). In this initial EIC request, the Company used an 18-month period (January 2007 – June 2008) to determine how much the proposed environment improvement projects would cost per month for the first 18 months. (APS Exhibit No. 37 at 4 [DeLizio]). Thereafter, the Company would use a 12-month period and the collected monthly amounts will be subject to a true-up. (Tr. Vol. XII at 2473[DeLizio]).

For the first 18 months, the EIC is set for $0.00016 per kWh and would be effective with customer bills rendered after January 1, 2007 (the date previously anticipated by APS that the new rates from this rate application will be effective). (APS Exhibit No. 38 at 2 [DeLizio]). The EIC ($/kWh) would apply to all kWh used by Standard Offer customers, but not to customers subscribed to Schedule SP-1 (Solar Partners), Schedule GPS-2 (Green Power Percent), and Schedule Solar-2. (APS Exhibit No. 37 at 4 [DeLizio]). The impact to an average residential customer using 1163 kWh monthly would be an increase of the customer's monthly bill by approximately 19 cents in 2007. (APS Exhibit No. 38 at 2 [DeLizio]). The average impact on total Company retail revenues, based on expenditures included in the APS EIC Plan for 2007 is approximately 0.19 percent. (APS Exhibit No. 38, Attachment GAD-1RB).

(3) Proposed Process To Determine And True-Up The EIC.

Under the Company's proposal, APS would prepare subsequent EIC requests for Commission review and approval on an annual basis by March 15. (APS Exhibit 37 at 5 [DeLizio]). These subsequent EIC requests would consist of two parts: (1) a true-up of the EIC revenues that had been approved by the Commission and collected the previous year; and (2) a proposal of the EIC revenue to be collected for the upcoming year. (*Id.* at 5; Tr. Vol. XII at 2566 [DeLizio]). To true-up the EIC revenues collected, the Company would provide actual data of the costs of environmental improvements for the previous year and compare that data to the EIC revenues collected during the same time. (*Id.*) If certain costs were determined to be imprudent by the Commission or if there was an over-collection of costs, then this amount – plus interest – would be used to offset the EIC calculation going forward. (Tr. Vol. XII at 2473, 2492, 2567

[DeLizio]). Essentially, the true-up mechanism would assure that customers only pay for actual and prudent costs. (Tr. Vol. XII at 2473, 2566 [DeLizio]). APS would also utilize actual and forecasted environmental improvement costs to derive the EIC revenues needed for improvements for the following year. (*Id.*) Commission Staff would review the proposal, seek clarification or additional information from the Company as needed, and prepare a Staff Report within 60 days of the Company's filing. (APS Exhibit No. 37 at 5 [DeLizio]).

The Commission then would consider the Company's EIC filing in an Open Meeting within 30 days of the Staff report filing. (*Id.*). Under the Company's proposal, if the Commission did not take action within this time period, the EIC filing would be deemed approved, subject to true-up the following year. (*Id.*) In addition to the prudency review of the Company's annual EIC request, the Commission can review the prudency of the EIC revenues collected in the Company's future general rate cases. (*Id.* at 6-7).

c. Protecting The Public Health And Environment Is In The Public Interest.

As pointed out by Staff, the Commission has a compelling public interest to protect the public from pollution. (Tr. Vol. XX at 3738 [Rowell]). By approving surcharges that encourage the use of renewable energy, implement demand side management programs, and recover the cost of arsenic remediation, the Commission has already demonstrated that environmental protection is a compelling public interest and that the use of surcharges is an appropriate mechanism to establish programs that support environmental protection. (APS Exhibit No. 35 at 3 [Fox]).

The EIC allows the Company to comply with existing environmental laws and to engage in long-term planning of providing service in one of the fastest growing service territories in the country. (APS Exhibit No. 34 at 7 [Fox]). Anticipating environmental requirements is appropriate and makes economic and environmental sense, as environmental laws of the United States have become increasingly stringent since the early 1970s. (Tr. Vol. XX at 3740 [Rowell]). A recent study from the National Association of Regulatory Utility Commissioners acknowledged this trend, and neither Staff nor any other party has provided testimony to the contrary. (*Id.*; APS Exhibit No. 34 at 16 [Fox]).

More stringent environmental laws equates to significant investments in technologies to decrease the amount of pollution. For example, recent proposed mercury regulations will require the installation of carbon injection projects for Cholla Units 1 through 3 and the baghouse for Unit 2 **earlier** than expected. (APS Exhibit No. 35 at 15-16 [Fox]). It is the Company's experience that once new environmental requirements become effective, the associated environmental technologies increase in cost. (APS Exhibit No. 34 at 15-16 [Fox]). Another example is the proposed carbon intensity standard in Arizona. A recent Governor's Climate Change Task Force issued a report recommending the enactment of a carbon intensity standard by 2010 or 2012. (Tr. Vol. XII at 1536 [Fox]). The proposed standard is the first of its kind in Arizona and would call for the decline of carbon emissions over a 15-year period. (*Id.*). The EIC would, with the input, review and approval of the Commission, provide a process that would encourage the Company to expedite compliance with new and proposed environmental regulations and even go beyond what is mandated where appropriate.

In addition, APS needs to be certain that it sustains its existing generating plants and stays ahead of environmental regulatory requirements. (Tr. Vol. XX at 3738 [Rowell]). As Staff's witness pointed out, coal-fired plants are exposed to expensive retrofits, curtailments, and possible shutdowns in order to make them more environmentally friendly. (Tr. Vol. XXII at 4114 [Antonuk]). The future costs of coal are uncertain in light of these environmental improvement requirements for coal-fired plants. (*Id.*). The failure to anticipate environmental regulatory requirements has resulted in lawsuits against utility companies by the Environmental Protection Agency and environmental groups. The result is that, in addition to the costs to expeditiously start and complete environmental improvement projects to meet regulatory requirements, these utility companies are also faced with the significant costs of litigation and regulatory fines. (Tr. Vol. XII at 1450 [Fox]; Tr. Vol. XIII at 1668 [Berry]; APS Exhibit No. 34 at 15-16 [Fox]). The EIC would reduce the chance of APS being sued or fined by enabling APS to proactively reduce emissions beyond simple mandates. (Tr. Vol. VIII at 1665 [Berry]).

As a supporter of the proposed EIC, WRA summed it up best, stating that the EIC mechanism is needed in Arizona because it highlights the environmental impacts of resource choices, encourages utilities to take actions that reduce environmental damages, and reduces the risk of complying with environmental regulations. (WRA Exhibit No. 1 at 19 [Berry]). APS echoes WRA's sentiments and urges the Commission to approve the EIC and find that it is in the public interest.

d. "Timing" Objections To The EIC Do Not Justify Rejection Of This Important Public Policy Initiative.

No party disputes the fact that APS has the right to recover its capital expenditures for environmental improvements, nor does any party dispute the method of calculation of the EIC. Rather, any objection to the EIC stems from the timing of recovery of environmental improvements. (Tr. Vol. VII at 1448 [Fox]). Staff and RUCO argue that recovery of environmental improvement costs outside of a rate case violates traditional ratemaking principles. The Company strongly disagrees with this position because the Commission can exercise its ratemaking authority by adopting automatic adjustor clauses as part of the utility's overall rate structure. *Residential Utility Consumer Office v. Arizona Corp. Comm'n,* 199 Ariz. 588, 591, 20 P.3d 1169, 1172 (App. 2001). Automatic adjustment clauses can only be established after a full rate hearing in order to meet the due process standards and ensure that the utility's rates are fair and reasonable. (*Id.* at 593-94, 20 P.3d at 1173-1174 (citing *Scates v. Arizona Corp. Comm'n,* 118 Ariz. 531, 534-535, 578 P.2d 612, 615-616 (App. 1978)). Furthermore, automatic adjustment clauses may be designed to recover specific and identifiable expenses. (*Id.*)

As a rate adjustment mechanism, the EIC satisfies these requirements because the EIC has been proposed in a rate case, and it is designed to recover only environmental improvement costs. The Commission can also be assured that the amounts collected through the EIC would be subject to true-up, which ensures that the Company would only recover its actual costs. (APS Exhibit No. 34 at 9 [Fox]). If an over-collection should occur, the amount of the over-collection, plus interest, would offset the EIC requests going forward.

In addition, Staff's witness conceded that adjustor mechanisms are exceptions to traditional single issue ratemaking restrictions. (Tr. Vol. XX at 3733 [Rowell]). Since all adjustor mechanisms are in some sense "single-issue" ratemaking, this concept is not a compelling reason to deny the EIC. (APS Exhibit No. 38 at 5 [DeLizio]). In consideration of important public policy concerns, such as environmental protection, the Commission has evidenced that adjustors and surcharges are appropriate by approving renewable energy, demand-side management, and arsenic remediation recovery mechanisms.

Staff contends that the denial of timely recovery of environmental improvements would not impose a significant financial burden on APS. (*Id.* at 3-4 [DeLizio]). However, Staff has missed one of the key points, if not **the** key point in this entire proceeding: capital is at a premium for APS. (*Id.*). APS is already under-earning and without the EIC, it will continue to do so. Without the EIC, environmental projects are just another capital need in a very long line of competing needs, which mostly likely will affect the ability to allocate capital to environmental improvement projects until such time as the projects become mandated, by which time they are likely to be more expensive and the environmental benefits in the interim will be lost. (*Id.*).

e. Innovation Is Not A Valid Criticism.

Although some parties have opposed the EIC because it appears to be new and unique, innovation is not a valid criticism of the EIC. (APS Exhibit No. 38 at 3 [DeLizio]; Tr. Vol. VIII at 1668 [Berry]). The Commission has established surcharges to pre-collect money when important public policy is in question such as the EPS and DSM. Establishing the EIC to expedite the prevention and control of pollution from conventional sources of electricity is an innovation to be embraced, not criticized. While the EIC may be innovative in its approach, there is nothing new about this Commission breaking new ground to achieve sound public policy. (APS Exhibit No. 35 at 10-11 [Fox]). The Commission has shown its leadership in concern for environmental impacts of decisions under its jurisdiction, including the EPS rules, which led the nation on renewables when first proposed. (*Id.* at 11).

Moreover, Arizona would not be the first state to have a mechanism that would allow utilities to recover the costs of environmental projects between rate cases. (Tr. Vol. VII at 1474-

75 [Fox]). Florida, Indiana, Kentucky, and West Virginia all have enacted environmental recovery mechanisms. (*Id.*). Specifically, Florida, Indiana,[90] and Kentucky allow utilities to submit environmental compliance plans outside of a general rate case to recover **projected** expenses associated with environmental compliance through a cost recovery mechanism. (APS Exhibit No. 34 at 17-18 [Fox] (citing Fla. Stat. § 366.8225 (2005), Burns Ind. Code Ann. § 8-1-27 *et seq.* (2004), K.R.S. § 278.183 (2004), *Kentucky Industrial Utility Customers, Inc. v. Kentucky Pub. Serv. Comm'n,* 983 S.W.2d 493, 500, 1998 Ky. LEXIS 165 (Dec. 1998)). In West Virginia, the Public Service Commission authorizes ratemaking allowances for electric utility investments in clean coal and clean air technology facilities or electric utility purchases of power from clean coal technology facilities in West Virginia pursuant to statute. (*Id.* at 18 (citing W. Va. Code § 24-2-1g (2005)).

In addition, WRA also testified that Public Service Company of Colorado **voluntarily** engaged in SO_2 and NO_x emission reduction in the Denver metropolitan area and recovered the costs of those projects through an air quality improvement rider, which is somewhat similar to the EIC. (Tr. Vol. VIII at 1666 [Berry]). The Commission and the State of Arizona have been national leaders in protecting the environment and public health. With other states enacting environmental recovery mechanisms, and with the environmental, economic, and public health benefits of the EIC, the EIC should be adopted by the Commission.

B. Net Metering.

1. The APS Proposal.

APS is seeking Commission approval of its proposed Rate Schedule EPR-5, which would create a three year pilot net metering program for customers that have renewable resource generation facilities of 10 kW or less, where the customer's generator(s) and load are located at the same premise. (APS Exhibit No. 37 at 9 [DeLizio]; *id.* at Attachment GAD-5). EPR-5 sets a proposed 15 MW[91] cap on total aggregate participation in the EPR-5 net metering pilot program.

[90] When the Indiana General Assembly enacted its environmental recovery mechanism, it noted that that Indiana needed to continue to be successful in attracting new businesses and jobs during its time of robust population and economic growth. (APS Exhibit No. 34 at 17 [Fox] (citing Burns Ind. Code Ann. § 8-1-8.8-1)).

[91] Staff agrees that 15MW aggregate amount is reasonable and in line with what most other states do as well. (Tr. Vol. XIX at 3530-3531 [Keene]).

(APS Exhibit No. 38 at 14 [DeLizio]). Renewable resources eligible to participate in this pilot program include solar and other renewable resources, as defined in the Commission's Environmental Portfolio Standard, A.A.C. R-14-2-1618. (APS Exhibit No. 37 at 9-10 [DeLizio]). Qualifying standard retail rate schedules for service under this pilot program would be limited to Rate Schedules E-12, ET-1, ET-2, ECT-IR and ECT-2 for residential customers and Rate Schedules E-32 and E-32TOU for general service customers with a monthly maximum demand of 20kW or less. (*Id.* at 10).

The EPR-5 rate is proposed as a pilot program and is, therefore, designed to be a limited offering to provide an incentive for small customers to participate in the Company's Solar Partners Incentive Program (credit purchase program). (APS Exhibit No. 38 at 14-15 [DeLizio]). The Company has proposed that the EPR-5 net metering rate be available to residential customers and general service customers with monthly demands less than or equal to 20 kW. (*Id.* at 16). The net metering program, as proposed within this rate schedule, is intended to attract small customers to install renewable generation by providing an additional incentive beyond the credit purchase under the Company's Solar Partners Incentive Program. (*Id.*).

By setting a participation limit of 15 MW[92] and limiting it to customer-owned renewable resource generation facilities with a nameplate rating of 10 kW or less, the Company has targeted customers who have renewable energy facilities for the primary purposes of meeting their own energy needs, but occasionally have excess energy to provide to the Company. (APS Exhibit No. 37 at 12 [DeLizio]). Although EPR-5 permits excess energy to be carried from month to subsequent months, the customer's excess supply provided to the Company would be reset to zero at the end of each calendar year. (*Id.*).

The proposed 10 kW cap on the individual generator size is appropriate for net metering, even in light of an expanded program under the proposed Renewable Energy Standard ("RES"), because the Company already offers net billing rate options for all distributed generation systems up to 100 kW, which options do not have any cap on aggregate participation. (APS Exhibit No. 38 at 13 [DeLizio]). APS also currently offers rate Schedule EPR-2, which is available to all

[92] Even with a 15MW cap, APS estimates potentially 5,000 3kW-unit customer installations. (Tr. Vol. VIII at 1811 [DeLizio]).

Qualifying Facilities ("QF"), cogeneration and small power production facilities, up to 100 kW. (*Id.*). The Company further offers Rate EPR-4 for renewable distributed generation up to 10 kW, and, in addition, provides partial requirement rates for distributed generators larger than 100 kW. (*Id.* at 14). Finally, the Company has proposed a partial service requirement rate, E-57, for solar installations up to 1MW with no aggregate cap.

As part of this pilot program, the Company would install the necessary bi-directional metering to measure power flow both to and from the customer. (APS Exhibit No. 37 at 10 [DeLizio]). The Company would have to make changes to its customer information systems, so participation under this schedule is subject to the availability of enhanced metering and billing system upgrades. (*Id.*). Renewable resource energy generated by the customer in excess of their monthly consumption would be accumulated on a kWh basis, and credited to the customer's future monthly bills within the same calendar year. (*Id.*). Under net billing,[93] excess power is purchased at an avoided cost rate,[94] while under net metering the excess power would be credited against power that the customer purchases from the Company in future billing periods and would, therefore, be compensated at full retail rates.[95] (APS Exhibit No. 37 at 3 [DeLizio]).

2. Uncollected Fixed Costs Or "Net Lost Revenues".[96]

EPR-5 would not yield appropriate revenue to cover fixed costs because customers that took service under this schedule and produced their own generation would not pay appropriate transmission and distribution costs, nor will they pay the full amount of non-avoidable charges, such as the Competition Rules Compliance Charge ("CRCC"), EPS Surcharge, DSM Cost Adjustment, PSA (for deferred fuel costs incurred during prior periods) and Transmission Cost

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[93] APS currently utilizes the net billing methodology for customers taking service under rate schedules EPR-2 and EPR-4. (APS Exhibit No. 38 at 13 [DeLizio]).

[94] Avoided costs are based on wholesale generation market rates for on-peak and off-peak generation by season.

[95] The Energy Policy Act of 2005 defines net metering as "....service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period...." (APS Exhibit No. 38 at 12 [DeLizio]). Net Billing, as defined in the Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules (Decision No. 68566), "...is a system of billing a customer who installs an eligible Renewable Energy Resource generator on the customer's premises for retail electricity purchased at retail rates while crediting the customer's bill for any customer-generated electricity sold to the Affected Utility at avoided cost." (*Id.*).

[96] In discussing the Company's net metering proposal, "uncollected fixed costs" have also been referred to as "Net Loss Revenues," and are not to be confused with DSM related net lost revenues.

Adjustment. (APS Exhibit No. 37 at 11 [DeLizio]).

Under the Company's proposal, the incremental cost for net metering would be funded through revenues collected through the current EPS surcharge. (*Id.* at 10). In addition, infrastructure costs, such as changes to the customer billing systems, would also be funded through the EPS surcharge. (*Id.*). Revenue associated with transmission and distribution, as well as non-avoidable costs that are not recovered from EPR-5 customers would also be funded by the EPS surcharge. (*Id.*).

The Company believes that it is appropriate to recover its uncollected fixed costs under EPR-5, which offers a special financial subsidy to customers as a means to promote small renewable distributed generation systems. (APS Exhibit No. 38 at 18 [DeLizio]). With regard to the proposed RES energy requirement associated with distributed generation, the Company is seeking recovery of the fixed costs component and expenses associated with the infrastructure necessary to connect customers to the grid. (Tr. Vol. VIII at 1784 [DeLizio]). The Company is not requesting to collect the generation energy component or the fuel component of such costs. (Tr. Vol. XII at 2576 [DeLizio]).

The potential loss of kWh sales and the related uncollected fixed costs from the proposed net metering program would occur for two reasons. First, the Company would be providing a subsidy through the net metering rate to encourage customers to install renewable distributed generation, which will reduce kWh cost recovery that the Company would otherwise have achieved absent the program. (Tr. Vol. XII at 2576 [DeLizio]). Although the customer would be providing a portion of their own energy needs through their distributed generator, they would still be connected to the grid and would rely on APS to back up their distributed generator and provide their remaining energy needs. (*Id.*). Because the proposed net metering rate does not include a customary standby charge to recover such costs, the customer would not pay their full costs for transmission, distribution or other fixed costs, especially for rate schedules that recover these costs through energy-based charges. (APS Exhibit No. 38 at 19 [DeLizio]).

Second, excess power that the customer generates above their own needs, which flows back to the grid, would be compensated at an amount that is above the Company's avoided cost.

(*Id.*). The customer would receive a credit equal to the entire energy charges in their applicable rate schedule, which includes generation, transmission, distribution, system benefits, DSM, PSA, regulatory assessment, CRCC, EPS and other energy-based charges. (*Id.*).

The Company would incur foregone kWh cost recovery equal to the customer's total kWh generation and incur the associated fixed costs consistent with the customer's otherwise applicable rate schedule. (APS Exhibit No. 38 at 19 [DeLizio]). The customers' generation kWh output would be calculated by applying a capacity factor to each customer's actual installed kW of generation. (*Id.*). The uncollected fixed costs would be derived by applying the average kWh charges in the customer's otherwise applicable rate schedule to the lost kWh. (*Id.*). The basic service charge and any kW charges would not typically be included in this calculation because the associated revenues are not likely to be reduced with distributed generation. (*Id.*). These uncollected fixed costs would be calculated for each billing month for each participating customer. (*Id.*).

The uncollected fixed costs would be netted against the associated avoided generation costs that the Company would not incur as the result of the distributed generation. (APS Exhibit No. 38 at 20 [DeLizio]). Both the generation energy and capacity cost savings from net metering would be based on the Company's PURPA avoided costs, which are used to purchase excess energy from qualifying small distributed generators in the EPR-2 rate schedule. (*Id.*). The uncollected fixed costs would be reflected within the EPS budget, collected through the EPS surcharge, and reported to the Commission as part of the reporting requirements of the EPS program. (*Id.*).

3. Staff's Recommendation.

Although Staff supported APS's recovery of uncollected fixed costs through the EPS, Staff would limit such recovery to the customers' excess generation,[97] not total generation. Staff also recommended that the limit on facility size be increased to 100kW and that participation not be limited by rate schedule. The Company's proposed recommendations already attempt to

[97] The difference between the retail value of the kWh that's rolled over to the next month and the Company's avoided cost. (Tr. Vol. XIX at 3510-3511 [Keene]).

strike a delicate balance between providing incentives to promote distributed renewable resources and the amount of such incentive being paid by other customers who would not be participating in the net metering program. (Tr. Vol. XII at 2429 [DeLizio]). Staff's position would upset that balance and provide an even greater subsidy to program participants at the expense of other APS customers.

Staff also recommended that the Company not necessarily require the use of bi-directional meters; rather Staff recommended the use of two separate meters if more economical. It is the Company's position that while the EPR-5 net metering rate could technically be implemented with two standard meters, a single bi-directional meter would be a better option because any initial savings realized with two standard meters would be eliminated due to additional electrical infrastructure costs, such as an additional meter base, sockets, adaptors and other meter-service costs. (APS Exhibit No. 38 at 17 [DeLizio]). The Company also prefers the operational benefits of the bi-directional meter for this application, which includes reduced meter inventory requirements, fewer meter sets and less meter reading, and it is already using a single bi-directional meter for the current distributed generation (partial service requirements) rates, EPR-2 and EPR-4. (*Id.*). In addition, the use of a bi-directional meter is consistent with industry and regulatory practice throughout the country. (*Id.*).

4. Solar Advocates' Proposal.

The Solar Advocates proposed that the cap on individual system size be increased to 2 MW, that the overall program cap be increased to some higher level commensurate with an expanded RES program, and that the rate be made available to larger commercial customers. Solar Advocates also opposed the recovery of uncollected costs resulting from the Company's proposed net metering program.

APS believes that the proposed 10 kW cap on the individual generator size is appropriate for net metering, even in light of an expanded RES program, because the Company already offers net billing rate options for distributed generation systems up to 100 kW (EPR-2), which do not have any cap on aggregate participation. (APS Exhibit No. 38 at 13 [DeLizio]). Under EPR-2, the customer's excess generation is compensated at an avoided cost rate, while EPR-5 would allow the excess energy to be netted against energy purchased from APS in subsequent months. (*Id.* at 14). In addition, the Company has proposed a net metering generation only rate, E-57, for solar installations up to 1 MW with no aggregate cap.

Most other jurisdictions that offer net metering have relatively small caps on the individual size of participating generators as well as the overall aggregate level of program participation. (APS Exhibit No. 38 at 15 [DeLizio]). Out of the 41 states referenced by the Interstate Renewable Energy Council that offer net metering, 33 have caps on generator size at or below 100 kW. (*Id.*). The Company believes that its proposal of 10 kW for the EPR-5 rate is consistent with these other jurisdictions, including Arizona, because the Company already offers net billing rates, which provide most of the benefits of net metering, for customers with generators up to 100 kW in size. (*Id.*).

Although Solar Advocates cited several states with relatively high caps for individual generator size and for total MW allowed on a net metering program, in fact, only two states allow participation in net metering of generators up to 2 MW. (APS Exhibit No. 38 at 15-16 [DeLizio]). Furthermore, in each of the states that Solar Advocates cited as examples, other than Colorado, the utilities have divested generation as part of retail competition and are facing very different generation procurement situations compared to APS. (*Id.*).

Solar Advocates also proposed that the overall cap of 15MW proposed by the Company should be increased. (Solar Exhibit No. 8 at 4-5 [Smeloff]). In contrast, the Company-proposed 15 MW cap on total aggregate participation in the EPR-5 net metering pilot program is appropriate, because (1) it is a pilot program designed to be a limited offering to provide an incentive for small customers to participate in the Company's Solar Partners Incentive Program (credit purchase program), and (2) the Company already offers other net metering/net billing type rates that do not have any aggregate cap on participation. (APS Exhibit No. 38 at 14-15 [DeLizio]).

Solar Advocates opposed the recovery of uncollected costs from the Company's proposed net metering program and claimed that such recovery is unnecessary, because the Company is experiencing rapid growth in its service territory. However, the issue of whether

APS sales are growing, remaining flat, or declining is irrelevant to the issues of uncollected fixed costs. Sales will be less than they would have been absent the distributed generator. (APS Exhibit No. 39 at 6 [DeLizio]). That particular customer will still have avoided paying for the cost of providing service to such customer. Moreover, APS's rapid growth also carries with it the additional costs to serve the Company's increasing customer base. (*Id.*). This additional financial burden heightens, not lessens, the importance of preserving the margins for fixed delivery costs from customers participating in public benefit programs like net metering. (*Id.*).

The Commission must make a policy decision as to the scope of the proposed net metering program, given the fact that there are uncollected fixed costs that need to be recovered and must determine whether it is more appropriate to recover such costs through the EPS or RES, or defer recovery of such costs until a general rate case and spread such costs among all classes through the cost of service. APS requests the Commission approve Rate Schedule EPR-5, without modification for customers that have renewable resource generation facilities of 10 kW or less. As part of EPR-5, APS proposes that the Commission enact a 15 MW cap on total aggregate participation in the EPR-5 net metering pilot program. The Company also requests Commission authorization to recover its uncollected fixed costs associated with the implementation of EPR-5, which offers a special financial subsidy to customers in order to promote small renewable distributed generation systems.

In response to an inquiry by Commissioner Mayes, the Company has submitted Appendix C (attached to APS Exhibit 105), which is a recalculation of APS Exhibit 73 using Staff's modified recommendation that only when a metered customer is producing a surplus of energy will there be unrecovered fixed distribution costs through the EPS or RES.[98] It is noteworthy that the aggregate level of unrecovered fixed distribution costs remains unchanged from APS Exhibit 73. These unrecovered costs are an undeniable aspect of net metering and, if not recovered through the RES, will impact base rates charged to non-participating customers.

[98] APS Exhibit 73 entitled "RES Surcharge Calculations for Impacts of Uncollected Fixed Costs under Net Metering" sets forth the calculation that was requested to show the revenue impact of uncollected fixed costs due to net metering. It includes distribution costs plus items such as system benefits and other kilowatt hour, or non-fuel non-purchased power, power supply fuel or related costs. (Tr. Vol. XXIII at 4313 [Rumolo]). Exhibit 73 makes the assumption that every three years the uncollected dollars from distributed net-metered customers would be rolled into the revenue requirements in a rate case. (*Id.*).

(Tr. Vol. XXIII at 4419 [Rumolo]).

C. Renewable Procurement.

1. Renewables As A Hedge.

a. Cost Of Renewable Energy Is Higher Than Natural Gas.

WRA has proposed that the Company use an increased amount of renewable energy as a hedge against high natural gas prices. 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. (APS Exhibit No. 47 at 2 [Dinkel]). In general, there is a cost premium for any "hedge", and careful consideration of the cost is required. (*Id.*). 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. (*Id.*). 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. (*Id.*). Although there may be recent projects in certain states where renewable energy can be procured at or below the cost of conventional resources, APS's experience in acquiring renewable resources indicates that such resources include paying a significant premium over the cost of conventional energy resources utilizing natural gas. (*Id.* at 3).

Arizona's renewable resources are limited and APS's 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. (*Id.*). Project specific analysis is required to adequately measure the economic value of each renewable project. (*Id.*). Because renewable energy is an intermittent source of power, this uncertainty means it may be difficult to schedule the gas purchases needed to counterbalance the renewable resource intermittency, resulting in increased costs. (*Id.* at 4).

2. Independent Evaluation / Solicitation Process.

Interwest Energy Alliance ("Interwest") has proposed that the Commission mandate the Company to use an independent evaluator when evaluating future renewable Request For

Proposals ("RFPs"). APS believes that an independent evaluator is unwarranted. First, the RES requires utilities to have procedures for selecting resources and also required certification by an independent auditor that the procedures are fair and unbiased and have been appropriately applied. (APS Exhibit No. 19 at 8 [Lockwood]). In addition, because it is a requirement of APS's compliance filing, it is appropriate for APS to work with the independent auditor to review its processes and procedures before applying them to select a resource. (APS Exhibit No. 20 at 7 [Lockwood]).

APS also plans to commission a Wind Integration Study to be conducted by academic and industry participants to assist in establishing guidelines to be used for RFP evaluations of wind projects. (APS Exhibit No. 47 at 4 [Dinkel]). Finally, the cost of an independent evaluator to review an RFP would be between $90,000 and $125,000. (APS Exhibit No. 19 at 8 [Lockwood]). Such additional costs are an unnecessary use of customers' money because of the clarity and rigor provided by the Wind Integration Study and RES requirements. (*Id.*). In addition, the RES does not mandate an RFP.

3. Mandated Procurement Schedules.

Interwest has also proposed that the Commission mandate RFPs related to renewable procurement. APS believes that determinations about how and when to procure renewable energy should be left to the Company, so that it can have the flexibility it needs to best serve its customers. (APS Exhibit No. 19 at 8-9 [Lockwood]). APS is committed to engaging the market in an open and fair manner, and anticipates conducting additional renewable energy RFPs in the future; however, mandated procurement schedules and procedures would not be in APS's customer's best interests. (*Id.*).

4. Wind Integration Study.

Both Interwest and WRA have raised concerns about APS's methodology for calculating wind integration costs in its renewable RFP's. APS believes it is in the public interest to study the impact of the integration of renewable resources into its portfolio. (APS Exhibit No. 47 at 4 [Dinkel]). To determine the system impacts and costs associated with effectively integrating potential wind projects into APS's system, APS is currently in discussion with Northern Arizona

University ("NAU") for the coordination of a Wind Integration Study. (*Id.*). The 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's system. (*Id.* at 5). It will address the nuances of APS's system, and the known characteristics of probable wind projects that may be made available to APS to better predict and evaluate the costs and impacts of integrating specific renewable resource technologies into APS's system, particularly those which demonstrate intermittency like wind and solar. (*Id.*).

The purpose of the study is to develop experience with actual renewable resources so APS will have the ability to better predict and evaluate the costs and impacts of integrating specific renewable resource technologies into APS's system, particularly those which demonstrate intermittency like wind and solar. (*Id.*). NAU would conduct the analysis with the direct involvement of industry experts, with the scope, technical process, and results overseen by a Technical Advisory Committee. (*Id.*). In addition, a Stakeholder Advisory Committee is being formed to provide review from a variety of stakeholders including other utilities and renewable energy advocates. (*Id.*). A timeframe is currently being evaluated, but APS expects the integration cost study to be complete in approximately 6 to 8 months. (*Id.*).

Interwest supported APS's efforts to conduct the study and indicated that the study would provide valuable information to assist the Company in understanding the costs and technical issues of integrating a substantive amount of wind into their system. (IEA Exhibit No. 5 at 2 [Ormond]). In addition, Interwest supports the Company's proposal to utilize a Technical Advisory Committee to provide expertise and guidance in the development of the study. (*Id.*).

D. <u>DSM.</u>

1. DSM Spending Should Remain At Its Current Level.

APS's demand-side management programs, in accordance with Decision No. 67744, are budgeted to spend $48 million by year-end 2007. (APS Exhibit No. 32 at 2 [Orlick]; Decision No. 67744, Settlement Agreement ¶ 40). However, as a result of delayed DSM program approvals, the time it takes to ramp up DSM spending, and the lag inherent with spending on energy efficient **new** construction projects, APS will not spend that $48 million by year-end

2007. (APS Exhibit No. 32 at 2 [Orlick]). Rather, the Company proposes, and SWEEP and Staff agree, that any unspent funds should be carried over and spent in subsequent years. (*Id.* at 3; SWEEP Exhibit No. 2 at 2 [Schlegel]; Staff Exhibit No. 17 at 2 [Anderson]). While DSM programs have been successfully rolled out, the Company disagrees with RUCO's assessment that the programs are "up and running," and believes that RUCO's proposed $4,000,000 increase in spending is unnecessary at this time given the flexibility of the DSM Adjustor.

Both Staff and the Company expect that DSM spending will continue at its present ordered level, until such time as APS files and the Commission approves modifications to the program design and budget requirements. (*Id.* at 3; Staff Exhibit No. 16 at 6 [Anderson]). In fact, the nature of the funding mechanism is comprised of 2 elements – one element is in base rates ($10,000,000) and the other element flows through the DSM Adjustor – that allow for DSM programming to continue and grow as cost-effective program opportunities emerge. (APS Exhibit No. 32 at 3 [Orlick]). Although APS will promote cost-effective DSM, such an aggressive escalation in spending is premature. The current funding program is sufficient for the development of the DSM programs; any increases at this time would be an inefficient use of funds.

a. It Is Premature And Not Cost Effective To Adopt SWEEP's Aggressive Energy Efficiency Standard.

APS's demand-side management programs have recently been approved by the Commission and APS needs time to get its DSM programs up to speed, gauge progress, and evaluate what is actually being achieved through the Measurement, Evaluation and Research ("MER") process. (APS Exhibit No. 32 at 4 [Orlick]). As such, Staff and the Company believe it is premature to make substantial changes by implementing the Energy Efficiency Standard ("EES") or savings target. (*Id.* at 3; Staff Exhibit No. 17 at 3 [Anderson]). The Commission appears to share this concern, as it only approved the non-residential DSM programs on an interim basis. This allowed APS to begin moving forward with DSM program implementation while evaluating program effectiveness. (APS Exhibit No. 32 at 4 [Orlick]; Decision No. 68488 at 6).

b. SWEEP's Proposed Savings Goal Is Unnecessary And Its Cost Is Uncertain.

Furthermore, SWEEP's proposal to switch to a savings goal, as opposed to a spending target, is unnecessary. (APS Exhibit No. 32 at 4 [Orlick]). The present DSM spending requirement adequately and reliably meets DSM needs, was approved by the Commission after review by Staff and the Collaborative Working Group, and promotes cost-effective program development. (*Id.* at 4-5). In fact, SWEEP's aggressive savings target exceeds that of many states with well established DSM programs. (*Id.* at 6).

SWEEP's savings goal incorporates an estimated funding level of 2 mills per kWh, which for 2007 alone is a significant annual funding increase of $28,000,000 over current base rates and a $22,000,000 increase over the target level of $16,000,000 per year. (*Id.* at 7-8). SWEEP's funding estimate is based on APS achieving DSM savings at an average cost of approximately 1.1 cents per lifetime kWh saved. This optimistic funding assumption neglects to account for the full range of DSM costs, which may be much higher than the 1.1 cents estimated by SWEEP. (APS Exhibit No. 32 at 7 [Orlick]). As such, even a slight increase in assumed cost under SWEEP's proposal would significantly increase the funding necessary to reach the savings goal. Even SWEEP acknowledges that actual funding, based on the proposed savings target, may vary. (SWEEP Exhibit No. 2 at 5 [Schlegel]).

c. SWEEP's Proposed 12 Year Implementation Plan Is Not An Efficient Use Of Planning Resources.

In addition to the EES and savings target, SWEEP suggests that a 12-year implementation plan should be developed within eight months of a decision in this matter. Since long term results are difficult to predict, this will likely be of little value; rather, APS suggests that shorter term horizons will actually prove more fruitful. (APS Exhibit No. 32 at 8 [Orlick]). In fact, the DSM Portfolio Plan establishes such a timeframe in the form of biennial updates following the 13-month DSM filing required by Decision Nos. 68488 and 68648. (*Id.* at 9). SWEEP agrees that the biennial plans will be valuable; and the remaining 10-year period would be conceptual only. (SWEEP Exhibit No. 2 at 6 [Schlegel]).

2. Interest On Unrecovered DSM Costs.

In Decision No. 67744, the Commission approved a DSM Adjustor Clause ("DSMAC") allowing APS to collect, on a deferred basis, DSM expenditures over and above rate base. Decision No. 67744 at ¶¶ 43-44. The DSMAC enables APS to timely recover costs associated with new and expanding DSM programs. (APS Exhibit No. 32 at 10 [Orlick]). Due to the deferred nature of cost recovery under the DSMAC, the Company believes that an interest charge is appropriate. (APS Exhibit No. 69 at 15 [Rumolo]). As such, the Commission should allow APS to accrue interest in accordance with a revised Plan of Administration. (*Id.* at 15-16).

Staff did not oppose "the inclusion of interest earning on the unrecovered DSMAC account balance … [measured] using the one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release H-15 or its successor publication." (Staff Exhibit No. 16 at 8 [Anderson]).

Although RUCO believed that DSMAC interest may be recoverable at a later time, RUCO contended that recovery is inappropriate now. According to RUCO, interest recovery was not addressed in the Settlement Agreement (Decision No. 67744) because the parties anticipated over-collection of DSM funds during "ramp up." RUCO further argued that the current interest free adjustor mechanism is reasonable given that APS is collecting DSM funds from rate base without paying interest to customers.

APS and Staff disagreed with RUCO, and acknowledged that APS should be allowed to recover DSM interest. RUCO has incorrectly claimed that APS's failure to spend its full amount of DSM funds should preclude it from interest recovery. Although APS could not, for reasons wholly outside its control, immediately meet the spending requirements allocated for DSM during the initial start-up period, it will shortly eclipse the $10,000,000 a year mark as DSM programs mature. Both Staff and APS agreed that the Company should be compensated for advancing DSM funds by permitting the Company to earn interest on the DSMAC.

3. Performance Incentive.[99]

Consistent with Decision No. 67744, and to encourage further DSM development and reward successful programming, Staff, RUCO, and APS all agreed that the Company should receive a DSM performance incentive. (APS Exhibit No. 33 at 2 [Orlick]; RUCO Exhibit No. 26 at 12 [Diaz Cortez]; Staff Exhibit No. 16 at 9 [Anderson]). Initial net benefit determinations should be based upon current and regionally similar energy savings data. (APS Exhibit No. 33 at 2 [Orlick]; Staff Exhibit No. 17 at 4 [Anderson]). However, beginning with the July-December 2007 semi-annual DSM report, net benefits going forward should be based upon measured savings as developed by the MER contractor. (*Id.*). APS also agreed with Staff's recommendation to set the performance incentive share at 10 percent of the net benefits from the energy efficiency achieved through approved DSM programs and that the incentive should be capped at 10 percent of spending, inclusive of the performance incentive. (APS Exhibit No. 32 at 10 [Orlick]; Staff Exhibit No. 16 at 10 [Anderson]).

Net benefits should be calculated as of the time DSM measures are placed into service and expenditures are incurred. (Staff Exhibit No. 16 at 12 [Anderson]). Furthermore, to calculate net DSM benefits, APS will continue to use the Societal Cost Test, which it also used to calculate net benefits in Decision Nos. 68488 and 68648. (APS Exhibit No. 32 at 11 [Orlick]).

a. The DSM Performance Incentive And The Proposed Conservation Adjustment[100] To Test Period Sales Are Not Mutually Exclusive.

In addition to the performance incentive, APS proposed that the Commission authorize a conservation adjustment normalizing APS's lost revenues to account for successful DSM programming. (APS Exhibit No. 17 at 10 [Ewen]). Staff and RUCO disagreed, arguing that such a conservation adjustment, when collected in conjunction with a DSM performance incentive, would allow the Company to be compensated twice for the same effort. First of all, this assertion is factually inaccurate. The proposed performance incentive is capped at 10

[99] The Company filed for approval of a performance incentive as part of APS's application for approval of the DSM programs consistent with Decision No. 67744. While the Commission approved these programs, the Commission never addressed the Company's request for a performance incentive.

[100] The term "conservation adjustment" has been used interchangeably with "net lost revenues". To avoid confusion with the "net lost revenues" or "uncollected fixed costs" that have been discussed related to the Company's net metering program, the term "conservation adjustment" is used in this discussion.

percent of the Company's DSM spending in a given year. (Tr. Vol. XIX at 3660-61 [Anderson]). This is far less than the lost margins attributable to these programs. Therefore, disallowing the conservation adjustment would almost certainly constitute a taking of APS's property, given that its lost revenues from the DSM programs will exceed this 10 percent cap. But, the two are not mutually exclusive – the conservation adjustment **accounts** for revenues lost to the successful implementation of DSM measures, while the performance incentive is a financial **reward** because the programs delivered net benefits to customers. The incentive is intended to be over and above the cost of the program, including net lost revenues. Otherwise, it is not an incentive at all, but merely partial compensation for a cost otherwise recoverable through rates. This Commission approved a combined incentive/net lost revenue conservation adjustment program for APS in a 1996 rate case settlement, and at no time did Staff or any other party suggest that such was inappropriate or somehow constituted a double recovery of program costs. *See,* Decision No. 59601 at 7.

4. Demand Response.

The Company agreed with Staff and RUCO that Demand Response programs have the ability to benefit the system, and concurred with their findings that a study group should be assembled to evaluate various Demand Response options. Demand Response programs, which are distinct from the Company's DSM offerings, rely upon market conditions and tiered pricing to reduce peak load. (Staff Exhibit No. 22 at 31-32 [Andreasen]). APS agreed with Staff and RUCO that Demand Response may be able to provide effective supply-side options for meeting system needs, in addition to introducing greater elasticity in energy demand and use. (APS Exhibit No 47 at 6 [Dinkel]). To be effective, Demand Response programs must be carefully designed to adequately address reliability requirements and provide economics that are favorable compared to other supply-side options. (*Id.*).

In creating a reliable, efficient, and effective Demand Response program, there are a variety of considerations, including implementation costs, benefits, infrastructure needs, and complexity of administration. (*Id.*). For those reasons, a thorough study is necessary to determine which programs would be likely to produce the most cost effective benefits. (*Id.* at 6-

7). APS and RUCO agreed that the Company should conduct the initial evaluation of Demand Response options. (*Id.* at 7; RUCO Exhibit No. 26 at 28 [Diaz Cortez]). This study will enable APS to narrow the list of Demand Response options to those that are most efficient and economical. (APS Exhibit No. 47 at 7 [Dinkel]).

RUCO recommended that APS establish a Demand Response task force to consider further development of load shaving and shifting opportunities. (RUCO Exhibit No. 24 at 6, 42 [Diaz Cortez]). However, prior to creating the task force, RUCO agreed with the Company that APS should conduct a preliminary Demand Response study. (RUCO Exhibit No. 26 at 28 [Diaz Cortez]). Preliminarily evaluating the programs is an efficient use of resources and will offer the task force a starting point when determining which programs are the best to use. (*Id.*). RUCO recommended that the Demand Response task force include APS, Staff, RUCO, and other stakeholders. (RUCO Exhibit No. 24 at 42 [Diaz Cortez]).

Staff agreed with APS that expansion of Demand Response may include "several unknowns." (Staff Exhibit No. 22 at 35 [Andreasen]). Staff further asserted that expansion will likely prove costly and should only occur when a properly designed Demand Response program has been developed. (*Id.*). Accordingly, Staff recommended a cost benefit analysis to determine the most appropriate ways in which to expand APS's Demand Response programs, as well as the establishment of a forum to explore Demand Response issues. (*Id.* at 35-36). Staff proposed that this analysis, which should outline beneficial Demand Response options and identify "which customer segments would be most likely to respond to such programs," should occur within eight months of the Commission's decision in this rate case. (*Id.* at 36). In addition, Staff contended that, concurrent with filing the Demand Response study, APS should file for Commission approval of one or more Demand Response programs. (*Id.* at 36-37).

Although Staff has proposed an eight-month feasibility study, the Company believes that truly effective Demand Response programs cannot be implemented, analyzed, and introduced to all customers in such a short amount of time. (APS Exhibit No. 47 at 7 [Dinkel]). In July 2006, APS implemented two new time-of-use rate schedules, offering alternative on-peak pricing as a means of evaluating customer interest in Demand Response. (APS Exhibit No. 69 at 16

[Rumolo]). Eight months is an insufficient amount of time to implement the rates and then evaluate customer response. Indeed, a time-of-use rate implemented in this eight-month window may completely bypass the summer months – Arizona's busiest time from a peak load perspective. It would be imprudent for APS to evaluate its proposed Demand Response programs with such a small sampling of data. As such, APS disagrees with Staff's eight-month proposal as being untenable and impractical. (APS Exhibit No. 47 at 7 [Dinkel]).

Funding for additional Demand Response programs is provided for in Decision No. 67744, and APS may request funding for Demand Response as part of its DSM program costs. (Decision No. 67744 ¶ 49). 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. (APS Exhibit No. 47 at 8 [Dinkel]).

5. Heat Island Effect.

In order to mitigate rising energy costs, APS and WRA[101] agree that urban heat island reduction measures should be taken. In urban areas, such as Phoenix, the large concentration of pavement and buildings has created an urban heat island effect and increasingly high temperatures, which strain the electric grid, requiring increased generation from intermediate and peaking power plants. (WRA Exhibit No. 1 at 15-16 [Berry]). APS is aware of this issue and is a founding lifetime sponsor of the Arizona State University ("ASU") Global Institute for Sustainability, which has been designated as the EPA Center for Excellence in working toward solutions to his growing problem. (APS Exhibit No. 32 at 12 [Orlick]; Tr. Vol. VII at 1385-86 [Orlick]).

Although APS agrees that it should study the benefits of a heat island reduction program, the Company disagreed with WRA's recommendation to expedite the adoption of "pre-approved" DSM programs. (APS Exhibit No. 32 at 14 [Orlick]). APS is willing to hold a DSM Collaborative Working Group meeting to further analyze these issues, and believes the current DSM custom project option is a viable tool for addressing the urban heat island effect. (*Id.* at 13;

[101] WRA expressed concern about this situation and suggested a pre-approved DSM offering, which would include shade trees, cool roofs and cool pavements. (WRA Exhibit No. 2 at 3 [Berry]). The Commission found cool roofs to be a cost ineffective DSM program in Decision No. 68488 at 33.

WRA Exhibit No. 2 at 3 [Berry]). In light of APS's long relationship with ASU, the unique nature of addressing urban heat island issues, and the valuable research APS anticipates over the next few years, adopting WRA's approach would not be a prudent course of action at this time. (APS Exhibit No. 32 at 14 [Orlick]).

6. Low Income Programs.

APS's modifications to the Low Income Plan of Administration are a valuable way to promote further enrollment in the Company's successful Energy Support Program ("E-3") and E-4 programs. APS's E-3 program offers discounts up to 40 percent off the cost of electricity for customers who meet certain income guidelines and exempts those same customers from PSA charges. (APS Exhibit No. 32 at 15 [Orlick]). The E-4 program provides additional discounts to eligible E-3 customers for their use of durable medical care equipment. (*Id.*). Participation in the E-3 program is of unlimited duration, provided the applicant continues to meet the income guidelines. (*Id.*).

Thus far, APS's new enrollment techniques, including pre-paid postage for applications and an electronic application pilot program, have been successful, with a total enrollment by August 2006 of over 36,000, including 566 Tribal customers, which is an increase of almost 30 percent. (*Id.* at 20; Tr. Vol. VII at 1429 [Orlick]). In addition to various marketing efforts, APS has begun sending program information and applications to all residential customers who are not already enrolled in E-3 and E-4. (APS Exhibit No. 32 at 19-20 [Orlick]). Applications are also distributed at APS offices, social service agencies and are downloadable on aps.com. (*Id.* at 19). The Arizona Department of Economic Security ("DES") is responsible for processing the applications, determining eligibility, and notifying APS to enroll applicants in the program. (*Id.*).

APS, consistent with Decision No. 68585, has evaluated additional ways to automatically enroll participants in the E-3 and E-4 programs. (*Id.* at 16; Decision No. 68685 ¶ 62). The Company's efforts, however, have been impeded by regulations that preclude DES from transmitting confidential client information to a party outside of DES. (APS Exhibit No. 32 at 16 [Orlick]). Alternatively, APS established an electronic application for E-3 that uses the APS

Electronic Agency Guarantee ("EAG") website and allows authorized community agencies to verify a client's account data and enroll federal Low Income Home Energy Assistance Program clients in the APS program. (*Id.* at 17). The pilot EAG program has proven successful, and APS is seeking to expand it to additional agencies and other programs that use the same income guidelines. (*Id.* at 18).

APS is proposing to modify the Plans of Administration for Schedules E-3 and E-4 in order to facilitate the automatic enrollment process. (*Id.* at 19). This modification will provide APS the flexibility to pursue other enrollment options, such as allowing community agencies that have access to APS's EAG website the ability to also enroll their clients into E-3. (*Id.*). This plan will broaden the reach of the E-3 and E-4 programs, and is supported by DES. (*Id.*).

E. <u>Reliability.</u>

Staff conducted a quality of service assessment for calendar years 2000 through 2005 and concluded that all electric facilities observed during the assessment were operational and well maintained. Staff thereby concluded that APS's Test Year improvements were used and useful. These findings were incorporated into an Engineering Report Utilities Division Arizona Corporation Commission, dated August 18, 2006 ("Engineering Report"), which was attached to the Direct Testimony of Staff witness Jerry Smith.[102] (Staff Exhibit No. 25). Staff concluded:

> 1. The scope of system improvements since the Westwing and Deer Valley Substation fires was substantial and impressive to observe in the field;
>
> 2. Most electric transmission systems including substations were well maintained in terms of security in and around the substations, and of proper maintenance of equipment in the yard and in the switchgear rooms; and
>
> 3. Poor performing substations and distribution feeders are being maintained, refurbished and repaired in a logical and sound manner. Some of these improvements being made to the facilities serving tribal territories are effectively improving service; and as recommended by APS Consultant EPRI Solutions, Inc., APS formed a predictive maintenance team to focus on predictive and preventive maintenance activities to find and repair equipment prior to failure. Staff determined that all electric facilities observed during the assessment were operational and well maintained; thereby concluding that APS's test year improvements were used and useful.

[102] At the hearing, this testimony and Engineering Report was adopted by Mr. Prem Bahl.

(*Id.* at 6-7).

Staff identified seven items associated with 2005 Test Year capital improvements that APS is aware of and has either rectified or is in the process of making such improvements.[103]

Staff also raised some issues regarding the quality of service in APS's Southeast Division, particularly the portions of the APS system that provide service to the communities of Douglas and Bisbee. APS acknowledged that reliability in the Southeast Division deserves heightened attention, and indicated that the Company 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 Southeast Division. (APS Exhibit No. 30 at 9 [Bischoff]). In 2004, APS began to route and construct a new 69 kV transmission line to energize a new substation being located in the Palominas area. (*Id.*). In addition, the main portion of the distribution feeder is being reconstructed on the same poles and will improve reliability of the feeder when completed. (*Id.*). A new Palominas 69/12 kV substation will be placed in service by June 1, 2008, and APS recently completed the rebuilding of a portion of the line along Highway 92 that was planned for 2006. (*Id.*).

In addition, as part of an agreement between APS, Sulphur Springs Valley Electric Cooperative ("SSVEC") and Southwest Transmission Cooperative ("STC"), these utilities are performing additions and improvements that will allow for a second emergency tie between APS's Palominas Substation and SSVEC's Miller Substation. (*Id.*). Upon completion in 2009, APS will be able to carry the entire APS load in the region through use of the two emergency ties without the need for the local generation at APS's Fairview (Douglas) Plant. (*Id.* at 9-10).

While the Engineering Report raised some concern regarding sustained service interruptions to customers in 2005, APS responded that when significant or unusual weather

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[103] (1) APS is currently in discussion with the City of Prescott regarding an expansion of the well field and the Chino Wells Substation will be rebuilt to accommodate the increased demand; (2) the inadequate capacity at the Fairview generator and an emergency 69 kV tie at Sulphur Springs Valley Electric Cooperative's McNeal Substation in the Southeast Division is expected to be remedied by the end of the year; (3) the Humbug transformer oil retention basin will be in compliance with the new Company standard by the end of 2006; (4) approximately 75 of the old wood poles have been removed on the Laguna Feeder #1; (5) APS replaced the 69 kV steel pole just north of Laguna Substation; (6) the auger bit at the Paulden substation has been removed from the yard; and (7) repairs to the roof of the control house at the San Luis Substation have been completed. (APS Exhibit No. 30 at 6-9 [Bischoff]; Tr. Vol. VI at 1346 [Bischoff]).

events were removed from the computation, there was no significant difference in outage rates from 2003 through 2005. (*Id.* at 10). At hearing, the Staff witness concurred that when those events were removed from the computation, there was no statistically significant difference in reliability metrics. (Tr. Vol. XXI at 3859 [Bahl]).

At hearing, Staff confirmed its satisfaction with the Company in meeting the requirements of Decision No. 67744 to place greater focus on service quality, particularly on the Navajo and Hopi Reservations. (Tr. Vol. XXI at 3853 [Bahl]). Specifically, APS has taken action on each of Staff's recommendations for the Hopi Reservation area to improve the reliability of service. (*Id.*). In addition, APS has added a capacitor bank and has changed out a transformer at the Tuba City Substation to correct the voltage level at the Cameron Substation and to provide voltage support for Tuba City. (*Id.* at 3853-3854). APS is currently negotiating with the City of Page to install a 69 kV circuit breaker at the Powell Substation (which belongs to the Western Area Power Administration) to replace an existing manual switch. (*Id.* at 3854). For the Hopi Reservation, APS has installed fault locators on the 70-mile long line which stretches from Cholla to Keams Canyon. The fault locators will facilitate the location of problems and allow the Company to quickly dispatch crews to correct the fault. (*Id.* at 3855).

F. Renewable Energy Resources ("Green Power)".

1. APS Supports The Intent Of The RES And The Development And Integration Of Renewable Energy Into Its Energy Portfolio.

In a letter dated July 17, 2006, Commissioner Mayes requested that Parties to this Docket consider exploring the implementation of the RES in this rate proceeding. (APS Exhibit No. 19 at 2 [Lockwood]). APS supports the intent of the RES and the development and integration of renewable energy into our energy portfolio. (*Id.* at 3). Renewable energy diversifies the Company's energy supply, which provides many benefits to APS customers and helps manage the environmental impacts of electricity generation. (*Id.*).

a. Green Power Rate Schedules.

APS is proposing to provide a mix of renewable energy resources to its customers. The

Company is offering Green Power to customers who wish to purchase renewable energy at a surcharge cost of $0.01 per kWh.[104] (APS Exhibit No. 38 at 7 [DeLizio]). APS's proposed Green Power rates are based on the actual cost of renewable energy from three projects for which APS has contracted. (APS Exhibit at 5-6 [Lockwood]). The renewable energy projects included in APS's proposed Green Power Rate Schedules include a geothermal project that entered service in January 2006, and two wind projects, one of which was scheduled to enter service in late-2006, and the second is scheduled to enter service in early-2007. (APS Exhibit No. 20 at 8 [Lockwood]). The cost for each of the three projects was weighted based on the specific contract price structure and projected energy production to establish an average annual portfolio price. (APS Exhibit No. 19 at 6 [Lockwood]).

If the initial amount of Green Power is fully subscribed, APS will seek to procure additional Green Power to serve additional customers under the Green Power schedules. (APS Exhibit No. 38 at 8 [DeLizio]). APS will compute a new Green Power premium associated with the additional Green Power costs and the most recently approved avoided cost filing. (*Id.*). If the new premium is different than the current premium, the Company will file new Green Power rates with the Commission for approval to accommodate the increased demand for the program. (*Id.*). These new Green Power rates will be in addition to the current Green Power rates, which will not be changed outside of a rate case. (*Id.* at 8-9). The initial offering of Green Power will be served under the proposed Green Power Rate Schedules GPS-1A and GPS-2A. (*Id.* at 9).

The energy provided under the Green Power rates will be in excess of the EPS/RES and Decision No. 67744 requirements. (APS Exhibit No. 20 at 8 [Lockwood]). A generation project may provide energy to both EPS/RES and Green Power requirements, but the energy will not be double-counted. (*Id.*).

As suggested by WRA, APS agreed:

[104] The Company has modified the premium charge and the block size for the Green Power Schedules, GPS-1A and GPS-2A as proposed in its initial filing. (APS Exhibit No. 38 at 7 [DeLizio]). The premium has changed from $0.03/kWh in the Company's initial filing to $0.01 per kWh. (*Id.*). The Company has also increased the block size from 25 kWh to 100 kWh per month. (*Id.*). As a result, the monthly premium for Green Power in Schedule GPS-IA, has been changed from $0.75 for a 25 kWh for block of Green Power, to $1.00 for a 100 kWh block. (*Id.*). The Company has also made commensurate changes in the Green Power premiums for the various percentages of monthly consumption in Schedule GPS-2A. (*Id.*).

1. To provide reports on customer participation, kWh sales, and revenue in its annual EPS/RES filings;
2. That the green schedule should be based on actual project costs;
3. To pursue green-e certification for its Green Power products;
4. To change the minimum block size in GPS-1 to 100 kWh/month.; and
5. To change the 30 percent option in GPS-2 to 35 percent to better coincide with recent changes to the Leadership in Energy and Environmental Design (LEED) standard for new buildings.

(APS Exhibit No. 19 at 6-7 [Lockwood]).

The Company requests that the Commission approve the Company's proposed Green Power Rates GPS-1A and GPS-2A for customers who wish to purchase renewable energy at a surcharge cost of one cent per kWh.

2. Total Solar.

a. APS Seeks Commission Approval Of Its Total Solar Rate (Schedule Solar-3) At The Premium Rate Of $0.166 Per kWh.

Because APS is aware of its customers' interest in renewable energy and, in particular, solar energy, APS is seeking Commission approval of a Total Solar Rate (Solar-3) as part of a pilot program. (APS Exhibit 19 at 7 [Lockwood]). APS currently has approximately 4,400 customers enrolled in its Solar Partners Rate Program, which allows customers to purchase 15 kilowatt hour blocks of solar energy. (*Id.* at 7-8). To date, 835 of APS's customers have chosen to participate in its Solar Partners Incentive Program to install their own solar energy system. (*Id.* at 7). However, many of APS's customers who are interested in solar energy may not wish or be able to own and operate their own system. (*Id.*). With Solar-3, APS takes on the responsibility for the generation and provides clean, renewable, solar energy to the customer. (*Id.*). Under Solar-3 Rate Schedule, customers would have the opportunity to support solar energy by purchasing APS-generated solar energy to offset either 50 percent or 100 percent of their energy consumption. (*Id.*).

The Solar-3 Rate Schedule would apply to customers who choose to participate in this program, in addition to their otherwise applicable rate schedule. (APS Exhibit No. 38 at 10

[DeLizio]). Customers would be charged a premium for the solar power and credited for avoided generation costs, which would be based on the Company's avoided costs filing. (*Id.*).

Several parties to this action raised concerns as to the cost of APS's Total Solar Rate. After APS filed its rejoinder testimony on October 6, 2006, APS issued a Request For Proposals ("RFP") for solar energy to provide energy for its proposed total solar rate. (Tr. Vol. V at 937-938 [Lockwood]). APS expected to receive quality proposals that would result in a total Solar Rate that would be substantially less than the original proposal. (*Id.* at 938). Although APS did not receive bids for this RFP, APS executed a Memorandum of Understanding and term sheet for a 50 percent interest in a total solar project associated with the Gila River Indian Community that will provide about one-half a megawatt of solar power to serve a portion of its current Solar Partners Rate Program, as well as the solar energy needed for the proposed Total Solar Rate program. On December 22, 2006, APS filed its revised (reduced) Total Solar Rate of $0.225 per kWh. (APS Exhibit No. 86).

G. <u>Other.</u>

1. Hook-Up Fees.

On August 31, 2006, Commissioner Mayes filed request that the Parties (specifically Staff, RUCO and the Company) file testimony on the implementation of hook-up fees in the Company's service territory.[105] The letter specifically referenced a March 28, 2006 letter from Commissioner Mundell which was also filed in this docket, where he wrote "[g]iven the significant peak load growth rate that APS is experiencing and the amount of CAPEX necessary to meet that load, I think it is time to explore the option of using hook-up fees so that existing customers are not continually subject to exorbitant rate increases." In response to Commissioners Mayes' and Mundell's request, the Company, RUCO and Staff analyzed the feasibility of using hook-up fees to help fund capital expenditures. All three parties presented evidence recommending that the Commission explore the feasibility of utilizing hook-up fees in a Commission-sponsored workshop.

[105] A hook-up fee is a fee that is charged to connect the utility-owned distribution facilities to the customer. Typically, the point of connection is the meter.

Based upon the Company's analysis as set forth in its testimony, a hook-up fee program would be an expensive vehicle for financing system improvements because of the accounting and tax implications to the Company. (APS Exhibit No. 70 at 21-22, 25 [Rumolo]). When an investor-owned utility receives contributed capital, such as through a hook-up fee, an immediate income tax liability is created because the payment is considered taxable income. Consequently, an additional "gross-up" or charge to the customer would be required to produce the same amount of after-tax cash. Additionally, under Generally Accepted Accounting Practices ("GAAP"), funds from contributions in aid of construction are booked as an offset to capital expenditures and are not treated as revenues to the Company. (*Id.*). Therefore, the revenue from the hook-up fees would not directly flow into the calculation that determines the Company's FFO. Instead, that revenue would, in fact, decrease the Company's FFO, because of the resultant increase in current income taxes. (APS Exhibit No. 64).

In contrast, entities (such as water and wastewater companies) that have limited access to capital markets use hook-up fees as an only readily available capital source for projects such as new water wells or treatment facilities. (APS Exhibit No. 70 at 22 [Rumolo]). Also, private water companies often grossed-up contributed capital to cover tax consequences. (*Id.*). Municipal corporations, which commonly use hook-up fees to pay for growth, do not have tax consequences of contributed capital that a utility like APS would face. After 1996, private water and sewer utilities were also exempted from tax on hook-up fees. (*Id.*).

The Company, Staff and RUCO all agreed that such a program should not be undertaken without careful study because the program would have "wide ranging ramifications" if it were to be implemented for an electric utility such as APS. For that reason, an examination should be conducted in the context of a generic workshop. (APS Exhibit No. 70 at 19 [Rumolo]; RUCO Exhibit No. 24 at 34 [Diaz Cortez]; Staff Exhibit No. 22 at 31 [Andreasen]). APS believes that significant policy issues would first have to be examined by all utilities and other interested parties at such a workshop. Those policy issues include:

- What would be the impact on growth in the service territories of regulated entities, vis-à-vis non-regulated utilities, and correspondingly the impact on government entities that rely on tax revenues from growth?

- What would be the impact on housing affordability?
- Which capital expenditures (e.g., all distribution plant or only local facilities, generation plant, general plant) should be included in the hook-up fee computation?
- What are the long-term impacts on the financial health of regulated companies?
- What are the short and long term rate impacts to customers?
- Should the amount of the hook-up fee include tax effects (i.e., gross-up vs. self pay);
- Could existing customers be responsible for hook-up fees?
- What would be the impact on homebuilders and the construction industry?

(APS Exhibit No. 70 at 19-20 [Rumolo]).

Staff also did not recommend that the Commission adopt hook-up fees at this time; it agrees that there remain numerous unanswered questions that should first be addressed. (Staff Exhibit No. 22 at 31 [Andreasen]). Staff pointed out that hook-up fees have been generally adopted by the Commission in the water and wastewater industries as a way of providing accelerated recovery to a utility for the installation of infrastructure necessary to serve customers. (*Id.* at 26). As noted above, both the financial and tax circumstances of such industries are different from those electric utilities. Staff recommended that if the Commission wished to pursue hook-up fees for electric and gas utilities, that it do so by opening a generic docket where parties could provide feedback and the Commission could evaluate the adoption of such fees for the energy industry. (*Id.* at 31). Staff further enumerated issues that need to be explored before a hook-up fee can be designed. They included:

- Should generation capacity be included in a hook-up fee given the complexities associated with determining and designing a rate to recover the cost associated with generation capacity?
- What type of generation unit or related index should be utilized as a proxy for calculating marginal cost for generation capacity?
- Should a study of marginal costs be required as a means of calculating a unit of demand, energy and distribution including customer-related cost?

- Should operation and maintenance expenses be included, as well as capital expenditures?
- What is the appropriate customer growth or customer decline assumption?
- Over what timeframe should costs be accrued for purposes of setting a rate?
- How should the cost be allocated to different customer classes and collected from individual customers?
- What is the impact on direct access customers, where a customer chooses to receive generation supply from a competitive electric service provider?
- What are the economic impacts of adopting hook-up fees within APS's service territory?
- If hook up fees are adopted for APS, would there be any impacts for natural gas suppliers within APS service territory?

(*Id.* at 28-29).

Given the significant amount of questions and issues that the Company, Staff and RUCO have identified, as well as the financial implications to the Company, and the potential impacts to other utilities and stakeholders, the Company believes that the Commission should defer consideration of the implementation of a hook-up fee program to a generic proceeding on this issue.

2. Advanced Metering Infrastructure.

APS is rolling out approximately 1000 "smart meters" a week as part of its Advanced Metering Infrastructure ("AMI"). (Tr. Vol. XXIII at 4364 [Rumolo]). The initial distribution has occurred in APS's more dense service segments of its service territory, including apartments and condominium projects. (*Id.*). APS estimates it will have installed approximately 12,000 of these meters by the end of 2006. (*Id.* at 4365). An advantage of an AMI program in light of the Company's high customer turnover rate, is that by installing the AMI infrastructure, APS can connect and reconnect customers without sending a crew to conduct two separate meter reads. (*Id.*). Another advantage is that APS would no longer have to physically reprogram meters if Time-of-Use ("TOU") rates changed. (*Id.* at 4394).

APS will be unable to achieve 100 percent penetration with AMI because the technology requires cellular communications, which is not available in all areas of Arizona. (Tr. Vol. XIV at 2859; APS Exhibit No. 105 at 2). In addition, APS does not meter all customers (e.g., street lighting). (APS Exhibit No. 105 at 2). The Commission can facilitate the AMI "roll-out" through four discreet actions:

- First, the Commission could adopt some of the ratemaking techniques suggested by APS in this rate case and improve the Company's financial condition.
- Second, the Commission should both authorize accelerated depreciation rates/lives for meters (presently lasting 30 years), thus minimizing the potential for stranded metering costs, and adopt a policy assuring recovery of meter costs for existing meters retired in favor of AMI.
- Third, the Commission consider authorization of an alternative funding mechanism, such as a per meter surcharge or pre-approval of recovery of investment of an AMI system.
- Lastly, the Commission's Electric Competition Rules, specifically A.A.C. R14-2-1615, prohibit APS from providing metering services to many non-residential customers selecting direct access. Although retail electric competition has not yet re-appeared in Arizona and this specific regulation awaits Attorney General Certification per the *Phelps Dodge* decision to become effective, the above provision potentially discourages the use of sophisticated APS metering for this category of APS customer. It should be modified to permit APS (at the customer's discretion) to continue to provide metering services to all direct access customers. (APS Exhibit No. 105 at 2-3).

3. House of Worship Rates.

APS is **not** proposing to eliminate Schedule E-20, which is available only to houses of worship. (APS Exhibit No. 70 at 14 [Rumolo]). E-20 was frozen as part of the Settlement Agreement in Decision No. 67744. (*Id.*). It would remain frozen under APS's and Staff's proposals.

The Settlement Agreement also provided for the elimination of a series of already frozen, experimental, time of use Rate Schedules E-21, E-22, E-23 and E-24. This case merely implements the actions of the Commission in the last case. (*Id.* at 14-15). These rates were limited participation rates that were established on an experimental basis several years ago. (*Id.* at 15).

APS now offers an improved Schedule E-32 TOU, which is open to all customers who can take advantage of lower off-peak prices. (*Id.*). New "houses of worship" and other general service customers whose primary hours of operation are evenings or weekends can likely save relative to the Company's standard general service rate schedule. (*Id.*).

APS has found that E-20 has historically caused administrative problems due to the difficulty in determining what classifies a customer for this particular rate. (Tr. Vol. XIV at 2818 [Rumolo]). Specifically, APS runs into problems when trying to classify a mixed use facility and whether such facility is eligible for the E-20 rate. (*Id.* at 2819-2820). In addition, it is always likely to produce unintended problems when one takes a subset of any group of customers and deem them to be different from the general service classification as a whole based solely on end use. (*Id.* at 2820 [Rumolo]).

4. Critical Peak Pricing.

The Energy Policy Act of 2005 ("EPACT 2005") identified several time-based rate options, including critical peak pricing, for utilities to consider offering. Critical peak pricing is a time-based rate schedule where time-of-use prices are in effect except for certain peak days when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption. (EPACT 2005 § 1252(a); Tr. Vol. XIV at 2851 [Rumolo]; Tr. Vol. XV at 3050-51 [Higgins]).

APS has begun looking at critical peak pricing as a time-based rate option, but such a rate schedule is not part of this proceeding. (Tr. Vol. XIV at 2848 [Rumolo]). If APS believes critical peak pricing is viable option in the future, then it will propose a critical peak pricing rate schedule in a future rate proceeding where the Commission can review the proposal and adopt it.

IX.
PALO VERDE PRUDENCE REVIEW

A. Introduction And Summary Of Matters Remaining In Dispute.

On February 2, 2006, APS filed with the Commission an application for approval of a PSA surcharge. APS is seeking recovery of $44.6 million plus accumulated interest in replacement power costs that were a result of outages at Palo Verde during 2005. The Staff retained GDS Associates, Inc. ("GDS") to examine the prudence of APS's actions associated with eleven outages at Palo Verde during calendar year 2005. These included two refueling outages and nine other forced and short notice outages. At the conclusion of its review, GDS submitted a report on August 17, 2006 and Direct Testimony by its Vice President, William Jacobs, on August 18, 2006. No other witnesses contested the prudence of any of the 2005 Palo Verde outages. For the reasons discussed hereinafter, all of the requested replacement power costs should be recovered, and the Commission should authorize a Step 2 PSA Surcharge coincident with a final order in this proceeding.

GDS concluded that APS had acted prudently in connection with both 2005 refueling outages as well as with respect to five of the nine forced or short notice outages. Thus, the prudence of the 2005 refueling outages as well as the following forced or short notice outages are not at issue in this proceeding.

- Unit 1 February 9 to February 19, 2005 outage
- Unit 1 August 11 to August 28, 2005 outage (except for 2 days of that outage due to a reactor trip on August 26)
- Unit 2 August 22 to August 26, 2005 outage
- Unit 3 May 22 to June 24, 2005 outage
- Unit 3 July 6 to July 13, 2005 outage
- Unit 3 October 2 to October 7, 2005 outage

Staff (through GDS) does challenge the prudence of APS's actions in connection with the following outages:

- Unit 1 March 18 to March 21, 2005 outage (diesel generator governor failure)
- Unit 1 August 26 to August 28, 2005 outage extension (reactor trip due to operator error)
- Unit 2 October 11 to October 20, 2005 outage (refueling water tank ("RWT") line declared inoperable)
- Unit 3 October 11 to October 20, 2005 outage (RWT line declared inoperable)

The Unit 1 March 18 to March 21, 2005 outage pre-dates the PSA. In his Direct Testimony, Dr. Jacobs of GDS initially recommended that $1.623 million not be eligible for consideration in establishing base fuel costs in the rate proceeding. (Staff Exhibit No. 47 at 4 [Jacobs]). However, during the hearing of this matter, Dr. Jacobs and Staff counsel acknowledged that this recommendation was irrelevant because no costs for this outage were included in the adjusted Test Year fuel costs proposed by any party to this proceeding. (Tr. Vol. XXIX at 5276-78 [Jacobs]).

With respect to the remaining three outages whose prudence Staff challenges, GDS initially calculated the replacement power costs for those outages as follows:

▪	Unit 1 August 26-August 28, 2005 outage extension	$1.134 million
▪	Unit 2 October 11-October 20, 2005 outage	$6.905 million
▪	Unit 3 October 11-October 20, 2005 outage	$6.905 million
	Total:	$14.944 million

(Staff Exhibit No. 46 at Attachment 15 [GDS Report]).

In addition to the $14.944 million in replacement power costs, the GDS Report also recommended disallowance of $2.103 million for what it described as margins on lost opportunity sales, plus interest on this total.

In response to the GDS Report and Dr. Jacobs' Direct Testimony, APS submitted Rebuttal Testimony by James Levine, Roger Mattson, Robert Denton, George Fitzpatrick and Peter Ewen. As a result of reviewing that testimony, Dr. Jacobs agreed to certain modifications to his recommended disallowances. He agreed to decrease the proposed disallowance for the October 11 to October 20, 2005 Unit 3 outage by $1.1 million and the proposed disallowance for the August 26 to August 28 reactor trip by $0.088 million (i.e., from $1.134 million to $1.046 million). (Staff Exhibit No. 48 at 45 [Jacobs]). Thus, the Staff's current proposed disallowance is $13,756,000 in replacement power costs plus $2,103,000 for alleged margins on lost opportunity sales, for a total of $15,859,000 plus interest.

As demonstrated below, APS has established, first, that no disallowances are appropriate because APS management acted prudently with respect to the outages in question. As NRC Regional Administrator Mallett told this Commission when he appeared before it in January of 2006, the RWT outages at Units 2 and 3 in October of 2005 were due to a new question the NRC posed regarding the adequacy of Palo Verde's design, a question that the NRC determined APS should not have anticipated, and APS took the appropriate step in shutting the plant down until the question was safely answered. For the Commission to conclude that APS was imprudent with respect to these outages would require rejection of Dr. Mallett's assessment on what the Staff's own witness, Dr. Jacobs, acknowledges is a technically complex issue. With respect to the reactor trip, this event was caused by an individual operator's error, not management imprudence. The system in question had not caused a reactor trip before the August 2005 event, and all operators had been trained in use of the system when it was installed.

Second, APS has established that, with respect to the two RWT outages, APS prudently conducted work that would have necessitated an outage even if the RWT outage had not occurred. At a minimum, as the Rebuttal and Rejoinder Testimony of James Levine and Peter Ewen establish, an offset of $5,100,000 in replacement power costs to any disallowance is appropriate. Moreover, as Mr. Ewen's Rebuttal Testimony demonstrates, an additional offset of $10,000,000 would be appropriate to reflect the better than expected performance of APS's baseload coal units. Finally, Mr. Fitzpatrick demonstrates that if one compares the performance of APS coal units against that of the industry, this superior performance totally eliminates the disallowances Staff proposes.

Third, regarding the $2,103,000 proposed disallowance for alleged margins on lost opportunity sales, the GDS analysis is based on the unwarranted assumption that, totally lacking in any support, APS would have sold all 187,000 MWh that Palo Verde could have produced if it was operating at 100 percent capacity factor on the outage days in question. Dr. Jacobs admitted that this assumption was unrealistic. (Tr. Vol. XXIX at 5304 [Jacobs]). Mr. Ewen submitted both Rebuttal and Rejoinder Testimony establishing through precise dispatch modeling that the correct quantity of off-system sales that would have been made if Palo Verde had been available was 9,000 MWh, for a total margin of $322,000, not the $2,103,000 that Dr. Jacobs proposes. Mr. Ewen also demonstrated that Dr. Jacobs had failed to account properly for replacement power costs already expensed in base rates, requiring a further reduction of $515,000 in any replacement power cost disallowance. Thus, even if the Commission were to conclude that APS had acted imprudently in connection with the outages in question, and were to reject APS's argument that no disallowance is appropriate because of the superior performance of the generation system as a whole, Dr. Jacobs' proposed disallowance of $15,859,000 would still have to be reduced to $8,444,000 (reflecting the reduction of $5,100,000 due to the time spent on other prudent work during the Unit 2 October outage, $1,800,000 in unsupportable off-system sales margins and $515,000 for replacement power costs already expensed in base rates).

In addition to the recommended disallowances for replacement power costs and margins on lost sales, Dr. Jacobs made several other recommendations in his Direct Testimony. He recommended that the Commission should implement a nuclear performance standard. He also recommended that the Commission should order APS to submit semi-annual reports on plant performance and two reports 120 days after the Commission's order in this case addressing (1) APS programs for receipt inspection and verification of parts prior to installation and (2) evaluating management of aging equipment issues. Finally, although he found APS action in connection with outages that were the result of failure of vendor-supplied equipment to have been prudent, Dr. Jacobs recommended that the Commission should address the degree to which APS has sought appropriate remedies.

As set forth in Mr. Levine's testimony, the Company is willing to file the reports recommended by Dr. Jacobs to the extent possible.[106] As for the Company's actions in connection with pursuing vendors for remedies resulting from equipment failure, Mr. Levine testified regarding the appropriateness of the Company's actions, and that testimony is undisputed.

The issue of a nuclear performance standard is more complex. The Staff and APS remain in dispute regarding the need for and appropriateness of such a standard. However, there would appear to be little or no dispute that, even if the Commission were inclined to adopt some type of performance standard, the current record provides an inadequate basis upon which to do so.

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[106] For example, as Mr. Levine testified, INPO information would have to be requested on a case-by-case basis and would be available for review only. (APS Exhibit No. 94 at 6 [Levine]). Similarly, with respect to the two other reports he recommended, Dr. Jacobs acknowledged that he did not have any specific plants in mind that had successfully managed such issues. Thus, the reports will address the issues identified in the recommendations but may not be in a format of assessing "programs established at other nuclear plants that have been successful in managing" these issues, as Dr. Jacobs initially recommended. (Staff Exhibit No. 46 at 4 [GDS Report]; APS Exhibit No. 94 at 6 [Levine]).

B. <u>Although Staff Witness Jacobs Correctly Articulates The Prudence Standard, He Fails To Properly Apply The Standard In His Analysis.</u>

1. The Arizona Prudence Standard.

The Arizona Administrative Code provides a definition for "prudently invested" which should guide the current prudence review of the 2005 Palo Verde outages:

> "Prudently invested" -- Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made.

(Ariz. Admin. Code § R14-2-103(A)(3)(l) (2004)).

The Administrative Code standard is consistent with the prudence standard provided by Dr. Jacobs and GDS in their report, which states that APS's performance should be compared to "the reasonable decisions and actions of a qualified and experienced utility manager given what was known or should have been known at the time without the benefit of hindsight." (Staff Exhibit No. 46 at 19 [GDS Report]).

The above definition from the Arizona Administrative Code and Dr. Jacobs' prudence standard are similar to the prudence standards used in other jurisdictions. For example, FERC's long-held standard for evaluating prudence is set forth below:

> [W]e reiterate that managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time. We note that while in hindsight it may be clear that a management decision was wrong, our task is to review the prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses.

(*New Eng. Power Co.*, 31 FERC ¶ 61,047 at 61,084 (1985), *aff'd sub nom.*, *Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986)).

All these definitions of prudence highlight that, in any situation confronting a utility, there may be a number of possible decisions that would be considered prudent. In other words, a utility is not imprudent as long as the decisions of a utility's management are reasonable, even if better decisions were possible, and the actual decision resulted in a power plant outage.

The Commission has addressed the issue of prudence in a number of decisions, some of which relate to Palo Verde. First, the Commission has held that prudence does not require perfection. In a 1984 decision, the Commission addressed prudence with respect to the construction of the Palo Verde nuclear plant, and considered, among other things, whether construction work in progress costs for Palo Verde should be included in APS's rate base. (Decision No. 54204 (Oct. 11, 1984)). With respect to the prudence of constructing Palo Verde, the Commission stated as follows:

> . . . Certainly errors were made in Palo Verde's construction. . . . After all, Palo Verde is being **built by human beings, not mistake-proof automata**. Only a comprehensive and independent construction audit can assure us that Palo Verde's total cost is reasonable, i.e., **that instances of good judgment and prudent management outweighed the inevitable examples to the contrary**.

(*Id.* at 15 (emphasis added)).

Second, the Commission has ruled that costs associated with outages should be carefully reviewed and are not per se unrecoverable. In Decision No. 55118, the Commission addressed arguments by Intervenor RUCO regarding purchased power costs due to extended outages. (Decision No. 55118 at 13 (July 24, 1986)). The Commission stated as follows:

> To the extent that RUCO means that purchased power costs attributable to "extended" outages should be carefully reviewed prior to their being passed on to ratepayers, we are in total agreement . . . . If RUCO means that such purchased power costs should be **per se** unrecoverable, we find that to be an **unreasonable and draconic position**.

(*Id.* (emphasis added)).

Therefore, the Commission has clearly recognized that the mere fact that an outage is "extended" is not a basis for a finding of imprudence. Indeed, as Staff counsel admitted in his Opening Statement, a utility is entitled to a presumption that its expenditures have been prudent. (Tr. Vol. XXVI at 4901 [Kempley]). That presumption can only be defeated by "clear and convincing evidence" of imprudence (Ariz. Admin. Code § R14-2-103(A)(3)(l)), or as the Federal Energy Regulatory Commission describes it, "reliable, probative, and substantial evidence" that casts serious doubt on the prudence of the utility's expenditure. *Wisconsin Power Co.*, 73 FERC ¶

63,019 at 65,225 (1995), *aff'd in relevant part*, 98 FERC ¶ 61,233 (2002).

Third, in rejecting RUCO's claims regarding "APS's poor management of its base load generating facilities," including its 1985 maintenance schedule and "the series of forced outages experienced in the summer and fall of that year," (Decision No. 55118 at 20), the Commission held:

> **[B]road assertions of "mismanagement" cannot substitute for hard evidence of specific acts of imprudence.** APS's scheduling of maintenance, although greater than in prior years, appeared to be reasonable given the facts known when the schedule was set. **The forced outages appear to have been purely unforeseen or the result of appropriate safety concerns.**

(*Id.* (emphasis added)).

Therefore, the imprudence of a specific power plant outage can only be demonstrated through evidence of specific imprudent acts by management. If an outage is unforeseen or results from appropriate safety concerns, it is not imprudent.

Finally, the Commission has held that both successes and failures should be analyzed when evaluating the performance of a power plant. RUCO argued that the Commission should disallow certain APS costs, based on APS's poor "operating performance." (*Id.* at 20). The Commission disagreed with RUCO's exclusive use of capacity factor for determining operating efficiency, and "its failure to give APS proper credit for performance above the historical average." (*Id.*). The Commission stated that "a realistic analysis of operating performance **must look at both the 'successes' and the 'failures'** if it is to avoid setting unobtainable goals of absolute perfection." (*Id.* (emphasis added)).

2. The Staff's Witness Does Not Present Clear And Convincing Evidence Of Imprudence But Instead Improperly Uses Hindsight And Unduly Relies On NRC, INPO And APS Documents.

Dr. Jacobs was the only witness to contest the prudence of any of the Palo Verde outages. Although he has some nuclear power plant experience, he has never held any type of management position with a nuclear utility, and his last management position of any sort involving a nuclear power plant was working for Westinghouse at plants in Yugoslavia and the Philippines in the early 1980s prior to those plants commencing operation. (Tr. Vol. XXIX at

5243-45 [Jacobs]). Nor has he ever worked for the Nuclear Regulatory Commission ("NRC"). (*Id.* at 5244).

Dr. Jacobs' analysis in this case violates the prudence standard set forth above in a number of significant ways. For example, although he recognizes that it is inappropriate to use hindsight in a prudence review, he quotes extensively from NRC documents and APS root cause analyses on the ground that such documents "do not rely on hindsight" and constitute a "contemporaneous investigation by Company personnel." (Staff Exhibit No. 48 at 15 [Jacobs]). The claim that these documents do not rely on hindsight is contradicted by Dr. Jacobs' own deposition testimony in a matter before the Texas Commission where he stated that utility root cause reports "can use hindsight." (APS Exhibit No. 98; Tr. Vol. XXIX at 5261-63 [Jacobs]). Indeed, Dr. Jacobs' prior testimony regarding root cause analyses' use of hindsight is consistent with that of Dr. Roger Mattson and Robert Denton.

In contrast to Dr. Jacobs, who has never worked for the NRC, Dr. Mattson spent almost 17 years at the NRC and was the Director of several NRC divisions having responsibility for much of the technical review of applications for construction permits, operating licenses and safety evaluations for plants under construction and operation, including Palo Verde. (APS Exhibit No. 87 at 4, 52-53 [Mattson]). In contrast to Dr. Jacobs' lack of nuclear utility management experience, Robert Denton served in various utility management capacities in a career spanning over 30 years, including Vice President of Nuclear Energy at Baltimore Gas & Electric Co. and President and CEO of Constellation Nuclear which owned and operated the Calvert Cliffs and Nine Mile Point Nuclear Units. (APS Exhibit No. 89 at 1-2 [Denton]). Both Dr. Mattson and Mr. Denton concur with Dr. Jacobs' earlier testimony that company self-assessments and NRC reports use hindsight, rendering such documents generally inappropriate for use in a prudence review. (*Id.* at 7, 10-11). At most, such documents must be looked at very carefully and critically to determine whether their inherent hindsight bias can be discounted, a task not always achievable. (APS Exhibit No. 87 at 8 [Mattson]; APS Exhibit No. 88 at 21-24 [Mattson]). As Dr. Jacobs admitted during the hearing, root cause evaluations do not necessarily distinguish between whether facts discussed in a root cause report were discovered during the course of the investigation following the event or whether such facts were known or should have been known to utility management at the time of the event in question. (Tr. Vol. XXIX at 5263-64 [Jacobs]).

Finally, with respect to Dr. Jacobs' claim that root cause reports constitute a "contemporaneous investigation," he acknowledged during the hearing that the Wisconsin Commission rejected this same claim as recently as last year. (*Id.* at 5264). Because such root cause reports did not provide evidence that certain repairs to the Kewaunee nuclear plant should have been made earlier, the Wisconsin Commission held that "as a consequence, the record does not present sufficient evidence to demonstrate that imprudent past management practices lead to the 2005 outage." (APS Exhibit No. 87 at 14, 63 [Mattson]; APS Exhibit No. 88 at 22 [Mattson]).

The Commission should reach the same result. Much of Dr. Jacobs' testimony, both with respect to overall Palo Verde performance and with respect to the outages that he maintains were due to APS management imprudent conduct, consists of simple block quoting of NRC and Company documents. (*E.g.*, Staff Exhibit No. 46 at 13-14, 25-26, 33-35 [GDS Report]; Staff Exhibit No. 48 at 26-27, 28-30 [Jacobs]). Because he fails to recognize that such documents freely use hindsight and are not contemporaneous reflections of what management knew or should have known at the time, Dr. Jacobs' testimony quoting these documents does not constitute evidence of imprudence.

Dr. Jacobs also relies extensively on INPO reports and INPO grades (Staff Exhibit No. 46 at 15-18 [GDS Report]) even though he admitted that INPO does not use the prudence standard in its evaluations (Tr. Vol. XXIX at 5245 [Jacobs]), but rather that INPO's "function is to promote excellence in nuclear power." (*Id.* at 5246). It is for this reason (as well as because, like NRC and Company root cause reports, INPO uses hindsight) that Mr. Denton testified that it is inappropriate to rely on INPO evaluations or reports in making a prudence assessment. (APS Exhibit No. 89 at 6-10 [Denton]).

Thus, Dr. Jacobs has not presented clear and convincing evidence of imprudence, and the presumption of prudence remains intact. However, even if there were any questions as to whether the burden had shifted to APS, as demonstrated below with respect to each of the outages in question, the evidence establishes that APS acted prudently and that no disallowances are appropriate.

3. Dr. Jacobs' Description Of Palo Verde Performance Is Inaccurate And His Testimony Is Inconsistent Regarding The Relevance Of Past Performance.

Although Dr. Jacobs states in his Surrebuttal Testimony that past performance is "irrelevant" and not "appropriate" to consider in a prudence determination (Staff Exhibit No. 48 at 3 [Jacobs]), significant parts of both the GDS Report and his testimony focus on past Palo Verde performance. For example, the GDS Report states that "the performance of Palo Verde during the 2003 to 2005 period was at the bottom of the U.S. nuclear industry." (Staff Exhibit No. 46 at 9 [GDS Report]).

In fact, Dr. Jacobs acknowledged at the hearing that Palo Verde's 2003 performance was "perfectly average." (Tr. Vol. XXIX at 5251-52 [Jacobs]). Dr. Jacobs also acknowledged that had Palo Verde Unit 2 not gone through a steam generator replacement outage in 2003, Palo Verde performance would not have been just average, it would have been significantly above average. (*Id.* at 5254-55 [Jacobs]). Dr. Jacobs was thus forced to acknowledge that the data from a <u>Nuclear News</u> article that he relied on for his claim of "bottom of the industry" performance for the period 2003 to 2005 was skewed by the clearly lower performance during 2005 and that he was not contesting 2003 and 2004 performance. (*Id.* at 5255-56 [Jacobs]). Indeed, faced with this data, Dr. Jacobs stated several times during the course of cross-examination that "my evaluation was focused on 2005" and that "the scope of my testimony and my evaluation was the year 2005." (*Id.* at 5246 [Jacobs]).

Dr. Jacobs also initially sought to portray Palo Verde's regulatory performance as having declined over a several year period. The GDS Report states that the NRC issued a yellow finding to Palo Verde in 2004. (Staff Exhibit No. 46 at 11 [GDS Report]). In fact, the yellow finding was not issued until April of 2005. (APS Exhibit No. 87 at 40 [Mattson]). Dr. Jacobs acknowledged that this was the case during cross-examination. (Tr. Vol. XXIX at 5258 [Jacobs]). Dr. Jacobs was also asked why GDS had not included in its report a positive NRC inspection report from August 2004 giving APS good marks for its problem identification and resolution efforts. His response was that "Again, I was looking at 2005. And things can change, as we have seen, quite quickly." (*Id.* at 5259 [Jacobs]). Thus, Dr. Jacobs essentially abandoned his claim that Palo Verde management could have recognized a declining performance trend in 2003 and implemented unspecified measures to address the decline "without Palo Verde sinking to the bottom of the nuclear industry." (Staff Exhibit No. 48 at 4 [Jacobs]). Indeed, as Dr. Mattson testified, recognizing any "decline" in 2003 would have been difficult given the good capacity factor performance the units were having (excluding the steam generator replacement outage) and the favorable NRC and INPO grades. (APS Exhibit No. 88 at 18 [Mattson]).

Turning to the question of whether Dr. Jacobs' characterizations of Palo Verde performance in 2005 as "poor" (Staff Exhibit No. 46 at 8 [GDS Report]) and "abysmal" (Staff Exhibit No. 48 at 6 [Jacobs]) are accurate, APS acknowledges that 2005 performance fell short of its own high standards. (APS Exhibit No. 94 at 10 [Levine]). However, Dr. Jacobs does not contest the prudence of most of the outages that led to Palo Verde's lower capacity factor in 2005. In fact, he challenges only 23 outage days as being due to imprudence. (Tr. Vol. XXIX at 5248 [Jacobs]). As Dr. Mattson testified, and Dr. Jacobs does not contest, those 23 outage days constitute a reduction in Palo Verde capacity factor of only 2.1 percent. (APS Exhibit No. 88 at 19 [Mattson]; Tr. Vol. XXIX at 5248 [Jacobs]). Thus, although Palo Verde's capacity factor in 2005 was less than desirable, the reasons for that lower performance make it inaccurate and unfair to characterize performance as "poor," much less "abysmal."

4. A Focus On A Longer Time Period And On The Performance Of All APS Baseload Generation Is Consistent With Commission Precedent And Demonstrates That APS Performance Has Conferred Substantial Benefits On Customers More Than Offsetting Any Potential Disallowance.

Dr. Jacobs rejects the APS position that Palo Verde performance should be analyzed over a longer period than the snapshot he offers in his testimony. (Staff Exhibit No. 48 at 4 [Jacobs]). He also rejects any consideration being given to the superior performance of the balance of the Company's baseload generation system. (*Id.* at 45 [Jacobs]). In these respects, Dr. Jacobs' testimony again is inconsistent with the principles established in prior Commission decisions.

As noted above, the Commission has stated that "a realistic analysis of operating performance must look at both the 'successes' and the 'failures' if it is to avoid setting unobtainable goals of absolute perfection." (Decision No. 55118 at 20). Such a realistic analysis entails looking at Palo Verde performance over a longer time frame and taking into account the superior performance of the Company's coal plants.

With respect to Palo Verde performance, Messrs. Levine and Fitzpatrick demonstrated that Palo Verde performance over the period 1995 through 2004 had conferred substantial benefits on APS customers. (APS Exhibit No. 91 at 4 [Fitzpatrick]; APS Exhibit No. 94 at 9-10 [Levine]). Comparing Palo Verde performance only against other pressurized water reactor ("PWR") nuclear plants resulted in a net benefit of $91.8 million. This result is based on the difference between Palo Verde's capacity factor over this period of 89.5 percent to 87.4 percent for all PWRs over 600 megawatts. (APS Exhibit No. 91 at Attachment GLF-5RB [Fitzpatrick]). Moreover, over this same period, Palo Verde performed even better when compared to the industry as a whole, i.e., 89.5 percent to 82 percent. (APS Exhibit No. 94 at 9 [Levine]). As Dr. Jacobs acknowledged during the hearing, the net benefit is much greater than $91.8 million when the comparison is against the entire industry. (Tr. Vol. XXIX at 5256 [Jacobs]).

Finally, turning to Dr. Jacobs' claim that "a nuclear power plant represents a bargain between the Company and its ratepayers" (Staff Exhibit No. 48 at 35 [Jacobs]), and that customers are not getting the benefit of the bargain (Tr. Vol. XXIX at 5324 [Jacobs]), even if one acknowledged this analogy to be correct,[107] which APS would not, the expectation for Palo Verde performance back at the time it was being built was an average capacity factor of only 75 percent, which the plant has greatly exceeded. (APS Exhibit No. 94 at 10 [Levine]; Tr. Vol. XXVII at 5073 [Fitzpatrick]). Staff's assertion that prior to the implementation of the PSA, this superior performance "flowed through to the APS bottom line" is inaccurate. (Tr. Vol. XXVI at 4904 [Kempley]). Had Palo Verde not performed in this superior fashion, APS would not have been able to agree to the rate decreases its customers enjoyed. (Tr. Vol. XXVII at 5073

[107] Dr. Jacobs claims that "the Company receives its reward in the form of a guaranteed rate of return" on its investment in Palo Verde. (Staff Exhibit No. 48 at 35 [Jacobs]). However, as Dr. Jacobs acknowledged at the hearing, it is possible that a utility will not achieve its authorized rate of return and that this has happened to APS in recent years. (Tr. Vol. XXIX at 5282 [Jacobs]).

[Fitzpatrick]). For specific example, Decision No. 59601 provided for an immediate rate decrease of $48,500,000 based on costs (including savings from base generation performance) for the 12 months ending June 30, 1995 and provided for future decreases to be based on a cost/kWh formula that also would have explicitly included the impact of such generating plant performance. (Decision No. 59601 at 3-4 (April 24, 1996)).

With respect to the Company's other baseload generation performance, Mr. Fitzpatrick testified that it was appropriate to consider those plants' performance because, like nuclear plants, they enjoy a significant cost advantage over purchased power and have the potential to confer a substantial benefit on APS's customers when run successfully. (APS Exhibit No. 91 at 10 [Fitzpatrick]). And APS's coal plants have been run very successfully. As Mr. Ewen testified, the Company's coal plants set an all-time high for capacity factor in 2005. (APS Exhibit No. 17 at 25 [Ewen]). The plants had 40 percent 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 $10,000,000. (*Id.* [Ewen]). As Mr. Ewen explained further at the hearing, had the coal plants not performed so well, there would have been 300 gigawatt hours more of unplanned outages that would have had to have been replaced at a cost of $10,000,000. (Tr. Vol. XXVIII at 5223 [Ewen]). That $10,000,000 savings is not reflected in the replacement power costs for Palo Verde, and, thus, it is an appropriate offset to these costs. (*Id.* at 5222 [Ewen]).

APS coal plant performance is even more exceptional when one compares it – not against APS's own high expectations of what a "normal" year should be, as Mr. Ewen did – but against APS's coal plants' industry peers. Over the same 10-year period of 1995 to 2004, APS coal units' superior performance resulted in a net benefit of $149,000,000. (APS Exhibit No. 91 at 13 [Fitzpatrick]). Even looking at 2005 alone, APS's coal plant superior performance resulted in purchased power cost savings (compared to peer plants) of $27,492,000. As Mr. Fitzpatrick testified, this more than offsets the amounts that Dr. Jacobs recommends be disallowed. (*Id.* [Fitzpatrick]).

C. <u>APS Management Was Not Imprudent Regarding The Four 2005 Palo Verde Outages At Issue In This Proceeding.</u>

1. The Unit 2 And Unit 3 October 2005 Outages Resulted From A New Question From The NRC About Air Entrainment And Not From Imprudent Actions Of APS Management.

a. Background.

In October 2005, the NRC conducted a follow-up inspection at Palo Verde to determine whether APS had implemented appropriate corrective actions regarding the voided sump suction line which resulted in a yellow finding in April 2005. (APS Exhibit No. 87 at 47 [Mattson]; APS Exhibit No. 88 at 3 [Mattson]; APS Exhibit No. 94 at 14 [Levine]; Staff Exhibit No. 46 at 31 [GDS Report]). APS had conducted an extensive design basis implementation review in response to the yellow finding and in advance of the October 2005 NRC follow-up inspection, including a review of the possibility of air entrainment in the RWT suction line leading to the emergency cooling pumps. (APS Exhibit No. 88 at 3 [Mattson]).

Early in the October 2005 follow-up inspection, an NRC contract inspector questioned whether the possibility of air entrainment had been considered in the design of the suction line between the RWT and the emergency cooling pumps. (*Id.* [Mattson]; Staff Exhibit No. 46 at 31 [GDS Report]). APS responded to the contract inspector that air entrainment was considered in the design of this line and that certain design features that were approved by the NRC to preclude air entrainment problems were implemented in the construction of the Palo Verde plant. (APS Exhibit No. 87 at 49 [Mattson]; APS Exhibit No. 88 at 3-4 [Mattson]). APS provided the contract inspector with documentation from the original licensing review in 1976 to demonstrate this. (APS Exhibit No. 88 at 4 [Mattson]; APS Exhibit No. 99; Tr. Vol. XXIX at 5266-69 [Jacobs]). APS showed the inspector that the NRC-approved calculations required 16 feet of elevation difference between the water in the containment sump and the pump suction header, and that Palo Verde greatly exceeds this requirement by including 40 feet of elevation difference. (APS Exhibit No. 87 at 52-54 [Mattson]).

The contract inspector nonetheless challenged APS's response, stating that the earlier calculations approved by the NRC were only based on "static" principles, and did not include "dynamic" considerations for the movement of the air and water in the suction line. (APS Exhibit No. 88 at 4 [Mattson]). The calculations the contract inspector requested to address these "dynamic" considerations had never been performed at Palo Verde or at any other plant of its type. (*Id.* [Mattson]). APS initially engaged Westinghouse to provide an answer to the new question from the contract inspector, but it became apparent that Westinghouse would not be able to readily provide the calculations requested. (APS Exhibit No. 87 at 56-57 [Mattson]). Palo Verde's technical specifications, as is the case at all nuclear plants, require that the plant shut down if the operability of a safety system under all possible situations cannot be absolutely verified in a relatively short amount of time. (APS Exhibit No. 88 at 4 [Mattson]; Staff Exhibit No. 46 at 31 [GDS Report]).

On October 11, 2005, based upon the Plant's technical specifications, APS declared the Unit 2 and Unit 3 RWTs inoperable and shut these two units down. (APS Exhibit No. 88 at 4 [Mattson]; Staff Exhibit No. 46 at 31 [GDS Report]). Unit 1 was already shut down for a scheduled refueling outage. (APS Exhibit No. 88 at 4 [Mattson]). APS quickly engaged a leading expert in the field of dynamic, two-component flow phenomena and developed an answer to the contract inspector's questions, which was provided to the NRC inspection team on October 17. (APS Exhibit No. 88 at 4 [Mattson]; APS Exhibit No. 94 at 16 [Levine]). The NRC reviewed and accepted APS's answers and Units 2 and 3 were restarted on October 20. (APS Exhibit No. 88 at 4 [Mattson]).

No changes were made or were necessary to the RWT, its associated systems, or any procedures prior to restarting Units 2 and 3. (*Id.* [Mattson]; APS Exhibit No. 94 at 16 [Levine]). Similarly, no changes have been made to the RWT systems for any of the units since this event. (APS Exhibit No. 88 at 4 [Mattson]). As stated by Dr. Jacobs, "APS ultimately concluded and demonstrated to the NRC that air entrainment from the RWT was not a safety issue." (Staff Exhibit No. 46 at 31 [GDS Report]). Dr. Mattson stated that "[i]n the final analysis, the original design of the RWT suction piping was shown to be adequately safe to justify resumption of operations of the two units with the same plant equipment, operating procedures and training that existed prior to their shutdown and the same ones that are in use at all three Palo Verde units today." (APS Exhibit No. 87 at 64 [Mattson]).

Shortly after this event, on January 26, 2006, NRC Region IV Administrator Bruce Mallett met with the Commission to discuss the 2005 Palo Verde outages, including the October RWT outages. (APS Exhibit No. 104). Commissioner Mayes questioned Dr. Mallett about "why in the world it took so long for someone to discover a flaw that required NRC to shut Palo Verde down." (*Id.* at 43). Dr. Mallett responded as follows:

> In the October time frame, when we raised this issue about the design flaw, **it was a new question**, okay, one that we hadn't come up across before, nor had they to the best of my recollection. And so **they did what we expected**. They searched that out and said we can't answer the question -- I am oversimplifying -- so that would put us in a condition that we don't believe is within our design. If you can't answer at NRC, and we can't answer it within this certain time frame, we have to shut the plant down by our technical specification until we get it resolved. And that's what they did. . . . [I]t was a question we raised and **they did the right thing** when they couldn't answer the question.

(*Id.* at 45-46 (emphasis added)).

Indeed, Dr. Jacobs agreed that once APS declared the RWTs inoperable, it had to shut down the units. (Tr. Vol. XXIX at 5386 [Jacobs]).

Commissioner Mayes then asked whether this was a question that APS should have asked itself earlier. (APS Exhibit No. 104 at 46). Dr. Mallett responded that "we do evaluate whether they should have found it before us" and "[i]n this instance, we didn't determine that they should have found it beforehand." (*Id.*). In summary, Dr. Mallett told this Commission that the NRC asked a new question, the NRC evaluated whether APS should have asked itself the question, and the NRC determined that APS should not have raised the question before the NRC did so. (*Id.* at 45-46).

b. Staff's Position.

Dr. Jacobs concludes that the October outages in Units 2 and 3 regarding the RWT were "avoidable and imprudent." (Staff Exhibit No. 46 at 35, 40 [GDS Report]). Dr. Jacobs believes that the October 2005 RWT air entrainment question is "closely related" to the 2004 yellow finding for the voided sump. (*Id.* at 32 [GDS Report]; Staff Exhibit No. 48 at 25 [Jacobs]). Dr. Jacobs stated that "[e]ven though the RWT was within the boundary of the evaluation of the yellow finding event, and the primary concern was the potential for damage to safety related pumps due to air entrainment, APS personnel did not identify the RWT concern until it was pointed out by NRC inspectors during the 95002 inspection in October 2005." (Staff Exhibit No. 46 at 32 [GDS Report]). He further believes that "[a] more comprehensive root cause evaluation with a broader focus should have identified this concern in 2004." (*Id.* at 32 [GDS Report]).

Dr. Jacobs initially recommended a disallowance of $7,672,000 ($6,905,000 after 90/10 sharing) for the October Unit 2 outage and $7,672,000 ($6,905,000 after 90/10 sharing) for the October Unit 3 outage. (*Id.* at Attachment 15 [GDS Report]). Dr. Jacobs later agreed with Mr. Ewen's conclusion that the proposed disallowance for the October Unit 3 RWT outage was overstated by $1,200,000 ($1,100,000 after 90/10 sharing), and should be $5,805,000 after 90/10 sharing. (APS Exhibit No. 17 at 21 [Ewen]; Staff Exhibit No. 48 at 43 [Jacobs]).

c. APS's Position.

APS's position is that its actions were not imprudent regarding the October 2005 RWT outages at Units 2 and 3. (APS Exhibit No. 87 at 68 [Mattson]; APS Exhibit No. 94 at 15 [Levine]). Palo Verde was constructed using a design based on the static calculations that were approved by the NRC. Dr. Mattson explains in detail why Dr. Mallett was clearly correct when he told this Commission that the question regarding dynamic calculations raised by the contract inspector was a new question that APS should not have anticipated prior to it being raised in October 2005. (APS Exhibit No. 87 at 47-59 [Mattson]; APS Exhibit No. 88 at 3-15 [Mattson]; APS Exhibit No. 94 at 15-16 [Levine]). As Dr. Mattson testified, dismissing the conclusions of Dr. Mallett, the most senior NRC official involved in the matter, would be wrong. (APS Exhibit No. 88 at 13 [Mattson]).

Dr. Jacobs offers no probative evidence to contest Dr. Mallett and Dr. Mattson and to support his claim that APS should have identified the RWT issue in 2004. His argument that the RWT is within the boundary of APS's response to the yellow finding is of no consequence. APS did examine the RWT system as part of its response to the yellow finding and confirmed that unlike the dry pipe section that resulted in the yellow finding, the RWT lines were filled with water. (Tr. Vol. XXVII at 5022-23 [Mattson]; Tr. Vol. XXVII at 5150-51 [Levine]; Tr. Vol. XXVIII at 5188-91 [Levine]).

APS quickly took the actions necessary to obtain an answer to the new question and restarted the units as soon as possible without any changes to the system. (APS Exhibit No. 87 at 64 [Mattson]; APS Exhibit No. 94 at 16 [Levine]). Moreover, even if Dr. Jacobs is correct that APS should have identified the RWT issue during its investigation following the yellow finding, since the yellow finding was not issued until April 2005, any identification of an air entrainment issue involving the RWT in response to this finding would have occurred during the PSA period, and could have had even a greater economic effect had it been identified during the summer peak period or while Unit 1 was not in a refueling outage. (APS Exhibit No. 88 at 6 [Mattson]; Tr. Vol. XXVI at 4966, 4974 [Mattson]). Thus, APS shut down Units 2 and 3 for reasons that were "purely unforeseen or the result of appropriate safety concerns" (Decision No. 55118 at 20), and consequently was not imprudent.

d. Analysis.

There is no doubt that NRC Regional Administrator Mallett's view is that air entrainment in the RWT suction line was a new question that should not have been anticipated by APS. (APS Exhibit No. 104 at 45-46). In response to Commissioner Mayes' question whether APS should have anticipated the issue, Dr. Mallett expressly stated that the NRC did "evaluate whether they should have found it before us" and that "we didn't determine that they should have found it beforehand." (APS Exhibit No. 94 at 15 [Levine]; APS Exhibit No. 95 at 4 [Levine]; APS Exhibit No. 104 at 43, 46). Thus, it was not a situation where Dr. Mallett was simply stating that the NRC had not made a determination one way or the other. (Tr. Vol. XXVIII at 5199-5200 [Levine]). Rather, Dr. Mallett clearly stated that the NRC had made a determination of whether APS should have asked itself the question regarding air entrainment in the RWT suction line prior to the contract inspector raising the issue in October 2005 and concluded that APS should not have done so. (APS Exhibit No. 87 at 12, 48-49 [Mattson]; APS Exhibit No. 94 at 15 [Levine]; APS Exhibit No. 104 at 46).

Dr. Mallett and his staff addressed the issue of whether APS should have identified the question earlier in order to assess whether the NRC should impose a violation for APS failing to do a proper extent of condition review (which it did not impose). (Tr. Vol. XXVI at 4924

[Mattson]; Tr. Vol. XXIX at 5389 [Jacobs]). Although Dr. Mallett was not making a prudence determination when he conducted this analysis, his conclusion that APS should not have raised the new question before it was raised by the NRC nonetheless demonstrates that APS was not imprudent.

Dr. Jacobs clearly recognized that Dr. Mallett's view was contrary to his own. (Staff Exhibit No. 48 at 33 [Jacobs]). Dr. Jacobs also recognized that the "technical issues [involved in the RWT air entrainment question] are quite complicated" (*Id.* at 24 [Jacobs]), and admitted at the hearing that Dr. Mallett was in a better position than this Commission to determine whether a question asked by one of his inspectors in this technically complex area was a new question or not. (Tr. Vol. XXIX at 5270 [Jacobs]). Nor did Dr. Jacobs claim to have more expertise than Dr. Mallett with regard to this issue. (*Id.* at 5390 [Jacobs]). Nonetheless, when asked: "So you think that this Commission should accept your recommendation and reject that of the NRC's highest officer who was responsible for this matter?" Dr. Jacobs replied: "In this case, yes." (*Id.* [Jacobs]).

As to why the Commission should accept his view over that of Dr. Mallett, Dr. Jacobs' only response was that "I think it's possible for qualified and competent individuals to reach different opinions given the set of circumstances, and that's what's happened in this case." (*Id.* [Jacobs]). However, as pointed out above, Dr. Jacobs has never worked at the NRC and has never held a management position with a U.S. nuclear utility. For this Commission to agree with Dr. Jacobs and conclude that APS should have identified a question regarding air entrainment in the RWT system earlier, then this Commission must also conclude that Dr. Mallett was wrong when he spoke to this Commission in January 2006 regarding this outage, and must reject the overwhelming evidence presented by Dr. Mattson explaining why the question was new and one that should not have been anticipated – none of which evidence Dr. Jacobs even addresses.

The yellow finding was issued to APS because APS had maintained a section of piping dry even though the design required the section of piping to be filled with water. (APS Exhibit No. 87 at 40 [Mattson]; Tr. Vol. XXVII at 5147 [Levine]). Following the yellow finding in April 2005, APS evaluated various systems, including the RWT system, to determine if similar problems existed. (Tr. Vol. XXVII at 5022-23 [Mattson]; Tr. Vol. XXVII at 5150-51 [Levine]; Tr. Vol. XXVIII at 5188-91 [Levine]). APS did not identify any voided portions of the RWT system. (Tr. Vol. XXVIII at 5188-91 [Levine]). During the October 2005 NRC inspection, the NRC asked the new question of whether the RWT system design that the NRC had approved back in 1976 prevented air from entering the system and damaging pumps during a plant accident. (APS Exhibit No. 87 at 53 [Mattson]; Staff Exhibit No. 46 at 31 [GDS Report]; Tr. Vol. XXVI at 4920-21 [Mattson]). This was a different issue from that which resulted in the yellow finding. Mr. Levine was questioned at the hearing about this difference between the yellow finding and the RWT air entrainment question. (Tr. Vol. XXVIII at 5190-91 [Levine]). He responded that the "[RWT] met the design basis, and we felt that we had the adequate backup information to support that. And it's really – again, it's two different things. You had a situation where the pipe was literally dry, it was maintained dry, versus another case where the pipe was full." (*Id.* at 5191 [Levine]). Thus, there is no basis to conclude that APS should have identified the RWT air entrainment question in response to the yellow finding for the voided sump suction line. (APS Exhibit No. 88 at 7 [Mattson]; Tr. Vol. XXVI at 4921 [Mattson]; Tr. Vol. XXVII at 5022-23 [Mattson]; Tr. Vol. XXVII at 5147, 5150-52 [Levine]). The Staff simply has not provided the type of "clear and convincing" evidence necessary to rebut the presumption of prudence on the part of APS management.

Dr. Jacobs made no attempt to interview Dr. Mallett regarding these events. (Tr. Vol. XXIX at 5265 [Jacobs]). Instead, he interviewed one of Dr. Mallett's subordinates, senior resident inspector Warnick (Staff Exhibit No. 46 at 32 [GDS Report]), who was not even involved in the inspection in question. (APS Exhibit No. 88 at 14 [Mattson]). Dr. Jacobs seems to believe that if Mr. Warnick considered this outage was avoidable, then Palo Verde must have been imprudent. (Staff Exhibit No. 46 at 32 [GDS Report]). Although there is no transcript of Mr. Warnick's comments, it appears likely that Mr. Warnick was simply speaking from the NRC perspective of continuous improvement using hindsight, rather than from the ACC perspective of prudence given information reasonably available at the time. (APS Exhibit No. 87 at 27 [Mattson]; APS Exhibit No. 88 at 14 [Mattson]). As he did throughout his testimony, Dr. Jacobs fails to distinguish between what **could** have been done (NRC standard) and what **should** have been done (prudence standard). (APS Exhibit No. 88 at 11 [Mattson]). Significantly, Dr. Jacobs never states that Mr. Warnick said that APS **should** have avoided the outage. Of course, even if Mr. Warnick had told Dr. Jacobs that APS should have anticipated the issue, such a conclusion would directly contradict Dr. Mallett, and would be entitled no weight given the fact that Mr. Warnick was not even a member of the inspection team that raised the issue and the inspection report did not issue a violation to APS for not finding the issue beforehand. (APS Exhibit No. 88 at 14-15 [Mattson]; APS Exhibit No. 94 at 17 [Levine]; Tr. Vol. XXIX at 5359 [Jacobs]). Again, reliance on an ambiguous oral hearsay statement by an NRC inspector not involved in the inspection in question and in the face of clearly contrary evidence from the NRC Regional Administrator does not constitute clear and convincing evidence of imprudence.

Finally, as Dr. Mattson explained, the Company must again emphasize that even if APS had identified the question of air entrainment in the RWT suction line in response to the yellow finding, it still would have had to shut down the Palo Verde units. (APS Exhibit No. 88 at 6 [Mattson]). Since the yellow finding was not issued until April 2005, any identification of a potential air entrainment issue in the RWT system in response to the yellow finding would have occurred during the PSA period. (Tr. Vol. XXVI at 4966 [Mattson]). This outage would have had a much larger economic impact if it had occurred when all three units were operating (Unit 1 was in a scheduled refueling outage during the October RWT outage) or if it had occurred during the peak summer months. (*Id.* at 4974 [Mattson]). No matter when an issue such as this is identified, all of the units must be shut down if the operability determination cannot ensure safe operation. (Tr. Vol. XXVII at 5028 [Mattson]).

e. Any Imprudent Costs Should Be Offset In The Amount Of $5,100,000 Due To Concurrent Prudent Maintenance That Prevented Later Outages.

(1) Background.

Even if the Commission disallows costs related to the October RWT outages at Units 2 and 3, it must consider whether a portion of any disallowed costs should be offset due to prudent maintenance performed during the outage on the Unit 2 Reactor Coolant Pumps ("RCPs") that prevented later outages and corresponding replacement power costs. Of course, if the Commission determines that APS was prudent regarding the October RWT outage, then it is unnecessary for the Commission to assess the impact of maintenance performed during the outage.

The replacement power costs associated with the 160 hours of outage time claimed to be avoided by performing the RCP maintenance during the Unit 2 RWT outage are $5,636,000 ($5,100,000 after the 90/10 share). (APS Exhibit No. 17 at 21-22 [Ewen]). Dr. Jacobs has not disputed the accuracy of this calculation. This offset is separate and apart from any of the other offsets recommended by APS. (Tr. Vol. XXVIII at 5223-24 [Ewen]). Therefore, Staff's recommended disallowance for the October Unit 2 RWT outage of $6,905,000 would be reduced by $5,100,000, for a total of $1,805,000 if the Commission concurs that the RCP maintenance avoided an outage and corresponding replacement power costs. As discussed in Section IX.F.1 below, this would also result in a corresponding deduction in margins on lost opportunity sales.

(2) APS's Position.

APS's position is that even if the October RWT outage had not occurred, Unit 2 would have had to shut down to perform maintenance on certain RCPs due to oil leakage. (APS Exhibit No. 94 at 19 [Levine]; APS Exhibit No. 95 at 6 [Levine]). APS presented substantial evidence regarding the need to take the plant out of service to perform maintenance on the RCPs. (APS Exhibit No. 95 at 5-7, Attachment JML-1RJ [Levine]).

(3) Staff's Position.

Dr. Jacobs' position is that APS's claim constitutes "pure speculation" and that "APS has provided no evidence that a subsequent outage was planned or would have occurred." (Staff Exhibit No. 48 at 40 [Jacobs]).

(4) Analysis.

The record contains substantial evidence that Palo Verde would have had to shut down Unit 2 to perform RCP maintenance had the October RWT outage not occurred. (APS Exhibit

No. 94 at 19-20 [Levine]; APS Exhibit No. 95 at 6 [Levine]). Prior to the RWT outage, the oil leakage from the Unit 2 RCP 2A thrust bearing oil seals had worsened to the point that a shutdown was imminent. (APS Exhibit No. 95 at 7 [Levine]). Palo Verde measures the oil leakage based on the frequency that oil must be pumped into the RCP oil reservoir to replenish oil that has leaked out, also known as the "pump-up" rate. (*Id.* at 7, Attachment JML-1RJ [Levine]). A more frequent pump-up rate means that the oil leakage is worse. (*Id.* at Attachment JML-1RJ [Levine]). The pump-up rate for the Unit 2 RCP 2A was approximately 9 hours at the time of the October RWT outage. (*Id.* at 7, Attachment JML-1RJ [Levine]; Tr. Vol. XXVIII at 5210 [Levine]).

Prior to the RWT outage, Unit 3 was shut down to perform maintenance on RCP 1A when the pump-up rate was at 12 hours. (APS Exhibit No. 95 at 7, Attachment JML-2RJ [Levine]). Therefore, at the time of the RWT outage, the oil leakage in Unit 2 was already worse than when Palo Verde had shut down Unit 3 earlier in the month to perform identical maintenance. (*Id.* at 7 [Levine]; Tr. Vol. XXVIII at 5210 [Levine]). Importantly, Dr. Jacobs concluded that these earlier outages, including the outage for Unit 3 RCP 1A, to perform the identical maintenance to the RCP were "reasonable and prudent." (Staff Exhibit No. 46 at 39 [GDS Report]). Whether or not there is any merit to Dr. Jacobs' claim that APS's rebuttal testimony on this issue was speculative is rendered moot by the further detail provided in APS's discovery responses to Dr. Jacobs and in Messrs. Levine's and Ewen's Rejoinder Testimony. Therefore, an offset of $5.1 million should be applied to any disallowance if the Commission determines that the RWT outage was imprudent.

2. The Unit 1 August 2005 Reactor Trip Was Caused By An Individual Operator Error, Not Management Imprudence.

a. Background.

On August 26, 2005, the reactor tripped at Palo Verde Unit 1 due to a high level in one of the steam generators. (APS Exhibit No. 94 at 22 [Levine]; Staff Exhibit No. 48 at 20-21 [Jacobs]). "The unit tripped due to an **operator error** in controlling the feedwater to the Steam Generator." (Staff Exhibit No. 46 at 24 (emphasis added) [GDS Report]). This reactor trip occurred when Palo Verde was starting up Unit 1 and the secondary control room operator switched the system used to control steam generator water level from manual to automatic control. (APS Exhibit No. 94 at 21 [Levine]). The operator did not believe the automatic control was properly controlling level, and switched the system back to manual, but without requesting concurrence or informing his supervisors. (*Id.* [Levine]). Thereafter, the operator switched between manual and automatic control several times while trying to maintain proper level in the steam generator, again without notice to or concurrence from supervision. (*Id.* at 22 [Levine]). These "errors by the secondary control room operator while attempting to place the Main Feedwater control in automatic resulted in an excessive feed rate to the steam generator and ultimately to a reactor trip on high steam generator water level." (*Id.* [Levine]; Staff Exhibit No. 48 at 20-21 [Jacobs]; Tr. Vol. XXVII at 5143-44 [Levine]).

b. Staff's Position.

Although Dr. Jacobs acknowledges that this event was caused by the errors of the secondary control room operator, he also argues that the reactor trip was the result of management imprudence. (Staff Exhibit No. 46 at 27 [GDS Report]). Dr. Jacobs' primary arguments are that this event is an example of human performance and problem resolution problems at Palo Verde, and that problems with the system that resulted in the outage were well known and the training of the operators did not correspond to the difficulties of the system. (*Id.* at 26-27 [GDS Report]).

Dr. Jacobs initially recommended a disallowance of $1,134,000 for this August outage, but later agreed with Mr. Ewen's correction that this amount was overstated by $88,000, for a total recommended disallowance by Dr. Jacobs for this outage of $1,046,000. (APS Exhibit No. 17 at 24 [Ewen]; Staff Exhibit No. 46 at Attachment 15 [GDS Report]; Staff Exhibit No. 48 at 43 [Jacobs]).

c. APS's Position.

APS's position is that this reactor trip occurred because of the failure of the secondary control room operator to follow procedures, and was not the result of imprudent actions by APS management. (APS Exhibit No. 94 at 21-23 [Levine]; APS Exhibit No. 95 at 8 [Levine]). APS bases this conclusion on a number of different factors. First, Palo Verde management was not involved in the cause of the reactor trip; rather, the operator's individual actions, without the knowledge of management and contrary to express procedures to inform his supervisor of the actions he planned to take, resulted in the reactor trip. (APS Exhibit No. 94 at 21 [Levine]; APS Exhibit No. 95 at 8 [Levine]). Second, had the operator simply followed procedures and left the level control system in automatic, the reactor would not have tripped. (APS Exhibit No. 95 at 8 [Levine]). Third, Palo Verde provided the appropriate amount of training to the operators on this system, especially given that the issue had never caused an earlier reactor trip. (APS Exhibit No. 94 at 23 [Levine]). As Mr. Levine states, "[w]e train our operators based on our best judgment of what the most significant issues are and what will best assist in the safe and efficient operation of the plant." (*Id.* [Levine]). Finally, Palo Verde has had relatively few unplanned reactor trips. (*Id.* at 22 [Levine]).

d. Analysis.

APS and Dr. Jacobs agree that this outage was caused by the errors of an individual operator, whose actions allowed the steam generator water level to rise too high and trip the reactor. (Staff Exhibit No. 46 at 24, 26 [GDS Report]; Staff Exhibit No. 48 at 20-21 [Jacobs]). However, Dr. Jacobs incorrectly believes that the errors of this operator may be imputed to APS management. First, as noted above, prudence does not require perfection. Just as the Commission stated in 1984 that Palo Verde was "built by human beings, not mistake-proof automata," Palo Verde is also operated by human beings, not machines. (Decision No. 54204 at 15). Prudence does not require that there never be a reactor trip at a nuclear power plant. Dr. Jacobs admits this. (Tr. Vol. XXIX at 5271 [Jacobs]). He further admits that all nuclear plants have reactor trips caused by operator errors, and that every trip caused by human error is not necessarily imprudent. (*Id.* at 5271, 5339 [Jacobs]).

Moreover, although he acknowledges the fact that the operator "failed to communicate his actions with shift management," (Staff Exhibit No. 46 at 26 [GDS Report]), Dr. Jacobs is silent on how this fact impacts the prudence analysis. Because the operator did not even notify his immediate supervision of his actions, APS management had no knowledge of the events that led to the reactor trip. In violation of procedures and policies, the operator's supervisors were not given the chance to approve or prevent the operator's actions. (Tr. Vol. XXVIII at 5195 [Levine]).

Dr. Jacobs' arguments that additional training should have been provided are likewise flawed. APS had provided training to all the operators when the system was upgraded from digital to analog in 2003. (Tr. Vol. XXVII at 5133 [Levine]). Moreover, APS also provides what is called "just-in-time" ("JIT") training before start-up. As Mr. Levine testified, "we run them through certain portions of the startup [in the simulator]. We don't do it all because the startup is a very long evolution." (*Id.* at 5131 [Levine]). Prior to this outage, APS focused its JIT training on other evolutions that had caused problems during startup in the past, and did not conduct JIT training on the steam generator level control system, because there had not been significant difficulties in the past. (*Id.* at 5131-32 [Levine]). In fact, there had never been a reactor trip due to the system. (*Id.* at 5131 [Levine]). At the hearing, the Staff questioned Mr. Levine about what his response would have been if he had been asked prior to the reactor trip whether he thought the operator "had been trained, was knowledgeable, had adequate procedures, and would be able to execute the startup effectively." (*Id.* at 5133 [Levine]). Mr. Levine responded "Yes," illustrating that his reasonable belief at that time was that the operator was adequately prepared to perform the evolution. (*Id.* [Levine]).

Dr. Jacobs attempted to argue that "[o]perators' concerns about the ability of the DFWCS were well known and long standing." (Staff Exhibit No. 48 at 22 [Jacobs]). However, at the hearing, Judge Farmer questioned Dr. Jacobs about how he knew this. (Tr. Vol. XXIX at 5362 [Jacobs]). Dr. Jacobs' response was "[f]rom reading the root cause evaluation of this event." (*Id.* [Jacobs]). When further questioned by APS about his support for this statement, Dr. Jacobs was unable to identify anything specific in the root cause evaluation that demonstrated that APS management was aware of any operator concerns with the DFWCS system. (*Id.* at 5395-97 [Jacobs]). Dr. Jacobs was only able to identify statements referring to knowledge of the operators. (*Id.* at 5396-97 [Jacobs]). Likewise, when Judge Farmer repeated her question, Dr. Jacobs could not demonstrate from the root cause evaluation that the perceived, but in fact nonexistent, problems with the system were known or should have been known by APS management. (*Id.* at 5399-5400 [Jacobs]).

Finally, any attempt by Dr. Jacobs to claim that post-outage modifications regarding training or procedures show imprudence is an exercise in impermissible hindsight and directly contradicts the NRC's Policy Statement cautioning state public utility commissions against undue reliance on such actions. (APS Exhibit No. 87 at 45 [Mattson]; APS Exhibit No. 101). The NRC stated the following:

> The [NRC] is also concerned about State public utility commission ratemaking actions that might be interpreted as penalizing a utility for improving its own procedures or methods of operation. For example, where a State public utility commission observes that a utility has modified its procedures following an incident, infers from the utility's actions that the original procedures must have been inadequate, and then disallows certain costs on the basis of such assumed inadequacies, the utility will have a strong disincentive voluntarily to enhance or improve its operations and procedures in the future. Such State public utility commission action can discourage utilities from making needed improvements in procedures and operations and, thus, can be detrimental to the long-term safety of operation.

(APS Exhibit No. 87 at 45 [Mattson]; APS Exhibit No. 101 at 3 of 4). Changes made by Palo Verde to procedures or training were simply part of Palo Verde's "goal to continuously improve performance," and are not an indication that the procedures or training prior to the reactor trip were not reasonable. (APS Exhibit No. 95 at 9 [Levine]).

In sum, the August 2005 reactor trip was due to the errors of an operator who violated express procedures to notify supervision before he took the actions in question. There is no basis upon which this Commission could conclude that APS management knew or should have known of this activity prior to its occurrence, and therefore, there is no basis to conclude that the outage was the result of management imprudence.

3. The Unit 1 March 2005 Outage Due To Failure Of A Diesel Generator Governor Was Not Caused By Management Imprudence.

a. Background.

On March 17, 2005, Palo Verde Unit 1's Diesel Generator "A" failed to achieve full speed during a post-maintenance retest. (APS Exhibit No. 94 at 25 [Levine]; Staff Exhibit No. 46 at 22 [GDS Report]). Palo Verde investigated the problem and determined that the diesel generator's governor should be replaced. (APS Exhibit No. 94 at 25 [Levine]). Although Palo Verde was able to quickly replace the governor, the unit's technical specifications required the unit to be shut down to conduct certain retests that must be performed following governor replacement. (*Id.* [Levine]; Staff Exhibit No. 46 at 22 [GDS Report]). Therefore, Palo Verde Unit 1 was shut down to perform the retests, and was subsequently restarted. (APS Exhibit No. 94 at 25 [Levine]).

Palo Verde performed a root cause investigation of the governor failure and determined that the direct cause was "contamination of the lube oil in the governor actuator." (*Id.* at 26 [Levine]). Nonetheless, no definite cause for the oil contamination was identified. (APS Exhibit No. 89 at 14 [Denton]; APS Exhibit No. 94 at 26 [Levine]). The three most probable root causes of the governor contamination, in the order of most probability, are water introduced by the vendor during a June 2000 governor refurbishment that was not completely drained, storage of the governor drained of oil at the Palo Verde warehouse, and water introduced during a governor oil change. (APS Exhibit No. 89 at 14-15 [Denton]; APS Exhibit No. 94 at 26 [Levine]; Staff Exhibit No. 46 at 23 [GDS Report]).

Dr. Jacobs did not recommend any disallowance because this event occurred prior to April 2005, but he did initially recommend that "[t]he amount of $1.623 million incurred before April 1, 2005 should not be eligible for consideration in establishing base fuel costs in the pending rate case." (Staff Exhibit No. 47 at 4 [Jacobs]; Tr. Vol. XXIX at 5272-73 [Jacobs]). APS responded that the pre-PSA outages do not have a bearing on the present rate case. (APS Exhibit No. 94 at 24-25 [Levine]). Staff Witness Antonuk's testimony, which states that Mr. Ewen's normalization did not use the actual 2005 performance of any unit, supports this conclusion. (Staff Exhibit No. 28 at 23 [Antonuk]). At the hearing, Dr. Jacobs agreed that if the 2005 outages were not used in APS's normalization, then this outage is "no longer relevant." (Tr. Vol. XXIX at 5273 [Jacobs]). Similarly, counsel for the ACC Staff acknowledged that there are no "PSA dollars" associated with this outage. (*Id.* at 5276-77 [Jacobs]). Although no party claims any economic impact on the present rate case based on the prudence of this outage, because Commissioner Mayes indicated that she thought the outage may be relevant to the issue of a Nuclear Performance Standard, the arguments of Staff and APS are addressed below. (*Id.* at 5277-78 [Jacobs]).

b. Staff's Position.

Dr. Jacobs argues that this March outage was due to imprudent actions by APS. (Staff Exhibit No. 46 at 24 [GDS Report]). In his initial report, Dr. Jacobs contends that this outage "was avoidable by ensuring that the storage conditions and pre-installation inspection of the re-furbished governor were commensurate with the importance of this equipment." (*Id.* [GDS Report]). In his Surrebuttal Testimony, Dr. Jacobs offers a new argument that APS should have performed more frequent routine analysis of lube oil. (Staff Exhibit No. 48 at 20 [Jacobs]).

c. APS's Position.

APS's position is that this outage was not due to management imprudence and no costs should be disallowed nor should this outage otherwise affect the rate case in any manner. (APS Exhibit No. 89 at 17-18 [Denton]; APS Exhibit No. 94 at 24-25 [Levine]). Palo Verde properly stored the governor in accordance with the manufacturer's recommendation. (APS Exhibit No. 89 at 15-16 [Denton]; APS Exhibit No. 94 at 26-28 [Levine]). Palo Verde also properly inspected the governor prior to installation. (APS Exhibit No. 89 at 16-17 [Denton]; APS Exhibit No. 94 at 27-28 [Levine]). Furthermore, Palo Verde had no reason to believe, and still has no reason to believe, that additional oil sampling and testing would have prevented the March outage. (APS Exhibit No. 90 at 3 [Denton]; APS Exhibit No. 95 at 11 [Levine]).

d. Analysis.

Prudence only requires that APS reasonably treated the diesel generator governor prior to its failure based on what APS management knew or reasonably should have known at the time of the governor failure (without hindsight). (Staff Exhibit No. 46 at 19 [GDS Report]). The evidence demonstrates that APS reasonably stored the governor, inspected the governor, and sampled the governor oil, and therefore was not imprudent.

Dr. Jacobs argues that "[s]torage of the governor drained of oil in a warehouse that was not climate controlled is not a good practice" and that the outage was avoidable by storing the governor commensurate with its importance. (*Id.* at 23-24 [GDS Report]). However, Dr. Jacobs provides no support for this assertion, such as industry standards or the practices of other utilities. APS, on the other hand, established that Palo Verde stored the governor in accordance with the manufacturer's recommendations. (APS Exhibit No. 89 at 15-16 [Denton]; APS Exhibit No. 94 at 26 [Levine]). Woodward Governor Company, the manufacturer of the governor, recommended that the governor be stored in a "clean and dry condition." (APS Exhibit No. 89 at 15, Attachment RED-1RB [Denton]; APS Exhibit No. 94 at 26, Attachment JML-1RB [Levine]). The governor that failed was stored precisely in this manner. (APS Exhibit No. 89 at 15 [Denton]; APS Exhibit No. 94 at 26 [Levine]). Indeed, Dr. Jacobs admits that the governor was stored in accordance with the manufacturer's recommendations. (Tr. Vol. XXIX at 5278 [Jacobs]).

With respect to inspection of the diesel generator governor prior to its failure, Dr. Jacobs again simply states that the outage "was avoidable by ensuring that the . . . pre-installation inspection of the re-furbished governor [was] commensurate with the importance of this equipment." (Staff Exhibit No. 46 at 24 [GDS Report]). However, Dr. Jacobs provides no evidence of how Palo Verde's pre-installation inspection was insufficient. His testimony thus falls into the category of "broad assertions of mismanagement" that this Commission has previously held are insufficient in a prudence review. (Decision No. 55118 at 20).

Palo Verde's inspection of the governor prior to installing it could not have identified any rust. (APS Exhibit No. 94 at 27 [Levine]). As illustrated by the independent failure analysis for this governor, any rust could only have been identified by a complete disassembly of the governor. (APS Exhibit No. 89 at 17 [Denton]; APS Exhibit No. 94 at 27, Attachment JML-2RB [Levine]; Tr. Vol. XXVII at 5048 [Denton]; Tr. Vol. XXVII at 5137 [Levine]). However, as Dr. Jacobs admitted at the hearing, to be prudent, Palo Verde was not required to disassemble the governor prior to installation. (Tr. Vol. XXIX at 5280-81 [Jacobs]). Thus, Dr. Jacobs does not provide any "hard evidence of specific acts of imprudence" to rebut APS's testimony and his own admissions regarding pre-installation inspection of the governor. (Decision No. 55118 at 20).

Once APS rebutted his conclusions about storage and inspection of the governor, Dr. Jacobs presented a new argument in his Surrebuttal Testimony that, following installation, "[a] routine analysis of the governor lube oil would also have identified the problem." (Staff Exhibit No. 48 at 20 [Jacobs]). This is simply not the case. For example, APS performed a lube oil sample on April 19, 2004, one of the periodic samplings that Dr. Jacobs admits was performed (Tr. Vol. XXIX at 5281 [Jacobs]), which indicated a very low amount of water. (APS Exhibit No. 90 at 3 [Denton]; APS Exhibit No. 95 at 11 [Levine]).

Dr. Jacobs relies on a high level of water in an oil sample taken in the shop after the governor was replaced to conclude that additional sampling would have prevented the outage. (Staff Exhibit No. 48 at 20 [Jacobs]). However, following the outage, Palo Verde performed a thorough review of the process for changing and sampling oil and did not identify any potential source of water addition. (APS Exhibit No. 90 at 2-3 [Denton]; APS Exhibit No. 95 at 11 [Levine]). Moreover, Mr. Levine explained that the high water level in the post-outage sample was due to the manner in which the post-outage sample was taken. (Tr. Vol. XXVII at 5138 [Levine]). Oil samples normally are taken from a spigot on the side of the oil reservoir, approximately one-half inch from the bottom. (*Id.* [Levine]). While taking the sample following the outage, the governor was tipped on its side such that the sample was taken directly off of the bottom of the oil in the oil reservoir. (*Id.* at 5138-39 [Levine]). Because any water in the reservoir separates from the oil and collects at the bottom of the reservoir where the sample was taken, this different sampling technique led to a higher water level in the oil sample. (*Id.* at 5139 [Levine]). Therefore, Dr. Jacobs' claim that this higher water level in the post-outage oil sample shows that additional sampling would have prevented the outage is incorrect, and is definitely insufficient to show imprudence.

D. <u>APS Prudently Entered Into Vendor Contracts Which Are Typical Of Contracts Used In The Nuclear Industry, And Has Sought Remedies From Vendors Where Appropriate.</u>

Although he found APS's actions in connection with outages that were the result of failure of vendor-supplied equipment to have been prudent, Dr. Jacobs recommended that the

Commission address the degree to which APS has sought appropriate remedies. (Staff Exhibit No. 46 at 52 [GDS Report]; Staff Exhibit No. 47 at 4 [Jacobs]). These outages included the February 2005 Unit 1 outage due to the wrong material o-ring, the May-June Unit 3 outage due to the improperly manufactured pressurizer heaters, and the August Unit 2 outage due to an error in the core protection calculator software. (APS Exhibit No. 94 at 28 [Levine]). APS provided a description of the steps that have been taken to obtain the appropriate remedies from these vendors. (*Id.* at 28-30 [Levine]; Tr. Vol. XXVII at 5170-72 [Levine]). Additionally, Mr. Denton reviewed vendor contracts and concluded that the Limitation of Liability provisions in the contracts are similar to those that are typically used in the nuclear industry, and that Palo Verde acted reasonably in entering into such contracts. (APS Exhibit No. 89 at 11-14 [Denton]; Tr. Vol. XXVII at 5049-50 [Denton]). Neither the ACC Staff nor any other party has challenged APS's actions with respect to these vendor contracts.

E. <u>A Nuclear Performance Standard ("NPS") Is Unnecessary And Inappropriate, And Even If Some Type Of Performance Standard Is Appropriate, The Staff Recommendation Lacks Key Elements.</u>

1. Staff's Own Witness Has Recently Recommended Termination Of A NPS To Another State Commission As Unnecessary, And The NRC Has Raised Concerns About The Appropriateness Of Such Standards.

Staff's witness Dr. Jacobs has recommended that the Commission implement a penalty-only form of a NPS for Palo Verde. (Staff Exhibit No. 46 at 52 [GDS Report]; Staff Exhibit No. 47 at 4 [Jacobs]). However, Dr. Jacobs recently recommended the termination of a NPS in Georgia. (Tr. Vol. XXIX at 5286 [Jacobs]). He did so based on the utility's response to a data request stating that the NPS had no impact on how the utility operated the plant. (APS Exhibit No. 100; Tr. Vol. XXIX at 5286 [Jacobs]). Following Dr. Jacobs' recommendation, the Georgia Commission terminated the program. (Tr. Vol. XXIX at 5285 [Jacobs]). Similarly, Mr. Levine testified that the existence of a NPS would not affect how APS operates Palo Verde. (Tr. Vol. XXVII at 5127 [Levine]). Thus, a NPS is at best unnecessary.

Moreover, in contrast to the incentive program that APS itself implements, which contains elements rewarding both safety performance and economic performance (Tr. Vol.

XXVIII at 5204, 5208-09 [Levine]), the penalty-only, capacity factor-only type of NPS that Dr. Jacobs proposes has prompted the NRC to express its concern about such programs' effects on safety. The NRC's Policy Statement "reflects the [NRC]'s concern that certain forms of economic performance incentive (EPI) regulation may adversely affect the operation of nuclear plants and the public health and safety." (APS Exhibit No. 87 at 45 [Mattson]; APS Exhibit No. 101 at 1 of 4). Similarly, the NRC stated that "an incentive program could directly or indirectly encourage the utility to maximize measured performance in the short term at the expense of plant safety (public health and safety)." (APS Exhibit No. 87 at 45 [Mattson]; APS Exhibit No. 101 at 3 of 4). Dr. Jacobs has presented no evidence to rebut these concerns of the NRC other than to call the NRC Policy Statement a "red herring." (Staff Exhibit No. 48 at 38 [Jacobs]). APS would of course do everything possible to avoid unintended consequences of a NPS. (Tr. Vol. XXVII at 5127 [Levine]). However, if a NPS is not going to cause a utility intentionally to do anything differently in order to achieve more efficient operation, it is not prudent to run any risk, no matter how small, that the NRC's concerns about potential negative impacts on safety would be realized.

2. Dr. Jacobs Has Not Provided Sufficient Information To Implement A Performance Standard.

Dr. Jacobs claims that he has provided sufficient information to implement a NPS (Staff Exhibit No. 48 at 38-39 [Jacobs]), although he inconsistently also states he is "well aware that the Commission may add details to [his] proposal in order to tailor it for the purposes of regulation in Arizona." (*Id.* at 34 [Jacobs]). Not only would the Commission have to "add details," but as demonstrated in the following section, it would have to drastically alter the proposed NPS.

Dr. Jacobs did not provide the Commission with a review of other performance standards, including earlier standards adopted by this Commission. Dr. Jacobs was asked whether he was aware that there was previously a performance standard in Arizona. (Tr. Vol. XXIX at 5288 [Jacobs]). Dr. Jacobs responded that he understood that one had been discussed, but had not been implemented. (*Id.* [Jacobs]). Not only was a performance standard adopted for

APS in 1984, but it was substantially different than the NPS now proposed by Dr. Jacobs. (Decision No. 54247 at 11-16 (Nov. 28, 1984)). Among other attributes, the performance standard adopted by this Commission included an incentive portion, did not include a penalty unless capacity factor was below 60 percent, included a dead band between 60-75 percent, and included coal plants. (*Id.* at 15-16). Dr. Jacobs acknowledged at the hearing that the Commission should consider its past history with performance standards. (Tr. Vol. XXIX at 5288 [Jacobs]). Dr. Jacobs likewise did not conduct any sort of study or review of other jurisdictions that include coal plants in their performance standards. (*Id.* at 5300-01 [Jacobs]). Dr. Jacobs admits that these also are issues the Commission should consider in adopting a standard. (*Id.* at 5301 [Jacobs]).

Dr. Jacobs also acknowledged that further development on the issue of a "cap" on the penalty would be necessary prior to the implementation of a performance standard. (*Id.* at 5291-92 [Jacobs]). Dr. Jacobs' proposed standard does not address the fact that there are 18-month and 24-month refueling cycles at different plants, which would penalize plants with 18-month cycles such as Palo Verde. (*Id.* at 5295-96 [Jacobs]; APS Exhibit No. 102). Dr. Jacobs admitted that this deficiency would have to be addressed. (*Id.* at 5296 [Jacobs]). His proposed standard does not state whether the mean or the median capacity factor should be used for the target value. (*Id.* at 5297 [Jacobs]). Dr. Jacobs' proposed NPS focuses entirely on a financial penalty, but he does not explain the details of how any penalties would be calculated. (APS Exhibit No. 2 at 20 [Wheeler]; APS Exhibit No. 91 at 17 [Fitzpatrick]).

Additional characteristics of Palo Verde, such as its size, location, and cooling water supply make the plant unique and add an additional layer of complexity to the development of any performance standard. (APS Exhibit No. 91 at 5 [Fitzpatrick]; APS Exhibit No. 92 at 5-6 [Fitzpatrick]; Tr. Vol. XXVII at 5064 [Fitzpatrick]). Dr. Jacobs does not consider the inclusion of additional safety-related attributes (like those contained in APS's employee incentive plan) to offset any of the potential negative effects of the capacity factor-only aspects of his proposed standard. (Tr. Vol. XXIX at 5298-99 [Jacobs]). All of these missing or inadequately treated features would have to be considered in any performance standard. As Mr. Fitzpatrick testified, "there are elements that need to be hammered out and agreed to by the parties" and "there's a lot more specificity required rather than just a general overview of principles." (Tr. Vol. XXVII at 5091 [Fitzpatrick]). Mr. Fitzpatrick testified that this is a process that requires months and is then followed by "bench testing [the proposed standard] with some data." (*Id.* at 5091-92 [Fitzpatrick]).

All of these attributes not addressed by Dr. Jacobs illustrate that his proposed NPS is incomplete, and much more discussion would be necessary to implement a performance standard in Arizona. However, APS would again urge the Commission to carefully consider whether, for the reasons stated in the preceding section, it is necessary and appropriate to implement a performance standard.

3. If A Performance Standard Is Adopted, It Should Contain Certain Important Attributes That Are Missing From Dr. Jacobs' Proposal.

As discussed above, Dr. Jacobs believes that the NRC's guidance regarding performance standards should be ignored by this Commission. (Staff Exhibit No. 48 at 38 [Jacobs]). APS disagrees and believes that as the regulatory agency for nuclear safety, the NRC's concerns regarding the impact of performance standards on nuclear plant safety should be carefully considered, and the NRC's guidance to prevent safety issues should be reflected in any performance standard adopted. (APS Exhibit No. 87 at 45 [Mattson]; APS Exhibit No. 88 at 26 [Mattson]; APS Exhibit No. 101; Tr. Vol. XXVII at 5127 [Levine]). The NRC's guidance and additional important attributes for a performance standard are discussed below.

a. A Performance Standard Should Include Incentives.

The NRC stated that a performance standard should include "equal opportunities for rewards and penalties." (APS Exhibit No. 101 at 4 of 4). Dr. Jacobs' proposed NPS does not do this; rather, it only penalizes APS and its shareholders. (Staff Exhibit No. 47 at 8 [Jacobs]; Staff Exhibit No. 48 at 34-35 [Jacobs]). Dr. Jacobs' principal argument for not including an incentive portion in his proposed NPS is that "the risk of poor performance is borne solely by the ratepayer." (Staff Exhibit No. 48 at 35 [Jacobs]). This is incorrect. At the hearing, Dr. Jacobs admitted that it is possible that a utility will not achieve its authorized rate of return, as APS did not in recent years. (Tr. Vol. XXIX at 5282 [Jacobs]). Further, as Mr. Brandt testified, "over a relatively long period [of] time we've never come close to earning our allowed return on equity." (Tr. Vol. II at 412 [Brandt]). APS has not earned its authorized ROE since 2003, with a shortfall for the one year period ending on June 30, 2006 of $134 million. (*Id.* at 411 [Brandt]).

Dr. Jacobs' arguments contradict this Commission's earlier conclusions when it implemented a performance standard in 1984. The Commission addressed whether the standard should be symmetrical, meaning including both an incentive and a penalty. (Decision No. 54247 at 13). The Commission stated that "[s]ymmetry is primarily a question of 'fairness' to the utility's shareholders." (*Id.* at 14). The Commission concluded that the performance standard should have equal opportunities for rewards and penalties, and held that "[s]uch a system has both the appearance, and in our opinion, the substance of 'fairness.'" (*Id.*).

Mr. Fitzpatrick described a standard that would be fair for all parties, when he testified:

> Any performance standard imposed should allow for both disallowances and benefits. In the interest of symmetry and fairness, if APS and its shareholders are now to be exposed to additional risk, then there should now also be an opportunity for shareholders to realize a monetary benefit from better-than-average performance. If a disallowance-only performance standard is to be imposed, then the Commission should consider granting an increase in APS' Allowed Return on Equity in recognition of the additional risk that APS shareholders would be shouldering.

(APS Exhibit No. 91 at 17 [Fitzpatrick]).

The additional risk here is that the NPS as proposed by Dr. Jacobs essentially makes APS a guarantor that Palo Verde's capacity factor will be above average. Presently, the utility is compensated through the PSA if it incurs above-normal replacement power costs provided that those costs are prudently incurred. Similarly, the customers benefit when the utility incurs below-normal replacement power costs due to superior performance of its generating units. If that system is to change, and APS is to be penalized any time it achieves below normal performance (even if it acted prudently), it is only fair that it be rewarded if it achieves better than average performance.

Indeed, one of the Staff's other witnesses, Mr. Antonuk, in testifying with respect to the PSA, criticized penalty-only programs, and explained why it is important that an incentive program provide a utility at least the opportunity to gain as much as it could lose:

> Well, I see regulation in the utility industry as doing the best job it can to model how the economy operates. And the way the economy operates is that it rewards efficiency and penalizes inefficiency. If all the economy did was penalize inefficiency, I don't think we would have much of an economy. So I just don't really see a one-sided effort as promoting positive performance for customers.

(Tr. Vol. XXI at 3999 [Antonuk]).

If the Commission decides to go forward with a performance standard, it should heed the advice of Mr. Antonuk and reject the penalty-only approach Dr. Jacobs proposes.

b. A Performance Standard Should Apply To The Entire System, Including Baseload Coal Plants.

The NRC recommends that a performance standard include "performance measures of the entire system instead of those of a specific unit." (APS Exhibit No. 101 at 4 of 4). APS agrees with the NRC that any performance standard should apply to all baseload units, whether nuclear or coal. (APS Exhibit No. 91 at 16 [Fitzpatrick]; Tr. Vol. XXVII at 5065-66 [Fitzpatrick]). As Mr. Fitzpatrick explained:

> Dr. Jacobs does not include APS Base Load Coal Units in his performance standard recommendations. These units should be included if a performance standard is adopted because they have a significant bearing on the ultimate cost of power to APS customers. Palo Verde accounts for only 39% of APS baseload capacity and, thus, should not be the sole focus of a generation performance standard. APS coal units do enjoy a significant $/MWH economic advantage over purchased power and contribute significant benefit to APS customers.
>
> (APS Exhibit No. 91 at 16 [Fitzpatrick]).

Dr. Jacobs' response to APS's argument was simply that coal plants and nuclear plants are different, and "[a] company wide performance plan for all baseload plants would be vastly different and is beyond the scope of my testimony." (Staff Exhibit No. 48 at 36 [Jacobs]). These are not valid reasons for rejecting the NRC's position. As demonstrated above, this Commission has previously adopted a performance standard that included coal baseload generating units. (Decision No. 54247 at 16).[108] Finally, the evaluation of nuclear and coal plants together conforms to the Commission's earlier holding that "a realistic analysis of operating performance

[108] As Mr. Fitzpatrick explains, because of differences in maintenance and refueling practices, a rolling six-year evaluation cycle would be appropriate for coal units while a shorter period could apply to Palo Verde. (APS Exhibit No. 91 at 17 [Fitzpatrick]).

must look at both the 'successes' and the 'failures' if it is to avoid setting unobtainable goals of absolute perfection." (Decision No. 55118 at 20).

c. Additional Attributes Are Essential To A Performance Standard.

As discussed above, Dr. Jacobs' proposed NPS does not include a cap on penalties. (APS Exhibit No. 91 at 17 [Fitzpatrick]). APS believes that a cap on any penalty would be very important to an implemented performance standard. (*Id.* [Fitzpatrick]; APS Exhibit No. 2 at 21 [Wheeler]). Dr. Jacobs later agreed and stated that "I believe that a cap on the amount of penalty is a reasonable request." (Staff Exhibit No. 48 at 38 [Jacobs]; Tr. Vol. XXIX at 5291 [Jacobs]). Therefore, the parties agree that a cap on penalties should be used if the Commission adopts a performance standard, but the details of such a "cap" need to be addressed.

Dr. Jacobs' proposed NPS also does not provide a "dead band." APS believes that a dead band, or as the NRC calls it "a null zone," around the target value, in which no penalty or incentive would be assessed, would be very important to account for normal variations between nuclear plants. (APS Exhibit No. 91 at 17 [Fitzpatrick]). The NRC proposed that if a performance standard is adopted, "a reasonably broad null zone of acceptable performance in which no rewards or penalties are imposed" should be included. (APS Exhibit No. 101 at 3 of 4). Additionally, the performance standard adopted by this Commission in 1984 included a dead band. (Decision No. 54247 at 15-16). The initial dead band for Palo Verde Unit 1 was 60-75 percent and the initial dead band for Four Corners was 65-75 percent. (*Id.* at 15). A careful statistically-derived dead band is especially important given the great variations in nuclear plant performance. As stated by Mr. Fitzpatrick, the standard deviation for the capacity factor of nuclear power plants can be as high as plus or minus 9 percent. (APS Exhibit No. 91 at 18 [Fitzpatrick]; Tr. Vol. XXVII at 5083 [Fitzpatrick]). Dr. Jacobs' proposed NPS would invoke a penalty for APS if the capacity factor was anywhere below the average. (Staff Exhibit No. 47 at 7-8 [Jacobs]). Without a dead band, it would be unfair to require a penalty for anything below the average capacity factor, given such a large standard deviation.

Additionally, Dr. Jacobs' proposed NPS would compare Palo Verde to all pressurized water reactors in the United States with a capacity greater than 600 MW. (*Id.* at 7 [Jacobs]).

APS concludes that the comparison group should be all plants greater than 1000 MW due to design and operational considerations. (APS Exhibit No. 91 at 17 [Fitzpatrick]). Dr. Jacobs responded that "either group will work." (Staff Exhibit No. 48 at 37 [Jacobs]). Therefore, a comparison group including plants greater than 1000 MW should be used if a performance standard is implemented.

F. <u>Additional Recommended Adjustments By Mr. Ewen To Dr. Jacobs' Proposed Disallowances.</u>

As noted in the Introduction and Summary of Matters Remaining in Dispute, APS and the Staff have agreed on certain issues that result in the Staff's current proposed disallowance being $13.756 million in replacement power costs plus $2.103 million for alleged margins in lost opportunity sales, for a total of $15.859 million plus interest. APS has demonstrated in Section IX.C.1.e above why an additional $5.1 million should be deducted from any disallowance that the Commission might order in connection with the RWT outages based on the fact that other necessary RCP maintenance work was performed during those outages. In addition, APS demonstrated in Section IX.B.4 above why a minimum of an additional $10 million offset is appropriate for better than expected APS coal plant performance, the benefit of which APS customers have already received. Alternatively, as also demonstrated in Section IX.B.4 above, when APS 2005 coal plant performance is measured not against APS's own very high expectations but against the performance of those plants' industry peers, it more than eliminates the entire disallowance Staff proposes. In this section, APS demonstrates that certain other adjustments would be required to Dr. Jacobs' calculations if the Commission were to find that imprudence had occurred and were not offset by the adjustments discussed above.

1. Off-System Sales Impact.

Dr. Jacobs argues that "[i]t is clear that reduced levels of nuclear generation due to unplanned outages at Palo Verde would result in lost off-system opportunity sales." (Staff Exhibit No. 46 at 46 [GDS Report]). APS agrees that these outages did affect off-system sales, but Dr. Jacobs' calculation grossly overestimates the financial impact of the outages on these sales. (APS Exhibit No. 17 at 20 [Ewen]). Dr. Jacobs calculated the lost sales by "multiplying the average margin amount per MWh for off-system sales from April through December 2005 times the MWh reduction in nuclear generation due to each imprudent Palo Verde outage," resulting in an estimated adjustment of $2,103,169. (Staff Exhibit No. 46 at 47 [GDS Report]).

Mr. Ewen demonstrated why Dr. Jacobs' calculation is erroneous:

> 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 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 outage in mid-October.

(APS Exhibit No. 17 at 20 [Ewen]).

Dr. Jacobs agreed that his calculation is inaccurate, and that not all 187,000 MWh used in his calculation would have been sold. (Tr. Vol. XXIX at 5304 [Jacobs]). He stated that he used this estimation because APS had not yet provided him with the detailed information. (*Id.* at 5303-04). However, APS subsequently provided him with its own detailed calculations and responded to his concerns about those calculations. (APS Exhibit No. 17 at 20-21 [Ewen]; APS Exhibit No. 97 at 3-5 [Ewen]). Although Dr. Jacobs still questions some of the results, he does not provide an alternate analysis. (Tr. Vol. XXIX at 5307-14 [Jacobs]). In fact, he stated that APS's "approach is probably the more accurate way to do it." (*Id.* at 5314). At the hearing, Dr. Jacobs stated that: "So I guess my recommendation would be to ask the company to go back and take another look and see if they can come up with an answer that doesn't have some clear discrepancies in it." (*Id.*). However, Mr. Ewen did this in his Rejoinder Testimony explaining that there are in fact no "discrepancies" in APS's calculations.

APS compared the actual results that the Company experienced on the days for the alleged imprudent outages against a simulation of the power system on these same days using actual load and market conditions and using the well-recognized RTSim production cost model. (APS Exhibit No. 17 at 20-21 [Ewen]). These calculations are presented in APS Exhibit No. 103. If the Commission agrees with APS that none of the outages were imprudent, then there would be no disallowance for lost off-system sales. If the Commission finds some imprudence, the appropriate figure for margins on lost off-system sales will vary depending on which outages are concluded to be the result of imprudence. Thus, if the Commission agrees with Dr. Jacobs that both the August reactor trip and October RWT outage costs should be disallowed, then the margin on lost off-system sales would be $322,000 (reducing the $2,103,000 figure by $1,781,000). (APS Exhibit No. 17 at 21 [Ewen]; APS Exhibit No. 103; Staff Exhibit No. 46 at 47 [GDS Report]). However, if the Commission concludes that the RCP maintenance prevented a separate outage, then the margin on lost off-system sales would further be reduced by $53,000 to $269,000 (reducing the $2,103,000 figure by $1,834,000). (APS Exhibit No. 103).

Under a second scenario in which the Commission concludes that only the October RWT outage was imprudent, then the margin on lost off-system sales would be $255,000 (reducing the $2,103,000 figure by $1,848,000). Again, if the RCP work prevented a separate outage, then the margin on lost off-system sales is $202,000 (reducing the $2,103,000 figure by $1,901,000). (*Id.*). Under a third scenario in which the Commission concludes that only the August reactor trip was imprudent, then the margin on lost off-system sales would be $67,000 (reducing the $2,103,000 figure by $2,036,000). (*Id.*).

Dr. Jacobs responded to APS's calculations and methodology, which were provided in a data request response, by stating that "[t]he information provided by APS in their data responses only raises new questions and casts further doubt on their proposed adjustment." (Staff Exhibit No. 48 at 43 [Jacobs]). Dr. Jacobs was concerned that in some instances the simulation calculated lower off-system sales volumes when Palo Verde was running and lower margins when off-system sales increased. (*Id.* at 42). Mr. Ewen responded to these concerns by explaining that these results were caused by better than expected coal performance and the use of certain generating units at low incremental heat rates. (APS Exhibit No. 97 at 4 [Ewen]). For example, when a "2x1" combined cycle unit is started due to an unplanned Palo Verde outage, once it is ramped up to minimum load, the incremental heat rates can be low enough to make off-system sales that would not have been made if Palo Verde was available and the unit had not been started in the first instance. (*Id.*). Similarly, the fact that margins were lower on certain days even though sales increased is by no means surprising and certainly not a "discrepancy" given the wide disparity in sale prices depending upon the time of day a sale is made. In fact, Dr. Jacobs conceded that megawatt hour sales could increase, but the margins could be lower. (Tr. Vol. XXIX at 5310 [Jacobs]). Finally, even if the Commission were to give credence to Dr. Jacobs' claimed discrepancies, this would only increase the lost off-system sales margins from $322,000 to $522,000 – still a far cry from the $2,100,000 disallowance that Dr. Jacobs initially proposed.

2. Offset For Costs Already Expensed.

APS's position is that Dr. Jacobs did not accurately apply the 90/10 sharing when he calculated his recommended disallowances, because his methodology discounts the normal amount of outages in the base rates, resulting in APS expensing $515,000 twice. (APS Exhibit No. 17 at 24 [Ewen]). Dr. Jacobs disagrees with APS and simply states that "[t]he problem with Mr. Ewen's proposed adjustment is that the amount of replacement power costs recovered in base rates assumes that the outage was <u>not</u> imprudent." (Staff Exhibit No. 48 at 44 [Jacobs]). Dr. Jacobs' testimony is simply not responsive to the error in his calculations that Mr. Ewen addressed.

Mr. Ewen explained the discrepancy in Dr. Jacobs' methodology as follows:

> 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.

(APS Exhibit No. 17 at 24 [Ewen]).

Accordingly, an additional $515,000 must be deducted from Dr. Jacobs' proposed disallowances.

X.
CONCLUSION

APS recognizes that its requested rate increase (which includes the emergency rate relief granted by the Commission last May) reverses a trend of steady or even declining electric rates for its customers extending back to the early 1990s. But APS respectfully submits that the requested increase is fully warranted and amply justified by increased fuel costs, increased operating costs, and the lack of opportunity for the Company to earn a fair and reasonable return on its invested equity in recent years. Moreover, the consequences to APS customers of inadequate rate relief in this case will be far more damaging than any perceived short-term benefit derived from continuing down the path of poor earnings, inadequate cash flow, and declining credit-worthiness.

In this proceeding, APS has demonstrated that its financial metrics have declined in recent years and are now at the threshold of non-investment "junk bond" status. APS has also shown that, due to the lag associated with recovery of huge capital expenditures averaging approximately $900 million per year, it has consistently failed to earn its allowed ROE in the past several years and that APS is not likely to have an opportunity to earn its allowed ROE in coming years unless the Commission addresses the issue in some manner. The cause of these financial woes and consistent under-earnings of the Company is readily apparent – existing rates are inadequate to cover the Company's increasing costs of service and related financial obligations for expansion of its growing customer base.

Establishing an adequate Base Fuel Cost and adjusting the PSA in the manner proposed by the Company or adopting the prospective PSA mechanism embraced by Staff would be significant steps in the right direction. By themselves, however, they are not sufficient to address the cost recovery and under-earnings issues raised by the Company. Indeed, the proposals by Staff and RUCO to essentially cut rates with respect to the Company's non-fuel costs would be a significant step in the **wrong** direction, would significantly undermine the Company's efforts to improve its financial metrics (and thereby avoid a slide to "junk bond" credit status), and would send an extremely negative message to the investment community and the credit rating agencies.

Consistent with the inquiries made by Chairman Hatch-Miller about ways to improve the Company's financial metrics and ensure that the Company can continue to meet the needs of the country's fastest growing service area, the Company respectfully submits that now is the time for the Commission to address the issues of cost recovery and under-earnings raised by the Company, not step back for fear that the needed rate increase will be perceived by some to be too large. In this regard, the Company urges the Commission to consider the proposals of CWIP in rate base, accelerated depreciation, earnings attrition allowance and other techniques discussed herein as sound and sensible ways to address these cost recovery and under-earnings issues.

With respect to costs associated with outages at Palo Verde in 2005, the Company respectfully submits that it has demonstrated that it acted prudently with respect to each of those outages, and therefore no disallowances are appropriate. Moreover, as shown in the table below, there are a number of corrections and offsets that reduce, and ultimately eliminate, the disallowances proposed by Staff's consultant. Therefore, the full amount of the requested Step 2 PSA Surcharge should be granted coincident with the new rates established in this proceeding.

	Staff Original Recommended Disallowance	Staff Corrections	Staff Current Recommended Disallowance	APS Additional Corrections and Offsets	Potential Disallowance if Imprudence Found
October Unit 2 RWT Outage	$6.905 million		$6.905 million	-$5.1 million [109]	$1.805 million
October Unit 3 RWT Outage	$6.905 million	-$1.1 million	$5.805 million		$5.805 million
August Reactor Trip	$1.134 million	-$0.088 million	$1.046 million		$1.046 million
Off-System Sales Impact	$2.103 million		$2.103 million	-$1.781 million[110] to -$2.036 million	$0.067 million to $0.322 million
Offset for Costs Already Expensed				-$0.515 million	-$0.515 million
		TOTAL =	**$15.859 million + interest**	**-$7.651 million to -$7.396 million**	**$8.208 million to $8.463 million + interest**
Offset for Coal Plant Performance Against Budget				-$10.0 million	
		TOTAL =			**No Disallowance**
Offset for Coal Plant Performance Against Peer Group				-$27.492 million	
		TOTAL =			**No Disallowance**

[109] This additional offset is for the maintenance performed on Unit 2 RCPs during the October outage that prevented a later outage for RCP oil seal leakage.

[110] The minimum correction of $1,781,000 is based on Staff's admittedly incorrect assumption that all 187,000 MWh could be sold, but accepting Staff's contentions regarding the imprudence of the reactor trip and RWT outages. This correction would be larger if the Commission determines that any of the outages were not caused by imprudent actions by APS or if the RCP work during the October Unit 2 RWT outage would have resulted in a separate outage, thereby precluding off-system sales. The required deduction from the Staff's $2,103,000 figure would be: $1,834,000 (rather than the minimum $1,781,000) if the reactor trip and RWT outage are found imprudent, but the RCP maintenance is determined to have prevented a later outage; $1,848,000 if only the RWT outages are found imprudent, but $1,901,000 if the RCP maintenance performed during the RWT outage is found to have prevented a later outage; and $2,036,000 if only the reactor trip is found imprudent.

Accordingly, APS respectfully submits that the full amount of its adjusted rate request – 11.7 percent over current Company revenue from rates (including the interim PSA Adjustor) – should be approved, along with the several structural changes to the PSA proposed by the Company and in conjunction with one or more of the rate adjustment mechanisms proposed by the Company. In addition, the Base Fuel Cost should be set at 3.2491¢/kWh as proposed by the Company (and as essentially accepted by Staff). Finally, APS submits that no disallowances with respect to outages at Palo Verde in 2005 are warranted or appropriate under all the facts and circumstances presented in this case.

RESPECTFULLY SUBMITTED this 22nd day of January, 2007.

ARIZONA PUBLIC SERVICE COMPANY

By: Thomas L. Mumaw
Thomas Mumaw
Pinnacle West Capital Corp.
400 East Van Buren
Phoenix, AZ 85004-2202

Original and 17 copies filed with
Docket Control and copies mailed
January 22, 2007, to:

Donna Bronski
Deputy City Attorney
3939 Drinkwater Blvd.
Scottsdale, AZ 85251

S. David Childers
AZ Competitive Power Alliance
Low & Childers, PC
2999 North 44th St., Suite 250
Phoenix AZ 85018

C. Webb Crockett
AECC & Phelps Dodge Mining
3003 N. Central Ave., Ste 2600
Phoenix, AZ 85012-2913

Michael M. Grant
Arizona Utility Investors Assoc,
c/o Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, AZ 85016

Timothy Hogan
SWEEP & WRA
202 E. McDowell Rd., Ste 153
Phoenix, AZ 85004

Jay I. Moyes
AZAG Group
c/o Moyes Storey Ltd.
1850 N. Central Ave., Ste 1100
Phoenix, AZ 85004

Bill Murphy
DEAA
5401 N. 25 St.
Phoenix, AZ 85016

Greg Patterson
AZ Competitive Power Alliance
916 W. Adams, Suite 3
Phoenix, AZ 85007

Lawrence Robertson, Jr.
Southwest Power Group II
c/o Munger Chadwick
PO Box 1448
Tubac, AZ 85646

Sean Seitz, President
AZ Solar Energy Industries Assoc.
3008 N. Civic Center Plaza
Scottsdale AZ 85251

Tracy Spoon
Sun City Taxpayers Association
12630 N. 103rd Ave., Suite 144
Sun City, AZ 85351-3476

Scott Wakefield
Chief Counsel, RUCO
1110 W. Washington St, Suite 220
Phoenix, AZ 85007

LTC Karen White
Chief. Air Force Utility Litig. Team
Federal Executive Agencies
139 Barnes Drive
Tyndall AFB, Florida 32403

Dan Austin
Comverge, Inc.
6509 W. Frye Road, Ste 4
Chandler, AZ 85226

David Berry
Western Resource Advocates
PO Box 1064
Scottsdale AZ 85252-1064

Andrew W. Bettwy
Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, NV 89150

George Bien-Willner
3641 N. 39th Ave.
Phoenix, AZ 85034

Douglas Fant
3655 W. Anthem Way
Suite A-109, PMB 411

Robert Geake
Arizona Water Company
PO Box 29006
Phoenix, AZ 85038-9006

Eric Guidry
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, CO 80302

Michael Kurtz
The Kroger Company
c/o Boehm Kurtz & Lowry
36 E. Seventh St, Suite 1510
Cincinnati, OH 45202

Michelle Livengood
Unisource Energy Services
One South Church St., Ste. 200
Tucson, AZ 85702

Gary Yaquinto
Arizona Utility Investors Association
2100 N. Central Ave., Suite 210
Phoenix, AZ 85004

Amanda Ormond
InterWest Energy Alliance
7650 West McClintock, Suite 103-282
Tempe, AZ 85284

Michael Patten
Roshka DeWulf & Patten, PLC
One Arizona Center
400 E. Van Buren St., Suite 800
Phoenix, AZ 85004-3906

Jeff Schlegel
SWEEP Arizona
1167 W. Samalayuca Drive
Tucson, AZ 85704-3224

Kenneth R. Saline
K.R. Saline & Associates PLC
160 North Pasadena, Ste. 101
Mesa, AZ 85201

Tammie Woody
10825 W. Laurie Lane
Peoria, AZ 85345

David Kennedy
Arizona Interfaith Coalition on Energy
818 E. Osborn Road, Ste. 103
Phoenix AZ 85014

Joseph Knauer
Jewish Community of Sedona
PO Box 10242
Sedona, AZ 86339

Birdie Cobb

Birdie Cobb

Table of Authorities
for
Initial Post-Hearing Brief
of
Arizona Public Service Company

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Docket No. E-01345A-05-0827

A. STATUTES

1. ARIZ. REV. STAT. § 42-14156.

2. ARIZ. REV. STAT. § 41-1276(I).

3. IND. CODE § 8-1-8.8-1.

4. IND. CODE § 8-1-27 *et seq.*

5. Energy Policy Act of 2005 ("EPAct 2005"), Pub. L. No. 109-58 § 1252(a), 119 Stat. 963 (codified as amended at 16 U.S.C. § 2621(d)(2005)).

6. FLA. STAT. § 366.8255.

7. KY. REV. STAT. § 278.183.

8. W. VA. CODE § 24-2-1g.

B. ADMINISTRATIVE CODES AND RULES

1. ARIZ. ADMIN. CODE R14-2-103(A)(3)(l).

2. ARIZ. ADMIN. CODE R14-2-212(G)(2).

3. ARIZ. ADMIN. CODE R14-2-1615.

4. ARIZ. ADMIN. CODE R14-2-1618.

5. WATER DIVISION, CALIFORNIA PUBLIC UTILITIES COMMISSION, STANDARD PRACTICE U-16-W, DETERMINATION OF WORKING CASH ALLOWANCE (May 16, 2002).

C. ADMINISTRATIVE DECISIONS

Arizona:

1. Decision No. 54204 (Oct. 11, 1984).
2. Decision No. 54247 (Nov. 28, 1984).
3. Decision No. 55118 (July 24, 1986).
4. Decision No. 55120 (July 24, 1986).
5. Decision No. 55228, 77 P.U.R. 4th 542 (Oct. 9, 1986).
6. Decision No. 58497, 149 P.U.R. 4th 251 (Jan. 12, 1994).
7. Decision No. 58644 (June 1, 1994).
8. Decision No. 59601 (Apr. 24, 1996).
9. Decision No. 67744 (Apr. 7, 2005) (with Settlement Agreement).
10. Decision No. 68437 (Feb. 2, 2006).
11. Decision No. 68566 (Mar. 14, 2006).
12. Decision No. 68685 (May 5, 2006).

Other Jurisdictions:

13. *DPUC Review of the United Illuminating Company's Rate Filing and Rate Plan Proposal*, State of Connecticut Department of Public Utility Control, Docket No. 01-10-10 (Sept. 26, 2002).
14. *In re Application of South Carolina Electric & Gas Company for Adjustments in the Company's Electric Rate Schedule and Tariffs,* Public Service Commission of South Carolina, Docket No. 88-681-E, Order No. 89-588 (July 3, 1989).
15. *In re Commonwealth Edison Co.*, 1982 Ill. PUC Lexis 33 (May 6 1982).
16. *In re Public Service Co. of Indiana*, 72 P.U.R. 4th 660 (Mar. 7 1986).
17. *ISO New England Inc.*, 117 F.E.R.C. P61,070 (Oct. 19, 2006).
18. *New Eng. Power Co.*, 31 F.E.R.C. P61,047 (1985).

19. *Providence Gas Company v. Edward Burman et. al.*, 22 P.U.R. 4th 103, 119 R.I. 78, 376 A.2d 687 (1977).

20. *In re Florida Power Corporation,* 138 P.U.R. 4th 472 (Oct. 22, 1992).

21. *In re GA. Power Co.*, 120 P.U.R. 4th 621 (Sept. 28, 1989).

22. *In re Hoosier Energy Rural Elec. Coop., Inc.*, 62 P.U.R. 4th 134 (June 29, 1984).

23. *In re Ind.-Am. Water Co., Inc.*, 169 P.U.R. 4th 252 (May 30, 1996).

24. *In re Intermountain Gas Co.,* 30 P.U.R. 4th 231 (Aug. 17, 1979).

25. *In re Kan. City Power and Light Co.*, 55 P.U.R. 4th 468 (July 8, 1983).

26. *In re Sierra Pac. Power Co.*, 129 P.U.R. 4th 470 (Jan. 31, 1992).

27. *Wisconsin Power Co.*, 73 F.E.R.C. P63,019 (1995).

28. *Wisconsin Power Co.*, 98 F.E.R.C. P61,233 (2002).

29. *In re The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado for Advice Letter No. 1454- Electric and Advice Letter No. 671-Gas*, Colorado Public Utilities Commission, Docket No. C06S-234EG, Decision No. C06-1379 (Nov. 20, 2006).

30. *In re Proposed Regulatory Plan of Kansas City Power & Light Co.*, Missouri Public Service Commission, Case No. EO-2005-0329 (July 28, 2005).

D. CASE LAW

Arizona:

1. *Residential Utility Consumer Office v. Arizona Corp. Comm'n,* 199 Ariz. 588, 20 P.3d 1169 (App. 2001).

2. *Scates v. Arizona Corp. Comm'n*, 118 Ariz. 531, 578 P.2d 612 (Ariz. App. 1978).

United States Supreme Court:

3. *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923).

4. *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1942).

Other Jurisdictions:

5. *Kentucky Industrial Utility Customers, Inc. v. Kentucky Pub. Serv. Comm'n,* 983 S.W.2d 493, 1998 Ky. LEXIS 165 (Dec. 1998).

6. *Public Serv. Co. of Colo. v. Pub. Utilities Commission of Colo.*, 653 P.2d 1117 (Colo. Sup. Ct. 1982).

7. *Violet v. F.E.R.C.*, 800 F.2d 280 (1st Cir. 1986).

E. TREATISES

1. ROBERT L. HAHNE & GREGORY E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES § 5.02 (1990).

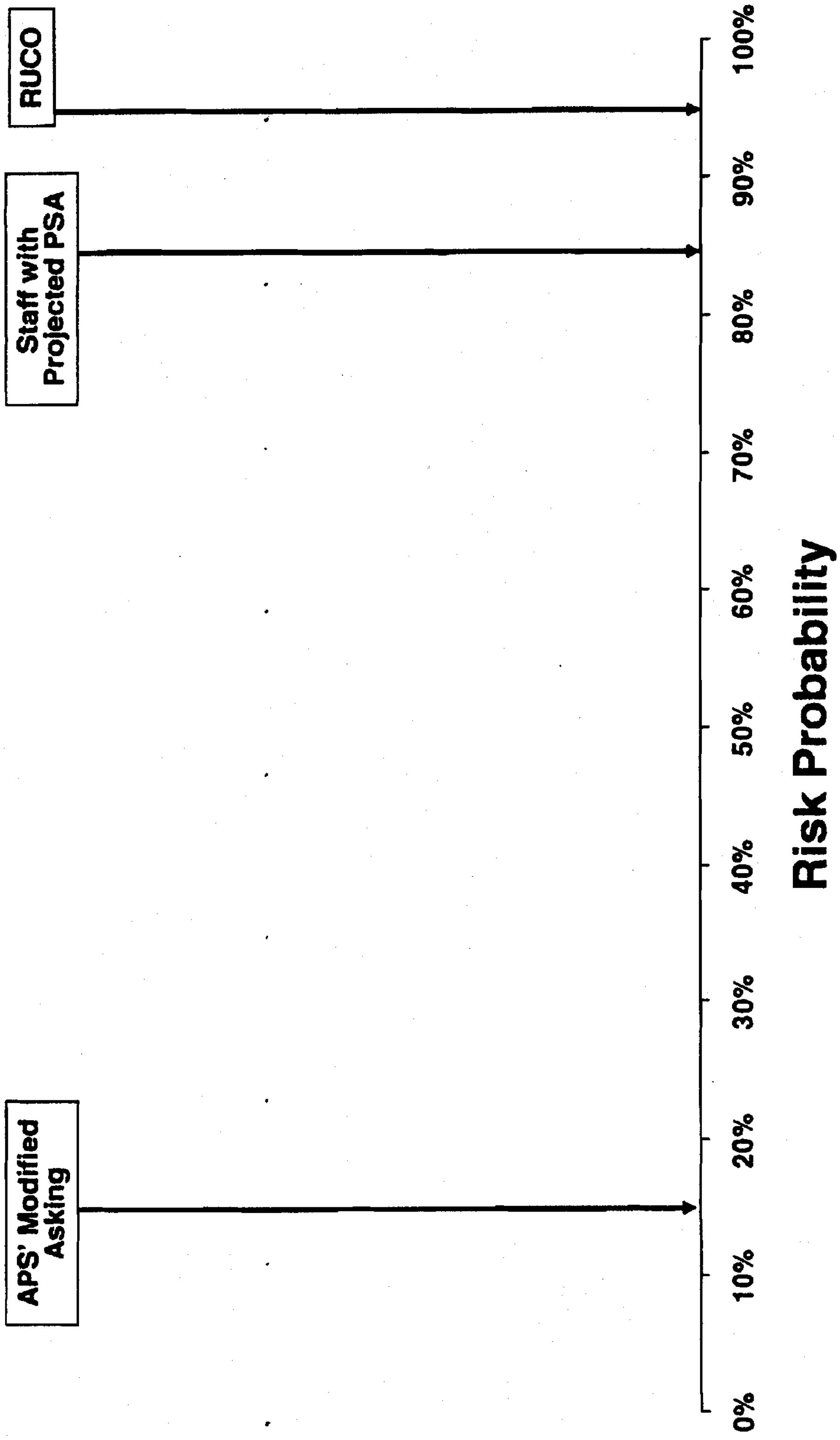
REJOINDER A-1
Submitted 10/30/06

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

		Electric - APS Rejoinder			
Line No.	Description	Original Cost	RCND	Fair Value	Line No.
1	**Adjusted Rate Base** 1/	**4,456,937**	**7,765,052**	**6,110,995**	1
2	Adjusted Operating Income 2/	129,539	129,539	129,539	2
3	Current Rate of Return	2.91%	1.67%	2.12%	3
4	Required Operating Income	389,091	389,091	389,091	4
5	**Required Rate of Return** 3/	**8.73%**	**5.01%**	**6.37%**	5
6	Operating Income Deficiency	259,552	259,552	259,552	6
7	Gross Revenue Conversion Factor 4/	1.6407	1.6407	1.6407	7
8	Adjusted Increase in Base Revenue Requirements	425,847	425,847	425,847	8
9	Environmental Improvement Charge 5/	4,542	4,542	4,542	9
10	Environmental Portfolio Standard 6/	4,250	4,250	4,250	10
11	**Total Increase in Revenue Requirement** 7/	**434,639**	**434,639**	**434,639**	11
12	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322	12
13	**Percentage Rate Increase**	**20.43%**	**20.43%**	**20.43%**	13

1/ Rebuttal Testimony of APS Witness Rockenberger, Attachment LLR-3-1RB, page 1.
2/ APS Exhibit 53, page 2 of 3 (Schedule C-1, as adjusted in Rebuttal Testimony of APS Witness Froggatt, Attachment CNF-1RB, page 2, with rejoinder adjustments).
3/ SFR Schedule D-1 page 1 of 2, filed 1/31/06.
4/ SFR Schedule C-3, filed 1/31/06.
5/ Rebuttal Workpapers of APS Witness DeLizio, GAD_WP4RB, page 1.
6/ Rebuttal Testimony of APS Witness DeLizio, page 6.
7/ As discussed in Rejoinder Testimony of APS Witness Wheeler, page 2. This is a reduction in revenue requirement of $16.8 million from the rebuttal revenue requirement shown in the Rebuttal Testimony of APS Witness Wheeler, Attachment SMW-1RB.

Arizona Public Service Company
Risk of Credit Rating Downgrade to Junk



22 December 2006
Americas/United States
Equity Research
Electric Utilities (Regulated Utilities) / UNDERWEIGHT

CREDIT SUISSE

Great Plains Energy (GXP)

Rating	UNDERPERFORM*
Price (21 Dec 06)	31.55 (US$)
Target price (12M)	(from 29.00) 30.00 (US$)
52 week high - low	32.80 - 27.33
Market cap. (US$ m)	2,526.6
Enterprise value (US$ m)	3,690.1

** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.*

Research Analysts
Dan Eggers, CFA
713 890 1659
dan.eggers@credit-suisse.com
Samantha Dennison
713 890 1661
samantha.dennison@credit-suisse.com

COMPANY UPDATE

All that I Want for Christmas

Last night the MO PSC issued a constructive order in KCP&L's rate case adopting an 11.25% ROE / 53.7% equity ratio vs. ask of 11.5% / 53.8% and staff testimony at 9.32-9.42% / 50.9%. The commission did not specify the rate change, which is expected in a few days. Further, the 11.25% ROE includes a 25 bps adder to reflect construction risk and allows KCP&L to keep off system sales for '07.

We are somewhat amazed the company got virtually all that it asked for. To GXP's credit, the company has done a better job managing the regulatory process than we originally anticipated.

We are raising our '07 EPS estimate to $2.25 from $2.15 to reflect the better than expected outcome in MO. Our updated estimates through '12 reflect a 25% increase in capex costs over '05 10-K disclosed amounts and a normalization of ROEs to 10.5% (industry average) going forward.

As a result of estimate increases, we are raising our target price by $1 to $30. If KCP&L were to maintain better than average regulatory relations in MO and KS with 11% ROEs over the medium term instead of our normalized 10.5% assumption, earnings could increase by $0.10-0.15 providing for $2-2.50 of support above our updated $30 target.

While we continue to like GXP's investment program, we remain concerned that the lift is already priced into the stock. Maintain Underperform.

Share price performance

On 12/21/06 the S&P 500 index closed at 1,418.30

Quarterly EPS	Q1	Q2	Q3	Q4
2005A	0.27	0.34	1.04	0.58
2006E	0.33	0.54	0.71	0.43
2007E				

Financial and valuation metrics

Year	12/05A	12/06E	12/07E
EPS (CS adj., US$)	2.23	2.01	2.25
Prev. EPS (US$)			2.15
P/E (x)	14.2	15.7	14.0
P/E rel. (%)	78.2	99.9	102.2
Revenue (US$ m)	2,604.9	—	—
EBITDA (US$ m)	441.2	450.2	493.1
OCFPS (US$)	5.59	4.99	4.27
P/OCF (x)	5.0	6.3	7.4
EV/EBITDA (current)	7.9	8.0	7.7
Net debt (12/05A, US$ m)	1,077.4	1,155.7	1,392.0
ROIC	—	—	—

Number of shares (m)	80	IC (current, US$ m)	—
BV/share (current, US$)	16.62	EV/IC (x)	—
Net debt (current, US$ m)	1,163.6	Dividend (current, US$)	1.66
Net debt/Total cap. (current)	46.6%	Dividend yield	5.3%

Source: Company data, Credit Suisse estimates

CREDIT SUISSE

Exhibit 1: **GXP Income Statement**

	2005A	Q106A	Q206A	Q306A	Q406E	2006E	2007E	2008E	2009E	2010E	2011E
Gross Margin	**972**	**216**	**250**	**283**	**227**	**976**	**1,026**	**1,001**	**1,035**	**1,071**	**1,188**
Other Operating Expenses	528	126	132	140	129	527	534	541	547	556	567
Loss on Property	4	0	(1)	0	(0)	(1)	(1)	(1)	(1)	(1)	(1)
EBITDA	**441**	**90**	**118**	**143**	**99**	**450**	**493**	**461**	**489**	**516**	**622**
D&A	153	39	39	40	41	160	170	172	176	178	194
Operating Income	**288**	**51**	**79**	**103**	**58**	**290**	**323**	**289**	**313**	**338**	**428**
Other Income / (Expense)	2	0	2	1	1	4	(1)	(1)	(1)	(1)	(1)
AFUDC - Other	1	0	1	1	7	9	26	36	40	45	9
Interest Charges	74	18	18	19	19	74	84	104	112	122	130
Interest Rate	*6.9%*	*6.5%*	*6.5%*	*11.2%*	*6.6%*	*6.6%*	*6.6%*	*7.0%*	*6.8%*	*6.8%*	*6.8%*
AFUDC - Borrowed	1	0	1	1	3	5	16	25	29	33	6
Pre Tax Income	**218**	**34**	**64**	**86**	**50**	**234**	**281**	**245**	**269**	**293**	**312**
Income Tax	42	9	21	29	15	74	87	75	83	92	100
Tax Rate	*19%*	*26%*	*34%*	*33%*	*30%*	*32%*	*31%*	*31%*	*31%*	*32%*	*32%*
Minority Interest	8	0	0	0	0	0	0	0	0	0	0
Equity Investments, net of tax	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)
Preferred Dividends	2	0	0	0	0	2	2	2	2	2	2
Recurring Net Income	**166**	**24**	**42**	**57**	**34**	**157**	**191**	**168**	**183**	**198**	**210**
MTM Gains / (Losses)	(3)	(21)	(1)	(16)	0	(38)	0	0	0	0	0
Other Non Recurring Items	(3)	(6)	(3)	14	0	5	0	0	0	0	0
Reported Net Income	161	(3)	37	55	34	124	191	168	183	198	210
Recurring EPS	**2.23**	**0.33**	**0.54**	**0.71**	**0.43**	**2.01**	**2.25**	**1.89**	**1.94**	**2.08**	**2.18**
Growth	*-8.1%*	*22.8%*	*61.2%*	*-32.2%*	*-26.5%*	*-9.6%*	*11.7%*	*-16.1%*	*2.8%*	*7.0%*	*5.1%*
Diluted Shares Outstanding	75	75	77	80	80	78	85	89	94	95	96
Share Price		28.44	28.25	29.91	31.92	29.63	32.73	34.06	35.44	36.88	36.88
Dividends Per Share	**1.66**	**0.42**	**0.42**	**0.42**	**0.42**	**1.66**	**1.66**	**1.66**	**1.66**	**1.66**	**1.66**
Payout Ratio	*74%*	*127%*	*77%*	*59%*	*97%*	*82%*	*74%*	*88%*	*86%*	*80%*	*76%*
EPS Breakdown											
KCP&L	1.92	0.24	0.44	0.70	0.41	1.81	2.27	1.93	1.95	2.08	2.20
Strategic	0.42	0.14	0.07	0.07	0.05	0.31	0.15	0.16	0.18	0.19	0.19
Other	(0.09)	(0.04)	0.04	(0.05)	(0.03)	(0.09)	(0.16)	(0.18)	(0.17)	(0.17)	(0.19)
Total	2.23	0.33	0.54	0.71	0.43	2.01	2.25	1.89	1.94	2.08	2.18

Source: Company data, Credit Suisse estimates

Exhibit 2: **GXP Balance Sheet**

Balance Sheet	2005A	Q106A	Q206A	Q306A	Q406E	2006E	2007E	2008E	2009E	2010E	2011E
Cash and Equivalents	103	88	96	59	59	59	59	59	59	59	59
Total Accounts Receivable	128	154	130	207	116	116	121	124	130	134	148
Unbilled Revenues	131	88	160	148	119	119	124	128	133	138	152
Inventories	74	79	88	85	72	72	72	76	78	81	90
Other	55	49	65	66	66	66	66	66	66	66	66
Total Current Assets	491	457	539	565	432	432	443	453	466	478	516
PP&E	4,960	4,999	5,050	5,224	5,336	5,336	5,954	6,604	6,915	7,342	7,539
Construction Work in Progress	101	124	220	160	170	170	213	275	344	423	438
Net Nuclear Fuel	28	35	41	38	38	38	38	38	38	38	38
Accumulated Depreciation	2,323	2,355	2,392	2,424	2,465	2,465	2,635	2,806	2,982	3,160	3,354
Net PP&E	2,766	2,803	2,919	2,998	3,080	3,080	3,571	4,109	4,314	4,642	4,661
Investment in Partnerships	28	26	25	24	24	24	24	24	24	24	24
Nuclear Decommissioning Trust	92	95	95	99	99	99	99	99	99	99	99
Other Investments	17	17	16	15	15	15	15	15	15	15	15
Intangible Assets	109	88	88	88	88	88	88	88	88	88	88
Other	331	332	339	325	325	325	325	325	325	325	325
Total Assets	3,834	3,819	4,021	4,115	4,063	4,063	4,564	5,113	5,332	5,671	5,727
ST and Current LT Debt	40	464	472	471	471	471	471	471	471	471	471
Accrued Interest Payable	13	13	14	14	12	12	12	13	13	14	15
Income Taxes Payable	38	42	61	97	41	41	40	42	43	45	50
Other Acc'ts Payable & Accrued Exp.	276	249	260	309	309	309	309	309	309	309	309
Energy Risk Mgm't Liabilities	0	0	0	0	0	0	0	0	0	0	0
Other	35	56	75	106	106	106	106	106	106	106	106
Total Current Liabilities	403	824	882	996	938	938	937	940	942	944	950
Postretirement Benefits	87	88	90	90	90	90	90	90	90	90	90
Deferred Income Tax Liability	621	610	608	583	583	583	583	583	583	583	583
Deferred Tax Credit	30	29	28	27	37	37	77	117	157	197	237
LT Debt	1,141	752	751	752	744	744	981	1,163	1,310	1,464	1,521
Other	289	302	318	335	333	333	336	340	343	346	350
Total Liabilities	2,571	2,605	2,678	2,783	2,726	2,726	3,005	3,233	3,425	3,625	3,731
Total Preferred Equity	39	39	39	39	39	39	39	39	39	39	39
Common Equity	1,223	1,175	1,304	1,292	1,298	1,298	1,521	1,841	1,867	2,007	1,957
Total Equity	1,262	1,214	1,343	1,331	1,337	1,337	1,560	1,880	1,906	2,046	1,996
Balance	0	0	0	0	0	0	0	0	0	0	0
Total Debt	1,180	1,216	1,223	1,223	1,215	1,215	1,451	1,634	1,781	1,935	1,991
Net Debt	1,077	1,128	1,127	1,164	1,156	1,156	1,392	1,575	1,721	1,875	1,932
Total Debt / Cap	48%	50%	48%	48%	48%	48%	48%	46%	48%	49%	50%
Net Debt / Cap	46%	48%	46%	47%	46%	46%	47%	46%	47%	48%	49%
Total Cap	2,443	2,430	2,567	2,554	2,552	2,552	3,011	3,514	3,687	3,980	3,987
FFO	421	65	87	131	75	357	374	334	346	353	445
FFO / Debt	34%	35%	65%	38%	29%	29%	28%	20%	20%	18%	22%
FFO Interest Coverage	5.7	5.7	5.9	6.1	4.8	4.8	4.4	3.2	3.1	2.9	3.4

Source: Company data, Credit Suisse estimates

Exhibit 3: **GXP Cash Flow Statement**

Cash Flow Statement	2005A	Q106A	Q206A	Q306A	Q406E	2006E	2007E	2008E	2009E	2010E	2011E
Net Income	162	(2)	38	55	34	125	191	168	183	198	210
D&A	177	45	46	47	41	178	170	172	176	178	194
Def. Taxes and Inv. Tax Credits	(27)	(18)	(1)	(17)	10	(25)	40	40	40	40	40
Changes in Working Capital	(4)	(8)	(32)	(4)	76	32	(11)	(7)	(12)	(9)	(32)
AFUDC					(10)	(10)	(43)	(61)	(69)	(79)	(15)
Other	109	40	4	46	-	90	16	16	16	16	16
Operating Cash Flow	**417**	**57**	**55**	**127**	**150**	**389**	**362**	**327**	**334**	**344**	**413**
Capex	(327)	(74)	(156)	(141)	(112)	(483)	(618)	(649)	(311)	(427)	(198)
Asset Purchases	(22)	(2)	(1)	(1)		(4)	0	0	0	0	0
Asset Sales	17	0	0	0		0	0	0	0	0	0
Other	4	(3)	(3)	13		8	0	0	0	0	0
Investing Cash Flow	**(328)**	**(78)**	**(160)**	**(128)**	**(112)**	**(479)**	**(618)**	**(649)**	**(311)**	**(427)**	**(198)**
Net Change in ST Debt	18	36	9	(2)		43	0	0	0	0	0
Net Change in LT Debt	(5)	0	(1)	0	(8)	(9)	236	182	147	154	57
Net Preferred Issues	0	0	0	0		0	0	0	0	0	0
Net Common Issues	9	3	147	2	5	157	173	300	0	100	(100)
Dividends Paid to Shareholders	(125)	(32)	(34)	(34)	(33)	(132)	(141)	(148)	(157)	(158)	(160)
Other	(10)	(1)	(7)	(2)	(2)	(13)	(13)	(13)	(13)	(13)	(13)
Financing Cash Flow	**(114)**	**5**	**114**	**(35)**	**(38)**	**46**	**255**	**322**	**(22)**	**83**	**(215)**
Other Cash Flow	0	0	0	0	0	0	0	0	0	0	0
Net Change in Cash	**(25)**	**(16)**	**9**	**(37)**	**0**	**(44)**	**0**	**0**	**0**	**0**	**0**
Beginning Cash	127	103	88	96	59	103	59	59	59	59	59
Ending Cash	**102**	**88**	**96**	**59**	**59**	**59**	**59**	**59**	**59**	**59**	**59**

Source: Company data, Credit Suisse estimates

Companies Mentioned *(Price as of 21 Dec 06)*
Great Plains Energy (GXP, $31.55, UNDERPERFORM, TP $30.00, UNDERWEIGHT)

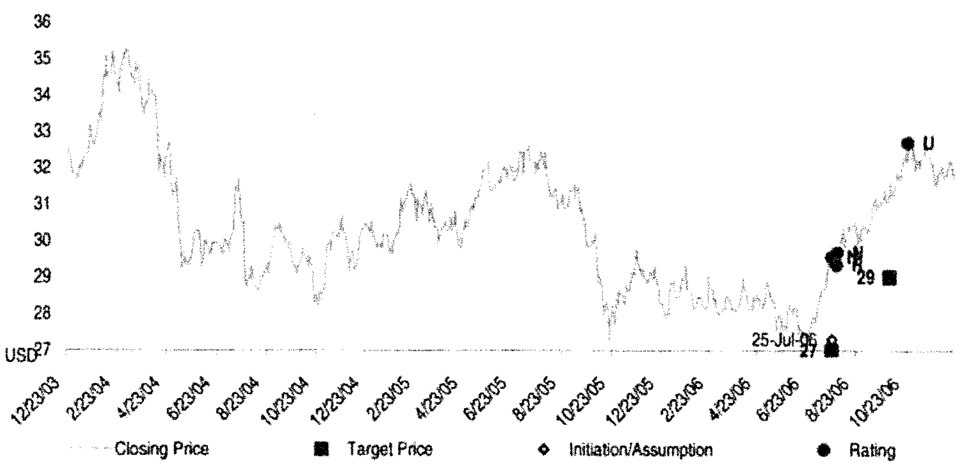
Disclosure Appendix

Important Global Disclosures

I, Dan Eggers, CFA, certify that (1) the views expressed in this report accurately reflect my personal views about all of the subject companies and securities 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 report.

See the Companies Mentioned section for full company names.

3-Year Price, Target Price and Rating Change History Chart for GXP



O=Outperform; N=Neutral; U=Underperform; R=Restricted; NR=Not Rated; NC=Not Covered

GXP Date	Closing Price Price (US$)	Target Price Price (US$)	Rating	Initiation/ Assumption
7/25/06	29.54	27	NEUTRAL	X
7/31/06	29.33		RESTRICTED	
8/1/06	29.66		NEUTRAL	
10/3/06	31.36	29		
10/25/06	32.7		UNDERPERFORM	

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Neutral: The stock's total return is expected to be in line with the industry average* (range of ±10%) over the next 12 months.

Underperform:** The stock's total return is expected to underperform the industry average* by 10-15% or more over the next 12 months.

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Market Weight: Industry expected to perform in-line with the relevant broad market benchmark over the next 12 months.

Underweight: Industry expected to underperform the relevant broad market benchmark over the next 12 months.

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Underperform/Sell*	15%	(52% banking clients)
Restricted	3%	

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Price Target: (12 months) for (GXP)

Method: We reach our $30 target price on Great Plains Energy primarily via a discounted cash flow model for each business unit and assumes 1% terminal growth. We use a 6.9% discount rate, in line with the broader Utility group rate. Additionally, we back up our valuation work using a dividend discount model to take into account GXP's healthy dividend, and traditional multiples.

Risks: Risks to our $30 target price on Great Plains Energy include: (1) regulatory overhang. While KCP&L has already received prudence approval for its capital program, regulatory overhang will remain a primary risk since absolute dollars spent will most likely require annual rate case fillings to receive timely recovery of capex spent. (2) volume growth at Strategic Energy. To reach GXP's overall earnings growth targets, Strategic will need to show modest levels of earnings growth. (3) interest rate exposure. As more of a pure play regulated utility with a robust dividend, GXP will be exposed to movements in interest rates with its yield support at risk.

See the Companies Mentioned section for full company names.

The subject company (GXP) currently is, or was during the 12-month period preceding the date of distribution of this report, a client of Credit Suisse.
Credit Suisse provided investment banking services to the subject company (GXP) within the past 12 months.
Credit Suisse provided non-investment banking services, which may include Sales and Trading services, to the subject company (GXP) within the past 12 months.
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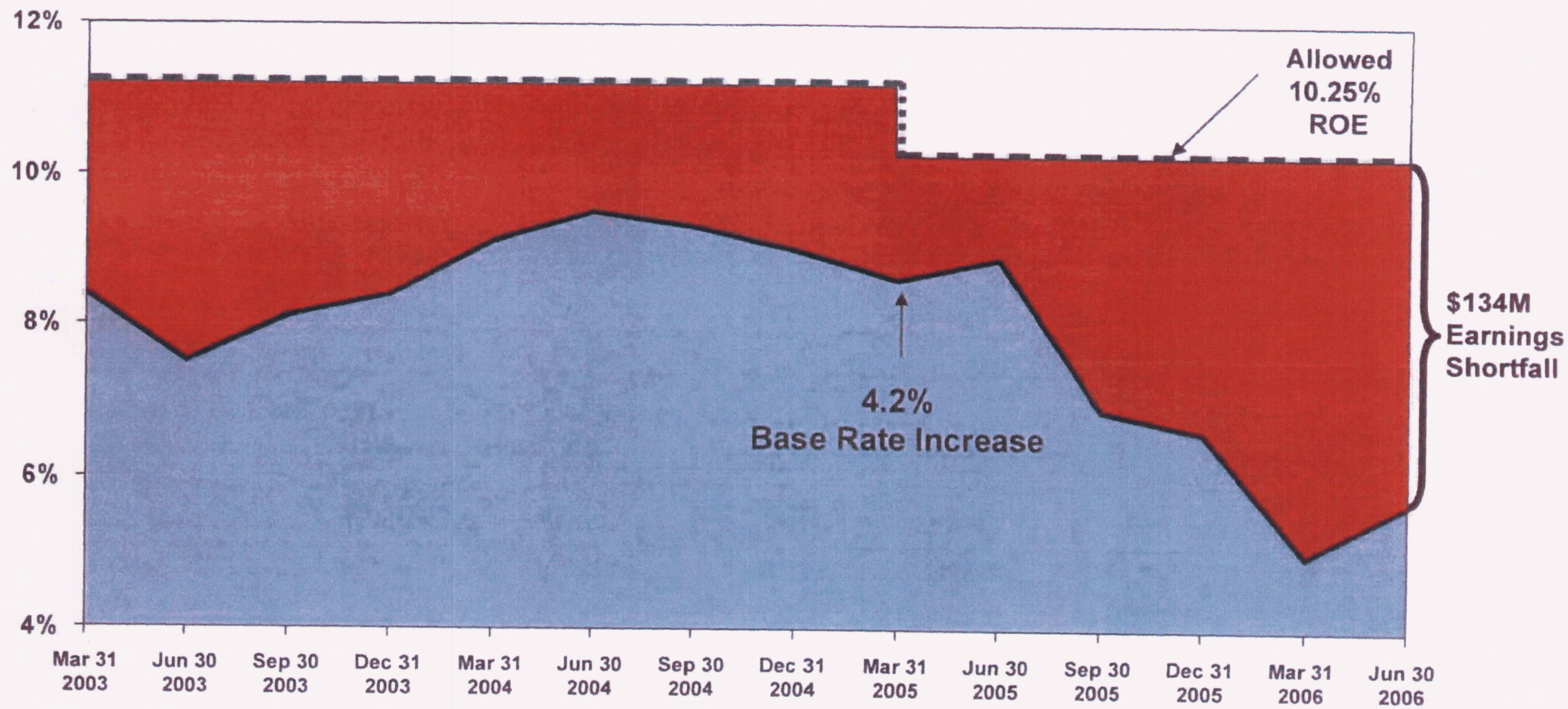
Arizona Public Service Company
Return on Equity
Twelve-Month Periods Ended March 31, 2003 to June 30, 2006



FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE B-1
Page 1 of 2

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Test Year Ended 9/30/2005
(Dollars in Thousands)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year [a] (A)	Pro Forma [b] (B)	Adjusted Test Year (C)	Unadjusted Test Year [c] (D)	Pro Forma [d] (E)	Adjusted Test Year (F)	Line No.
1.	Gross Utility Plant in Service	$ 10,818,902	$ 38,296	$ 10,857,198	$ 9,222,352	$ 37,695	$ 9,260,047	1.
2.	Less: Accumulated Depreciation & Amort.	4,170,525	(38,669)	4,131,856	3,548,546	(38,247)	3,510,299	2.
3.	Net Utility Plant in Service	6,648,377	76,965	6,725,342	5,673,806	75,942	5,749,748	3.
	Deductions:							
4.	Deferred Taxes	1,203,998	1,766	1,205,764	1,062,993	1,903	1,064,896	4.
5.	Investment Tax Credits	-	-	-	-	-	-	5.
6.	Customer Advances for Construction	59,807	-	59,807	59,807	-	59,807	6.
7.	Customer Deposits	54,860	-	54,860	54,860	-	54,860	7.
8.	Pension Liability	72,920	-	72,920	68,699	-	68,699	8.
9.	Liability for Asset Retirement	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	10.
11.	Unamortized Gain-sale of Utility Plant	46,901	-	46,901	46,360	-	46,360	11.
12.	Regulatory Liabilities	168,048	-	168,048	160,744	-	160,744	12.
13.	Total Deductions	1,981,782	8,142	1,989,924	1,823,367	7,910	1,831,277	13.
	Additions:							
14.	Regulatory Assets	88,046	(3,515)	84,531	67,380	(3,360)	64,020	14.
15.	Miscellaneous Deferred Debits	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	16.
17.	Allowance for Working Capital	168,146	(5,019)	163,127	152,433	(4,344)	148,089	17.
18.	Total Additions	589,251	(7,496)	581,755	545,132	(6,666)	538,466	18.
19.	Total Rate Base	$ 5,255,846	$ 61,327	$ 5,317,173	$ 4,395,571	$ 61,366	$ 4,456,937	19.

NOTES:
[a] For Column (A) amounts, see Column (A) of Standard Filing Requirement Schedule B-1, page 1 of 2, filed January 31, 2006.
[b] For Column (B) amounts, see APS Closing Brief Exhibit 5, Schedule B-2, Column 8(O).
[c] For Column (D) amounts, see Column (D) of Standard Filing Requirement Schedule B-1, page 1 of 2, filed January 31, 2006.
[d] For Column (E) amounts, see APS Closing Brief Exhibit 5, Schedule B-2, Column 8(P).

Amounts in columns (B) and (E) are the sum of all rate base adjustments proposed by APS in its direct, rebuttal, and rejoinder testimony and reflect APS' final position on each issue.

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Test Year Ended 9/30/2005
(Dollars in Thousands)

		RCND						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year [a] (A)	Pro Forma [b] (B)	Adjusted Test Year (C)	Unadjusted Test Year [c] (D)	Pro Forma [d] (E)	Adjusted Test Year (F)	Line No.
1.	Gross Utility Plant in Service	$ 17,767,330	$ 11,877	$ 17,779,207	$ 15,145,398	$ 11,581	$ 15,156,979	1.
2.	Less: Accumulated Depreciation & Amort.	7,243,608	(64,911)	7,178,697	6,163,319	(64,186)	6,099,133	2.
3.	Net Utility Plant in Service	10,523,722	76,788	10,600,510	8,982,079	75,767	9,057,846	3.
	Deductions:							
4.	Deferred Taxes	1,203,998	1,749	1,205,747	1,062,993	1,886	1,064,879	4.
5.	Investment Tax Credits	-	-	-	-	-	-	5.
6.	Customer Advances for Construction (c)	59,807	-	59,807	59,807	-	59,807	6.
7.	Customer Deposits	54,860	-	54,860	54,860	-	54,860	7.
8.	Pension Liability	72,920	-	72,920	68,699	-	68,699	8.
9.	Liability for Asset Retirement	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	10.
11.	Unamortized Gain-sale of Utility Plant	46,901	-	46,901	46,360	-	46,360	11.
12.	Regulatory Liabilities	168,048	-	168,048	160,744	-	160,744	12.
13.	Total Deductions	1,981,782	8,125	1,989,907	1,823,367	7,893	1,831,260	13.
	Additions:							
14.	Regulatory Assets	88,046	(3,515)	84,531	67,380	(3,360)	64,020	14.
15.	Miscellaneous Deferred Debits	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	16.
17.	Allowance for Working Capital (d)	168,146	(5,019)	163,127	152,433	(4,344)	148,089	17.
18.	Total Additions	589,251	(7,496)	581,755	545,132	(6,666)	538,466	18.
19.	Total Rate Base	$ 9,131,191	$ 61,167	$ 9,192,358	$ 7,703,844	$ 61,208	$ 7,765,052	19.

NOTES: [a] For Column (A) amounts, see Column (A) of Standard Filing Requirement Schedule B-1, page 2 of 2, filed January 31, 2006
[b] For Column (B) amounts, see APS Closing Brief Exhibit 5, Schedule B-3, Column 8(O).
[c] For Column (D) amounts, see Column (D) of Standard Filing Requirement Schedule B-1, page 2 of 2, filed January 31, 2006
[d] For Column (E) amounts, see APS Closing Brief Exhibit 5, Schedule B-3, Column 8(P).

Amounts in Columns (B) and (E) are the sum of all rate base adjustments proposed by APS in its direct, rebuttal, and rejoinder testimony and reflect APS' final position on each issue.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE B-2
Page 1 of 3

		(1)		(2)		(3)	
		Actual at End of Test Year 9/30/2005		Regulatory Disallowance for West Phoenix Unit 4		Spent Fuel Storage	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service (a)	$ 10,818,902	$ 9,222,352	$ (13,833)	$ (13,833)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort. (a)	4,170,525	3,548,546	(2,032)	(2,032)	-	-
3.	Net Utility Plant in Service (a)	6,648,377	5,673,806	(11,801)	(11,801)	-	-
4.	Less: Total Deductions	1,981,782	1,823,367	(646)	(646)	(3,761)	(3,700)
5.	Total Additions	589,251	545,132	-	-	(9,630)	(9,475)
6.	Total Rate Base	$ 5,255,846	$ 4,395,571	$ (11,155)	$ (11,155)	$ (5,869)	$ (5,775)

(1) For Column (A) amounts, see Column (A) of Standard Filing Requirement Schedule B-2, page 1 of 3, filed January 31, 2006.
For Column (B) amounts, see Column (B) of Standard Filing Requirement Schedule B-2, page 1 of 3, filed January 31, 2006.

(2) Adjustment to reduce Test Year rate base for the regulatory disallowance for West Phoenix Unit 4 as required in Decision No. 67744.
For Column (C) amounts, see APS Exhibit 56 at Attachment LLR-1-2 [Rockenberger Direct].

(3) Adjustment to Test Year rate base to include System Benefit related Interim Spent Fuel Storage costs consistent with Decision No. 67744.
For Column (E) amounts, see APS Exhibit 56 at Attachment LLR-1-3 [Rockenberger Direct].

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE B-2
Page 2 of 3

		(4)		(5)		(6)	
		Palo Verde Unit 1 Steam Generators		Bark Beetle Regulatory Asset		Long Term Disability (SFAS 112)	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service (a)	$ 52,129	$ 51,528	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort. (a)	(36,637)	(36,215)	-	-	-	-
3.	Net Utility Plant in Service (a)	88,766	87,743	-	-	-	-
4.	Less: Total Deductions	5,870	5,802	2,793	2,793	3,886	3,661
5.	Total Additions	-	-	7,153	7,153	-	-
6.	Total Rate Base	$ 82,896	$ 81,941	$ 4,360	$ 4,360	$ (3,886)	$ (3,661)

(4) Adjustment to Test Year rate base to include the replacement of the Palo Verde Unit 1 Steam Generators in 2005 and the retirement of Palo Verde Unit 1 Steam Generator and Low Pressure Turbine Rotors.
For Column (G) amounts, add together the amounts found on APS Exhibit 56 at Attachment LLR-1-4 [Rockenberger Direct] and APS Exhibit 57 at Attachment LLR-2-1RB [Rockenberger Rebuttal].

(5) Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.
For Column (I) amounts, add together the amounts found on APS Exhibit 56 at Attachment LLR-1-5 [Rockenberger Direct] and APS Exhibit 57 at Attachment LLR-2-2RB [Rockenberger Rebuttal].

(6) Additional rate base pro forma to include deferred credits related to expenses for employees on long term disability.
For Column (K) amounts, see APS Exhibit 49 at Attachment CNF 5-RB [Froggatt Rebuttal].

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE B-2

		(7)		(8)		(9)	
		Allowance for Working Capital		Total Original Cost Rate Base Pro Forma Adjustments		Adjusted at End of Test Year 9/30/2005	
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
1.	Gross Utility Plant in Service (a)	$ -	$ -	$ 38,296	$ 37,695	$ 10,857,198	$ 9,260,047
2.	Less: Accumulated Depreciation & Amort. (a)	-	-	$ (38,669)	$ (38,247)	4,131,856	3,510,299
3.	Net Utility Plant in Service (a)	-	-	76,965	75,942	6,725,342	5,749,748
4.	Less: Total Deductions	-	-	8,142	7,910	1,989,924	1,831,277
5.	Total Additions	(5,019)	(4,344)	(7,496)	(6,666)	581,755	538,466
6.	Total Rate Base	$ (5,019)	$ (4,344)	$ 61,327	$ 61,366	$ 5,317,173	$ 4,456,937

(7) Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.
For Column (M) amounts, see APS Exhibit 57 at Attachment LLR-2-3RB [Rockenberger Rebuttal].

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE B-3
Page 1 of 3

		(1)		(2)		(3)	
		Actual at End of Test Year 9/30/2005		Regulatory Disallowance for West Phoenix Unit 4		Spent Fuel Storage	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service (a)	$ 17,767,330	$ 15,145,398	$ (13,833)	$ (13,833)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort. (a)	7,243,608	6,163,319	(2,032)	(2,032)	-	-
3.	Net Utility Plant in Service (a)	10,523,722	8,982,079	(11,801)	(11,801)	-	-
4.	Less: Total Deductions	1,981,782	1,823,367	(646)	(646)	(3,761)	(3,700)
5.	Total Additions	589,251	545,132	-	-	(9,630)	(9,475)
6.	Total Rate Base	$ 9,131,191	$ 7,703,844	$ (11,155)	$ (11,155)	$ (5,869)	$ (5,775)

(1) For Column (A) amounts, see Column (A) of Standard Filing Requirement Schedule B-3, page 1 of 3, filed January 31, 2006.
For Column (B) amounts, see Column (B) of Standard Filing Requirement Schedule B-3, page 1 of 3, filed January 31, 2006.

(2) Adjustment to reduce Test Year rate base for the regulatory disallowance for West Phoenix Unit 4 as required in Decision No. 67744.
For Column (C) amounts, see Column (C) of Standard Filing Requirements Schedule B-3, page 1 of 3, filed January 31, 2006.

(3) Adjustment to Test Year rate base to include System Benefit related Interim Spent Fuel Storage costs consistent with Decision No. 67744.
For Column (E) amounts, see Column (E) of Standard Filing Requirements Schedule B-3, page 1 of 3, filed January 31, 2006.

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE B-3
Page 2 of 3

		(4)		(5)		(6)	
		Palo Verde Unit 1 Steam Generators		Bark Beetle Regulatory Asset		Long Term Disability (SFAS 112)	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service (a)	$ 25,710	$ 25,414	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort. (a)	(62,879)	(62,154)	-	-	-	-
3.	Net Utility Plant in Service (a)	88,589	87,568	-	-	-	-
4.	Less: Total Deductions	5,853	5,785	2,793	2,793	3,886	3,661
5.	Total Additions	-	-	7,153	7,153	-	-
6.	Total Rate Base	$ 82,736	$ 81,783	$ 4,360	$ 4,360	$ (3,886)	$ (3,661)

(4) Adjustment to Test Year rate base to include the replacement of the Palo Verde Unit 1 Steam Generators in 2005 and the retirement of Palo Verde Unit 1 Steam Generator and Low Pressure Turbine Rotors.
For Column (G) amounts, add together the amounts found in Column (G) of Standard Filing Requirements Schedule B-3, page 2 of 3, filed January 31, 2006 and APS Exhibit 57 at Attachment LLR-3-2RB, Column (E) [Rockenberger Rebuttal].

(5) Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.
For Column (I) amounts, add together the amounts found in Column (I) of Standard Filing Requirements Schedule B-3, page 2 of 3, filed January 31, 2006 and APS Exhibit 57 at Attachment LLR-3-2RB, Column (E) [Rockenberger Rebuttal].

(6) Additional rate base pro forma to include deferred credits related to expenses for employees on long term disability.
For Column (K) amounts, see APS Exhibit 57 at Attachment LLR-3-2RB, Column (C) [Rockenberger Rebuttal].

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE B-3
Page 3 of 3

Line No.	Description	(7) Allowance for Working Capital Total Co. (M)	(7) Allowance for Working Capital ACC (N)	(8) Total Original Cost Rate Base Pro Forma Adjustments Total Co. (O)	(8) Total Original Cost Rate Base Pro Forma Adjustments ACC (P)	(9) Adjusted at End of Test Year 9/30/2005 Total Co. (Q)	(9) Adjusted at End of Test Year 9/30/2005 ACC (R)
1.	Gross Utility Plant in Service (a)	$ -	$ -	$ 11,877	$ 11,581	$ 17,779,207	$ 15,156,979
2.	Less: Accumulated Depreciation & Amort. (a)	-	-	$ (64,911)	$ (64,186)	7,178,697	6,099,133
3.	Net Utility Plant in Service (a)	-	-	76,788	75,767	10,600,510	9,057,846
4.	Less: Total Deductions	-	-	8,125	7,893	1,989,907	1,831,260
5.	Total Additions	(5,019)	(4,344)	(7,496)	(6,666)	581,755	538,466
6.	Total Rate Base	$ (5,019)	$ (4,344)	$ 61,167	$ 61,208	$ 9,192,358	$ 7,765,052

(7) Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.
For Column (M) amounts, see APS Exhibit 57 at Attachment LLR-3-2RB, Column (G) [Rockenberger Rebuttal].

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE C-1
Page 1 of 2

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
(Dollars in Thousands)

		Total Company			
Line No.	Description	Actual For The Test Year Ended 9/30/05 [a] (A)	Proforma Adjustments [b] (B)	Test Year Results After Proforma Adjustments (C)	Line No.
1.	Electric operating revenues	$ 3,371,546	$ (772,059)	$ 2,599,487	1.
	Operating expenses:				
2.	Purchased power and fuel	1,822,565	(549,126)	1,273,439	2.
3.	Operations and maintenance	573,962	89,682	663,644	3.
4.	Depreciation and amortization	318,961	25,467	344,428	4.
5.	Income taxes	153,962	(144,839)	9,123	5.
6.	Other taxes	124,972	15,159	140,131	6.
7.	Total	2,994,422	(563,657)	2,430,765	7.
8.	Operating income	377,124	(208,402)	168,722	8.
	Other income (deductions):				
9.	Income taxes	56,698	-	56,698	9.
10.	Allowance for equity funds used during construction	10,433	-	10,433	10.
11.	Regulatory disallowance	(143,217)	-	(143,217)	11.
12.	Other income	26,019	-	26,019	12.
13.	Other expense	(15,176)	-	(15,176)	13.
14.	Total	(65,243)	-	(65,243)	14.
15.	Income before interest deductions	311,881	(208,402)	103,479	15.
	Interest deductions:				
16.	Interest on long-term debt	141,301	-	141,301	16.
17.	Interest on short-term borrowings	6,285	-	6,285	17.
18.	Debt discount, premium and expense	4,344	-	4,344	18.
19.	Capitalized interest	(7,257)	-	(7,257)	19.
20.	Total	144,673	-	144,673	20.
21.	Net income	$ 167,208	$ (208,402)	$ (41,194)	21.

NOTES: **[a]** For Column (A) amounts, see Column (A) of Standard Filing Requirement Schedule C-1, page 1 of 2, filed January 31, 2006.
[b] For Column (B) amounts, see APS Closing Brief Exhibit 5, Schedule C-2, Column (WWW).

Amounts in column (B) are the sum of all operating income adjustments proposed by APS in its direct, rebuttal, and rejoinder testimony and reflect APS' final position on each issue.

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE C-1
Page 2 of 2

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
(Dollars in Thousands)

Line No.	Description	ACC Jurisdiction: Actual For The Test Year Ended 9/30/05 [a] (A)	Proforma Adjustments [b] (B)	Test Year Results After Proforma Adjustments (C)	Line No.
1.	Electric Operating Revenues	$ 3,303,455	$ (758,435)	$ 2,545,020	1.
	Other Operating Expenses:				
2.	Purchased power and fuel	1,779,046	(535,727)	1,243,319	2.
3.	Operations and maintenance	661,264	84,739	746,003	3.
4.	Depreciation and amortization	283,555	23,174	306,729	4.
5.	Income taxes	140,791	(141,023)	(232)	5.
6.	Other taxes	104,631	15,031	119,662	6.
7.	Total	2,969,287	(553,806)	2,415,481	7.
8.	Operating income	$ 334,168	$ (204,629)	$ 129,539	8.
	Other income (deductions):				
9.	Income taxes	-	-	-	9.
10.	Allowance for equity funds used during construction	-	-	-	10.
11.	Regulatory disallowance	-	-	-	11.
12.	Other income	-	-	-	12.
13.	Other expense	-	-	-	13.
14.	Total	-	-	-	14.
15.	Income before interest deductions	334,168	(204,629)	129,539	15.
	Interest deductions:	-	-		
16.	Interest on long-term debt	-	-	-	16.
17.	Interest on short-term borrowings	-	-	-	17.
18.	Debt discount, premium and expense	-	-	-	18.
19.	Capitalized interest	-	-	-	19.
20.	Total	-	-	-	20.
21.	Net income	$ 334,168	$ (204,629)	$ 129,539	21.

NOTES: **[a]** For Column (A) amounts, see Column (A) of Standard Filing Requirement Schedule C-1, page 2 of 2, filed January 31, 2006.

[b] For Column (B) amounts, see APS Closing Brief Exhibit 5, Schedule C-2, Column (XXX).

Amounts in column (B) are the sum of all operating income adjustments proposed by APS in its direct, rebuttal, and rejoinder testimony and reflect APS' final position on each issue.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE C-2
Page 1 of 13

		(1)		(2)		(3)	
		Regulatory Assessment and Franchise Fees		Base Rate Component for EPS		Demand Side Management (DSM)	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Electric Operating Revenues	$ (15,947)	$ (15,723)	$ 6,779	$ 6,779	$ (4,907)	$ (4,907)
2.	Purchased Power and Fuel Costs	-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	(15,947)	(15,723)	6,779	6,779	(4,907)	(4,907)
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	(15,947)	(15,723)	6,000	6,000	2,989	2,989
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	(15,947)	(15,723)	6,000	6,000	2,989	2,989
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	(15,947)	(15,723)	6,000	6,000	2,989	2,989
12.	Operating Income Before Income Tax	-	-	779	779	(7,896)	(7,896)
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	-	-	779	779	(7,896)	(7,896)
15.	Current Income Tax Rate - 39.05%	-	-	304	304	(3,083)	(3,083)
16.	Operating Income (line 12 - line 15)	$ -	$ -	$ 475	$ 475	$ (4,813)	$ (4,813)
	WITNESS:	FROGGATT		FROGGATT		FROGGATT	

(1) Adjustment to Test Year operations to exclude regulatory assessments and franchise fees from both operating revenue and operating expense.
For amounts in Column (A), see APS Exhibit 48 at Attachment CNF 1-1 [Froggatt Direct].

(2) Adjustment to Test Year operations related to the base rate component of the Company's System Benefits Charge which is used to fund the Environmental Portfolio Standard. Revenue is adjusted to reverse Test Year entries for contributions in aid of construction and to include the expenses allowed by the Commission.
For amounts in Column (C), see APS Exhibit 48 at Attachment CNF 1-2 [Froggatt Direct].

(3) Adjustment to Test Year operations to reflect the operating income impact of Demand Side Management programs required by Decision No. 67744.
For amounts in Column (E), see APS Exhibit 48 of Attachment CNF 1-3 [Froggatt Direct].

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Line No.	Description	(4) Interest on Customer Deposits Total Co. (G)	ACC (H)	(5) Amortization of Regulatory Assets Total Co. (I)	ACC (J)	(6) PWEC Loan 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	2,400	2,400	-	-	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	2,400	2,400	-	-	-	-
7.	Depreciation and Amortization	-	-	381	381	(3,330)	(3,292)
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	2,400	2,400	381	381	(3,330)	(3,292)
12.	Operating Income Before Income Tax	(2,400)	(2,400)	(381)	(381)	3,330	3,292
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	(2,400)	(2,400)	(381)	(381)	3,330	3,292
15.	Current Income Tax Rate - 39.05%	(937)	(937)	(149)	(149)	1,300	1,286
16.	Operating Income (line 12 - line 15)	$ (1,463)	$ (1,463)	$ (232)	$ (232)	$ 2,030	$ 2,006
	WITNESS:	FROGGATT		FROGGATT		FROGGATT	

(4) Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits.
For Column (G) amounts, add together the amounts found on APS Exhibit 48 at Attachment CNF 1-4 [Froggatt Direct] and APS Exhibit 49 at Attachment CNF 6-RB [Froggatt Rebuttal].

(5) Adjustment to Test Year operations to include on-going amortization of regulatory assets.
For Column (I) amounts, see APS Exhibit 48 at Attachment CNF 1-5 [Froggatt Direct].

(6) Adjustment to Test Year operations to reflect a 264 basis point differential and amortization of loan proceeds as required in Decision Nos. 65796 and 67744.
For Column (K) amounts, see APS Exhibit at Attachment CNF 1-6 [Froggatt Direct].

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Line No.	Description		(7) Out-of-Period Income Tax Adjustments Total Co. (M)	(7) ACC (N)	(8) Generation Production Income Tax Deduction Total Co. (O)	(8) ACC (P)	(9) Income Tax/Interest Synchronization Total Co. (Q)	(9) 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		-	-	-	-	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		-	-	-	-	-	-
12.	Operating Income Before Income Tax		-	-	-	-	-	-
13.	Interest Expense		-	-	-	-	(7,705)	(6,461)
14.	Taxable Income		-	-	-	-	7,705	6,461
15.	Current Income Tax Rate -	39.05%	(1,287)	(243)	(3,089)	(3,054)	3,009	2,523
16.	Operating Income (line 12 - line 15)		$ 1,287	$ 243	$ 3,089	$ 3,054	$ (3,009)	$ (2,523)
	WITNESS:		FROGGATT		FROGGATT		FROGGATT	

(7) Adjustment to Test Year operations for out-of-period income tax true-ups.
For Column (M) amounts, see APS Exhibit 48 at Attachment CNF 1-7 [Froggatt Direct].

(8) Adjustment to Test Year operations to reflect the tax benefit associated with the American Jobs Creation Act.
For Column (O) amounts, add together the amounts on APS Exhibit 48 at Attachment CNF 1-8 [Froggatt Direct] and APS Exhibit 49 at Attachment CNF 7-RB [Froggatt Rebuttal].

(9) Adjustment to Test Year operations to reflect the synchronization of interest expense using the adjusted September 30, 2005 capital structure and cost of long-term debt, as well as the use of the statutory income tax rate.
For Column (Q) amounts, add together the amounts on APS Exhibit 48 at Attachment CNF 1-9 [Froggatt Direct] and APS Exhibit 49 at Attachment CNF 8-RB [Froggatt Rebuttal].

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		(10)		(11)		(12)	
		Regulatory Disallowance for West Phoenix Unit 4		PWEC Units		Sundance Units	
Line No.	Description	Total Co. (S)	ACC (T)	Total Co. (U)	ACC (V)	Total Co. (W)	ACC (X)
1.	Electric Operating Revenues	$ -	$ -	$ (1,791)	$ (1,762)	$ -	$ -
2.	Purchased Power and Fuel Costs	-	-	(666)	(655)	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	(1,125)	(1,107)	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	22,363	22,105	2,110	2,086
5.	Maintenance	-	-	9,741	9,629	2,750	2,718
6.	Subtotal	-	-	32,104	31,734	4,860	4,804
7.	Depreciation and Amortization	(230)	(227)	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	20,415	20,180	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	(230)	(227)	52,519	51,914	4,860	4,804
12.	Operating Income Before Income Tax	230	227	(53,644)	(53,021)	(4,860)	(4,804)
13.	Interest Expense	(275)	(275)	-	-	-	-
14.	Taxable Income	505	502	(53,644)	(53,021)	(4,860)	(4,804)
15.	Current Income Tax Rate - 39.05%	197	196	(20,948)	(20,705)	(1,898)	(1,876)
16.	Operating Income (line 12 - line 15)	$ 33	$ 31	$ (32,696)	$ (32,316)	$ (2,962)	$ (2,928)

WITNESS:	ROCKENBERGER	ROCKENBERGER	ROCKENBERGER

(10) Adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant.
For Column (S) amounts, see APS Exhibit 56 at Attachment LLR-2-1 [Rockenberger Direct].

(11) Adjustment to Test Year operations to annualize operating costs for the PWEC Units, which transferred to APS at 7/29/05, as authorized by Decision No. 67744. The PWEC Units include West Phoenix Combined Cycles No. 4 and No. 5, Redhawk Combined Cycles No.1 and No. 2, and Saguaro Combustion Turbine No. 3. Includes revenue adjustment related to plant auxiliary power.
For Column (U) amounts, see APS Exhibit 56 at Attachment LLR-2-5 [Rockenberger Direct].

(12) Adjustment to Test Year operations to include a projected year of O&M for the Sundance Units as authorized by Decision No. 67504.
For Column (W) amounts, see APS Exhibit 56 at Attachment LLR-2-6 [Rockenberger Direct].

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		(13)		(14)		(15)	
		Nuclear Decommissioning		Spent Fuel Storage		Palo Verde Unit 1 Steam Generators Depreciation	
Line No.	Description	Total Co. (Y)	ACC (Z)	Total Co. (AA)	ACC (BB)	Total Co. (CC)	ACC (DD)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs	-	-	10,828	10,653	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	(10,828)	(10,653)	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	-	-	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	-	-	-	-	-	-
7.	Depreciation and Amortization	3,883	3,820	-	-	1,785	1,764
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	3,883	3,820	-	-	1,785	1,764
12.	Operating Income Before Income Tax	(3,883)	(3,820)	(10,828)	(10,653)	(1,785)	(1,764)
13.	Interest Expense	-	-	(144)	(142)	2,041	2,017
14.	Taxable Income	(3,883)	(3,820)	(10,684)	(10,511)	(3,826)	(3,781)
15.	Current Income Tax Rate - 39.05%	(1,516)	(1,492)	(4,172)	(4,104)	(1,494)	(1,477)
16.	Operating Income (line 12 - line 15)	$ (2,367)	$ (2,328)	$ (6,656)	$ (6,549)	$ (291)	$ (287)

WITNESS: ROCKENBERGER ROCKENBERGER ROCKENBERGER

(13) Adjustment to Test Year operations to increase contributions to the nuclear decommissioning trust funds to the amount authorized by Decision No. 67744.
For Column (Y) amounts, see APS Exhibit 56 at Attachment LLR-2-7 [Rockenberger Direct].

(14) Adjustment to Test Year operations to amortize deferred Interim Spent Fuel Storage expenses consistent with Decision No. 67744.
For Column (AA) amounts, add together the amounts in APS Exhibit 57 at Attachment LLR-2-2 [Rockenberger Direct] and APS Exhibit 57 at Attachment LLR-4-3RB [Rockenberger Rebuttal].

(15) Adjustment to Test Year depreciation related to the replacement of the Palo Verde Unit 1 steam generators.
For Column (CC) amounts, add together the amounts in APS Exhibit 56 at Attachment LLR-2-3 [Rockenberger Direct] and APS Exhibit 57 at Attachment LLR-4-1RB [Rockenberger Rebuttal].

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Line No.	Description	(16) Bark Beetle Remediation Total Co. (EE)	ACC (FF)	(17) Four Corners Coal Reclamation Total Co. (GG)	ACC (HH)	(18) Annualize Depreciation and Amortization Total Co. (II)	ACC (JJ)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ 480	$ 452
2.	Purchased Power and Fuel Costs	-	-	1,305	1,284	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	(1,305)	(1,284)	480	452
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	1,548	1,548	-	-	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	1,548	1,548	-	-	-	-
7.	Depreciation and Amortization	-	-	-	-	23,055	20,799
8.	Amortization of Gain	-	-	-	-	(77)	(71)
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	1,548	1,548	-	-	22,978	20,728
12.	Operating Income Before Income Tax	(1,548)	(1,548)	(1,305)	(1,284)	(22,498)	(20,276)
13.	Interest Expense	151	151	-	-	-	-
14.	Taxable Income	(1,699)	(1,699)	(1,305)	(1,284)	(22,498)	(20,276)
15.	Current Income Tax Rate - 39.05%	(664)	(664)	(510)	(501)	(8,785)	(7,918)
16.	Operating Income (line 12 - line 15)	$ (884)	$ (884)	$ (795)	$ (783)	$ (13,713)	$ (12,358)
	WITNESS:	ROCKENBERGER		ROCKENBERGER		ROCKENBERGER	

(16) Adjustment to Test Year operations to exclude expenses related to bark beetle remediation over and above normal 2002 operational expense as required by Decision No. 67744 and to amortize 2005 - 2006 estimated costs over a three year period. For Column (EE) amounts, add together amounts in APS Exhibit 56 at Attachment LLR-2-4 [Rockenberger Direct] and APS Exhibit 57 at Attachment LLR-4-2RB [Rockenberger Rebuttal].

(17) Adjustment to Test Year operations to reflect the annual final coal reclamation expense for the Four Corners Power Plant. For Column (GG) amounts, see APS Exhibit 56 at Attachment LLR-2-8 [Rockenberger Direct].

(18) Adjustment to Test Year operations to include depreciation and amortization expense based on the technical update to the depreciation rates authorized in Decision No. 67744; operating revenue related to depreciation and amortization billed to APSES; and amortization of gain authorized in Decision No. 64306.
For Column (II) amounts, see APS Exhibit 56 at Attachment LLR-2-9 [Rockenberger Direct].

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			(19)		(20)		(21)	
			Annualize Property Taxes		Annualize Payroll		Underfunded Pension Liability	
Line No.	Description		Total Co. (KK)	ACC (LL)	Total Co. (MM)	ACC (NN)	Total Co. (OO)	ACC (PP)
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		-	-	5,326	5,025	43,695	41,166
5.	Maintenance		-	-	3,913	3,692	-	-
6.	Subtotal		-	-	9,239	8,717	43,695	41,166
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	-	-	-	-
10.	Other Taxes		15,159	15,031	-	-	-	-
11.	Total		15,159	15,031	9,239	8,717	43,695	41,166
12.	Operating Income Before Income Tax		(15,159)	(15,031)	(9,239)	(8,717)	(43,695)	(41,166)
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		(15,159)	(15,031)	(9,239)	(8,717)	(43,695)	(41,166)
15.	Current Income Tax Rate -	39.05%	(5,920)	(5,870)	(3,608)	(3,404)	(17,063)	(16,075)
16.	Operating Income (line 12 - line 15)		$ (9,239)	$ (9,161)	$ (5,631)	$ (5,313)	$ (26,632)	$ (25,091)
	WITNESS:		ROCKENBERGER		ROCKENBERGER		ROCKENBERGER	

(19) Adjustment to Test Year operations to annualize property taxes calculated using December 31, 2004 plant balances plus adjustment to Test Year operations to remove the 2007 phase-in cost increase for new generation plant.
For Column (KK) amounts, add together the amounts in APS Exhibit 56 at Attachment LLR-2-12 [Rockenberger Direct] and APS Exhibit 57 at Attachment 4-4RB [Rockenberger Rebuttal].

(20) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax, and benefit expenses to December 2005 employee levels, December 2005 wage levels for performance review employees, and April 2006 wage levels for union employees. Includes adjustment to remove officer incentive expense.
For Column (MM) amounts, see APS Exhibit 56 at Attachment LLR-2-14 [Rockenberger Direct].

(21) Adjustment to Test Year operations to increase pension expense to accelerate the recovery of the Company's underfunded pension liability.
For Column (OO) amounts, see APS Exhibit 56 at Attachment LLR-2-15 [Rockenberger Direct].

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Line No.	Description	(22) Advertising Total Co. (QQ)	(22) Advertising ACC (RR)	(23) Miscellaneous Adjustments Total Co. (SS)	(23) Miscellaneous Adjustments ACC (TT)	(24) Base Fuel and Purchased Power Including Off-System Sales Total Co. (UU)	(24) Base Fuel and Purchased Power Including Off-System Sales ACC (VV)
1.	Electric Operating Revenues	$ -	$ -	$ 2,217	$ 2,217	$ 17,494	$ 17,212
2.	Purchased Power and Fuel Costs	-	-	-	-	276,911	276,724
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	2,217	2,217	(259,417)	(259,512)
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	(6,311)	(5,952)	(892)	(841)	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	(6,311)	(5,952)	(892)	(841)	-	-
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	(337)	(312)	6,985	4,778	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	(6,648)	(6,264)	6,093	3,937	-	-
12.	Operating Income Before Income Tax	6,648	6,264	(3,876)	(1,720)	(259,417)	(259,512)
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	6,648	6,264	(3,876)	(1,720)	(259,417)	(259,512)
15.	Current Income Tax Rate - 39.05%	2,596	2,446	(1,514)	(672)	(101,302)	(101,339)
16.	Operating Income (line 12 - line 15)	$ 4,052	$ 3,818	$ (2,362)	$ (1,048)	$ (158,115)	$ (158,173)
	WITNESS:	ROCKENBERGER		ROCKENBERGER		EWEN	

(22) Adjustment to Test Year operations to exclude advertising expenses related to Company branding.
For Column (QQ) amounts, add together the amounts in APS Exhibit 56 at Attachment LLR-2-16 [Rockenberger Direct] and APS Exhibit 57 at Attachment LLR-4-7RB [Rockenberger Rebuttal].

(23) Adjustment to Test Year operations to eliminate non-recurring and out-of-period expenses.
For Column (SS) amounts, see APS Exhibit 56 at Attachment LLR-2-17 [Rockenberger Direct].

(24) 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.
For Column (VV) amounts, add together the amounts in Column (VV) of SFR Schedule C-2 filed January 31, 2006, the amounts in APS Exhibit 49 at Attachment CNF-2RB, Column (FF) [Froggatt Rebuttal] and the amounts in APS Exhibit 53, page 2 of 2, Column (e).

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Line No.	Description		(25) Normalize Non-Nuclear Maintenance Expense Total Co. (WW)	ACC (XX)	(26) Normalize Nuclear Maintenance Expense Total Co. (YY)	ACC (ZZ)	(27) Annualize Customer Levels to Year End 2004 Total Co. (AAA)	ACC (BBB)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ 44,663	$ 44,663
2.	Purchased Power and Fuel Costs		-	-	-	-	13,890	13,890
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	-	-	30,773	30,773
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		-	-	-	-	2,455	2,455
5.	Maintenance		1,456	1,435	(729)	(718)	-	-
6.	Subtotal		1,456	1,435	(729)	(718)	2,455	2,455
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	-	-	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		1,456	1,435	(729)	(718)	2,455	2,455
12.	Operating Income Before Income Tax		(1,456)	(1,435)	729	718	28,318	28,318
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		(1,456)	(1,435)	729	718	28,318	28,318
15.	Current Income Tax Rate -	39.05%	(569)	(560)	285	280	11,058	11,058
16.	Operating Income (line 12 - line 15)		$ (887)	$ (875)	$ 444	$ 438	$ 17,260	$ 17,260
	WITNESS:		EWEN		EWEN		EWEN	

(25) Adjustment to Test Year operations to reflect the normalization of fossil production maintenance expense and to include O&M costs of generators acquired for compliance with the Environmental Portfolio Standard.
For Column (WW) amounts, see APS Exhibit 16 at Attachment PME-15, page 1 of 2 [Ewen Direct].

(26) Adjustment to Test Year operations to reflect the normalization of nuclear production maintenance expense.
For Column (YY) amounts, see APS Exhibit 16 at Attachment PME-15, page 2 of 2 [Ewen Direct].

(27) Adjustment to Test Year operations to reflect the annualization of customer counts at December 31, 2004.
For Column (AAA) amounts, see APS Exhibit 16 at Attachment PME-19 [Ewen Direct].

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		(28)		(29)		(30)	
		Normalize Weather Conditions		Annualize 4/1/05 ACC Rate Levels		E-3/E-4 Promotional Expense	
Line No.	Description	Total Co. (CCC)	ACC (DDD)	Total Co. (EEE)	ACC (FFF)	Total Co. (GGG)	ACC (HHH)
1.	Electric Operating Revenues	$ 10,938	$ 10,938	$ 17,136	$ 17,136	$ -	$ -
2.	Purchased Power and Fuel Costs	4,224	4,224	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	6,714	6,714	17,136	17,136	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	747	747	-	-	62	62
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	747	747	-	-	62	62
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	747	747	-	-	62	62
12.	Operating Income Before Income Tax	5,967	5,967	17,136	17,136	(62)	(62)
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	5,967	5,967	17,136	17,136	(62)	(62)
15.	Current Income Tax Rate - 39.05%	2,330	2,330	6,692	6,692	(24)	(24)
16.	Operating Income (line 12 - line 15)	$ 3,637	$ 3,637	$ 10,444	$ 10,444	$ (38)	$ (38)
	WITNESS:	EWEN		RUMOLO		RUMOLO	

(28) Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2004.
For Column (CCC) amounts, see APS Exhibit 16 at Attachment PME-18 [Ewen Direct].

(29) Adjustment to Test Year operations to reflect the annualization of ACC rate levels for the 4/1/05 rate increase authorized in Decision No. 67744.
For Column (EEE) amounts, see APS Exhibit 69 at Attachment DJR-5 [Rumolo Direct].

(30) Adjustment to Test Year operations to reflect increased promotional expense for low-income rate options as required by Decision No. 67744.
For Column (GGG) amounts, see APS Exhibit 69 at Attachment DJR-6 [Rumolo Direct].

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE C-2

			(31)		(32)		(33)	
			Schedule 1 Changes		Tax Consulting Fees		Unregulated APS Marketing and Trading Activity	
Line No.	Description		Total Co. (III)	ACC (JJJ)	Total Co. (KKK)	ACC (LLL)	Total Co. (MMM)	ACC (NNN)
1.	Electric Operating Revenues		$ 127	$ 127	$ -	$ -	$ (849,248)	$ (835,567)
2.	Purchased Power and Fuel Costs		-	-	-	-	(855,618)	(841,847)
3.	Oper Rev Less Purch Pwr & Fuel Costs		127	127	-	-	6,370	6,280
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		(38)	(38)	(2,778)	(2,746)	(6,618)	(6,511)
5.	Maintenance		-	-	-	-	-	-
6.	Subtotal		(38)	(38)	(2,778)	(2,746)	(6,618)	(6,511)
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	-	-	(2,161)	(2,126)
10.	Other Taxes		-	-	-	-	-	-
11.	Total		(38)	(38)	(2,778)	(2,746)	(8,779)	(8,637)
12.	Operating Income Before Income Tax		165	165	2,778	2,746	15,149	14,917
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		165	165	2,778	2,746	15,149	14,917
15.	Current Income Tax Rate -	39.05%	64	64	1,085	1,072	5,916	5,825
16.	Operating Income (line 12 - line 15)		$ 101	$ 101	$ 1,693	$ 1,674	$ 9,233	$ 9,092
	WITNESS:		RUMOLO		FROGGATT		FROGGATT	

(31) Adjustment to Test Year operations to reflect revenue related changes to Schedule 1 as authorized in Decision No. 67744. For Column (III) amounts, add together amounts in APS Exhibit 69 at Attachment DJR-7 [Rumolo Direct] and APS Exhibit 49 at Attachment CNF-2RB, Page 6 of 7, Column (GG) [Froggatt Rebuttal].

(32) Additional adjustment to operating expense to remove out-of-period and non-recurring tax consultant fees. For Column (KKK) amounts, see APS Exhibit 49 at Attachment CNF-9RB [Froggatt Rebuttal].

(33) Additional operating income pro forma to remove APS unregulated marketing and trading activities from operating expense. For Column (MMM) amounts, see APS Exhibit 49 at Attachment CNF-3RB [Froggatt Rebuttal].

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE C-2
Page 12 of 13

Line No.	Description		(34) Federal and State Income Tax Total Co. (OOO)	ACC (PPP)	(35) Administrative and General Total Co. (QQQ)	ACC (RRR)	(36) Pension Expense Total Co. (SSS)	ACC (TTT)
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		-	-	-	-	2,249	2,119
5.	Maintenance		-	-	-	-	-	-
6.	Subtotal		-	-	-	-	2,249	2,119
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	(8,520)	(8,422)	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		-	-	(8,520)	(8,422)	2,249	2,119
12.	Operating Income Before Income Tax		-	-	8,520	8,422	(2,249)	(2,119)
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		-	-	8,520	8,422	(2,249)	(2,119)
15.	Current Income Tax Rate -	39.05%	(4,838)	(4,588)	3,327	3,289	(878)	(827)
16.	Operating Income (line 12 - line 15)		$ 4,838	$ 4,588	$ 5,193	$ 5,133	$ (1,371)	$ (1,292)

WITNESS: FROGGATT ROCKENBERGER ROCKENBERGER

(34) Additional adjustment to the Company's original cost-of-service income tax expense to reflect a top-down tax calculation including permanent tax items.
For Column (OOO) amounts, see APS Exhibit 49 at Attachment CNF-4RB [Froggatt Rebuttal].

(35) Remove out-of-period and other legal costs from administrative and general expense.
For Column (QQQ) amounts, see APS Exhibit 57 at Attachment LLR-4-8RB [Rockenberger Rebuttal].

(36) Adjustment to Test Year operations to reflect actual 2006 pension expense.
For Column (SSS) amounts, see APS Exhibit 57 at Attachment LLR-4-5RB [Rockenberger Rebuttal].

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

FINAL APS POSITION
CONSOLIDATED STANDARD FILING REQUIREMENTS
SCHEDULE C-2

			(37)		(38)	
			Post Retirement Medical Benefits		Total Income Statement Adjustments	
Line No.	Description		Total Co. (UUU)	ACC (VVV)	Total Co. (WWW)	ACC (XXX)
1.	Electric Operating Revenues		$ -	$ -	(772,059)	(758,435)
2.	Purchased Power and Fuel Costs		-	-	(549,126)	(535,727)
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	(222,933)	(222,708)
	Other Operating Expenses:					
4.	Operations Excluding Fuel Expense		(3,191)	(3,006)	56,169	53,885
5.	Maintenance		-	-	17,131	16,756
6.	Subtotal		(3,191)	(3,006)	73,300	70,641
7.	Depreciation and Amortization		-	-	25,544	23,245
8.	Amortization of Gain		-	-	(77)	(71)
9.	Administrative and General		-	-	16,382	14,098
10.	Other Taxes		-	-	15,159	15,031
11.	Total		(3,191)	(3,006)	130,308	122,944
12.	Operating Income Before Income Tax		3,191	3,006	(353,241)	(345,652)
13.	Interest Expense		-	-	(5,932)	(4,710)
14.	Taxable Income		3,191	3,006	(347,309)	(340,942)
15.	Current Income Tax Rate -	39.05%	1,246	1,174	(144,839)	(141,023)
16.	Operating Income (line 12 - line 15)		$ 1,945	$ 1,832	$ (208,402)	$ (204,629)

WITNESS: ROCKENBERGER

(37) Adjustment to Test Year operations to reflect actual 2006 post retirement medical expenses.
For Column (UUU) amounts, see APS Exhibit 57 at Attachment LLR-4-6RB [Rockenberger Rebuttal].

(38) Income Tax Line 15 for the Total Income Statement Adjustments columns is not 39.05% of Total Taxable Income due to the required calculations for the Out-of-Period Income Tax Adjustment, Federal and State Income Tax, and Generation Production Deduction pro forma adjustments.