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PART 2 OF 2
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REBUTTAL TESTIMONY OF TERESA A. ORLICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Teresa A. Orlick, 400 North Fifth Street, Phoenix, Arizona 85004.

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

A. I am the Manager of Customer Information and Programs for Arizona Public Service Company.

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. My qualifications are set forth in Appendix A to my testimony.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony provides an overview of APS' DSM programs for residential and non-residential customers and the progress of those programs to date. Next, I discuss Southwest Energy Efficiency Project's ("SWEEP") proposed Energy Efficiency Standard ("EES") and APS' concerns regarding the effect of SWEEP's proposed changes to the current DSM requirements. In addition, I comment on RUCO's proposed increase in mandatory funding level and testify to APS' support of Staff's recommended DSM Performance Incentive. I also respond to the concerns raised by Western Resource Advocates ("WRA") regarding heat island effect and APS' efforts and recommendations to mitigate this problem.

Finally, I describe APS' Energy Support Programs for Low Income Customers and APS' efforts to implement automatic enrollment in these programs. In

addition, I describe APS' marketing efforts designed to encourage enrollment in these low income programs.

III. OVERVIEW OF DSM PROGRAM PROGRESS TO DATE

Q. WOULD YOU PLEASE PROVIDE AN OVERVIEW OF APS' DSM PROGRAM?

A. Pursuant to Decision Number 67744, APS filed a DSM Portfolio Plan on July 1, 2005, which included 10 proposed DSM programs. The programs were developed with the input and review of the DSM Collaborative working group[1]. These 10 DSM programs for residential, non-residential, and low income customers were approved by the Commission in three separate open meetings, the first of which occurred in August 2005, with the last one taking place in April 2006. The DSM programs are budgeted to spend $48M by year-end 2007.

Q. WHAT DSM SPENDING HAS BEEN ACHIEVED TO DATE?

A. APS has spent $3.2M in 2005 for DSM and $3.5M through August 2006. This spending is across residential, commercial, industrial, schools and low income sectors. Furthermore, the Business Solutions program for non-residential customers has reservations through August 2006 of over $1.5M in incentives for projects that have yet to be completed.

Q. DOES APS EXPECT TO SPEND THE $48M BY THE END OF 2007?

A. Due to the delayed approval of the programs and the steep ramp-up from a level of $1M of DSM spending per year prior to Decision 67744 to the current level of $16M per year, APS does not believe that $48M will be spent by year end 2007. An additional reason for the shortfall in spending by 2007 is the new construction

[1] The DSM Collaborative Working Group is composed of representatives from APS, ACC Staff, RUCO, SWEEP, WRA, Arizona State Energy Office and other Settlement Parties, as noted in Decision 67744.

element of the programs. Although integrating energy efficiency measures in a new building is often the most cost-effective way to achieve energy savings, the completion of many of these projects is likely to extend past 2007.

Q. HOW DOES APS INTEND TO MEET ITS SPENDING OBLIGATION FOR YEARS 2005 – 2007?

A. Any under spending of the $48M will be carried over and spent in subsequent years, in addition to the $16M per year spending requirement for each of those years.

Q. WHAT ARE APS' PLANS REGARDING DSM PROGRAMS BEYOND 2007?

A. It is our expectation that the programs will continue at the same funding level and with the same design until APS submits proposals to modify program design and/or budget requirements and such modifications are approved by the Arizona Corporation Commission ("Commission"). The programs are essentially "evergreen" in the absence of proposed modifications or Commission intervention. The nature of our funding mechanism, comprised of 2 elements – one element is in base rates ($10M) and the other element flows through the DSM Adjustor - allows for DSM programming to continue and grow as cost-effective program opportunities emerge.

IV. ENERGY EFFICIENCY STANDARD PROPOSAL

Q. THE TESTIMONY OF SWEEP PROPOSES THAT APS IMPLEMENT AN EES AS PART OF ITS DSM PROGRAM. DOES APS NEED TO IMPLEMENT AN EES?

A. Not at this time. It is premature to make substantial changes in the DSM Portfolio by imposing a kWh and kW savings target as proposed by SWEEP. The DSM programs now in effect were just recently approved by the Commission and are

still in the early stages of roll-out. The non-residential programs were approved in February 2006 and are only approved on an interim basis, due to the Commission's concerns about obtaining actual program costs and results before granting formal program approval. Furthermore, the residential programs were approved in April and are just getting ramped up.

Very little time has elapsed over which to assess the success of current programs. Time is needed to get DSM programs up to speed, gauge progress, and evaluate what is actually being achieved through the measurement, evaluation and research ("MER") process. Some of the most cost effective program savings (and biggest program spending levels) come from new construction and it may take one to two years before these projects are completed and able to be evaluated.

Q. DOES APS HAVE CONCERNS REGARDING THE PROPOSED GOALS OF THE EES PROPOSAL?

A. Yes. The EES as proposed by SWEEP is a savings goal as opposed to a spending goal. Although both are inextricably linked because spending is needed to achieve savings, a kWh and kW savings target is unnecessary because APS already has a DSM spending requirement that meets energy savings goals and was approved in Decision 67744. APS, Staff and the DSM Collaborative participated in determining what DSM programs should be offered, how funding should be divided, and how much savings could be achieved with the DSM programs at the given spending level. The current spending goal is an effective target because only cost-effective measures are installed. Their cost effectiveness was proven by the Societal Cost Test[2] as performed by APS as well as by Commission Staff

[2] The Commission's 1991 Resource Planning Decision No. 57589 established that the Societal Cost Test should be used for the purpose of establishing whether a DSM program can be considered cost-effective.

("Staff").

Q. WHAT DO OTHERS USE FOR THEIR DSM GOALS?

A. A recent study of 15 jurisdictions with a relatively high level of investment in DSM was conducted by the Regulatory Assistance Project[3], on behalf of CAMPUT[4]. It found that nine of these express their targets in terms of spending, either as a mills/kWh rate or as a percentage of revenues. Assuming the approved programs are cost-effective, savings result as a matter of course.

It is difficult to predict with certainty what savings can be achieved with a given spending goal, particularly with new programs in an untried market. In addition, in order for a savings goal to be achieved, it needs to be adequately funded. A DSM spending goal is more appropriate and ensures that appropriate funding is allocated to DSM rather than guessing what funding might be needed to achieve a set saving goal. This is particularly true when coupled with a framework that provides for stakeholder review of program design and cost effectiveness.

Q. DO YOU HAVE CONCERNS WITH THE LEVEL OF SAVINGS AND THE ASSOCIATED SPENDING IN THE EES PROPOSAL? IF SO, PLEASE ELABORATE.

A. Yes, the proposal is very aggressive. The current DSM spending level of $16 million per year on energy efficiency represents approximately 0.75% of revenue.

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[3] The Regulatory Assistance Project (RAP) is a non-profit organization, formed in 1992 by experienced utility regulators, that provides research, analysis, and educational assistance to public officials on electric utility regulation.

[4] CAMPUT is the Canadian Association of Members of Public Utility Tribunals, roughly equivalent to the US National Association of Regulatory Utility Commissioners ("NARUC").

According to the 2005 ACEEE Efficiency Program Compendium[5], this exceeds the national average spending of 0.52% of revenue. SWEEP's proposed spending for APS would be equal to nearly 2.5% of revenue. Additionally, only three states nationally (Vermont, Massachusetts, Washington) spend more than 2% of revenue on energy efficiency and these states have gradually increased funding over time. This is likely due to concerns about impact on ratepayers, the impracticality of increasing targets too quickly given the need to build infrastructure and customer awareness over time, and inherent delay in new construction program spending.

Q. SWEEP MAKES COMPARISONS TO OTHER STATES AS PART OF ITS SUPPORT FOR AN EES. ARE THESE COMPARISONS APPROPRIATE?

A. It is arguable whether the seven states used by SWEEP [6] are an appropriate "peer" group. They are Connecticut, California, Maine, Minnesota, Oregon, Rhode Island and Washington. Four of these (Connecticut, California, Maine and Rhode Island) have a significantly higher price per kWh than Arizona, which makes the DSM programs and measures more cost-effective. Major cities in three of these states rank at the top of the country in terms of consumer attitudes about "green" issues (Oregon, California, and Minnesota) which may be used as an indicator of their inclination to adopt energy efficiency measures. All these states have a longer, more consistent history of significant DSM programs to rely on for setting goals. Also, elements of these states' programs are more aggressive. For example, California has more generous incentives that pay up to 100% of a customer's

[5] "American Council for an Energy Efficient Economy ("ACEEE")'s 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State-Level Activity". October 2005, York/Kushler.

[6] (JS, p 5, line 37 to p 6 line 2)

incremental cost. The Commission has determined that end-use measures approved in APS programs should be capped at between 50-75% of a customer's incremental cost. It is unlikely that the current incentive levels for APS would be aggressive enough to meet the EES goal.

Q. HAS SWEEP PROVIDED SUFFICIENT EVIDENCE TO SHOW THAT THEIR PROPOSED FUNDING LEVEL WOULD BE ADEQUATE TO ACHIEVE THE EES GOALS ?

A. APS acknowledges and agrees with SWEEP that it is essential that adequate funding be provided in order to meet DSM goals. SWEEP estimates that 2 mills per kWh of DSM funding would be needed to achieve the EES savings goals. This funding estimate is based on APS achieving DSM savings at an average cost of approximately 1.1 cents per lifetime kWh saved, per Exhibit JS-1, line 13. This is an optimistic assumption given SWEEP's testimony that "The utility program cost to APS ratepayers is...about one to two cents per lifetime kWh saved"[7]. The cost per kWh saved of SWEEP's proposal is on the very low end of this range. At the upper end of the range, two cents per lifetime kWh saved, the requisite funding level would increase from 2 mills to approximately 3.8 mills. Viewed a different way, the proposed funding level would be able to fund approximately half of the EES based on SWEEP's testimony.

Q. WHAT IS THE BILL IMPACT IN TERMS OF COSTS TO CUSTOMERS OF ADOPTING THE EES PROPOSAL BY SWEEP?

A. SWEEP states that their proposed funding in 2007 would grow "from about $25 million to $38 million, an increase of about $13 million."[8] In reality, SWEEP's proposal would be a $28 million increase over base rates and a $22 million

[7] (JS, p. 4, lines 27-29)

[8] (JS, p.7, lines 2-4).

increase over the target level of $16 million.

Q. SWEEP SUGGESTS THAT THE CURRENT PROGRAMS COULD BE EXPANDED TO GET TO A SIGNIFICANTLY HIGHER SPENDING LEVEL. IS THIS FEASIBLE?

A. While it is likely that some expansion is possible, it is questionable as to whether the Commission-approved existing programs could be expanded to the spending and savings levels that SWEEP is proposing. This is particularly true under current Commission criteria where APS incentive levels are set no higher than 75% of incremental cost and the ability to adjust budgets is constrained. APS believes that much more aggressive program design would be required where incentives in some cases were 100% of incremental cost. Also, in many cases to make the energy-efficiency projects economical, the customer may need a shorter payback period than a 75% maximum incentive would afford.

In addition, DSM program implementation requires an infrastructure of contractors, builders, and other trade allies to be developed while programs are ramping up. It also takes time to build customer awareness, interest and adoption. The goal that SWEEP proposes does not appear to reflect program implementation considerations, particularly in the early years.

Q. WHAT ARE YOUR THOUGHTS ON THE RECOMMENDATION BY SWEEP THAT AN EES IMPLEMENTATION PLAN SHOULD BE DEVELOPED?

A. APS believes that SWEEP's proposal that a 12 year Implementation Plan be filed within eight months would have little actionable value in planning and/or implementation of DSM programs because long range results are very difficult to predict. APS believes that periodic planning updates based upon shorter term planning horizons result in a more actionable plan.

Q. WHAT PLANNING REQUIREMENTS DOES APS PROPOSE?

A. APS anticipated the need for periodic planning updates and the 2005-2007 DSM Portfolio Plan filed July 1, 2005 states that APS plans a "biennial submission" of a DSM Portfolio Plan to the Commission. In addition, in spring 2007 APS will be submitting an updated DSM filing ("13-month filing") pursuant to Decisions 68488 and 68648, where the first year's performance and earnings will be incorporated. The schedule for the biennial filing of the DSM Portfolio will be based on the outcome of the 13-month filing. As with the existing Portfolio Plan, APS anticipates working with the DSM Collaborative and Staff to jointly develop the plan.

Q. IS AN ALTERNATE DSM FUNDING MECHANISM NEEDED IN THIS RATE CASE?

A. No, the DSM adjustor mechanism was created to provide the ability to alter DSM funding with Commission approval outside of a rate case to match spending. Decision 67744 authorizes an annual "minimum spending" requirement of $10 million per year in base rates with an additional $6 million authorized through an adjustor. In fact, SWEEP and RUCO both acknowledge that due to delays in approval process, APS will need to "catch up" with the current level of funding authorized in base rates. In the future when the Portfolio is spending at the $16M level, the adjustor will allow for additional program funding. APS supports the current approach, with a combination of base rates and the DSM adjustor mechanism. This mechanism provides a flexible means of cost recovery, which can be adjusted between rate cases as needed. In fact, RUCO's proposal, as outlined in Ms. Diaz Cortez' testimony, to increase the annual mandatory spending in the surcharge from $6M to $10M post-expiration of the Settlement Agreement is not needed at this time due to the flexibility of both the programs

and the funding mechanism. As existing programs mature and new programs evolve, spending levels may increase further. The DSM adjustor mechanism is in place to recover any additional spending for approved programs.

V. DSM PERFORMANCE INCENTIVE

Q. DOES APS AGREE WITH STAFF'S ANALYSIS OF THE DSM PERFORMANCE INCENTIVE?

A. Yes. APS agrees with Staff that the performance incentive is appealing as a tool to reward a utility's performance in conducting successful DSM programs.[9] APS also agrees with Staff's recommendation to set the performance incentive share at 10% 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.[10] APS also agrees with Staff's recommendation that APS should share in the benefits of the DSM measures as they are placed into service and expenditures are incurred, and that APS should include a request for the performance incentive payment in each semi-annual report filing. [11]

Q. WHAT SPECIFIC CALCULATIONS OR METHODOLOGY SHOULD BE USED TO DETERMINE THE NET BENEFITS OF DSM MEASURES UNDERTAKEN?

A. In Arizona, the Societal Cost Test is used as the measure of program benefit/cost ratio. This test considers the net present value of the benefits of a program that derive from the utility avoided cost savings (capacity, energy/fuel/O&M, T&D savings) as a result of kWh and peak kW savings from DSM measures

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[9] (Direct Testimony of Jerry D. Anderson (JDA), p. 9, lines 14-19)

[10] (JDA, p.10, lines 5-8).

[11] (JDA, p.12, lines 8-14).

undertaken. Program costs include the net present value of all the utility non-incentive program costs and the customer's incremental cost for upgrading to a more energy efficient end use. The formula is:

Net Benefits = Total Societal Benefits – Total Societal Cost

Where:

Total Societal Benefits is the utility avoided cost savings,

and

Total Societal Cost is the sum of utility non-incentive program costs and customer incremental cost

This is the same basic cost/benefit equation that Staff used in their calculation of program net benefits, as demonstrated by Decisions 68488 and 68648.

In addition, APS agrees to provide Staff with backup workpapers and input data to substantiate numbers for net benefits and performance incentives included in each semi-annual DSM report.

Q. FOR THE PURPOSES OF THE PERFORMANCE INCENTIVE COMPUTATION, HOW WILL KW AND KWH SAVINGS BE DERIVED?

A. These savings are the product of the number of measures installed and their associated savings per unit. The measures installed are actual figures, and for prescriptive measures APS recommends that program savings should be based on the program filed savings numbers until such time that MER results are available. It is important to clarify that the program filed savings numbers are NOT engineering calculations. Rather they reflect actual savings from field measurements collected over many years of energy efficiency program implementation, in environments representative of our service territory. Additionally, these savings figures are well vetted by many experts and it is common industry practice to use these in DSM program design and evaluation

and for purposes of performance incentive calculations. For custom projects, an energy savings analysis will be performed for each specific project, they must follow strict program criteria, and realistic savings figures are expected to result. All custom energy savings analysis will be verified by an energy engineer. As MER results become available, these results will be used to refine savings estimates going forward.

VI. RESPONSE TO TESTIMONY OF WESTERN RESOURCE ADVOCATES.

Q. DOES APS SUPPORT THE CONCEPT OF MITIGATING THE HEAT ISLAND EFFECT IN METROPOLITAN AREAS WITHIN ITS SERVICE TERRITORY?

A. Yes, APS does support efforts to mitigate the heat island effect, especially when tied to energy conservation. In fact, APS is a sponsor of the ASU Global Institute for Sustainability ("GIOS"), through its Sustainable Materials and Renewables Technologies Alliance ("SMART"), and as a Sustainer/Lifetime contributor to this effort. The GIOS was established to advance interdisciplinary research on environmental, economic and social sustainability, especially as it relates to urban areas. The SMART Alliance provides information on research, education and resources to enable metropolitan areas to be more sustainable and less vulnerable to the heat island effect.

Q. WOULD APS BE WILLING TO BRING OUTSIDE EXPERTS TOGETHER TO INFORM AND EDUCATE THE DSM COLLABORATIVE GROUP ON HEAT ISLAND EFFECTS?

A. Yes, APS will schedule a DSM Collaborative Meeting that will include a presentation from a representative of ASU's GIOS to provide an update on actions and research currently underway to mitigate the heat island effect throughout Arizona.

Q. DO YOU AGREE WITH WRA'S PROPOSAL TO CREATE A NEW DSM PROGRAM THAT IS DESIGNED SPECIFICALLY TO REDUCE URBAN HEAT ISLAND EFFECTS?

A. Because we feel APS' current DSM Programs sufficiently covers these types of measures, a separate and distinct program is not needed at this time. APS' non-residential DSM Programs already include a custom efficiency component in which any measure that falls outside the prescriptive list of measures might qualify. When a customer files an application for a custom project, the entire project and all energy efficiency measures proposed is reviewed to determine the associated energy savings and benefit to society using the "Societal Cost Test". All measures that demonstrate kWh savings and pass the test would qualify for the custom incentive. This seems a very logical place to review and provide incentives for projects like those suggested by Dr. Berry.

Q. WHY IS THE CUSTOM APPLICATION A LOGICAL PLACE TO CONSIDER PROJECTS OF THIS NATURE FOR DSM PURPOSES?

A. Because of the many different ways to address urban heat islands, these projects are often unique in nature. The type of project and energy efficiency measures being installed will likely vary. The type of business and size of the facility in square footage is also likely to vary from project to project. Therefore, developing "prescriptive" measures (defined as a pre-approved "menu" list) for these kinds of unique measures may not be practical, and the custom application where a comprehensive review of each project is completed is warranted.

Q. WHAT OTHER REASONS MIGHT WARRANT THE REVIEW OF HEAT ISLAND MITIGATION MEASURES AS CUSTOM VERSUS PRESCRIPTIVE?

A. Some of the cool roof measures included in WRA's urban heat island program proposal have already been disallowed as end-use measures in our DSM

Programs, as they did not receive Commission approval in Decision No. 68488. In fact, Staff's recommendation in that Decision states "that no incentives be paid for the cool roofs measure at this time". This would include cool-roof membranes and cool-roof reflective coatings.

Furthermore, any additional measures or new program designed to reduce the urban heat island effect should need to demonstrate energy savings and pass the Societal Cost Test to qualify, just as any other measure in our approved programs are required to do.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION REGARDING THIS ISSUE.

A. My recommendation is that projects such as those proposed by WRA that incorporate measures to reduce the urban heat island effect, can be reviewed and approved, on a custom basis, under currently approved programs. Applications including heat island mitigation measures (e.g., landscape vegetation, certain cool materials, etc.) are eligible for consideration of incentives when applied for as part of a custom application. However, some cool roof measures would be excluded as Staff and the Commission did not approve cool roofs (reflective coatings and membranes) incentives because they did not pass Staff's analysis and calculation of the Societal Cost Test.

Furthermore, much research and development is still being conducted related to the heat island effect and APS continues to support these efforts as part of ASU's GIOS program. We believe that the research underway should yield substantial results before proceeding down the path of developing an entire heat island effect DSM program.

VII. <u>APS ENERGY SUPPORT PROGRAMS FOR LOW INCOME CUSTOMERS</u>

Q. PLEASE PROVIDE AN OVERVIEW OF APS' E-3 AND E-4 PROGRAMS.

A. APS' Energy Support Program ("E-3") offers discounts up to 40% off the cost of electricity for customers who meet certain income guidelines. Specifically, the income guidelines are based on 150% of the federal poverty guidelines as determined by the Arizona Department of Economic Security ("DES") and changed every July 1. Additionally, customers on E-3 are exempt from the Power Supply Adjuster ("PSA") charges.

The E-4 program incorporates a medical care equipment program which provides additional discounts to eligible customers who qualify for the E-3 discount. The customer needs to provide a letter from their medical provider showing that they require some type of durable medical equipment, for example, an oxygen concentrator.

Q. HOW DO CUSTOMERS ENROLL IN ENERGY SUPPORT PROGRAMS?

A. Once a year, APS sends program information and applications to all residential customers not already enrolled in E-3 and E-4. This solicitation includes a postage prepaid return. Applications are also distributed at APS offices, social service agencies and are downloadable on aps.com. The customer whose name is on the APS account is required to fill out, sign, and send the completed application to DES. DES is responsible for processing the application and determining the eligibility of the applicant, and notifying APS to enroll the applicant.

Q. FOR HOW LONG DOES AN ELIGIBLE CUSTOMER REMAIN ON THE E-3 PROGRAM?

A. The customer can remain on E-3 indefinitely as long as they continue to meet the income guidelines. The customer must recertify for the program each year. DES

automatically sends the necessary paperwork for recertification. The customer must return the paperwork to maintain the discount.

VIII. AUTOMATIC ENROLLMENT FOR E-3

Q. WHY IS APS INCLUDING A DISCUSSION OF AUTOMATIC ENROLLMENT IN THE LOW-INCOME PROGRAMS?

A. In April 2006, Decision 68685 (APS Emergency Rate Case) requested APS to propose ways to implement automatic enrollment into our low-income programs for customers who participate in applicable means-tested assistance programs.

Q. WHAT STEPS HAS APS TAKEN TO INVESTIGATE AUTOMATIC ENROLLMENT IN ITS LOW INCOME PROGRAMS?

A. In 2005, APS met with the Arizona Community Action Association ("ACAA") and DES to determine the feasibility of automatically enrolling food stamp recipients. After several meetings, there was a suggestion to have DES provide an electronic file with all of their food stamp recipients to APS. The parties were then tasked with investigating the issues involved with this approach.

Q. AFTER INVESTIGATION, WHAT CONCLUSIONS WERE REACHED BY THE PARTIES ON THE FEASIBILITY OF AUTOMATICALLY ENROLLING FOOD STAMP RECIPIENTS?

A. The parties came to the conclusion that taking this approach could potentially involve legal liability involving the transmittal of confidential client information, especially as it relates to income. According to the "Authorization for Release of Information" form that is part of the DES application for state assistance, "DES will not release this information to any other person or agency outside of the DES or its agents."

Q. WHAT OTHER STEPS HAS APS TAKEN TO IMPLEMENT AUTOMATIC ENROLLMENT?

A. APS has an Electronic Agency Guarantee ("EAG") website that allows authorized community agencies to verify a client's account data, and post a payment guarantee. It is used to facilitate payments from various assistance programs, including the federal Low Income Home Energy Assistance Program ("LIHEAP"). Since LIHEAP uses the same income guidelines as APS' E-3 program, which is 150% of the federal low income guideline, this provides an excellent proxy to qualify a customer for E-3. Therefore we have integrated E-3 enrollment into this process and can enroll LIHEAP clients to our program.

Q. WHAT STEPS HAS APS TAKEN TO IMPLEMENT E-3 ELECTRONIC SIGN-UP USING THE EAG?

A. On June 1, 2006, APS initiated a pilot program to test this concept. Now, when a customer goes to a community action agency and is eligible for LIHEAP assistance, the caseworker informs the client that they can also enroll in APS' E-3 Low Income program and receive a discount on the cost of their electricity. If the customer agrees, the caseworker can enroll the client into E-3 at the same time that they provide the payment guarantee.

Q. PLEASE DESCRIBE THE PROCESS FOR ENROLLMENT IN THE E-3 PROGRAM VIA EAG?

A. When an APS customer goes into a community action agency for assistance with their utility bill, the agency determines the customer's eligibility for LIHEAP. If they are eligible, the case worker signs onto the EAG website and is able to look up the customer's information. On that page, there is a check box for E-3. Once clicked, the system asks if the customer is eligible for E-3. If yes, then the system asks if the customer has agreed to sign up for E-3. If the answer is yes, the checked box is selected. At this point, the case worker clicks "submit" and the E-3 application information is sent via an encrypted e-mail to a secure DES

mailbox. DES gets the e-mail and processes the E-3 application.

Q. WHAT AGENCIES PARTICIPATED IN THIS PILOT PROGRAM?

A. Participating agencies for the pilot program included Community Action Human Resource Agency ("CAHRA") and the Coconino County Community Services.

Q. WHAT IS THE STATUS OF APS' PILOT PROGRAM?

A. The pilot program commenced in July 2006 and as of September 1, 2006, there have been 70 enrollments. APS analyzed the pilot results and obtained feedback from DES. Initial results indicate the system is working effectively, and APS has recently opened the EAG/E-3 process to all agencies utilizing the EAG to make LIHEAP assessments and City of Phoenix, five Maricopa County Community Services offices, Western Arizona Council of Governments ("WACOG") and Gila County Community Action Program have started.

Q. ON A GOING-FORWARD BASIS, WHAT ARE APS' FUTURE PLANS RELATED TO THE EAG / E-3 PROGRAM?

A. During the pilot phase, APS tied income verification to eligibility for LIHEAP, since the guidelines were identical. In the future, APS may want to add other programs which use the same income guidelines, for example, the Temporary Assistance to Needy Families ("TANF") and food stamps. APS is exploring these programs along with the agencies that administer them.

APS is interested in expanding the number of agencies utilizing EAG. Currently, there are 28 agencies using EAG. APS continues to approach other agencies about using EAG. For instance, on May 15, 2006 APS held a forum at which details of the EAG / E-3 program were shared with 20 community action agencies. APS has been contacting agencies that perform means-testing for other

programs (e.g. TANF and food stamps) to assess their willingness and interest in partnering with APS to electronically sign-up customers.

Q. PLEASE EXPLAIN WHY APS IS PROPOSING TO MODIFY THE ADMINISTRATION OF THE E-3 AND E-4 DISCOUNT PROGRAMS.

A. The Company is proposing to modify the Plans of Administration for Schedules E-3 and E-4 in order to facilitate the automatic enrollment process, as discussed in the rebuttal testimony of Mr. DeLizio. The reason we would like to broaden this language is to provide us with the flexibility to pursue other enrollment options, such as allowing community agencies that have access to APS' EAG website the ability to also enroll their clients into E-3. Since these agencies have programs that follow the same income guidelines, it makes sense to provide them with the ability to also enroll their clients directly into our E-3 program. Considering the emphasis that the Commission is placing on our Low Income outreach efforts, this change would allow us to broaden our reach to enroll likely candidates in the program. Additionally, we have spoken with DES and they are amenable to this change.

IX. E-3 AND E-4 MARKETING EFFORTS

Q. PLEASE DESCRIBE STEPS APS HAS TAKEN TO PROMOTE ITS E-3 AND E-4 LOW INCOME DISCOUNT PROGRAM.

A. APS sends program promotions via customer bills to all residential customers every year and applications are always available at Community Action Agencies and government economic assistance offices. APS promoted the programs via articles in the April/May 2005, October/November 2005 and June/July 2006 APS "Arizona Lifestyle" newsletters, and expanded information on aps.com, including an on-line application for customers. APS held a forum with numerous social services agencies in an effort to create a joint partnership with these agencies to

promote the low income assistance programs. In addition, APS has engaged in a relationship with HUD in an effort to coordinate marketing and promotion of E-3 and E-4 to their low-income housing clients.

Q. PLEASE DESCRIBE APS' ENERGY SUPPORT PROGRAM MARKETING AND PROMOTIONAL EFFORTS TO TRIBAL CUSTOMERS.

A. As a result of Decision 67744, APS developed marketing efforts to attract a greater number of Tribal customers to E-3 and E-4. In the spring of 2006, APS sent letters to all of our Tribal customers explaining the benefits and eligibility criteria of the E-3 and E-4 program and included the application. This mailing included an endorsement by Tribal leadership. In the letter, leaders of the Navajo and Hopi Nations encouraged their members to participate in the programs. This was followed in the summer of 2006 with media promotion of E-3 to its tribal customers through print and radio ads. While the response to these marketing efforts has increased Tribal customer enrollment by over 150% in 2006, APS is in the midst of an additional direct-mail campaign to yet further increase Tribal customer participation.

Q. PLEASE DESCRIBE THE CURRENT ENROLLMENT FOR E-3 AND E-4 LOW INCOME PROGRAMS.

A. During the Test Year, APS had an enrollment of approximately 28,000 on the E-3 and E-4 low income program, which included 206 customers on Tribal lands. By August 2006, enrollment increased to over 36,000 with 566 Tribal customers.

X. CONCLUSION

Q. AND DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

APPENDIX A

Statement of Qualifications

Teresa A. Orlick

Teresa A. Orlick is Arizona Public Service Company's Manager of Customer Information and Programs. In that capacity she oversees the planning, marketing and implementation of customer programs for APS. These programs include the portfolio of demand side management programs, SurePay (the APS direct debit payment plan), Equalizer (the APS levelized payment plan) and E-3/E-4 (the APS low income discount plan). She also oversees the market research function for APS.

Before joining APS, she was the Marketing Manager at Wisconsin Electric and prior to that, at Wisconsin Natural Gas, where she oversaw the marketing of energy efficiency and energy-related products for the residential and multifamily market segments. She also managed the Residential Conservation Service home energy audit program.

She has served on various professional committees including EPRI's Residential Task Force, and EEI's Residential Marketing Communications Task Force and Residential Strategic Action Committee.

She received a Bachelors of Science degree in Business Administration from Marquette University in Wisconsin.

REBUTTAL TESTIMONY OF BARBARA D. LOCKWOOD

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Barbara D. Lockwood. I am the Manager of Renewable Energy for Arizona Public Service Company ("APS" or "Company").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold a Bachelor of Science in Chemical Engineering from Clemson University and a Master of Science degree in Environmental Engineering from Georgia Institute of Technology. I am a registered professional chemical engineer in Arizona and California. I joined the Company in 1999.

Prior to my current position, I held various policy and environmental positions at APS. I began my career in the chemical industry at E.I. DuPont de Nemours in various engineering and management roles on the east coast. I then moved into environmental consulting in California and Arizona where I managed diverse projects for national clients across the United States.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. While I have not testified in previous rate proceedings, I have testified on several occasions before the Arizona Corporation Commission ("Commission") regarding the development of the Renewable Energy Standard ("RES") and Tariff, as well as APS's applications involving our renewable energy customer program.

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

A. 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 fully supports the Commissions efforts to achieve the overall proposed RES targets, and I will provide testimony that generally describes APS' views on the RES and related issues.

I will also respond to the testimony of Dr. David Berry with Western Resource Advocates associated with Green Power Tariffs and the cost of procuring renewable energy. In addition, I am responding to the testimony of Ms. Amanda Ormond with Interwest Energy Alliance associated with the APS' renewable energy procurement process.

Finally, I am adopting as my own testimony, that portion of APS witness Ed Fox's Direct Testimony, Section IV, pages 19-22 regarding the Company's Green Power offerings. I will be offering certain modifications to the proposal based on suggestions made by Dr. Berry and the Company's experience with its existing renewable portfolio.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY IN THIS RATE CASE DOCKET.

A. APS supports the goal of increasing the use of renewable resources to meet customers' growing energy needs and believes the RES proceeding is the appropriate forum to discuss this issue. In my testimony, I generally describe our approach to implementing the RES, should it be approved by the Commission in its current form.

I will also respond to Ms. Ormond's suggestions with regard to independent evaluators and mandated request for proposals for renewable energy. Finally, I will also describe our proposed modifications to the green power offering previously submitted by Mr. Fox and provide information in support of the proposed total solar schedule sponsored by APS witness Greg DeLizio.

III. RENEWABLE ENERGY STANDARD

Q. PLEASE DESCRIBE APS' GENERAL VIEWS ON THE DRAFT RES.

A. APS supports the intent of the draft RES and the development and integration of renewable energy into our energy portfolio. Renewable energy diversifies the Company's energy supply, which provides many benefits to our customers. Renewable energy can also help manage the environmental impacts of electricity generation.

APS has previously expressed concerns to the Commission about a few components of the draft RES including the penalty provisions and the magnitude of the distributed generation component. Although I will not discuss those concerns in this testimony, APS will continue to provide support for the RES and make constructive suggestions for its improvement in the rulemaking process.

Q. HOW WILL APS OBTAIN THE RENEWABLE ENERGY TO MEET THE DRAFT RES TARGETS?

A. To meet the draft RES targets, APS anticipates obtaining most of our renewable energy from bulk power purchase of renewable energy or through generation of renewable energy from APS-owned projects. (Distributed energy projects will make up the balance). APS is currently providing over 16 megawatts of renewable energy to our customers from APS-owned solar facilities and a power purchase agreement (PPA) for 10 megawatts of geothermal energy from a project

in California. APS anticipates adding 105 megawatts of wind energy within the next 6 months, and 20 megawatts of biomass and biogas energy within about 18 months, all through long term PPAs.

Most of these projects were obtained through APS' 2005 renewable energy Request for Proposals (RFP). APS' experience in the 2005 RFP indicates that the market place is willing to offer renewable energy from small to medium scale renewable power projects. APS continues to evaluate additional projects including Arizona and California geothermal projects, regional wind projects and large-scale Arizona solar projects.

For the foreseeable future, the cost for energy from such projects is anticipated to continue to be in excess of the comparable cost of conventional alternatives. Renewable energy projects are being developed in Arizona, but to effectively manage the costs of the program, APS will look both in Arizona and regionally for the most cost effective projects.

Q. PLEASE DESCRIBE APS' GENERAL APPROACH TOWARD THE DISTRIBUTED ENERGY REQUIREMENT OF THE DRAFT RES.

A. The draft RES currently requires an increasing percentage of total renewable energy to be derived from distributed resources. The distributed energy requirement starts at 5% in 2007 and increases to 30% in 2012 and beyond. APS understands and supports the objectives of the distributed energy requirement of the draft RES, even though we have significant concerns over the magnitude of the requirement, the adequacy of necessary funding, and the cost compared to other renewable alternatives.

APS' customers have indicated their support for distributed energy by increasing participation in our Solar Partners Incentive Program (formerly referred to as the

Credit Purchase Program). As of the end of August 2006, 835 customers have installed renewable energy systems through our program including grid-tied and off-grid photovoltaic generation resulting in 1.7 megawatts of distributed generation. APS supports our customer's interest and will build on our already successful program.

APS believes that consumer awareness regarding APS' distributed generation program will be fundamental to its success, and is currently implementing a significant customer awareness campaign. We are also in the process of contracting with an outside firm to develop a full marketing and communications plan for implementation in early 2007.

APS' approach to the distributed energy requirement of the draft RES would also involve incorporation of the Uniform Credit Purchase Program (UCPP).

IV. APS' GREEN POWER OFFERINGS (GPS-1 AND GPS-2)

Q. IS APS STILL PROPOSING GREEN POWER OFFERINGS AS DISCUSSED BY MR. FOX?

A. Yes. I am adopting Section IV of Mr. Fox's direct testimony. As Mr. Fox explained, some of APS' customers have expressed an interest in subscribing to specific blocks or percentages of renewable resources in their energy purchases. In his direct testimony, Mr. Fox discussed the framework of the Company's proposal. I am not proposing to change that general framework, but I am proposing an updated method for calculating the tariff amounts.

Q. PLEASE EXPLAIN APS' GREEN POWER PROPOSAL.

A. APS is proposing to provide to customers a mix of renewable energy resources representing our available renewable generation portfolio. The rates are constructed based on the actual cost of renewable energy from three projects for

which APS has contracted.[1] 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. The expected energy production profiles for each project were used to develop energy projections fitting both seasonal and time-of-day windows. The result was weighted average costs of $62.35 per megawatt hour and $62.74 per megawatt hour for 2007 and 2008 respectively. Mr. DeLizio uses these costs in the designing the Green Power rates.

APS also proposes to change the 30% option in GPS-2 to 35% to better coincide with recent changes to the Leadership in Energy and Environmental Design (LEED) standard for new buildings. As described by Mr. DeLizio, APS is proposing initial green power rates based on two year cost projections. APS is proposing to update the green power rates when customer demand exceeds the available supply from these three projects (if additional energy is available from other projects) through a process discussed by Mr. DeLizio.

Q. ARE THERE ANY OTHER PROVISIONS TO APS' GREEN POWER PROPOSAL?

A. Yes. As suggested by Dr. Berry, APS proposes to provide reports on customer participation, kWh sales, and revenue in its annual EPS/RES filings.

Q. DO YOU AGREE WITH OTHER SUGGESTIONS FROM MR. BERRY RELATED TO APS' GREEN POWER PROPOSAL?

A. Yes. APS agrees with Dr. Berry that the green schedule should be based on actual project costs and has revised our proposal accordingly. APS will pursue green-e

[1] One of these projects, a 10 MW geothermal project, is in operation today. The other two projects are wind resources totaling 105 MW, and they will be in operation in late-2006 or early-2007, before the green schedule becomes available to customers.

certification for its green power products and is proposing to change the minimum block size in GPS-1 to 100 kWh/month.

Q. APS IS ALSO PROPOSING A NEW TOTAL SOLAR SCHEDULE. PLEASE EXPLAIN THE PURPOSE OF THIS SCHEDULE.

A. APS is aware of our customer's interest in renewable energy and, in particular, solar energy. To date, 835 of our customers have chosen to participate in our Solar Partners Incentive Program to install their own solar energy system. However, many of our customers who are interested in solar energy may not wish to own and operate their own system. With the Total Solar schedule (Solar-3), APS takes on the responsibility for the generation and provides clean, renewable, solar energy to the customer.

With the new Total Solar schedule, APS is proposing to offer our customers the opportunity to support solar energy by purchasing APS-generated solar energy to offset 50% or 100% of their energy consumption. APS proposes to provide the solar energy from utility-scale solar systems. The price of solar energy included in the initial Total Solar schedule sponsored by Mr. DeLizio is $0.39 per kilowatt hour. The price was developed based upon a single-axis photovoltaic system using an installed capital cost of $7,000 per kilowatt DC, average production of 2,400 kilowatt hours per kilowatt DC, 25-year system life, and APS' requested cost of capital. The size and technology was selected so that APS could offer the lowest cost, readily available technology which could be added in manageable increments. The initial projects would be constructed at APS facilities for efficiency of construction, maintenance and operations. Mr. DeLizio describes the rate design and associated cost.

APS currently has approximately 4,400 customers enrolled in our Solar Partners Rate program which allows customers to purchase 15 kilowatt hour blocks of

solar energy. APS has proposed to freeze the Solar Partners Rate (SP-1) with the introduction of the new Green Power and Total Solar schedules.

V. RENEWABLE PROCUREMENT

Q. INTERWEST ENERGY ALLIANCE HAS PROPOSED THAT THE COMMISSION APPOINT AN INDEPENDENT EVALUATOR FOR RFP PROCESSES. DO YOU AGREE?

A. No. The draft RES requires utilities to have procedures for selecting resources and also requires certification by an independent auditor that the procedures are fair and unbiased and have been appropriately applied. In addition, Mr. Dinkel describes APS' plans for a Wind Integration Study. APS believes that by conducting the Wind Integration Study academic and industry participants can assist in helping establish guidelines to be used for RFP evaluations of wind projects. Therefore, an independent evaluator for RFPs is unnecessary. Finally, in response to APS Data Request IEA-1-5, Interwest Energy Alliance calculated the cost of an independent evaluator to review an RFP at between $90,000 and $125,000[2], with such costs being included in the administrative costs of procuring renewable energy or from the System Benefits Charge.[3] Such additional costs are an unnecessary use of customers' money because of the clarity and rigor provided by the Integration Study and draft RES requirements.

Q. INTERWEST ENERGY ALLIANCE ALSO PROPOSED MANDATED RFP'S RELATED TO RENEWABLE PROCUREMENT. DO YOU AGREE?

A. No. APS believes that 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

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[2] Interwest Energy Alliance estimated the cost between $65,000 and $85,000 if a Staff person were to perform that function.

[3] See Interwest Energy Alliance response to APS-IEA-1-5.

customers. As such, APS should be allowed to evaluate all options and secure renewable energy in the most cost effective manner that best fits with the overall resource strategy. 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 our customer's best interests.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS believes that increasing the usage of renewable energy is a worthy objective for many different reasons. APS supports the intent of the draft RES and believes that the RES rulemaking is the proper forum for addressing renewable energy. In addition, APS has proposed green power schedules and the Total Solar schedule that provide additional customer choice.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

REBUTTAL TESTIMONY OF MARK K. GORDON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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REBUTTAL TESTIMONY OF MARK K. GORDON ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark K. Gordon. My business address is One Embarcadero Center, Suite 1400, San Francisco, California 94111.

Q. HAVE YOU PROVIDED PREVIOUS TESTIMONY IN THIS PROCEEDING?

A. No, I have not.

Q. PLEASE DESCRIBE THE NATURE AND PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. I was asked to analyze APS' incentive compensation programs, evaluate the goals and effectiveness of the programs, and respond to the suggestions by certain Staff and Intervenor witnesses that some of the costs of these programs should be disallowed by the Commission in calculating APS' recoverable costs.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. My educational background includes a Bachelors degree in Psychology and a Masters in Business Administration from the University of California at Berkeley.

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

A. I am a principal with Hewitt Associates LLC and a senior consultant in our Talent and Organization Consulting practice.

Q. PLEASE DESCRIBE THE NATURE OF THE BUSINESS OF HEWITT ASSOCIATES.

A. Hewitt Associates LLC ("Hewitt") is a global human resources management and administration consulting firm. Since 1940, Hewitt has provided well over 10,000 organizations with a broad range of consulting and administrative services related to total compensation and other human resource needs. Hewitt consults with many mid- and large-sized organizations, including over half of the *FORTUNE*® 500 companies. In addition, our proprietary Total Compensation Measurement™ (TCM™) DataBase represents the total compensation (including base salary, annual- and long-term incentives, supplemental benefits and perquisites) practices of over half of the *FORTUNE* 500 companies and a substantial representation of the electric and gas utility sector.

Q. PLEASE DESCRIBE YOUR OWN PROFESSIONAL QUALIFICATIONS.

A. I work with a broad range of public and private general industry corporations including utility and energy service businesses in the West Region. I have twenty years of management consulting experience with Hewitt, specializing in executive and broad-based compensation program strategy, design, and implementation. My testimony is based on my own professional experience; the collective compensation consulting experience of Hewitt Associates; our extensive library of published, private, and proprietary compensation surveys; and our understanding of the Arizona Public Service Company's ("APS") incentive plans.

Q. HOW DOES THE EXPERIENCE YOU HAVE DESCRIBED ABOVE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My educational background in psychology and business emphasized the study of motivation theory and organizational behavior management. This perspective is very helpful in assessing the effectiveness of incentive design from both an

objective and qualitative point of view. Over the past twenty years, I have been personally involved in the design and review of hundreds of officer, management and broad based employee incentive plans covering annual and multi-year performance periods for clients in a variety of industries, including regulated gas and electric utilities. This experience, in the context of consulting on "total compensation" strategy and evaluation of competitive market practice provides a strong foundation for me to comment on the structure, potential value and effectiveness of APS' Variable Incentive Plan. In addition to my client activity, I have years of experience working annually with a variety of published and private survey sources which help me stay current on competitive market practices and trends in compensation management.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I was asked to comment on the purpose, prevalence, cost, and effectiveness of variable pay incentive programs in corporate America, including the utility industry and respond to the suggestions by certain Staff and Intervenor witnesses that some of the costs of these programs should be disallowed by the Commission in calculating APS' recoverable costs. In addition, I was asked to evaluate the nature and effectiveness of APS' incentive compensation program based on a variety of objective data and interviews with selected APS employees representing various organization levels who are participants in the program. My testimony addresses the benefits these types of incentive programs provide for key constituents (including customers, employees, and shareholders); the motivational value of incentive programs in encouraging employees to achieve

key operational, customer service, and cost containment goals; and the need to be market competitive to attract and retain a stable, talented workforce. My testimony also addresses my evaluation of the effectiveness of APS' incentive compensation program in achieving its stated goals and objectives.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE APS COMPENSATION PROGRAMS.

A. Based on my review of APS' annual variable incentive plans, and the long-term incentive plan, I conclude that these plans are designed consistently with competitive market practices, and their targeted compensation value is either below or consistent with competitive market practices. This indicates to me that cash compensation has been conservatively managed at APS.

I believe these plans are integral in providing a reasonable, competitive "total" compensation program at all levels of the organization. The elimination of any of these programs would significantly impair APS' ability to attract and retain employees critical to its successful ongoing operation. In fact, it could lead to higher turnover rates which would likely result in reductions in productivity, increase recruiting and training costs as well as damage employee morale and erode the Company's value system of high performance, accountability and pay for performance. Given my years of experience and knowledge of competitive practices, I view these compensation and benefit programs as a normal and reasonable "cost of doing business" and therefore the costs of these programs should not be disallowed by the Commission in calculating APS' recoverable costs.

In addition, the variable incentive plan has demonstrated effectiveness at aligning employees with its business objectives and reinforcing a high performance

culture. The design and administration of the variable pay programs, including the goals and objectives, appear to correlate well with performance results that have significantly benefited customers over the past 10 years. APS' commitment to goal setting at all levels of the organization and ongoing communication serve to motivate employees and create a clear focus on accountability and pay for performance.

Given the current demographics of APS' workforce, including the high percentage of employees who are currently or soon will be eligible to retire, and the projected decrease in talented candidates entering the workforce, APS' ability to maintain stability with its current workforce and effectively compete for new talent will be critical to its future performance. Providing a competitive total compensation opportunity is fundamental to APS' ability to attract and retain high performing employees and in the best interests of customers.

III. NATURE OF WORK PERFORMED

Q. PLEASE EXPLAIN WHAT YOU DID AND WHAT YOU REVIEWED AS PART OF YOUR WORK ON THIS MATTER.

A. When I agreed to testify for APS, I asked for and was furnished with the following information by APS management to better understand the APS compensation program including incentive plan designs, award structures, performance results and payout history as of 2005:

- APS Variable Incentive Plans (PNW Chairman and CEO, Officer, Senior Management, Management, and Employee)
- Ten years of history (1996-2005) of APS performance metrics, goals and incentive results

- Industry performance benchmarking results on a variety of operating, customer and safety criteria
- Description of the APS Performance Share plan and Pinnacle West Capital Corporation 2002 Long Term Incentive Plan document

I also requested and was provided with the most recent (October 2005) results of an annual independent consultant market assessment of APS executive compensation levels compared to a Board approved peer group of other utilities with similar operating characteristics and general industry companies. I supplemented my analysis with additional benchmark information from Hewitt's proprietary executive compensation database, including detailed plan design and administrative specifications for incentives and target award opportunities at a selected group of approximately 20 electric and gas utilities.

In addition to reviewing the above documentation, I interviewed selected APS non-officer employees at various organization levels to gather anecdotal experience and perceptions related to the understanding and motivational value of the annual Variable Incentive Plan. I also had access to management for clarification of any program designs or administrative activities, as needed.

I was also recently provided with a copy of the direct testimonies of Mr. James R. Dittmer on behalf of the Utilities Division Staff (dated August 18, 2006) and Ms. Marylee Diaz Cortez, CPA on behalf of the Residential Utility Consumer office.

My testimony reflects the independent evaluation of this background information, my understanding of market practices and my extensive experience working with clients on these types of programs.

IV. OVERVIEW OF VARIABLE PAY INCENTIVE PROGRAMS

Q. PLEASE PROVIDE AN OVERVIEW OF WHAT YOU CALL VARIABLE PAY INCENTIVE PROGRAMS.

A. Corporate America, including the utility industry, has undergone significant changes and restructuring over the past two decades. Evolving business strategies, deregulation, global competition, workforce demographics, and the competitive labor market are key factors driving companies to create flexible organization structures and human resource systems necessary for ongoing business success. One of the more subtle but sweeping changes in human resource strategy over this time period has been the widespread implementation of variable incentive compensation programs at virtually all organization levels as an integral element of the total compensation and performance management systems. These programs and systems, once reserved for senior management, increasingly have been extended to cover all employees in some form.

I'd like to make an important distinction between a "bonus" program and "incentive" program. A bonus program is often viewed as a discretionary "add-on" to base pay, with the award size subjectively determined at the end of the year. Whereas, an annual incentive 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 on objective criteria and the actual award earned is variable based on actual results relative to the pre-set goals. This type of system provides a more clear connection between variable pay and performance.

A properly designed incentive program with a competitive award structure has become a critical part of employee retention strategies as well as for attracting new talent and motivating desired performance. In many organizations, it also plays a strategic role in aligning pay with performance results and engaging employees to take more ownership in business success. A company without an incentive compensation program today is clearly at a competitive and operational disadvantage.

Q. WHAT IS THE PURPOSE OF SUCH VARIABLE PAY INCENTIVE PROGRAMS?

A. 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.

In other words, incentive plans serve many purposes. Principally, however, they are intended to improve business results by focusing employees on critical goals, motivating them to direct their behaviors and rewarding them for performance achievement, all while maintaining a reasonable compensation level.

Moreover, incentive plans are undertaken because the benefits (or performance outcomes) associated with payments generally outweigh the program costs. The key benefits of incentive plans include motivating performance which achieves desired results, making total compensation cost variable depending on company performance, delivering a total compensation program that is attractive to

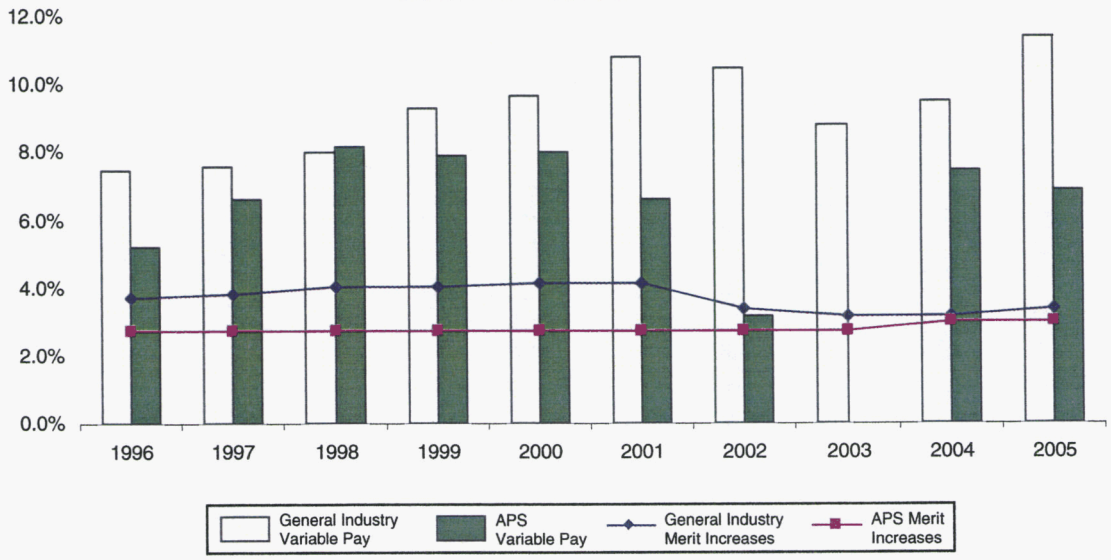
existing and potential employees and aligning and focusing attention on key behaviors or specific goals.

Q. HOW PREVALENT ARE SUCH INCENTIVE COMPENSATION PROGRAMS IN CORPORATE AMERICA TODAY, WHAT ARE THE TYPICAL COSTS OF THESE PROGRAMS, AND HOW DOES APS COMPARE?

A. A recent Hewitt survey (*2005 Salary Increase Survey*) shows that the prevalence of U.S. companies with at least one broad-based variable compensation plan has increased from 60% in 1994 to over 75% in 2005. Company spending on variable pay for salaried exempt employees (as a percent of payroll) below the officer level over this period increased from 6.4% to 11.4%. Over the same time period (1994-2005), average annual merit base salary increases have declined from approximately 4.0% of payroll to 3.6%.

The following table summarizes the ten year historical spending trend in employee variable pay and annual merit increases for salaried exempt employees among general industry companies compared with APS:

General Industry vs. APS Spending on Broad-Based Cash Compensation for Salaried Exempt Employees (as a % of Payroll)



As shown in the table, APS' spending on variable pay has been considerably below industry averages in all years except 1998 and base salary increases have likewise been below industry averages in all years. This indicates to me that cash compensation has been conservatively managed at APS for a number of years.

Q. DOES THE NATURE OF THE UTILITY INDUSTRY, AS DIFFERENTIATED FROM CORPORATE AMERICA GENERALLY, MAKE INCENTIVE COMPENSATION PROGRAMS LESS IMPORTANT OR LESS BENEFICIAL?

A. Absolutely not. In fact, incentive compensation plans have taken on increasing importance in helping utilities provide a competitive "total compensation" package that allows them to compete with general industry companies to attract and retain a competent, stable workforce that in turn provides efficiencies and costs savings for the company and its customers and shareholders. As job mobility across industries and heightened competition for leadership and top talent has increased in recent years, workforce stability and the retention of key leadership throughout the employee ranks provide several benefits to a utility company and its customers, including:

- Minimizing costs associated with high turnover including recruiting, training, and decreased productivity associated with filling vacant positions.
- Continuity of the executive, management, and professional teams to develop and implement effective business strategies.
- More consistent and efficient customer service, with resultant cost savings and other customer benefits.

In the regulated public utility industry, companies must meet the needs of multiple stakeholders including customers, shareholders, and the communities in which they operate. Incentive compensation programs, if properly designed and implemented, provide benefits to all of those constituents.

V. THE DESIGN OF APS' INCENTIVE COMPENSATION PROGRAM

Q. DOES THE BASIC DESIGN OF APS' INCENTIVE COMPENSATION PROGRAM COMPORT WITH THE GENERAL OBJECTIVES AND PURPOSES OF SUCH INCENTIVE PROGRAMS?

A. Yes. APS' annual program as of 2005 is called the Variable Incentive Plan and has five distinct organization levels of participation—PNW Chair/CEO, Officer (includes APS President, EVP and VP), Senior Management, Management and Broad-Based Employees. These plans combine a focus on Company performance and Business Unit results defined as Critical Success Indicators ("CSIs") and provide a monetary incentive when these goals are accomplished. At APS, the current plan is funded when Company earnings exceed a threshold level of performance. Having a corporate performance threshold based on earnings is consistent with a large majority (88%) of similar gas and electric utilities reported in the Hewitt database. The amount of the funded pool that is earned is based on the achievement of Company Earnings and Business Unit CSIs. CSIs are key business goals covering areas including operational efficiency, safety, environment, and customer satisfaction. The incentive program has been in place at APS for over ten years and is an integral part of the overall business and human resource strategy to align employees with the Company's mission, strategy, and value system and enhance awareness of key business objectives.

A unique dimension to the employee alignment strategy of the APS incentive program is the inclusion of IBEW members, which represent almost one-third of the workforce, and at the participation level of other frontline employees. The participation of represented groups is not common in the utility industry, and I believe it has been particularly effective at APS in directing their behavior and reinforcing the importance of key operating goals and objectives throughout the organization across all employee groups.

Factors that have been identified through research and reported in general industry surveys as enhancing incentive plan effectiveness include:

- Setting realistic goals/targets.
- Effectively communicating plans.
- Using appropriate measures.
- Ensuring a clear understanding of plan objectives.
- Correlating accomplishments with rewards.

In addition, motivation theory suggests that the effectiveness of an incentive plan is driven by the employees' perception of the ability to impact performance results, the probability of achieving pre-set goals, and the meaningfulness of rewards. APS' Variable Incentive Plan is designed consistent with these underlying "effectiveness" factors.

Finally, APS' variable incentive compensation helps to manage the Company's ongoing cost structure of total pay because incentive awards must be "re-earned" every year.

Q. COULD YOU PLEASE EXPLAIN IN MORE DETAIL HOW APS' INCENTIVE COMPENSATION PROGRAM OPERATES TO ACHIEVE THE GOAL AND OBJECTIVES OF THE PROGRAM?

A. APS has used its annual Variable Incentive Plan to focus employee behavior and provide a meaningful opportunity to impact and share in the Company's operating results. APS provides a threshold, midpoint and maximum award opportunity (as a percent of base pay) to its employees consistent with those reported among other utility and general industry companies. A midpoint, or "target" award is the amount which an employee will receive if the actual results generally equal those budgeted. Actual payments are based on the results achieved and are below target if the overall performance is less than planned or above target if performance exceeds plan goals.

APS's incentive awards are determined based on a combination of financial and operating performance results. The APS incentive payment is based on the Company meeting a threshold earnings goal and, at the Business Units, the level of achievement of CSIs. If the threshold earnings goal is not met, no payout is made. After the threshold earnings goal is met, the incentive award is generally determined 50% based on Company earnings and 50% based on CSIs through the EVP level. This performance/award structure effectively balances participants' focus on customers and shareholders. For Frontline employees, an additional award "kicker" of up to 2% of pay is awarded based on customer satisfaction scores. In 2005, no Officer awards were granted. The 2005 incentive payout was approximately $30 million (of which a significant part was paid by non-APS generation plant participants). Non-officer management awards represented 35% of the pool and Frontline employee (including IBEW) awards represented 65% of the total incentive pool. Awards at these organization levels

reflected Corporate earnings performance and the achievement of Business Unit CSIs (as described above). The performance/award structure effectively balances the focus on performance for customers and shareholders, with an increasing emphasis on incentives tied to customer performance metrics below the Officer level, providing a more meaningful focus on pay for performance for the Frontline employees.

Q. HOW DO THE 2005 TARGETS AND ACTUAL INCENTIVES OF THE APS PROGRAM COMPARE TO THOSE OF OTHER COMPANIES THAT HAVE INCENTIVE COMPENSATION PROGRAMS?

A. APS's target award structure, in general, appears to be reasonably positioned and in some cases lower than median when compared with the opportunity at comparable utilities and general industry companies. A target award (generally expressed as a percentage of base pay) is the expected award level assuming all performance goals are met at "plan" or "budgeted" levels. The following table compares APS's 2005 target awards to the typical market range of target annual business incentive awards at the Officer level (Chair/CEO/President, EVP, VP) Salaried Exempt—Management, Salaried Exempt/Non-Exempt—Frontline, and Union Hourly—Frontline levels [1].

[1] Results from Hewitt's 2005 Total Compensation Measurement™ DataBase survey of industrial and service organizations and 2005 Competitive Compensation Analysis of executive and officer positions at APS.

Employee Group	2005 Utility Industry Target (%)			2005 General Industry Target (%)			APS Target (% of base pay)
	Average	Median	75th %ile	Average	Median	75th %ile	
Chair/CEO	-	85%	100%	-	104%	-	125%
President	-	80%	85%	-	99%	-	75%
EVP	-	50%	60%	-	60%	70%	50%
VP	-	40%	45%	-	45%	50%	35%
Salaried Exempt—Management	11.3	10.0	13.1	11.1	10.0	15.0	7.5%
Salaried Exempt/ Non-Exempt—Frontline	7.6	5.5	10.5	5.6	5.0	7.0	3%+1%
Union Hourly—Frontline	3.8	2.9	5.0	3.8	3.5	5.0	3%+1%

As summarized above, the PNW Chair/CEO target is somewhat above average but as pointed out later total target direct pay is below the market median. All other organization levels appear to have target award opportunities that are at or below the market median. While the Senior Management level is not shown in the table due to the lack of a direct general market comparison, based on my experience, I believe that APS' target of 15% for this participant level would also be at or below the market median. The large majority of incentive plan structures provide for a potential range of actual awards from 0 to two times the target award (e.g., if the management target is 7.5% of pay, the maximum award for significantly exceeding budgeted goals is 15% of pay). APS' award range opportunity is consistent with this market practice.

The following table compares APS' actual 2005 incentive awards (as a % of base pay) and 5-year average actual awards to the 2005 market actuals for the same participant levels:

Employee Group	2005 Utility Industry Actual (%)			2005 General Industry Actual (%)			APS Actual (% of base pay)	
	Average	Median	75th %ile	Average	Median	75th %ile	2005	2001 –2005 Average
Chair/CEO		103%	148%		104%	178%	0%	65.1%
President	-	-	-	-	-	-	0%	42.4%
EVP	-	61%	120%	-	66%	119%	0%	21.0%
VP	-	43%	78%	-	47%	92%	0%	15.8%
Salaried Exempt—Management	12.3	10.0	16.8	11.4	10.0	15.0	12.6%	8.0%
Salaried Exempt/ Non-Exempt—Frontline	8.1	6.5	9.9	5.9	5.0	7.8	5.00%	3.8%
Union Hourly—Frontline	3.7	2.3	5.0	4.0	4.0	5.0	5.00%	3.2%

As summarized above, the actual 2005 and 5-year average annual awards (expressed as a percentage of base pay) under the APS plan show a dramatic shortfall for the executive and officer levels, 2005 Management awards were near the market average and Frontline awards were below the median for salaried non-exempt employees and at the 75th percentile for IBEW participants. Five year average awards were below market averages at all levels. Overall, these award levels continue the trend of APS' conservative management of cash compensation relative to the market.

VI. THE BENEFIT TO CUSTOMERS

Q. HOW DOES APS' INCENTIVE COMPENSATION PROGRAM BENEFIT CUSTOMERS?

A. APS' incentive program directly benefits customers in a number of ways. In general, as part of a total compensation program that helps to attract, motivate and retain key employees, it is a key factor in driving a high performance culture. By retaining high-performing employees, customers benefit not only from the heightened experience of these valued employees but also by minimizing turnover costs arising from recruiting, "downtime" and retraining. In addition,

variable incentive compensation helps to manage payroll expenses because incentive awards must be "re-earned" every year.

APS' incentive program goals emphasize a balanced performance focus on customers, shareholders, and the communities in which it operates. As mentioned above, management and broad-based employee participants have specific goals contributing to operational efficiency, improved productivity, safety, environment, customer service, and cost control. All of these goals contribute to two common results: reducing costs, which can then be passed along to customers in the form of reduced rates or which can free up funds for other investments to benefit customers, and higher levels of customer service.

APS' performance goals are specific, meaningful, achievable, relevant and time sensitive. The measures directly benefit customers by focusing on controlling costs, providing good customer service, and promoting safety. Goals are established at the Corporate level, but also at the operating Business Unit (e.g., Fossil, Delivery, Shared Services) level to provide employee "line-of-sight" with measures that they impact day-to-day. Goals are communicated to participants to help them understand why objectives are important and how accomplishment of "local" goals contributes to achievement of higher-level Company goals. For example, APS' Delivery Unit CSIs include Safety goals measuring weeks without a preventable recordable injury, Customer Satisfaction as measured by survey results, Business Performance Trends, System Average Interruption Frequency Index ("SAIFI") performance and Environmental Incidents. These measures clearly have a strong correlation with customers.

VII. THE EFFECTIVENESS OF THE APS PROGRAM

Q. WHAT DETERMINATIONS ABOUT THE ACTUAL EFFECTIVENESS OF THE APS INCENTIVE COMPENSATION PROGRAM HAVE YOU MADE?

A. I reviewed data prepared by APS comparing its performance against industry performance on a variety of operating metrics. My conclusion is that, over the past ten years, APS has a demonstrated performance record of cost containment, system operating reliability and safety as summarized in:

- **Attachment MKG-1** summarizes the Non-Generation O&M per Customer APS v. Similar Sized and Regional Utilities 1995-2005 which shows that APS has outperformed other regional and similarly sized utilities in every year since 1995
- **Attachment MKG-2** summarizes the Edison Electric Institute's 2004 Reliability Report based on System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) from 1996 to 2004 which shows that APS has improved SAIFI by 38% and SAIDI by 44% while the National Average SAIFI has gotten worse by 9% and the National Average SAIDI has gotten worse by 109% during the same period.
- **Attachment MKG-3** summarizes how APS has consistently ranked among the top utilities according to the Edison Electric Institute Safety Survey for the lowest total recordable injury incidence rate from 1996-2005
- **Attachment MKG-4** summarizes the JD Powers Studies of Residential and Business Customers which show that APS has ranked among the top

third of utilities in each of the last five years, including the top ten in three of those years on customer satisfaction.

As described previously, these operating, safety and customer service metrics are Critical Success Indicators in the annual Variable Incentive Plan. Based on my review of plan documents and discussions with employees and officers, I believe the incentive process has significantly contributed to APS' impressive and consistent results on these criteria.

I also conducted interviews with selected plan participants below the officer level to gain insight into the motivational value and understanding of the incentive plan purpose and mechanics. The interviews suggest that the annual variable incentive plan has been effective in enhancing employee awareness of critical operating activities and, particularly at the Management level and above, influencing behavior. The plan is well communicated and understood and is viewed as an important part of the total compensation program at all organization levels. Generally, the employees I spoke with believe that the structure of the incentive program and award determinations is reasonable. The interview results are further evidence that the APS incentive programs have been effective and continue to meet the program purpose and objectives.

VIII. IMPORTANCE OF THE STOCK COMPONENT OF APS'S PROGRAM

Q. TO WHAT EXTENT IS THE STOCK COMPENSATION COMPONENT OF THE APS INCENTIVE COMPENSATION PROGRAM AN IMPORTANT ELEMENT OF THE PROGRAM?

A. Long-term incentives have been the fastest growing component of executive and officer compensation over the past fifteen years. Today, long-term incentive awards account for more than one-third of officer direct pay and are integral to a

company's ability to attract and retain management personnel. Based on the most recent competitive analysis of APS' executive compensation program, 93% of its utility peer companies provide long term incentives to executives and officers in the form of stock-based awards (e.g., stock options, restricted stock, and performance shares) and/or cash awards.

In 2002, the PWCC board adopted, and shareholders approved the 2002 Long Term Incentive Plan, which provided for the granting of stock options, performance shares and stock ownership awards. In Mr. Dittmer's testimony, he says that the stated purpose of the Plan is to promote the success and enhance the value of PWCC by linking the participants' personal interests to those of shareholders. However, the complete description of the stated objectives of the Plan, as disclosed in the PWCC proxy statement relating to the May 22, 2002 Annual Meeting of Shareholders, is as follows: "The Plan is designed to attract, motivate and retain selected employees of the Company. These objectives are accomplished by making long-term incentive awards under the Plan, thereby providing Participants with a proprietary interest in the growth and performance of the Company."

My understanding is that APS' long-term incentive plan for its officers has awarded limited performance shares and stock ownership awards, but it has not granted stock options since 2003.

Under the performance share plan, participants are granted a "target" number of shares, with a grant value that was determined to be below the market median in the independent consultant study for the PNW Chairman/CEO, APS President/CEO and EVP level and at the market median for other officers.

Awards are earned based on the Company's compound annual growth rate in Earnings Per Share over a three-year performance period relative to the S&P Electric Utilities Super Composite EPS growth rate over the same period. Minimum, target and superior achievement goals are set at the beginning of the performance period and final award levels may range from 0 to 2 times the "target" grant size. However, for the three-year performance period ended December 31, 2005, there were no payouts under the performance shares.

Half of the APS peer companies reported granting performance shares to its executive officers and more than three-quarters (79%) reported some form of multi-year performance plan. Typical performance periods cover three or four years and EPS is a commonly used metric for determining award size among other utilities and general industry companies.

In addition to serving as a key component of a competitive total compensation opportunity, enabling APS to attract and retain key leadership talent, the long-term incentive plan also 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. Using Earnings Per Share as the long-term performance goal focuses on cost management and productivity gains which directly translate into ongoing savings for customers. It serves as

the broadest measure of all the functions of utility cost performance, both within and between years.

- Long-term financial health provides Company 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.

Q. DOES APS HAVE A SPECIFIC EXECUTIVE RETENTION INCENTIVE?

A. No, and because the Company stopped granting stock options after 2003 and its performance shares have a grant value below the market median for senior officers, I believe the Company should address this issue. After discussions with management, I understand that the Company is now considering retention measures that would better position the Company to offer a competitive overall compensation package. I also understand that such action would not adversely affect APS' rates or financial ratios.

IX. RESPONSE TO RUCO'S PROPOSED 20% DISALLOWANCE

Q. RUCO HAS PROPOSED TO DISALLOW 20% OF ALL INCENTIVE COMPENSATION FROM APS'S RECOVERABLE COSTS ON THE THEORY THAT APS SHOULD SHARE THE COST OF ELECTRICITY PRICE HIKES. DO YOU AGREE WITH THIS SUGGESTION?

A. No, I do not agree. While I understand the principle being suggested, it would be inappropriate to exclude any portion of incentive compensation as this is part of the normal "cost of doing business". As previously stated, incentive

compensation is an integral part of a competitive total pay program necessary to attract and retain employees. The variable incentive program has also been critical in reinforcing APS' achievement of Critical Success Indices and its pay for performance culture. The 2005 executive compensation market study showed that total direct pay levels for the PNW Chairman/CEO, APS CEO/President and EVP levels were below the market median and VP levels were at the competitive market median. This study reflected cash incentive awards paid in 2005 for 2004 performance. Given that no executive and officer cash awards were paid in 2006 for 2005 performance, I expect that all levels will be well below market median in the 2006 study. Had the 5-year average incentive awards been reflected in the study, the conclusion would still have been that APS executives' total direct pay has been below the market median. I believe that it is in the best interest of customers that APS continue to provide a competitive variable incentive compensation opportunity to drive pay for performance. Even Mr. Dittmer acknowledged in staff testimony (page 110 line 20), that the cash incentives in place today are primarily tied to performance measures that directly benefit APS consumers.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Given the current demographics of APS' workforce, including the high percentage of employees who are currently or soon will be eligible to retire, and the projected decrease in talented candidates entering the workforce, APS' ability to maintain stability and effectively compete for new talent will be critical to its future performance. Providing a competitive total compensation opportunity is fundamental to APS' ability to attract and retain high performing employees.

APS' use of an annual variable incentive compensation program and a long term performance plan is consistent with competitive market practices in terms of design, and the targeted compensation value is either below or consistent with competitive market practices.

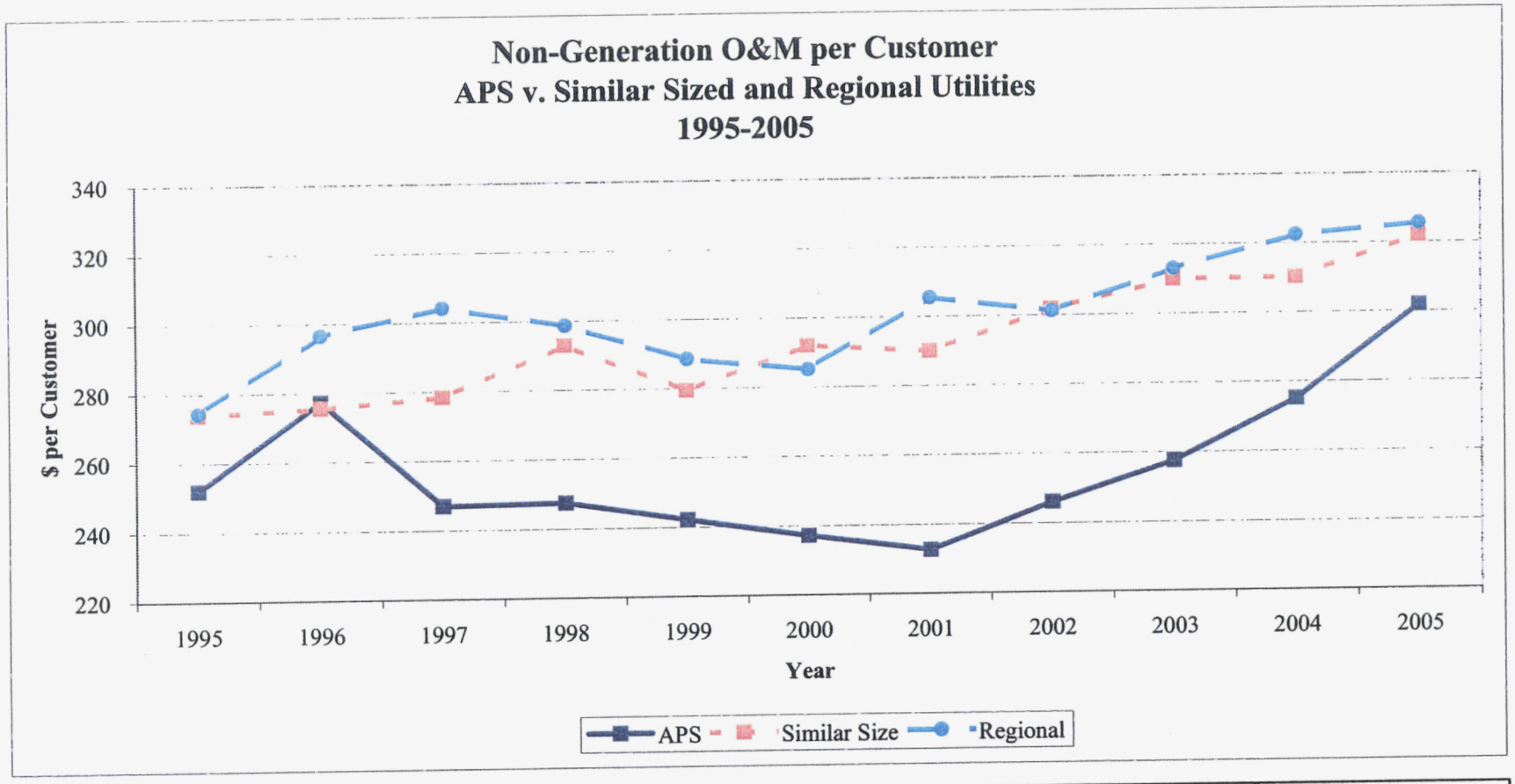
The results of the most recent (2005) competitive market study for officers and executives demonstrated that the total direct (base pay, annual- and long-term incentives) compensation package for the PNW Chairman/CEO, APS President/CEO and EVP levels are below the market median and the VP level, generally, is competitive with the market median only when annual incentives are paid. Since annual incentive awards were not paid to executives and officers for 2005 performance, and no performance shares were awarded, the competitive position significantly drops below the market median for all levels. The elimination of any of these programs would significantly impair APS' ability to attract and retain employees critical to its successful ongoing operation. In fact, it could lead to higher turnover rates which would likely result in reductions in productivity rates, increased recruiting and training costs as well as damage employee morale and erode the Company's value system of high performance, accountability and pay for performance.

In addition, the annual incentive plan has demonstrated effectiveness at aligning employees with key business objectives and reinforcing a high performance culture. The design and administration of the variable pay programs, including the goals and objectives, appear to correlate well with performance results that have significantly benefited customers over the past 10 years. APS' commitment to goal setting at all levels of the organization and ongoing communication serve to motivate employees, enhance awareness and create a clear focus on

accountability and pay for performance. In sum, APS' incentive compensation programs are integral to its ability to attract and retain its employees, align employee behavior with company goals and motivate employee performance, all of which are critical to the success of a high-performing and efficient energy generation and distribution company in today's competitive business environment.

Q. DOES THIS CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.



	Sample	Years											1995-2005 Change	
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Nominal	CPI Adjusted
Non-Gen O&M per Customer	APS	252	277	247	248	242	237	233	246	258	275	302	19.7%	-6.6%
	Similar Size	274	276	278	293	280	292	290	302	310	310	322	17.6%	-8.2%
	Regional	274	297	304	299	289	285	306	301	313	322	326	18.6%	-7.4%

Summary of EEI Annual Reliability Reports Attachment MKG-2

EEI National Average

Year	SAIFI	SAIDI	Number of Companies
1996	1.35	181.80	46
1997	1.24	170.40	44
1998	1.62	248.40	41
1999	1.45	230.40	62
2000	1.53	252.60	58
2001	1.48	208.20	47
2002	1.53	330.00	64
2003	1.59	364.90	68
2004	1.47	380.54	75

APS Average

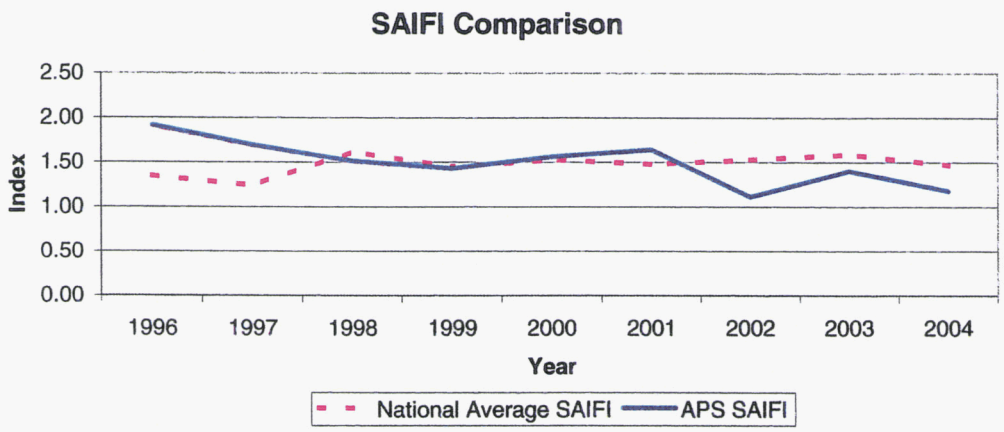
	SAIFI	SAIDI
1996	1.91	170.40
1997	1.69	132.60
1998	1.51	112.20
1999	1.43	96.60
2000	1.56	127.20
2001	1.64	125.40
2002	1.11	106.80
2003	1.40	111.60
2004	1.18	95.40

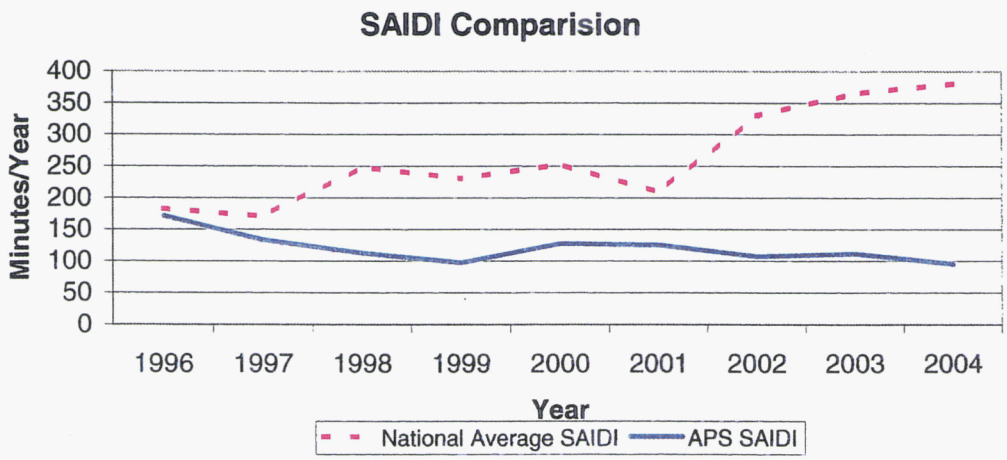
APS change from 1996:

SAIFI Improvement	38%
SAIDI Improvement	44%

EEI change from 1996:

SAIFI Change	-9%
SAIDI Change	-109%





Source: Annual EEI Reliability reports

Arizona Public Service Company **Attachment MKG-3**

Edison Electric Institute Safety Survey (Group Number 2)

Total Recordable Incidence Rate

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1 Worse	8.37	6.08	8.45	5.29	8.36	10.25	8.17	7.63	5.98	5.95
2	6.10	5.83	4.65	4.75	6.71	5.26	6.65	5.41	5.68	5.67
3	5.63	5.48	4.62	3.29	5.54	4.68	5.50	5.26	5.16	4.37
4	5.62	4.31	4.30	3.27	5.52	4.59	5.17	4.99	4.50	3.61
5	5.28	3.61	3.12	3.12	5.49	4.22	4.98	3.92	4.26	3.47
6	5.11	3.21	2.83	2.53	5.15	3.2	4.70	2.88	4.08	2.55
7	5.11	2.23	2.25	2.18	2.53	2.09	3.53	2.71	3.58	2.44
8	3.52	2.18	1.98	1.98	2.29	1.79	2.92	2.70	2.52	2.28
9	3.45	1.56	1.86	1.91	2.15	1.70	2.49	2.18	2.42	2.21
10	3.32	0.97	1.68	1.77	1.55	1.63	2.42	1.84	1.89	1.53
11	3.12	0.77	1.55	1.17	1.18		1.81		1.53	0.81
12	2.71									
13	2.41									
14	1.90									
15 Better	1.47									
APS	1.90	2.18	1.68	1.77	2.29	1.79	1.81	2.18	1.53	2.28
Rank	#2	#4	#2	#2	#4	#3	#1	#2	#1	#4
Percentile	93	73	91	91	73	80	100	90	100	73

Industry data source:
Edison Electric Institute Group Number 2 (4,000 to 6,999 Employees).

APS Electric Utility Residential Customer Satisfaction

1999-2006[1]

Customer Satisfaction Index

Year	Industry	APS	Ranking
1999	97	96	51st among 78 utilties
2000	98	102	43rd among 75 utilities
2001	98	98	50th among 70 utilities
2002	100	104	22nd among 74 utilities
2003	101	110	7th among 77 utilities
2004	98	107	9th among 78 utilities
2005	99	111	6th among 78 utilities
2006	94	100	24th among 78 utilities[2]

Notes:

[1] Information prior to 1999 is not available as that is the first year JD Power conducted the study.

[2] In 2006 APS was ranked in the top quadrant among Investor Owned Utilities (IOUs) nationwide and second among the West Region IOUs.

Source:

JD Power Study of Residential Customers, 1999-2006.

APS Electric Utility Business Customer Satisfaction

2004-2006[1]

Customer Satisfaction Index

Year	Industry	APS	Ranking
2004	100	104	12th among 52 utilities
2005	103	105	13th among 53 utilities
2006	104	108	9th among 52 utilities[2]

Notes:

[1]Comparable information prior to 2004 is not available.

[2]In both 2005 and 2006 APS was the top ranking IOU in the West Region

Source:

JD Power Study of Business Customers, 2004-2006.

REBUTTAL TESTIMONY OF JOHN R. DENMAN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is John R. Denman. I am the Vice President of Fossil Generation for Arizona Public Service Company ("APS" or "Company").

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have worked for APS for more than 40 years in various positions relating to fossil generation. I have been the Vice President for Fossil Generation since 1997. From 1986 to 1997, I was the Director of Fossil Generation, with the same basic responsibilities I have as Vice President of Fossil Generation. Prior to 1986, I held various positions within fossil generation, including Plant Manager for the Four Corners Power Plant.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

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

A. I am responding to the testimony by John Antonuk regarding the examination and evaluation of the Company's procurement and management of fuel and energy conducted by the Arizona Corporation Commission's ("Commission") Utilities Division Staff. I will focus on issues and recommendations relating to coal procurement and plant operations. APS witnesses Don Brandt and Tom Carlson will address issues and recommendations relating to gas commodity procurement, gas transportation, and hedging.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. APS was pleased that Mr. Antonuk has confirmed that the Company appropriately handles fuel and energy procurement and effectively operates its fossil generating facilities, and that the recommendations are intended to improve already-appropriate systems and operations. We considered all of Mr. Antonuk's recommendations in those areas and agree with most of them. In several cases, such as with the process for handling coal weights, we already had addressed or were addressing the recommendations at the time of the audit. In other cases, such as the inventory target at the Cholla Power Plant and the coal contract management process, we agree that the suggested changes will improve our systems, and we will implement those recommendations. Finally, with respect to some of the recommendations, we believe we already had in place the suggested changes but that perhaps we did not adequately explain the Company's process during the audit process.

III. FUEL CONTRACT MANAGEMENT AND ADMINISTRATION

Q. MR. ANTONUK OFFERS VARIOUS RECOMMENDATIONS REGARDING FUEL AND ENERGY PROCUREMENT AND MANAGEMENT. DID YOU REVIEW THOSE RECOMMENDATIONS?

A. Yes, and I agree with Mr. Antonuk's overall conclusion that the Company handled these areas "in a manner that produced appropriate costs during the April through December 2005 period," the period covered by the fuel audit.

Q. DO YOU AGREE WITH MR. ANTONUK'S RECOMMENDATIONS REGARDING FUEL CONTRACT MANAGEMENT AND ADMINISTRATION?

A. In general, yes. Mr. Antonuk offers a few recommendations regarding the Company's fuel contract management processes that in general APS finds to be appropriate. In fact, the Company already was implementing several of those recommendations when Mr. Antonuk's firm, Liberty Consulting, conducted its assessment. The following paragraphs summarize the status and response to the contract management recommendations relating to the Company's coal acquisitions. Mr. Carlson will respond to those recommendations relating to the acquisition of the Company's gas supply.

- Develop a complete set of procedures related to the management and administration of coal contracts: The APS Fuel Procurement Department will review its procedures for fuel contract management and administration and, as appropriate, incorporate additional detail to reflect the processes used.

- Streamline the procedures for handling of information on coal weights: APS agrees that the manual process used for handling coal weight information for the coal sample analysis should be reevaluated for possible automation. Mr. Antonuk's recommendation that APS improve the automation of the data entry of weight information from the coal belt scales at the Four Corners and Cholla Power Plants appears to have merit. APS will evaluate the cost of automating these activities and implement those changes are found to result in a positive cost benefit.

- Revise the inventory target for Regular Coal at the Cholla Power Plant from 25 days of supply to 35 days of supply: As Mr. Antonuk testifies, the Cholla Power Plant practice has been to carry a coal inventory in excess of the lower inventory target. Mr. Antonuk concluded that the Plant's *practice* was appropriate and that the *target* should be revised to reflect that practice. APS Fuel Procurement will work with Cholla Power Plant management to review the inventory target and adjust it to reflect the appropriate inventory practice.

- Conduct a comprehensive analysis of gas purchasing and management under El Paso Natural Gas's revised rate structure, and report to the Commission: Mr. Antonuk clarified in discussions with APS that the Company has taken appropriate steps to date to address pipeline transportation cost concerns. To that end, APS takes a comprehensive approach to investigating alternatives for increasing the Company's options relating to gas transportation. With respect to infrastructure needs, APS has worked with both Kinder Morgan and TransWestern Pipeline to encourage the construction of a new pipeline to serve Arizona. In addition, as Mr. Carlson discusses in his testimony, APS continues to examine options relating to natural gas storage and liquefied natural gas ("LNG").

Mr. Antonuk's recommendation, therefore, focuses on encouraging the Company to continue that proactive approach in addressing these issues in light of continuing developments relating to the El Paso Natural Gas rates. As Mr. Antonuk discusses in his testimony, it will be important for APS to continue to evaluate options relating to natural gas transport. APS

will conduct the recommended "analysis of gas purchasing and management under [El Paso's] revised rate structure" and will submit a confidential report to the Commission summarizing its analysis within one year of the decision in this docket.

IV. PLANT OPERATIONS

Q. MR. ANTONUK ALSO OFFERS SEVERAL RECOMMENDATIONS RELATING TO APS PLANT OPERATIONS. DO YOU HAVE ANY RESPONSES TO THOSE RECOMMENDATIONS?

A. Yes, I do. Although I agree with some of Mr. Antonuk's recommendations, I believe that other recommendations may have been based on an inaccurate or incomplete understanding of the processes APS currently uses to evaluate plant operations.

Q. LET'S START WITH MR. ANTONUK'S RECOMMENDATION THAT APS "FOCUS ON OPTIMIZING THE PERFORMANCE" OF THE REDHAWK AND WEST PHOENIX CC5 UNITS AS THEY TRANSITION INTO APS. DO YOU HAVE ANY RESPONSE TO MR. ANTONUK'S RECOMMENDATIONS?

A. Yes. First, however, I would like to reiterate that Mr. Antonuk found that APS "has appropriately recognized the shift in the market paradigm brought about" by the movement of the Redhawk and West Phoenix CC5 units into APS. As Mr. Antonuk noted, those units have experienced "representative outage frequency and duration."

APS continuously focuses on optimizing the performance of all of its fossil generating units, including Redhawk and West Phoenix CC5. Because of that focus, the transition of these gas-fired units into an intermediate dispatch operation has gone very well overall. As with any generating unit that initially is

designed for base-load operation and then changed to intermediate duty, certain systems and equipment have required re-engineering for the new duties.

With respect to Redhawk, many of the start-up and unit operational issues already have been resolved. For example, several steam by-pass valves have been replaced and relocated, additional generator endturn blocking has been added, and larger start-up drains have been added. Because of these efforts, among others, Redhawk is operating at a combined equivalent availability factor ("EAF") of 96.5% for 2006 year-to-date.

At West Phoenix CC5, APS also has addressed operational and start-up issues. Many of the by-pass and feedwater regulating valves have been replaced, and the remaining are scheduled to be replaced during planned future outages. The rotor air cooler system has been redesigned and heater retubing is scheduled for October 2006. Like other units throughout the industry with the same turbine design, West Phoenix CC5 has experienced some problems with the low pressure steam turbine last stage blades ("L-O Blades"). These L-O Blades are the largest turbine blades in each unit. In addition to requiring frequent unit outages for blade inspection, the unit must be operated in a manner that results in higher unit heat rate. We anticipate installing a newly designed blade in the first quarter of 2008. Because of these efforts, among others, West Phoenix CC5's year-to-date EAF is 91.6%.

Q. MR. ANTONUK ALSO RECOMMENDS THAT APS "PREPARE AND EXECUTE AN ACTION PLAN THAT WILL IMPROVE ECONOMIC EVALUATIONS RELATED TO MINIMIZATION OF OUTAGE TIME." DO YOU AGREE WITH THAT RECOMMENDATION?

A. We believe APS already has such a process in place. APS schedules required planned outages using a production cost model, which produces the least cost

replacement power for the system. All scheduled outages at APS base-load and intermediate units are planned using a critical path planning tool to minimize outage time. The Company schedules planned outages to obtain the shortest duration to minimize replacement power cost. Planned outages for peaking units are scheduled during off-peak times to ensure that scheduled work is performed at the least cost.

Forced outages on the intermediate and peaking units are worked based on value to the system, replacement power cost at the time of the outage, and forecasted near term anticipated dispatch of the unit. We perform an assessment of each unit to determine options for extending the time between required outages. For example, we may install upgraded materials or change equipment design to reduce wear. With respect to outage duration, we work to reduce outage time by making sure appropriate resources (such as labor, tools, parts, contract support) are available so the outage is as short as possible.

Q. ALTHOUGH MR. ANTONUK'S RECOMMENDATION IS BROADLY STATED, THE ASSOCIATED CONCLUSION IN THE AUDIT REPORT FOCUSES ON APS'S REFLECTION OF NET REPLACEMENT POWER COSTS IN ITS ECONOMIC EVALUATIONS. DO YOU HAVE ANY COMMENT ON THAT ISSUE?

A. I absolutely agree with Mr. Antonuk that net replacement power cost should be considered in economic evaluations relating to spare parts and inventory and, in fact, APS considers those costs already. At the Company's intermediate gas plants, capital spare parts are justified and purchased for inventory based on an economic evaluation using differential fuel cost and projected loss of generation. Major spare parts are evaluated for consideration to stock (i.e., kept as inventory) based on expected lead time to purchase, expected refurbish time for the maintenance spare, and the expected time between planned maintenance.

With respect to replacement combustion hardware, for example, one set of spare combustion hardware costs well over $8 million dollars, and the Company has determined that one set of spares for the Redhawk units and a second set of spares for West Phoenix is reasonable and appropriate. In addition, the Company's Long Term Service Agreements ("LTSAs") guarantee that APS will be provided with needed combustion parts beyond our in-house inventory levels without any delay in scheduled or forced outage time.

The Company purchases routine inventory spares based on frequency of need, risk of failure, and criticality to plant operations. We have evaluated all systems as both base-load and intermediate load units with the objective of identifying spare parts and spare equipment needs. Where it is cost effective to do so, spare parts and equipment have been purchased.

Q. HOW DO YOU RESPOND TO MR. ANTONUK'S RECOMMENDATION THAT APS EVALUATE THE REPLACEMENT OF BOILER SECTIONS AT FOUR CORNERS POWER PLANT UNIT #5 AND NAVAJO GENERATING STATION UNITS #2 AND #3?

A. Boiler tube leaks on coal fired generating units usually constitute the major contributor to lost generation for these types and vintage of units. Many factors influence boiler tube leaks, including boiler design, fuel quality, and age of the different boiler components, among others. Because APS (for Four Corners) and SRP (for Navajo Generating Station) continuously review and research new applications of boiler maintenance procedures and the use of up-graded materials to anticipate and reduce boiler tube leaks, APS believes that Mr.. Antonuk's recommendation already is being met.

APS and SRP each have an integrated boiler tube leak reduction program that includes inspection and testing to anticipate leaks in addition to 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. Based on our comprehensive boiler tube leak reduction program, planned boiler components replacement is performed at each planned outage. All major component replacements are based on an estimated remaining life assessment and economic evaluation of component failure.

Q. MR. ANTONUK ALSO RECOMMENDS THAT APS CONDUCT A REVIEW OF OPERATOR AND MAINTENANCE ERRORS TO DETERMINE WHY SUCH ERRORS APPEAR TO OCCUR MORE FREQUENTLY AT FOUR CORNERS UNIT #3 AND NAVAJO UNIT #3. HOW DO YOU RESPOND?

A. It is important to first clarify that operator and maintenance errors at all APS base-load coal plants and at the Navajo Generating Station, operated by Salt River Project ("SRP"), already are investigated for root causes. With respect to the plants that APS operates, I receive daily reports on plant operation and review monthly plant performance issues with plant management. In addition, I require each coal plant to provide me a quarterly report on all lost generation. That report also sets out the plant's corrective action plans to address any issues identified.

We regularly conduct operational assessments at each of the base-load and intermediate load plants that APS operates to assure that operators are knowledgeable and are following good operational practices. Appropriate corrective action is identified based on investigation findings when a human performance error occurs. Corrective actions can include training, changes in procedures, additional procedures, and/or employee coaching.

With respect to the Navajo Generating Station, SRP provides daily status and monthly lost generation reports to me, the APS Manager of Technical Services and the APS Manager of Generation Engineering, both of whom report to me. APS representatives also attend quarterly Engineering & Operating ("E&O") Committee meetings where SRP provides detailed information about Navajo's operations, including lost generation events, to all plant owners. SRP also identifies corrective actions that it has taken or plans to take to address issues and problems identified.

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. In February 2006, the Company identified the actual root cause—a faulty check valve. The Company decided not to correct the 2005 data to reflect that these five reported errors were *not* in fact operator errors.

There were six human performance errors reported at Navajo Unit 3 in 2005. All were related to unit start up and operator experience. Consistent with the plant's root cause policy, each of these events was investigated and appropriate action taken to help insure that human performance errors are kept to the lowest possible level. Procedures, employee training, employee coaching, and operations audits are used to keep human performance errors to the lowest level possible.

In short, we do not agree that there is any unusual pattern of operator errors at these two units requiring the suggested special evaluation. The current practice of root cause analysis of outages with follow up corrective actions, if needed, is sufficient.

Q. DO YOU AGREE WITH MR. ANTONUK'S RECOMMENDATION THAT APS "IMPLEMENT FOR WEST PHOENIX #5 THE REQUIREMENT FOR ROOT CAUSE ANALYSIS WHEN GENERATION IS LOST"?

A. I agree with Mr. Antonuk's endorsement of root cause analysis, but West Phoenix CC5 *already* is required to comply, and does comply, with the same requirement for root cause analysis that applies to the rest of the Company's fossil generating units. In addition, as I indicated above, I meet with the Plant Manager of each fossil plant monthly to discuss lost generation events. I require the plants to develop specific Action Plans to address root cause corrective actions and review them regularly with plant management to assure implementation.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING COMMENTS?

A. I appreciate Mr. Antonuk's overall conclusion that APS's fuel procurement and plant operations are effective and appropriate, as we have worked hard to have an effective operation. Any operation can be improved, however, and as I indicated above, the Company already has in place or is implementing a number of the recommendations made by Mr. Antonuk. We will continue to implement those processes. In addition, we will update our analysis of options relating to gas transportation and provide the Commission with a confidential report on that analysis within one year after the decision in this proceeding.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

REBUTTAL TESTIMONY OF EDWARD Z. FOX

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Edward Z. Fox, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes. I filed Direct Testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of various Arizona Corporation Commission ("ACC" or "Commission") Staff and intervenor witnesses relating to the implementation of the Environmental Improvement Charge ("EIC"), and the proposed adjustment mechanism that would provide for the timely recovery of the cost associated with the substantial capital investment necessary for adding and improving environmental controls. I will also provide updated cost estimates for the projects that are currently planned to comply with existing and future federal and state laws, regulations and policies, as well as describe those additional projects, which were not included in my direct testimony.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In my rebuttal testimony, I respond to Staff and Intervenor opposition based upon their assertions that the EIC is unique and violates the traditional ratemaking

process. As such, I describe why APS believes that the EIC is appropriate and describe the benefits that Arizona will see as a result. To put the benefits into context, I identify the relevant environmental standards that APS will be required to meet and the connection between such standards and the environmental projects proposed. In relation to such standards, I discuss why pollution control projects should be pursued sooner rather than later and why traditional ratemaking treatment to recover such expenses is not sufficient.

Next, I identify the currently planned projects addressing conventional pollutants at the Cholla plant and the estimated costs that APS will seek recovery for through the EIC. Finally, I identify the types of costs that should be subsequently recoverable through the EIC, including costs associated with addressing greenhouse gas emission and future improvements at the Four Corners and Navajo Power Plants.

III. ENACTMENT OF THE EIC DOES NOT VIOLATE THE COMMISSION'S TRADITIONAL RATEMAKING PROCESS.

Q. SEVERAL PARTIES OPPOSE EIC AS A CONCEPT BECAUSE IT FALLS OUTSIDE TRADITIONAL RATEMAKING. DO YOU AGREE?

A. No. According to the direct testimony of Kevin Higgins on behalf of Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition, a mechanism like the EIC can be considered by the Commission if it determines that there is a "compelling public interest" to do so.[1] We agree this is the correct test and, as discussed below, APS believes that there is a compelling public interest to enact a mechanism designed to expedite pollution control in a cost effective manner.

[1] (Kevin C. Higgins (KCH), p18, line 11.)

Q. WHAT ARE THE MAJOR CONCERNS OF OTHER PARTIES THAT OPPOSE THE EIC?

A. Staff opposed the EIC because it appears to be unique and the environmental impacts for implementing the EIC are unclear. In addition, Staff has concerns that the EIC seeks to recover estimated future costs for projects not yet mandated.[2]

Q. DOES APS AGREE WITH STAFF'S POSITION?

A. No. This Commission, through its past decisions, has 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.

Q. COULD YOU PLEASE EXPLAIN?

A. The Commission has approved surcharges to encourage use of renewable energy as well as to implement demand side management programs. More recently, the Commission has authorized the use of a surcharge mechanism to recover the cost of arsenic remediation. Each of these programs has a significant environmental benefit. And, we believe the Commission should give the same consideration to emissions reduction and air pollution remediation and authorize APS to implement a surcharge that aggressively reduces the pollutants associated with the generation of low cost power. The environmental benefits of the proposed EIC are discussed below on Pages 12 and 13 of this testimony.

Q. TO SUPPORT THEIR RECOMMENDATION THAT THE EIC NOT BE ENACTED, STAFF CITES AN INCOMPLETE STUDY CONDUCTED BY CAMBRIDGE ENERGY RESEARCH ASSOCIATES ("CERA)". IS SUCH A COMPARISON APPROPRIATE?

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[2] (Matthew J. Rowell, p. i).

A. No. Staff acknowledges that the study is incomplete.[3] Furthermore, Staff does not cite any specific provision of the study, but instead relies upon representations made by CERA to conclude that either no surcharges for environmental improvements to coal plants are allowed or if they are, those surcharges are designed to recover expenses "actually incurred."[4] We anticipate that the Commission will see the benefit to continuing its longstanding commitment to protecting the environment by allowing APS to implement a surcharge mechanism that will allow it to proactively and aggressively confront environmental concerns.

Q. STAFF ALSO CITED THE NARUC STUDY[5] OF STATE INCENTIVES REFERENCED IN YOUR DIRECT TESTIMONY. SPECIFICALLY, STAFF IDENTIFIES THE STATE OF WISCONSIN AS BEING INNOVATIVE IN THE AREA OF FINANCING ENVIRONMENTAL IMPROVEMENTS TO SUPPORT THE USE OF BONDS AS AN ALTERNATIVE TO EIC FINANCING. IS SUCH A COMPARISON APPROPRIATE?

A. No. Wisconsin has promulgated Act 152 entitled, "Financing of Environmental Improvements to Energy Utility Facilities." The Act creates a mechanism by which bonds would be issued by the Wisconsin Public Service Commission, to be repaid from revenues collected from fees paid by customers.[6] The Act specifies that the environmental trust bonds are not a debt of the state and do not impose any financial obligation on the state or its political subdivision.[7]

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[3] (Matthew J. Rowell, p7, line 25).

[4] (Matthew J. Rowell, p7-8, lines 20-26, 1-12).

[5] *A Survey of State Initiatives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities; Policy and Regulatory Initiatives;* The National Association of Regulatory Utility Commissioners (June 2004).

[6] 2003 Wisconsin Act 152.

[7] *Id.*

Q. DOES ARIZONA HAVE ANYTHING EQUIVALENT TO WISCONSIN?

A. No. Arizona has no specific bonding authority for addressing pollution at energy utilities. In fact, Arizona's bonding authority is based upon federal law which in 1986 specifically deleted air pollution projects from eligibility. Thus Arizona has no bonding capacity or program available to address the projects APS needs to implement.

Q. DO YOU HAVE OTHER CONCERNS ABOUT STAFF'S ANALYSIS OF THE NARUC STUDY?

A. Yes. Although Staff cites the inapposite example of Wisconsin, Staff was silent in its analysis of the environmental cost recovery programs discussed in my Direct Testimony, including the states of Florida, Indiana, West Virginia and Kentucky. Although the programs are not identical to EIC, they provide a mechanism for recovery for programs that improve environmental performance. For example, Florida passed a statute that authorizes recovery of prudently incurred environmental compliance costs through a cost-recovery factor, separate from a rate case. Indiana has enacted a statute that requires the Public Utility Commission to approve the estimated cost schedule for development and implementation of an environmental compliance plan. West Virginia provides rate incentives for utility investments in clean coal and clean air technology facilities. Finally, Kentucky allows a regulated utility producing energy from coal to recover costs through a surcharge for complying with certain federal, state and local environmental requirements related to the production of energy through coal.

Q. STAFF SUGGESTS THE USE OF ENVIRONMENTAL BONDS TO FINANCE THE PROPOSED PROJECTS. HAS APS LOOKED INTO THIS OPTION?

A. Yes. According to Goldman Sachs[8], air pollution control facilities, which include facilities that control or abate air pollution by removing, altering, storing or disposing of the pollutants, do not qualify for tax exempt bond financing unless they started construction prior to 1985. That is why APS' recent pollution bonding efforts only include the refinancing of older air pollution projects.

Q. DOES ANY OTHER PARTY OPPOSE THE EIC?

A. Yes. The Residential Utility Consumer Office ("RUCO") opposes the EIC, because in its opinion, the EIC violates the normal ratemaking process which requires a plant to be actually built (known and measurable) and in-service (used and useful) prior to being given ratemaking consideration in the context of a rate case. To support this proposition, RUCO states: "Even in the case of the U.S. Environmental Protection Agency ("EPA") arsenic mandate, the Commission has continued to require that the plant actually be in-service prior to allowing the arsenic surcharge to be collected."[9]

Q. DO YOU AGREE WITH RUCO'S ANALYSIS?

A. No. In Decision No. 67163 (August 10, 2004), the Commission approved Mountain Glen Water Service Company's arsenic surcharge to repay a loan issued by the Water Infrastructure Financing Authority ("WIFA") to fund arsenic remediation. Staff's recommendations, adopted in Decision No. 67163, stated as follows:

> [T]hat the arsenic surcharge mechanism described above would become effective with the Company's first billing cycle four months after the closing of the WIFA loan, the surcharge would be shown as a separate line item on the customer bills as an "arsenic surcharge," and that the debt service component of the surcharge

[8] "Development of Tax-Exempt Financing" Presentation to APS, September 7, 2005.

[9] Direct Testimony of Marylee Diaz Cortez, p 36, footnote 4).

> collection would be deposited in a separate interest-bearing account and disbursements from the account would be made only for arsenic treatment capital expenditures associated with servicing the WIFA loan.

There was no requirement that regulatory assets be in service prior to the enactment of the surcharge.

Q. ARE YOU AWARE OF ANY OTHER CASES IN WHICH THE COMMISSION AUTHORIZED SURCHARGES PRIOR TO HAVING COSTS ACTUALLY INCURRED?

A. Yes. In Decision No. 68858 (July 28, 2006), Arizona-American Water Company requested inclusion of post-test year fire flow projects in rate base to encourage improvement in public fire safety and to minimize deferral costs to future periods.[10] Staff recommended approval because, in part, the projects would protect customers' lives and properties.[11] By approving the recovery of the fire flow improvement costs through an alternative fire flow surcharge, the Commission agreed with Staff and also reasoned that the improvements were for the health and safety of the ratepayers.[12]

IV. ENACTMENT OF THE EIC IS GOOD PUBLIC POLICY

Q. WHY DOES APS BELIEVE THAT THE EIC IS APPROPRIATE?

A. By almost any measure, the electric utility industry is in a transition with regard to future fuels and generation technologies, a transition toward cleaner-burning fuels and cleaner more efficient technologies. Whether it relates to conventional pollutants like SO_2, NO_x and particulates, or climate change, this transition is being driven by concerns about the impacts of fossil fuel generation on public health and the environment. In fact, during the past 15 years the Commission has

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[10] Decision 68858 at 6.

[11] *Id* At 7.

[12] *Id at 11.*

held workshops to discuss the costs of these impacts. Often called "externalities," the issue is how to account for the costs of pollution from fossil plants that are not controlled under existing regulations. The EIC is an appropriate mechanism to begin to address these concerns.

Any future resource plan to provide the needed electricity for APS' rapidly growing customer base will require not only the inclusion of new resources, but also the sustaining of our existing generating plants. These new resources, both renewables under the current Environmental Portfolio Standard ("EPS") rules or the proposed Renewable Energy Standard & Tariff ("REST") rules, and new conventional generation, will all be significantly cleaner than today's generation.

While renewables and other new technologies are inherently cleaner, the lingering question remains, "What do we do with existing generation?" This question is of great importance because the existing fleet of fossil generation is critical to navigating the transition in a cost effective manner. APS' fleet of coal units range from 26 to 44 years old. They represent 49% of our power generation and produce electricity at less than 2 cents per kWh. Other than the Palo Verde Nuclear Generating Station ("PVNGS"), these are the most cost effective units in the APS fleet. They have many years of operating life left, but they are older technologies with older pollution control equipment.

As APS manages the transition to cleaner, more efficient generation in the future, it is incontrovertible that the existing fossil fleet must be maintained both for its reliability and cost effectiveness. If, however, the future demands cleaner generation, which APS believes to be true, then the existing fleet (the fleet that will keep the electricity flowing during the transition) must be as clean as reasonably practical. We believe that for the existing fossil generation, the EIC is

the corollary to the EPS and proposed REST. It is a program that creates an incentive for APS to make its existing fleet of fossil generation as clean as practical.

Q. SHOULD APS WAIT UNTIL NEW ENVIRONMENTAL REGULATIONS ARE ACTUALLY PROMULGATED?

A. No. Since the early 1970s, environmental laws in the United States have become increasingly stringent. As the science regarding the health and environmental impacts of pollution has evolved and emission control technologies become more cost-effective, emission limits for facilities like utility generating units have become increasingly stringent. Today, we are on the verge of another wave of new, more stringent standards for the so-called "criteria pollutants" (including SO_2, NO_x, and particulates). The utility industry also faces the first-ever regulation for the pollutant mercury, and the growing trend to regulate greenhouse gas ("GHG") emissions that contribute to climate change.

For many pollutants, the science and technology to control the pollutants is well known long before the political process results in a final regulatory program. More often than not, the delays to implementing a final program are the result of special interest legal and political challenges. It is rare, however, for these challenges to actually stop a program once it has been proposed.

Q. DO YOU HAVE ANY EXAMPLES?

A. Yes. One example of this delay is the Grand Canyon Visibility Transport Commission ("GCVTC"). Established in the 1990 Clean Air Act Amendments, the GCVTC was created to propose how to reduce visibility impairment in National Parks and wilderness areas in the western United States. After nearly

five years of work, a Citizens Advisory Group appointed by 9 western governors, comprised of all the stakeholders, including utilities, environmental groups, Native American representatives and others, unanimously recommended a program to improve visibility in the West. Ten years later, that program has not been implemented because of lawsuits and political challenges by special interest groups. In the meantime, the program to reduce SO_2 and NO_x to help improve visibility, which is well known and understood, has not been implemented.

APS believes that if we understand the science and the need to control pollutants, and if the technology is commercially available to achieve the emission reductions, it is good public policy to consider taking early action to control those pollutants.

Q. WHY ISN'T THE TRADITIONAL RATEMAKING PROCESS SUFFICIENT TO RECOVER COSTS ASSOCIATED WITH ENVIRONMENTAL EXPENDITURES?

A. Under traditional rulemaking, utilities incur expenses and then, after the fact, seek recovery and a rate of return. The standard for review is whether the expenditure is prudent. Historically, this process has been a major obstacle to proactively addressing concerns such as the environment. If the pollution control was not absolutely required, utilities faced a potential negative prudency decision, thereby creating a disincentive to taking early action.

Q. WHY SHOULD THE ACC ALLOW SUCH COSTS TO BE RECOVERED IF THE SPECIFIC PROJECTS ARE NOT YET REQUIRED?

A. The measure by which the ACC should determine the appropriateness of the EIC is whether it is in the public interest. It is hard to posit that reducing pollution is not in the public interest.

Arizona has been in the vanguard on many environmental issues over the past 25

years. The 1980 Arizona Groundwater Management Act and the 1995 Aquifer Pollution Protection Program were ground-breaking when first proposed. The ACC has also 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.

While the EIC may be unique in construction, there is nothing unique about Arizona and the ACC breaking new ground to achieve a sound public policy. Establishing a program, like the EIC, that creates an incentive for utilities to control pollution to the greatest extent practical is good public policy and is in the public interest.

Q. ARE THERE OTHER REASONS THAT IT IS APPROPRIATE TO EXPEND MONIES ON MANDATES THAT ARE NOT YET IN EFFECT?

A. Yes. APS believes that it is prudent to expend monies on pollution control projects for several reasons: to minimize its environmental risk; to meet future regulatory requirements, and to protect and enhance the health and welfare of the citizens of Arizona and our environment.

Over the past several years, numerous other utilities have been sued by EPA or environmental groups in an effort to force emission reductions. Based upon conversations with EPA and various environmental groups, APS has good reason to believe that by voluntarily committing to make reductions, APS has avoided protracted and expensive litigation that may well have resulted in a settlement agreement to install these same controls and possibly impose fines and penalties.

In addition, almost all of these projects will be required in the future to meet regulatory requirements. The proposed Clear Skies legislation was intended to amend the Clean Air Act to consolidate in one place all emission reductions

required under the Act and in accordance with a new schedule. Because Congress did not pass that proposal, EPA began implementing multiple regulatory programs under the existing Clean Air Act. For example, the mandates to reduce SO_2, NO_x, PM, and mercury are currently in place, including the federal and proposed state mercury rules, the regional haze rules, and the state opacity standards.

The lead time on newly mandated requirements is dependent on the mandate; however, typically these types of projects take several years to complete. APS believes it is appropriate to be in compliance before a mandate is effective rather than wait until the last minute.

Additionally, we know from the simple rules of supply and demand that waiting until a time closer to the mandated compliance will drive up costs as other companies compete for the technology, equipment and labor to do the capital improvements. By doing the projects before the increased demand, APS will avoid the run up in costs driven by the increased demand.

Q. WHAT ENVIRONMENTAL BENEFIT WILL ARIZONA SEE AS A RESULT OF THE EIC?

A. Under the EIC, as currently proposed, APS will be retrofitting baghouses on Cholla Units 1 and 3, upgrading SO_2 controls on Unit 1, retrofitting SO_2 controls on Unit 3, and retrofitting Low NO_x Burners on all three Units owned by APS.[13] These projects will significantly reduce SO_2, NO_x, mercury, and particulate matter emissions from the plant. The attached charts[14] show the projected emission reductions of these pollutants. For example, annual SO_2 emissions will decline

[13] There are four units at Cholla. Unit 4, which is also being retrofitted with controls, is owned, and the retrofits will be paid, by PacifiCorp.

[14] See Attachment EZF-1RB.

from 32,475 tons in 2007 to 5,148 tons in 2010 and beyond. Those reductions are expected to help protect visibility in nearby Class I areas (protected by Clean Air Act Section 169A), as well as contribute to lowering ambient fine particle concentrations. These reductions will result in significant public benefit and similar beneficial effects are expected from reductions in other pollutants.

Q. WHAT TYPE OF EXPENDITURES IS APS SEEKING TO RECOVER THROUGH THE EIC?

A. APS is committed to securing our existing fleet of fossil fuel units for the long-term benefit of our customers and to making sure that these units comply with all environmental requirements. The process for implementing government environmental mandates often takes many years, even after the science is understood. Where emission reductions or pollution control activities are needed to protect the environment and public health, APS anticipates recovery through the EIC, including those costs necessary for complying with existing laws and anticipated future requirements. APS believes this proactive approach is in the best interests of our customers and Arizona.

V. <u>EIC FUNDING FOR PROPOSED PROJECTS</u>

Q. IF THE PROPOSED EIC INCLUDES ACTUAL AND FORECASTED COSTS, HOW WILL THE COMMISSION BE ASSURED THAT THE IMPLEMENTED EIC WOULD RECOVER ONLY ACTUAL COSTS OF PROJECTS, AS SUCH COSTS ARE INCURRED?

A. While the proposed EIC rate per kilowatt hour is calculated on actual and forecasted costs, an annual true-up mechanism between dollars collected through the EIC and the actual costs of these capital projects will assure the Commission that only actual costs associated with these capital projects will be recovered.

Q. REGARDING YOUR WORKPAPER EZF-WP9, HAVE THE ESTIMATES RELATED TO THE PROJECTED ANNUAL CAPITAL EXPENDITURES

CHANGED SINCE THE JANUARY FILING OF THE COMPANY'S APPLICATION?

A. Yes, the estimates for these seven EIC projects have changed from the figures shown in Work Paper EZF-WP9. The estimates for five of these projects have changed slightly, and are now based upon detailed engineering and supplier bids. The estimates for the other two projects (Unit 3 Scrubber and Unit 3 Baghouse) are currently still preliminary estimates, but have increased significantly (approximately 25%) based upon contractor bids received on similar projects for Unit 4. The detailed estimates for these projects are planned to be developed over the next six to nine months. This is the normal progression for developing estimates for capital projects, beginning with conceptual engineering and estimates to a preliminary phase to detailed engineering and estimates, with final costs determined by actual contractor bids. Additional insights into the costs of the projects became apparent during negotiations with an EPC (engineer, procure and construct) contractor for the scope and costs of the scrubber and fabric filter project. In addition, at the time of my pre-filed testimony in January 2006, the scope of the projects was in the early stage of development when the costs estimates were prepared. Since that time, additional engineering has been completed, and cost estimates reflect the more refined scope of the project.

Q. BASED UPON THE DETAILED ENGINEERING AND SUPPLIER BIDS, WHAT IS THE PROJECTED COST OF THE NEEDED CAPITAL EXPENDITURES?

A. The estimated costs currently are approximately $160 million,[15] as compared to the $135 million shown in EZF-WP 9. In addition, since the filing of my January 2006 testimony, the Company has determined that additional environmental

[15] See Attachment EZF-3RB

improvement projects beyond the seven projects set out in my workpapers will be mandated in the near future. Specifically, there are six additional projects that APS requests be included in the EIC.[16] As set forth in the rebuttal testimony of Mr. DeLizio, the EIC charge will be recalculated to show the impact of these updated costs, as well as the additional costs and the additional projects. The update of the $160 million in capital expenditure includes only mandated requirements. Of course, any amounts collected under the EIC will be subject to later true up once actual capital expenditures have been incurred.

Q. PLEASE DESCRIBE THE SIX ADDITIONAL PROJECTS.

A. The six additional projects all relate to the Cholla plant. The total cost of these additional projects is $83.2 million, broken down as follows: a lime-slaking project at a cost of $10.5 million; a slurry disposal project at a cost of $3 million; and carbon-injection for Units 1, 2 and 3, at a combined cost of $7.7 million. In addition, APS is adding a Unit 2 baghouse at a cost of $62 million.

Q. IS APS SEEKING TO RECOVER THE ENTIRE $160 MILLION THROUGH THE EIC AT THIS TIME?

A. No. As set forth in the direct testimony of Greg Delizio, the EIC is designed to recover capital costs on an annual basis as the costs are incurred. For the initial request only, the Company will use an eighteen month period (January 2007 through June 2008) to calculate the EIC.

Q. CAN YOU PLEASE EXPLAIN WHY ADDITIONAL PROJECTS WERE ADDED SINCE THE ORIGINAL APPLICATION WAS FILED?

A. Recently proposed mercury regulations would require the installation of the carbon injection projects for Cholla Units 1 through 3, and the installation of the

[16] See Attachment EZF-4RB.

Unit 2 baghouse project sooner than was previously anticipated. In addition, the need for slurry disposal was discovered during preliminary engineering, not at the time of conceptual engineering, when the projects were originally submitted in this rate case. Finally, the lime-slaking project should have been included in the original submittal, but was inadvertently excluded.

VI. OVERVIEW OF THE ENVIRONMENTAL CHALLENGES FACING APS

Q. WHAT IS THE STATE OF CLIMATE POLICY IN THE UNITED STATES TODAY?

A. There is significant uncertainty surrounding many aspects of climate change policy, including the timing of any mandatory program, the degree of restriction that might be required, and the projected costs of such a program. On the other hand, individual states, cities and regions are taking action, and we believe it is only a matter of time before an Arizona or national program is adopted.

Recently, California passed a mandatory cap on greenhouse gas emissions. And on Sept. 8, 2006, Governor Napolitano signed an Executive Order establishing a statewide goal of reducing future greenhouse emissions to 2000 levels by the year 2020 and 50% below that level by 2040. The Governor left open the possibility of accelerating the 2020 goal to 2012. The Executive Order follows recommendations of the Climate Change Advisory Group, which the governor appointed to come up with proposals for lowering greenhouse gas emissions.

APS believes that a national program is the appropriate way to address this issue because climate change is a global, not a state or even a regional, issue. However, APS recognizes that states like Arizona are moving forward in the absence of a national program. It is therefore imperative to develop incentives to encourage industry to make early reductions to carbon emissions and/or carbon intensity,

and for regulated utilities to be provided with a process by which expenditures on emission reductions are deemed prudent and recoverable.

Q. HOW DOES APS PROPOSE DEALING WITH THE COSTS OF CLIMATE CHANGE?

A. Climate change is a long-term problem requiring long-term vision and steadfast effort. APS has been at the forefront of utilities that have taken prudent actions to respond to climate change issues, as discussed above. However, to truly offset the emissions associated with meeting growing customer demands will require expenditures that, absent a process like the EIC, have a risk of becoming stranded in future regulatory programs.

Coordinating climate change efforts with our generation forecasting and planning efforts better allows APS to evaluate the potential financial and operating impacts of proposed legislation and regulatory programs. In this context, APS is considering the potential future costs of carbon emissions as a criterion in evaluating our current generation Request for Proposals.

Q. WOULD APS BE ABLE TO RECOVER THE COST OF COMPLYING WITH FUTURE GREENHOUSE GAS EMISSION REGULATIONS THROUGH THE EIC?

A. Yes. While the current proposed plan addresses only conventional pollutants and mercury, the proposed EIC is broad enough to allow other environmental costs, such as those that might be incurred addressing greenhouse gas emission or complying with future climate change regulations.

Q. WHAT EFFORTS HAVE BEEN MADE TO ANALYZE THE RISKS OF GREEN HOUSE GAS ON APS' OPERATIONS?

A. With respect to historic action on this issue, the Company is aware of the "stranded asset" risk and is making efforts to preserve the value of early GHG

efforts to the extent possible, including ongoing monitoring and evaluating of evolving GHG reporting programs and registries. Over the past several years, several utilities have published reports outlining their GHG and other air pollutant emissions and assessing their risks from future GHG regulations. These companies include AEP, Cinergy, TXU, Southern, DTE Energy, and Progress Energy. APS is working on an analysis of greenhouse gas risks.

Q. COULD YOU DESCRIBE APS' RESPONSE TO THE ISSUE OF CLIMATE CHANGE AS RAISED BY DAVE BERRY OF WESTERN RESOURCE ADVOCATES?

A. APS has been engaged with climate change issues for over a decade. In 1994, APS was one of the signatories to the U.S. Department of Energy's ("DOE") Climate Challenge Program, in which APS committed to maintain system-wide GHG emissions, including CO_2, (tons) below 1990 levels and to achieve that goal by the year 2000. APS met its commitment, primarily through improved performance and capacity at PVNGS.

Over time, however, APS' customer growth and increased electricity demand have resulted in an increase in the overall company CO_2 emissions. APS has had to increase generation to meet this demand, and beginning in 2000, APS' system-wide emissions began to climb above the 1990 level. While obtaining the generation needed to meet customer demand resulted in actual tons of CO_2 exceeding the 1990 levels, the Company did focus its resource acquisition on fuel sources (natural gas rather than coal) that created a less intense impact on CO_2 emissions (lbs/MWH). This means APS has become more efficient at providing electricity to our customers, with fewer CO_2 emissions per megawatt-hour generated. This "climate efficiency" trend is projected to continue through 2012, primarily through increased use of gas-fired plants, renewable energy sources,

energy efficiency programs, DSM[17], our partnership with EPA to reduce atmospheric releases of SF6, use of plant by-products (ash) for cement manufacturing, and planting trees to sequester CO_2.

Recently, APS committed to this trend in its 2005-2010 Business Plan. The Company has set a goal of reducing carbon intensity at its power plants by 10 percent by 2010 from the baseline year 2000. This goal is particularly noteworthy in light of the Company's rapidly increasing customer base.

Recognizing APS' past and current actions to minimize GHG emissions, the U.S. EPA selected APS from among all the utility companies in the country to receive its 2006 Climate Protection Award.

Q. WHAT OTHER ENVIRONMENTAL CHALLENGES DOES APS FACE?

A. In the late 1990's, the EPA commenced a national enforcement initiative targeting electric utilities, pursuant to the Clean Air Act's New Source Review and Prevention of Significant Deterioration (collectively "NSR") program. EPA began its enforcement initiative by sending Clean Air Act Section 114 requests for information to numerous coal-fired power plants in the country requesting detailed reports on historical emissions of sulfur/nitrogen oxides and particulate matter and pollution control projects undertaken at the plants since the mid-1970s. EPA reviewed company responses and, in some cases, issued additional Section 114 information requests. EPA also initiated settlement negotiations with some companies, including Salt River Project (relating to operations at the Coronado Generating Station).

APS received Section 114 requests for information in July 2000 for its Cholla and

[17] See Attachment EZF-2RB.

Four Corners Power Plants and submitted responses in September 2000. Notably, APS has not received any follow-up requests from EPA.

After reviewing the various Section 114 responses, the EPA filed a number of lawsuits against coal-fired power plants alleging NSR violations. Several of these companies, including Tampa Electric Company, PSEG Fossil LLC, Virginia Electric and Power Company, Southern Indiana Gas and Electric Company and others, have settled the lawsuits and agreed to pay large penalties in addition to retrofitting pollution control equipment. A few companies have chosen to fight the lawsuits, and the litigation continues in various courts, including the United States Supreme Court.

Q. DOES APS FACE ENFORCEMENT RISKS FROM EPA?

A. Yes. While APS is in compliance with Federal, State and local environmental laws and has Environmental Systems in place to ensure compliance, it is a fact that not all the rules are absolutely clear and, indeed, the EPA and States periodically change their interpretation of existing rules, thus creating risk for all utilities.

EPA's NSR enforcement initiative, referenced above, is based upon a new interpretation concerning which "modifications" at coal plants trigger NSR. Under NSR, utilities that make major modifications to their units that result in a significant net increase in emissions are required to treat the unit as if it were new, including installing state-of-the-art pollution control equipment that would not otherwise be required. Although EPA did not formally announce its new interpretation of which changes triggered NSR, EPA's position became clear in its NSR enforcement initiative. The new interpretation relates to which changes constitute "routine maintenance, repair and replacement" and are thus exempt

from NSR. The litigation also involves a dispute regarding how to calculate whether a significant emissions increase has occurred.

The extent of this regulatory uncertainty is highlighted by the fact that several courts have adopted radically different interpretations of the NSR program. For example, the Seventh Circuit Court of Appeals (in the *Cinergy* case) agreed with EPA's interpretation of NSR. By contrast, the Fourth Circuit Court of Appeals (in the *Duke* case) agreed with the utility industry's interpretation of NSR. This regulatory uncertainty provides strong incentive for the utility industry to proactively implement measures to reduce emissions and thereby reduce its enforcement risk, to the extent possible.

Q. ARE THERE OTHER LITIGATION RISKS KNOWN TO APS?

A. Yes. Several environmental groups have also filed citizen suits against coal plants alleging various violations of the Clean Air Act, with the intent of forcing those plants to add pollution control equipment. The suits involving power plants at Hayden in Colorado, Mohave in Nevada, and San Juan Generating Station in New Mexico, among others, resulted in settlements requiring significant upgrades.

Q. HAVE THE EPA, ADEQ OR ENVIRONMENTAL GROUPS PURSUED LITIGATION AGAINST APS?

A. No. Starting in late 1990s, prior to the initial set of NSR lawsuits and the enforcement initiative, APS initiated a dialogue with several environmental interest groups relating to pollutant emissions from APS' coal-fired plants. The goal of this initial dialogue was to determine whether there was any concern with environmental performance at APS' coal plants. Based upon the favorable initial discussions and after commencement of the EPA enforcement initiative, the dialogue was expanded to include EPA and ADEQ. These discussions resulted in

a plan to implement enhanced pollution controls at the Cholla plant. The emission control projects included in the EIC are a direct result of those discussions. The plan has concurrence from state and federal agencies (ADEQ, EPA, and the National Park Service). Based upon discussions with EPA personnel and the environmental groups, APS believes that the regulatory agencies did not pursue enforcement against Cholla because of our dialogue with these agencies and the environmental organizations, and our commitment to new, enhanced controls.

Although APS' discussions with the environmental groups and agencies involved projects at Cholla that were not yet legally mandated, APS fully recognized that such controls would indeed be required in the future. In an effort to minimize its environmental risk, and in anticipation of impending regulatory requirements to reduce emissions, APS elected to implement the projects earlier than would otherwise be required. APS' commitment to these projects is a prudent approach to environmental compliance and risk management: APS' early commitment to the projects very likely kept APS from being sued, and these projects will be required to meet future environmental standards.

VII. ENVIRONMENTAL STANDARDS

Q. PLEASE DESCRIBE THE RELEVANT ENVIRONMENTAL STANDARDS AND PROPOSED PROJECTS THAT APS WILL BE IMPLEMENTING WITH THE PROPOSED EIC CHARGE.

A. The EPA's Clean Air Visibility Rule ("CAVR") will be implemented in Arizona through the Regional Haze State Implementation Plan ("SIP") being prepared by ADEQ. Under that SIP, due to EPA by 2007, irrespective of whether ADEQ follows Regional Haze Rule 40 CFR § 51.308 or § 51.309, Cholla Units 2 and 3 will be expected to reduce SO_2 and NO_x emissions to Best Available Retrofit Technology ("BART") levels or, depending on which program ADEQ adopts,

acquire "allowances" to offset its emissions. Because there is no certainty that a viable allowance market will exist, APS has no choice but to reduce emissions from those units. Cholla plans to comply with the SIP requirements before the anticipated Regional Haze SIP deadline of 2013. The proposed changes will enable the units to significantly reduce emissions and meet the presumptive BART limits.

In addition, Cholla's Acid Rain (SO_2) program allowances under Phase II of the Clean Air Act Acid Rain Program will be reduced in 2010. The scrubber additions and changes will ensure program compliance with these requirements. The addition of the Unit 1 fabric filter will ensure compliance with the new Arizona SIP requirement of 20% opacity.

Arizona will also submit a SIP to implement the EPA's Clean Air Mercury Rule ("CAMR") by November 2006. Based on discussions with ADEQ and a review of ADEQ's draft mercury rules, published in the *Arizona Register* on August 11, 2006, the SIP is expected to include more stringent mercury control requirements than those in the CAMR, and will require compliance with Phase 2 requirements much sooner (by 2013).

At this time, we know that fabric filters and scrubbers are the first step technology to address mercury control, but it may be necessary to add additional equipment to reach the required mercury emission limits set by the State. This additional equipment is included in our amended request to the Commission.

Specifically, APS is planning to implement the following pollution control projects at the Cholla Power Plant:

- Installation of a baghouse on Unit 1 in order to meet the State of

Arizona's new 20% opacity limitation. This limitation became effective in April 2006, and Cholla obtained a compliance schedule in its air permit that affords it time to construct the new baghouse.

- Installation of baghouses on all units (including baghouse on Unit 1 described above) in order to meet the State of Arizona's anticipated mercury rules. Although it is uncertain what the ADEQ will require in its final mercury rules (which have been drafted but not yet finalized), Arizona will be required to meet its allocated mercury emissions budget beginning in 2010, and ADEQ is expected to require at least 90% mercury removal by 2013. At a minimum, baghouses will be required to meet this removal efficiency.

- Installation of SO_2 absorbers on Unit 3 in order to meet the State of Arizona's anticipated regional haze rules, compliance with which must be achieved no later than January 2013. Again, it is uncertain what ADEQ will require in its final regional haze rules (which have not yet been developed), but EPA's regional haze program established "presumptive" control levels, and it is anticipated that any regional haze control determination for Cholla would be similar to EPA's presumptive levels.

- Installation of low NO_x burners on Units 2, 3 and 4 to comply with the State of Arizona's anticipated regional haze rules by 2013. Again, APS will not know with certainty what is required until ADEQ promulgates its final regional haze rules and makes a determination regarding emission control levels for Cholla. However, it is reasonable to expect that low NO_x burners will be required to comply with anticipated NO_x

limits.

- Installation of a SO_2 absorber on Unit 3 and changes to the existing SO_2 absorber on Unit 1 in order to assure compliance with applicable emission limitations.

Q. WHAT PERMITS WERE NECESSARY TO COMMENCE INSTALLATION OF THE ABOVE PLANT CHANGES?

A. In September 2005, APS met with ADEQ and agreed to submit an air permit application to allow the installation of the Unit 1 fabric filter (mandated by new opacity standards) and the scrubber project in 2007, and the Unit 3 fabric filter scrubber in 2009. APS submitted the permit application on September 28, 2005. APS received the final permit on May 3, 2006. APS also submitted a permit application for the low NO_x burners in August 2006.

Q. WERE THERE ANY SUBSEQUENT MODIFICATIONS TO THE PROPOSAL?

A. In January 2006, APS amended the permit application to remove the low NO_x burners from the permit application because it was unable to reach agreement with ADEQ regarding applicable regulatory requirements. In July 2006, ADEQ and APS agreed upon a regulatory approach for the NO_x burner projects, and APS submitted a permit application for the NO_x burner projects in August 2006.

Q. IN YOUR DIRECT TESTIMONY, YOU STATE THAT ADDITIONAL IMPROVEMENTS AT THE FOUR CORNERS AND NAVAJO POWER PLANTS MAY BE NECESSARY AND/OR DESIRABLE IN THE COMING YEARS. CAN YOU EXPLAIN?

A. The EPA has developed a program to regulate regional haze and mercury emissions from power plants, and a number of utilities have been sued to force further emissions reductions. Although the specific levels of controls or reductions that will be required have not yet been finalized, APS is planning

emission control improvement projects based upon anticipated requirements.

Under the regional haze program, EPA has issued "presumptive" control levels for NO_x and SO_2, and it is expected that most power plant units will be required to meet these or similar control levels. (The control levels vary according to the type of boiler, type of coal burned, level of current controls, etc.) EPA is expected to issue final emission requirements for Four Corners and Navajo Generating Station sometime in late 2007 or 2008.

In addition, Federal lawsuits around the country have generally sought (and in several settlements have obtained) control levels that require the installation of the best available control technologies for NO_x control.

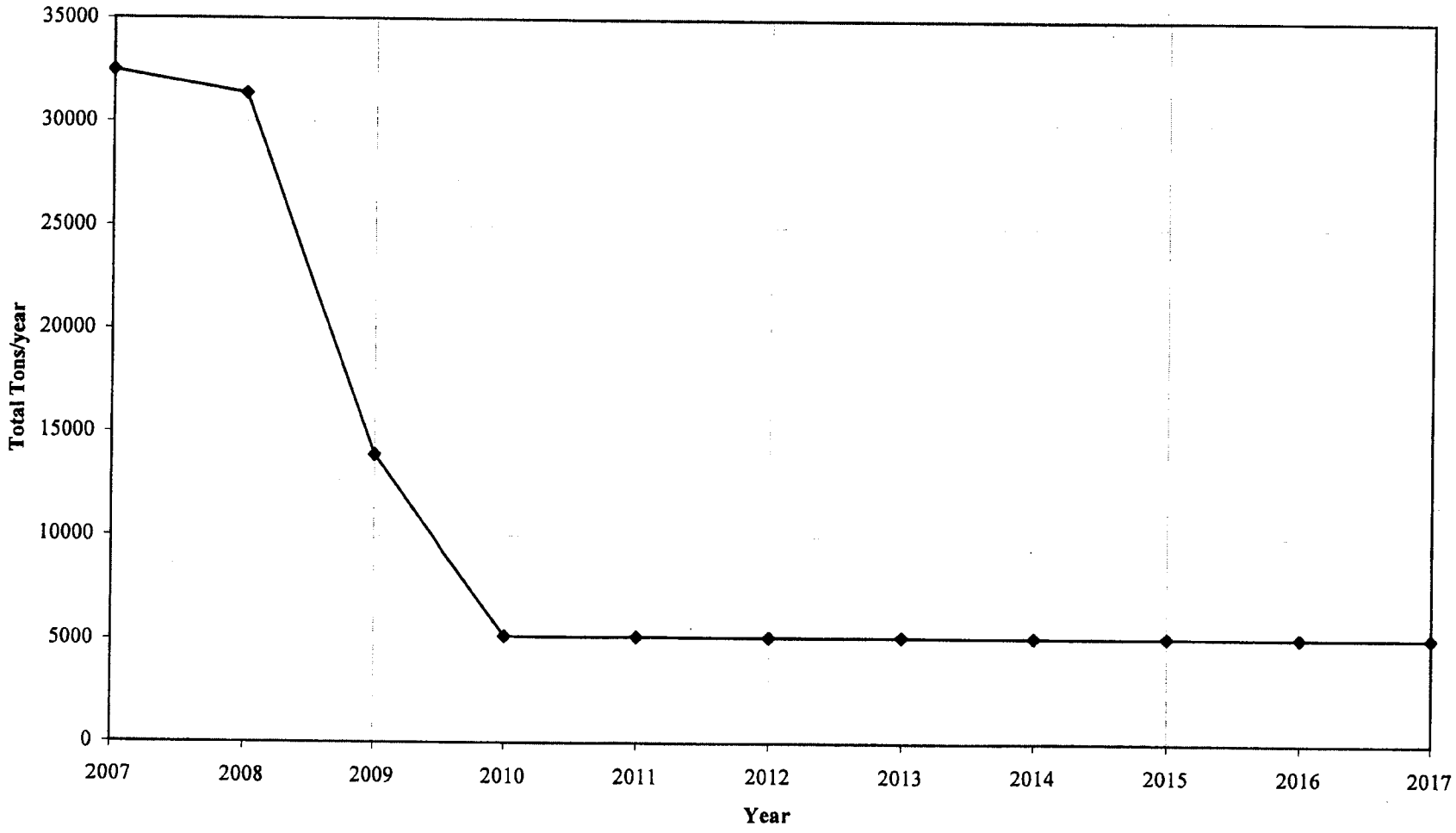
EPA is expected to implement its Clean Air Mercury Rule on the Navajo reservation starting in 2010, and it will apply to Four Corners and Navajo Generating Station. Based on information of current emissions levels, APS may not have to make any significant capital investments to comply with the rule by 2018.

VIII. CONCLUSION

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

A. Yes.

Projected Emission Reductions
Cholla 1-3 Annual SO2 Emissions (Tons/year)



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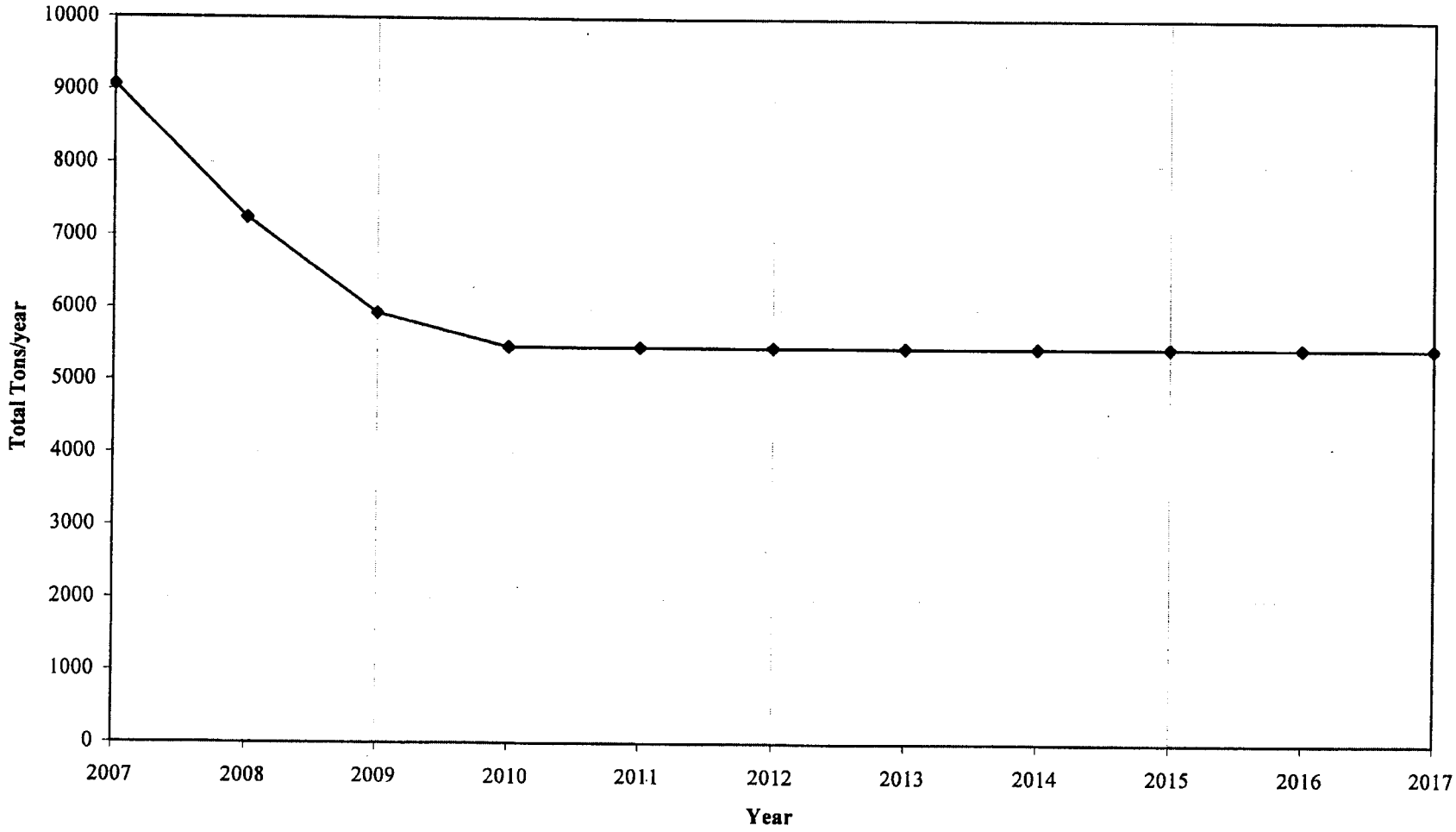
Projected Emission Reduction
Cholla 1-3 Annual NOx Emissions (Tons/year)



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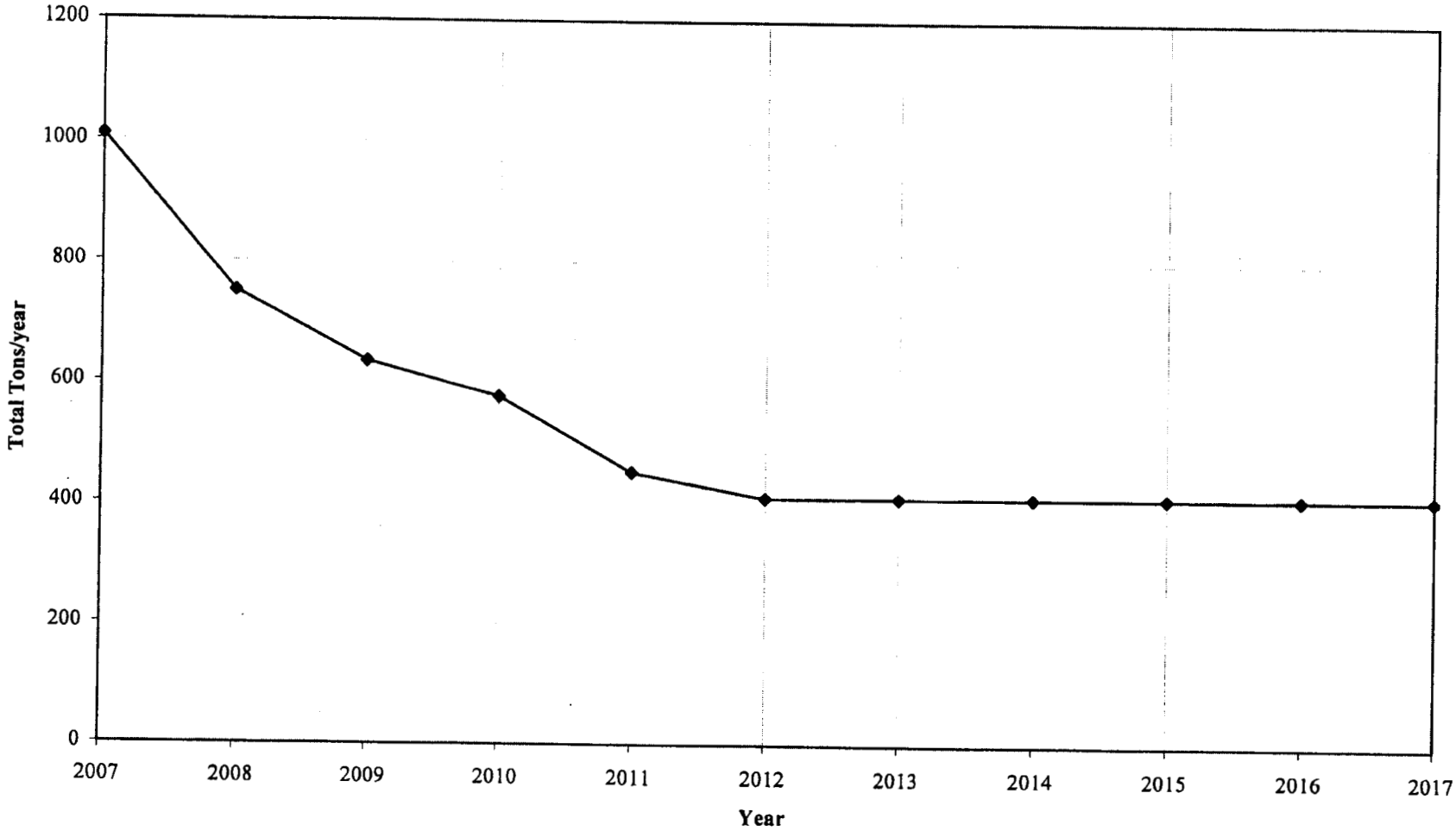
Projected Emission Reduction
Cholla 1-3 Annual PM10 Emissions (Tons/year)



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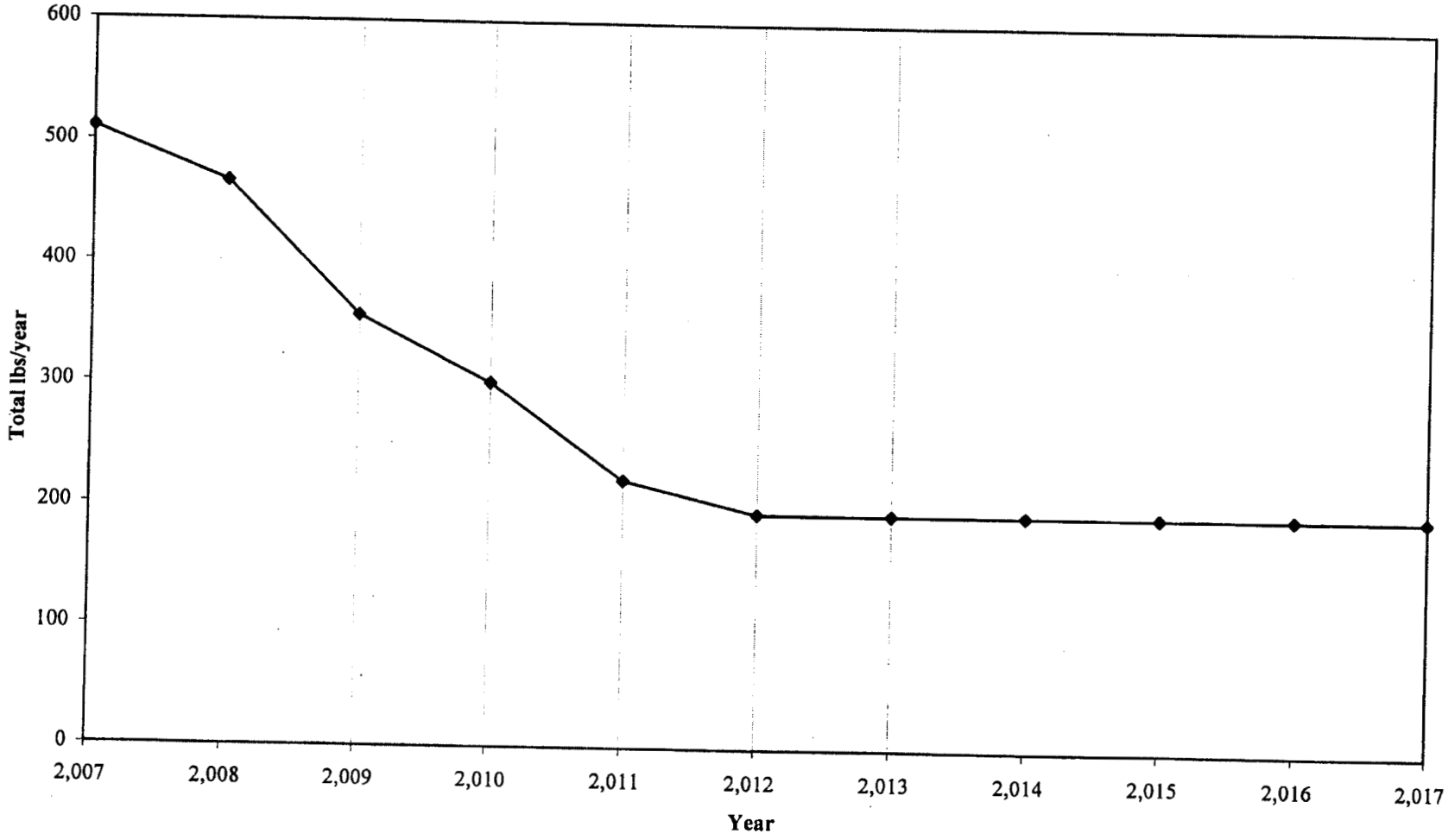
Projected Emission Reduction
Cholla 1-3 Annual Hg Emissions (Pounds/year)



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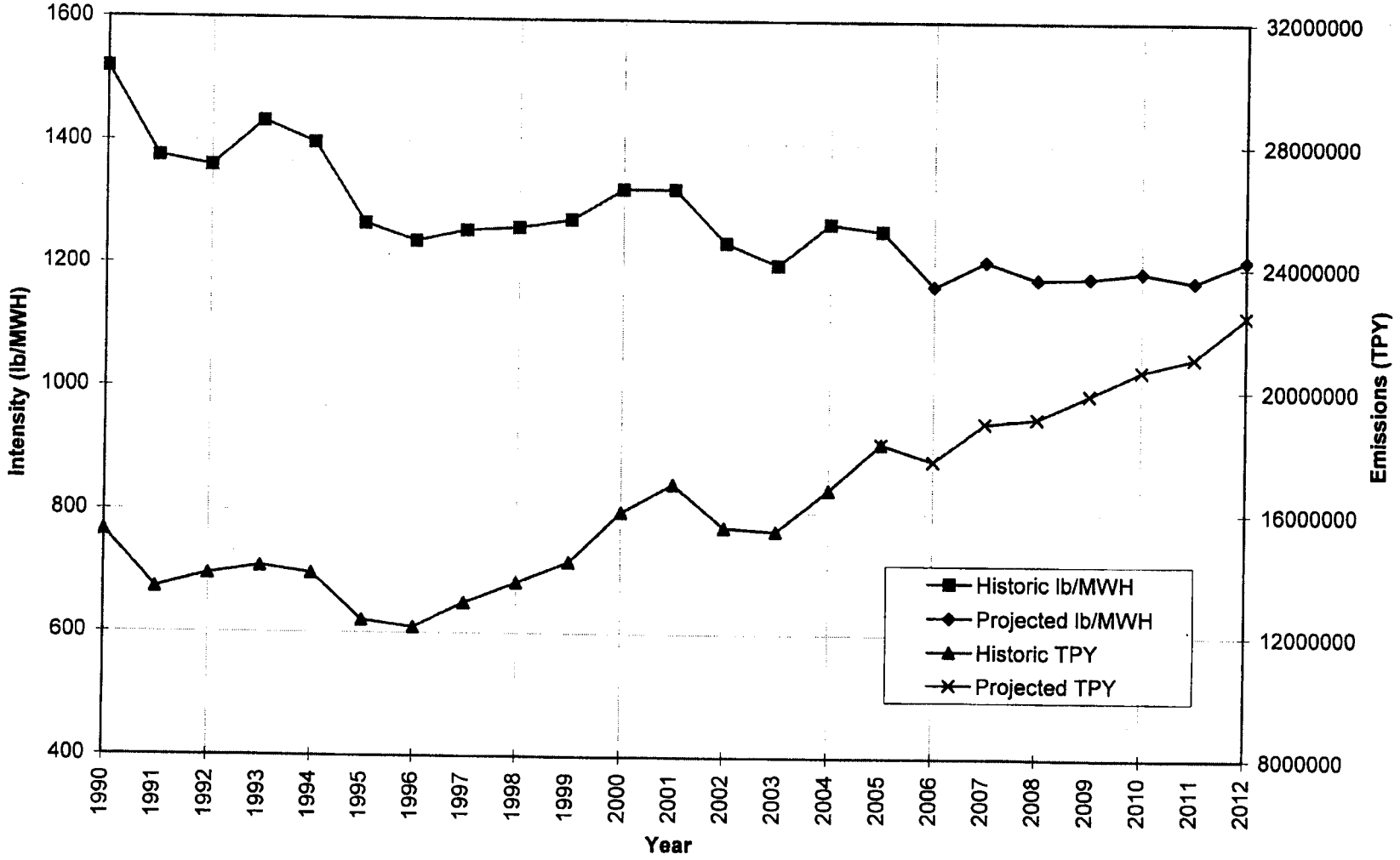
APS Historic/Projected CO2 Emissions



EZF-2RB

Estimated EIC Project Costs
Environmental Improvement Projects
Updated Projected Annual Capital Expenditures

($ x 1000)

June 2006 Estimate:

Project	In-Service Year	Project Estimate Total	Project Estimate Details	Actuals 2004	Actuals 2005	Actuals Jan-May 2006	Forecast Jun-Dec 2006	Forecast 2007	Forecast 2008	Forecast 2009
Cholla:										
Unit 1 Baghouse	2007	21,718	Attach. 1	374	3,123	3,498	10,382	3,906	435	
Uint 1 Scrubber Upgrade	2007	5,418	Attach. 2		88	97	665	4,498	70	
Unit 1 Low NOx Burners	2007	4,806	Attach. 3			19	485	4,202	100	
Unit 2 Low NOx Burners	2008	6,032	Attach. 4	48	4	12	0	1,438	4,530	
Unit 3 Scrubber	2009	60,500				35	965	18,000	28,000	13,500
Unit 3 Baghouse	2009	56,000				7	493	12,000	26,500	17,000
Unit 3 Low NOx Burners	2009	5,284	Attach. 5			1	3	180	1,400	3,700
Total		**159,758**		**422**	**3,215**	**3,669**	**12,993**	**44,224**	**61,035**	**34,200**
						16,662				

Prior Estimate (as shown in EZF WP9):

Project	Total	2004	2005	2006	2007	2008	2009
Cholla:							
Unit 1 Baghouse	22,129	373	3,147	15,571	3,038		
Uint 1 Scrubber Upgrade	5,011		174	1,873	2,964		
Unit 1 Low NOx Burners	4,350			200	4,150		
Unit 2 Low NOx Burners	5,951	48	3	0	1,400	4,500	
Unit 3 Scrubber	47,000			940	17,860	21,150	7,050
Unit 3 Baghouse	45,000			900	17,100	20,250	6,750
Unit 3 Low NOx Burners	5,600					200	5,400
Total	**135,041**	**421**	**3,324**	**19,484**	**46,512**	**46,100**	**19,200**

Additional EIC Projects
Updated Environmental Improvement Projects
Projected Annual Capital Expenditures

($ x 1000)

June 2006 Estimate:

Project	In-Service Year	Project Estimate Total	Project Estimate Details	Actuals 2004	Actuals 2005	Actuals Jan-May 2006	Forecast Jun-Dec 2006	Forecast 2007	Forecast 2008	Forecast 2009	Forecast 2010	Forecast 2011
Cholla:												
Unit 1 Baghouse	2007	21,718	Attach. 1	374	3,123	3,498	10,382	3,906	435			
Uint 1 Scrubber Upgrade	2007	5,418	Attach. 2		88	97	665	4,498	70			
Unit 1 Low NOx Burners	2007	4,806	Attach. 3			19	485	4,202	100			
Unit 2 Low NOx Burners	2008	6,032	Attach. 4	48	4	12	0	1,438	4,530			
Unit 3 Scrubber	2009	60,500				35	965	18,000	28,000	13,500		
Unit 3 Baghouse	2009	56,000				7	493	12,000	26,500	17,000		
Unit 3 Low NOx Burners	2009	5,284	Attach. 5			1	3	180	1,400	3,700		
Total		**159,758**		**422**	**3,215**	**3,669**	**12,993**	**44,224**	**61,035**	**34,200**		
						16,662						
Additional Projects:												
Cholla:												
Lime Slaking Upgrade	2008	10,500			1	96	903	8,500	1,000			
Slurry Disposal	2008	3,000					100	2,000	900			
Unit 1 Carbon Injection	2009	1,500						100	400	1,000		
Unit 3 Carbon Injection	2009	3,000							1,000	2,000		
Unit 2 Baghouse	2011	62,000							700	13,400	29,600	18,300
Unit 2 Carbon Injection	2011	3,200								250	2,400	550
Added Projects Total		**83,200**			**1**	**96**	**1,003**	**10,600**	**4,000**	**16,650**	**32,000**	**18,850**
Grand Total		**242,958**		**422**	**3,216**	**3,765**	**13,996**	**54,824**	**65,035**	**50,850**	**32,000**	**18,850**
						17,761						

EZF-4RB

REBUTTAL TESTIMONY OF GREGORY A. DeLIZIO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gregory A. DeLizio. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. SUMMARY

Q. WOULD YOU SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony addresses a number of issues and recommendations raised by Staff of the Arizona Corporation Commission ("Staff") and other parties in their direct testimony concerning the Company's proposals for an Environmental Improvement Charge ("EIC"), green power (electricity from renewable resources) rates, rates for partial requirements service, and rates for renewable resources. In addition, I address issues concerning the Company's Service Schedule 1.

III. SCHEDULE EIC - ENVIRONMENTAL IMPROVEMENT CHARGE

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE ENVIRONMENTAL IMPROVEMENT CHARGE (EIC) AS PROPOSED IN YOUR DIRECT TESTIMONY?

A. Yes. As indicated in Mr. Fox's rebuttal testimony, the Company has updated some of the costs of the environmental projects that were included in the EIC which was proposed in my direct testimony. In addition, APS has added six new

projects to the EIC plan, which are described in the Rebuttal Testimony of Mr. Ed Fox.

Q. HAS THE COMPANY CHANGED THE METHOD OF CALCULATING THE EIC COSTS AS PROPOSED IN YOUR DIRECT TESTIMONY?

A. No. The method of calculation and the underlying assumptions supporting the results have not changed from what was proposed in my Direct Testimony.

Q. WHAT IS THE CUSTOMER IMPACT OF THE PROPOSED CHANGES IN THE EIC CHARGE?

A. The updated initial EIC charge would be $0.00016 per kWh, which would be in place through June 2008. This charge would result in an average revenue increase of 0.19% and would increase the bill of an average residential customer consuming 1163 kWh per month by $0.19 per month. The EIC charge is projected to change over time, subject to subsequent Commission approval, as more environmental projects are undertaken. The updated Rate Schedule EIC is provided as Attachment GAD-1RB.

Q. IS THE COMPANY PROPOSING TO MAKE ANY CHANGES TO THE IMPLEMENTATION OF THE EIC?

A. No. The implementation of the EIC will be the same as what the Company originally proposed in my Direct Testimony, as detailed in the Plan of Administration attached to such testimony.

Q. HAVE YOU REVIEWED THE TESTIMONY OF STAFF AND OTHER PARTIES CONCERNING THE EIC?

A. Yes.

Q. PLEASE SUMMARIZE THEIR TESTIMONY.

A. Staff and the Residential Utility Consumer Office ("RUCO") oppose the EIC and

believe that environmental improvement costs should be recovered under the "traditional" rate making philosophy of waiting until the improvements are in service before determining whether the Company is entitled to recover for them. Their chief objection appears to be that the EIC is new and unique, that it doesn't fit what they believe are "traditional" rate making standards, and that it allows for cost changes outside of a general rate case. In addition, Staff opposes the EIC because, in their opinion, it would create a complicated audit process. RUCO also opposes the EIC because they believe that it violates the constitutional requirement for fair value rate making. Finally, AECC witness Kevin Higgins opposes the EIC without offering any empirical support for his opposition, other than the implementation of the EIC amounts to single issue rate making.

In contrast, Dave Berry, on behalf of Western Resource Advocates ("WRA"), supports the EIC to recover environmental improvement costs, including costs associated with green house gas abatement. Mr. Berry emphasizes that the EIC is needed 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.

Q. WHAT IS YOUR RESPONSE TO STAFF'S POSITION ON THE EIC?

A. As addressed by Mr. Fox in his Rebuttal Testimony, it is impractical and counter productive to require that the Company first quantify the environmental benefits of emission control equipment before a project can be funded. Furthermore, Staff's contention that the denial of timely recovery of these types of costs would not impose a significant financial burden on the Company and that the Company should make the investment first and then seek recovery through traditional rate making or debt financing has missed one of the key points, if not the key point in

this entire proceeding, which is discussed in the Rebuttal Testimony of Mr. Wheeler. Capital is at a premium for APS and without the EIC, environmental projects are just another capital need in a very long line of competing needs. In addition, Mr. Fox in his Rebuttal Testimony, provides further detail on the expected environmental benefits of the EIC and why such a mechanism is necessary for the recovery of expected environmental costs instead of through a traditional rate case or bond financing or otherwise.

Q. IS THE COMPANY ASKING FOR PREAPPROVAL OF THE ENVIRONMENTAL PROJECTS AND/OR THEIR COSTS?

A. No. The Company is only seeking a more timely recovery of the environmental project costs. The Arizona Corporation Commission ("Commission" or "ACC") would still have an opportunity to review the projects and their costs for prudence, either in a general rate case or other proceeding.

Q. PLEASE EXPLAIN.

A. The Commission would have an opportunity to determine the prudency of such projects during APS' annual EIC filing, which is outlined in my Direct Testimony. The Commission would also have the opportunity for a prudence review of the costs of environmental projects as part of a rate case, when the Company seeks rate base treatment of those assets.

Q. WHAT HAPPENS IF PROJECT COSTS CHANGE IN SUBSEQUENT YEARS?

A. The EIC would be updated to reflect the actual project costs, as well as changes in projected costs, and then subject to the Commission's approval during the annual EIC filing.

Q. PLEASE ADDRESS STAFF'S CONCERN ABOUT THE AUDITING

PROCESS FOR THE EIC.

A. As outlined in my Direct Testimony, the Company has proposed a process for identifying and documenting the specific project costs and related revenue requirements to be recovered through the EIC. While the information would contain detailed project costs, the Company does not believe that any audit process would be any more complicated than auditing any other new plant addition because the information would be carefully separated from other Company costs.

Q. DO YOU AGREE WITH RUCO THAT THE EIC WOULD VIOLATE FAIR VALUE RATE MAKING?

A. I'm not a lawyer, but the Commission has already adopted similar mechanisms, such as the DSM, EPS and PSA adjustor mechanisms, as well as the arsenic surcharges discussed by Mr. Fox in his Rebuttal Testimony, which recover costs outside of a rate case. In addition, when APS seeks rate base treatment in the context of a rate case, the Commission has the opportunity to review and approve the projects and their costs.

Q. AECC CLAIMS THAT THE EIC AMOUNTS TO SINGLE ISSUE RATE MAKING. DO YOU AGREE?

A. Yes. That's true of all adjustment mechanisms, but it is not a compelling reason to deny the EIC. As I noted above, the Commission has historically approved similar mechanisms for recovery of public benefit programs, such as DSM and renewable costs outside of a rate case.

IV. <u>ADJUSTMENT SCHEDULE EPS-1 ENVIRONMENTAL PORTFOLIO STANDARD</u>

Q. WHY IS THE COMPANY PROPOSING TO MODIFY SCHEDULE EPS-1?

A. Decision No. 68668 required APS to set aside $4.25 million for additional funding for the Environmental Portfolio Standard ("EPS") Uniform Credit Purchase Program.

Q. HOW DOES APS INTEND TO RECOVER THIS ADDITIONAL FUNDING REQUIREMENT?

A. In her Direct Testimony, Ms. Keene of Staff recommends that APS be allowed to recover the $4.25 million through the Company's Adjustment Schedule EPS-1.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION?

A. Yes. The revised Adjustment Schedule EPS-1, which recovers the additional $4.25 million funding requirement, is provided as Attachment GAD-2RB. The rates and surcharge limits are identical to those proposed by Ms. Keene in her Direct Testimony.

V. PROPOSED GREEN POWER SCHEDULES

Q. DID STAFF OR ANY OTHER PARTIES COMMENT ON THE COMPANY'S PROPOSED GREEN POWER RATES GPS-1 AND GPS-2?

A. Yes, as set forth in the Direct Testimony of Ms. Keene, Staff recommends approval of Schedules GPS-1 and GPS-2 as proposed in my Direct Testimony. WRA witness Mr. Berry supports the concept of green power rates but recommends several revisions to APS' proposed rates.

Q. DO YOU AGREE WITH MR. BERRY'S RECOMMENDATIONS?

A. As addressed in the Rebuttal Testimony of Ms. Lockwood, APS agrees with a number of recommendations made by WRA concerning the green power rates, which are reflected in the revised Green Power Rate Schedules GPS-1A and GPS-2A.

Q. HOW IS THE COMPANY MODIFYING THE PROPOSED GREEN POWER RATE SCHEDULES?

The Company has modified the premium charge and the block size for the Green Power Schedules, GPS-1A and GPS-2A, which are the Green Power Block Schedule and the Green Power Percent Schedule respectively. The premium has changed from $0.03/kWh, as proposed in my Direct Testimony, to $0.01 per kWh. The Company is also proposing to increase the block size from 25 kWh, as proposed in my Direct Testimony, to 100 kWh per month. As a result, the monthly premium for green power in Schedule GPS-1A, has been changed from $0.75 for a 25 kWh for block of green power, as proposed in my direct testimony, to $1.00 for a 100 kWh block. The Company has also made commensurate changes in the green power premiums for the various percentages of monthly consumption in Schedule GPS-2A. The revised rate schedules GPS-1A and GPS-2A are provided as Attachments GAD-3RB and GAD-4RB.

Q. HOW WAS THE PREMIUM FOR GREEN POWER CALCULATED?

A. As described by Ms. Lockwood in her Rebuttal Testimony, the green power costs are based on actual energy costs for renewable projects that are used to serve the green power rate schedules. The Company's avoided generation costs are then netted against the renewable energy costs to derive the premium for green power.

Q. HOW DOES YOUR PROPOSED CALCULATION METHOD COMPARE WITH THAT PROPOSED BY WRA?

A. WRA witness Mr. Berry proposes that the premium for green power be calculated by determining the total cost per kWh for green power and subtracting the avoided generation costs as measured by the base power supply cost, the PSA and the allowance for capacity credits associated with the green power. Our proposed method is similar to WRA's proposal, except that we base the avoided generation

costs on the Company's avoided costs, which were filed on June 30, 2006, instead of the fuel, PSA, and capacity credits as proposed by Mr. Berry. We believe that our method provides a more accurate and fair way of determining the credit for the fuel and any capacity costs that the Company avoids as a result of the green power resource.

In addition, Mr. Berry suggests that the PSA could alternatively be factored into the equation by exempting the kWh served by green power from the customer's PSA charge, instead of subtracting the PSA from the green power cost to derive the green power premium. Mr. Berry suggests that the former method would help to stabilize the green power premium over time because the premium would not automatically change when the PSA is modified. The Company believes that this suggested change is unnecessary and inconsistent with our proposal because, as discussed, we propose to base the green power premium on filed avoided costs rather than using explicit values for fuel, PSA, and capacity credits as proposed by Mr. Berry.

Q. WHAT HAPPENS IF THE INITIAL GREEN POWER RESOURCES BECOME FULLY SUBSCRIBED OR IF THE PRICE OF GREEN POWER CHANGES?

A. 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 will compute a new green power premium associated with the additional green power costs and the most recently approved avoided cost filing. 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. 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. The initial offering of green power will be served under the proposed green power rates GPS-1A and GPS-2A. Any additional offering of green power will be served under new green power rates. If the green power rates are fully subscribed, additional green power will not be available to customers until the new rates are approved by the Commission. The individual green power rates will subsequently be consolidated into one rate in the next general rate case.

Q. WRA RECOMMENDED THAT THE GREEN POWER KWH BE EXEMPT FROM THE EIC AND EPS CHARGES. DO YOU AGREE?

A. Yes. The Company agrees that the green power kWh purchased through Schedules GPS-1A and GPS-2A should be excluded from the EPS and EIC charges. A customer participating in a green power rate would continue to be subject to EPS and EIC charges for the portion of their consumption that is not served under the green power rate schedules. Customers would also be subject to all other provisions in their otherwise applicable rate schedule, including adjustments, as applied to their total monthly consumption, which includes the green power portion. For example, the customer's total monthly consumption would be applied to the Power Supply Adjustment, the Transmission Cost Adjustment, the Competition Rules Compliance Charge, the Demand Side Management Adjustment, and any applicable taxes and government impositions.

In other words, the customer would be billed for their total monthly consumption according to all the provisions in their otherwise applicable rate schedule. However, the EIC and EPS charges would be based on the customer's total consumption less the green kWh. The green power premium, which includes the green power cost netted with the appropriate avoided generation costs associated with the green power kWh would then be added to the customer's bill.

Q. IS THE COMPANY RECOMMENDING ANY OTHER CHANGES TO GREEN POWER RATES?

A. Yes. The Company is proposing a Solar Power Pilot Program for residential customers, Schedule Solar-3. This Pilot Program will provide an option to residential customers to have either 50% or 100% of their monthly energy needs served from solar power. The Company will construct new utility-owned solar plants to serve customers participating in the program. The total amount of solar generation sold will not exceed the solar resources available from these solar plants. The Pilot Program will be available for three years.

Q. WHY IS THE COMPANY PROPOSING SCHEDULE SOLAR-3?

A. As described by Ms. Lockwood in her Rebuttal Testimony, the Total Solar Pilot Program will provide customers the option to have their energy needs served from solar power resources, that may not otherwise be able to (or desire to) participate in the Company's Solar Partners Inventive Program (formerly named as the Credit Purchase Program) for the installation their own solar photovoltaic system.

Q. PLEASE EXPLAIN RATE SCHEDULE SOLAR-3.

A. Schedule Solar-3 will apply to customers participating in the Total Solar Pilot Program in addition to their otherwise applicable rate schedule. Customer will be charged a premium for the solar power and credited for avoided generation costs, which will be based on the Company's avoided costs filing. The initial solar power cost of $0.394 per kWh will be netted against an avoided cost credit of $0.059 per kWh, which results in a premium for solar power of $0.335 per kWh. The solar kWh will not be subject to the EPS or EIC charges. All other provisions and charges of the customer's otherwise applicable rate schedule will be applied to their total monthly consumption, including the portion generated by solar

power. For example, the customer's total monthly consumption would be applied to the Power Supply Adjustment, the Transmission Cost Adjustment, the Competition Rules Compliance, the Demand Side Management Adjustment, and any applicable taxes and government impositions. Schedule Solar-3 is provided as Attachment GAD-6RB.

Q. HOW WAS THE PREMIUM FOR SOLAR POWER DERIVED?

A. The premium is based on the projected 25 year levelized cost of a single axis solar generation plant divided by the projected annual energy output from the solar plant. The premium is being addressed by Ms. Lockwood in her Rebuttal Testimony.

Q. HOW WAS THE AVOIDED COST CREDIT CALCULATED?

A. The avoided cost credit included in the proposed Solar-3 rate schedule is based on APS' 2007 non-firm seasonal avoided costs, which were filed with the ACC on June 30, 2006, as applied to the generation profile of a single axis solar generation plant over various seasons and time-of-use periods.

VI. NET METERING RATE EPR-5

Q. PLEASE SUMMARIZE THE TESTIMONY OF STAFF AND OTHER PARTIES CONCERNING THE PARTIAL SERVICE REQUIRMENTS SCHEDULE EPR-5 (NET METERING).

A. Staff witness Barbara Keene generally supports the EPR-5 net metering rate, but recommends that the proposed cap on the size of a participating renewable generator be increased from 10 kW to 100 kW and that the rate be available to customers on all rate schedules. Ms. Keene also recommends that two separate meters be used instead of the recommended bi-directional meter. That being said, Ms. Keene appears to generally support the Company's proposal to recover

incremental implementation costs and net lost revenue from the net metering program from environmental portfolio standard funds.

Solar Advocates witness Ed Smeloff proposes 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. Mr. Smeloff does not object to the concept of the recovery of net lost revenues from the net metering program, but he does oppose that those amounts be funded out of the RES funds instead of through rates. Mr. Smeloff also proposes certain net metering policy issues, which go beyond the EPR-5 rate itself.

Q. THE TERMS NET METERING AND NET BILLING ARE USED FREQUENTLY IN DISCUSSIONS INVOLVING RENEWABLE RESOURCES DISTRIBUTED GENERATION. PLEASE EXPLAIN THESE TERMS.

A. 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...." 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." The customer is charged the appropriate retail rate under the applicable APS rate schedule for their energy usage (sales to the customer). The

utility purchases excess energy from the customer at the current buy-back rate in accordance with the provisions of the applicable APS partial requirements rate schedule (EPR-2 or EPR-4). A bi-directional meter containing two separate metering registers is used to record sales to the customer and purchases from the customer. The main difference between net billing and net metering is reflected in this buyback rate.

The buyback rate is based on APS' avoided generation cost, which reflects the Company's most recently filed avoided costs and are based on wholesale generation market rates for on-peak and off-peak generation by season. Purchases from the customer only occur when the customer's generation exceeds the customer load at any given instant.

APS currently utilizes the net billing methodology for customers taking service under rate schedules EPR-2 and EPR-4.

Q. PLEASE EXPLAIN WHY THE COMPANY BELIEVES THE PROPOSED CAP ON INDIVIDUAL GENERATOR SIZE FOR THE SCHEDULE EPR-5 PARTIAL SERVICE REQUIREMENTS (NET METERING) PILOT PROGRAM IS APPROPRIATE.

A. 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, which do not have any cap on aggregate participation.

For example, APS currently offers rate Schedule EPR-2, which is available to all Qualifying Facilities ("QF") cogeneration and small power production facilities up to 100 kW. EPR-2 is similar to the proposed EPR-5 net metering rate in a number of ways. For example, the EPR-2 customer operates a distributed generation system in parallel with the APS grid. The customer is allowed to

generate all or part of their own energy needs with the backing of APS' system without paying for any standby charges. The customer is also compensated for any excess generation that flows back to the APS grid. The key difference between EPR-2 and the proposed EPR-5 net metering rate is that under EPR-2, the customer's excess generation is compensated at an avoided cost rate, while EPR-5 allows the excess energy to be netted against energy purchased from APS in subsequent months. The EPR-2 rate also has an additional monthly service charge to pay for the increased service costs, which the Company is proposing to eliminate as discussed below, while EPR-5 does not have an additional monthly charge.

The Company also currently offers Rate EPR-4 for renewable distributed generation up to 10 kW. EPR-4 is similar to EPR-2, but does not have the additional monthly service charge. Again, this rate offers most of the benefits of the proposed EPR-5 net metering rate; the difference being the method for compensating the customer for excess generation.

In addition, the Company provides partial requirement rates for distributed generators larger than 100 kW, as discussed in detail below. The Company believes that it is appropriate to handle these larger generators in this manner, rather than through a net metering arrangement, because of the standby issue discussed above.

Q. WHAT ABOUT THE OVERALL PROGRAM CAP OF 15 MW FOR THE NET METERING PILOT PROGRAM?

A. The Company believes that the proposed 15 MW cap on total aggregate participation in the EPR-5 net metering pilot program is appropriate, even in light of a potential expanded renewable energy program. 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). In addition, as summarized above, the Company already offers other net metering/net billing type rates that do not have any aggregate cap on participation.

Q. WHAT LEVELS OF CAPS DO OTHER JURISDICITONS PLACE ON THEIR NET METERING PROGRAMS?

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. 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. The Company believes that its proposal of 10 kW for the EPR-5 rate is consistent with these other jurisdictions because, as discussed, 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.

Furthermore, 23 of the 41 states have caps on the aggregate level of participation. 18 of the 23 states that limit aggregate program participation have caps that are at or below 0.2% of the utility's peak load. Many of these states also have renewable energy standard requirements. The Company's proposed cap of 15 MW on aggregate participation is roughly equal to 0.2% of our "own-load" system peak, which is consistent with many other jurisdictions.

Q. DO YOU AGREE WITH MR. SMELOFF'S RECOMMENDATIONS FOR PROGRAM CAPS?

No. Mr. Smeloff cites several states with relatively high caps for individual generator size and for total MW allowed on a net metering program. The

Company believes that Mr. Smeloff's examples are outliers and should not be adopted in Arizona. In fact, only two states allow participation in net metering of generators up to 2 MW, as Mr. Smeloff is proposing for Arizona. Furthermore, in each of the states that Mr. Smeloff cites as examples to be followed, other than Colorado, the utilities have divested generation as part of retail competition and are facing very different generation procurement situations compared to APS. Therefore, their net metering programs are not illustrative of the best practices for APS and its customers.

Q. DO YOU AGREE THAT SCHEDULE EPR-5 SHOULD BE AVAILABLE TO ALL CUSTOMERS?

No. 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. 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.

Q. BUT WON'T LARGER COMMERCIAL CUSTOMERS ALSO WANT TO INSTALL RENEWABLE GENERATION?

A. We believe so. However, as discussed above, the Company already has other rates for larger customers with renewable generation, some of which have similar benefits of the proposed EPR-5 net metering rate. Again, the Company believes that the proposed availability of the EPR-5 rate in concert with other partial requirement rates will offer customers of all sizes on all rates beneficial and appropriate options for accommodating renewable generation, as well as other types of distributed generation.

Q. DO DISTRIBUTED GENERATION CUSTOMERS TYPICALLY SUPPLY EXCESS ENERGY TO THE APS DISTRIBUTION GRID?

A. No. The primary purpose of installing distributed generation has been to replace a portion of the utility provided electric load with on-site generation from a renewable resource. APS has interconnected over 300 distributed generators and only a small percentage of these customers supply excess energy to APS. In most instances the customer's load is significantly higher than the amount of on-site generation and 100% of the output of the distributed generator is used by the customer. The ability to sell excess energy to APS does not have a profound impact on the customer's decision to install on-site distributed generation.

Q. MS. KEENE RECOMMENDS THAT THE NET METERING RATE USE TWO METERS, RATHER THAN A SINGLE BI-DIRECTIONAL METER. DO YOU AGREE?

A. No. While the EPR-5 net metering rate could technically be implemented with two standard meters, the Company believes that a single bi-directional meter is a better option. At this time, two standard meters have a lower initial cost for the meter compared with a bi-directional meter. However, the customer would require additional electrical infrastructure costs, such as an additional meter base, sockets, adaptors and other meter-service costs, which eliminate any meter cost savings advantage. Furthermore, the Company prefers the operational requirements of the bi-directional meter for this application, which includes meter inventory, meter sets and meter reading. In fact, the Company is already using a single bi-directional meter for the current distributed generation (partial service requirements) rates, EPR-2 and EPR-4, discussed above. So the Company's metering proposal for EPR-5 would be consistent with our existing operations.

Q. WHAT KIND OF METERING DO OTHER JURISDICTIONS USE FOR NET METERING RATES?

A. Referring again to the net metering programs cited above, the vast majority of other jurisdictions which offer net metering use a single bi-directional meter to implement the rate; many jurisdictions require it. In fact, the Company has not been able to identify a single state that requires using two meters to implement net metering. Therefore, the Company believes that its proposal for using a bi-directional meter is consistent with industry and regulatory practice throughout the country.

Q. DID STAFF AND OTHER PARTIES SUPPORT THE RECOVERY OF NET LOST REVENUES FOR THE NET METERING PILOT PROGRAM?

A. In the direct testimony of Ms. Keene, Staff supports the concept of net lost revenue recovery for net metering. Solar Advocates witness Mr. Smeloff does not oppose net lost revenue recovery, but testified that the recovery should not be funded out of the EPS budget.

Q. DO YOU AGREE WITH THEIR RECOMMENDATIONS?

A. As I discussed in my Direct Testimony, the Company believes that it is appropriate to recover net lost revenue from the Net Metering Pilot Program, which offers a special financial subsidy to customers in order to promote small renewable distributed generation systems. The potential loss of kWh sales and the related net-revenue loss from the net metering program occur for two reasons. First, the Company is providing an incentive through the net metering rate to encourage customers to install renewable distributed generation. This generation reduces kWh sales that the Company may otherwise have made absent the program. While the participating customer provides some of their own energy needs through their distributed generator, they are still connected to the grid and rely on APS to back up their distributed generator and provide their remaining

energy needs.

The proposed net metering rate does not include a standby charge to recover APS' costs to back up the customer's generator, which is typical in other partial requirement rates which the Company offers. As a result, the customer will not pay their full costs for transmission, distribution or other fixed costs, especially for rate schedules that recover these costs through energy-based charges.

The second source of potential net-revenue loss occurs because the excess power that the customer generates above their own needs, which flows back to the grid, is compensated at an amount that is above the Company's avoided cost. The customer receives 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.

Q. HOW WOULD THE NET LOST REVENUES BE CALCULATED?

A. The Company would incur lost kWh sales equal to the customer's total kWh generation and incur the associated lost revenues consistent with the customer's otherwise applicable rate schedule. The customers' generation kWh output would be calculated by applying a capacity factor to each customer's actual installed kW of generation. The lost revenues would be derived by applying the average kWh charges in the customer's otherwise applicable rate schedule to the lost kWh. 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, as billed with the net metering rate schedule. This lost revenue would be calculated for each billing month for each participating customer.

The lost revenue would be netted against the associated avoided generation costs that the Company would not incur as the result of the distributed generation. Both the generation energy and capacity cost savings from net metering will 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. The Company's most recently filed avoided costs are based on wholesale generation market rates for on-peak and off-peak generation by season. These values would be used to assess the potential generation cost savings for solar, wind, biomass and other renewable technologies that could participate in a net metering program. A sample calculation of net lost revenue from net metering, which is based on assumptions concerning program participation, types of renewable systems, and excess power rates, is provided as Attachment GAD-5RB.

Q. HOW WOULD THE NET LOST REVENUES BE ADMINISTERED?

A. The net lost revenues would be recovered through the EPS budget and reported to the Commission as part of the reporting requirements of the EPS program.

VII. RATES FOR PARTIAL SERVICE REQUIREMENTS

Q. PLEASE EXPLAIN THE CONCEPT OF PARTIAL REQUIREMENT RATES.

A. Partial requirement rates are applicable to customers who utilize distributed generation to self-provide a portion of their electric load. In order to provide reliable service to a partial requirements customer, APS must have adequate facilities in place to meet 100% of the customer's electric load requirements when the distributed generator is not in operation (e.g. generator outage, scheduled maintenance, etc.).

Q. WHAT ARE APS' CURRENT PARTIAL REQURIEMENT RATES?

A. APS offers the following partial requirements service rate schedules:

EPR-2: EPR-2 is 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.

EPR-3: 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% of their electric requirements while selling 100% of the output of the generator to APS. This rate is frozen to new customers.

EPR-4: EPR-4 is 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.

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

E-51: 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.

E-52: 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.

E-55: 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.

EQF-S: 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.

EQF-M: 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.

Q. WHAT WERE OTHER PARTIES COMMENTS ON APS' PARTIAL REQUIREMENT RATES?

A. Distributed Energy Association of Arizona ("DEAA") witness William Murphy took exception to APS' partial requirements rates and recommended the development of a new partial requirements rate schedule. Mr. Murphy also proposed criteria which, in his opinion, should be used to develop new partial requirements rates.

Q. DO YOU AGREE WITH MR. MURPHY'S COMMENTS?

A. For the most part, no. As discussed in the Rebuttal Testimony of APS witness

David Rumolo, Mr. Murphy's general rate design philosophy is fundamentally flawed and his proposed partial requirements rate design philosophy has no basis in cost causation. Furthermore, Mr. Murphy presents no evidence to support his claims that APS' demand and energy rate schedule components are not cost-based. Thus, the Company strongly disagrees with both of these assertions.

Mr. Murphy also claimed that the Company's partial requirements rates were complicated and not easy to understand. The Company agrees that Partial Requirement Rate Schedules E-52 and E-55 are somewhat complicated and is proposing several changes to the partial requirement rate schedules to address this issue. In addition, the Company 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.

Q. WHAT ARE THE CHANGES THAT THE COMPANY IS PROPOSING FOR ITS PARTIAL REQUREMENTS RATES?

A. In addition to the new EPR-5 rate schedule proposed in my Direct Testimony and discussed in more detail above, the Company is proposing modifications to the existing EPR-2 rate schedule and is proposing two additional partial requirements rate schedules (E-56 and E-57). APS is proposing to: (1) eliminate existing rate schedules EPR-3, EQF-S, EQF-M, and E-52, which are currently frozen and therefore not available to new customers; (2) close (freeze) existing rate schedules E-32R, and E-55 to new customers and eliminate them in the next rate case; (3) eliminate schedule E-51, which is currently frozen, in the Company's next rate case, and (4) consolidate Schedule EPR-4 into the revised Schedule EPR-2.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO RATE SCHEDULE EPR-2.

A. The Company has updated the buyback rate in schedules EPR-2 to incorporate the avoided costs, which were filed on June 30, 2006. 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' 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. The revised Schedule EPR-2 is provided as Attachment GAD-7RB.

Q. WHY IS SCHEDULE EPR-3 BEING ELIMINATED?

A. 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. EPR-3 is frozen with no customers currently on the rate.

Q. WHY IS SCHEDULE EPR-4 BEING CONSOLIDATED WITH SCHEDULE EPR-2?

A. The Company's proposed revisions to Schedule EPR-2 make the provisions of service identical to the existing Schedule EPR-4. Therefore, Schedule EPR-4 is being consolidated into the revised EPR-2 rate. The Company is currently serving 249 customers under the EPR-4 rate.

Q. WHY ARE SCHEDULES E-52, EQF-S, AND EQF-M BEING ELIMINATED?

A. 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.

Q. WHAT DOES THE COMPANY PROPOSE FOR RATE SCHEDULE E-51?

A. The Company proposes that rate schedule E-51, which is currently frozen, should be eliminated in the next general rate proceeding because it will be replaced by the proposed rate E-56. APS currently has two customers served under Schedule E-51.

Q. WHY ARE SCHEDULES E-32R AND E-55 BEING FROZEN TO NEW CUSTOMERS?

A. APS' 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.

Q. PLEASE DESCRIBE THE PROPOSED PARTIAL REQUIREMENTS RATE E-56.

A. Partial Service Rate Schedule E-56 is applicable to general service customers having distributed generating equipment 100 kW or greater capable of supplying all or a portion of its power requirements. 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.

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. Rate Schedule E-56 is provided as Attachment GAD-8RB.

Q. PLEASE DESCRIBE THE PROPOSED SOLAR PARTIAL REQUIREMENT RATE E-57.

A. Rate schedule E-57 is 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% 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 above-mentioned Basic Service component); and,

(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.

(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.

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. Rate Schedule E-57 is provided as Attachment GAD-9RB.

VIII. GENERAL TERMS AND CONDITIONS

Q. HAS THE COMPANY PROPOSED ANY ADDITIONAL CHANGES TO SCHEDULE 1?

A. Yes. In addition to the changes discussed in my Direct Testimony, we have proposed a few minor wording changes that clarify certain changes and their application. The revised Schedule 1 is provided as Attachment GAD-10RB.

Q. DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDATION CONCERING THE $75 TRIP CHARGE?

A. No. As discussed in my Direct Testimony, Section 2.2.4 refers to charges for work performed outside of normal work hours, at the customer's option and request, which usually requires a crew with more than one person. 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 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.

IX. E3 AND E4 LOW INCOME AND MEDICAL DISCOUNT PROGRAMS

Q. WHY IS THE COMPANY PROPOSING TO CHANGE THE E-3 AND E-4 MEDICAL DISCOUNT PROGRAM AT THIS TIME?

A. In Decision No. 68685 the Commission directed APS to propose ways to implement automatic enrollment of customers in the E-3 and E-4 low income and medical discount programs as part of this rate case. These changes are discussed in the Rebuttal Testimony of APS witness Terry Orlick. The proposed changes to the related rate schedules and plans of administration are necessary to ensure that all eligible customers can participate in the programs and to enable additional

enrollment mechanisms for the E-3 discount program.

Q. HOW DOES APS PROPOSE TO CHANGE SCHEDULES E-3 AND E-4 AND THE RELATED PLANS OF ADMINISTRATION?

A. The Company proposes to insert additional language in the Plans of Administration for Schedules E-3 and E-4 that would allow other community action agencies, in addition to the Arizona Department of Economic Security ("DES"), to apply the income eligibility guidelines specified in the rates. Currently only DES can determine if a customer is eligible for the rates. In addition, the Plan of Administration for Schedule E-3 required some minor language changes to ensure that residential customers on all rate schedules are eligible for the discount. Clarifying language has also been added to Schedules E-3 and E-4 to clarify that customers cannot participate in both the E-3 and E-4 discounts concurrently, which is consistent with current practice. The revised Schedules E-3 and E-4 are provided as Attachment GAD-11RB and Attachment GAD-12RB respectively. The revised Plans of Administration for E-3 and E-4 are provided as Attachment GAD-13RB and Attachment GAD-14RB respectively.

X. ADMINISTRATIVE ISSUES

Q. WOULD THE COMPANY BE ABLE TO IMPLEMENT ALL OF THE PROPOSED RATE CHANGES IMMEDIATELY AFTER RECEIVING COMMISSION APPROVAL?

A. The Company is planning for the necessary changes to customer billing, metering and related systems required to implement the proposed changes to the Rate Schedules discussed in my Direct and Rebuttal Testimony. However, some of the optional rates which I have proposed in my Direct and Rebuttal Testimony will require additional time to implement after an order is received in this proceeding to accommodate required billing, metering and related systems .

XI. CONCLUSION

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. APS is requesting that the Commission authorize the following: the implementation of the EIC as proposed by the Company; modification of the Company's Schedule EPS-1 to recover an additional $4.25 million spent by the Company; adoption of two new Company proposed Green Power Schedules GPS-1A and GPS-2A; a new Company proposed Schedule Solar-3; partial requirements rates in EPR-5 for net metering and E-56 and EPR-57 for customer distributed generators in excess of 100kW; consolidation of EPR-4 and EPR-2; freezing of E-55, E51 and E32-R to new customers; and withdrawal of EQF-S and EQF-M. The Company also requests approval to modify its Service Schedule 1 and Service Schedule 4, as proposed.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

ENVIRONMENTAL IMPROVEMENT CHARGE

APPLICATION

The Environmental Improvement Charge ("EIC") shall apply to all retail Standard Offer service, excluding kWh served in accordance with solar rates SP-1 (Solar Partners), Solar-2, Solar-3, and Green Power Schedules GPS-1 and GPS-2. All provisions of the customer's current applicable rate schedule shall apply in addition to charges under this EIC.

The EIC was approved by the Arizona Corporation Commission ("ACC") in Decision No. XXXXX. Cost recovery under the EIC shall be in accordance with the method described in the filed Environmental Improvement Charge Plan of Administration.

The EIC recovers the cost associated with investment and expenses for environmental improvements at APS' generation facilities that the ACC has approved for recovery. Approved environmental improvements include those implemented on or after January 1, 2004, for which costs have not been fully recovered under current approved rates, ongoing environmental improvement projects, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC) and toxins such as mercury (Hg).

RATE

The charge shall be calculated at the following rate:

EIC

All kWh	$0.00016 per kWh

APPLICATION

The Environmental Portfolio Surcharge Adjustor shall apply to all retail Standard Offer or Direct Access service, excluding kWh served in accordance with solar rates SP-1 (Solar Partners), Solar-2, Solar-3, ~~SP-1~~, and Green Power Schedules GPS-1 and GPS-2. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. From time to time the EPS program spending requirements will be evaluated and if necessary the charge and/or caps will be altered if approved by the Commission. Any new charges/caps will be applied in billing cycle 1 beginning in the month following Commission approval and will not be prorated. Details regarding the administration of this surcharge can be found in the filed Environmental Portfolio Surcharge Plan for Administration. The EPS Surcharge and the Demand Side Management Adjustment Charge may be combined on the customer's bill and shown on the "Environmental Benefits Surcharge" line.

RATES

The bill shall be calculated at the following rates:

All kWh	~~$ 0.000875~~$0.001392	per kWh

SURCHARGE LIMITS

The monthly total of the Environmental Portfolio Surcharge shall not exceed the following limits:

Residential Customers	~~$ 0.35~~$0.56	per service per month
Non-residential Customers	~~$13.00~~$20.68	per service per month
Non-residential Customers with demand of 3,000 kW or higher per month for three consecutive months	~~$39.00~~$62.04	per service per month

APPLICATION

The Environmental Portfolio Surcharge Adjustor shall apply to all retail Standard Offer or Direct Access service, excluding kWh served in accordance with solar rates SP-1 (Solar Partners), Solar-2, Solar-3, and Green Power Schedules GPS-1 and GPS-2. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. From time to time the EPS program spending requirements will be evaluated and if necessary the charge and/or caps will be altered if approved by the Commission. Any new charges/caps will be applied in billing cycle 1 beginning in the month following Commission approval and will not be prorated. Details regarding the administration of this surcharge can be found in the filed Environmental Portfolio Surcharge Plan for Administration. The EPS Surcharge and the Demand Side Management Adjustment Charge may be combined on the customer's bill and shown on the "Environmental Benefits Surcharge" line.

RATES

The bill shall be calculated at the following rates:

All kWh	$0.001392	per kWh

SURCHARGE LIMITS

The monthly total of the Environmental Portfolio Surcharge shall not exceed the following limits:

Residential Customers	$0.56	per service per month
Non-residential Customers	$20.68	per service per month
Non-residential Customers with demand of 3,000 kW or higher per month for three consecutive months	$62.04	per service per month

APPLICATION

The Green Power Block Schedule shall be applied to Standard Offer customers who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. However, the charges in Schedule EIC and Adjustment Schedule EPS-1 will not apply to the kWh served in accordance with Schedule GPS-1A.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable resource including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer electricity generated from renewable resources through the Company's electric distribution system.

The customer shall subscribe for a specific number of blocks of electricity generated from renewable resources. Each block shall equal 100 kWh per month. The monthly charge is based upon the number of blocks subscribed for by the customer. The Company may assign limits to the number of kWh blocks sold per customer.

Subscription to GPS-1 may be limited by the availability of renewable resources in APS' green power portfolio.

Customers are required to subscribe for a minimum of one year. Customers may cancel GPS-1 service if the charge increases during the one year commitment.

SERVICE CHARGES

The bill for service under this rate schedule shall be $1.00 per month for each 100 kWh block of electricity generated from renewable resources.

SCHEDULE GPS-2A
CLASSIFIED SERVICE
GREEN POWER PERCENT SCHEDULE

APPLICATION

The Green Power Percent Schedule shall be applied to Standard Offer customers who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. However, the charges in Schedules EIC and Adjustment Schedule EPS-1 will not apply to the kWh served in accordance with Schedule GPS-2A.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable source including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer Green Power through the Company's electric distribution system.

Subscription to GPS-2 may be limited by the availability of renewable resources in APS' green power portfolio.

Customers are required to subscribe for a minimum of one year. Customers may cancel GPS-2 service if the charge increases during the one year commitment.

SERVICE CHARGES

Four options are available. The charges hereunder represent charges to be added to energy charges ($/kWh basis) under the customer's applicable schedule.

A. Green Power shall account for 100.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.01

B. Green Power shall account for 50.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.005

C. Green Power shall account for 35.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.0035

D. Green Power shall account for 10.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.001

ARIZONA PUBLIC SERVICE COMPANY

Attachment GAD-5RB

Potential Revenue Erosion and Net Lost Revenues from Net Metering Rate

Assumptions

3	capacity of PV system (kw)
1500	kWh per kw-AC per year
4500	kWh per system per year
6%	Excess kWh sold back to APS per year (%)
225	Excess kWh sold back to APS per year (kwh)
3,000	participation - total installed systems

Revenue erosion and net lost revenue from excess customer generation
For 3,000 photovotaic systems at 3 KW capacity each
Valued at average energy-related charges - proposed rate
(excludes basic service charge and demand charges)

	Installed Systems	Total Generation kWh	Rates Annual Average $/kWh	Lost Revenue	Avoided Cost Annual Average $/kwh	Avoided Cost $	Net Lost Revenue
E12	1,200	5,400,000	0.10895	$ 588,352	$ 0.05765	$ 311,303	$ 277,049
ET1	1,200	5,400,000	0.09913	$ 535,324	$ 0.05765	$ 311,303	$ 224,021
ECT1R	300	1,350,000	0.05007	$ 67,589	$ 0.05765	$ 77,826	$ (10,237)
E32 (0-20 kW)	300	1,350,000	0.11466	$ 154,791	$ 0.05765	$ 77,826	$ 76,965
	3,000	13,500,000		$ 1,346,055		$ 778,257	$ 567,798

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. The Solar Power Pilot Program is offered as a three-year pilot program and is available to residential standard offer customers who wish to purchase electricity generated from solar sources for their homes. The Company will construct new utility-owned solar plants to support customers taking service under this Rate Schedule. The total amount of solar generation sold shall not exceed the solar resources available from these solar plants.

APPLICATION

Service under this schedule provides all or a portion of the customer's service from solar electric generating systems producing AC electricity and delivered via APS' electric power grid. All provisions of the Customer's current applicable rate schedule will apply, including the unbundled generation components as applied to the Customers total monthly energy consumption. However, the charges in Schedule EIC and Adjustment Schedule EPS-1 will not apply to the kWh served in accordance with Schedule Solar-3. The customer is required to subscribe for a minimum term of one year. Direct Access customers are not eligible for service under this rate schedule.

SERVICE CHARGES

The customer shall be charged a Solar Power Premium Rate for all Solar Power Energy (kWh) served under this rate schedule. The Solar Power Premium Rate shall be the Solar Power Price, which represents the Company's price for Solar Power used to serve this rate schedule credited for the Avoided Cost, which represents the Company's associated savings in generation costs. The Solar Power Premium Rate shall be applied to the Solar Power Energy on a monthly basis.

Solar Power Price:	$0.394 per kWh
Avoided Cost Credit:	$0.059 per kWh
Solar Power Premium Rate:	$0.335 per kWh

Solar Power Energy shall be a percentage of the customer's total monthly energy (kWh). Two options are available:

A. Solar Power shall account for 100.0% of the customer's monthly energy.

B. Solar Power shall account for 50.0% of the generation mix in the customer's service.

TERMS AND CONDITIONS

Subject to Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contain provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES 100KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by Company.

APPLICATION

This rate schedule is applicable to all cogeneration and small power production facilities with a nameplate continuous AC output power rating of 100 kW or less where the facility's generator(s) and load are located at the same premises and that otherwise meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) electing to configure their systems as to require partial requirements service from the Company in order to meet their electric requirements.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the QF will be responsible for all incremental costs incurred to accommodate such an arrangement.

PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the Customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the Customer for any energy purchased as calculated on the standard purchase rate (see below).

MONTHLY PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (May - October)	6.486	4.531	7.630	5.330
Winter Billing Cycles (November - April)	6.384	4.905	7.510	5.770

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually.

CONTRACT PERIOD

As provided for in any Supply/Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service – Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

3. Non-Firm Power - Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided, and the power can be interrupted by the Customer at any time.

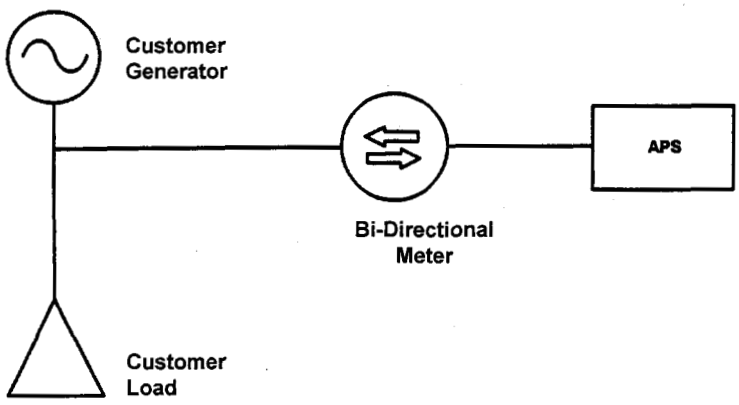
4. Firm Power - Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection Requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.

METERING CONFIGURATION



~~RATE~~ SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
~~UNDER~~ 100 ~~kW~~KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by the Company.

APPLICATION

This rate schedule is applicable to all cogeneration and small power production facilities with a nameplate continuous AC output power rating of 100 kW or less where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying status pursuant to Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. ~~This schedule is a~~Applicable only to qualifying facilities (QF's) electing to configure their systems as to require ~~only~~ partial requirements ~~or interruptible~~ service from the Company in order to meet their electric requirements.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by the customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the QF will be responsible for all incremental costs incurred to accommodate such an arrangement.

PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the customer for any energy purchased as calculated on the standard purchase rate (see below).

MONTHLY PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (~~June~~ May - October)	~~3.551~~6.486	~~2.257~~4.531	~~5.433~~7.630	~~3.453~~5.330
Winter Billing Cycles (November - ~~May~~April)	~~2.552~~6.384	~~1.871~~4.905	~~3.904~~7.510	~~2.862~~5.770

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually. ~~to reflect changes in the Company's fuel costs.~~

~~SERVICE CHARGE~~

~~The monthly service charge shall be determined in accordance with the type of customer service characteristics as set forth below:~~

	~~Monthly Charge~~
~~Single Phase Service:~~	
~~0-200 amp service~~	~~$ 7.34~~
~~Three Phase Service:~~	
~~0-200 amp service~~	~~$ 8.87~~
~~201-400 amp service~~	~~$ 18.31~~

CONTRACT PERIOD

~~Any applicable contract period will be set forth in the customer's~~As provided for in any Supply/Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service - ~~A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company.~~Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their ~~QF's~~ own generation facilities). This configuration~~also~~ may also be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   - ~~Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements.~~

3. Non-Firm Power - Electric power which is supplied by the ~~power producer~~Customer's generator at the Customer's~~producer's~~ option, where no firm guarantee is provided, and the power can be interrupted by the Customer~~power producer~~ at any time.

4. Firm Power - Power available, upon demand, at all times (except for forced outages~~and scheduled maintenance~~) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

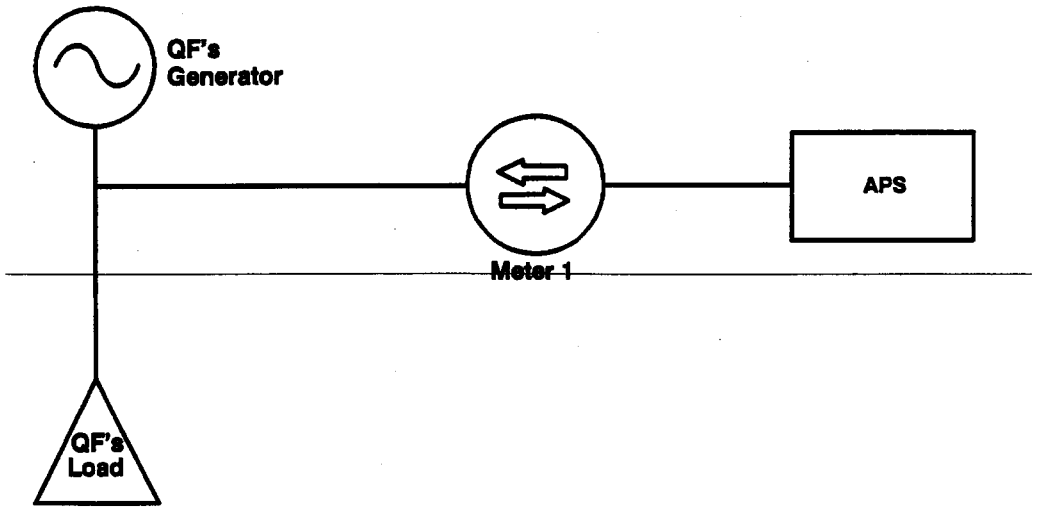
5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

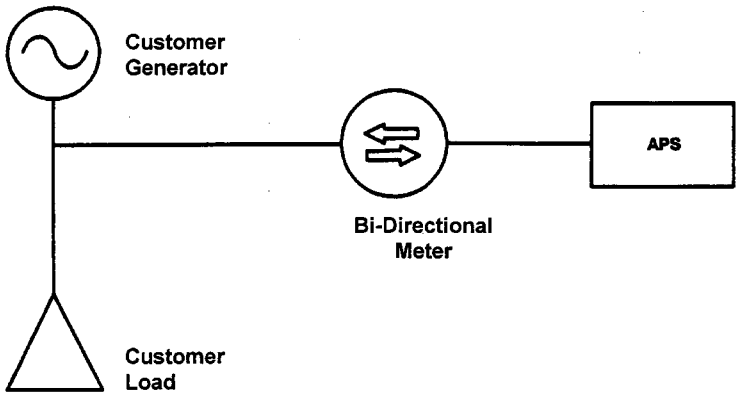
TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to ~~supplemental or~~ special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.~~pursuant to the customer's Purchase Agreement with the Company.~~

~~The customer and the Company will share in the cost of the bi-directional meter used to record sales to the customer and purchases from the customer. The Company shall be responsible for all costs up to and equal to the installed cost of a residential time-of-use meter, and the customer shall be responsible for the difference between the installed cost of the bi-directional meter compared to a standard residential time-of-use meter. The customer shall have the option to pay the incremental metering costs initially or in monthly installments over a five year time period.~~

METERING CONFIGURATION





AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

This rate schedule is applicable to any general service customer having generation equipment 100 kW and greater capable of supplying all or a portion of its power requirements for other than emergency purposes requiring supplemental, maintenance, and/or standby power. Direct access customers are not eligible for service under this rate schedule.

RATES

The bill shall be the sum of the amounts computed under A, B, and C below, including any applicable adjustments:

A. Basic Service: The Basic Service and Revenue Cycle Service Charges included in the customer's applicable General Service rate schedule will continue to apply.

B. Supplemental Service: Supplemental service will be provided in accordance with the rate levels contained in the customer's applicable General Service rate schedule, excluding the monthly Basic Service and Revenue Cycle Service Charges.

C. Standby and Maintenance Service: The monthly charge for Standby and Maintenance Service shall be the sum of:

(1) Demand Charge:

The unbundled transmission charge, if applicable, contained in the Customer's otherwise applicable General Service rate schedule plus the unbundled delivery charge contained in the customer's applicable General Service rate schedule. This summation is then multiplied by the amount of Contract Standby Capacity.

(2) Energy Charge:

The unbundled transmission charge, if applicable, contained in the Customer's otherwise applicable General Service rate schedule plus the per kWh monthly firm power purchase rates shown in rate schedule EPR-2.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

A. Supplemental Demand:

Supplemental demand shall be the highest 15-minute interval during the billing month which shall equal the (a) 15-minute integrated kW demand calculated for every 15-minute interval as recorded on the Supply Meter, plus (b) the simultaneous 15 minute measured kW output of the of each customer self-generation as recorded on the Generator Meter(s), less (c) the aggregate Contract Standby Capacity of all the customer's generating units; however, the result shall never be less than zero (0) for purposes of determining Supplemental Demand. If Company authorized scheduled maintenance was being performed on any of the customer's generators at the

time of the highest 15 minute interval during the billing month, the amount of demand recorded on the Supply Meter shall be reduced by the applicable Maintenance Power Level of the generator unit(s) undergoing authorized scheduled maintenance for purposes of calculating supplemental demand used for billing.

Customer's maximum Supplemental Service kW requirements shall not exceed that established in the Electric Supply Agreement.

B. Supplemental Energy:

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF CONTRACT STANDBY CAPACITY

For each specific customer generating unit for which the Company is providing Standby Service, Contract Standby Capacity shall be the greater of a) the measured kW output of each customer generation unit at time of start-up test, or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed Customer's actual total load.

DETERMINATION OF STANDBY AND MAINTENANCE ENERGY

Standby and Maintenance Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full outages, unscheduled partial outages, and scheduled maintenance periods of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters during simultaneous periods is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month. When the sum of the energy measured on both the Supply and Generator(s) Meter is equal to or less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

MAINTENANCE REQUIREMENTS

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per generation unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months. Customer shall provide Company with its planned maintenance schedule 90 days in advance of any planned maintenance in order for the Company to coordinate customer's scheduled maintenance with that of the Company. Upon review, Company shall either approve customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

TERMINATION PROVISION

Should Customer cease to operate his generation unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this tariff. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

SCHEDULE E-57
CLASSIFIED SERVICE
SOLAR PARTIAL REQUIREMENTS SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

This rate schedule is applicable to any general service customer having solar/photovoltaic generation equipment with a nameplate service continuous rating of greater than 100 kW but less than 1000 kW capable of supplying all or a portion of its power requirements. Direct access customers are not eligible for service under this rate schedule.

RATES

The bill shall be the sum of the amounts computed under A, B, and C below, including any applicable adjustments:

A. Basic Service: The Basic Service and Revenue Cycle Service Charges included in the customer's applicable General Service rate schedule will continue to apply

B. Supplemental Service: Supplemental service will be provided in accordance with the rate levels contained in the customer's applicable General Service rate schedule, excluding the monthly Basic Service and Revenue Cycle Service Charges.

C. Standby Service: The monthly charge for standby service shall be calculated as follows:

The unbundled delivery charge contained in the customer's applicable General Service rate schedule is multiplied by the 15 minute integrated kW measured on the Generator Meter during the customer's monthly peak demand.

METERING

The Company will install, at the customer's expense, a bi-directional meter at the point of delivery to the customer (Supply Meter) and meter(s) at the point(s) of output from each of the customer's generators (Generator Meter). All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company.

PAYMENT FOR PURCHASES FROM THE CUSTOMER

The Company will pay the Customer for any energy purchased at the per kWh monthly non-firm purchase rates as shown in rate schedule EPR-2.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

A. Supplemental Demand:

Supplemental demand shall be the highest 15-minute integrated kW demand as recorded on the Supply Meter during the billing period.

B. Supplemental Energy:

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter.

DETERMINATION OF CONTRACT STANDBY CAPACITY

For each specific customer generating unit for which the Company is providing Standby Service, monthly Contract Standby Capacity shall be the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter(s) at the time the customer's Supply Meter registers the highest 15 minute integrated kW demand during the billing period.

TERMINATION PROVISION

Should Customer cease to operate his generation unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this schedule. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition to terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS, that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and/or sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.2 Service Establishment and Customer Request for Special Service Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month.

2.2.1 The customer will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to the point of delivery.

2.2.2 The customer will additionally be required to pay an after-hours charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established after 5:00 p.m. on a day other than the day of request.

2.2.3 The customer will additionally be required to pay a same day connect charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established,

reconnected, or re-established on the same day the request is being made, and Company agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by Company~~,~~ on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The customer will additionally be required to pay $75.00 per crew person per hour when customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3 Customers will be charged for work such as metering equipment installations, including instrument transformers (excluding meters), maintenance or planned outages requested by the Customer , etc. that require the availability of Company employees after hours, on a weekend day, or on a Company holiday. The number of employees utilized by Company in fulfilling such requests shall be at the sole discretion of Company.

Company holidays are New Year's Day, Martin Luther King, Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the service establishment charge where:

2.2.5.1 No field trip is required because applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last meter read and meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

2.2.5.3 Where multiple connects are performed during the same site visit, in the same applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two delivery points.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.5 or 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill from the same or a prior service address.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill from the same or a prior service address.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Residential Establishment of Credit or Security Deposit

2.5.1 Establishment of Credit - Company shall not require a security deposit from a new applicant for service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 The applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received within six (6) months of the current date which states that the applicant had a timely payment history for the prior twelve (12) consecutive months at the time of service discontinuation.

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Credit or Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit– All non-residential applicants will be required to place a cash deposit to secure payment of bills for service as prescribed herein, unless:

2.5.3.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.3.2 The applicant provides a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Eestablishment or Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

2.7.2 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by Company in accordance with this section:

2.7.2.1 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.2.2 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that Company is providing bundled electric service.

2.7.2.3 If the customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 Optional Rates – Certain optional rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. Billing under the alternate rate will become effective from the next regularly scheduled meter reading, after the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access service will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access service for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer service.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, at customer's request, adjacent and contiguous sites not separated by private or public property or right of way

and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than fifteen (15) calendar days from the billing date. Any payment not received within this time frame will be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved charges. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered

4.3.2.1 Refunds to customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the last Company obtained meter read date.

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer will be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Termination Process Charges

4.5.1 Company will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.2 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.3 To avoid termination of service, the customer will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company will require payment of an On-site Evaluation Charge of $82.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of whether the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated point of delivery, as specified in Section 6.3 of this Schedule, at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service, except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have satisfactory unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any rate options where, in Company's opinion, access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter plus the cost incurred to install the specialized meter and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this schedule.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of an extension to serve a customer, which is either on sites owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way granted to, or obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an

easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense. Company will notify the customer in writing of the violations.

5.6 Load Characteristics – The customer shall exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. Customer shall meet power factor requirements as specified on applicable rate schedules.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery except for Company's meters and special equipment. The customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.asp.

6.1.2 Where a customer requests, and Company approves of, a special meter reading device or communications services or devices to accommodate the customer's needs, the cost for such additional equipment and usage fees shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the customer, and/or its agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. If Company must temporarily replace the MSP's meter and/or associated metering equipment during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter.

6.3.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.3.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors.

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry Company issued identification which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company (or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule 10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's Schedule 8, Bill Estimation, as filed with the Arizona Corporation Commission. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the MRSP, the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy and, if applicable, demand, for the period in which the energy eversion took place. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer will also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.3.1 Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company will, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $16.50 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $50.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments – Company will allow master metering for high rise residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

~~1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.~~

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and/or sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

~~2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.~~

2.2 Service Establishment and Customer Request for Special Service Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. ~~Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.~~

~~The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.~~

2.2.1 The customer ~~may~~will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to ~~meter panel~~the point of delivery.

2.2.2 The customer ~~may~~will additionally be required to pay an after-hours charge of $75.00 ~~should~~if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established ~~during a period other than regular working hours, or on the same day of their request,~~after 5:00 p.m. on a day other than the day of request.

2.2.3 The customer will additionally be required to pay a same day connect charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same day the request is being made, and Company agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by Company~~.~~ on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The customer will additionally be required to pay $75.00 per crew person per hour when customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3 Customers will be charged for work such as metering equipment installations, including instrument transformers (excluding meters), maintenance or planned outages requested by the Customer , etc. that require the availability of Company employees after hours, on a weekend day, or on a Company holiday. The number of employees utilized by Company in fulfilling such requests shall be at the sole discretion of Company.,

Company holidays are New Year's Day, Martin Luther King, Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the service establishment charge where:

2.2.5.1 No field trip is required because applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last meter read and meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

~~2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be $75.00 per hour.~~

2.2.5.3 Where multiple connects are performed during the same site visit, in the same applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two delivery points.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.5 or 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill from the same or a prior service address.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill from the same or a prior service address.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Residential Establishment of Credit or Security Deposit

2.5.1 Establishment of Credit - Company shall not require a security deposit from a new applicant for service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 The applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received within six (6) months of the current date which states that the applicant had a timely payment history for the prior twelve (12) consecutive months at the time of service discontinuation~~.~~

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Credit or Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit ~~- All nonresidential customers may~~ - All non-residential applicants will be required to:~~2.5.3.1 Place~~ place a cash deposit to secure payment of bills for service as prescribed herein, ~~or~~unless:

2.5.3.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.3.2 ~~Provide~~The applicant provides a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 E~~Ree~~stablishment or Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

2.7.2 ~~2.7.1~~ Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by ~~the~~ Company in accordance with this section:

~~2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,~~

2.7.2.1 ~~2.7.1.2~~ If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.2.2 ~~2.7.1.3~~ If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that ~~APS~~Company is providing bundled electric service.

~~2.7.2 Separate security deposits may be required for each service location.~~

2.7.2.3 If the customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the

balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by ~~the~~ Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is ~~being served on a Standard Offer rate~~receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous ~~Standard Offer~~ rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 ~~Standard Offer~~ Optional Rates – Certain optional ~~Standard Offer~~ rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective

initially or after service has been established. ~~A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company.~~ Billing under the alternate rate will become effective from the next regularly scheduled meter reading, ~~or when~~after the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access ~~rate selection~~service will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer ~~making a~~that selects Direct Access ~~rate selection~~service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access service for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer service.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, at customer's request, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than ~~fifteen~~~~nineteen~~ ~~(15~~~~19)~~ fifteen (15) calendar days from the billing date. Any payment not received within this time frame ~~shall~~will be considered delinquent. All delinquent bills for which payment has

not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved ~~services~~charges. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until ~~the~~ Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. ~~Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.~~

4.3.2.1 Refunds to customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

~~4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.~~

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the last Company obtained meter read date.

~~4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.~~

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer ~~shall~~will be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Termination Process Charges

4.5.1 ~~4.5 Field Call Charge~~ – Company ~~may~~will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment ~~of~~on a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

~~4.5.1~~4.5.2 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.3 ~~4.5.2~~ To avoid termination of service, the customer ~~may~~will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company ~~may~~will require payment of an On-site Evaluation Charge of $82.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of ~~if~~whether the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated point of delivery, as specified in Section 6.3 of this Schedule, at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service, except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have satisfactory unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any ~~existing~~ rate options where, in Company's opinion, access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter plus~~and~~ the cost incurred to install the specialized meter and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this schedule.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of ~~the~~an extension to serve a customer, which is either on sites owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way granted to, or obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an

easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense. Company will notify the customer in writing of the violations.

5.6 Load Characteristics – The customer shall exercise reasonable care to ~~assure~~ensure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. ~~The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.Customers found to have a power factor of less than 90%, or leading, or other detrimental conditions shall be required to remedy problems in order to achieve a power factor in conformance with above standards, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs~~Customer shall meet power factor requirements as specified on applicable rate schedules.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery except for Company's meters and special equipment. The customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.asp.

~~6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.~~

6.1.2 ~~6.1.3~~ Where a customer requests, and Company approves of, a special meter reading device or communications services or devices to accommodate the customer's needs, the cost for such additional equipment and usage fees shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will ~~be charged~~result in charge to the MSP of the replacement costs ~~less five (5) years depreciation,~~ plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. ~~In the event~~If Company must temporarily replace the MSP's meter and/or associated metering equipment ~~as necessary~~ during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter.

6.3.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.3.2 ~~6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.~~ For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. ~~For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are~~

~~permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials~~

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry Company issued identification which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company (or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule ~~10.~~10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's Schedule 8, Bill Estimation, as filed with the Arizona Corporation Commission. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the MRSP, the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy ~~consumption~~and, if applicable, demand, for the period in which the energy eversion took place.~~that would have registered had all energy and demand usage been properly metered.~~ Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer ~~may~~will also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.3.1 ~~6.4.4 Customer will be billed~~Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company ~~shall~~will, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $16.50 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading

Data Obligations, Company may, at its option, obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $50.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums ~~and Other Multiunit Residential Buildings~~ - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered ~~unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.~~ unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments – Company will allow master metering for high rise residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

RATE SCHEDULE E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Schedule E-4 Medical Support Care Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision Nos. 55931, 56680 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 400 kWh	40%
401 – 800 kWh	26%
801 – 1200 kWh	14%
1201 kWh and above	$13.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Schedule E-4 Medical Support Care Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision Nos. 55931, ~~and~~ 56680 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 400 kWh	40%
401 – 800 kWh	26%
801 – 1200 kWh	14%
1201 kWh and above	$13.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Schedule E-3 Energy Support Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision Nos. 59222 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 800 kWh	40%
801 – 1400 kWh	26%
1401 – 2000 kWh	14%
2001 kWh and above	$26.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

RATE SCHEDULE E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Schedule E-3 Energy Support Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision Nos. 59222 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 800 kWh	40%
801 – 1400 kWh	26%
1401 – 2000 kWh	14%
2001 kWh and above	$26.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

RESIDENTIAL ENERGY SUPPORT PROGRAM
PLAN FOR ADMINISTRATION

I. GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of the ACC's ordered "lifeline" rate discount program for low-income residential customers (Energy Support Program, Rate E-3). The Plan is pursuant to Decision Nos. 55931 dated 04/01/1988, 56680 dated 10/25/1989, and xxxxx dated xx/xx/xxxx.

II. ELIGIBILITY FOR DISCOUNT:

1. Income Eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be available in a number of locations including food banks, Salvation Army offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under an APS residential rate schedule in order to qualify for the discount.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

III. DISCOUNT LEVELS:

Discounts under the Energy Support Program are specified in the Company's Rate Schedule E-3.

IV. FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in guideline income levels and other externalities which may affect this program.

V. ATTACHMENTS:

Attached are copies of the following documents that are pertinent to the administration of the program:

1. Applications for the APS Energy Support Program (E-3), written in English and Spanish;
2. A bilingual informational brochure;
3. The Company's Rate Schedule E-3 which specifies applicable discounts;
4. An announcement suitable for posting which provides the present income qualifications for the program;
5. Listing of agencies where applications can be obtained.

Attachment GAD-13RB

ARIZONA PUBLIC SERVICE COMPANY

Plan for Administration
Of
Residential Energy Support Program (E-3)
Pursuant to ACC Decision Numbers 55931 dated 04/01/88
56680 dated 10/25/89
XXXXX dated XX/XX/XX

Effective ~~October 25, 1989~~XX/XX/XXX

I. GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of the ACC's ordered "lifeline" rate discount program for low-income residential customers (Energy Support Program, Rate E-3).

II. ELIGIBILITY FOR DISCOUNT:

1. Income Eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be available in a number of locations including food banks, Salvation Army offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under ~~residential rates E-10 or E-12~~an APS residential rate schedule in order to qualify for the discount.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

III. DISCOUNT LEVELS:

Discounts under the Energy Support Program are specified in the Company's Rate Schedule E-3.

IV. FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in guideline income levels and other externalities which may affect this program.

V. ATTACHMENTS:

Attached are copies of the following documents that are pertinent to the administration of the program:

1. Applications for the APS Energy Support Program (E-3), written in English and Spanish;
2. A bilingual informational brochure;

3. The Company's Rate Schedule E-3 which specifies applicable discounts;
4. An announcement suitable for posting which provides the present income qualifications for the program;
5. Listing of agencies where applications can be obtained.

I. GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of a rate discount program for low-income residential customers where medical care equipment essential for sustaining life is in use within the customer's premise.

II. ELIGIBILITY FOR DISCOUNT:

Customer must meet Rate E-3 criteria which is:

1. Income eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be provided in a number of locations including food banks, Salvation Army Offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under an APS residential rate schedule.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

In addition to meeting the E-3 eligibility requirements, APS must have a signed statement of verification of medical care equipment. The verification must be signed by the physician responsible for the care of the individual living at the premise where medical care equipment is required. The medical care equipment must be in use, and "essential" to the sustaining of life of an individual living within the premise. Essential is defined as "medical equipment where discontinuance of service from the equipment for a period longer than four (4) hours could be especially dangerous to an individual's health."

Annual reverification by the physician will be required for the discount to be extended beyond one year.

III. DISCOUNT LEVELS:

Discounts under the Medical Care Program are specified in the Company's Rate Schedule E-4.

IV. QUALIFIED MEDICAL CARE EQUIPMENT:

Use of the following equipment will qualify for the E-4 program:

Ventilator
Oxygen Concentrator
Peritoneal Dialysis Cycler
Hemo Dialysis Equipment
Feeding Pump
Infusion Pump
Suction Machine
Small Volume Nebulizer
Oximeter

V. FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in the guideline levels and other externalities which may affect this program.

VI. ATTACHMENTS:

The Company's Rate Schedule E-4 which specifies applicable discounts.
Customer notification.
F.Y.I. Notice to Arizona Community Action Associates, DES, and Human Services Magazine.

Attachment GAD-14RB

ARIZONA PUBLIC SERVICE COMPANY

PLAN FOR ADMINISTRATION OF MEDICAL CARE EQUIPMENT PROGRAM

GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of a rate discount program for low-income residential customers where medical care equipment essential for sustaining life is in use within the customer's premise.

ELIGIBILITY FOR DISCOUNT:

Customer must meet Rate E-3 criteria which is:

1. Income eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be provided in a number of locations including food banks, Salvation Army Offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under ~~a~~ an APS residential rate schedule.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

In addition to meeting the E-3 eligibility requirements, APS must have a signed statement of verification of medical care equipment. The verification must be signed by the physician responsible for the care of the individual living at the premise where medical care equipment is required. The medical care equipment must be in use, and "essential" to the sustaining of life of an individual living within the premise. Essential is defined as "medical equipment where discontinuance of service from the equipment for a period longer than four (4) hours could be especially dangerous to an individual's health."

Annual reverification by the physician will be required for the discount to be extended beyond one year.

DISCOUNT LEVELS:

Discounts under the Medical Care Program are specified in the Company's Rate Schedule E-4.

QUALIFIED MEDICAL CARE EQUIPMENT:

Use of the following equipment will qualify for the E-4 program:

Ventilator
Oxygen Concentrator
Peritoneal Dialysis Cycler
Hemo Dialysis Equipment
Feeding Pump
Infusion Pump
Suction Machine
Small Volume Nebulizer
Oximeter

FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in the guideline levels and other externalities which may affect this program.

ATTACHMENTS:

The Company's Rate Schedule E-4 which specifies applicable discounts.
Customer notification.
F.Y.I. Notice to Arizona Community Action Associates, DES, and Human Services Magazine.

REBUTTAL TESTIMONY OF ROGER J. MATTSON, PH.D.

On Behalf of Arizona Public Service Company

DOCKET NO. E-01345A-05-0816

September 15, 2006

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ATTACHMENTS

Acronyms	Attachment RJM-1RB
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1. QUALIFICATIONS OF ROGER MATTSON

Q. PLEASE STATE YOUR NAME, EMPLOYMENT AND BUSINESS ADDRESS.

A. My name is Roger J. Mattson and my business address is 2511 Fossil Trace Court, Golden, CO 80401. I am self-employed.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am appearing on behalf of Arizona Public Service Company (APS). (A list of Acronyms is provided in Attachment RJM-1RB.) I was asked by APS to perform an independent assessment of the safety regulatory aspects of its operation of Palo Verde Nuclear Generating Station (Palo Verde) in 2005 and to describe the Nuclear Regulatory Commission's (NRC's) process for such regulation in comparison to state economic regulatory processes. APS also requested that I review its actions in connection with outages that occurred at Palo Verde during 2005 and to consider whether those actions were prudent. In particular, I have reviewed the outage of Units 2 and 3 between October 11 and 20, 2005 to address a question raised by an NRC inspector regarding the potential for air entrainment in suction piping from the refueling water tank. I have also been asked to address some of the analysis, conclusions and recommendations contained in the August 17, 2006 report of GDS Associates, Inc. (GDS), consultant to the staff of the Arizona Corporation Commission (ACC) in this proceeding.

Q. PLEASE SUMMARIZE YOUR EDUCATION, EXPERIENCE AND QUALIFICATIONS.

A. My qualifications are described in detail in a resume in Attachment RJM-2RB and summarized here. I am a mechanical engineer. I received a Ph.D. in mechanical engineering from the University of Michigan in 1972. My Bachelors and Masters Degrees are also in mechanical engineering, from the Universities of Nebraska and New Mexico, respectively. After my first job, a three year stint designing test reactors and irradiation experiments at Sandia National Laboratory in

Albuquerque, New Mexico, I served with the headquarters staff of the federal government agencies responsible for regulating the safety of nuclear power plants, the Atomic Energy Commission (AEC) and its successor, the Nuclear Regulatory Commission for most of the period from 1967 through early 1984. For a brief period in 1980 and 1981, I managed radiation protection and emergency preparedness activities in the Environmental Protection Agency (EPA). Hereinafter, the AEC and the Nuclear Regulatory Commission will be referred to as NRC.

My last seven years at the NRC were spent as Director, in succession, of three Divisions: Systems Safety, Safety Technology, and Systems Integration, in the Office of Nuclear Reactor Regulation. In those positions, I was responsible for much of the technical review of applications for construction permits, operating licenses, and license amendments for nuclear power plants. People under my supervision reviewed applications for those licensing actions in the following technical areas: reactor systems, containment systems, reactor core performance, fuel design, instrumentation and control systems, power systems, balance of plant systems, spent fuel storage, accident analysis, radiation protection, emergency preparedness, and a variety of engineering disciplines, depending on the time period, including structural design, codes and standards, seismic analysis, fire protection, and equipment qualification. I had signature authority for the technical content of safety evaluations in all of these disciplines for all plants under construction or in operation.

In various capacities, I managed development and implementation of the NRC's regulatory requirements for most of the period from 1974 to 1984. I have or persons reporting to me have performed safety reviews of all the nuclear power plants now operating in the United States, including Palo Verde.

I have continued to be involved in assuring the safety of nuclear power plant

construction, operation and decommissioning subsequent to my NRC experience. From 1984 to 1987, I worked for International Energy Associates Limited (IEAL). It was a technical services company specializing in nuclear technology with utility and government clients in the United States, Western Europe and Asia. I joined SCIENTECH, Inc. in 1987. SCIENTECH provided services in environmental protection; nuclear power plant design, operations, reliability, and maintenance; replacement of obsolete instrumentation and controls for nuclear power plants; reliability of aircraft; information systems; interactive networks; and security systems. I served as the Chief Operating Officer of both IEAL and SCIENTECH. I retired from SCIENTECH in 2002 and have worked as an independent consultant since that time.

Some of the projects in which I have been personally involved since leaving employment with the NRC are as follows:

- Co-chair of a panel to develop the International Atomic Energy Agency's Safety Principles for nuclear power plants (INSAG-3) after the accident at Chernobyl in the former Soviet Union;
- Reviews of advanced reactors for the Department of Energy (DOE), including advanced light water reactors being developed by Westinghouse and General Electric Companies, the gas-cooled Next Generation Nuclear Plant, the New Production Reactor and the fast burner reactors recently proposed for the President's Global Nuclear Energy Project;
- Reviews of combined operating license applications for advanced nuclear power plants co-funded by DOE;
- Assistance in developing nuclear plant life extension and advanced reactor licensing approaches for NRC;
- Studies of safety, cost and schedule effects of NRC regulation on about 20 nuclear construction projects and about 20 operating plants;
- Chair of operational readiness reviews for Limerick 2 nuclear power plant and DOE's Savannah River K Reactor and Rocky Flats plutonium facility;

- Studies of environmental, safety, and health vulnerabilities of production reactors, uranium facilities and plutonium facilities at Savannah River, Rocky Flats, Livermore, Los Alamos, Hanford and Pantex facilities;
- Member of Nuclear Safety Review Boards for Limerick and Peach Bottom nuclear power stations and for DOE's N-Reactor;
- Vice-chair of Nuclear Safety Review Board for the Rocky Flats Site;
- Vice-chair of Nuclear Safety Review Panel for a project in the Dynamic Experiments Division at Los Alamos National Laboratory;
- Studies of regulatory implications of claims of radiation injury at six nuclear facilities; and
- Safety and management consultant on decommissioning of Maine Yankee and Connecticut Yankee nuclear power plants.

Also, I have consulted on nuclear safety matters in England, Spain, France, Germany, Ukraine, Russia, Kazakhstan, Egypt, China, Japan, Taiwan, and Korea.

I have testified as an expert witness or Federal agency representative before committees of the U.S. House of Representatives and Senate, DOE, EPA, NRC, NRC's Advisory Committee on Reactor Safeguards, Defense Nuclear Facilities Safety Board, DOE's Advisory Committee on Nuclear Facility Safety, President's Commission on Three Mile Island, President's Nuclear Safety Oversight Board, licensing and rule-making hearing boards, regional planning commissions, state public service commissions, courts, and international organizations.

2. SUMMARY OF TESTIMONY

Q. WHAT DID YOU DO IN PREPARING YOUR TESTIMONY?

A. I reviewed correspondence from NRC to APS from January 1, 2004 to July 24, 2006. I also interviewed a number of employees and senior managers of APS to understand the context of the various NRC and APS documents. I also reviewed a

number of CRDRs (Condition Report/Disposition Requests) and reports of assessments performed by or for APS. I found these latter reports to be very helpful in understanding both sides of the matters described in NRC correspondence.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In brief, my testimony will demonstrate the following:

- The safety standards that the NRC applies and those applicable to prudence cases such as this are markedly different. The NRC consistently uses hindsight in its safety analyses, and it is indisputably inappropriate to do so in a prudence determination. The NRC has also issued a Policy Statement on the content of economic performance standards set by State public utility commissions.
- Palo Verde's performance has been within industry norms over the decade from 1995 to 2005. Although it has experienced a decline recently, as most plants do at some point, APS is addressing this decline through its Performance Improvement Program. Self-critical reports and assessments are always a part of such improvement efforts and are not an indicia of imprudence.
- The October 2005 outages at Units 2 and 3 were not the result of APS imprudence. Palo Verde personnel responded reasonably to a new question the NRC raised – a question which the company should not have anticipated. Once APS answered the NRC's new question, the units restarted without any change to the equipment, training or procedures related to the systems in question.

In the sections of this testimony that follow, I will first explain, in Section 3, the NRC's regulatory process for oversight of nuclear power plants. I will describe the differences between the standards the NRC employs and the standards applicable to a prudence determination. Of course the NRC's first and foremost requirement is that nuclear plants operate safely, and there is no dispute that Palo Verde has done so, as both the NRC's Regional Administrator Bruce Mallett and ACC staff consultant GDS have told this Commission.

Unlike economic regulatory bodies, such as the ACC, the NRC does not consider whether utility management's actions were reasonable at the time such actions were taken. Rather, the NRC uses hindsight to continually improve safety performance and has done so successfully over the years. As a result, average performance today is much better than good performance was in the past.

The NRC focuses on results. In contrast, there is a focus on process in an ACC review of whether there has been adherence to a prudence standard. An understanding of the different standards applied by the NRC is critical to evaluating NRC actions and documents that may be offered as evidence in a prudence proceeding. In sum, NRC actions and documents generally can be relevant only to the prudence of utility management actions taken after learning of the NRC action or receiving the NRC document in question. This is an important issue in this case because GDS has said that it adheres to a prudence standard while in its report it makes no attempt to account for the hindsight typically found in NRC reports.

In Section 4, I describe the manner and extent to which NRC actions and documents may be relevant to prudence proceedings. I provide some background on the history and development of the NRC's assessment processes and demonstrate that the NRC has rejected some of its past efforts, such as the Watch List, as being unduly subjective and lacking in guidance to licensees. I point out that, unlike the majority of commercial nuclear power plants, Palo Verde was never on the NRC Watch List and never received a Trending Letter. I also describe the current Reactor Oversight Process and note that although it is generally recognized as a considerable improvement over the past, the NRC and the stakeholders in the process have recognized that it has weak areas, including areas that bear on recent NRC assessments of Palo Verde, e.g., NRC inspector acceptance of the original design basis of a plant and the role of NRC's

identification of cross cutting issues. Understanding these aspects of NRC's regulatory practices is important because GDS has either not addressed them, as in the case of the original design basis, or interpreted them incorrectly, as in the case of cross-cutting issues.

It is my understanding that the ACC has previously pointed out that, in examining the operating performance of power plants, one must look at both a plant's "successes" and "failures" in order to perform a fair review. This is not what GDS did in its report, choosing instead to concentrate on Palo Verde's performance in 2004 and 2005. I have chosen a longer time period to review Palo Verde's performance, 1995 through 2005, so that both successes and failures are brought to light. NRC data can be helpful in such a review.

Accordingly, I have set forth in detail in Section 5 and Attachment RJM-3RB of this testimony a comparison of how Palo Verde has performed relative to other nuclear power plants, over time, in a large number of categories. The categories are ones NRC uses to compare the performance of similar plants. These comparisons show Palo Verde's performance to be superior when viewed over the period since 1995. These data are consistent with the fact that Palo Verde represents the culmination of a significant design effort that extended over many years and many earlier plants by the Combustion Engineering Corporation (CE), now owned by Westinghouse. I think of it as the flagship of the CE product line. In significant measure it is among the best plants in the country and many of its design features will carry over into the advanced designs of light water reactors now being prepared for deployment in the U.S. The peer group that NRC has defined for Palo Verde performs better on the average than other pressurized water reactors in the U.S., and Palo Verde often performs better than its peers.

In Section 5, I also assess the recent regulatory performance of Palo Verde. Factoring into this assessment are citations by NRC in early 2005 of two violations

connected with voiding that was found in the lines leading from the containment sump to the ECCS pumps. These are the violations that led NRC to declare that Palo Verde has a degraded (yellow) cornerstone in the area of mitigating systems. The voids in the lines stemmed from the original design of the plants, and the missed opportunity for detecting the problem occurred in 1992. Thus, the two violations have no bearing on the current condition of the plant or capability of the APS staff.

The new reactor oversight process that NRC implemented in 2000 provides four levels of increasing scrutiny of licensees above the normal level of NRC oversight. Palo Verde is now at the second level of increased oversight (yellow cornerstone), and there are indications that it will successfully return to the lowest level of NRC scrutiny. In the meantime, NRC has not interfered with its continued operations.

NRC has raised concerns with cross-cutting aspects of Palo Verde operations (human performance and problem identification and resolution). These issues did not cause the yellow cornerstone or the outages experienced in 2005, and they have been controversial within the industry. In response to general industry criticism of the cross-cutting issues, NRC has recently acknowledged it has its own difficulty in understanding and dealing with cross-cutting findings and in early 2006 proposed new ways of dealing with them. The Government Accountability Office (GAO) recently told the U.S. House of Representatives that three-quarters of the country's 103 operating plants have been subjected to oversight beyond the baseline inspections for varying amounts of time, so Palo Verde is not unusual in receiving the increased NRC attention that it did in 2004 and 2005. GAO also told Congress that cross-cutting issues identified by NRC have increased dramatically across the industry so Palo Verde is not alone in its experience with these issues, either.

In response to the increased NRC oversight arising from the yellow cornerstone,

APS has implemented a Performance Improvement Program or PIP. It has been underway at Palo Verde since October 2005 and is beyond NRC's expectations for a station at Palo Verde's current level of performance. That is, the PIP is typical of improvement programs that have been implemented at many operating plants, but usually when they were experiencing worse performance problems than Palo Verde. Such programs involve self-assessments that use hindsight to identify opportunities for improvement, and they often do so in harsh terms that are expected by NRC and are the industry norm. Although I agree with the GDS report at pages 2 and 11 that the PIP should be successful in improving performance at Palo Verde, I strongly disagree with the manner in which GDS has taken out of context the harsh self criticism of the APS analyses connected with the PIP and incorrectly portrayed them as self condemnation. In fact, neither APS nor NRC has said that operations of Palo Verde are or have been imprudent or unsafe in light of recent performance, nor do I believe the performance to be indicative of imprudence.

At the end of Section 5, I discuss statements by the NRC about the features of an economic performance standard such as that recommended by GDS for Palo Verde. These NRC statements demonstrate that NRC is concerned that such economic incentives not create disincentives to safety. The GDS recommendation is not consistent with the NRC advice on this matter. I conclude that an economic performance standard is not needed for Palo Verde at this time based on its long-term record of superior performance and the Performance Improvement Program now underway to ensure such performance in the future.

Finally, in Section 6 of this testimony I address the prudence of outages of Units 2 and 3 in October 2005 connected with the possibility of air entrainment in the suction piping leading to the emergency core cooling system from the refueling water tank (RWT). In my review of the RWT outages, I could find no connection with the NRC and APS concerns with cross-cutting issues and the yellow

cornerstone, unlike the conclusions reached by GDS. I conclude that APS was prudent in its handling of the RWT air entrainment issue because it could not reasonably have anticipated the emergence of the new requirement that NRC levied, and, once the issue emerged, APS followed its only available line of response. My conclusion is similar to the conclusions reached by GDS for several of the other outages in 2005, i.e., APS could not reasonably have foreseen the reason for the outage. My conclusion also is consistent with that of NRC Region IV Administrator Bruce Mallett as evidenced by what he told the ACC on January 26, 2006, namely, the issue was a new question, one that NRC and APS had not come across before, APS did what NRC expected, and NRC did not determine that APS should have found the issue beforehand.

The new question dealt with adequacy of the design basis while the 2004 question involved implementation of the design basis. When APS responded to the new question in October 2005 by showing how air entrainment had been handled in the original operating license review by NRC and how the conditions flowing from that review had been factored into Palo Verde's design, the answer was deemed by the contract inspector to be insufficient. Because the additional question the inspector asked went beyond the original licensing basis of the plant, it could not be answered readily by APS. Accordingly, the safety systems in question were declared inoperable, and the two operating units (Units 2 and 3) were shut down on October 11 in accordance with their Technical Specifications.

The NRC's new, surprise question was resolved sufficiently to support a system operability declaration for Units 2 and 3, and they were restarted on October 20 without any changes in the procedures, hardware or training associated with the systems in question, a condition that remains the same on the three units as they operate today. The outage served to provide NRC inspectors greater assurance of safety, but the safety of the plant and the licensing basis of the plant are the same

today as they were before the new question was asked. APS was prudent in the manner in which it dealt with this issue before and after the issue was raised by the NRC.

In seeking to bolster its conclusion that the cause of the RWT outage could have been found beforehand, GDS says that the NRC senior resident inspector for Palo Verde told GDS that the RWT outages could have been avoided. First, it should be noted that this inspector did not participate in the inspection or in writing the inspection report. Second, I do not believe the senior resident inspector intended to make a prudence statement by such a remark. Nor do I believe he would have contradicted the NRC Regional Administrator who said the opposite to the ACC on January 26, 2006. Also, the inspection report of January 27, 2006 that addresses these matters did not contain a finding or violation for a failure to do an adequate evaluation of the extent of condition of air entrainment in the ECCS. Finally, since NRC does not examine the prudence of its licensees' actions and does not make prudence determinations, it is likely that the senior resident inspector was using the typical NRC retrospective viewpoint in opining on what might have been avoided with the benefit of hindsight. I also note that the scope of the proposed interview of the senior resident inspector approved by the NRC in a letter dated March 15, 2006, did not include solicitation of his opinion on the reasonableness of APS actions in connection with the outages in 2005. In any event, the senior resident inspector's view does not alter my conclusion that APS was prudent in not anticipating the RWT.

It is instructive to note that a situation similar to the one here occurred in another jurisdiction involving some of the same individuals, including GDS, and resulted in a finding by the cognizant public service commission that the utility involved had dealt with the issue prudently. I have learned in preparing this testimony that on January 27, 2005, the same NRC contract inspector, Craig Baron, raised the issue of air entrainment during a special NRC "pilot inspection" at the Kewaunee

nuclear power plant in Wisconsin. Baron asked if air entrainment had been considered in the design of the auxiliary feedwater (AFW) system at Kewaunee. After several days of analysis by the licensee, the unit was shut down because a way to get air into the AFW pumps was discovered that had not been considered in the original design. On December 22, 2005, the Wisconsin Public Service Commission found "that the costs associated with this outage were not imprudently incurred because the record does not support the allegations [by witness William R. Jacobs, Jr. of GDS Associates, Inc.] that revisions to the AFW system should have been made in the past in order to avoid the issues resulting in the outage."

3. DIFFERENCES BETWEEN SAFETY STANDARDS AND PRUDENCE STANDARDS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section addresses the question of whether and to what extent actions taken by the NRC in the safety regulation of its licensees can be used to answer the economic regulatory question of whether management's operation of a nuclear plant has been prudent. I address these matters because the GDS report relies heavily on NRC documents and does so heedless of NRC's intentional use of hindsight in its inspection reports.

Q. DO THE NRC'S SAFETY STANDARDS DIFFER FROM THE STANDARDS AGAINST WHICH PRUDENCE IS GENERALLY DETERMINED?

A. Yes. As I will explain below, the bedrock of the NRC's standards is adequate protection of public health and safety, not reasonableness. Prudence, on the other hand, as commonly stated, is determined against a standard of reasonableness. Because utility management decisions must be made before their outcome can be known, an evaluation of their reasonableness must occur within the context of the information that was available to the decision makers at the time decisions were

made. For these reasons, the definition of prudence or good utility practice used by economic regulators to evaluate whether utility management has been prudent is generally some variation of the following definition used by the Federal Energy Regulatory Commission:

> [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. (Federal Energy Regulatory Commission, *New England Power Co.,* Opinion No. 49, 31 FERC § 61,047 at 61,048 (1985))

The regulations of the Department of Agriculture provide another example that applies to loans made by the Rural Electrification Association. It reads as follows:

> *Prudent Utility Practice* shall mean any of the practices, methods and acts which, in the exercise of reasonable judgment, in light of the facts, including, but not limited to, the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry prior thereto, known at the time the decision was made, would have been expected to accomplish the desired result consistent with cost-effectiveness, reliability, safety and expedition. It is recognized the Prudent Utility Practice is not intended to be limited to optimum practice, method or act, to the exclusion of all others, but rather is a spectrum of possible practices, methods or acts which could have been expected to accomplish the desired result at the lowest reasonable cost consistent with cost-effectiveness, reliability, safety and expedition. (7 CFR Part 1718, Subpart B, Appendix A, Article 1.01 Definitions)

In Arizona, the standard is similar. It is my understanding that the Arizona Administrative Code contains the following provision regarding investments by utilities:

> "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. (Arizona Administrative Code § R14-2-103 (A)(l))

It is also my understanding that the ACC in a previous decision (Decision No. 55118, page 20) 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." As I discuss below, this is one of the reasons why my analysis examines whether Palo Verde has been operating within industry norms over the past decade, a period over which any company could be expected to have some "successes" and "failures."

Q. DID GDS ARTICULATE AND APPLY A PRUDENCE STANDARD?

A. At page 19 of its report, GDS articulated a standard that is generally consistent with these various prudence standards. Unfortunately, in its analysis, GDS did not apply the standard it articulated, choosing instead to use NRC and APS documents written with the benefit of hindsight to judge the prudence of actions that were taken without such benefit.

Q. DOES THE STANDARD AGAINST WHICH PRUDENCE IS JUDGED ALLOW FOR A RANGE OF REASONABLE UTILITY MANAGEMENT ACTIONS?

A. Yes. The prudence standard acknowledges that there is a range of options available to utility management, and it accepts that different utility managers might choose different alternatives from among a set of reasonable options. Also, a negative outcome is not necessarily indicative of an imprudent decision – sometimes the best we can do with the information we have is to make a wrong choice.

Q. DOES THE NRC EVALUATE THE PERFORMANCE OF PLANTS BASED

ON THE INFORMATION THAT WAS KNOWN OR REASONABLY AVAILABLE TO LICENSEE MANAGEMENT?

A. No. The NRC evaluates the results of plant management decisions primarily based on hindsight. The NRC has a policy of continuing to learn from operating experience, and it requires the same from its licensees. The NRC might describe an event as "avoidable", but in doing so, it would take full advantage of knowledge that was gained after the fact. Thus, significant events are studied (including root cause and extent of condition assessments) to identify lessons learned to help avoid that type of event or more serious events in the future. NRC uses this approach to assure that the safety of nuclear power plants is continually rising, always striving to make plants safer tomorrow than they are today. However, it is not an approach that is appropriate under a prudence standard.

4. NRC'S REGULATORY PROCESS AND ITS RELEVANCE TO PRUDENCE DETERMINATIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I will describe in more detail the various actions and processes used by the NRC to oversee safe operation of its licensees and how they may be relevant to a prudence examination. This information is intended to provide background for understanding the testimony in Sections 4 and 5, dealing with Palo Verde.

Q. HOW DOES THE NRC IMPLEMENT ITS POLICY OF CONTINUOUS IMPROVEMENT?

A. When a significant event happens at a nuclear power plant, the NRC and the licensee typically analyze the event and draw conclusions with the benefit of hindsight. For example, the NRC could conclude that a component failed because it was inadequately maintained or because the procedures for its use were unsatisfactory, even if the NRC had previously inspected and approved the maintenance program for that component or the procedures for its use. These

inspections focus on the state of knowledge at the time the NRC is performing its inspection. The NRC intentionally seeks to benefit from analysis that can be undertaken only with the benefit of hindsight and knowledge of the outcome.

Q. ON WHAT BASIS DOES THE NRC EVALUATE THE PERFORMANCE OF NUCLEAR POWER PLANT OPERATIONS?

A. The Atomic Energy Act of 1954, as amended, requires the NRC to provide "reasonable assurance of adequate protection of public health and safety" (Sections 182 and 189) during nuclear power plant operation. The NRC takes a variety of actions to ensure protection of the public health and safety, such as issuing an operating license that contains restrictions on how a nuclear power plant is to be operated; conducting regular and special inspections to see that the license and applicable regulations are implemented; issuing inspection reports, notices of violation, and civil penalties; on occasion requiring certain actions to be taken before a plant can resume operation after an outage; and issuing confirmatory action letters (CALs) or orders that specify any special measures that may be needed, in NRC's judgment, to provide adequate protection.

The safety of nuclear power plants is required, as a matter of national policy, to be maintained at very high levels established by the NRC. The NRC has promulgated regulations and other guidance to licensees to define its requirements for assuring adequate protection. Although the NRC's regulations change only occasionally, its safety performance expectations are continually rising through changes in the interpretation of its regulations.

For example, in 2000 the NRC implemented a new Reactor Oversight Process (ROP). The ROP is based on four decades of nuclear power plant operating experience and is designed to take advantage of the maturity of the nuclear industry. It uses insights to safety significance based on risk assessment techniques that were pioneered by the NRC in the mid 1970s and are now widely used in the

industry. The NRC implemented the ROP without changing its regulations.

Q. BRIEFLY, WHAT IS AN OPERATING LICENSE?

A. An operating license is the authorization issued by the NRC to a licensee, such as APS, to operate a nuclear power station, such as Palo Verde, in conformance with the regulations of the NRC and the conditions of the license. It is based on an extensive safety analysis performed by the license applicant and reviewed by the NRC, a review that spans several years, involves many man-years of engineering and analysis effort on both sides, and is documented in a Final Safety Analysis Report (FSAR) that fills several book shelves. When I was working at the NRC in the late 1970s and early 1980s, the FSAR for Palo Verde was being reviewed and approved by the staff reporting to me. It is important to appreciate that a detailed technical review is performed by the NRC at the time the operating license is issued for every nuclear power plant because the outages connected with the refueling water tanks at Palo Verde in October 2005 involved an *ad hoc* rejection by NRC inspectors of conclusions reached in the operating license review by NRC headquarters staff for Palo Verde more than 20 years before.

Q. WHAT ARE TECHNICAL SPECIFICATIONS?

A. Technical Specifications are contained within the Operating License. The Tech Specs, as they are sometimes called, list the safety equipment that is required to be operable for the various modes of operation of the nuclear reactor, from full power operations to cold shutdown. The Technical Specifications also describe what must be done to demonstrate operability and the time required for such demonstration whenever there is uncertainty about the capability of safety equipment to perform its function. For example, Technical Specification 3.5.5 in the Palo Verde license requires that if a refueling water tank is inoperable for one hour, the affected Unit must be shut down and be in mode 3 (hot standby – no power generation and temperature greater than 350 F) within 6 hours and mode 5 (cold shutdown – no power generation and temperature less than 210 F) in 36 hours. This is what happened with Palo Verde Units 2 and 3 in October 2005.

Q. WHAT IS AN OPERABILITY DECLARATION?

A. An operability declaration (or determination, as some plants call it) occurs whenever the operability of safety equipment is placed in doubt (e.g., because of a failed component, a new analysis, or a new question about safety). In such a case, a decision must be made by a licensed senior reactor operator (SRO) on the shift crew operating a nuclear power plant as to whether there is reasonable assurance that the equipment can perform its specified safety function. The SRO cannot take into account the low probability of the demand for the safety function – he or she must decide only whether the equipment will perform or not. In making a declaration that certain equipment is operable, the SRO also must have assurance that the attendant instrumentation, controls, electrical power, cooling water, lubrication and other auxiliary equipment are capable of performing their related support functions. The Technical Specifications also set time limits on such determinations.

The GDS report at page 34 quotes the NRC Inspection Report of January 27, 2006 in criticizing the manner in which operability decisions were reached for the refueling water tanks leading up to the October 2005 outages in Units 2 and 3. Such criticism by NRC had nothing to do with the need for or duration of the outages and is not germane to the prudence determination sought in this proceeding. Rather, the criticism by NRC only had to do with how APS reached the decision to shut down and answer the question raised by the contract inspector, not with the correctness of the decision. Also, NRC requirements on operability determinations have recently changed so it is not unexpected that any operability decision in any operating nuclear power plant would attract some helpful NRC criticism at this time.

Q. YOU ALSO SAID EARLIER THAT NRC STANDARDS CHANGE WITH TIME. DOES THE NRC COMMUNICATE SUCH CHANGES TO ITS LICENSEES?

A. Yes. The NRC uses several methods to communicate changes in its requirements to licensees. In addition to generic information (i.e., information applying to more than one licensee) communicated through rulemaking, regulatory guidelines, Generic Letters, and Information Notices, the NRC uses licensee-specific means. Examples of the latter include reports of inspections, notices of violations, identification of cross-cutting issues, identification of degraded cornerstones of safety having risk significance, and civil penalties.

Q. DO THESE FORMS OF COMMUNICATION ENABLE LICENSEES TO PREDICT NRC REGULATORY EXPECTATIONS?

A. The NRC processes for issuing new or revised regulations and Regulatory Guides provide for public comment periods, so it is possible to predict what is expected in those instances. For the other forms of communication, it is only possible to tell what is expected after the fact, i.e., after the new requirement is issued.

Rising expectations conveyed through the inspection process are the most difficult to predict. Such new requirements are revealed and their meaning is defined for each plant after-the-fact, on an *ad hoc* basis, in meetings, inspection reports, violations, periodic assessments, identification of cross cutting issues and degraded cornerstones, and other forms of communication that often lack direct linkage to the formal requirements of NRC, i.e., those contained in its regulations. Through these less formal devices, NRC urges further performance improvement even where there is full compliance with formal regulatory requirements. Also, the communications of these rising standards are inherently negative in tone, seldom, if ever, providing recognition for good performance.

As I will describe later in this testimony, the outages of Units 2 and 3 connected with the refueling water tanks at Palo Verde in October 2005 were the result of a new, informal safety requirement communicated to APS through the inspection process in a way the company could not predict. The GDS report completely

misses this point, and it is the crux of whether these outages were prudent or not.

Q. WHAT IS THE END RESULT OF NRC'S ESCALATING SAFETY STANDARDS?

A. The potential hazards of nuclear power are significant so the nuclear industry is a highly regulated industry; it is probably the most closely regulated industry in the United States. Due to the intense scrutiny and high standards of safety performance demanded of licensees, the levels of performance achieved by nuclear power plants are very high. Average performance in the nuclear industry is always rising, so much so that average performance in years past is low performance today.

Q. ARE THE ACTIONS AND DOCUMENTS OF THE NRC IRRELEVANT TO PRUDENCE DETERMINATIONS?

A. No. As stated above, because the NRC uses hindsight, its actions and documents generally are not relevant to determinations of the prudence of utility management conduct prior to issuance of the documents or prior to the actions of NRC officials. However, NRC actions and documents can be relevant to assessments of the prudence of subsequent actions taken by utility management.

Q. CAN YOU GIVE SOME EXAMPLES OF HOW NRC DOCUMENTS AND ACTIONS CAN BE RELEVANT TO PRUDENCE DETERMINATIONS?

A. Yes. First, the performance indicator data accumulated by the NRC provide a way to judge whether a particular licensee is keeping up with the long-term performance improvements of the nuclear power industry that result from the NRC policy of continuous improvement. Performance improvements occur over time and licensees may have good years and bad years in achieving improvements, but a long term failure to keep pace would provide a basis for inquiring into what management was doing or had done to address why this was occurring. I show by analyses described in Section 5 and Attachment RJM-3RB of this report that Palo Verde has been a superior performer when viewed over the long term using performance indicator data. Thus, I disagree with the manner in which the GDS has portrayed Palo Verde as one of the worst performers in the industry by looking

only at data for a short period of time where the plant admittedly had a decline in performance. (GDS report page 9)

Second, NRC often issues correspondence (e.g., Generic Letters and Information Notices) to the entire industry about undesirable circumstances arising at a particular plant or group of plants, including reactions to operating experience and possible changes in design. The intent of such correspondence is to give all licensees the opportunity to take corrective action appropriate to their plant design to avoid those circumstances. These issuances of NRC can be helpful in determining whether subsequent actions by utility management to avoid undesirable circumstances have been prudent. Conversely, if NRC does not issue generic guidance arising from regulatory experience at a particular plant, this fact may have implications for prudence determinations for NRC licensees, as it does in connection with Palo Verde Unit 2 and 3 outages associated with the refueling water tanks that occurred in October 2005, as I explain in Section 6.

Q. CAN PLANT-SPECIFIC COMMUNICATIONS FROM THE NRC BE HELPFUL IN A PRUDENCE DETERMINATION?

A. Yes, if one is mindful that plant-specific communications, e.g., inspection reports, are almost always critical and based on hindsight. They serve to show what was known by a utility about the acceptability of its performance as of the date of the communication. Like many other NRC communications, they can be relevant to a prudence determination only in evaluating whether the licensee's response to such a communication is reasonable.

From 1980 to 1998, the NRC periodically (approximately every 18 months) summarized how its correspondence to a particular utility should be viewed. It was called the Systematic Assessment of Licensee Performance or SALP program. It provided a retrospective view of the overall strengths and weaknesses of a licensee's performance and identified common themes or symptoms that could be

derived from NRC correspondence to the licensee during the evaluation period. Additionally, the NRC used SALP ratings to assist in determining how to allocate its inspection resources in the coming months. From January 1995 through April 1998, when the station received its last SALP ratings, Palo Verde received SALP scores that averaged 1.5, that is, midway between superior and good performance.

Beginning in 2000 the SALP reports were replaced by continuous assessments of licensee performance made by NRC under its new Reactor Oversight Process. According to NRC's Inspection Manual Chapter 0305, its Regional Offices are to conduct quarterly, semi-annual and annual reviews of NRC's inspection results, and performance indicator data. The annual reviews roll up the results of the quarterly and semi-annual reviews. An annual assessment report is issued to the licensee to forecast NRC's planned inspection activities at the subject plant for the next 18 months and to address any substantive cross-cutting issues observed during the evaluation period. The periodic reviews for Palo Verde were routine until those issued for 2004 through mid 2006 wherein corrective actions associated with the yellow cornerstone and two substantive cross-cutting issues have been prominent.

Q. WHAT IS A SUBSTANTIVE CROSS-CUTTING ISSUE?

A. In its current reactor oversight process, NRC has identified three aspects of licensee performance that are common to all seven cornerstones of safety (initiating events, mitigating systems, barrier integrity, emergency preparedness, occupational radiation safety, public radiation safety, physical protection) and important to maintaining safe operations. NRC refers to these three performance aspects as cross-cutting areas. They are human performance, problem identification and resolution, and safety conscious work environment. If NRC finds multiple examples of cross-cutting aspects in a 12-month inspection period, as it has at Palo Verde for the first two of these areas, NRC may identify a "substantive" cross-cutting issue in its correspondence to that licensee. Doing so serves as a notice that NRC sees opportunities for improvement in the cross-

cutting area and will concentrate its inspection efforts there.

From pages 12 to 15 of its report, GDS discusses the NRC's identification of substantive cross-cutting issues at Palo Verde (GDS cites three such issues but the NRC has identified only two) and quotes liberally from the subsequent self assessments performed by APS in seeking opportunities to improve performance in these two areas. GDS makes no mention that such self assessments are possible only with the use of hindsight. It is not clear what use GDS would have the ACC make of these quotations since the NRC has made no connection between the quotations and the four outages in 2005 that GDS finds to be imprudent. One thing is clear, however; GDS lifts these quotes from critical self assessments out of context, without recognition of their retrospective nature, in an attempt to blame APS management and thereby hinder these and future uses of the NRC-mandated process to help improve performance at Palo Verde. Furthermore, these self assessments are at the heart of the Performance Improvement Program that GDS says will probably succeed. Unlike GDS, I find these self assessments to be prudent management behavior and consistent with what other licensees have done to recover excellent performance. That is, prudent managers continually seek ways to improve their performance and to do so openly, honestly and frankly. Their effort lies at the heart of the industry's efforts to implement the national policy of continuous improvement in the operation of nuclear power plants.

Q. IS IT APPROPRIATE TO RELY ON NRC STAFF OPINIONS IN DETERMINING THE PRUDENCE OF A PLANT'S MANAGEMENT ACTIONS?

A. Not in my opinion, having worked for the NRC, and not in the opinion of other managers from NRC. As a senior manager from the NRC has said, regarding Consolidated Edison Company of New York, which at the time operated the Indian Point 2 Nuclear Power Plant, a Notice of Violation does not prove imprudence because the NRC does not have the "role to review or judge that [prudence], nor do I endeavor to have the expertise to decide such matters; NRC inspections are

not designed to obtain the necessary information or perspectives to judge such matters." (A. Randolph Blough, NRC Region I Division Director, July 26, 2000 E-mail to Region I staff. –RJM_WP1RB)

At page 32 of the GDS report, it is claimed that the NRC's Senior Resident Inspector at Palo Verde stated that the RWT outages could have been avoided. The implication apparently intended by GDS is that the inspector had the necessary perspective and information to make a judgment about the prudence of APS in not avoiding these outages. I doubt this is true for six reasons, namely

- The senior resident inspector in question was not a member of the inspection team that dealt with the RWT issue nor did he write the January 27, 2006 report of that inspection (Attachment 3 to GDS report),
- As noted above, NRC inspectors are not trained or qualified to make such judgments,
- Region IV Administrator Mallett told the ACC on January 26, 2006 that NRC did not determine that APS should have found the new question beforehand,
- The inspection report of January 27, 2006 that dealt with this matter did not contain an NRC finding or a violation for APS's failure to find the new question beforehand,
- The NRC's approval of the GDS interview of the senior resident inspector was approved by the NRC in a letter dated March 15, 2006 from Troy W. Pruett of NRC to Janet Wagner of APS (RJM_WP2RB) and did not include solicitation of the inspector's opinion on the reasonableness of APS actions in connection with the outages in 2005, and
- There is an alternate interpretation of the senior resident's statement, i.e., he was speaking from his NRC perspective of continuous improvement using hindsight, not from the ACC perspective of judging prudent

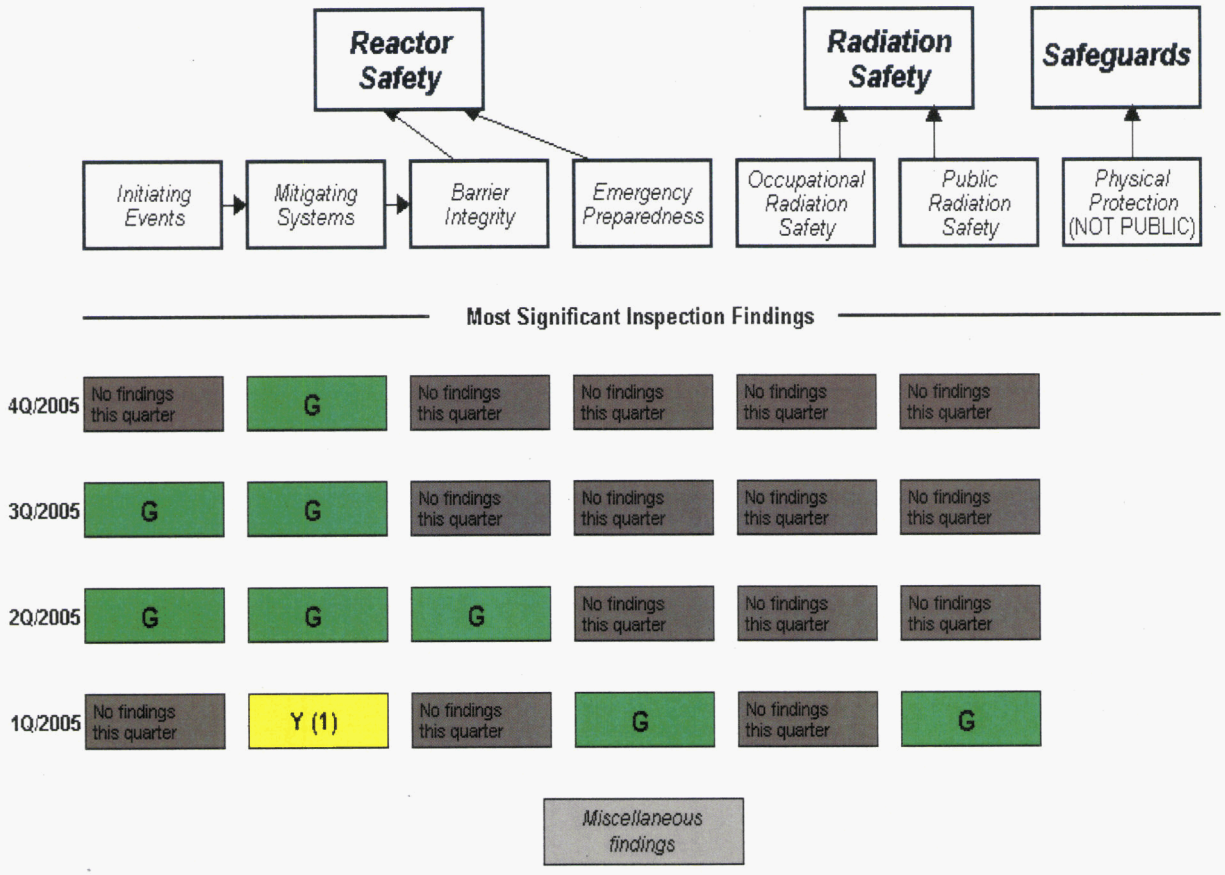
performance according to information reasonably available at the time.

Q. YOU MENTIONED THAT THE NRC ALSO INSPECTS EACH PLANT FOLLOWING ISSUANCE OF ITS OPERATING LICENSE. WHAT IS THE ROLE OF THE NRC'S INSPECTION PROCESS FOR AN OPERATING NUCLEAR POWER PLANT?

A. The primary purpose of the inspection program for operating power plants is to determine whether there is reasonable assurance that they are being operated safely and in accordance with NRC requirements. Most inspections are designed to identify situations that could be forerunners of future safety events. That is, inspections are intended to identify opportunities to improve plant safety.

Q. CAN YOU DESCRIBE HOW NRC USES THE FINDINGS IN ITS INSPECTION REPORTS?

A. Yes. Under the Reactor Oversight Process, NRC arranges its inspection findings in an Action Matrix just like the one it uses for current performance indicators, i.e., according to the seven cornerstones of safety. The Inspection Findings Action Matrix for Palo Verde Unit 1 for the last quarter of 2005 is shown on the following page.



The green blocks (boxes labeled G) in this figure represent areas in which there were NRC findings or violations of minor safety significance. The grey (shaded) blocks indicate areas that received no NRC findings or violations. The 2004 discovery that voided suction piping had existed between the containment sump and the ECCS since the plant first began operations is the source of the one yellow finding shown in this figure for the first quarter of 2005 under the Mitigating Systems cornerstone. It is discussed further in Section 5.

Q. ARE THERE ANY SPECIAL INSPECTIONS THAT ARE CONDUCTED UNDER NRC'S NEW REACTOR OVERSIGHT PROCESS?

A. Yes. Under the Reactor Oversight Process, there are three types of team inspections that are used in connection with recovery from degraded cornerstones. These team inspections are intended to assure that licensees have adequately assessed and understood the root causes of their degraded cornerstones, that the

generic implications of the root causes (extent of condition) are identified, and that the licensee's planned corrective actions are sufficient to address the root causes and generic implications and to prevent recurrence. These three types of team inspections are defined in accordance with the significance of the deficiencies identified by NRC. NRC Inspection Manual Chapter 0305 prescribes who in the NRC management hierarchy is empowered to take action on the basis of the results of these team inspections, as follows:

- Inspections conducted under Procedure 95001 "Supplemental Inspection for One or Two White inputs in a Strategic Performance Area" lead to action at the level of a branch chief or division director in the regional office;
- Inspections conducted under Procedure 95002 "Supplemental Inspection for One Degraded Cornerstone or any Three White Inputs in a Strategic Performance Area" lead to action at the level of a division director in a regional office or the regional administrator; and
- Inspections conducted under Procedure 95003 "Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input" lead to action at the level of the Executive Director for Operations in conjunction with the Director of the Office of Nuclear Reactor Regulation in NRC headquarters and the Regional Administrator.

The NRC's supplemental inspection at Palo Verde in the fall of 2005 using Inspection Procedure 95002 is discussed in Section 6, below.

Q. YOU MENTIONED EARLIER THE NRC WATCH LIST. WHAT WAS THE NRC WATCH LIST?

A. The Watch List was a means for NRC senior managers to identify plants that warranted additional NRC attention, such as increased NRC inspections or inspections with greater headquarters involvement, or more frequent meetings

between NRC and licensee management. Twice each year, the senior staff of the NRC conducted a Senior Management Meeting to determine which plants required placement on the Watch List.

Q. HOW MANY PLANTS WERE PLACED ON THE WATCH LIST?

A. The first group of plants to be placed on the Watch List was announced in May 1986. At that time, 13 units were placed on the list. From 1986 until its discontinuation in 1998, a total of 42 units were placed on the list. This number equates to about 40% of the total nuclear units that operated during that period. In June 1993, NRC's senior managers initiated a program whereby a Declining Trend Letter could be sent instead of placing a plant directly on the Watch List. A total of 14 nuclear units received a declining Trend Letter up to the time the program ended. Thus, more than half of all nuclear power units that operated during the period that the Watch List existed were either placed on the list or received a declining Trend Letter. Palo Verde was never on the Watch List and never received a Trending Letter.

Q. YOU HAVE SAID THAT BOTH THE WATCH LIST AND THE SALP PROGRAM WERE ELIMINATED IN 2000 WITH THE CREATION OF THE NEW REACTOR OVERSIGHT PROCESS. CAN YOU SAY WHY THE NRC DECIDED ON THIS APPROACH?

A. Yes. The NRC decided to eliminate the Watch List and the SALP Program because years of implementation of these programs demonstrated that they were too subjective. As NRC Chairman Shirley Jackson described in a written statement to the U.S. Senate Subcommittee on Air, Wetlands, Private Property, and Nuclear Safety on July 30, 1998, at the time the new ROP was being developed to replace the Watch List and the SALP programs,

> A major area of criticism focused on NRC processes that result in expending undue NRC and licensee resources to address NRC requirements that are of relatively low safety significance....In the area of reactor performance assessment, the strongest overall criticism has centered around the subjectivity and lack of scrutability of our assessment process....The NRC agrees with the thrust of these criticisms.

Q. AFTER THE ELIMINATION OF THE SALP PROGRAM AND THE WATCH LIST IN 2000, DID THE NRC USE A DIFFERENT SYSTEM TO CHARACTERIZE THE ATTENTION THAT IT WOULD GIVE A PLANT?

A. Yes. As currently implemented, the Reactor Oversight Process has four levels of NRC response to non-Green inspection findings or performance indicators. Two of the four levels are administered at the Regional Level and two of them are administered at the Agency Level (i.e., at NRC Headquarters in Rockville, MD).

Q. HAS NRC PLACED PALO VERDE IN ONE OF THESE CATEGORIES?

A. Yes. Palo Verde is in the second Regional Response category because it was identified as having a yellow degraded cornerstone for mitigating systems. This level of heightened attention is lower than the two levels of attention associated with the Agency Response level. The Agency Response Levels are similar to the previous Trending Letter and Watch List identifications. Although APS was not expected to implement a Performance Improvement Program at this level of increased regulatory scrutiny, it has voluntarily done so as discussed further in Section 5, below.

Q. IS IT UNCOMMON FOR NRC TO APPLY EXTRA SCRUTINY TO ITS LICENSEES?

A. No, NRC frequently applies extra resources to its oversight of individual licensees. The application of extra resources is a key part of NRC and licensee efforts to detect declining trends in performance before they turn into safety problems. In June 19, 2006 testimony before the Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, U.S. House of Representatives, John Wells, Director of Natural Resources and Environment for the GAO, noted "On the basis of its findings and the performance indicators, NRC has subjected more than three-quarters of the 103 operating plants to oversight beyond the baseline inspections for varying amounts of time." (RJM_WP3RB)

Q. IS THE ROP ACHIEVING WHAT IT WAS INTENDED TO ACCOMPLISH?

A. In some ways it is. The process provides assessments of utility performance that are more standardized, understandable, and predictable than the assessments conducted under the previous programs. The process is risk-informed so it helps to focus NRC and utility resources on those issues that have the greatest safety and risk significance. However, some of the outputs of the ROP are still subjective and unpredictable, subject to variations in the judgment of individual inspectors and inspection teams. The process is still a work in progress and subject to continued refinement.

Q. HOW IS NRC SEEKING TO IMPROVE THE ROP?

A. Beginning in 2003, the NRC staff sought stakeholder feedback on the ROP. It issued a survey that contained 20 questions and was designed by Brookhaven National Laboratory (BNL) under contract to the NRC. The results of this survey are reported in "Final Results – USNRC Office of Nuclear Reactor Regulation Regulatory Impact Survey, " August 3, 2004. (RJM_WP4RB)

Q. WHAT DID THE STAKEHOLDERS TELL BNL AND NRC ABOUT THE ROP?

A. Most of the responses expressed satisfaction with the way the ROP works. However, there were criticisms voiced about two aspects of the ROP that have relevance to this proceeding and to the GDS report.

First, there were comments pertaining to the staff's unpredictable pursuit of generic issues on a case-by-case basis. This practice was evidenced at Palo Verde in the refueling water tank outages of Units 2 and 3 in October 2005, outages owing to an unanticipated backfit of the design basis for Palo Verde that was imposed by NRC inspectors instead of pursuing a generic issue under NRC procedures. The applicable comments in the 2004 BNL Report were as follows:

- NRC is failing to address generic issues in a generic manner…[it] is addressing too many such issues on a docket by docket basis; and
- [There is] disappointment at NRR's [NRC's Office of Nuclear Reactor

Regulation] failure to pick up and pursue an issue that clearly had generic implications.

Second, BNL conveyed industry comments pertaining to the NRC staff's reluctance to accept the original licensing basis of a plant, insisting instead that a licensee backfit the design to a more modern approach without going through the required backfit process. (The term "backfit" (a.k.a. ratchet) is defined in 10 CFR 50.109 as the modification of equipment, approvals or procedures at a plant required by a change in NRC requirements or in NRC staff interpretations of NRC requirements, imposed after a plant was originally constructed.) The backfit process at NRC is designed to prevent an individual or small group in the staff from imposing new requirements on a licensee or a group of licensees without adequate analysis and management approval. The costs (monetary and otherwise) and benefits of new requirements are intended to be assessed under NRC's backfit process. The NRC inspectors imposed such a backfit at Palo Verde without going through the backfit process in October 2005 in the case of the refueling water tank suction piping issue, as described more fully in Section 6, below. The comments in the 2004 BNL report that reflect similar backfitting occurring at other operating plants were as follows:

- Better understanding [is needed by NRC inspectors] of the licensing bases that older plants used and the analyses [sic] techniques which provided margins to address issues. Current codes and techniques were not available to early licensees, but this shouldn't be a ratchet for re-analyses;
- In the inspection arena issues arise that are not based in regulation.... It appears nothing prior to 2000 has any meaning;
- The NRC is not effectively utilizing precedents when reviewing licensing submittals;
- Regulatory requirements were at one stage being written through inspection and ...there was poor consistency between what was acceptable in the past and present;

- Inspectors appear to be making new regulatory requirements through inspection and enforcement; and
- Staff positions change without backfit considerations.

Q. WAS THERE ANOTHER SURVEY IN 2004?

A. Yes. It is reported in a paper from the Executive Director for Operations to the NRC Commissioners entitled "Reactor Oversight Process Self-Assessment for Calendar Year 2004," SECY-05-0070, April 25, 2005, without attachments. (RJM_WP5RB)

Q. WHAT DID IT HAVE TO SAY ABOUT HOW THE REACTOR OVERSIGHT PROCESS IS WORKING?

A. This report did not have the direct quotes of the external stakeholders that were provided in the 2004 BNL report. Instead, the NRC staff summarized the responses received in the annual survey, saying that most people thought the ROP was an improvement over the past. The report noted that the responses were generally in line with responses to earlier surveys. The staff said that it "continues to experience significant challenges in certain ROP areas and recognizes the need for further improvement." One of the areas listed as requiring focus in 2005 was "further improving guidance related to cross-cutting issues." This area relates to statements made in the GDS report and to NRC's recent inspection reports for Palo Verde, as discussed more fully in Section 5, below.

Q. HAS NRC MADE PROGRESS IN DEALING WITH THE CROSS-CUTTING ISSUES?

A. Yes. In a June 19, 2006 statement on behalf of the NRC Commissioners to the Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, U.S. House of Representatives, Commissioner Edward McGaffigan, Jr. noted "The NRC has made numerous improvements to the ROP since its initial implementation, many as a result of independent program evaluations and feedback from internal and external stakeholders...The plant assessment process has been modified to improve its predictability, particularly in the treatment of

cross-cutting issues…." The improvements concerning cross-cutting issues to which the Commissioner referred were described in a May 24, 2006 NRC Policy Paper wherein NRC developed new definitions for each of its cross-cutting issues and provided additional guidance on their treatment once they are identified. (SECY-06-0122, "Safety Culture Initiative Activities to Enhance the Reactor Oversight Process and Outcomes of the Initiatives") Specific procedures were also provided for dealing with substantive cross-cutting issues. The relevance of this latest information on cross-cutting issues to this case is that even NRC did not have a good understanding of the role of such issues in the regulatory process until only recently, certainly well after a number of them had been identified at Palo Verde during the time period of interest here.

GAO, in the June 19, 2006 testimony to the House Subcommittee noted above, reported that between 2001 and 2005 cross-cutting issues had grown from 23% to 68% of all NRC inspection findings. The bearing of cross-cutting issues on Palo Verde is also discussed further in the next section of this testimony.

5. PALO VERDE PERFORMANCE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony discusses the performance of the three Palo Verde units. It contains data reflecting both the operational performance and the regulatory performance of Palo Verde. By operational performance I mean the performance of the people and equipment involved in generating electric power and assuring safety. By regulatory performance I mean the performance of APS in meeting the rules, regulations, and other expectations of the NRC. Finally, this section addresses the suggestion by GDS that the ACC adopt economic performance standards for Palo Verde.

Q. IS THE INFORMATION THAT THE NRC GATHERS ON NUCLEAR

POWER PLANT PERFORMANCE COMMUNICATED TO LICENSEES?

A. Yes. The NRC has always published its Performance Indicator data. The data were originally published and distributed quarterly, but in September 1995, the NRC changed to an annual publication consistent with the Federal government's fiscal year. Since implementation of the new ROP in 2000, the Performance Indicator data for each plant are updated quarterly on the NRC website.

The NRC's first Performance Indicator program ended in 1999. Thereafter, the NRC compiled performance data for its Industry Trend Program and for the ROP. I used data from these programs for this review of APS performance. To accomplish this task I designed and oversaw a project by SCIENTECH LLC in Clearwater, Florida that compiled a variety of performance indicator data for Palo Verde and the industry, using the Monthly Operating Reports that licensees were required to file with the NRC through 2004.

Q. HAS THE NRC ENDORSED THE USE OF COMPARISONS OF PERFORMANCE DATA WITHIN PEER GROUPS AND ACROSS THE INDUSTRY?

A. Yes. The NRC makes such comparisons itself. For making such comparisons the NRC assigned all nuclear power plants to their respective peer groups based upon similarity of design and vintage. Comparison of peer plants allows for evaluation of overall performance relative to similar plants constructed in a similar regulatory environment. Each peer group defined by NRC is based on nuclear steam system supplier, plant vintage, generating capacity, and licensing date.

Comparison of individual plant performance to peer group averages over time provides a relative measure of a plant's performance trend. NRC and licensees have used such comparisons to see whether special action was required to address problem areas or warrant closer NRC oversight at a particular plant. The NRC developed this program to provide itself and licensee management with early

warning of declining trends in performance that warranted special attention.

Q. OF WHICH PEER GROUP IS PALO VERDE A MEMBER?

A. Palo Verde belongs to the group of later Combustion Engineering plants (NRC calls this peer group 2) consisting of Arkansas Nuclear Unit 2, Waterford, San Onofre Units 2 and 3 and Palo Verde Units 1, 2 and 3. The Palo Verde units were the last of these plants to be placed in service and are the only ones that incorporate the System 80 Standard Plant Design of Combustion Engineering.

Q. WHAT PERFORMANCE INDICATOR DATA ARE YOU PRESENTING AND HOW ARE THE INDICATORS DEFINED?

A. I have compared Palo Verde's performance to its peers, other PWRs, the nuclear power industry, and, in one case, Region IV plants. I provide the comparisons for several parameters encompassing two time periods, before and after 2000 when the new ROP was implemented and the NRC performance indicators were changed. In addition to comparisons with its peer group of plants, I compared Palo Verde's performance to the entire industry for performance indicators that are independent of reactor design and to other PWRs for performance indicators that are not independent of reactor design. I made a Region IV comparison where the parameter was subject to variation among the four NRC Regions.

Some data under the old Performance Indicator Program have been compiled by SCIENTECH through 2001, even though NRC implemented the new ROP in 2000 and ceased to publish the old indicators at that time. I have included those SCIENTECH data where available. The data provided In Attachment RJM-3RB reflect the performance of Palo Verde during the period 1995 through 2004. I have included data for 2005 where available. I chose the 10-year period because it is long enough to show trends in performance. I chose the indicators as being the ones that best describe the safety and productivity of the station.

Q. WHAT DO THE NRC QUANTITATIVE PERFORMANCE INDICATORS GENERALLY REVEAL ABOUT THE PERFORMANCE OF PALO

VERDE?

A. The Performance Indicator data shown in Attachment RJM-3RB reveal that Palo Verde has performed well within industry norms when compared to its peer group, other PWRs and the nuclear industry.

Q. SHOULD THE PERFORMANCE OF NUCLEAR PLANTS BE EVALUATED ON THE SHORT-TERM OR THE LONG-TERM?

A. The performance of nuclear power plants should be evaluated over the long-term. As seen in the data of Attachment RJM-3RB, some of the events measured by Performance Indicators occur quite infrequently. Thus, the occurrence of one or two in a short period of time may or may not be statistically significant. Also, some indicators, such as worker radiation exposure, are keyed to long-term cycles in plant operation that can extend over several years. For example, the Palo Verde plants have nominal 18-month fuel cycles, and radiation exposures are highest during refueling outages when most of the maintenance of radioactive equipment is accomplished. Therefore, cumulative radiation exposures tend to spike every 18 months on each unit.

Q. PLEASE IDENTIFY THE PERFORMANCE INDICATORS THAT YOU CHOSE AND TELL US HOW YOU INTERPRET THEM.

A. The charts provided in Attachment RJM-3RB graphically depict Palo Verde's performance for each of the performance indicators that I chose. I chose indicators that bear on the reliability and safety of operations. I left out those relating to barrier integrity, emergency preparedness, public radiation safety and security because they do not bear on plant safety and reliability and involve issues that are not germane to this proceeding. I have provided a definition and a chart for each of the indicators that I chose. Each chart shows by year the average performance of the Palo Verde units and the performance of other units appropriate for comparisons for that indicator.

In sum, there are 18 indicators, some treating similar variables over the two

periods, 1995 to 1999 and 2000 to 2005. The average performance of the Palo Verde units meets or exceeds the average performance of the PWRs or all nuclear power plants for 16 of these 18 indicators. The average performance of Palo Verde is better than its peer group for 15 of the 18 indicators. I made these comparisons on a year-by-year basis, not accounting for how much the Palo Verde performance was under or over the comparison groups in any one year.

Based on these data, Palo Verde is a high performing station.

Q. DID YOU FORM ANY CONCLUSIONS REGARDING THE SAFETY OF THE PALO VERDE UNITS DURING THIS TIME PERIOD?

A. Yes, I concluded that there is no indication in the Performance Indicators, the NRC and APS documents, or the results of my interviews that the Palo Verde units were operated unsafely at any point in this time period.

Q. DOES NRC AGREE WITH THAT CONCLUSION?

A. Yes, on January 26, 2006, Bruce Mallett, Administrator of NRC Region IV, addressed the ACC and stated the same conclusion. Specifically for the years 2004 and 2005 Mallett said (Transcript page 18),

> First and foremost, the licensee, Arizona Public Service, has operated the Palo Verde nuclear plant in a safe and secure condition. They have ensured the protection of the public health and safety. And they have ensured the protection of the environment. They have also responded to emergent plant conditions and emergency events with safety as a primary focus.
>
> There have been problems, though, some identified by the licensee and some identified by the NRC, that have challenged the plant safety systems. If you remember in the first comments I made, those systems consist of people, facilities and procedures. This means that their performance is degraded in certain areas and that they and the NRC are taking actions to ensure improvements in these areas. This does not mean, however, that their operation is unsafe.

Q. YOU HAVE MENTIONED THE DISCOVERY IN 2004 OF VOIDED PIPING IN THE SUCTION LINES LEADING FROM THE

CONTAINMENT SUMP TO THE ECCS. WHY WAS THIS IMPORTANT?

A. In August 2004 NRC conducted a special inspection at Palo Verde following a finding by APS that some sections of the suction piping from the containment sump to the HPSI and containment spray systems were voided (i.e., did not contain water) in all three units. Initially, the voiding was a result of draining of the lines during ECCS testing conducted quarterly since the start of operations. This condition could affect the ability of these systems to perform their safety function in a loss of coolant accident. The inspection resulted in two potentially greater than green findings even though the condition had existed throughout the life of the plant. The two most significant findings of the inspection were

- Failure to maintain safety injection sump suction piping full of water in accord with UFSAR (Updated Final Safety Analysis Report), and
- Failure in 1992 to perform a written safety evaluation, in accord with 10 CFR 50.59, when the practice of intentionally draining the lines on plant restart was first implemented.

There were professional differences of opinion on whether the UFSAR specifically required that the lines be filled with water and on whether the ECCS pumps in question would be damaged by the air in the voided lines.

These differences were aired over several months at both the regional and headquarters levels of NRC, and, in the end, the NRC staff prevailed, viz. the risk significance of the finding was judged, by a narrow margin, to be sufficient to justify a yellow cornerstone under the ROP. The Inspection Report on this matter was issued on January 5, 2005, and the yellow cornerstone was issued on April 8, 2005.

As I write this testimony, the yellow cornerstone still exists, although most of the associated corrective actions have been accepted by the NRC. GDS says, at page 11 of its report, "While APS officials attempt to minimize this [yellow] rating,

stating that Palo Verde is in the 3rd column only because of the yellow finding,...the Action Matrix Summary reflects overall plant performance and is updated regularly..." That is not a correct interpretation of the yellow cornerstone. Rather, as Region IV Administrator Mallett told the ACC on January 26, 2006, (transcript page 24),

> They are in what we call the third column or yellow column [i.e., the second column of increased oversight] of our action matrix because they had a finding with this voiding issue in their emergency core cooling pipe system late 2004 that was risk significant. And we felt that needed to be corrected. So that's what put them into that column. Once they correct [accomplish] the actions they need to take for that specific issue and complete it, they will go back to the first column, or green column of performance where we don't have increased oversight of them.
>
> In addition to that action matrix, however, these other problems I listed, we issued them based on their performance, these two cross-cutting issues [of] problem identification and resolution and human performance. These have to be corrected by them[APS]. They have to address those issues. But they will still be in the green column with those issues.
>
> The reason we identified them [cross-cutting issues] is those are indicators that we believe lead you to getting into one of the columns to the right of the matrix... the yellow or red column. So we identify those issues early and hope to turn them around so...their performance doesn't get worse.

Q. RELYING ON THE COMPANY'S OWN SELF-CRITICAL DOCUMENTS, GDS CONTENDS THAT REGULATORY PERFORMANCE AT PALO VERDE HAD BEEN DECLINING FOR SEVERAL YEARS. IS THERE ANY CONTEMPORANEOUS EVIDENCE TO THE CONTRARY?

A. Yes. On August 16, 2004 NRC issued a report describing a May to July inspection of the APS program for Problem Identification and Resolution (PI&R), i.e., the corrective action program. (RJM_WP6RB) The report stands in stark contrast to the conclusions of the NRC in the January 5, 2005 inspection report relative to the voided sump suction piping. The PI&R inspection report stated that the "team determined that in general the corrective action program was appropriately

implemented; thresholds for identifying issues remained appropriately low and corrective actions were adequate to address conditions adverse to quality." A few examples were noted where problems were not properly identified, evaluated or corrected and operating experience reviews and actions were often extended. The inspectors also concluded "a positive safety conscious work environment exists at PVNGS."

Q. HAD THERE BEEN ANY INDICATION FROM NRC PRIOR TO THE JANUARY 5, 2005 INSPECTION REPORT THAT IT HAD DOUBTS ABOUT THE IMPLEMENTATION OF THE DESIGN AT PALO VERDE OR THE ADEQUACY OF 10 CFR 50.59 REVIEWS?

A. No, in fact there was contemporary evidence to the contrary. On August 27, 2004, NRC issued a report on a Safety System Design and Performance Capability Inspection. (RJM_WP7RB) This report described a 2-week, 5-person, on-site inspection in June and July "to verify that the licensee adequately preserved the facility safety system design and performance capability and that the licensee preserved the initial design requirements in subsequent modifications of the systems selected for review." The outcome of this inspection was excellent and contrary to the two most significant findings of the sump suction piping inspection that began only one month later.

Q. YOU HAVE CITED TWO EXAMPLES WHERE NRC INSPECTED SOME PALO VERDE PROGRAMS AND FOUND THEM SATISFACTORY, IF NOT SUPERIOR, AND THEN A SHORT TIME LATER FOUND SOMETHING QUITE DIFFERENT. HOW DO YOU EXPLAIN THESE DRAMATIC DIVERGENCES IN SUCH A SHORT TIME?

A. These two instances involving design implementation and problem identification and resolution demonstrate that, when dealing with an industry that has very high performance, extraordinary measures are applied by NRC to monitor performance so that early detection of a decline in performance is assured. They also indicate that the decline that has occurred at Palo Verde probably is relatively small. Finally, they indicate the high degree of subjectivity that remains in the NRC's reactor oversight process, as others have told NRC in the annual feedback on the

ROP that I described in Section 4, above. It is for this reason that I believe GDS overstates the case in the portion of its report (pages 11 to 15) addressing APS's regulatory performance.

Q. AT PAGES 2, 10 AND 11 OF ITS REPORT, GDS DISCUSSES THE PERFORMANCE IMPROVEMENT PLAN THAT APS ADOPTED IN OCTOBER 2005 AND CONCLUDES "BASED ON OUR EXPERIENCE WITH SIMILAR PLANS AT OTHER NUCLEAR PLANTS, GDS IS OPTIMISTIC THAT APS WILL BE SUCCESSFUL IN ACHIEVING IMPROVED PERFORMANCE AT PALO VERDE." DO YOU AGREE?

A. Yes. The PIP (Attachment 1 to GDS report) directs the activities that APS management has decided to undertake to reverse declining performance at Palo Verde. Within the Plan are specific action plans related to root causes identified by APS for the performance decline. NRC will review the effectiveness of the actions in the PIP in determining, among other things, whether the substantive cross-cutting aspects its inspectors identified have been suitably addressed. Successful completion of the actions in the PIP to improve the corrective action program and its utilization at the station will be instrumental in demonstrating that the needed improvements noted earlier by NRC have been made.

Q. WHAT CONCLUSIONS HAVE YOU FORMED ABOUT APS'S REGULATORY PERFORMANCE?

A. The new reactor oversight process that NRC implemented in 2000 provides four levels of increasing scrutiny of licensees above the normal level of NRC oversight. Palo Verde is now at the second level of increased oversight because of an error that was made in 1992 and found in 2004. There are recent indications that the station will be successfully returned to the lowest level of NRC scrutiny. For example, Mallett's statements to the ACC on January 26, 2006, (Transcript pages 24-25) about the corrective actions for the yellow column being separate from the substantive cross-cutting issues, as quoted above.

The cross-cutting issues did not cause the yellow cornerstone or the outages experienced in 2005. The NRC findings that contained these cross-cutting issues

were all green findings (low safety significance). NRC has acknowledged difficulty in understanding the significance of the cross-cutting findings. NRC has recently issued new guidance on identifying and resolving cross-cutting issues, guidance that was not available to assist either the NRC inspectors or APS in the period in which large numbers of these issues were identified for Palo Verde.

The only 2005 outage experienced at Palo Verde that involved actions by the NRC staff was the one in October concerning reexamination of the design basis for air entrainment in the suction line from the refueling water storage tank. My conclusions about APS's prudent handling of this unforeseeable backfit by the NRC staff are summarized below. Also, Region IV Administrator Mallett in his January 26, 2006 discussion with the ACC gave this event as an example of APS actions that "have been in compliance with our requirements and timely and thorough in response to events and emergent issues." (Transcript pages 19 – 20) These views are in marked contrast to those expressed about this outage at pages 31 to 35 and 39 to 40 in the report of GDS.

The NRC has described increased inspection efforts at Palo Verde owing to the yellow cornerstone. Mindful of these various statements, I conclude that there has been a decline in regulatory performance at Palo Verde from the previous level of excellence, and that APS and NRC are applying extra effort to reverse the trend. Neither APS nor NRC has said that performance at Palo Verde is imprudent or unsafe.

The Performance Improvement Process underway at Palo Verde is beyond NRC's requirements and expectations for a station at its level of performance and typical of such programs that have been implemented at many operating plants in the country, often more than once. Such processes always involve self-assessments that are expected by NRC and the industry generally to use hindsight and to identify opportunities for improvement in open, frank and often harsh terms.

Q. EARLIER IN THIS SECTION, YOU HAVE DISCUSSED THE PAST OPERATIONAL AND REGULATORY PERFORMANCE OF PALO VERDE. AT PAGE 52 OF ITS REPORT GDS RECOMMENDS THAT THE ACC ESTABLISH A MINIMUM STANDARD FOR FUTURE PERFORMANCE AT PALO VERDE, INCLUDING PENALTIES IF THE PLANT FAILS TO MEET THIS STANDARD. WHAT HAS THE NRC SAID ABOUT SUCH STANDARDS?

A. On July 24, 1991, the NRC published in the Federal Register a Final Policy Statement on "Possible Safety Impacts of Economic Performance Incentives". (RJM_WP8RB) The 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." In the Policy Statement, the NRC identified four types of incentives for which it had particular concern because they "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)."

The NRC also said that it was concerned

> "...about any State public utility commission's undue reliance on a utility's corrective actions following an incident to justify the disallowance of costs related to the incident.... 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 assume 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."

The NRC went on to identify four features that it had reviewed

> "...and believes State Public Utility Commissions (PUCs) may want to consider... in establishing programs that prompt licensees to both economically and safely operate nuclear power plants. These features include

> (1) capacity factor targets based upon industry's average performance to account for problems throughout the industry,
> (2) equal opportunities for rewards and penalties,
> (3) the 'banking' of superior performance to offset lower performance, and
> (4) using performance measures of the entire system instead of those for a specific unit."

NRC also noted in the Policy Statement that it requires its licensees to inform it whenever a State PUC develops or substantially revises EPIs.

I note that the recommendation by GDS does not include three of the four features that NRC offered in its Policy Statement for consideration by State public utility commissions.

On June 26, 2001, Joseph R. Gray, NRC's Associate General Counsel for Licensing and Regulation, presented testimony on behalf of the NRC to the U.S. Senate Committee on Energy and Natural Resources concerning "Price-Anderson Act Renewal and Nuclear Energy Production and Efficiency Incentives". (RJM_WP9RB) With regard to incentive provisions such as one then being considered by the Senate, Gray said

> "The [NRC] has previously elaborated upon the potential impacts of performance incentives in a 1991 policy statement 'Possible Safety Impacts of Economic Performance Incentives: Final Policy Statement,' published in the Federal Register on July 24, 1991 (56 FR 33945). The Commission stated a concern with incentive plans such as the one proposed here, that, in the interest of real or perceived short-term economic benefit, the utility might hurry work, take short cuts, or delay shutdown for maintenance in order to meet a deadline, a cost limitation, or other incentive plan factor. Therefore, such an incentive program could directly or indirectly encourage the utility to maximize measured performance in the short term at the expense of plant safety and public health and safety.... A primary problem with the proposed production incentive is the short-term interval for measuring performance. Performance measurements for short-term intervals would encourage the licensee to focus on the short-term target, potentially diverting attention from long-term goals of reliability and

operational safety."

Q. HAVE YOU FORMED AN OPINION ABOUT THE NEED FOR AN ECONOMIC PERFORMANCE STANDARD FOR PALO VERDE?

A. Yes. In my opinion an economic performance standard is not needed for Palo Verde at this time based on its long-term record of superior performance and the Performance Improvement Program now underway to ensure such performance in the future.

6. PRUDENCE ASSESSMENT OF REFUELING WATER TANK OUTAGES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section I will show that the Outages of Units 2 and 3 in October 2005 were not the result of imprudence, as claimed by GDS. Rather, these outages resulted from a new question that NRC inspectors raised, one that they and APS had not come across before, and one that APS could not have known beforehand. In other words, the inspectors imposed a backfit on Palo Verde in a way that APS could not reasonably anticipate, and the backfit led to the outages. Thus, APS was prudent in its dealings with this issue both before and after it was raised by the NRC.

Q. PLEASE DESCRIBE THE OUTAGES CONNECTED WITH THE SUCTION HEADER ON THE REFUELING WATER TANK (RWT).

A. The RWT issue arose during an NRC inspection pursuant to its Inspection Procedure 95002 "Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area." The inspection was a standard NRC follow-on to the problem with voided piping from the containment sump identified by APS in 2004 as having occurred in 1992, i.e., the issue that led to NRC's conclusion that Palo Verde had a degraded (yellow) cornerstone for Mitigating Systems, as discussed more fully in Section 5, above. The inspection occurred over

the period September 12 to December 12, 2005. Four NRC inspectors and one inspector intern from Region IV, one inspector from Region III, one NRC headquarters subject matter expert, and one NRC contractor conducted the inspection. During the inspection one of the NRC contractors raised a question about the design of the suction header serving several safety systems in each Unit.

As NRC Region IV Administrator Bruce Mallett later told the Arizona Corporation Commission on January 26, 2006 (Transcript pages 42-44),

> In the October [2005] time frame, when we raised this issue about the design flaw, it was a new question, okay, one that we hadn't come across before, nor had they [APS] 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 over simplifying – so that would put us in a condition we don't believe is within our design. If you can't answer [the] NRC, and we [APS] can't answer it within this certain time frame, we have to shut the plant down by our technical specifications until we get it resolved. And that's what they did....All I can say in this case is that it was a question we raised and they did the right thing when they couldn't answer the question....***In this instance we didn't determine that they should have found it beforehand....*** But the issue, I think, was it was a new question that was asked. If they were investigating and looking at that system, you would expect them to find out, but I am not sure we would expect them to go in and look at that system at the time we were looking at it....We have an inspection we are conducting at the time and we have a report that is coming out....we will probably issue it tomorrow....And that report will make our conclusions final in that instance that we looked at. [emphasis added]

As Mallett acknowledged, the question was a new one. It went beyond the questions about air entrainment in these lines that had been addressed in NRC's original licensing review of the plant. It went to the adequacy of the original licensing basis, and thus was outside the scope of an extent of condition review for the problem found in 2004 with voiding in the sump suction lines, which was a design basis implementation issue; i.e., the question went to whether the design the NRC had approved back before the plant operated was adequate rather than

whether APS had properly implemented the NRC-approved design.

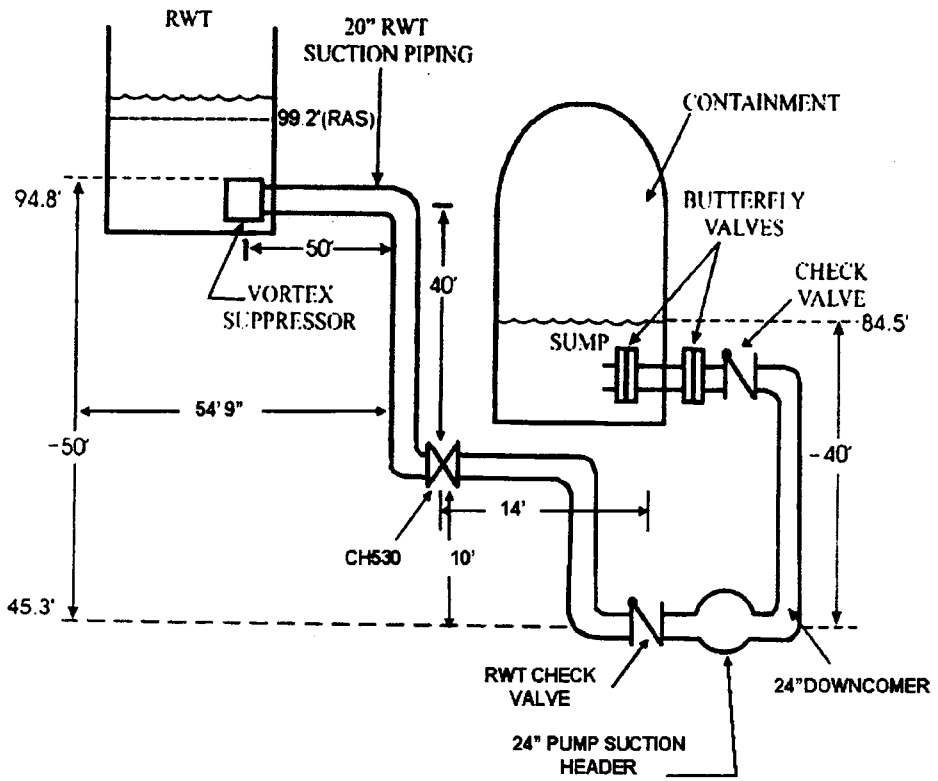
The interaction between APS and the contract inspector started out routinely. APS first showed him how the potential for air entrainment in the RWT suction line had been dealt with in NRC's operating license review of the plant, and how the conditions flowing from that review had been factored into Palo Verde's design. That approach was deemed insufficient by the contract inspector. Then came the new question: What about the dynamic behavior of the air water mixture during the switch-over of pump suction from the RWT to the containment sump? Because the new question went beyond the original licensing basis of the plant, it could not be readily answered by APS. Accordingly, the safety systems in question were declared inoperable, and the two operating units (Units 2 and 3) were shut down on October 11 in accordance with their Technical Specifications. Unit 1 was already shut down for refueling at the time. The NRC's surprise question was resolved sufficiently to support a system operability declaration for Units 2 and 3, and they were restarted on October 20. The total outage time for each of the two units was about nine days. The RWT issue did not prolong the Unit 1 refueling outage.

Q. PLEASE DESCRIBE IN MORE DETAIL THE QUESTION THAT THE NRC CONTRACTOR RAISED THAT APS COULD NOT READILY ANSWER.

A. I will do that, but first I need to describe the safety systems involved in the question. The question concerned the design of the suction piping (labeled as 20" RWT SUCTION PIPING in the schematic diagram shown below) that feeds the containment spray system and the emergency core cooling system (ECCS). These systems are required to function to mitigate the consequences of a breach in the reactor coolant system that leads to a loss of coolant accident (LOCA).

The suction header (a line running perpendicular to the lowest horizontal line in the schematic diagram and labeled '24" PUMP SUCTION HEADER') receives water from several sources during recovery from a LOCA. First, during the so-

called injection phase of a LOCA, makeup water is pumped from the refueling water tank into the reactor coolant system, to replenish water that has discharged out the breach through which the loss of coolant occurs, and to the containment to cool the steam that discharged from the breach. When the RWT is emptied, recovery from the accident enters its recirculation phase. An instrument that detects low water level in the refueling water tank sends a signal to the control room noting the changeover from injection to recirculation. The signal is called the recirculation actuation signal or RAS and the corresponding water level in the RWT is shown in the schematic diagram.



In the recirculation phase, water is recirculated from the containment sump, through the ECCS or containment spray pumps, into the reactor or containment atmosphere. The switchover from the injection phase to the recirculation phase of recovery from a LOCA occurs in every pressurized water reactor (PWR).

The Palo Verde units were among the last to be designed in the United States. They were based on a standardized design (System 80) provided by the Combustion Engineering Company. As such, they incorporated design refinements that had been made on earlier models sold by Combustion and other manufacturers of PWRs. To many people, the Palo Verde design is among the best now operating anywhere in the world. Refinements in this design include the arrangement of the two lines from the RWT and the containment sump that feed the suction header so that neither the closure of an automatic isolation valve nor prompt operator action is required after a LOCA occurs. Rather, there are passive design features that assure emergency pump suction is transferred from the RWT to the containment sump at the appropriate time. Later, after the transfer has occurred, the operating procedures at Palo Verde require the operators to close motor operated valves in the lines coming from the RWT. (Palo Verde Emergency Operating Procedure 40EP-9EO03, Revision 20, pages 24 and 25 of 69, Steps 50 and 51, and Associated Technical Guideline 40DP-9AP08 Revision 13, pages 39 and 40 of 64)

The foregoing schematic diagram serves to illustrate the passive nature of this design, a design feature that is much admired in reactor safety systems because, in general, the fewer parts that have to move in an emergency the better. The two lines feeding the pump suction header are the RWT suction piping and the line from the containment sump (labeled in the schematic as 24" DOWNCOMER). With this arrangement, when the water level drops low in the suction piping from the RWT, the pressure in the containment sump line leading to the suction header overcomes the pressure in the RWT suction piping leg and closes the check valve in that piping (labeled as RWT CHECK VALVE in the schematic). After the check valve closes, all of the supply of water to the ECCS and containment spray pumps comes from the containment sump.

When Combustion Engineering designed this arrangement it required that Palo

Verde and other plants incorporating the System 80 standardized design must supply 16 feet of elevation difference between the water in the containment sump and the pump suction header. As can be seen in the schematic, the Palo Verde layout provides 40 feet of elevation difference, more than enough to assure that the check valve in the RWT suction piping would close, thus assuring that the ECCS and containment spray pumps would perform their function during the recirculation phase of LOCA recovery.

This arrangement enabled the switchover from the injection phase to the recirculation phase of recovery from a LOCA to occur without credit being given for operator action in the safety analysis. Over the years, as a general philosophy, NRC had encouraged the development of safety system designs that did not depend on early manual action by operators to cause equipment to change in the high stress environment that would follow a LOCA. Designers had struggled with how to implement this idea on the RWT suction lines typical of pressurized water reactors. Some of them had opted for a valve that automatically closed to isolate the RWT from the containment sump. Others relied on early operator action. The disadvantage of the automatic valve design was that the valve might malfunction and close prematurely, thereby shutting off the supply of water to the ECCS. The disadvantage of relying on early operator action is that the operator would be distracted by other events and forget to accomplish the required actions. The arrangement developed by Combustion Engineering in the System 80 design used at Palo Verde solved this dilemma. It eliminated the need to rely on either operator action or automatic isolation valves. (Although operators are instructed in the emergency operating procedures to close the isolation valves in these lines (labeled CH350 in the schematic) as an added precaution, they are not required to do so in the immediate aftermath of a LOCA and their action to do so is not credited in the safety analysis.)

The NRC headquarters staff reporting to me approved this passive design feature

as part of its review in the late 1970s and early 1980s of the Safety Analysis Report for System 80 and the Final Safety Analysis Report for Palo Verde. Our conclusion that the Palo Verde design was sufficient to prevent air entrainment from the RWT did not include consideration of the dynamic effects that could occur in switching the pump suction from the refueling water tank to the containment sump following a loss of coolant accident. The calculations for Palo Verde were like the calculations we accepted for every other PWR in the Untied States; they were static calculations (i.e., stationary water sitting in the lines), not dynamic calculations (i.e., water oscillating up and down as pressure fluctuates in the lines during switchover).

Just before the NRC supplemental inspection in October 2005, Craig Baron, one of the contractors serving on the NRC inspection team, told APS that the inspection team would look at the refueling water tank and other water sources to determine if their designs had been implemented. APS and its contractors assembled 35 volumes of documentation on the RWT and five other safety systems in preparation for the inspection to demonstrate how the original designs of these systems had been implemented. Early in the inspection Baron asked whether, during the switchover from injection to recirculation, air from the RWT could be entrained in the suction piping leading to the suction header and then be carried into the pumps, leading to their damage and loss of function.

Q. HOW DID APS INITIALLY RESPOND TO THIS QUESTION?

A. The APS staff prepared a short summary of the licensing basis described above for the RWT suction piping leading to the suction header. The document showed how the interface requirements (between the System 80 reactor and the rest of the plant supplied by the plant's architectural and engineering contractor, Bechtel) that were approved in the operating licensing review by NRC had been met by the design configuration at Palo Verde that had been in existence since the plants first went into operation (including the requirement for 16 feet of elevation difference

between the containment sump level and the suction header). The document provided by APS to Mr. Baron concluded that the original design basis was intended to preclude air entrainment. (NRC 95002 Inspection Action Item 51 "Isolation of the PVNGS RWT and Potential for Air Entrainment at RAS, Revised Assessment attaching original assessment," APS, October 4, 2005. RJM_WP10RB)

Q. DID THE NRC CONTRACT INSPECTOR ACCEPT THE FIRST APS ANSWER?

A. No. Baron pointed out that, during the draw down period when the water level drops out of the RWT down into the line leading to the suction header, a vortex could form and entrain air in the section of pipe that transitions from a horizontal to a vertical run (see schematic diagram above). At that time, most of the flow to the pump suction header is coming from the RWT suction piping, and the check valve is open. The issue Baron raised is a dynamic effect as compared to the static analysis made in the original design.

A revised APS response to his question, issued on October 6, said that there was sufficient margin in the design to assure that these dynamic effects could be overcome and the intent of the design would be met. The revised response also provided evidence that Combustion Engineering had been aware of the potential for air entrainment when the interface requirements related to the design had been established. The revised response was discussed with Baron, and additional calculations were requested of APS's consultant Westinghouse to confirm that the margin in the static design basis was sufficient to accommodate the dynamic effect raised by Baron. The APS Engineering staff and Operations staff judged the revised response sufficient to justify continued operation of Units 2 and 3.

The information supplied to Baron on October 6 is important because it is the source of an apparent misunderstanding on his part that eventually made its way

erroneously into the January 27, 2006 Supplemental Inspection Report. The information he received included a question by the NRC staff and an answer by Combustion Engineering back in 1976 that was part of the licensing basis for Palo Verde. The information is identified by the title "ECCS Piping Interface Requirement per 'Outstanding CESSAR Review Matter' Number 38," Calculation MISC-REC-249, Combustion Engineering, Inc., Engineering Department, Approved by R. P. O'Neill, 1/19/76. (RJM_WP11RB) It describes the problem raised by the NRR licensing staff (possible air entrainment in the RWT suction piping) and then goes on to describe how CE would resolve the issue by providing an elevation difference between the containment sump level and the check valve in the RWT line to assure closure of the check valve soon after the RWT was emptied and before air from the RWT could enter the sump suction header.

This CE document clearly shows that air entrainment in the line from the RWT to the ECCS and containment spray pumps and the potential for cavitation in the pumps was considered by CE and foreclosed by the CESSAR design and interface requirements. It also shows that NRC staff raised this matter and, because the 16-foot elevation differential was accepted in the Final Safety Analysis Report for Palo Verde, the NRC staff accepted the answer.

These facts are at variance with statements at page 12 of the January 27, 2006 NRC Supplemental Inspection Report concerning this point. (Attachment 3 of GDS report) At page 12 of the report, NRC said, "The inspectors determined that the potential air entrainment into the ECCS suction header from the RWT was a licensee performance deficiency. This condition did not conform to the plant design basis and had not been analyzed." To the contrary, the plant was in conformance with its design basis, the design basis had taken into account the potential for air entrainment, the design had been found by NRC in the late 1970s to preclude entry of air into the suction header, and the inspectors had been provided with documentary evidence to prove those points. The problem that then

arose was that the inspector did not accept the technical basis for the design that had been accepted by the NRC in the original licensing of Palo Verde. Instead, he asked for a dynamic analysis to prove the adequacy of the design.

Thus, the new question the contract inspector raised did not concern compliance with the design (i.e., the issue that had led to the yellow cornerstone on which the inspection was intended to follow up and for which APS had prepared). Rather the new question concerned the adequacy of the design. The inspector challenged the adequacy of the license authorization that the NRC granted 20 years ago. He wanted more and better evidence that air entrainment would not damage the ECCS and containment spray pumps. He wanted dynamic calculations not static calculations. It is unreasonable to expect that APS could have anticipated that he would do so, and that essentially is what Mallett told the ACC on January 26, 2006 (quoted above). This is an understanding of the situation that is in stark contrast to the story told by GDS at page 32 and 33 of its report wherein it is claimed that APS did not do a thorough enough extent of condition of analysis in preparation for the inspection and APS did not understand the design of its plant. Clearly, the facts described above show those conclusions by GDS to be erroneous.

Q. HOW DID APS ADDRESS THE NEW QUESTION, AND HOW DID IT TURN OUT?

A. APS engaged Westinghouse to provide an answer to the question. Westinghouse initially tried to prove that margin provided by containment pressure tended to support the adequacy of the static design to account for the dynamic design question. It was not until late in the afternoon of October 11 that word was received by APS from Westinghouse that the calculations could not support the adequacy of the static design to account for the dynamic design question if there were low temperatures in the RWT at the time of a LOCA, temperatures that were allowed by the Plant's Technical Specifications. This new information from Westinghouse resulted in discussions at Palo Verde among staff from Operations,

Engineering and Regulatory Affairs at a Management Review Team meeting, leading to a decision in the control rooms to declare the RWTs inoperable and shut down Units 2 and 3. Their shutdowns were commenced about 4 o'clock in the afternoon on October 11.

Q. THEN WHAT HAPPENED?

A. APS promptly undertook maintenance work in Units 2 and 3 so as not to waste the opportunities afforded by access to the containment during reactor shutdown, e.g., maintenance on reactor coolant, main feedwater and auxiliary feedwater pumps and the main generator in Unit 2, and repair of some valves and the auxiliary feedwater pump in Unit 3. Meanwhile, the APS engineering staff worked with a consultant to develop a new analytical approach for determining whether the as-built conditions of the RWT suction piping and the pump suction header were adequate to preclude air being entrained into the safety pumps for the dynamic design scenario posed by the contract inspector.

Q. WHAT WAS THE NEW ANALYTICAL APPROACH?

A. APS engaged a subsidiary of Westinghouse called Fauske and Associates and a subject matter expert named Robert Henry who works there to develop models and perform analyses that had never been attempted before in the design or licensing of any nuclear power plant in America. This is an important point – the question raised by the NRC contractor was sufficiently beyond the design basis of any power reactor in the country that one of the leading hydrodynamic analysts in the world had to be engaged in a crisis atmosphere to advance the state of the art.

Q. WOULD YOU CALL THIS A BACKFIT, I.E., A CHANGE TO THE PREVIOUSLY APPROVED LICENSING BASIS THAT APS COULD NOT ANTICIPATE?

A. Yes, but when you have a NRC technical question about a plant's safety, you are expected to get an answer not challenge the appropriateness or fairness of the question of the question. Once such a question is posed for the operations crew at an operating plant, that is, a question about the ability of the safety equipment to

perform its intended function, it has to be answered by a senior reactor operator in a short time prescribed by the Technical Specifications or the equipment needs to be declared inoperable and the appropriate steps taken. In this case the plant had to be shut down until the question could be answered and the operability of the safety equipment involved could be demonstrated.

Q. HOW DID DR. HENRY'S ANALYTICAL APPROACH TURN OUT?

A. He produced a 36-page report on October 17 concluding that the original design was adequate. Specifically his report said that the design interface criterion assures closure of the flow path through the RWT suction piping to the pump suction header, once the RWT inventory is depleted; that the interface criterion is satisfied in a conservative manner at Palo Verde (40 feet elevation difference rather than 16 feet between the containment sump water level and the ECCS suction header); and that when consideration is given to the dynamic response of the water flowing through the check valve there is always sufficient pressure differential to close the RWT check valve in all LOCA sequences. He went on to say that although some air would be pulled into the RWT suction piping, it would not result in air being pulled into the safety pumps.

Q. DID NRC ACCEPT DR. HENRY'S CONCLUSIONS?

A. Yes. The NRC sent its own subject matter expert from its headquarters staff in Rockville, Maryland, Steve Unikewicz, to Palo Verde to review Henry's report. According to APS staff, Unikewicz accepted the technical analyses that were presented in the report but asked APS to have it revised so that it could stand alone. Dr. Henry provided Revision 1 of the report on November 17, 2005. The report expanded from 36 to 103 pages between the two editions and the conclusion was essentially unchanged, namely, "Dynamic hydraulic mechanisms associated with suction transfer are presented that demonstrate that the RWT suction flow terminates, and full suction flow is provided by the containment sump *prior to the point* where significant (bulk) quantities of air are entrained in the RWT suction and subsequently transported to the High Pressure Safety Injection and

Containment Spray pump suctions." In other words, the check valve closes before air can damage the pumps.

Q. WHEN DID THE TWO SHUTDOWN UNITS RETURN TO POWER OPERATIONS?

A. Units 2 and 3 returned to power shortly after midnight on October 21, based on the justification provided by Dr. Henry's first report.

Q. DO YOU HAVE ANY UNDERSTANDING OF WHY THE EXPERT FROM NRC HEADQUARTERS REQUESTED THAT THE REPORT BE MODIFIED AFTER THE UNITS HAD BEEN RESTARTED AND THE REVISED REPORT FILED ON THE PALO VERDE LICENSING DOCKET AT NRC?

A. My understanding is that the NRC Headquarters' project manager for Palo Verde told APS staff that he was requesting that the report be filed on the Palo Verde licensing docket (as opposed to simply letting the documents be filed in station records as the basis for the plant operability decisions that had been made) so that it would become available for NRC to use to "solve some issues at other plants." He also pressed them for the data that APS had obtained in tests it conducted in connection with the voided piping issue in 2004 to support its claim that pumps could function with the amount of air that was involved.

Q. PLEASE EXPLAIN WHY NRC WOULD WANT THAT INFORMATION PUT ON THE PALO VERDE LICENSING DOCKET.

A. Earlier in my testimony I described the process by which NRC addresses generic issues. In the case of its apparent concern with air entrainment in RWT suction piping, NRC would be expected to issue a Generic Letter if it was a safety issue of sufficient significance to require a new analysis to be performed, and potentially a design modification, as occurred at Palo Verde. For reasons unknown to me, the issue is being raised on a case-by-case basis rather than as a generic issue.

Q. YOU SAY THAT THIS AIR ENTRAINMENT ISSUE IS BEING PURSUED ON A CASE-BY-CASE BASIS. AT PAGE 35 OF ITS REPORT, GDS SEEMS TO AGREE WITH YOU BY PROVIDING A LONG QUOTATION FROM THE NRC'S JANUARY 27, 2006 INSPECTION REPORT THAT

CRITICIZED BUT DID NOT ISSUE A VIOLATION TO APS FOR NOT KNOWING ABOUT CERTAIN "OPERATING EXPERIENCES". WAS APS IMPRUDENT FOR NOT KNOWING OF THESE PREVIOUS REGULATORY EXPERIENCES?

A. I conclude that APS's lack of knowledge of these experiences was not because of imprudence and not from a lack of programs that keep the company current on developments in the industry. Rather, the lack of knowledge by APS owed to the obscurity of the information about these events and the failure of NRC to attach generic significance to them.

In the January 27, 2006 Inspection Report NRC staff referred to two other plants where NRC had raised the issue (i.e., a regulatory issue, not "operating experience"), namely, Brunswick and D.C. Cook, the former being a boiling water reactor compared to the PWRs at Palo Verde and the latter being a PWR with different reactor and containment designs than Palo Verde.

I have reviewed descriptions of the pump suction issues that NRC raised at those two plants. In the case of D.C. Cook, a contract inspector of the NRC raised a question about whether the containment sump would fill rapidly enough with water to be able to supply the required suction pressure for the ECCS pumps before the refueling water tank was empty and pump suction was switched to the sump. American Electric Power, the licensee for the Cook plant, could not answer the question quickly because it was beyond the original design basis of the plant. Accordingly, both units at Cook were shut down. Although the issue at Cook involved pump suction issues, it was different in significant ways from Palo Verde, namely, it involved a different postulation of circumstances leading to air entrainment in the RWT suction piping, it involved a different piping configuration (horizontal rather than vertical), and it involved a highly compartmentalized ice condenser pressure-suppression containment rather than a much larger and less compartmentalized dry containment like Palo Verde. (E-mail entitled "ASME

Study" from Jeffrey Clark, NRC Region IV, Chief of Engineering Branch 1, to Daniel Hautala, APS, November 2, 2005, transmitting an ASME paper from the Proceedings of the 2001 International Joint Power Generation Conference, New Orleans, June 4-7, 2001, "Air Entrainment in a Partially Filled Horizontal Pump Suction Line," R. C. Sanders, et al.)

The circumstances at Brunswick were even more remote from the Palo Verde situation. The experience was documented in an INPO Operating Experience Report dated November 10, 2003. In short, it involved potential air entrainment in the Condensate Storage Tank due to vortexing prior to completion of the auto transfer (on reaching low level in the condensate storage tank) of the suction of the high pressure coolant injection pump to the torus of the containment. (Brunswick is an old, small, boiling water reactor with a first generation pressure suppression containment that has no resemblance to the dry containment used at Palo Verde.)

APS had not reviewed reports of either the Cook or Brunswick experiences prior to the Fall 2005 Supplemental Inspection at Palo Verde. Neither of these reports would be expected to set off alarm bells at Palo Verde, or any of the other operating PWRs with large dry containments, because Brunswick is a boiling water reactor with a pressure suppression containment and Cook has an ice condenser containment. Thus, neither experience has direct applicability for large dry containments that are typical of the vast majority of PWRs. The NRC Supplemental Inspection Report of January 27, 2006 at pages 10 and 11 identified APS's failure to know of these experiences in advance of the inspection as a "performance deficiency" but did not identify it as either a finding or a violation.

It is instructive to note that no malfunction or other off-normal events were associated with either the Cook or Brunswick situations, so the experiences were regulatory experiences not operating experiences. Licensees depend primarily on NRC to use generic communications to inform them of new regulatory

requirements or new safety information flowing from regulatory experiences. NRC has not done so in the case of air entrainment in ECCS suction lines. Also, I do not fault APS staff for failure to know of the ASME publication associated with the Cook experience because of the large number of technical reports published, the relative obscurity of this particular conference, the lack of a nexus between the Cook design and the Palo Verde design, and the lack of notice of the importance the NRC staff or its consultants attached to the paper. Thus, I do not find that APS can be faulted for being unaware of or failing to take advantage of these two experiences before the RWT-related shutdown at Palo Verde.

Q. SUBSEQUENT TO RAISING IT AT PALO VERDE, HAS THE NRC RAISED THE RWT AIR ENTRAINMENT ISSUE ELSEWHERE?

A. Yes. After raising the RWT air entrainment issue at Palo Verde, Region IV inspectors raised it at San Onofre, a two unit nuclear station that was designed by Combustion Engineering and is operated by Southern California Edison. San Onofre is in the same peer group as and began operation a few years before Palo Verde. Edison was only able to answer the NRC's question without shutting down its station because APS supplied the Henry Report for Southern California Edison to use in answering the NRC's query.

Q. HAVE YOU RECENTLY LEARNED OF ANOTHER PLANT WHERE NRC RAISED AIR ENTRAINMENT ISSUES RELATIVE TO SAFETY SYSTEM PERFORMANCE?

A. Yes, I have learned in preparing for this testimony that on January 27, 2005, the same NRC contract inspector, Craig Baron, raised the issue of air entrainment on a special NRC "pilot inspection" at the Kewaunee nuclear power plant in Wisconsin. This was one of four pilot inspections of this type that includes challenges to the adequacy of the existing design basis. No such inspection has yet been conducted at Palo Verde. Baron asked if air entrainment had been considered in the design of the auxiliary feedwater (AFW) system at Kewaunee. After several days of analysis by the licensee, the unit was shut down because a way to get air into the pumps was discovered that had not been considered in the original design. On December

22, 2005, the Wisconsin Public Service Commission found "that the costs associated with [this outage] were not imprudently incurred because the record does not support the allegations [by witness William R. Jacobs, Jr. of GDS Associates, Inc.] that revisions to the AFW system should have been made in the past in order to avoid the issues resulting in the outage." (RJM_WP12RB, pg. 24)

Q. WHAT IS THE SIGNIFICANCE OF THIS INFORMATION ABOUT HOW THE AIR ENTRAINMENT ISSUE WAS RAISED AT PALO VERDE AND OTHER NUCLEAR POWER PLANTS TO THE QUESTION OF THE PRUDENCE OF APS?

A. I conclude that APS was not imprudent for not anticipating the surprise question from contract inspector Baron because

- APS had no reasonable way to be informed of the regulatory issues raised by NRC at Brunswick and Cook or of the ASME paper that was associated with the Cook experience, and
- APS had no reasonable way to be informed of the air entrainment issue raised by NRC contract inspector Baron at Kewaunee on January 25, 2005 as part of a new inspection initiative NRC was undertaking on a pilot basis.

The fact that NRC inspectors later raised the issue at San Onofre is further proof to me that the inspectors are following an unauthorized, case-by-case imposition of a new requirement.

The actions by the NRC inspectors to raise the dynamic aspects of the switchover of ECCS suction in PWRs from the RWT to the sump constitute a backfit because such effects were not considered in the original licensing basis for these plants. Disregard for the original licensing basis is one of the complaints that the nuclear industry has voiced about NRC implementation of the reactor oversight process, as I described in Section 4, above. Additionally, this backfit was not done in accord with NRC procedures, which would have required it to be technically justified as being required for assurance of adequate protection of public health and safety. It also would have had to be approved by senior management in NRC's Office of

Nuclear Reactor Regulation. There is no reasonable way APS or any other NRC licensee can anticipate spontaneous backfits of this type, conducted outside of NRC's rules and procedures.

Nonetheless, after the new question about dynamic effects was raised at Palo Verde, APS had to either answer it on the spot or shut the operating units down until it was answered. The latter approach was the only one available to APS because of the way the issue was raised by the NRC, i.e., without advance notice of the backfit, and because of the technical complexity of the method required to be used to answer the question. Thus, APS actions were prudent, both before and after the question was raised. Also, Region IV Administrator Mallett in his January 26, 2006 discussion with the ACC gave this event as an example of APS actions that "have been in compliance with our requirements and timely and thorough in response to events and emergent issues." (Transcript page 19 – 20)

In 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.

7. SUMMARY OF CONCLUSIONS

Q. WHAT GENERAL CONCLUSIONS HAVE YOU MADE ABOUT THE NRC REGULATORY PROCESS THAT RELATE TO THIS PROCEEDING?

A. I have made the following conclusions about the NRC process for overseeing reactor safety as it bears on the issues of this case:

- There are differences between the standards the NRC employs and the

standards applicable to a prudence determination.

- The NRC's first and foremost requirement is that nuclear plants operate safely, and there is no dispute that Palo Verde has done so.
- The NRC does not consider whether utility management's actions were reasonable at the time such actions were taken, unlike economic regulatory bodies such as the ACC. Rather, the NRC uses hindsight to continually improve safety performance and has done so successfully over the years. NRC actions and documents generally can be relevant only to the prudence of utility management actions taken after learning of the NRC action or receiving the NRC document in question.
- The NRC license for every nuclear power plant in the U.S. contains technical specifications with prescriptive rules concerning how operability of safety equipment must be quickly determined whenever questions are raised about conformance with those specifications.
- NRC normally uses Generic Letters or Information Notices for new safety issues, and industry depends on NRC to do so, but they have not done so in the case of the RWT air entrainment issue that NRC inspectors brought to Palo Verde in October 2005.
- NRC has rejected some of its past efforts, such as the Watch List, as being unduly subjective and lacking in guidance to licensees.
- The current Reactor Oversight Process is generally recognized as a considerable improvement over the past, but the NRC and the stakeholders in the process have recognized that it has weak areas, including areas that bear on NRC assessments of Palo Verde, e.g., NRC inspector acceptance of the original design basis of a plant and the role of NRC's identification of cross cutting issues.

Q. WHAT CONCLUSIONS HAVE YOU FORMED REGARDING THE SAFETY OF THE PALO VERDE UNITS DURING THE TIME PERIOD 2004 TO 2005?

A. There is no indication in the NRC correspondence, in my interviews with APS

staff, or in APS documents I reviewed that the Palo Verde's units were operated unsafely at any point in this time period. On January 26, 2006, Bruce Mallett, Administrator of NRC Region IV addressed the ACC and made the same conclusion.

Q. WHAT GENERAL CONCLUSIONS HAVE YOU MADE ABOUT THE PERFORMANCE OF THE PALO VERDE STATION?

A. The Performance Indicator data reveal that Palo Verde has performed within industry norms when compared to its peer group, other PWRs and the nuclear industry. More specifically, the performance of the Palo Verde units was average or above in 16 of the 18 performance indicators that I examined from 1995 to 2005. Palo Verde's performance relative to its peers, PWRs and the industry slipped in 2004 and 2005, but all plants have their ups and downs. To account for this, I recommend the approach suggested by the ACC in a previous ruling, i.e., one must look at both a plant's "successes" and "failures" in order to perform a fair review. The NRC performance indicator data show Palo Verde's performance to be superior when viewed over the period 1995 to 2005.

Q. WHAT CONCLUSIONS HAVE YOU FORMED ABOUT APS'S REGULATORY PERFORMANCE?

A. Palo Verde was treated by NRC as a superior plant under NRC's old process for overseeing nuclear power plants. It received SALP scores that averaged 1.5, was never on the NRC's Watch List, never received a Trending Letter, and never received a shutdown order.

The new reactor oversight process that NRC implemented in 2000 provides four levels of increasing scrutiny of licensees above the normal level of NRC oversight. Although Palo Verde is now at the second level of increased oversight, it is there because of an action that was taken in 1992, and there are indications that it will successfully return to the lowest level of NRC scrutiny. The vast majority of nuclear power plants have undergone increased inspection efforts by NRC at some

time in their life.

NRC has raised concerns with cross-cutting aspects of Palo Verde operations (human performance and problem identification and resolution). These issues did not cause the yellow cornerstone or the outages experienced in 2005. NRC has recently acknowledged difficulty in understanding and dealing with cross-cutting findings and in early 2006 proposed new ways of dealing with them.

The Performance Improvement Process underway since October 2005 is beyond NRC's expectations for a station at Palo Verde's current level of performance. The PIP is typical of improvement programs that have been implemented at many operating plants, usually when they were experiencing worse performance problems than Palo Verde. Such processes always involve self-assessments that use hindsight to identify opportunities for improvement, and they often do so in harsh terms that are expected by NRC and the industry.

Q. WHAT CONCLUSION HAVE YOU FORMED ABOUT ECONOMIC PERFORMANCE INCENTIVES?

A. From its statements made in 1991 and 2001 summarized in my foregoing testimony, I conclude that the NRC is concerned that ill-chosen economic performance incentives set by State public utility commissions could create disincentives to safe operation of nuclear power plants. Accordingly, the NRC has offered advice in its statements that may be helpful in selecting performance standards that promote both safe and economic performance and in avoiding performance standards that would be counter to safety. The GDS recommendation to apply such a standard to Palo Verde is not consistent with the NRC advice on this matter. Finally, I conclude that an economic performance standard is not needed for Palo Verde at this time based on its long-term record of superior performance and the Performance Improvement Program now underway to ensure such performance in the future.

Q. WHAT CONCLUSIONS HAVE YOU FORMED REGARDING THE TWO-UNIT OUTAGE ASSOCIATED WITH THE AIR ENTRAINMENT ISSUE THAT THE NRC RAISED FOR THE REFUELING WATER TANK?

A. I have formed several conclusions for the RWT-related shutdown of Units 2 and 3 for nine days in October 2005, as follows:

- APS responded reasonably to the line of inquiry about air entrainment in the suction piping from the RWT by showing proof that air entrainment had been considered in a static calculation recorded in the original licensing basis of the plant.
- APS could not have anticipated that the contract inspector would then have questioned the adequacy of the original design by asking if there was a dynamic analysis, because static analysis was the basis for design and licensing of ECCS suction lines for all pressurized water reactors in the U.S., not just Palo Verde.
- Thus, the question was typical of one of the problems that have been identified to the NRC by the industry in its annual feedback associated with the reactor oversight process, namely, the inspection part of the reactor oversight process has begun to address the adequacy of the original licensing process wherein the safety basis was established;
- However, once NRC raised the question, APS was required to address it. When APS could not answer the question in the time prescribed by the plant's Technical Specifications, the two operating units had to be shut down until the answer could be developed. The answer required extending the state of the art for such analysis.
- As Region IV Administrator Mallett told the Arizona Corporation Commission on January 26, 2006, the issue was a new question, one that NRC and APS had not come across before, APS did what NRC expected, and NRC did not determine that APS should have found the issue beforehand.
- The units restarted and continue to run today without any changes in the

equipment, training or procedures associated with the systems in question.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment RJM-1RB

ATTACHMENT RJM-1RB. ACRONYMS

ACC	Arizona Corporation Commission
AEC	Atomic Energy Commission
AFW	Auxiliary Feedwater (System)
AIT	Augmented Inspection Team (from NRC)
APS	Arizona Public Service Company
BNL	Brookhaven National Laboratory
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CE	Combustion Engineering
CFR	Code of Federal Regulations
CRDR	Condition Report/Disposition Request
CSS	Containment Spray System
ECCS	Emergency Core Cooling System
EPA	Environmental Protection Agency
FSAR	Final Safety Analysis Report
HPCI	High Pressure Coolant Injection (part of ECCS on BWR)
HPSI	High Pressure Safety Injection (a subsystem of the ECCS on a PWR)
I&C	Instrumentation and Control (Systems)
IEAL	International Energy Associates Limited
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
OCS	Operations Computer Systems
ORR	Operational Readiness Review
PI&R	Problem Identification and Resolution
PVNGS	Palo Verde Nuclear Generating Station
PWR	Pressurized Water Reactor
RAS	Recirculation Actuation Signal
RHR	Residual Heat Removal
ROP	Reactor Oversight Process (of the NRC)
RWT	Refueling Water Tank
SIS	Safety Injection System (part of ECCS, another name for HPSI)
UFSAR	Updated Final Safety Analysis Report

Attachment RJM-2RB

ATTACHMENT RJM-2RB. RESUME OF ROGER J. MATTSON

Summary

Forty-two years in nuclear safety and related fields
Thirty-nine years in nuclear facility licensing
Expert in nuclear safety, licensing and risk management

Education

Ph.D., Mechanical Engineering, University of Michigan, 1972
M.S., Mechanical Engineering, University of New Mexico, 1966
B.S., Mechanical Engineering, University of Nebraska, 1964, cum laude

Qualifications

Reactor Licensing – Dr. Mattson participated in the licensing programs of the U.S. government for 17 years, the last 7 directing the technical review of applications to construct and operate nuclear power plants and to amend their operating licenses. The scope of his responsibilities included reactor systems, nuclear fuel and core design, balance of plant, associated structures, and electrical, mechanical, and fluid systems; radiation protection and emergency preparedness; and geology, seismology, and meteorology. He introduced probabilistic risk assessment and TMI requirements into the licensing process. He has participated in technical safety reviews of every U.S. nuclear power plant. Since leaving government service, he has helped NRC licensees implement regulatory requirements and assisted NRC with new rules for advanced reactors and life extension/license renewal. He assisted DOE in designing a system of safety criteria for tritium production reactors that met or exceeded requirements of NRC. In 2006 he assisted DOE in an independent review of two advanced, commercial nuclear power plant designs that are to be submitted to the NRC for combined construction permits and operating licenses. In 2005 and 2006, he assisted Idaho National Laboratory in upgrading the Advanced Test Reactor in comparison to commercial reactor safety standards, in a review of safety and licensing aspects of the Next Generation Nuclear Plant that utilizes high temperature gas technology, and in a review of the development plan for the Global Nuclear Energy Partnership.

Non Reactor Nuclear Facility Licensing – In addition to reactor licensing experience Dr. Mattson has experience with licensing projects for non reactor facilities, including the setting of NRC licensing standards for safety, radiation protection, and environmental protection of fuel cycle facilities, including waste management facilities; representation of NRC in EPA's rulemaking for uranium fuel cycle standards; assistance to nuclear power plants in utilization of dry cask storage for spent nuclear fuel destined for shipment to DOE's Yucca Mountain facility; independent analysis of the licensing history of decommissioned uranium and mixed oxide fuel fabrication plants; and independent review of the test phase plan for the Waste Isolation Pilot Plant at Carlsbad.

Nuclear Safety – Dr. Mattson conducted safety reviews for AEC and NRC for 17 years covering more than 110 nuclear power plants and other radiological facilities. His nuclear safety review experience includes all types of safety systems. He assisted the International Atomic Energy Agency by co-chairing the development of safety principles for nuclear power plants after the accident at Chernobyl (INSAG-3, updated to INSAG-12) that were promulgated to all member nations for implementation. He developed NRC's new requirements after the accident at Three Mile Island in 1979. He has served as a consultant to DOE and its operating contractors in overseeing safety of nuclear facilities, including Rocky Flats, Savannah River Plant, Los Alamos National Laboratory, Pantex Plant, Mound Laboratory, Idaho National Laboratory and Livermore National Laboratory. He has served on nuclear safety review boards for five operating nuclear power plants, the N Reactor at Hanford, the Rocky Flats Environmental Technology Site and the DynEx Program

at Los Alamos. He oversaw two environmental radiochemistry labs involved in radioactive waste management. He assisted in streamlining the safety authorization basis for decommissioning of Rocky Flats.

Safety Analysis – Dr. Mattson developed and applied safety analysis techniques for nuclear facilities, including plant dynamic analysis, systems interaction studies, probabilistic safety (risk) assessment, reliability analysis, hazards analysis, technical safety appraisals, operational readiness reviews, independent design reviews, fire protection reviews, and management reviews. He pioneered use of independent analyses by nuclear safety oversight groups in the United States and abroad. He assisted in NRC analysis of the TMI accident in 1979 and the Chernobyl accident in 1986, including plant failure modes and effects analysis. He has reviewed Hazards Analysis Reports and Safety Analysis Reports and developed Safety Evaluation Reports for a range of private and government facilities.

System Safety Appraisals – Dr. Mattson participated in safety analysis and field reviews of nearly 150 nuclear facilities in the United States, Europe, the former Soviet Union, China, Taiwan and Korea. Such reviews included licensing reviews, hazard assessments, inspections of construction progress, incident response, preparation for litigation, independent design reviews, safety system functional inspections, safety and security vulnerability assessments, and operational readiness assessments.

Regulatory Policy – Dr. Mattson developed and applied regulatory policies of AEC, NRC, EPA, and DOE. He has conducted policy studies in nuclear safety, radiation protection, environmental monitoring, worker protection, standardized design, independent commissions, and security of nuclear facilities and materials. He assisted DOE and its operating contractors with order compliance for advanced and operating reactors, plutonium manufacturing plants, and nuclear weapons facilities. He participated in the Nuclear Utility Safety Standards program of the International Atomic Energy Agency and assisted development of regulatory policy for nuclear facilities in China, Taiwan, Japan, Korea, Spain, Russia, Ukraine, Kazakhstan, and Egypt.

Operational Readiness Reviews - In 1980 Dr. Mattson organized the transfer of operational readiness review (ORR) practices from NASA and DOD to the NRC for general application in the nuclear industry. He has reviewed the results of ORRs on a number of commercial and government facilities and has led ORRs at Limerick 2 nuclear power plant, the plutonium chemistry facility at Rocky Flats Plant, and K-Reactor at Savannah River Plant. He was the senior advisor to DOE managers in their first application of ORR techniques in 1990, developing the first Criteria and Review Approach Document and assisted later in the drafting of predecessor requirements to DOE Order 425.1A. He assisted a review of Kaiser-Hill's ORR program at Rocky Flats.

Decommissioning – Dr. Mattson oversaw the decommissioning of two licensed radiochemistry laboratories in the private sector. He advised the Department of Energy on approaches for decommissioning of plutonium contaminated ductwork at Rocky Flats Production Plant and Hanford Plutonium Finishing Plant. He assisted in streamlining the safety authorization basis for facilities undergoing decommissioning at Rocky Flats Environmental Technology Site and served as Vice Chairman of the Nuclear Safety Review Board for the Rocky Flats decommissioning project. He has reviewed decommissioning activities for NUMEC/B&W uranium and mixed oxide fuel fabrication facilities in preparation for litigation. He led an independent oversight team in selection of the decommissioning approach for Maine Yankee nuclear power plant and assisted the President of Maine Yankee and Connecticut Yankee in management of decommissioning activities. He participated in a study of alternative decommissioning approaches for Millstone 1 nuclear power plant.

Emergency Preparedness – Dr. Mattson assisted in response to the accident at Three Mile Island and several other nuclear incidents. He directed the NRC's radiation protective measures team in the headquarters emergency response organization. He coordinated EPA's national radiation emergency response network. He has participated in emergency response exercises for commercial and government-owned radiological facilities in a number of states. He developed federal regulations for radiological emergency preparedness and directed their implementation. He helped to establish the earliest interagency coordination program for response to clandestine fission explosives.

Criticality Safety – Dr. Mattson participated as senior safety expert in criticality safety assessments of DOE's plutonium facilities at Hanford, Rocky Flats and Los Alamos. He assisted in a root cause review of an intentional violation of criticality limits at Rocky Flats. He conducted independent reviews of the criticality safety program at Rocky Flats and has reviewed the criticality safety programs at other nuclear materials processing facilities.

Radiation Protection – Dr. Mattson has managed radiation protection activities as an employee of the AEC, NRC and EPA and has assisted DOE, NRC, and private companies in implementing radiation protection measures for workers and the public. He chaired the radiation protection committee of a radiochemistry laboratory, led the development of Federal radiation guidelines for all licensed radiological facilities in the U.S., including those related to 10 CFR Parts 20, 50, and 70, and 40 CFR Part 190. He managed the review of radiation protection measures for U.S. nuclear power plants. He reviewed radiation protection programs for DOE and commercial nuclear facilities.

Environmental Protection – Dr. Mattson wrote environmental impact statements and developed federal guidelines to implement Clean Air, Clean Water, Safe Drinking Water, and National Environmental Policy Acts. He has managed consulting and laboratory services in environmental risk management. He developed and implemented environmental standards for ionizing and nonionizing radiation. He led historical reconstructions of radioactive source terms for several nuclear facilities following guidelines of the National Academy of Sciences.

Quality Assurance – Dr. Mattson implemented federal regulations governing nuclear quality assurance by reviewing license applications for nuclear power plants and assisting oversight of QA programs at nuclear plants under construction and in operation. He assisted Dupont Corporation in the application of nuclear QA techniques to the Savannah River Plant. He assisted DOE and its prime contractors in implementing nuclear QA programs for nuclear facilities. He has performed independent analysis of the effects of QA requirements on safety and cost of nuclear facilities.

Expert Testimony – Dr. Mattson has testified on the effects of regulation on safety and costs of nuclear facilities before the United States Congress, several Presidential Commissions, the Nuclear Regulatory Commission, the Defense Nuclear Facilities Safety Board, the Advisory Committee on Nuclear Facility Safety, the Advisory Committee on Reactor Safeguards, Federal and State Courts, panels of the American Arbitration Association, and State Public Utility Commissions.

Security – Dr. Mattson developed NRC's security standards for the commercial nuclear industry in the mid 1970s and managed security-consulting services in the 1980s. He has written threat definitions and participated in security response for nuclear facilities and materials. From 1987 to 2002 he oversaw security equipment research by SCIENTECH for a range of U.S. government clients.

Site-Related Disciplines – Dr. Mattson led the siting standards development effort for NRC and

assisted the International Atomic Energy Agency in its development of siting standards for nuclear power plants. The standards addressed site safety, geology, meteorology, hydrology, demographics and environmental protection.

Employment

Independent Consultant, 2002 – present time, Risk Management, Licensing, Safety, Quality, Security, and Management Assessments

SCIENTECH, Inc., Senior Vice President, 1987-2002, Safety Analysis and Appraisals, Operational Readiness Reviews, Nuclear Safety and Licensing, Strategic Planning, Decommissioning, Security

International Energy Associates Limited, Engineer then President, 1984 -1987, Nuclear Safety and Licensing, Management, Litigation Support, Security

U.S. Nuclear Regulatory Commission, Director of Systems Integration, Nuclear Reactor Regulation, 1981-1984, Nuclear Safety and Licensing, Regulatory Policy, Emergency Preparedness, QA, Radiological Protection

U.S. Environmental Protection Agency, Director, Radiation Surveillance, Radiation Programs Office, 1980-1981, Radiological Protection, Emergency Preparedness, Management

U.S. Nuclear Regulatory Commission, Director of Systems Safety, Nuclear Reactor Regulation, 1977-1980, Nuclear Safety Regulation, TMI Response

U.S. Nuclear Regulatory Commission, Director of Site, Health, Safeguards Standards, 1975-1977, Environmental and Radiological Protection, Emergency Preparedness, Site Related Disciplines, Security

U.S. Atomic Energy Commission, Engineer then Supervisor, 1967-1975, Safety Analysis, Nuclear Design, Assistant to Commissioner, Security of Nuclear Materials and Facilities

Sandia Corporation, Engineer, 1964 -1967, Hardware Design, Safety Analysis, Thermal-Hydraulic Analysis

Honors

NRC Distinguished Service Award, 1980, for work on TMI accident
NRC Meritorious Service Award, 1976, for leadership in standards development
NRC and AEC letters of commendation for performance on various task forces
National Science Foundation Research Assistantship, 1971
Sigma Xi (Science Honorary Society)
Pi Tau Sigma (Mechanical Engineering Honorary Society)
Pi Mu Epsilon (Mathematics Honorary Society)
Sigma Tau (Engineering Honorary Society)

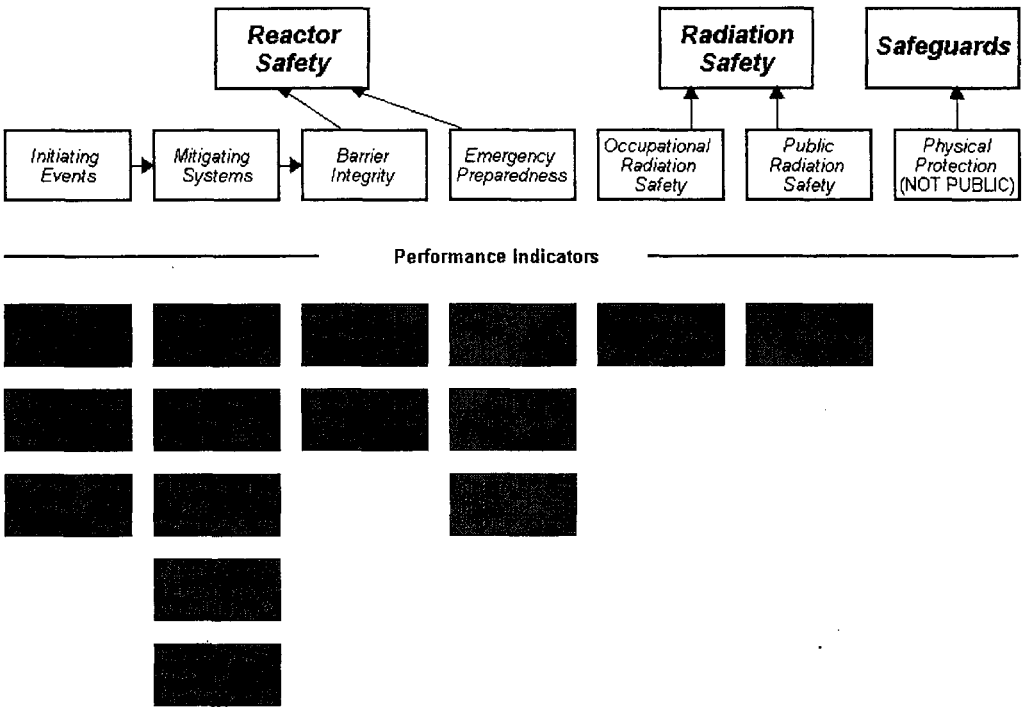
Attachment RJM-3RB

ATTACHMENT RJM-3RB. PERFORMANCE INDICATOR DATA

The NRC established a Performance Indicators Program in 1986 to provide data for early indication of declining trends in plant performance. Based on experience with its use, the first performance indicator program was discontinued in 1999 and replaced in 2000 by the Reactor Oversight Process that included another set of performance indicators. NRC has used performance indicators from 1986 to today to help identify issues or circumstances that the NRC should examine further, i.e., where to apply its inspection resources.

The first NRC Performance Indicator Program monitored plant performance in the following areas: automatic scrams while critical, safety system actuations, significant events, safety system failures, forced outage rate, and equipment forced outages per 1,000 critical hours, collective radiation exposure and the causes of Licensee Event Reports (LERs). The new performance indicators are arrayed in seven cornerstones of safety namely, Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Occupational Radiation Safety, Public Radiation Safety, and Physical Protection.

Under the Reactor Oversight Process, color-coded summaries of performance indicators and inspection findings are provided quarterly for each plant in what NRC calls action matrices. The action matrix for a particular plant determines NRC's regulatory response to current circumstances. If the findings in a matrix are all green or if there are no findings, then the NRC applies its baseline inspection program. If the findings in the matrix are not all green but include some white, yellow or red cornerstones, then the NRC applies additional inspection resources. In rare instances when actions different from those indicated by the Action Matrix are needed, NRC may increase or decrease its response. Since 2000, these deviations have been to provide heightened NRC oversight at five nuclear power stations, Davis-Besse, Salem, Hope Creek, Indian Point 2 and Point Beach. The NRC's Performance Indicator Action Matrix for Palo Verde Unit 1 for the last quarter of 2005 is shown below.



Performance indicators can be compared among plants of similar vintage and design that the NRC has grouped into "peer groups." The performance indicators for particular plants can also be compared to their generic design type (pressurized water reactors or PWRs in the case of Palo Verde) and to the entire industry. Such comparisons aid the assessment of Palo Verde's performance against industry performance norms.

The charts provided below graphically depict Palo Verde's performance for each of the performance indicators that I chose. I chose indicators that bear on the reliability and safety of operations. I left out those relating to emergency preparedness and security. I have provided a definition and a chart for each of the indicators. Each chart shows by year the average performance of the Palo Verde plants and the performance of other plants appropriate for comparisons for that indicator. It is important to remember as one looks at these charts that at any given point in time, say 1998, the NRC and the managers of Palo Verde would have only been able to utilize this information in hindsight.

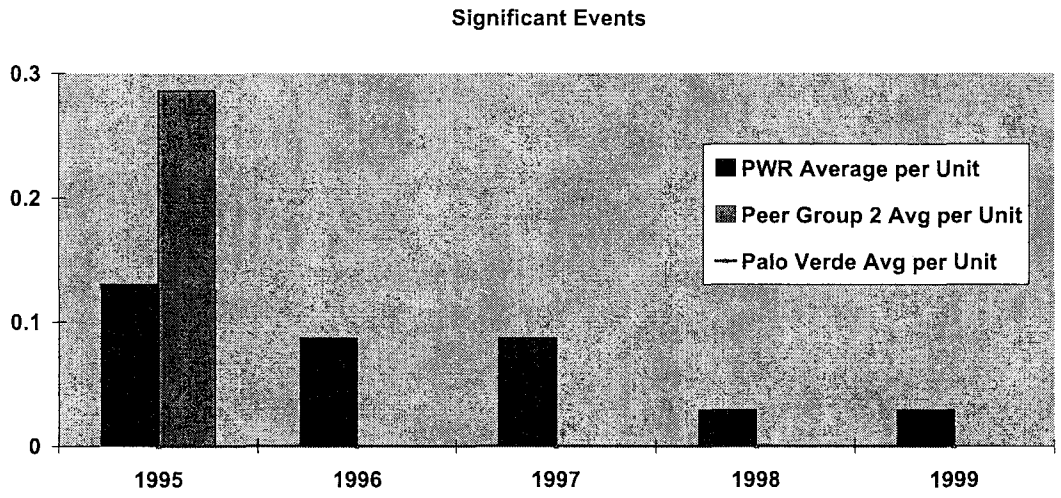
In sum, there are 18 indicators, some treating similar variables over the two periods, 1995 to

1999 and 2000 to 2005. The average performance of the Palo Verde units meets or exceeds the average performance of the PWRs or all nuclear power plants for 16 of these 18 indicators. The average performance of Palo Verde is better than its peer group for 15 of the 18 indicators. I made these comparisons on a year-by-year basis, not accounting for how much the Palo Verde performance was under or over the comparison groups in any one year.

The performance in each of these 18 areas is described in the following numbered paragraphs.

1. Significant Events

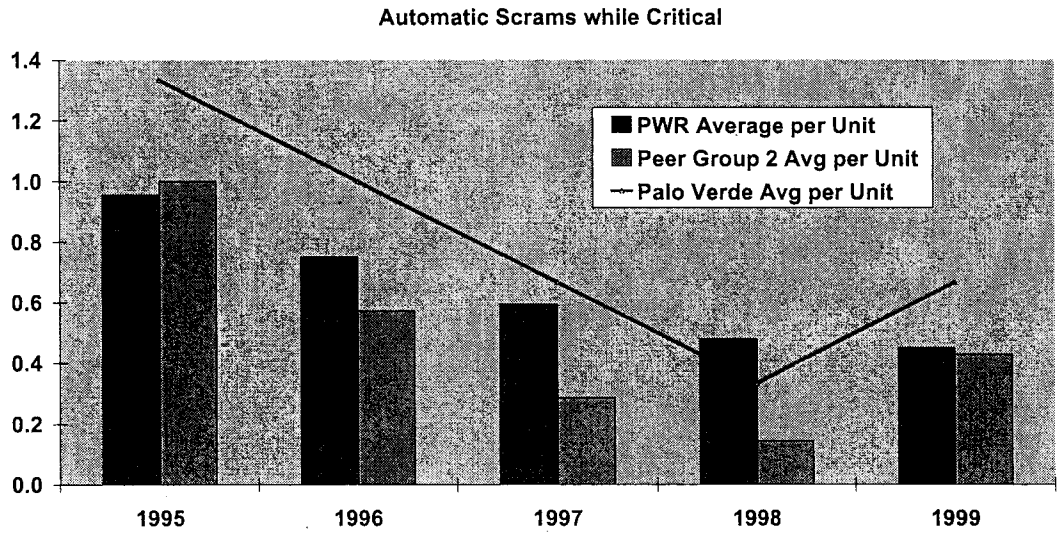
This indicator is the total number of events during the year that directly challenged the safety of the unit, such as degradation of important safety equipment, unexpected plant response to a transient, degradation of fuel integrity or the primary pressure boundary, or reactor scram with complications. On average, between 1995 and 1999, U.S. nuclear units experienced one significant event approximately every 10 years. The Palo Verde Units experienced none of these events in that time period, performing better in this category than their peer group and the other PWRs, as illustrated by the following chart. NRC eliminated this indicator when the new ROP came into being in 2000.



2. Automatic Scrams While Critical

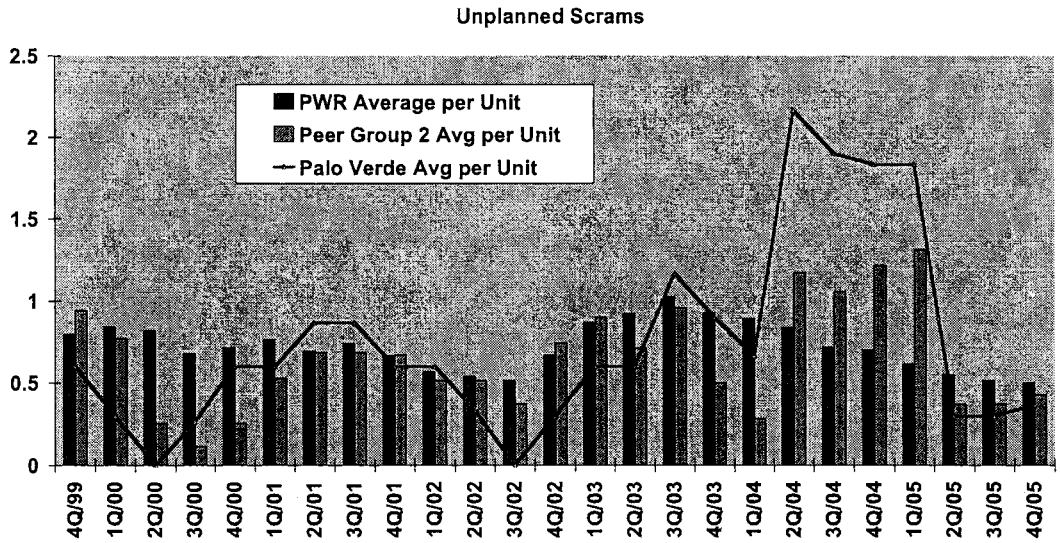
This indicator is the total number of unplanned automatic reactor scrams that occur while the reactor is critical and that automatically and promptly shut the reactor down. Such scrams require the reactor operators and the plant equipment to perform in a stressful and off normal manner,

thus providing a challenge to plant safety. The reactor is said to be critical when it is being started up and when it is in power operation. This indicator is one way to track how often plant safety is challenged by unanticipated events. Palo Verde Units 1, 2 and 3 had more scrams than both their peer group and the other PWRs during the period 1995 to 1999, as shown in the following graph. This indicator was dropped in 2000 with the advent of the new ROP and replaced by another indicator called Unplanned Scrams.



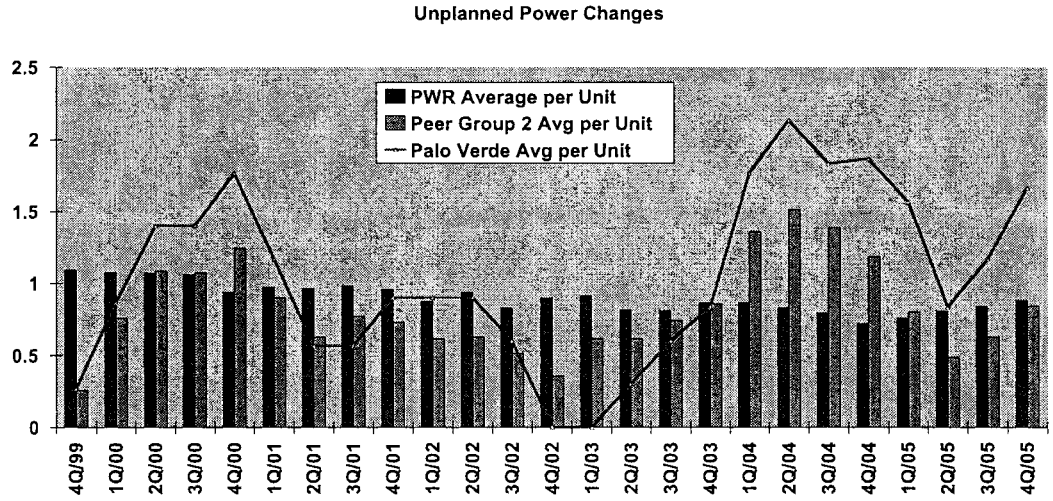
3. Unplanned Scrams

This indicator was adopted by NRC in 2000 and is an input to the Initiating Events Cornerstone. It is similar to the automatic scrams while critical indicator described above, but includes unplanned manual scrams. The indicator is equal to the number of unplanned scrams while the reactor was critical in the previous 4 quarters, times 7000 hours, divided by the number of hours critical in the previous 4 quarters. As shown in the following chart the Palo Verde units averaged slightly better than their peers and other PWRs for this indicator over the period 2000 to 2005. The graph illustrates the fact that once a unit has a failure of this type, the indicator stays high for four quarters (from the second quarter of 2004 to the first quarter of 2005, for example). The high values in 2004 reflect the loss of offsite power event that led to the trip of all three units, plus trips in individual units in May, June and July.



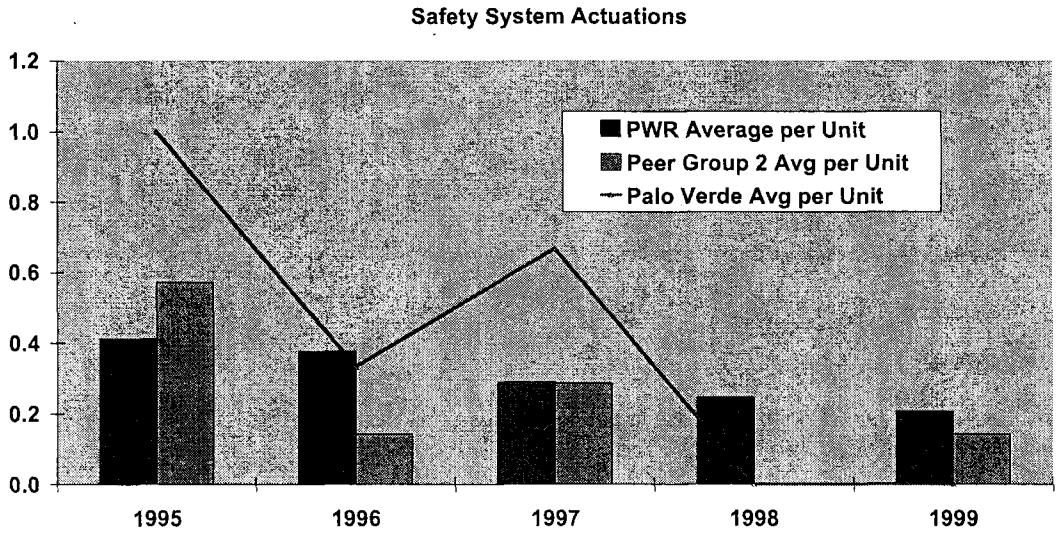
4. Unplanned Power Changes per 7,000 Critical Hours

This indicator was created at the time the ROP was initiated. It monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. It is equal to the number of unplanned power changes in reactor power greater than 20% of full power over the previous 4 quarters, times 7,000 hours, and divided by the total number of hours critical in the previous 4 quarters. As shown in the following graph, since the indicator was created and through the fourth quarter of 2005, the Palo Verde Units on the average performed equal to or better than the average of all PWRs 13 quarters out of 25, and 8 out of 25 when compared to their peer group. This is another indicator whose definition causes a high reading for each such power change to persist for 12 months.



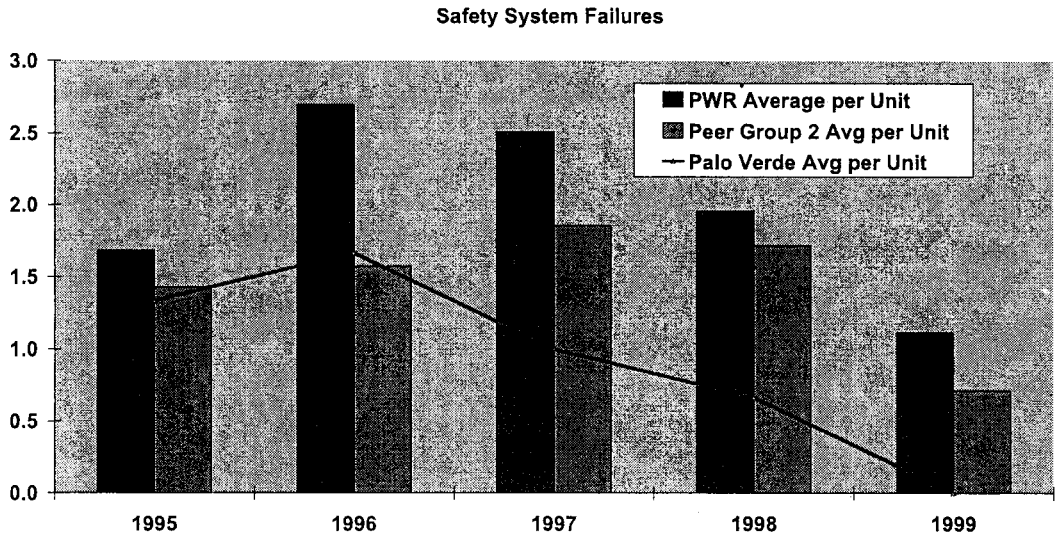
5. Safety System Actuations

This indicator combines manual and automatic actuations of the logic or equipment of either certain Emergency Core Cooling Systems or the Emergency AC Power System. It includes both faulty and authentic actuations. It is a measure of how frequently safety systems are being challenged – the more frequent the challenge, the greater the likelihood of eventual failure. The Palo Verde Units had a better than average number of safety system actuations compared to other PWRs from 1995 to 1999 and slightly worse than the average of their peer group, as shown in the following graph. The NRC eliminated this indicator when the new ROP was initiated in 2000.



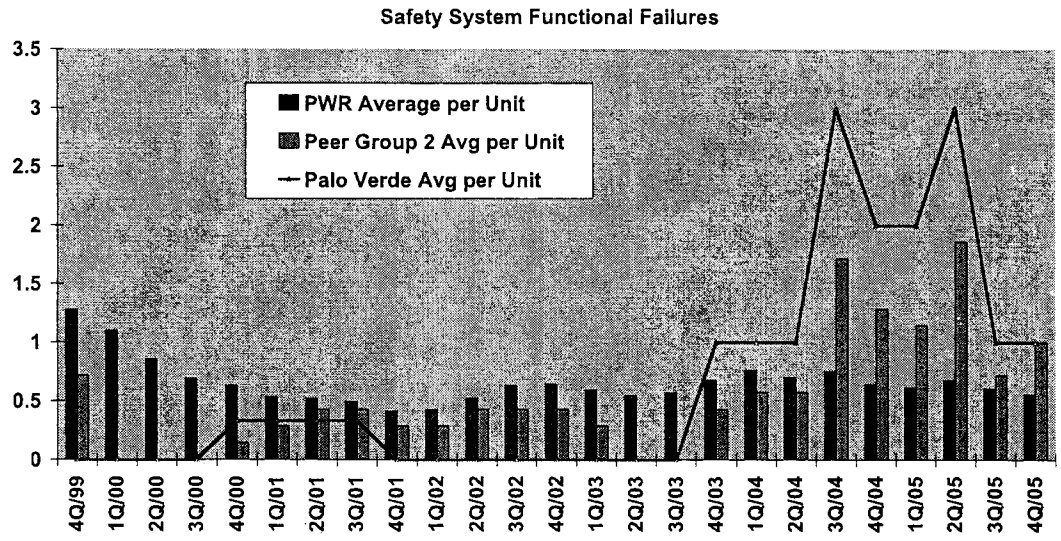
6. Safety System Failures

These are events or conditions that could prevent the fulfillment of the safety function of structures, systems or components related to safety. This indicator includes failures on demand and failures during testing. It is a measure of how well the safety equipment in a plant is designed and maintained. As shown in the following graph, the Palo Verde Units performed better than both their peer group and other PWRs for this indicator for the period 1995 to 1999. In 2000, with the advent of the ROP, an indicator called Safety System Functional Failures replaced this indicator, as discussed next.



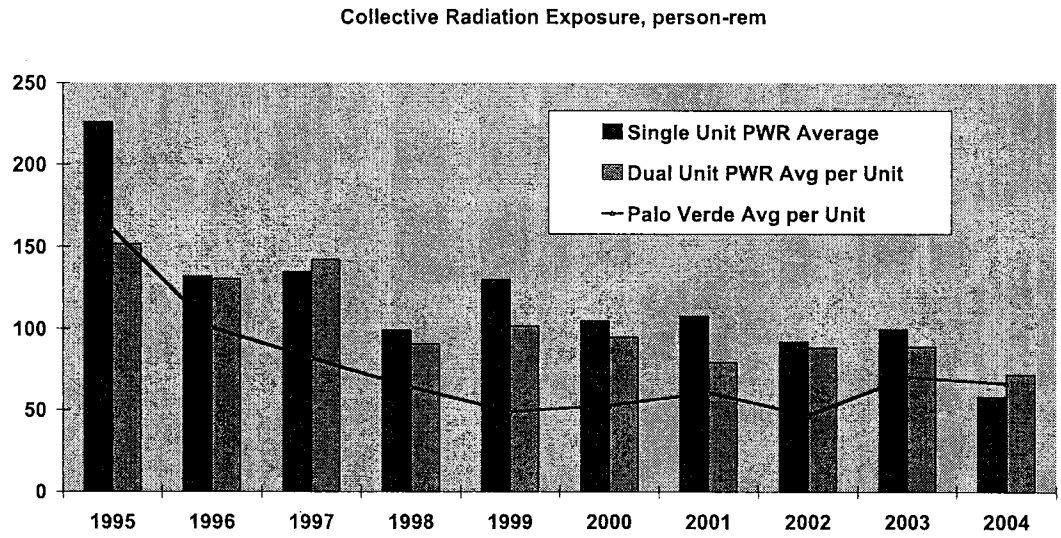
7. Safety System Functional Failures

This indicator is an input to the Mitigating Systems Cornerstone in the NRC's Reactor Oversight Process. It is equal to the number of events or conditions in the previous 4 quarters that prevented or could have prevented the fulfillment of the safety functions of reactor shutdown, removal of residual heat, control of radioactivity releases, and mitigation of accident consequences. The Palo Verde Units on the average have equaled or outperformed other PWRs 16 quarters out of the 25 that this indicator has been used, and their peer group 15 out of 25. The following graph again illustrates the fact that once a unit has a failure of this type, the indicator stays high for four quarters. In the fourth quarter of 2003 the containment pedestal cranes were found to have a seismic qualification issue in all three units. The high number of failures that show up in this indicator at Palo Verde in the third quarter of 2004 relate to the voided sump suction lines and the loss of offsite power that both affected all three units. Similarly, the flattening of the Palo Verde line late in 2005 is related to the declared inoperability of the refueling water tank in the fourth quarter of 2005.



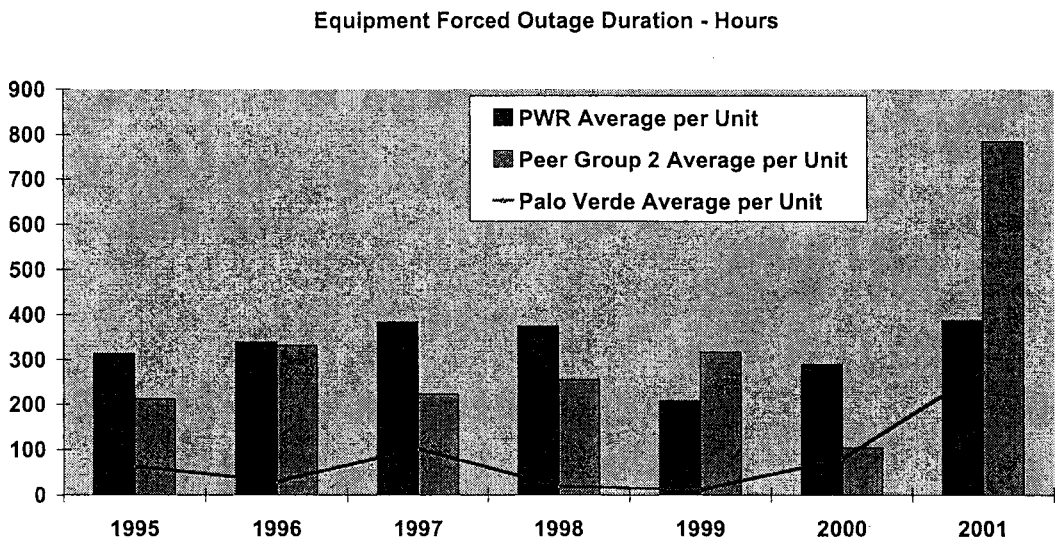
8. Collective Radiation Exposure

This indicator is the total radiation dose accumulated by plant personnel. It indicates the effectiveness in planning and performing work in a manner that minimizes exposure of workers to radiation. It also is an indicator of how well the physical condition of a unit is maintained as it ages. Between 1995 and 2004, the last year for which data are available, the average exposure for the Palo Verde Units generally was better than the PWR averages for both single and dual unit plants, as shown in the following graph.



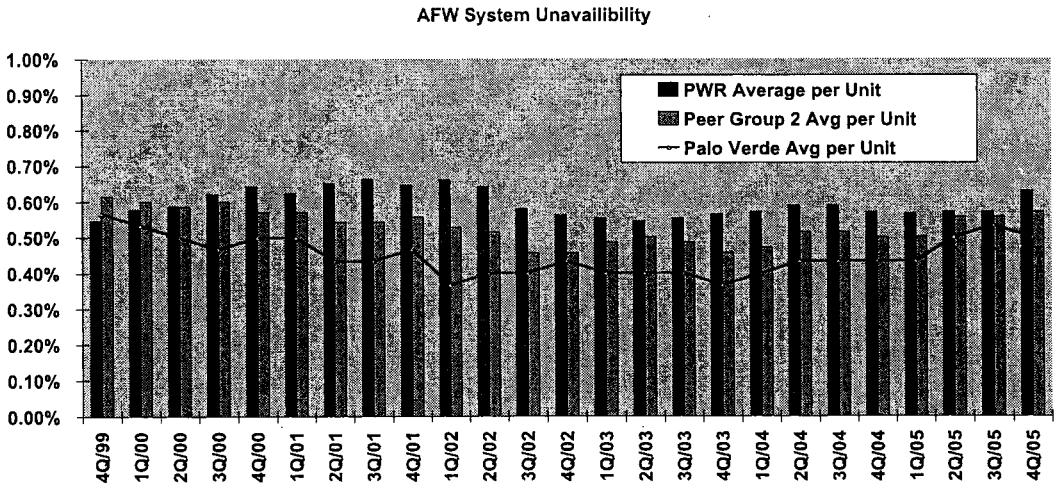
9. Equipment Forced Outage Duration

Equipment Forced Outage Duration is the number of hours of forced outage of safety equipment. For the period 1995-2001, the Palo Verde Units had average equipment forced outage durations that were better than their peers and the other PWRs, as shown in the following graph. This performance indicator was eliminated in 2000 with the advent of the ROP.



10. Safety System Unavailability

In 2000 with the advent of the ROP the Equipment Forced Outage indicators of the NRC were replaced by indicators of the unavailability of four key safety systems, namely, auxiliary feedwater, residual heat removal, high pressure safety injection, and emergency AC power. These four indicators provide important input to the Mitigating Systems Cornerstone concerned with the ability to prevent or reduce the consequences of accidents. As shown in the four graphs that follow, The Palo Verde Units on the average perform as well as or better than their peers and other PWRs except for the high pressure safety injection system or HPSI. This system is performing adequately whenever its unavailability is less than 2%. For the years 2001 to 2003 it averaged about the same unavailability as the peer plants, then the unavailability trended higher in 2004 and 2005 due to the voided sump suction and refueling water tank issues.


AFW System Unavailibility
PWR Average per Unit
Peer Group 2 Avg per Unit
Palo Verde Avg per Unit
1.00%
0.90%
0.80%
0.70%
0.60%
0.50%
0.40%
0.30%
0.20%
0.10%
0.00%
4Q/99
1Q/00
2Q/00
3Q/00
4Q/00
1Q/01
2Q/01
3Q/01
4Q/01
1Q/02
2Q/02
3Q/02
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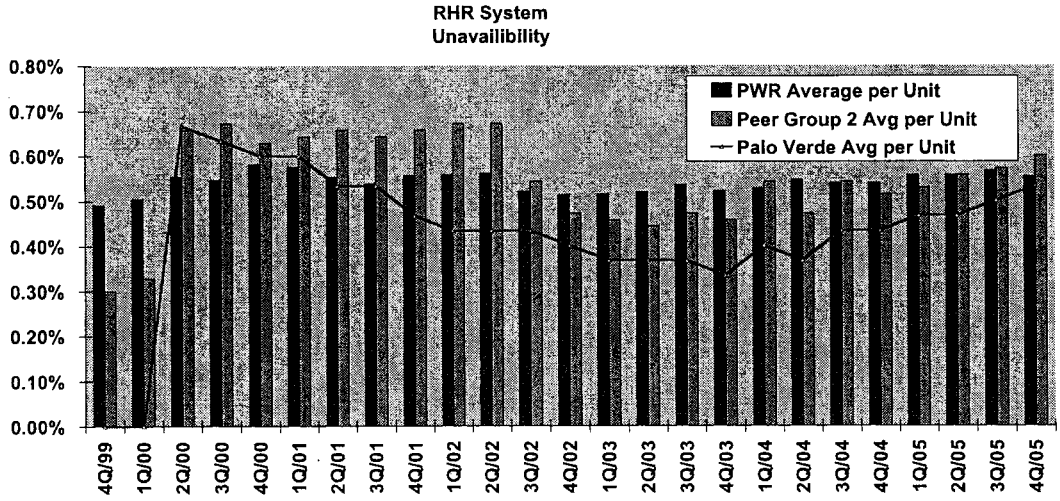
RHR System
Unavailibility
PWR Average per Unit
Peer Group 2 Avg per Unit
Palo Verde Avg per Unit
0.80%
0.70%
0.60%
0.50%
0.40%
0.30%
0.20%
0.10%
0.00%
4Q/99
1Q/00
2Q/00
3Q/00
4Q/00
1Q/01
2Q/01
3Q/01
4Q/01
1Q/02
2Q/02
3Q/02
4Q/02
1Q/03
2Q/03
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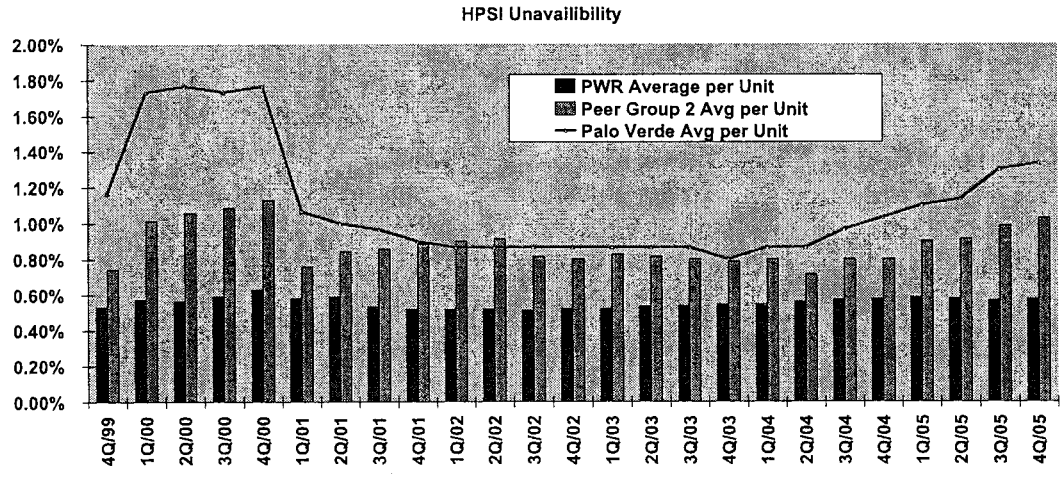
2Q/05
3Q/05
4Q/05


HPSI Unavailibility
PWR Average per Unit
Peer Group 2 Avg per Unit
Palo Verde Avg per Unit
2.00%
1.80%
1.60%
1.40%
1.20%
1.00%
0.80%
0.60%
0.40%
0.20%
0.00%
4Q/99
1Q/00
2Q/00
3Q/00
4Q/00
1Q/01
2Q/01
3Q/01
4Q/01
1Q/02
2Q/02
3Q/02
4Q/02
1Q/03
2Q/03
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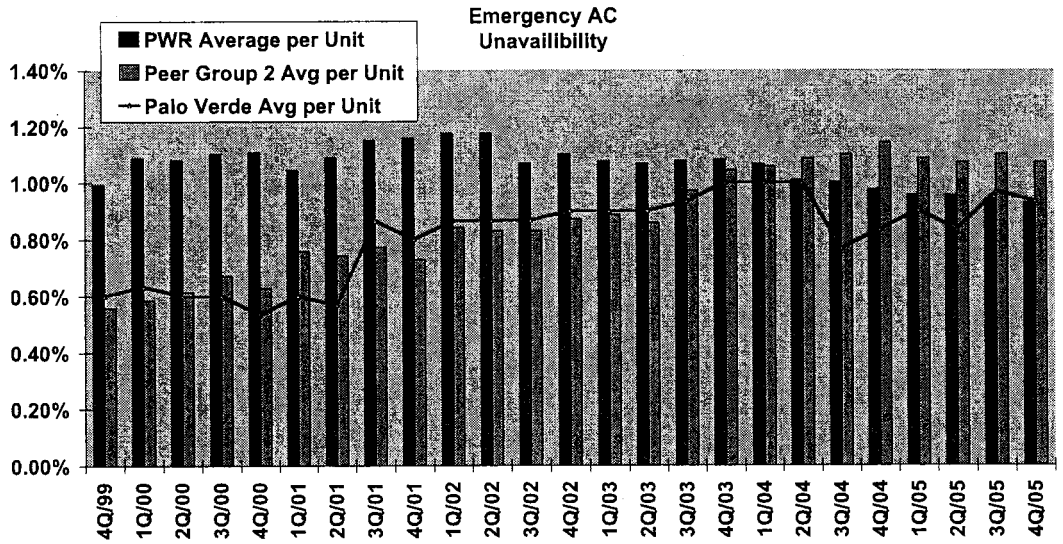
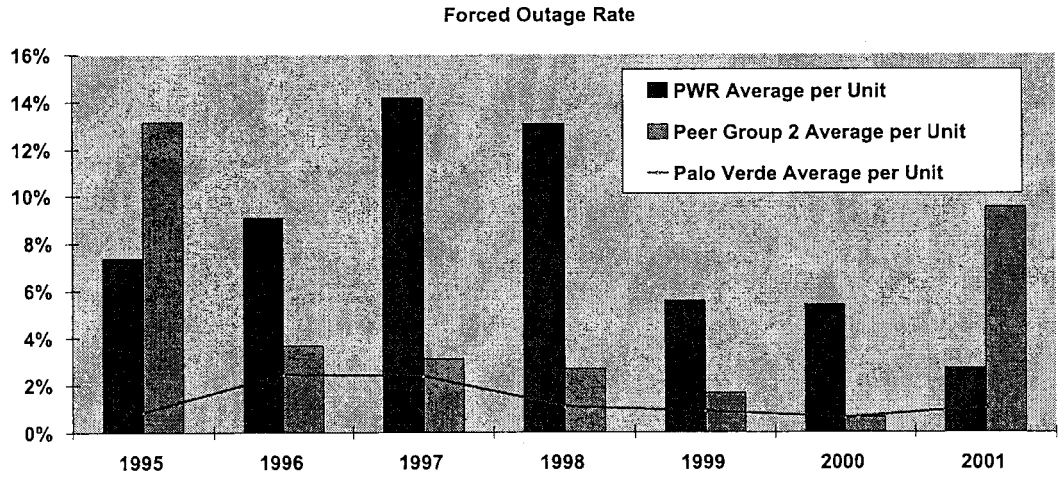
2Q/05
3Q/05
4Q/05



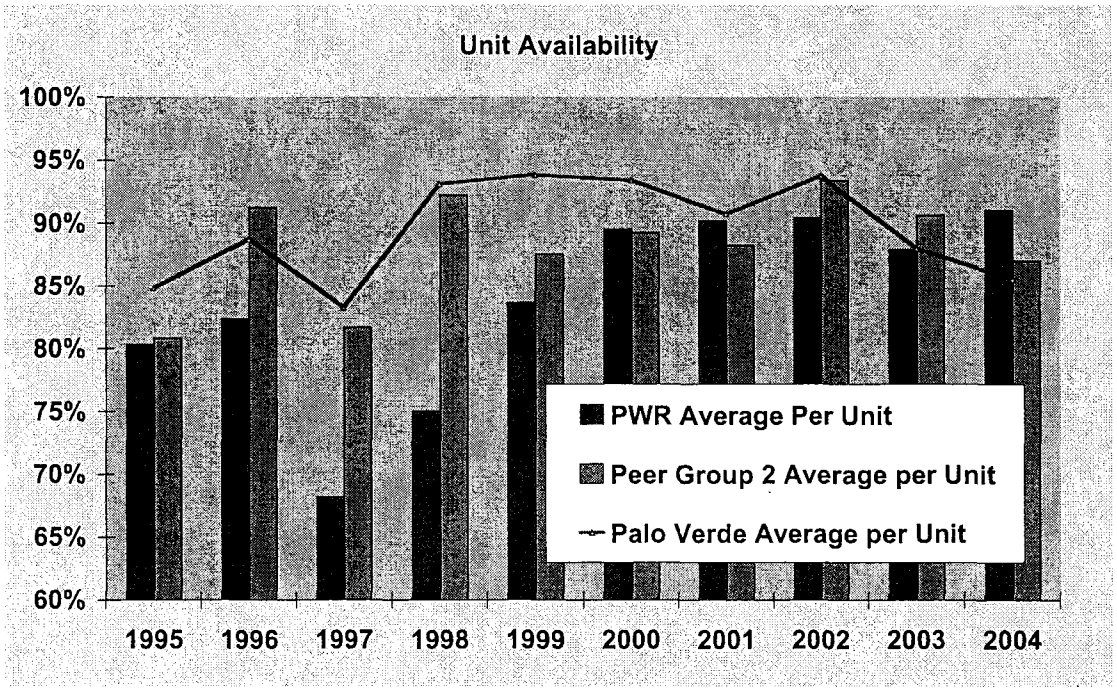
11. Forced Outage Rate

This indicator consists of the number of forced outage hours, multiplied by 100, divided by the sum of the unit service hours and forced outage hours. It is a measure of how long unanticipated conditions require a unit to be shut down relative to the total time it otherwise would have been available to produce power. For the period 1995 – 2001, the Palo Verde Units on the average achieved a forced outage rate better than their peer group and other PWRs, as shown in the following graph. This performance indicator was eliminated in 2000 with the advent of the ROP. APS has calculated that the Forced outage Rate of the Palo Verde Units averaged 5.5% in 2004 and 6.1% in 2005.



12. Yearly Average Availability

This indicator is a measure of the performance of the plant in producing power. It is computed by dividing the actual yearly power output in megawatt hours by the theoretical maximum output (100% power times the number of hours in a year). The low average availability in the industry in 1997 was caused by extended outages at a number of plants. The average availability factors for the Palo Verde Units were generally better than their peer group and other PWRs over the period 1995 – 2004, as shown in the following graph. In 2005, the availability of the Palo Verde Units averaged about 78%.

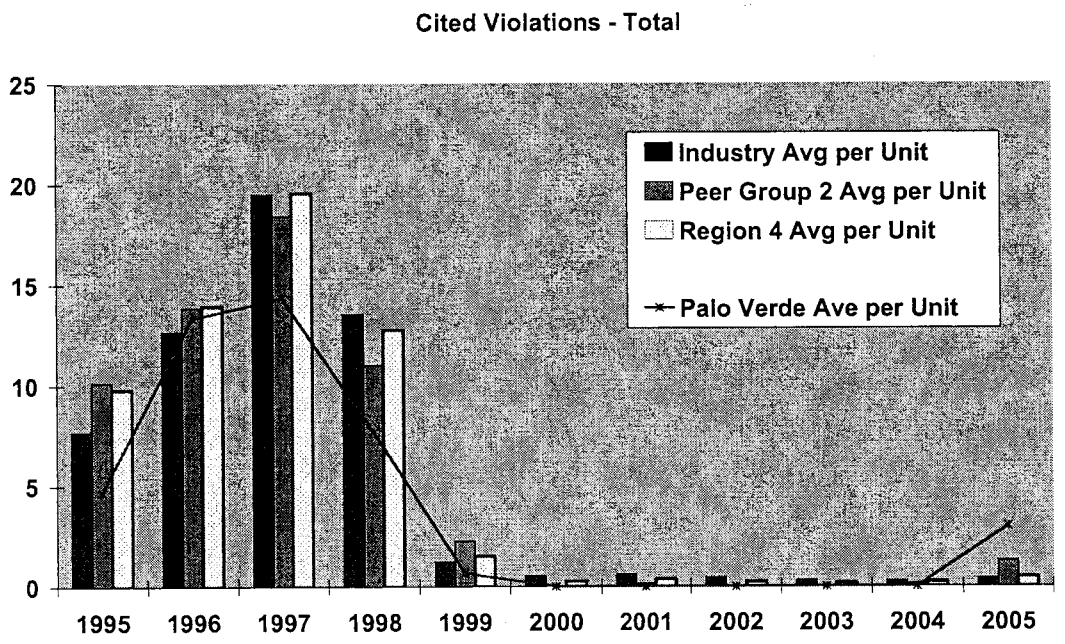


13. Violations of NRC Requirements

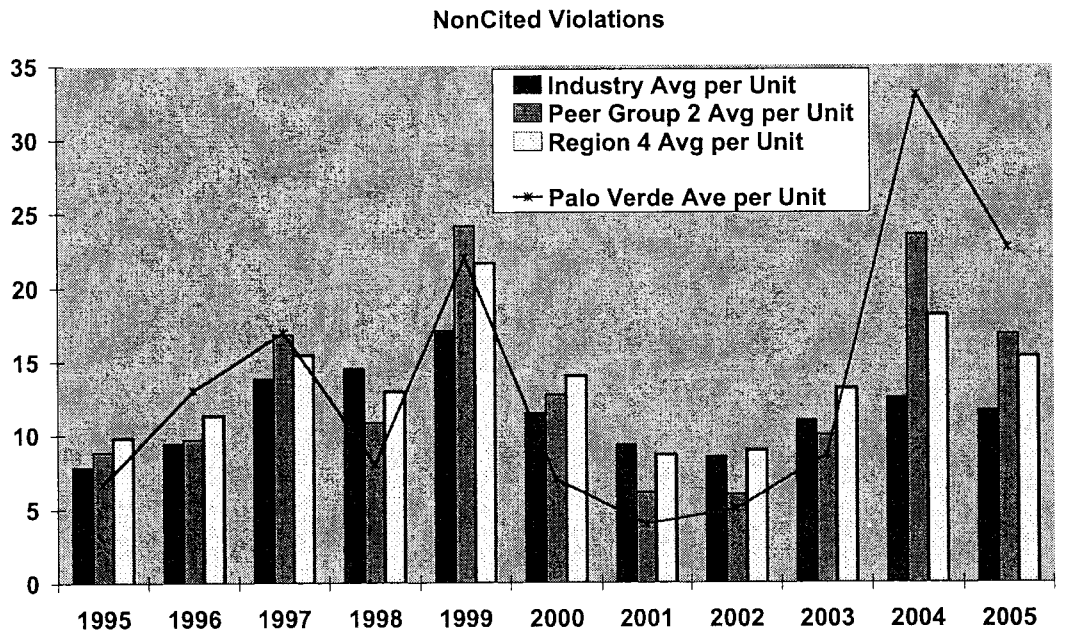
Comparisons of the numbers of violations cited against licensees over time provide a sense of how a particular licensee is fairing relative to others in the receipt of negative NRC feedback. As described above, NRC issues both cited and non-cited violations, and the relative number of the two changed with the advent of the ROP in 2000 (in fact, the number of cited violations took a precipitous drop in 1999 as the new ROP was being discussed internally to the NRC and prepared for implementation in 2000).

Palo Verde has had good performance in terms of the number of cited violations. During the period 1995 through 2005, the three Palo Verde units averaged fewer notices of violation than

the industry average (BWRs and PWRs), fewer than the average for their NRC-defined peer group, and fewer than the other units in Region IV, as shown in the following graph.

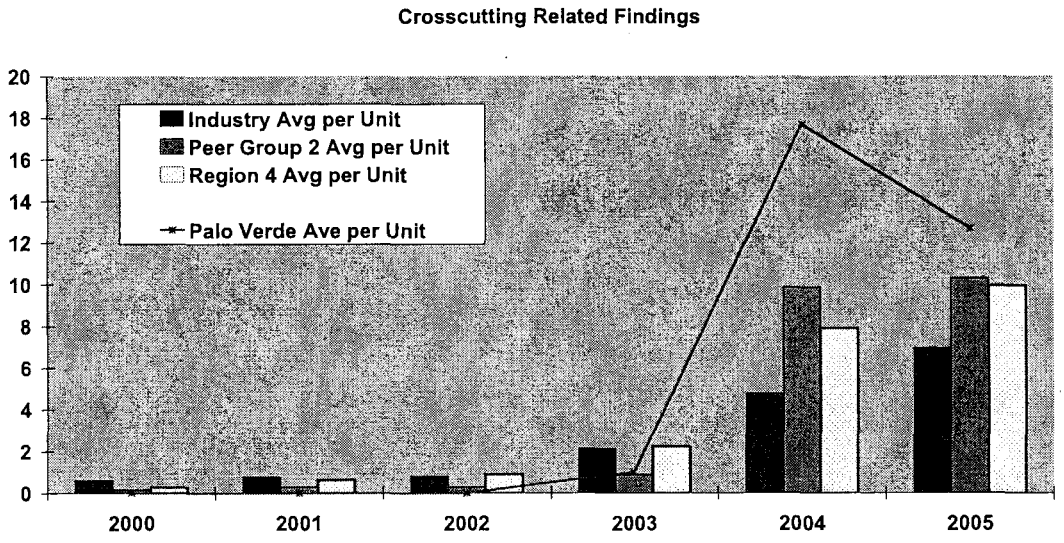


As shown in the following chart of non-cited violations, the Palo Verde Units also averaged better than their peers, other units in Region IV and other units in the industry (BWRs and PWRs) for most of the 11-year period from 1995 to 2005.



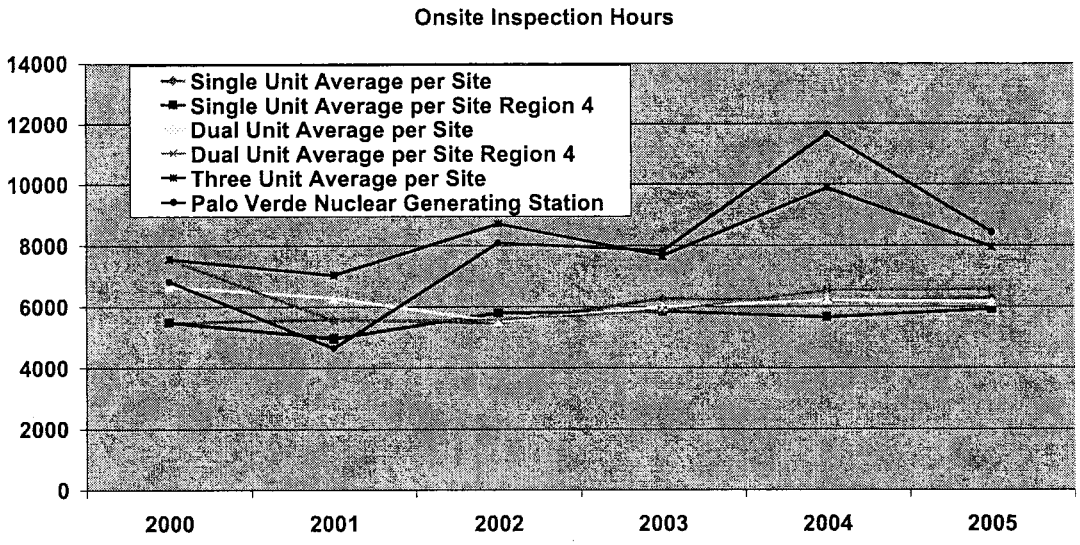
14. Cross-Cutting Findings

These are findings defined by the ROP as inadequacies in a licensee's activities that affect all or most safety cornerstones. There are only three areas defined by the NRC for cross-cutting issues, namely, problem identification and resolution, human performance, and safety conscious work environment. NRC says that findings in these areas are important because they indicate systemic weaknesses that could degrade multiple cornerstones if not corrected. The performance indicator shows excellent performance by Palo Verde from 2000 to 2003 with only one such issue identified in 4 years, and then a very steep increase in 2004 when NRC found all that the three units averaged 16 such issues. Performance at Palo Verde improved in 2005 as the indicator for the three units moved back toward the averages for the peer group and Region IV. This trend is consistent with the industry trend information identified by the U. S. Government Accountability Office and discussed in Section 3, above, i.e., between 2001 and 2005 cross-cutting issues grew from 23% to 68% of all NRC inspection findings.



15. Onsite Inspection Hours

This parameter reflects the level of NRC scrutiny applied to a particular site each year. It shows that NRC averages about 6000 hours per year (3 person years) at single- and dual-plant sites and about 8000 hours (4 person years) at 3-plant sites. Prior to 2004, Palo Verde received average or less oversight than the one other 3-unit site. This level of oversight changed in 2004 when NRC expended 12,000 person hours at PVNGS. In 2005, the NRC oversight at PVNGS dropped back toward the average level for the 3-Unit sites.


Onsite Inspection Hours
14000
12000
10000
8000
6000
4000
2000
0
Single Unit Average per Site
Single Unit Average per Site Region 4
Dual Unit Average per Site
Dual Unit Average per Site Region 4
Three Unit Average per Site
Palo Verde Nuclear Generating Station
2000
2001
2002
2003
2004
2005

REBUTTAL TESTIMONY OF ROBERT E. DENTON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)

September 15, 2006

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Palo Verde Levels of Material Storage		ATTACHMENT RED-2RB

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

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert Elmo Denton. My business address is 79 Redwood Lane, Weems, Virginia 22576.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Physics from Duke University (1965). I completed the U.S. Navy Nuclear Power Training course prior to serving in the fleet. I also attended the following educational programs: The Executive Management Program, Pennsylvania State University, and the Executive Leadership Program of the Edison Electric Institute.

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

A. I am self-employed and provide management and technical consulting to the utility industry.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND, WORKING TOWARDS THE PRESENT.

A. After having served five years in the Navy Nuclear Propulsion Program, I was employed by Baltimore Gas and Electric (BG&E) in 1970, and between 1970 and 1978 I received various operating job assignments during the construction, startup and early operation of the Calvert Cliffs Nuclear Units. In 1974 I obtained a Senior Operators license from the Atomic Energy Commission, and held that license for eight years.

From 1978 – 1980, I served as the General Supervisor of Operations at Calvert Cliffs, and from 1980 – 1985 I headed the plant technical services group.

In 1989, after a four year assignment in the Corporate Finance Division, I returned to the nuclear power plant as Manager – Quality Assurance and Staff Services.

In 1990, I was promoted to Plant General Manager and was responsible for the operation and maintenance of Calvert Cliffs. During this time I oversaw the improvement process which resulted in the removal of Calvert Cliffs from the Nuclear Regulatory Commission (NRC) "Troubled Plants" list, also known as the "Watch List," in early 1992.

From 1992 – 1996, I served as Vice President of Nuclear Energy and was responsible for all aspects of the nuclear power program.

From 1996 – 2000, I was Senior Vice President and then Executive Vice President of Generation at BG&E and Chief Nuclear Officer for the BG&E nuclear program. In this capacity I was responsible for all regulated generation facilities, i.e., nuclear, fossil, and hydro-electric.

In July of 2000, the State of Maryland deregulated electric generation facilities. At that time, BG&E remained as the regulated distribution company and the generation facilities were placed in non-regulated companies as wholly owned subsidiaries of the Constellation Energy Group. I became the President and CEO of Constellation Nuclear, a subsidiary of the Constellation Energy Group, which owned and operated the Calvert Cliffs and Nine Mile Point Nuclear Units. At the same time, I continued as Chief Nuclear Officer for Constellation Nuclear. I retired effective January 1, 2002.

Q. HAVE YOU SERVED ON ANY NUCLEAR INDUSTRY COMMITTEES?

A. Yes. I have served on various committees and advisory boards for the Institute of Nuclear Power Operations (INPO), the Electric Power Research Institute (EPRI), the Nuclear Energy Institute (NEI), and the Association of Edison Electric Illuminating Companies (AEIC).

Q. HAVE YOU SERVED ON ANY CORPORATE OR UNIVERSITY BOARDS?

A. Yes. I was a director on the Board of Directors of Baltimore Gas and Electric Company and the Safe Harbor Water Power Corporation. I have also served on advisory boards of engineering schools at the University of Maryland and Duke University. I was appointed by the Governor of Maryland to the Board of Trustees of the Chesapeake Bay Trust.

Q. HOW DOES THE EXPERIENCE YOU HAVE DESCRIBED ABOVE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My experience at BG&E in front line assignments at Calvert Cliffs and later in executive and senior executive capacities is directly applicable to my review of the Palo Verde operations. The Calvert Cliffs plant is a ten year older, slightly smaller version of Palo Verde. The nuclear steam supply system for both facilities was designed and manufactured by Combustion Engineering, Inc. of Windsor, Connecticut. The layout of the plants, much of the equipment, the licensing basis, the Technical Specifications, and the operating practices are the same or very similar at both facilities. Moreover, as a former senior nuclear plant executive, whose responsibilities included, among other things, the successful elimination of Calvert Cliff's "troubled plant" status, I have extensive experience in dealing with the NRC and INPO.

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

A. I have been engaged by Arizona Public Service Company (APS) to review its actions as the operator of the Palo Verde Nuclear Generating Station (Palo Verde or Company) in connection with certain outages that occurred at Palo Verde during 2005. I have also been asked to evaluate portions of the report of GDS Associates, Inc. (GDS) and the testimony of GDS Vice President, Dr. William Jacobs, testifying on behalf of the Staff claiming that APS acted imprudently in some instances. In that regard, I address in this testimony GDS' conclusions that Palo Verde was safely operated and that the Company's Performance Improvement Program will be successful in returning Palo Verde to the level of excellence it enjoyed for so many years. I also address the appropriateness of GDS' reliance on NRC reports, INPO reports and Company self-critical documents to prove imprudence on APS' part with respect to certain outages. Third, I address GDS' recommendation to the Commission that it should consider whether APS has sought appropriate remedies from vendors whose equipment caused certain of the 2005 outages. Finally, I address GDS' conclusion that APS was imprudent in connection with an outage that occurred at Unit 1 in March of 2005 due to the failure of a diesel generator governor.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. As discussed above, I reviewed the GDS report and the Company's actions regarding the 2005 outages. From this review, I made the following conclusions, which are described in more detail in my testimony below:

- I agree with GDS that Palo Verde was operated safely in 2005.
- I also agree with GDS and am optimistic that Palo Verde's Performance Improvement Plan will return it to excellent performance.

- GDS inappropriately used NRC, INPO, and Company self-critical documents in attempts to show imprudence.

- The Palo Verde contracts that I reviewed are typical contracts in the nuclear industry. It is a normal practice in this industry to exclude liabilities for consequential damages for contractor negligence.

- Finally, I conclude that Palo Verde was prudent regarding the March 2005 diesel generator governor outage because Palo Verde stored the governor at a higher level than the manufacturer recommended and could not have discovered any rust in the governor during a reasonable pre-installation inspection.

III. PALO VERDE PERFORMANCE

Q. HAVE YOU REVIEWED THE SECTION OF THE GDS REPORT ENTITLED "PALO VERDE PERFORMANCE"?

A. Yes I have.

Q. DO YOU CONCUR WITH GDS' CONCLUSIONS REGARDING SAFETY?

A. Yes I do. Based on my own review of Palo Verde operations, I too conclude that the plant was operated safely during 2005.

Q. HAVE YOU REVIEWED THE PALO VERDE PERFORMANCE IMPROVEMENT PLAN ISSUED ON OCTOBER 15, 2005?

A. Yes. I reviewed that plan, and based on my experience I find it to be well designed and comprehensive. I share GDS' optimism that when the plan is fully implemented the result will be a return to excellent performance.

Q. FOR PURPOSES OF EVALUATING THE PRUDENCE OF APS' ACTIONS, WHAT STANDARD OF PRUDENCE DID YOU APPLY?

A. I applied the following standard set forth in the Arizona Administrative Code regarding prudent utility investments:

> "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.

Q. IS THIS STANDARD CONSISTENT WITH YOUR OWN VIEW OF PRUDENT UTILITY INDUSTRY PRACTICE?

A. Yes. In a plant operated in accordance with prudent utility practice, management's actions should be consistent with those that a reasonable manager, with appropriate education, training and experience, would take in light of the information available at the time the actions were taken. The decisions made and the actions taken should be reasonable efforts intended to maintain nuclear safety, to comply with the regulatory requirements of the NRC, and to achieve industry standards of reliability and efficiency.

An evaluation to determine whether management's actions met this standard should avoid hindsight; i.e., judgments based upon the results of management decisions or based upon information that could reasonably have become known only after the decisions were made.

Q. IN DETERMINING WHETHER THE STANDARD OF REASONABLENESS HAS BEEN MET, IS IT APPROPRIATE TO RELY ON NRC OR INPO DOCUMENTS, OR ON SELF-CRITICAL COMPANY DOCUMENTS?

A. Usually, the answer would be no.

Q. WHY?

A. Because such documents are usually prepared with full benefit of hindsight, and they typically do not present a balanced view of events. Additionally, they are not intended to, and do not, measure reasonableness of management actions.

Q. WHAT ARE THE ROLES OF THE NRC AND INPO IN CONNECTION WITH COMMERCIAL NUCLEAR POWER PLANTS?

A. NRC and INPO are the two organizations principally responsible for setting standards for commercial nuclear plants. The NRC is an independent agency of the U.S. government. The stated NRC mission is to "ensure adequate protection of public health and safety to promote the common defense and security and to protect the environment." The NRC is purely a regulator of nuclear plant safety – it is not concerned with efficiency or production results. As such, the NRC publishes rules and standards for the civilian nuclear industry aimed at ensuring the protection of the public from hazards associated with the operation of nuclear reactors. Plants are then inspected to ensure compliance with these rules and standards.

It should be noted here that the NRC primarily uses hindsight to evaluate the results of the decisions made by plant management. One of the principal lessons learned from the 1978 incident at Three Mile Island Unit 2 (TMI-2) was the need to continually learn from the operating experience of every nuclear plant. Therefore, every incident, event, or deviation from standards, even those of very low safety significance, is analyzed for "lessons learned." Consequently, all organizations are expected to make improvements to prevent similar or more serious future events.

Keeping in mind the NRC's mission and methods, it is my experience that NRC written reports have what appears to be an overwhelming amount of criticism.

They come across as principally negative documents even when plants are highly regarded as excellent performers. This flavor is due to the method of examining each detailed variation from standards, no matter how small, to learn and improve. It is my understanding that Dr. Mattson will address the role of the NRC in greater detail in his testimony.

Additionally, the nuclear electric utility industry created INPO in 1979 after the TMI-2 incident. INPO's mission is to promote the highest levels of safety and reliability and to promote excellence in the operation of nuclear electric generating plants. All U.S. organizations that operate commercial nuclear power plants are INPO members. Among INPO's activities are:

- Analysis of reported events and dissemination of the lessons learned.
- Promoting the exchange of information and good practices among all nuclear utilities.
- Benchmarking against international best practices.
- Developing and monitoring a set of 10 performance indicators.
- Maintaining evaluation and peer review programs.

All U.S. nuclear plants are inspected by a team of INPO staff and peer industry personnel every 18 to 24 months. Note that INPO does include production in its review – it is weighted heavily in the 10 performance indicators. The INPO team compares plant performance to the best practices in the industry and its reports point out where deficiencies, when compared to best practices, are present. These are referred to as "areas for improvement." This standard is explicitly set forth in the INPO report upon which GDS relies, although GDS makes no mention of the standard. INPO states that "areas for improvement are based on best practices

observed in the industry, rather than on minimum acceptable standards or requirements." Again, this focus leads to a negative-sounding report.

Q. HAVE YOU REVIEWED THE SECTION OF THE GDS REPORT ENTITLED INPO EVALUATION RESULTS?

A. Yes, and even though the GDS report appears to accurately reflect the areas pointed out by INPO as "areas for improvement," I do not agree with the GDS characterization of these areas as "significant problems." My own review of the same INPO report and my experience with numerous INPO reviews concludes that the INPO term "area for improvement," as I mentioned earlier, is compared to the best practices in the industry. This is in keeping with INPO's mission to promote excellence in operations.

Q. ARE THERE OTHER AREAS IN THE GDS DISCUSSION OF INPO RESULTS WITH WHICH YOU DISAGREE?

A. Yes. The GDS definition of a grade of 3 from the INPO review is not correct. The GDS report characterizes an INPO 3 as denoting "a plant with significant problems." In my experience, having attended numerous INPO exit meetings, an INPO 3 is assigned to plants at which overall performance is generally in keeping with the high standards of the nuclear industry. However, improvements are needed in a number of areas, and a few significant weaknesses may exist. My recollection is also consistent with APS' data request response PB-3.9. Again, weaknesses mentioned in the INPO definition are measured against a standard of best practices, not good practices or minimum acceptable practices.

Also, GDS does not correctly characterize Table 2 of its report. The INPO performance indicator is a mix of parameters as stated by GDS, but the production numbers such as capability factor are most heavily weighted, much more so than safety system performance for example. Thus, even though GDS concurs that the

bulk of the outage time that the Palo Verde units experienced in 2005 was not due to imprudence, the INPO Performance Index will still "penalize" Palo Verde for these prudent outages. This is why it is inappropriate to rely on INPO reports or the INPO Performance Index in a prudence evaluation.

Q. DOES THE INPO APPROACH OF CRITICISM AGAINST A STANDARD OF EXCELLENCE FIND ITS WAY INTO INTERNAL UTILITY AUDITS AND REPORTS?

A. Yes. As described previously, the culture fostered in the nuclear industry is to always seek to improve, and one of the principal methods is to be openly accepting of and in fact to promote strong self-criticism. Therefore, to the uninitiated, internal reports will also appear overwhelmingly negative, as do the NRC and INPO reports I mentioned earlier.

Q. DO YOU FIND EXAMPLES OF THIS IN THE GDS REPORT?

A. Yes I do. The excerpts on pages 13 and 14 of the GDS report, from the CRDRs submitted as Attachments 6 and 7, when taken out of the context of a purposefully self-critical report, appear to be much more onerous than when set in context of the continuous improvement standard of the industry.

Q. IN DETERMINING WHETHER THE STANDARD OF REASONABLENESS HAS BEEN MET, IS IT APPROPRIATE TO RELY ON SELF-ASSESSMENT AND IMPROVEMENT EFFORTS?

A. No, because good nuclear power plant managers undertake improvement efforts to attempt to keep pace with the rising standards that are a fact of life in the U.S. commercial nuclear power industry. Therefore, using the results of Company self-assessment and improvement efforts as evidence of mismanagement would be inappropriate. To the contrary, such efforts to identify areas for improvement, and to make improvements, are evidence of good management. Successful

management is an iterative process. Not all management plans are immediately successful, nor can every project be given top priority.

Using NRC reports, INPO documents, or Company self-critical documents as proof of "imprudence" creates a disincentive for a company to engage in critical self-examination, thereby potentially impeding the effort to improve performance. I urge the Commission not to go down this path.

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THIS PORTION OF GDS' REPORT?

A. I conclude the following based on both my review of the GDS report and my evaluation of APS management performance:

1. I agree with GDS that the Palo Verde units were operated safely in 2005.

2. I agree with GDS that when the Performance Improvement Plan is fully implemented the plants will return to a standard of excellence in operations.

3. I believe GDS has unfairly utilized the continuous improvement/self-critical culture of the industry to portray a more onerous and damaging sense of the areas for improvement noted in various reports than actually exists.

Q. PLEASE DESCRIBE YOUR APPROACH TO THE EVALUATION OF APS MANAGEMENT PERFORMANCE.

A. First, I did an extensive review of documentation. I did an initial round of interviews in conjunction with this document review. I then toured Unit 3 and inspected the equipment and plant areas of importance. Fortunately, since the plant was in a refueling outage at the time, I was able to gain access to portions of the plant not otherwise readily accessible. I then conducted further interviews of both plant personnel and senior management.

Q. HOW DID YOU USE THE INFORMATION THAT YOU OBTAINED?

A. I applied the knowledge and experience I acquired during my over 35 years involvement in naval and commercial nuclear power plant operation to evaluate the documentary, physical and interview information I obtained.

Q. HAVE YOU REVIEWED GDS' RECOMMENDATION THAT THE COMMISSION REVIEW THE DEGREE TO WHICH APS HAS SOUGHT REMEDIES AGAINST VENDORS WHOSE EQUIPMENT CAUSED CERTAIN OF THE 2005 OUTAGES?

A. Yes.

Q. HAVE YOU HAD ANY EXPERIENCE WITH RESPECT TO CONTRACTS WITH VENDORS FOR UTILITY POWER PLANTS?

A. Yes. As plant manager at Calvert Cliffs Nuclear Plant, Vice President of Nuclear for BG&E and as Executive VP of Generation for BG&E, I had contract approval authority on behalf of the corporation for increasing levels of expenditure.

Q. HAVE YOU REVIEWED THE "LIMITATION OF LIABILITY" PORTION OF CERTAIN CONTRACTS PROVIDED TO YOU ON BEHALF OF APS RELATED TO THE GDS REPORT?

A. Yes, I have reviewed those provisions of the following contracts and purchase orders:

1. The contracts between APS and Combustion Engineering Inc. for Field Services, Engineering Services, and Renewal Parts and Factory Repair Work. These contracts relate to the Core Protection Calculator (CPC) software upgrade.

2. The Purchase Order for the purchase of the Reactor Coolant Pump upper thrust bearing o-rings.

The Limitation of Liability provisions are similar in the contracts that I reviewed. For example, Section 10.1 of Agreement No. PV 87-10370 on Field Services

between APS and Combustion Engineering (now Westinghouse) states the following:

> Contractor and its subcontractors of any tier shall not be liable, whether in contract, tort (including negligence), or otherwise, to Participants, for any loss or damages in the nature of partial or complete loss of use of any generating facility, loss of power, cost of replacement of power, for any loss of interest, revenue, or anticipated profits resulting therefrom, or any other indirect or consequential loss or damages of a similar nature.

Q. HAVE YOU SEEN SIMILAR PROVISIONS IN OTHER CONTRACTS INVOLVING NUCLEAR POWER PLANT EQUIPMENT OR SERVICES?

A. Yes. I have seen many contracts like those at issue here that specifically state that the supplier will not be responsible for consequential damages for negligence, including the cost of replacement power. The Palo Verde contracts that I reviewed are typical of those used in the nuclear industry.

Q. IN YOUR EXPERIENCE, WHY ARE SUCH DAMAGES EXCLUDED?

A. In the electric utility business, a plant shutdown or substantial power limitation, especially on a base load plant, often results in substantial replacement power costs. Even the largest supplier companies are unwilling to take on the risk of guaranteeing such costs, especially since most have multiple contracts that could substantially compound these liabilities.

Q. DID YOU SIGN OR APPROVE CONTRACTS WITH SUCH PROVISIONS?

A. Yes.

Q. WHY DID YOU DO SO?

A. As I stated, suppliers would not agree to provide services or equipment and accept the risks I mentioned above. The nuclear industry already has fewer suppliers than

we would like to have. As an executive of a company in that industry, I accepted that as a normal practice liabilities for consequential damages associated with contractor negligence were excluded. Of course, there may be contractor liability under other factual situations not precluded by such provisions.

Q. DID APS ACT REASONABLY IN ENTERING INTO THE CONTRACTS WITH COMBUSTION ENGINEERING (NOW WESTINGHOUSE) AND THE O-RING SUPPLIER?

A. Yes. As noted above, the contracts that I reviewed between APS and Combustion Engineering (now Westinghouse) and the O-ring supplier use wording that is typical of the contracts used in the nuclear industry.

Q. HAVE YOU REVIEWED THE FAILURE OF THE UNIT 1 EMERGENCY DIESEL GENERATOR (EDG) 'A' GOVERNOR RELATED TO THE UNPLANNED OUTAGE OF MARCH 18-21, 2005?

A. Yes. I have reviewed CRDR 2782680 (provided as Attachment 10 to the GDS Report) and interviewed the system engineers responsible for the EDG. This CRDR includes a root cause investigation of the governor failure. The exact root cause of the failure was not found, but several probable causes were set forth.

Q. WHAT WERE THESE PROBABLE CAUSES?

A. The three most probable causes (CRDR 2782680, pp. 15-16) identified are:

1. Rust caused by water introduced during the refurbishment of the governor at Woodward Governor Company in June 2000 and not fully removed when the unit was returned to Palo Verde.

2. Rust forming while the governor was stored in the warehouse drained of lube oil for approximately 9 months, i.e., any water left in the governor during refurbishment and the draining of oil at Woodward combined with the addition of

air during the 9 months of storage could lead to rust formation in the internals of the governor.

3. Water introduced during an oil change in April 2004. However, walk down of the oil change process could not identify any possible source of water.

Q. WHY WAS THE OIL DRAINED BEFORE THE GOVERNOR WAS SHIPPED FROM WOODWARD TO PALO VERDE?

A. The oil was drained to comply with Department of Transportation regulations.

Q. DOES THE GOVERNOR MANUFACTURER, WOODWARD GOVERNOR COMPANY, MAKE ANY RECOMMENDATIONS REGARDING STORAGE OF THE EQUIPMENT?

A. Yes, in a letter (Attachment RED-1RB) to Engineering Systems Inc., Woodward recommends that the equipment be stored in a "clean and dry condition: any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years." Woodward did not recommend that governors should be stored filled with oil.

Q. WHAT ARE THE STORAGE CONDITIONS FOR GOVERNORS AT PALO VERDE?

A. Palo Verde stores the governors in a "Level B" area. Level B is defined in Palo Verde's Nuclear Administrative and Technical Manual (Attachment RED-2RB) as fire resistant, tear resistant, weather tight, and well ventilated building or equivalent enclosure. The manual states that items in Level B storage shall be placed on pallets or shoring to permit air circulation and the minimum temperature should be 40°F and a maximum of 140°F.

Q. IN YOUR EXPERIENCE, IS THIS STORAGE LEVEL WHAT YOU WOULD EXPECT FOR THE TYPE OF EQUIPMENT?

A. This level is actually higher than what I would expect for this type of equipment, especially considering the very low humidity conditions at the Palo Verde site.

Q. WHAT ABOUT THE WOODWARD RECOMMENDATION REGARDING MOISTURE AND CONDENSATION?

A. The governor was received from Woodward in July 2000 and installed in April 2001, much sooner than the 5 year examination recommended for storage in areas of moisture and condensation.

Q. IN YOUR ESTIMATION, IS THE ANALYSIS OF THIS EVENT IN THE GDS REPORT ACCURATE?

A. No. I do not believe the outage was avoidable. There was no reason for Palo Verde to suspect that water had been left in the governor assembly. That being the case, storage in a Level B storage area was entirely appropriate. The GDS report provides no supporting data for the statement that this storage method "is not a good practice."

Q. WHAT IS YOUR VIEW OF THE QUOTATIONS FROM THE WOODWARD GOVERNOR TECHNICAL MANUAL THAT GDS INCLUDES IN ITS REPORT?

A. The GDS quotations from the Woodward Governor Technical Manual regarding oil contamination and particles of dirt and water in the oil do not address the probable causes in this case. It is postulated here that the rust occurred either at Woodward or during the 9 month storage period following refurbishment. Thus, these quotations from the Woodward manual provide no support to GDS' claim that APS storage practices were imprudent.

Q. GDS ALSO CLAIMS THAT THIS OUTAGE COULD HAVE BEEN AVOIDED BY PRE-INSTALLATION INSPECTION OF THE GOVERNOR. DO YOU AGREE?

A. No. To find the rust which was eventually discovered at the test facility, Engine Systems Inc. (ESI), the governor would have to be completely disassembled. It would not be reasonable to expect the plant to disassemble all critical components, and then reassemble them prior to installation.

Q. HAVE YOU REVIEWED THE PRUDENCE STANDARD SET FORTH IN THE GDS REPORT?

A. Yes, I have. They propose essentially the same standard as I do.

Q. IN YOUR ESTIMATION, DID GDS IMPLEMENT THIS STANDARD WITH RESPECT TO ITS EDG GOVERNOR ANALYSIS?

A. No, GDS did not. GDS' standard requires it to make comparisons "without the benefit of hindsight." In the case of the EDG governor, GDS contends that Palo Verde should have instituted special climate controlled storage requirements for the governor to prevent rusting, when there was no reason to believe water had been introduced into the governor. As stated above, Palo Verde actually stored the governor at a level (Level B) that was higher than that recommended by the manufacturer. Only with the benefit of the post-failure disassembly could one be aware of the rust and potential residual water in the mechanism.

IV. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. First, Palo Verde operated in a safe manner throughout 2005 and has implemented a Performance Improvement Plan which should return it to a level of excellent performance. Second, GDS inappropriately relied on NRC, INPO, and Company self-critical documents in its report. GDS analyzed Palo Verde using a standard much higher than prudence. Third, the contracts that I reviewed between Palo Verde and certain vendors are typical of those used in the nuclear industry. It was reasonable for Palo Verde to enter into these contracts. Finally, Palo Verde was

prudent with respect to the March 2005 outage due to the EDG governor. Palo Verde exceeded the storage requirements for the governor and the only way that Palo Verde could have discovered any rust prior to installation would have been to disassemble the governor, which is unreasonable.

Q. DOES THIS CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.

Attachment RED-1RB

WOODWARD GOVERNOR COMPANY
SERVING PRIME MOVER CONTROL AND ACCESSORY MARKETS
ENGINE CONTROLS
1000 East Drake Road • P.O. Box 1519 • Fort Collins, Colorado 80522-1519
Telephone 303 482-5811 • Fax 303 498-3058 • Telex 4-5691
ESTABLISHED 1870

Frank Amend
Engine Systems Incorporated/Power Control Services
Post Office Box 1928
Rocky Mount, NC 27802-1928

Reference: Oil Changes and Governor Refurbishment

Dear Frank,

I am writing this letter to explain Woodward Governor Company's recommendations on governor oil change and refurbishment cycle times.

Since the most important variable affecting governor life is the environment in which it operates, Woodward Governor Company has no precise guidelines for governor maintenance. However, we offer the following general recommendations which could be incorporated into preventative maintenance specifications for nuclear applications:

Oil Change Interval: Woodward Governor Company recommends that mechanical actuator/governor oil should be changed at the second or third refueling outage. If there has been no indication of problems with the unit (specifically water and/or rust), this interval can be extended. If problems do occur, Woodward Governor Company recommends the interval to be shortened to every first or second refueling outage and/or until the problem's root cause has been identified and corrected.

Overhaul Interval: Woodward Governor Company recommends that mechanical hydraulic governors and actuators be refurbished every five (5) to ten (10) years.

Shelf Life: Mechanical hydraulic governors and actuators should be stored in a clean and dry condition: any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years.

As Woodward Governor Company has chosen Engine Systems Incorporated/Power Control Services to qualify, support, and market controls for nuclear applications, I request that you inform the nuclear industry of these latest guidelines. If any questions develop within the nuclear industry pertaining to these guidelines, Woodward Governor Company requests that they be direct to your organization.

Regards,

Steve Thompson
Nuclear Coordinator/Contract Review

Attachment RED-2RB

3.3 Material Storage

As described in ANSI N45.2.2, levels and methods of storage necessary are defined to minimize the possibility of damage or lowering of quality due to corrosion, contamination, deterioration, or physical damage from the time an item is stored upon receipt until the time the item is removed from storage and placed in its final location.

3.3.1 Levels of Storage

ANSI N45.2.2 defines levels of Storage. PVNGS storage levels are identified for each APN and are as follows:

Level A - PVNGS does not require Level A storage. The MLIS equivalent is considered to be temperature/humidity controlled.

Level B - APNs stored to Level B shall be stored within a fire resistant, tear resistant, weathertight and well ventilated building or equivalent enclosure. Precautions shall be taken against vandalism. The floor shall be paved or equal, well drained and not subject to floods.Items shall be placed on pallets or shoring to permit air circulation.The minimum temperaure shall be 40°F and a maximum of 140°F. The MLIS equivalent is considered to be "temperature controlled" Storage Level.

Level C - APNs stored to Level C shall be stored indoors or in equivalent environment with all provisions and requirements as set forth in Level B, except that heat and temperature control are not required. The MLIS, equivalent is considered to be "Indoor" Storage Level.

Level D - APNs stored to Level D may be stored outdoors in an area marked and designated for storage, which is well drained and preferably gravel covered or paved. Items shall be stored on cribbing or equivalent to allow for air circulation and avoid trapping water. The MLIS equivalent is considered to be "outdoor" Storage Level.

REBUTTAL TESTIMONY OF GEORGE L. FITZPATRICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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

I. INTRODUCTION:

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. George L. Fitzpatrick, 898 Veterans Highway, Suite 430, Hauppauge New York 11788.

Q. WHAT IS YOUR CORPORATE AFFILIATION?

A. I am the Managing Principal and CEO of Harbourfront Group, Inc. I have been engaged as a management and technical consultant, and Managing Principal, with Harbourfront Group, Inc. and its predecessor company, Applied Energy Group, for the past 25 years.

Q. WOULD YOU PLEASE DESCRIBE YOUR QUALIFICATIONS RELATED TO THE TESTIMONY YOU ARE NOW GIVING?

A. I have been performing statistical and econometric analyses for electric and gas utilities since 1974. Further, I have developed Performance Standard-related measurement analyses for companies such as Georgia Power Company, Atlanta Gas Light, El Paso Electric Company, Westar Energy and Long Island Lighting Company.

I have developed and testified to statistically based normalization and forecast analyses for such utilities as Western Resources, Texas Utilities Corp., Georgia Power Company, Freeport Electric, KeySpan Energy, Long Island Lighting Company, The New York Power Pool, El Paso Electric Company, Oklahoma Natural Gas, Missouri Public Service Company, The Empire District Electric Company, Union Gas Limited and Minnegasco.

I have been performing and evaluating econometric, econometric-end use, and statistical-based analyses for over 30 years for such utilities as American Electric Power, Arizona Public Service Company, Atlanta Gas Light Company, Bermuda Electric Light Company Limited, Consolidated Edison Company of New York Inc., Long Island Lighting Company, Freeport Electric, Georgia Power Company, El Paso Electric Company, The Empire District Electric Company, New York Power Authority, Union Gas Limited, Texas Utilities Corp. (TXU), Kansas Gas & Electric Company, Missouri Public Service Company, San Diego Gas & Electric Company, Western Resources Inc., and Westar Energy. I have also been engaged in the planning, design, and evaluation of Demand Side Management (DSM) programs and technologies, having directed the evaluation of approximately 400 DSM programs over my career for over twenty utilities.

On the subject of nuclear and fossil power generation economics, I have performed over thirty lifecycle comparative economic analyses on a variety of generation and renewable alternatives including nuclear, coal, combined-cycle gas turbines and wind generation for the following companies: American Electric Power Company, Arizona Public Service Company, Consolidated Edison Company of New York, El Paso Electric Company, Georgia Power Company, Kansas City Power & Light Company, Kansas Gas & Electric Company, Long Island Lighting Company, New York Power Authority, San Diego Gas & Electric Company, Texas Utilities Company (TXU) and Western Resources. A complete list of my qualifications can be found in Attachment GLF-1RB to my testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have presented testimony on behalf of the Arizona Public Service Company ("APS" or "Company") in ACC Docket Nos.U-1345-85-156 and U-1345-85-367.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is threefold:

First, I rebut Dr. Jacob's assertion that Palo Verde's historical operating performance has been "poor" based upon taking a one-year, 2005, look at Palo Verde performance.

Second, and consistent with the recognition by the Arizona Corporation Commission ("ACC" or "Commission") in its Decision No.55118 on page 20, that it is appropriate to consider both a utility's "successes" and "failures" in order to perform "a realistic analysis of operating performance", I will assess the full impact of APS' total baseload generation performance on its customers, rather than focus on one plant as does the one-year snapshot that Dr. Jacobs provides in the GDS report and his testimony, in order to refute the notion that a disallowance for Palo Verde performance in 2005 is appropriate.

Third, I will provide commentary on, and analysis of, Dr. Jacobs' Palo Verde Performance Standard proposal from both regulatory fairness and statistical perspectives. Although I am not proposing the Commission adopt a performance standard in this instance, I will describe elements of what an appropriate performance standard for APS baseload generation should include if the Commission were to consider adopting such a standard.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY

A. Looking at Palo Verde standing alone, the year 2005 brought with it a number of challenges for Palo Verde, resulting in a performance level that was below expectations. However, this occurrence is common among all nuclear plants and is not significant enough to enable one to portray Palo Verde performance as "poor" as Dr. Jacobs contends. Over a longer time period, Palo Verde has clearly performed better than its peers and over the 10 year period prior to 2005 (i.e., 1995 thru 2004), the performance of Palo Verde has resulted in a net benefit to APS and its customers of approximately 2,016,000 MWHs which equates to $91.8 million in avoided purchased power costs; (using 2005 Average Purchased Power Costs/MWH).

More fundamentally, instead of the one year Palo Verde-only snapshot approach Dr. Jacobs uses in his prudence analysis, I present an approach that 1) is more consistent with the principles underlying the prospective standard that he proposes and 2) more accurately reflects the net benefits/burdens that APS' baseload generation performance confers on its customers by also looking at the performance of APS's baseload coal generating plants. After performing these calculations and analyses, I have concluded that:

- Over the 10 year period between 1995 and 2004, APS' coal baseload generating units outperformed their respective comparison plant groups, resulting in APS and its customers enjoying a net benefit of approximately 4,382,000 MWHs which equates to $149 million in avoided purchased power costs (using 2005 Average Purchased Power Costs/MWH).

- In 2005, and recognizing that all of Palo Verde's lower-than-average performance was due to outages that were not the result of alleged imprudence, the very significant better-than-average 2005 performance of APS' coal units more than outweighed the disallowance that Dr. Jacobs proposes.

Turning to the issue of a prospective performance standard, Dr. Jacob's performance standard is too general and omits key technical and fairness components. Due to the Palo Verde successful performance over the long term a performance standard does not appear to be necessary. If the Commission decides to consider a performance standard, such a standard should provide for an equal probabilistic opportunity for compensation to both customers, for lower-than-expected baseload power plant performance, and to APS shareholders, for better-than-average baseload power plant performance. Any such standard should also include the appropriate performance metric for each generation type included, statistically-derived deadbands surrounding the targets developed, specific and symmetric limits on the magnitude of both rewards and penalties, explicit consideration of APS' aging generating fleet, planned outage scheduling, and differences in the annual probabilistic planned outage frequency differences between comparison samples. There should also be recognition of the NRC's concerns over the potential safety impact of such a plan. Further, I would suggest that all of APS' baseload generation units be considered in any performance standard ultimately imposed. Other suggestions on the statistical construct of such a standard are included below.

It is my opinion that the imposition of a fair performance standard for Palo Verde would be uniquely difficult since Palo Verde's configuration and location makes it a "one of a kind" plant. For example, Palo Verde is the only three unit nuclear plant in the U.S., regardless of type (i.e., PWR or BWR). Palo Verde's unique wastewater treatment system for processing effluent into purified cooling water for all three units is unique to the industry and adds another layer of complexity to the plant's operation.

III. DR. JACOBS' CRITICISM OF HISTORICAL PALO VERDE PERFORMANCE IS UNFOUNDED

Q. HAVE YOU REVIEWED THAT PORTION OF DR. JACOBS' REPORT THAT CHARACTERIZES PALO VERDE'S PERFORMANCE AS "POOR" BASED ON CERTAIN CAPACITY FACTOR AND PRODUCTION COST DATA?

A. Yes.

Q. HAVE YOU ANALYZED PALO VERDE'S CAPACITY FACTOR PERFORMANCE PRIOR TO 2005?

A. Yes. I have evaluated Palo Verde's historical capacity factor performance from two statistically-based perspectives using my standard performance group of U.S. pressurized water reactors ("PWR's"), specifically those greater than 1000 MW, as well as the group that Dr. Jacobs has recommended as appropriate for the benchmarking of Palo Verde (greater than 600 MW U.S. PWR's). The following table displays those capacity factor average results:

Table GLF1

Comparison of Palo Verde Capacity Factors to Two PWR Comparison Groups

Period	Palo Verde	>600 MW PWR	>1000 MW PWR
1995-2004	89.5%	87.4%	87.7%
2002-2004	88.4%	90.8%	90.7%

Q. WHAT DID YOU CONCLUDE FROM THIS COMPARISON?

A. Over the 1995-2004 timeframe, Palo Verde performed better than either peer comparison group.

Q. HAVE YOU QUANTIFIED THE BENEFIT FROM THIS BETTER THAN AVERAGE PERFORMANCE?

A. Yes. As described more fully on pages 13 and 14 of my testimony, I calculated the additional MWH's produced by Palo Verde as a result of its higher-than-comparison group performance over the 1995-2004 time period. I then calculated the savings of the additional MWH production using the dollar difference between APS' 2005 average purchased power costs per MWH and Palo Verde's average 2005 variable production costs per MWH. This calculation resulted in a net benefit to APS and its customers of $91.8 million over this 10 year time period.

Q. WHAT ABOUT THE THREE-YEAR PERIOD REFERENCED BY DR. JACOBS?

A. Looking at the time period 2002-2004, Palo Verde's performance was somewhat lower. However, in evaluating such comparative performance between three year samples of different sizes, I would not place much value in simplistic point estimates comparisons, regardless of whether the subject plant was underperforming or outperforming the comparison group selected. Rather, I would construct confidence bandwidths around the larger sample estimates in order to recognize some degree of normal year-to-year variability in the operation of such plants. For example, I have calculated the Standard Deviation for both the "> 600MW PWR Group" (+/-8.8 percentage points of annual Capacity Factor for the 2002-2004 three year average) and for the ">1000 MW PWR Group" (+/-9.2 percentage points of annual Capacity Factor for the 2002-2004 three year average). When confidence bands (+/- (.678 * Standard Deviation)) that would capture the middle 50 % of all comparison group observations are placed around the two comparison groups, Palo Verde's 2002-2004 Capacity Factor average (88.4 %) falls well within a reasonable range of both comparison groups. Further, when one recognizes that one of the Palo

Verde units underwent a Steam Generator replacement in 2003, thus reducing the overall Palo Verde plant capacity factor by approximately 1% over that three year period, this would serve to adjust Palo Verde's average 2002-2004 capacity factor to within approximately 1.4% if the actual peer group average. Thus, while recent Palo Verde performance has been below expectations, it is inappropriate to take this short term snapshot and characterize Palo Verde performance as "poor."

Q. IS THE USE OF SIMPLE INDUSTRY AVERAGES THE BEST WAY TO EVALUATE THE PERFORMANCE OF PALO VERDE?

A. No. The use of simple averages can be quite misleading in the case of PWR's, especially Palo Verde. Palo Verde is a one-of-a-kind, three unit PWR plant with a unique cooling water acquisition and treatment system. While there are economies of scale in the purchasing and warehousing of spare parts, for example, there are other aspects of Palo Verde's operation related to locational and climatic considerations that disadvantage its operating performance.

Q. COULD YOU ELABORATE ON THAT LAST SENTENCE?

A. Yes. When originally designed and constructed, Palo Verde was one of the most ambitious baseload generation projects ever undertaken by a group of electric utilities. Palo Verde's 3808 MW Maximum Dependable Capacity, proximity to the APS load center (approximately 60 miles to the west) and its use of reclaimed water for cooling were and continue to be important attributes that have contributed to the economic growth and vitality, as well as improved electric system reliability, of Phoenix and surrounding areas. While most nuclear power plants are located near significant bodies of water, Palo Verde has its cooling water delivered approximately 60 miles through a pipeline. This adds to

the cost of operation but provides a proximate and reliable source of relatively low cost energy for APS customers.

The three unit configuration of Palo Verde presents additional challenges to outage planning personnel to coordinate all outages in the safest and most cost effective manner. These challenges are not as significant at one or even two unit sites. Moving to an 18 month refueling cycle has helped Palo Verde outage planners become even more efficient, but, as with all nuclear plants, safety is always the number one priority.

IV. CRITIQUE OF DR. JACOBS' PROPOSED PALO VERDE DISALLOWANCE

Q. DO YOU AGREE WITH DR. JACOBS' PROPOSED DISALLOWANCE FOR 2005 PALO VERDE PERFORMANCE?

A. No. Other APS witnesses have addressed the substance of Dr. Jacobs prudence argument and the technical reasons why the proposed dollar disallowance is inappropriate. I have focused on an important financial counterbalancing argument that Dr. Jacobs has not addressed which is that the Commission ought to give considerable weight to the superior and offsetting performance of the Company's coal units during that same and other time periods.

Q. WHY HAVE YOU ELECTED TO INCLUDE APS' COAL-FIRED BASELOAD GENERATION IN YOUR ANALYSES?

A. I have performed many nuclear and fossil generation benchmarking analyses, and have proposed performance standards for nuclear and fossil generation, distribution reliability, and customer service performance elements. In my opinion, it is relevant to provide evidence to this Commission on the overall performance of APS' baseload generation, of which Palo Verde's capacity represents only 39%. That baseload generation includes APS' coal-fired units

which, like nuclear units, enjoy a significant cost advantage over purchased power and have the potential to confer a substantial benefit on APS' customers when run successfully

Q. WHY HAVE YOU ELECTED TO INCLUDE ONLY BASELOAD PLANTS IN YOUR PERFORMANCE ANALYSIS?

A. Baseload power plants are constructed by utilities to be the backbone of their electric production systems. Especially in the case of APS, baseload power plants are dispatched for power production into the APS system most of the time that they are available for safe operation.

Baseload power plants are also relatively higher capital cost investments that utility shareholders fund and commissions typically evaluate for the prudency of the capital spent for these assets. While more expensive to construct, these assets have the advantage of producing electricity at significantly lower costs per KWH, often for a longer lifecycle than either intermediate or peaking capacity.

Finally, intermediate and peaking power plants are operated for the purpose of electric production relatively few hours of each year, and are often substituted by utility system operators with other sources that have lower operating costs whenever practical.

Thus, since the lion's share of capital investment and electric system reliance is placed upon baseload generation, it is logical that these baseload plants, taken together, be evaluated for their collective contribution to the APS electric production system.

Q. PLEASE DISCUSS THE METHODOLOGY THAT YOU EMPLOYED IN PERFORMING YOUR HISTORICAL BASELOAD GENERATION PERFORMANCE ANALYSES OF APS' PLANTS.

A. As a start, APS provided me with a list of all of the generating units that it operates which are considered to be baseload generating resources. Attachment (GLF-2RB), entitled, "APS Baseload Generation Summary", provides a list of these units, along with the vintage (Commercial Operation Year), most recent MW rating and APS's share of that plant. Additionally, I asked APS to provide me with a general description of the generating technology employed at each unit so that my engineering staff could group units, where possible, in order to minimize the development of distinct unit comparison groups. Attachment (GLF-3RB), entitled "Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups" contains listings of the units included in final four baseload coal plant comparison groups that were ultimately selected for this comparative analysis.

Next, my staff reviewed the North American Electric Reliability Council's GADS (General Availability Data System) database in order to draw representative samples in terms of similar commercial operating date, maximum dependable capacity and vintage for the four major comparison groups for the most recently available 10-year period (1995-2004). Performance data for the year 2005 was not available at the time this testimony was prepared.

Attachment (GLF-4RB) entitled, "Statistical Comparisons of APS Baseload Plant Performance vs. Performance of Relevant Comparison Group: Average Group Values for 2002-2004, 1999-2004 and 1995-2004", contains the summary statistical data for these comparison groups for the measures Equivalent Availability Factor (EAF), Net Capacity Factor (NCF), and Effective Forced Outage Rate (EFOR). Statistical analyses of the data included the computation of Means, Medians, Standard Deviations, Standard Errors of the

Mean and Coefficients of Skewness for each measure selected for both APS units and each relevant comparison group.

For the purposes of developing "apples to apples" comparisons for the coal generating units, I selected EAF as the most relevant measure for assessing comparative coal unit performance even though I used net capacity factor or "NCF" in my earlier discussion of Palo Verde. NCF or simply CF is the most relevant measure for assessing comparative nuclear unit performance. Dr. Jacobs also employs Capacity Factor in his proposed nuclear performance standard.

Q. HOW DID YOU CALCULATE THE POTENTIAL DOLLAR IMPACTS FOR DIFFERING LEVELS OF COAL PLANT PERFORMANCE IN YOUR ANALYSES?

A. It was quite similar to the method used to calculate the earlier benefits of Palo Verde performance. As a first step, I calculated the weighted average cost for Purchased Power that APS incurred during the calendar year 2005 ($50.91 per MWH) using APS records for each transaction. This information was obtained from SNL Financial Services, a well recognized sector-specific information and research firm in the financial information marketplace specializing in the banking, specialized financial services, insurance, real estate, and energy sectors. Next, I received from APS its average variable production costs for its coal plants ($16.80/MWH), also for 2005. The resultant purchased power impacts were then calculated using this information in combination with the MWH deficits or surpluses resulting from the comparative analyses by plant type.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. The following are the key results of my analysis:

Over the 10-year period, 1995-2004, APS Coal units, on a weighted average basis, outperformed their respective peer groups similarly weighted. APS and its customers experienced an approximate total net benefit of $149 million over this period. Attachment (GLF-5RB, Page 1 of 2), entitled "Comparison of APS Weighted Baseload Generation(Combined NCF and EAF) vs. Relevant Comparison Groups for the Period 1995-2004", shows the details of this calculation.

Next, I looked at the performance of the APS Coal Baseload Units, taken together, for the most recent full year, 2005, and compared to the peer group performance for the most recently available GADS six-year averages for the relevant comparison groups (i.e., 1999--2004). The six year average is appropriate based upon the standard maintenance/overhaul cycle that APS employs at its coal plants. I then took Dr. Jacobs' recommended 2005 Palo Verde disallowance based upon his calculation of the financial impact of 2005 Palo Verde outages that he alleges to be imprudent. I compared the calculated coal plant benefit with Dr. Jacobs' recommended Palo Verde disallowance. Netting out the Baseload Coal purchased power cost savings of $27,492,000 (based on the 6-year average comparison) from Dr. Jacobs' recommended disallowance served to more than eliminate Dr. Jacobs' recommended Palo Verde disallowance of $17,373,000. Attachment (GLF-6RB, Page 3 of 3) entitled "Comparison of APS Weighted Baseload Coal Generation (EAF) 2005 Only vs. Relevant Comparison Groups for the Period 1999-2004" shows the details of this calculation).

. This analysis, based upon a three-year average comparison, shows a cost saving for the Coal units of $25,749,000 . Attachment (GLF-6RB, Page 1 of 3) entitled "Comparison of APS Weighted Baseload Coal Generation EAF vs. Relevant Comparison Groups for the Periods 2002-2004 and 2005 Only" shows the details of this calculation).

This approach recognizes the fact that although Palo Verde did not perform as well as expected in 2005, there were only 25 Palo Verde outage days whose prudence Dr. Jacobs challenges. The remainder of the 2005 Palo Verde outage occurrences were not identified as being imprudent by Dr. Jacobs in his report. While the financial benefit of APS' coal unit performance was significant, another way of looking at this performance is in terms of the additional MWH's that were available from the APS baseload units as compared to the relevant industry peer groups. The following table highlights this information:

Table GLF 2

1995-2004 Additional Coal and Nuclear MWH Made Available to APS and its Ratepayers from APS Baseload Generation

APS's Palo Verde	2,016,000 MWH
APS Baseload Coal	4,382,000 MWH

Q. WHAT WOULD HAVE BEEN THE RESULTS OF THIS ANALYSIS IF CAPACITY FACTOR WAS USED AS THE EVALUATION PERFORMANCE MEASURE?

A. The calculated benefit for APS baseload coal units would have been dramatically higher than the EAF-based comparison. For the 1995-2004 period, for example, the net benefit based upon Capacity Factor comparison would have been approximately 11,742,000 MWH or $401 million using 2005 purchased

power and APS coal variable productions costs. See Attachment (GLF-5RB, Page 2 of 2), entitled, "Comparison of APS Weighted Baseload Generation NCF Only vs. Relevant Comparison Groups for the Periods 1995-2004 " for the detail of this analysis.

Q. DO THESE RESULTS REINFORCE YOUR EARLIER CONCLUSIONS REGARDING THE APPROPRIATENESS OF DR. JACOBS' RECOMMENDATION FOR A TOTAL DISALLOWANCE OF $17,373,000?

A. Yes. Imposition of Dr. Jacobs' recommended disallowance by the Commission would be most inappropriate based upon Dr. Jacobs' focus on only part of the available relevant facts in this case.

First, as I discussed in the prior Section, Palo Verde has performed well over an extended time period. Even if one used a shorter time period, when one applies even a relatively small confidence band to the performance of Palo Verde, and either Dr. Jacobs' or my choice for a comparison group, Palo Verde's average capacity factor falls within the range of reasonable performance compared to both comparison groups.

Second, the above average performance of APS' other baseload units in 2005 more than made up for the costs that Dr. Jacobs concludes were incurred as the result of Palo Verde imprudence.

Thus, based on my quantitative analyses of the good performance of APS baseload coal units in 2005, the recommendation for a disallowance by GDS is not appropriate. APS' coal units have delivered real, measurable value to APS ratepayers in the very timeframe that Dr. Jacobs recommends penalizing the Company for one aspect of its total performance in 2005.

V. REVIEW AND CRITIQUE OF DR. JACOBS' PROPOSED PERFORMANCE STANDARD:

Q. HAVE YOU REVIEWED DR. JACOBS' RECOMMENDATIONS FOR THE CONSTRUCTION OF A NUCLEAR PERFORMANCE STANDARD?

A. Yes.

Q. DO YOU AGREE WITH THE ATTRIBUTES AND FEATURES THAT HE HAS PROPOSED?

A. I don't agree that a Palo Verde performance standard should be imposed in this instance, because of the long term performance and unique characteristics of Palo Verde which I discussed earlier, and because of the concerns noted in APS witnesses Mattson's and Wheeler's Rebuttal Testimony concerning the potential for creating unintended incentives to shortcut maintenance and safety concerns. But if the Commission were to consider instituting such a standard, I would suggest that the following critical comments on Dr. Jacobs' proposal be recognized and specifically addressed by the Commission since Dr. Jacobs' recommendations are too general, and omit key technical and fairness components:

1) 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.

2) 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.

3) Concerning the magnitude of any potential benefit or disallowance, I agree with Dr. Jacobs that there should be a cap on the potential magnitude of these adjustments to APS earnings. However, Dr. Jacobs is silent on the magnitude of that cap, does not propose how any "penalties" would be calculated, and does not recognize the need for symmetry. Further, Dr. Jacobs recommendations do not recognize the reality that APS earnings are currently below its allowed ROE as indicated in Mr. Brandt's Rebuttal testimony. This is an important factor for the Commission to consider before there is any detailed discussion of the specific structural elements of a performance standard.

4) A three-year average for the computation of such a metric may be appropriate for nuclear plants if a "deadband" is calculated and placed around the Comparison Group Mean Value in order to recognize, for example, the probabilistic differences in the frequency of normally occurring outages in the comparison group sample vs. the Palo Verde sample. However, a rolling "previous six year" evaluation cycle would have to be employed for APS' baseload coal units. The reason for this is that APS utilizes a six-year preventive maintenance and overhaul cycle for each of its large coal baseload units. Thus, utilization of a six-year average would insure that the Comparison Groups and APS Coal Unit Groups would be compared in a synchronized manner. However, consideration may need to be given for future changes in the preventative maintenance and overhaul cycles.

5) Dr. Jacobs recommends a comparison group of PWR's >600MW. I believe that a comparison group of PWR's >1000MW is more appropriate for the measurement of Palo Verde since this family of plants is more consistent with Palo Verde's design and operational considerations. Looking at both groups for the most recently available 2002-2004 comparison period yields the following averages and calculated deadbands:

Comparison Group	# of PWR'	Mean CF	Standard Deviation-CF
>600 MW	34	90.8%	8.8%
>1000MW	27	90.7%	9.2%

6) For the development of the Coal Plant Comparison Group component of any performance standard, the comparison groups that would be employed must recognize the age, size and key technological aspects of the APS units to which they will be compared. Further, I would recommend that the Equivalent Availability Factor be the metric used for comparison. In my earlier comparisons, I have recognized each of these factors in order to draw the most representative comparisons. For more detail on this component, please see Attachments GLF-2RB, GLF-3RB and GLF-4RB to my testimony.

7) Dr. Jacobs proposal includes elements that the NRC considers inappropriate in economic performance incentives and fails to include those features the agency considers more appropriate as described in its policy statement attached to Dr. Mattson's rebuttal testimony.

Q. DO YOU AGREE WITH DR. JACOBS' RECOMMENDATION #3 THAT CALLS FOR THE EXCLUSION OF ANY "...U.S. PWR'S WITH A 3-YEAR CAPACITY FACTOR OF LESS THAN 60%..."?

A. Not automatically; it would be important for the Commission and Company to understand the circumstances surrounding the abnormally poor three year performance of any comparison PWR that met that condition in order to insure that there are not any design issues or operating conditions that are common to Palo Verde as well. Evaluation of such an event may lead to suspension or modification of any adopted performance standard.

Q. PLEASE SUMMARIZE THE MAJOR CONCLUSIONS OF YOUR TESTIMONY?

A. The major conclusions of my testimony are as follows: 1) over the 1995-2004 time period Palo Verde outperformed the PWR comparison group that has been recommended by Dr. Jacobs. The total benefit that has accrued to APS and its

ratepayers totals $91.8 million. 2) Dr. Jacobs' recommendation of a $17,373,000 disallowance for 2005 Palo Verde outages is more than compensated for by the excellent performance of APS' baseload coal units. 3) Dr. Jacobs' performance standard recommendations are too general and omit key technical and fairness components. While I would not recommend the imposition of a performance standard in this instance, I have provided a summary list of missing performance standard elements that should be considered by the Commission if they choose to pursue an even-handed, statistically appropriate and comprehensive measurement process.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Attachment_GLF-1RB:

GEORGE L. FITZPATRICK
PRINCIPAL/CEO
Harbourfront Group, Inc.
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Hauppauge, New York 11788
631.348.4090

OVERVIEW

George L. Fitzpatrick is the Managing Principal/CEO of Harbourfront Group, Inc. His professional experience includes eight years of service at Long Island Lighting Company managing the Load Research, Forecasting, and Cost of Service Divisions. After that, he held the position of Vice President of Demand Planning with Stone and Webster Management Consultants, Inc.

Twenty-two years of his career have been spent with Applied Energy Group, Inc. as its founder, CEO and Managing Principal. Over his tenure as CEO, he built the firm from one consultant to over twenty-five employees. In 2002, he reached an agreement to sell his share of the firm in order to pursue management consulting and expert witness assignments that were specific to his experience, expertise and past utility client relationships.

In 2002, Mr. Fitzpatrick formed Harbourfront Group, Inc. to focus on the provision of expert witness services and litigation support in areas that have been central to Mr. Fitzpatrick's practice over his career. More information about the firm and its professional resources can be found at www.harbourfrontllc.com.

Mr. Fitzpatrick has provided expert direct and rebuttal testimony before federal and state regulatory bodies and judicial authorities on subjects such as:

- Lifecycle Economic Evaluation of Utility Investments
- Econometric/statistically-based Load and Energy Forecasting
- Weather Normalization Studies of both gas and electric test year sales
- Weather Normalization probabilistic correction of System Peaks and Class components
- Strategic Planning
- Comparative Economics of Electric Generation Investments
- Load Research Program Sample Design, Implementation and Analysis
- Nuclear and Fossil Power Plant Cost and Performance analyses
- Econometric and Statistical Studies on Utility- related Issues
- Rate Design
- Cost of Service Studies
- DSM/ Renewable Program Evaluation
- Performance Standard design and statistical construction
- SAIDI / SAIFI-related statistical investigations

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- Rebuttal testimony on a wide range of statistical and econometric-related subjects.

Specific to the subject of nuclear and fossil cost and performance analyses, Mr. Fitzpatrick has developed a series of statistical analyses that have been used by his clients in both regulatory, confidential negotiations and arbitration proceedings as recently as 2005-2006. On the subject of Nuclear Plant (PWR) cost and performance analyses, Mr. Fitzpatrick has developed a series of pooled non-linear multiple regression models that explain and quantify variations in O&M Costs, Capital Additions Costs, Planned and Forced Outage Rates, Capacity Factors and other related measures. These models capture regional cost differentials, key design differences, and multiple unit operating efficiencies, among other key variables. These models were originally used in the mid-1980's by Mr. Fitzpatrick as part of an overall comparative lifecycle economic analysis comparing nuclear vs. other generation-or DSM- alternatives. Now they are used to evaluate nuclear cost and performance performance, set the value of a plant being purchased or as a due diligence tool for minority plant owners. On the subject of Fossil Plant costs and performance, similar statistical analyses have been developed for similar metrics. In addition to the development of these analyses, Mr. Fitzpatrick has provided both expert testimony and cross-examination assistance on the technical analyses that underlie these studies from 1984 to the present.

Over Mr. Fitzpatrick's consulting career he has provided services to over 50 electric and gas utility clients both in the U.S. and abroad. However, there are a number of clients that have utilized his services on an ongoing basis over the years as a senior management consultant and/or expert witness. These clients include:

- Arizona Public Service Company (Pinnacle West)
- American Electric Power
- Bermuda Electric Light Company Limited
- Consolidated Edison Company of New York
- El Paso Electric Company
- Entergy
- Freeport Electric
- Georgia Power Company (Southern Company)
- KeySpan Energy
- New England Electric System
- Niagara Mohawk Power Corp. (National Grid)
- New York Power Authority
- Northeast Utilities
- San Diego Gas & Electric Co.
- TXU Electric (TXU)
- Union Gas Limited
- Westar Energy (and its three predecessor companies)

Over his 26 year professional consulting career, he has also served his client base as a negotiator, often playing a key role in the negotiation of multi-million dollar, short and long term utility power supply and franchise contracts (e.g., Ft Bliss, White Sands Missile Range, University of Texas, and El Paso Water Utilities and El Paso Electric Vs. the City of Las Cruces).

Mr. Fitzpatrick has a Master of Business Administration degree in Economic Theory and a Bachelor of Arts in Economics, both from St. John's University. He has also completed course work toward a Master of Science degree in Management Engineering from Long Island University (C.W. Post) as well as advanced training in Box Jenkins forecasting techniques and econometric and statistical modeling. He possesses a Certificate of Mastery in Reengineering from the Hammer Institute and is a member of the Association of Energy Engineers (AEE) and the Energy Services Marketing Society.

PROFESSIONAL EMPLOYMENT

2003-Present — Harbourfront Group, Inc.
Managing Principal and CEO

Founded Harbourfront in 2002. HFG's focus is the development of strategies, analyses and expert testimony to assist its primarily investor-owned utility client base in objectively and expertly presenting and defending issues central to the client's corporate mission. Primary areas of the practice are electric and gas forecast development and review; engineering economic studies; comparative economic studies; lifecycle economic studies; statistical and econometric analyses and rebuttal; rate design and cost of service studies; performance standard statistical design and rebuttal; distribution reliability-related analyses and utility accounting-related matters.

1982 - 2003 — Applied Energy Group, Inc.
Founder, President & CEO

Founded AEG in 1982. The focus of this consulting practice centered in the areas of Peak Load and Energy Forecasting, Load Research program sample design, implementation and analysis, Demand Side Management Program Evaluation, Electric and Gas Weather Normalization Studies, Nuclear and Fossil Generation Cost and Performance Studies and Comparative Engineering Economic Studies of Utility Generation and other investments. Mr. Fitzpatrick provided expert testimony on the above-mentioned areas and also provided clients with leadership services in the startup of new diversification ventures.

1979 - 1981 — Stone & Webster Management Consultants, Inc.
Vice President—Demand Planning

Responsible for the coordination and direction of consulting activities in the Planning, Load Research, Load Forecasting, and Load Management areas within the corporation. Additional responsibilities included analysis of data processing requirements and potential new markets for consulting activities - a diversification from Stone & Webster's traditional lines of business.

1971 - 1979 — Long Island Lighting Company
Manager—Load Research, Costing and Forecast Division

Primary responsibilities centered on Electric Peak and Energy Forecasts; Electric and Gas Weather Normalization; Statistical Sample Design Development; Load Research Study Implementation; Load Data Management and Analysis; Long Island Lighting Company's Annual Population Survey; all Long-Range Demographic Projections; the collection, processing, and overall supervision of the billing of customers under the Long Island Lighting Company's commercial/industrial time-of-use rate, the Electric Class of Customer Annual System Load Research Study; and all statistical and econometric- based studies performed by Long Island Lighting Company's Economic Research Department.

In 1978, responsibilities were expanded to include fully allocated and marginal cost-of-service studies for electric and gas and total factor productivity studies.

PROFESSIONAL EXPERIENCE

EXPERT TESTIMONY AND REGULATORY SUPPORT (SELECTED ASSIGNMENTS)

El Paso Electric vs. City of Las Cruces, New Mexico-2000 Federal Court-Ordered Mediation:
Participated as part of El Paso Electric's officer/attorney team in the final court-ordered mediation sessions that resulted in the settlement of the 10-year dispute between the two parties. Prior to this mediation, worked on behalf of the Company to negotiate a settlement with the City's consultants.

Freeport Electric-1995 Docket No. 95-E-0676, 2001 Docket No. 01-E0965, 2003Docket No. 03-E-0686:
Provided direct testimony supporting Freeport's KWH sales and peak demand forecasts in four NYPSC proceedings. Constructed econometric models based forecast methodology by calls along with weather normalization of the test year sales. Provided testimony on the selection of Freeport-specific DSM programs to meet Commission requirements.

Indian Point 2 and Indian Point 3 / Consolidated Edison Company of New York, Inc. and New York Power Authority - NRC Docket Nos. 50-247-SP and 50-286-SP:
Prepared rebuttal testimony comparing the economics of early retirement of the Indian Point units vs. potential conservation investment alternatives in New York State.

KeySpan Energy-1998 Docket Nos. ER98-11-000 and EL98-22-000, 2003; Docket Nos. ER04-112-000 and ER04-112-001:
Provided expert testimony before FERC on the appropriate segmentation of fossil generating plant fixed and variable O&M Costs. Developed statistical models, by plant, to support this segmentation. Testimony was updated again in 2003 for the FERC Docket related to the renewal of the contract that was originally brought before FERC in 1998.

Palo Verde 1, 2, & 3 / Arizona Public Service Company-Docket Nos. U-1345-85-156 and U-1345-85-367:
Provided direct testimony presenting comparative economic analysis of Palo Verde vs. hypothetical coal unit alternative. Provided econometrically developed estimates of Operation and Maintenance Costs, as well as Capital Additions Costs. Provided independent statistically derived estimates of lifecycle Capacity Factors for the Palo Verde units.

Palo Verde 1 & 2 / El Paso Electric Company / Texas - Docket No. 7460:
Provided direct testimony on lifecycle economics of nuclear vs. coal alternative. Provided direct testimony on decisional prudency of company to enter into nuclear investment. Provided load forecast of company's future energy and peak demand needs. Participated in the training of Company witnesses.

Palo Verde 1, 2, & 3 / El Paso Electric Company Docket Nos. 8892, 9069 and 9165:
Provided Direct Testimony presenting comprehensive industry analysis and statistical analysis of Nuclear Performance Standards. Presented statistically derived optimal Performance Standard for Palo Verde Units 1, 2, and 3. Provided Rebuttal Testimony discussing theoretical and statistical flaws in intervenor's Performance Standard proposal.

HF
GL

Plant Hatch and Plant Vogtle / Georgia Power Company / Georgia - Docket Nos. 3554-U and 3673-U:
For the Vogtle Financing Case, the Vogtle Rate Case and the Hatch Rate Case: Provided rebuttal testimony on comparative economics of Plant Vogtle, provided rebuttal testimony (with presentation to Commission) on Vogtle's economics, and statistically derived projections of Vogtle's performance and Hatch O&M Costs, participated in witness training, and developed internal statistically-based O&M and Capital Additions "Targets" for Plant Hatch and Plant Vogtle.

Plant Hatch and Plant Vogtle / Georgia Power Company - Docket No. 3840-U:
Provided Rebuttal Testimony that pointed out methodological and statistical flaws in Staff consultant's Performance Standard proposal. Presented parameters for a statistically unbiased, optimal Performance Standard.

Shoreham / Long Island Lighting Company / New York-Docket No. 28252:
Provided rebuttal testimony on most likely performance of Shoreham Unit. Provided testimony on most likely Operation and Maintenance Cost levels and Capital Additions Cost level for Shoreham based upon econometric analysis of nuclear industry. Provided testimony on demand-side vs. supply-side alternatives for the Long Island Lighting Company.

Westar Energy-2005 KCC Docket No. 05-WSEE-981-RTS
Provided direct and rebuttal testimony on the subjects of distribution reliability and reliability-based performance standards. Developed a series of statistical analyses that set performance standards for five utility performance metrics: SAIDI, SAIFI, EFOR, Answered Calls and Meters Read. Developed daily 1998-2004 SAIDI and SAIFI non-linear multiple regression-based weather normalization models for use by the Company.

Western Resources-2001 KCC Docket No. 1-WSRE-436-RTS:
Provided direct testimony and supporting statistical / engineering economic analyses on the prudence of Western's investment in the Stateline Generating Plant. Also provided direct testimony on the statistical weather normalization of test year sales.

Developed comparative economic analysis on the benefits to Westar and remaining customers of special power supply contracts for Large C&I customers.

Western Resources – 1996 KCC Docket Nos.193, 305 and 193,30; -U96-KG&E-100-RTS:
Developed an accelerated depreciation plan for Wolf Creek Nuclear Unit to reduce cost of production to market-based competitive levels by 2000 - 2005.

Western Resources – 1996 KCC Docket No. 193,307-U96-WSRE-101-DRS:
Provided expert testimony and supporting statistical analysis for test year, class weather normalization, as well as, primary and secondary economic benefits of key customer discounted contracts.

Western Resources - Missouri Testimony in Generic Proceeding (1994:)
Provide expert testimony during the Missouri Public Service Commission's rule making proceeding concerning Integrated Resource Planning. The testimony discussed the consideration of alternative fuel sources as an end-use measure when developing their resource plan. (MPSC Docket)

Wolf Creek / Kansas Gas and Electric Company / Kansas City Power and Light Company/Kansas-1984 Docket Nos. 84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185:

Provided rebuttal testimony on lifecycle economics of nuclear vs. coal alternative. Provided first-year and lifecycle statistically based estimates of Wolf Creek's Operation and Maintenance Costs and Capital Additions Costs. Provided first-year and lifecycle estimates of Wolf Creek's Capacity Factors. Participated in the preparation of KG&E witnesses on the subjects of statistics, econometrics, forecasting, and engineering economics.

Atlanta Gas Light – Georgia (1997):
Worked with senior management to develop testimony for a performance based rate plan in support of the unbundling of gas service.***El Paso Electric Company -Texas (1997-1998):***
Developed unbundling strategy and performance based rate plan in support of ongoing Texas PUC workshops on the unbundling of electric service.

Empire District - Missouri (1992):
Provided econometric rebuttal testimony critiquing MPSC Staff's direct testimony on Empire District's forecast. Staff accepted rebuttal testimony and the Company's forecast was accepted for use in the rate case.

Minnegasco - Docket No. G-008/GR-92-400 (1993 - 1994):
Developed a set of econometrically derived, short run forecasts for Minnegasco's major customer classes. Provided direct expert testimony regarding the use of these forecasts as a factor in determining the need for and magnitude of Minnegasco's requested rate increase. Assisted in preparation of cross-examination of intervening parties.

On rebuttal, supported the implementation of weather normalization adjustments and discussed the effects of an adjustment on varying classes of customer use.
All testimony was accepted by Staff.

Missouri Public Service (MOPUB) - (1992):
Provided econometric-based rebuttal testimony critiquing MPSC Staff's direct case criticizing MOPUB's forecast. Rebuttal testimony resulted in Staff stipulating to the use of the Company's forecast.

Palo Verde / Arizona Nuclear Power Project:
Developed computer software to facilitate budget tracking and comparison. Developed econometric-based target estimation models of Operation and Maintenance Costs. Developed target estimation of Capital Additions Costs based upon econometric modeling. Developed forced and planned outage statistical models to be used in regulatory proceedings for all participants as well as for internal outage planning. Acted as Advisor to Palo Verde Participant's Engineering and Operating Committee on Palo Verde Cost and Performance budget targeting.

Iowa Power Company:
Preparation of a generic proceeding-related evaluation of Iowa Power Company's current and planned DSM activities in light of its specific planning related need for DSM resources.

Long Island Lighting Company :(1974-1979)
Testified as an expert witness, usually in both the direct and rebuttal phases, in the following New York State Public Service Commission proceedings: Docket Numbers:

- 26733
- 26829
- 26985
- 27136
- 27154
- 80003
- 27319
- 27374
- 27375
- 28223
- 28252

on subjects such as econometric and econometric-end use Electric and Gas Peak and Energy Forecasts, Load Research studies for cost-of-service analysis, Load Management, Cogeneration, Conservation and statistical studies for weather normalization of gas send out and electric energy requirements data.

SELECTED CONSULTING ASSIGNMENTS

Westar Energy
Mr. Fitzpatrick served as the Principal Statistical Consultant on a joint Distribution Reliability project with Davies Consulting. This project had as its objective the evaluation of Westar's distribution integrity and repair metrics (i.e.; SAIFI and SAIDI) and the development of non-linear multiple regression models to normalize these metrics over time for those major weather elements affecting SAIFI and SAIDI performance. The results of this analysis were presented to both Westar Senior Management and the Kansas Corporation Commission.

Generation Investment Analysis (Westar La Cygne 2 and SDGE SONGS related analysis.)

Westar La Cygne 2 Sale Leaseback Analysis
Provided an industry based statistical study of lifecycle availability and O&M cost Expectation in connection with Westar Sale/Leaseback of the La Cygne 2 Unit.

San Diego Gas & Electric SONGS O&M and Capital Additions
Served as the technical project manager for the development of several non-linear multiple regression analysis developed to evaluate SONGS mayor cost components as compared to a focused sample of like plants.

American Electric Power 2005
Served as the subject matter expert and project manager for the development of the DSM and Renewables Components for AEP's Comprehensive 2005 Integrated Resource Plan for each of its 10 operating areas.

Freeport Electric
Served as the principal-in-charge of the statistical analysis to develop the Freeport Electric 2005 Normalized System Peak and the estimation of Freeport's 2006 ICAP peak responsibility for the New

York ISO. Also served as the project manager for the development of Freeport Electric's 2005 Load & Energy Forecasts.

Duquesne Light
Served as the Principal-in-charge of the statistical analysis to develop Duquesne Light's 2005 Normalized Summer Peak as well as the development of the major rate class contribution to that peak.

El Paso Electric Company
Developed a business plan for and then implemented an Energy Services Business Unit (ESBU) that had as its mission key customer retention contracting and the provision of value added products and services in the areas of energy efficiency, power quality, standby generation, and "behind the fence" maintenance and support services.

Bermuda Electric Light Company, Ltd.
Consulted senior management on opportunities for diversification and franchise protection; from 1993 through 1997. Businesses developed include a full service ESCO (BESCO) and Power Protection Leasing Programs for Residential and Commercial customers.

Western Resources
In 1995, was retained by Western Resources to provide expert advisory services and supporting research to assist in the development of a non-traditional Energy Service Company (ESCO). This engagement also involved the analysis of profitability of certain customer classes.

WPI Group International
In 1993 through 1994, provided advisory services for the acquisition of MICROPALM by WPI. After acquisition, provided strategic market and product planning advisory services to the CEO.

Delmarva Power & Light Company (DP&L)
From 1994 to 1998, supported a market research and business plan development project for the development of a dispatchable photovoltaic power supply system business. Based on our initial contribution, DP&L turned over the entirety of the Phase II commercialization to my firm.

Richardson & Associates
Since 1982, has provided expert technical, economic and business plan analysis for over 15 energy-related venture capital business opportunities. This consulting relationship is ongoing.

Applied Energy Technologies Corporation (AET)
Led the formation of a jointly held subsidiary with Delmarva Power & Light Company, A.C. Battery Corporation (a subsidiary of General Motors) to advance both grid-connected and non-grid-connected dispatchable photovoltaics to domestic and international commercialization. Other contributors include the U.S. Department of Energy, Solarex Corporation (a division of Amoco/Enron), and Ascension Technologies

NCR Corporation
In 1981 through 1983, was retained by NCR to develop a diversification business in the automatic meter-reading field. Developed business plans, marketing plans, and product functional specifications. Worked with NCR's CEO and senior management team.

Confidential Diversification Studies and Business Planning Engagements
Senior Management advisory services, development of business plans, and diversification strategies for twelve nationally known organizations. Since these assignments are governed by strict confidentiality agreements, they cannot be publicly identified.

Time of Use Rate and Load Management-Related Experience (selected Projects)

Development of the First Residential and Commercial Time of Use Rates in the US
One of the authors of Long Island Lighting Company's SC-2MRP and SC-1 MRP time of use rates. Mr. Fitzpatrick led the load research-related activities necessary to identify the width of the rating periods and the relative cost of service levels associated with those rating periods. At the time that these rates were developed, Mr. Fitzpatrick managed the Load Research, Cost of Service and Forecasting Divisions of the Long Island Lighting Company.

Development of Energy Cooperative Programs for PG&E, Long Island Lighting Company and El Paso Electric
Mr. Fitzpatrick led teams of professionals in the setting up of the design, pricing, implementation and evaluation of results for these programs at the host utilities. This type of program involved working with large commercial-industrial customers to first identify significant, isolatable load shedding opportunities within a customer's facility and then negotiating a contract that would provide incentives for performance and sometimes, penalties for non-performance. Finally, a two-way communication strategy would be custom designed to keep customers interested in the program and provide the mechanism with which to notify them that a load shed would be required within a certain number of hours of notification.

Tasks included the setting of cost-justified rebate levels, program marketing strategies, metering selection and implementation, Utility-commercial/industrial participating customer communication strategies and equipment; setting criteria for the calling of "critical days" for load shedding purposes; calculation and delivery of rebates in manners that fostered longer term commitments.

This type of program was allowed to be counted as "spinning reserve" by New York Power Pool. Fitzpatrick participated in the PG&E installation and managed the installation of the LILCO and El Paso Electric programs.

DSM Load Shedding/ LOAD Shifting and Time Of Use Rate Program Evaluations
Mr.Fitzpatrick served as the Principal-in Charge for over 400 DSM- related process and impact evaluations for 10 utilities in primarily in the North East. Many of these programs had time of use considerations associated with them.

DOE PV Bonus Program
Mr.Fitzpatrick served as the Principal-In –Charge for the Project Management of DOE's PV Bonus Program. This program was a multimillion collaborative effort among the DOE, GM and Shell Solar to develop a stand alone power source that utilized photovoltaic arrays married to battery technology in a stand alone package. Projected use of this type of system was for "village power" in remote locations and remote distribution reinforcement in rural areas. Successful prototypes in the 30kw range were successfully built and tested.

Stand-By Generation Program

Mr. Fitzpatrick served as the Principal-in Charge for the development and implementation of a standby generation program and an associated rate design that was instrumental in placing over 40 MW of customer-owned generation in the El Paso Electric service territory. Unit sizes ranged from 750 kw to 20 MW. Customers were given incentive to run their generation through the use of an Interruptible-type rate. These units were used in three ways- to pick up a segment of a customer's load, thus removed that load from the customer's metered demand, to isolate the customer from the grid and pick up the entire load of the customer, and to synchronize with the grid and feed surrounding areas.
This program was a win-win for customers with critical loads, and provided bill savings to customers while reducing EPE's overall cost to serve.

Four Million Gallon Chilled Storage Project for the University of Texas-El Paso
In order to prevent the University of Texas-El Paso from adopting a proposal to install self generation and disconnect from the EPE grid, Fitzpatrick was the Principal-in –Charge for the development, funding, rate design and contracting for an 12 MW load shedding project that had as its mission the provision of all of UTEP space conditioning needs with chilled storage. Mr. Fitzpatrick worked with UTEP, the university of Texas system and its performance contractor in making this project a reality and providing a win for all parties involved.

The contract between UTEP and the rate design employed within that contract served to both decrease UTEP's effective electric rates and overall energy costs while actually making this customer a more profitable customer for EPE to serve.

Planning & Forecasting (Selected Projects)

New York State Electric & Gas Corporation (NYSEG) - (1994 -1997)
Served as Responsible Officer for AEG's development of a Multi-Equational Small Area Forecast Modeling System. This system is used to track monthly sales geographically in the NYSEG system, identifying significant weather normalized monthly variances almost in "real time" so that NYSEG can recognize and react to significant changes in a shorter elapsed time.

Western Resources/Westar - (1984 - 2004)
Provide continuing advisory services to Western Resources (now Westar) on potential methodological upgrades to their forecast and weather normalization methodologies.

Long Island Lighting Company (LILCO)
Directed the preparation of LILCO's Annual Long Range Peak and Energy Forecasts during the years 1974 - 1979. Constructed the first Engineering End Use and Econometric End Use models for electric forecasting in New York State; utilized Box-Jenkins stochastic and multiple transfer functions for short run electric forecasts; employed two and three stage regression techniques in SIC-based commercial-industrial forecasting.

In 1994, provided advisory services to review adequacy of the econometric methodologies for the capture of "market transformation" DSM and efficiency effects.

Saudi Arabia - 1995
Selected from an international list of experts to perform a comprehensive review of Saudi Arabia's largest utility's overall planning and forecasting procedures, methodologies, and results. This two-phase project also called for the reengineering of these processes once the analytical and fact-finding phase was complete.

Bermuda Electric Light Company, Ltd. (BELCO) - (1994)
Reviewed BELCO's existing forecasting process and provided a "phase in" solution for enhancing their forecasting systems.

Freeport Light & Power - (1995-2004)
Have and continue to prepare Freeport's short and long-term electric peak and energy forecasts. Have presented and defended Freeport's forecasts and weather normalization studies in its last three rate cases.

Innovative Market Segmentation & Profitability Studies

Western Resources
Served as Responsible Officer for a Competitive Assessment of Western Resources key customer's responses to cost competition.

Union Gas Limited-2004
Performed a detailed evaluation of the Union Gas forecasting methodology and results. Developed a written report containing an evaluation opinion and forecast improvement suggestions. This report was filed with the Ontario Energy Board.

CINergy
In 1995, advisor to senior staff in a multi-phase project that had as its objective the meaningful (from a risk-profit perspective) segmentation of CINergy key customer markets and the analysis of profitability of the segments. This was followed by the development of strategies to optimize the use of CINergy's marketing resources to maximize shareholder returns while ensuring the long-term viability of the company.

Demand-Side Management Program Design, Reengineering, & Evaluation

Bermuda Electric Light Company, Ltd.
Directed a multi-faceted evaluation of the potential for DSM on Bermuda. Conducted in-depth research of various customer classes to determine likelihood of adoption of available DSM technologies. Building on this research, developed a series of pilot programs that were implemented in 1993, as well as evaluation strategies to be employed at the programs' conclusion.

Consolidated Edison Company of New York, Inc.
Project Manager for a Conservation Assessment Study which included designing a methodology and performing analysis to impact Conservation measures in the residential and commercial sectors to meet requirements imposed by New York PSC in Case No. 28223.

Long Island Lighting Company (LILCO)
Directed a research project focusing on the right-sizing of LILCO's DSM program in the face of a maturing market condition, as well as on the measurement of the extent to which LILCO's programs have successfully moved the market to energy efficient technologies. Research includes an assessment of the impacts of pure market forces on DSM and the role of rebates and information in overall market capture for DSM technologies.

Project Manager for LILCO's 1992 Research and Development Initiative entitled, "Institutional Barriers to Conservation in Master-Metered, Tenant-Occupied Commercial Office Space." The project involved determining the market conservation potential, identifying institutional barriers through focus groups and interviews with landlords and tenants, and establishing a pilot program and blueprint lease to implement in order to enhance DSM measures in the relevant market.

Directed the comprehensive evaluation of LILCO's 1987 Conservation and Load Management Programs. This evaluation is contained in a three-volume report, which has been called the "most comprehensive" effort to date in this area.

Directed the evaluation of LILCO's 1988 and 1989 Conservation and Load Management Programs. Directed the preparation of a June 1988 Load Management Study. Specific responsibilities included estimating Load Management reductions included in LILCO's Load Forecasts by major components.

Minnegasco
Served as the Senior Management Advisor to Minnegasco's DSM/Load Research Program from 1993 through mid-1995. Responsibilities included contract negotiations with consultants, supervision of consultant's activities, and resolution of technical issues, and on-site presence as required to effectively oversee all Load Research-related activities.

New York Power Authority (NYPA)
Served as the Senior Management Advisor for NYPA's $120 million High Efficiency Lighting Program (HELP) having primary responsibility for drafting and negotiating DSM cost sharing umbrella contracts with New York State and New York City.

Analysis on behalf of NYPA of Energy Systems Research Group's (ESRG) Conservation Assessment Report submitted in FERC Case No. 2729: Prattsville Pumped Storage Facility.

Supervised the development of an evaluation of potential Load Management strategies for the NYPA's municipal customers, including a cost/benefit analysis and specific Load Management test programs.

Named "Advisor" to NYPA's extensive Conservation Ten-Year Program.

New York Power Pool
Analyzed the conservation forecasts contained within the Member Systems' individual long-range forecasts and critiqued intervenors' conservation forecasts and analyses.

New York State Electric & Gas Corporation (NYSEG)
Served as Responsible Officer for NYSEG's 1991 & 1992 Commercial / Industrial Process and Impact Evaluations. Served as Responsible Officer in the development of NYSEG's June 1994 DSM Market Transformation Study.

Orange and Rockland Utilities (O&R)
Assessed the potential for and designed an Energy Cooperative Program for O&R's commercial customers. Directed project to assess new regulated and unregulated business opportunities to diversify O&R from its core business.

Rochester Gas & Electric Corporation
Served as Responsible Officer for RG&E's 1990-94 DSM Evaluations. Represented RG&E in all DSM-related interactions with PSC Staff.

Load Research

Electric Power Research Institute (EPRI)
Advisor to EPRI's Demand Program. Author of RP 1588-3 "Load Data Management and Analysis"; co-author of EPRI Rate Design Study Topic Paper 3: "Issues in Load Research."

Elizabethtown Gas Company
Asked by Senior Management to assess Elizabethtown's Load Research Program and develop a set of recommendations that would result in full cost-effective utilization of the Load Research resource, developed study plan, conducted in-depth technical interviews of potential load research clients, and presented findings and recommendations to all levels of Management.

Iowa Power Company
Directed weather normalization analysis on historical system peak demands. Results from analysis will be utilized in future system peak demand forecasts.

Long Island Lighting Company (LILCO)
Designed and implemented stratified sampling software that employed Dalenius-Hodges and Neyman Allocation techniques with stratum optimization and validation. Also directed LILCO's Load Research Program.

New England Power Service Company (NEPSCo)
Reviewed NEPSCo's Load Research Data Management and Analysis System from analytical and data perspectives and developed a NEPSCo-specific computer hardware and software plan for implementation.

New York Power Authority
Directed the review of the existing Load Research Program and formulated a Management Plan to specify future needs in the areas of sample design, hardware, software, and staffing.

Assisted in the development of specifications for a microcomputer-based Load Research Data Collection, Editing and Analysis System.

New York State Electric & Gas Corporation (NYSEG)
Served as Technical Advisor to the Manager of NYSEG's Load Research Department.

Northeast Utilities Service Company
Performed a comprehensive audit of the technical, software, and organizational aspects of the Northeast Utilities Load Research Program, including the identification of current uses and recommended future cost-effective uses within the company.

Supervised development of a study to analyze load research, weather, and attribute data for the small Commercial and Industrial customer group.

Northern States Power Company (NSP)
Directed the review of all aspects of NSP's load research process and presented findings in a comprehensive presentation to senior management.

Pacific Gas & Electric Company (PG&E)
Performed a comprehensive audit of the PG&E Load Research Data Management and Analysis System. Also, assessed the value of Load Research to all relevant departments in the company including recommendations for more cost-effective uses of Load Research data for both current and future applications.

Tennessee Valley Authority (TVA)
Conducted review of TVA's Sampling Plan strategies and methodologies.

DSM Bidding

Orange and Rockland Utilities
Directed the economic evaluation of the first utility bidding program in New York State.

Cogeneration

Caribbean Gulf Refining Corporation
Performed an economic review for the construction of a nine-megawatt Cogeneration facility.

Day and Zimmermann, Inc.
Performed a detailed analysis on the potential for Cogeneration Systems in the United States, which included the development of a comprehensive marketing strategy.

Orange and Rockland Utilities
Developed a Corporate Strategy for Cogeneration in the O&R service territory.

PUBLICATIONS, PRESENTATIONS, AND SEMINARS

Speaker, "The Electrotechnologies Conference," El Paso Electric Company; El Paso, Texas; March 31, 1998.

Speaker, "The Customer Information Seminar," El Paso Electric Company; El Paso, Texas; October 7, 1997.

Speaker, "The Energy Revolution Conference," El Paso Electric Company; UTEP Campus; El Paso, Texas; June 3, 1997.

Speaker, "Customer/Market Segmentation to Optimize Competitive Opportunities," AMRA 1996 Annual Symposium; New Orleans, Louisiana; September 10, 1996.

Speaker, "Customer Segmentation," Infocast; Deloitte & Touche; Strategic Marketing Seminar; Atlanta, Georgia; May 1996.

Speaker, "Reengineering Customer Service & DSM - Keys to Building Competitive Advantage in the Future" with Steven J. Maslak; CARILEC CEO Conference; Freeport, Bahamas; June 1 & 2, 1995.

Speaker, "A Presentation To The Deloitte & Touche Partners" with Steven J. Maslak; Public Utilities SLIP Meeting; Las Vegas, Nevada; December 12-13, 1994.

Speaker, "Demand Side Management Alternatives for the Caribbean," Caribbean High-Level Workshop on Renewable Energy Technologies; December 5-9, 1994.

Speaker, "Projects For Energy Efficiency, And The Conservation Of Economic And Environmental Resources," The Caribbean Workshop On Renewable Energy Technologies; St. Lucia, West Indies; December 5-8, 1994.

Speaker, "Demand Side Management As An Economic Development Tool," MEUA Conference; Syracuse, New York; October 13, 1994.

Speaker, "The Effect Of The Market Transformation Phenomenon On DSM And Utility Competitiveness," EUMMOT Fall 1994 Meeting; Corpus Christi, Texas; September 9, 1994.

Speaker, "Evaluation Protocols: Preparing For DSM Evaluation," Presentation to the 4th Quarter EUMMOT Meeting; Columbia Lakes, Texas; December 13, 1993.

Author, "Incentive Regulation in the United States: an Update," EEI; 1992.

Speaker, "The Career Challenges Facing the Electric Industries in the 1990's," Hofstra University, M.B.A. Career Forum; Hempstead, New York; April 1992.

Speaker, "DSM Evaluation for Incentives: How Heavy Should the Burden of Proof Be?" Washington Gas Least-Cost Planning Conference; Washington D.C.; April 1992.

Speaker, "Practical Cases in Evaluating Energy Efficiency Initiatives," Hydro-Quebec Symposium; Montreal, Canada; November 1992.

Author, "Integration of Load Research into the DSM Evaluation Framework," Chapter 8; DOE DSM Evaluation Handbook.

Speaker, "Measuring the Impacts of Demand Side Management Programs," Northern States Power DSM Evaluation Overview; Minneapolis, Minnesota; December 1991.

Speaker, "Incentive Regulation an Overview of Operating Incentive Programs in the U.S. Today," The Southeastern Electric & Gas Conference; University of Georgia; Atlanta, Georgia; August 1991.

Speaker, "The Comparative Costs of and Sensitivities Surrounding the ALWR vs. Alternate Generation Options," EEI Working Group; Washington D.C.; July 1991.

Speaker, "The Role of Load Research in DSM Evaluation," NYSEG Conference; Saratoga Springs, New York; May 1991.

Speaker, "The Role of Load Research in Demand Side Management" with Joseph Lopes; Northeast AEIC Load Research Conference; Farmington, Connecticut; September 1989.

Speaker, "The Role of Load Research in Demand Side Management," 1989 APPA Accounting, Finance, Rates and Information Systems Workshop; Chicago, Illinois; September 1989.

Speaker, "Demand Side Management; The Key to Measuring Success and Cost Recovery," Iowa Utility Association; Integrated Resource Planning Conference; Des Moines, Iowa; August 1989.

Speaker, "DSM Program Monitoring & Evaluation Workshop," Rochester, New York; December 1988.
Speaker, "The Massachusetts Joint Utility Monitoring Projects" with Eric P. Cody; Northeast Regional AEIC Load Research Conference; Farmington, Connecticut; September 1986.

Author, "The Load Research Process Above and Beyond PURPA," Public Utilities Fortnightly; March 18, 1982.

"Load Data Management and Analysis," EPRI RP1588-3; December 1981.

Co-Author, "Issues in Load Research," Topic Paper 3; EPRI Rate Design Study; 1981.

Instructor, "Load Research and Load Management Seminar," Stone and Webster Utility Management Development Course; New York (2 courses); 1980.

Speaker, "Allocating Revenues Between Service Classifications: Necessary Load Research," National Regulatory Research Institute; Ohio State University; 1980.

Speaker, "Issues in Load Research," EPRI Rate Design Study Executive Transfer Conferences; San Francisco, Kansas City, and Washington D.C.; 1980.

"How Electric Utilities Forecast," EPRI Peak Load Forecasting Methodologies; EPRI Symposium Proceedings; New Orleans, Louisiana; 1979.

"Report of the Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Article 3, Section 5, 112 of the Energy Law of New York State, Exhibit 7," LILCO Load Forecast Methodology; 1979.

Speaker, "Load Forecasting Working Group Chairman Reports (3)," Utility Modeling Forum (EPRI sponsored); San Francisco, California; 1979.

"Report of the Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Article 8, Section 149-b of the Public Service Law, Exhibit 7," LILCO Load Forecast Methodology; 1974-1978.

AFFILIATIONS

Association of Energy Engineers

American Statistical Association

American Economic Association

Mathematical Association of America

Omicron Delta Epsilon

Advisor to American Management Association

EDUCATION

St. John's University, M.B.A., Economic Theory, 1972

St. John's University, B.A., Economics, 1969

C.W. Post College, course work toward an MS, Management Engineering

Mr. Fitzpatrick has also completed course work in Engineering Economics, Load Research, Demand Forecasting in Electric Power Systems, Box-Jenkins Forecasting Techniques, logistic curve analyses; two and three stage multiple regression techniques; advanced econometric modeling and the utilization and interpretation of multiple regression models and associated analytical techniques. Mr. Fitzpatrick also holds a "Certificate of Mastery" in Reengineering from the Hammer Institute's Speaker: Center for Reengineering Leadership.

APS Baseload Generation Summary

Unit Name	Type	Year in Service	Fuel	Ownership	Net Accredited Capacity (MW)	PNW Share (%)	Capacity Owned by PNW (MW)	Category for Comparison
CHOLLA								
Unit 1	Steam	1962	Coal	APS	110	100	110	A - Small Old
Unit 2	Steam	1978	Coal	APS	260	100	260	B- Small New
Unit 3	Steam	1980	Coal	APS	260	100	260	B- Small New
FOUR CORNERS								
Unit 1	Steam	1963	Coal	APS	170	100	170	A - Small Old
Unit 2	Steam	1963	Coal	APS	170	100	170	A - Small Old
Unit 3	Steam	1964	Coal	APS	220	100	220	A - Small Old
Unit 4	Steam	1969	Coal	APS-SRP-PNM-	750	15	113	C- Large Pressurized
Unit 5	Steam	1970	Coal	SCE-TEP-EPE	750	15	113	C- Large Pressurized
NAVAJO								
Unit 1	Steam	1974	Coal	APS-SRP-NPC-	750	14	105	D - LG Balance Draft
Unit 2	Steam	1975	Coal	U.S.-TEP-	750	14	105	D - LG Balance Draft
Unit 3	Steam	1976	Coal	LADWP	750	14	105	D - LG Balance Draft
PALO VERDE								
Unit 1	Steam	1986	Uranium	APS-SRP-EPE-	1247	29.1	363	E-PWRs
Unit 2	Steam	1986	Uranium	SCE-PNM-SCP-	1314	29.1	382	E-PWRs
Unit 3	Steam	1988	Uranium	LADWP	1247	29.1	363	E-PWRs

Type	Average Age	Group	Average Size	Total APS Owned	% of Base Load
Mid Size - Coal	1963	A - Small Old	168	670	24%
Mid Size - Coal	1979	B- Small New	260	520	18%
Large Size - Coal	1970	C- Large Pressurized	750	226	8%
Large Size - Coal	1975	D - LG Balance Draft	750	315	11%
Nuclear	1986	E-PWRs	1269	1108	39%
		APS Total		**2,839**	

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**A-Old**
Plant Query Design:	
Unit Type:	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	Utility	Region	Unit Name	Commercial Date
1	HOLYOKE WATER POWER CO.	NPCC	MT TOM #1	7/1/1960
2	NRG ENERGY (NIAGARA MOHAWK POWER CORP.	NPCC	DUNKIRK #4	8/21/1960
3	MIRANT NEW YORK (ORANGE& ROCKLAND)	NPCC	LOVETT #4	3/20/1996
4	MIRANT - NEW ENGLAND	NPCC	LOVETT #4	3/20/1996
5	NRG - NEW YORK	NPCC	DUNKIRK #4	8/21/1960
6	FIRST ENERGY (PENN ELECTRIC)	MAAC	SHAWVILLE #4	4/4/1960
7	POTOMAC ELECTRIC POWER CO.	MAAC	DICKERSON #2	4/14/1960
8	POTOMAC ELECTRIC POWER CO.	MAAC	DICKERSON #3	3/16/1962
9	MIRANT POTOMAC RIVER	MAAC	DICKERSON #2	4/14/1960
10	MIRANT POTOMAC RIVER	MAAC	DICKERSON #3	3/16/1962
11	RELIANT ENERGY SYSTEMS - WEST	MAAC	SHAWVILLE #4	4/4/1960
12	PROGRESS ENERGY CAROLINAS	SERC	ASHEVILLE #1	4/22/1964
13	PROGRESS ENERGY CAROLINAS	SERC	ROBINSON #1	4/30/1960
14	GULF POWER CO.	SERC	SMITH 1	6/1/1995
15	SAVANNAH ELECTRIC AND POWER CO.	SERC	KRAFT #3	5/24/1995
16	SOUTH CAROLINA ELECTRIC & GAS CO.	SERC	CANADYS #1	4/1/1962
17	SOUTH CAROLINA ELECTRIC & GAS CO.	SERC	CANADYS #2	5/1/1964
18	VIRGINIA POWER	SERC	CHESTERFIELD #4	6/28/1960
19	VIRGINIA POWER	SERC	CHESAPEAKE #4	5/15/1962
20	CINERGY (CINCINNATI GAS & ELECTRIC CO.)	ECAR	MIAMI FORT #6	11/30/1960
21	DUQUESNE LIGHT CO.	ECAR	ELRAMA #4	11/30/1960
22	EAST KENTUCKY POWER COOP., INC.	ECAR	COOPER #1	2/9/1965
23	INDIANAPOLIS POWER & LIGHT CO.	ECAR	HARDING ST #6	5/3/1961
24	LOUISVILLE GAS AND ELECTRIC CO.	ECAR	CANE RUN #4	5/4/1962
25	LOUISVILLE GAS AND ELECTRIC CO.	ECAR	CANE RUN #5	5/13/1966
26	FIRST ENERGY (OHIO EDISON)	ECAR	WH SAMMIS #2	7/1/1960
27	FIRST ENERGY (OHIO EDISON)	ECAR	WH SAMMIS #3	7/1/1961
28	FIRST ENERGY (OHIO EDISON)	ECAR	WH SAMMIS #4	11/13/1962
29	PENNSYLVANIA POWER CO.	ECAR	NEW CASTLE #5	8/1/1964
30	CINERGY (P.S. COMPANY OF INDIANA)	ECAR	GALLAGHER #3	4/15/1960
31	CINERGY (P.S. COMPANY OF INDIANA)	ECAR	GALLAGHER #4	3/1/1961
32	FIRST ENERGY (TOLEDO EDISON)	ECAR	BAYSHORE #3	8/1/1963
33	CINERGY	ECAR	GALLAGHER #3	4/15/1960
34	CINERGY	ECAR	GALLAGHER #4	3/1/1961
35	CINERGY	ECAR	MIAMI FORT #6	11/30/1960
36	AMEREN (CENTRAL ILLINOIS LIGHT)	MAIN	E.D EDWARDS #1	5/1/1960
37	AMEREN-CIPS	MAIN	MEREDOSIA #3	7/14/1960
38	WISCONSIN PUBLIC SERVICE CORP.	MAIN	PULLIAM #8	12/1/1964
39	BASIN ELECTRIC POWER COOP., INC.	MAIN	LELAND OLDS #1	1/30/1966
40	MID AMERICAN ENERGY CO.	MAPP	RIVERSIDE #5	4/11/1961
41	XCEL ENERGY (NORTHERN STATES POWER CO.)	MAPP	BLACK DOG #4	10/1/1960
42	OMAHA PUBLIC POWER DISTRICT	MAPP	NORTH OMAHA #4	2/28/1963
43	KANSAS CITY POWER & LIGHT CO.	SPP	MONTROSE #2	4/9/1960
44	KANSAS CITY POWER & LIGHT CO.	SPP	MONTROSE #3	4/20/1964
45	KPL, A WESTERN RESOURCE CO.	SPP	TECUMSEH #8	4/17/1962
46	KPL, A WESTERN RESOURCE CO.	SPP	LAWRENCE #4	3/11/1960
47	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #1	5/1/1963
48	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #2	6/1/1963
49	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #3	4/1/1964
50	ARIZONA PUBLIC SERVICE CO.	WECC	CHOLLA #1	3/8/1962
51	XCEL ENERGY (PS CO. OF COLORADO)	WECC	CHEROKEE #3	6/15/1962
52	XCEL ENERGY (PS CO. OF COLORADO)	WECC	VALMONT #5	5/1/1964
53	XCEL ENERGY (PS CO. OF COLORADO)	WECC	HAYDEN #1	7/19/1965
54	PACIFICORP	WECC	NAUGHTON #1	5/15/1963

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**B-New**
Plant Query Design:	
Unit Type:	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	Utility	Region	Unit Name	Commercial Date
1	SOUTH CAROLINA PUBLIC SERVICE	SERC	WINYAH #2	3/31/1977
2	SOUTH CAROLINA PUBLIC SERVICE	SERC	WINYAH #3	4/24/1980
3	SOUTH CAROLINA PUBLIC SERVICE	SERC	WINYAH #4	5/30/1981
4	COLUMBUS SOUTHERN POWER CO.	ECAR	CONESVILLE #5	11/24/1976
5	COLUMBUS SOUTHERN POWER CO.	ECAR	CONESVILLE #6	6l 1/1978
6	EAST KENTUCKY POWER COOP., INC.	ECAR	SPURLOCK #1	7/25/1977
7	LOUISVILLE GAS AND ELECTRIC CO.	ECAR	MILL CREEK #3	6/28/1978
8	NORTHERN INDIANA PUBLIC SERVICE	ECAR	R.M. SCHAHFER #17	3/29/1983
9	AMEREN (CENTRAL ILLINOIS LIGHT)	MAIN	DUCK CREEK #1	6/26/1976
10	ALLIANT ENERGY (WISCONSIN P&L)	MAIN	EDGEWATER #5	3/1/1985
11	WISCONSIN PUBLIC SERVICE CORP.	MAIN	WESTON #3	12/23/1981
12	DAIRYLAND POWER COOP.	MAPP	MADGETT #1	11/3/1979
13	ALLIANT ENERGY (INTERSTATE PWR)	MAIN	LANSING #4	5/10/1977
14	OTTER TAIL POWER CO.	MAPP	COYOTE #1	5/1/1981
15	SOUTHWESTERN PUBLIC SERVICE CO.	SPP	HARRINGTON #1	7/2/1976
16	SOUTHWESTERN PUBLIC SERVICE CO.	SPP	HARRINGTON #2	5/18/1978
17	SOUTHWESTERN PUBLIC SERVICE CO.	SPP	HARRINGTON #3	5/28/1980
18	SUNFLOWER ELECTRIC COOP., INC.	SPP	HOLCOMB #1	8/1/1983
19	WESTERN FARMERS ELECTRIC COOP	SPP	HUGO #1	4/1/1982
20	ARIZONA PUBLIC SERVICE CO.	WECC	CHOLLA #2	5/15/1978
21	ARIZONA PUBLIC SERVICE CO.	WECC	CHOLLA #3	5/15/1980
22	MONTANA POWER CO.	WECC	COLSTRIP #2	9/23/1975
23	MONTANA POWER CO.	WECC	COLSTRIP #1	5/22/1976
24	NEVADA POWER CO.	WECC	REID GARDNER #4	6/10/1983
25	PLATTE RIVER POWER AUTHORITY	WECC	RAWHIDE #1	4/1/1984
26	XCEL ENERGY (PS CO. OF COLORADO)	WECC	COMANCHE #2	11/25/1975
27	XCEL ENERGY (PS CO. OF COLORADO)	WECC	HAYDEN #2	9/1/1976
28	SALT RIVER PROJECT	WECC	CORONADO #1	7/21/1979
29	SALT RIVER PROJECT	WECC	CORONADO #2	8/2/1980
30	PACIFICORP	WECC	HUNTER #1	6/1/1978
31	PACIFICORP	WECC	HUNTER #2	6/4/1980
32	PACIFICORP	WECC	HUNTER #3	6/1/1983
33	PACIFICORP	WECC	CHOLLA #4	6/5/1981
34	PACIFICORP	WECC	HUNTINGTON #1	6/1/1977
35	TUCSON ELECTRIC POWER CO.	WECC	SPRINGERVILLE #1	6/1/1985

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type:	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200
Furnance Draft Type	Pressurized Draft

	Utility	Region	Unit Name	Commercial Date
1	FIRST ENERGY "PENN ELECTRIC)	MAAC	KEYSTONE #1	6/18/1967
2	FIRST ENERGY "PENN ELECTRIC)	MAAC	KEYSTONE #2	8/13/1968
3	PENNSYLVANIA POWER & LIGHT CO.	MAAC	BRUNNER ISLAND #3	6/13/1969
4	PENNSYLVANIA POWER & LIGHT CO.	MAAC	MONTOUR #1	2/1/1971
5	PENNSYLVANIA POWER & LIGHT CO.	MAAC	MONTOUR #2	4/30/1973
6	RELIANT ENERGY SYSTEMS - WEST	MAAC	KEYSTONE #1	6/18/1967
7	RELIANT ENERGY SYSTEMS - WEST	MAAC	KEYSTONE #2	8/13/1968
8	ALABAMA POWER CO.	SERC	BARRY 5	10/19/1971
9	GEORGIA POWER CO.	SERC	BOWEN 1	10/21/1971
10	GEORGIA POWER CO.	SERC	BOWEN 2	9/26/1972
11	APPALACHIAN POWER CO.	ECAR	AMOS #1	9/1/1971
12	APPALACHIAN POWER CO.	ECAR	AMOS #2	6/6/1972
13	COLUMBUS SOUTHERN POWER CO.	ECAR	CONESVILLE #4	6/7/1973
14	KENTUCKY POWER CO.	ECAR	BIG SANDY #2	7/24/1969
15	OHIO POWER CO.	SCAR	MITCHELL #1	4/22/1970
16	OHIO POWER CO.	SCAR	MITCHELL #2	3/18/1971
17	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #4.	5/22/1969
18	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #5	4/6/1970
19	SOUTHERN CALIFORNIA EDISON CO.	WECC	MOHAVE #1	11/27/1970
20	SOUTHERN CALIFORNIA EDISON CO.	WECC	MOHAVE #2	7/21/1971

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**D-Balance Draft**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1970-1980
Net Dependable Capacity (MW)	650-850
Furnance Draft Type	Balanced Draft

	Utility	Region	Unit Name	Commercial Date
1	FIRST ENERGY (PENN ELECTRIC)	MAAC	CONEMAUGH #1	5/21/1970
2	FIRST ENERGY (PENN ELECTRIC)	MAAC	CONEMAUGH #2	5/27/1971
3	RELIANT ENERGY SYSTEMS - WEST	MAAC	CONEMAUGH #1	5/21/1970
4	RELIANT ENERGY SYSTEMS - WEST	MAAC	CONEMAUGH #2	5/27/1971
5	ALABAMA POWER CO.	SERC	GORGAS10	10/27/1972
6	DUKE POWER CO.	SERC	MARSHALL #4	5/1/1970
7	GEORGIA POWER CO.	SERC	WANSLEY 1	8/1411976
8	GEORGIA POWER CO.	SERC	WANSLEY 2	1/14/1978
9	DETROIT EDISON CO.	ECAR	MONROE #1	5/3/1971
10	DETROIT EDISON CO.	ECAR	MONROE #2	1/14/1973
11	DETROIT EDISON CO.	ECAR	MONROE #3	3/11/1973
12	DETROIT EDISON CO.	ECAR	MONROE #4	3/16/1974
13	PENNSYLVANIA POWER CO.	ECAR	BRUCE MANSFIELD #1	4/5/1976
14	PENNSYLVANIA POWER CO.	ECAR	BRUCE MANSFIELD #2	10/1/1977
15	PENNSYLVANIA POWER CO.	SCAR	BRUCE MANSFIELD #3	9/29/1980
16	ALLEGHENY ENERGY SUPPLY (ECAR)	SCAR	HARRISON #3	12/31/1974
17	KANSAS CITY POWER & LIGHT CO.	SPP	LA CYGNE #1	6/1/1973
18	SALT RIVER PROJECT - ARIZONA PUBLIC SERVICE	WECC	NAVAJO #1	2/1/1974
19	SALT RIVER PROJECT - ARIZONA PUBLIC SERVICE	WECC	NAVAJO #2	12/3/1974
20	SALT RIVER PROJECT - ARIZONA PUBLIC SERVICE	WECC	NAVAJO #3	11/29/1975

**Statistical Comparison of APS Baseload Plant Performance vs.
Performance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004**

Group:	**A-Old**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Cholla (1) Four Corners (1,2,3))	70.14	85.62	6.03	68.49	85.23	5.70	66.07	85.55	5.88
Mean (Excludes Cholla (1) Four Corners (1,2,3))	68.56	85.36	5.84	66.96	85.13	5.59	64.78	85.39	5.74
Mean (Cholla (1) Four Corners (1,2,3))	85.18	88.09	7.84	83.16	86.18	9.69	78.82	87.09	9.06
Median (Includes Cholla (1) Four Corners (1,2,3))	69.63	88.02	4.52	67.81	87.33	4.43	66.72	88.13	4.53
Median (Excludes Cholla (1) Four Corners (1,2,3))	68.11	87.47	4.33	66.91	87.19	3.97	65.12	87.96	4.11
Median (Cholla (1) Four Corners (1,2,3))	86.30	89.40	7.68	83.15	88.40	9.12	80.80	88.55	8.75
Standard Deviation (Includes Cholla (1) Four Corners (1,2,3))	11.65	8.78	6.11	12.67	9.35	6.36	14.31	9.44	6.14
Standard Deviation (Excludes Cholla (1) Four Corners (1,2,3))	11.01	9.04	6.37	12.19	9.63	6.47	14.05	9.69	6.19
Standard Deviation (Cholla (1) Four Corners (1,2,3))	4.84	5.38	1.92	6.10	6.10	3.06	9.95	6.36	3.35
Count (Includes Cholla (1) Four Corners (1,2,3))	126.00	126.00	126.00	254.00	254.00	254.00	436.00	436.00	436.00
Count (Excludes Cholla (1) Four Corners (1,2,3))	114.00	114.00	114.00	230.00	230.00	230.00	396.00	396.00	396.00
Count (Cholla (1) Four Corners (1,2,3))	12.00	12.00	12.00	24.00	24.00	24.00	40.00	40.00	40.00
Standard Error (Includes Cholla (1) Four Corners (1,2,3))	1.04	0.79	0.55	0.80	0.59	0.40	0.69	0.45	0.29
Standard Error (Excludes Cholla (1) Four Corners (1,2,3))	1.04	0.85	0.60	0.81	0.64	0.43	0.71	0.49	0.31
Standard Error (Cholla (1) Four Corners (1,2,3))	1.46	1.62	0.58	1.27	1.27	0.64	1.59	1.02	0.54
Skewness (Includes Cholla (1) Four Corners (1,2,3))	0.13	(0.82)	0.74	0.16	(0.67)	0.60	(0.13)	(0.82)	0.66
Skewness (Excludes Cholla (1) Four Corners (1,2,3))	0.12	(0.70)	0.71	0.01	(0.64)	0.75	(0.07)	(0.79)	0.79
Skewness (Cholla (1) Four Corners (1,2,3))	(0.70)	(0.73)	0.25	0.00	(1.09)	0.56	(0.60)	(0.69)	0.28

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	A-Old
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	1995			1996			1997			1998			1999		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Cholla (1) Four Corners (1,2,3))	59.80	86.22	6.89	59.80	86.22	6.89	62.41	84.04	5.50	66.74	86.62	5.36	65.70	84.91	6.00
Mean (Excludes Cholla (1) Four Corners (1,2,3))	59.13	85.85	7.00	59.13	85.85	7.00	60.88	83.67	5.14	65.89	86.99	4.74	64.40	84.94	5.51
Mean (Cholla (1) Four Corners (1,2,3))	66.71	90.03	5.75	66.71	90.03	5.75	78.48	87.92	9.26	75.48	82.77	11.69	79.37	84.61	10.98
Median (Includes Cholla (1) Four Corners (1,2,3))	61.26	89.62	4.35	61.26	89.62	4.35	63.78	87.03	4.90	66.51	87.50	5.14	66.74	86.80	5.08
Median (Excludes Cholla (1) Four Corners (1,2,3))	60.35	89.62	3.99	60.35	89.62	3.99	63.30	86.67	4.50	66.32	87.86	4.78	65.02	86.80	4.17
Median (Cholla (1) Four Corners (1,2,3))	68.48	90.73	6.44	68.48	90.73	6.44	80.56	90.50	8.04	77.31	83.13	11.90	78.63	84.85	9.09
Standard Deviation (Includes Cholla (1) Four Corners (1,2,3))	18.24	10.79	7.77	18.24	10.79	7.77	16.01	10.42	4.15	12.87	7.76	3.56	14.43	10.78	5.32
Standard Deviation (Excludes Cholla (1) Four Corners (1,2,3))	18.84	11.04	8.09	18.84	11.04	8.09	15.57	10.84	4.03	13.02	7.97	2.87	14.41	11.21	5.17
Standard Deviation (Cholla (1) Four Corners (1,2,3))	8.75	7.82	3.53	8.75	7.82	3.53	12.33	7.62	3.87	7.37	3.81	4.20	3.54	4.78	4.74
Count (Includes Cholla (1) Four Corners (1,2,3))	45.00	45.00	45.00	45.00	45.00	45.00	46.00	46.00	46.00	45.00	45.00	45.00	46.00	46.00	45.00
Count (Excludes Cholla (1) Four Corners (1,2,3))	41.00	41.00	41.00	41.00	41.00	41.00	42.00	42.00	42.00	41.00	41.00	41.00	42.00	42.00	41.00
Count (Cholla (1) Four Corners (1,2,3))	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

Group:	**A-Old**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	2000			2001			2002			2003			2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Cholla (1) Four Corners (1,2,3))	67.45	85.47	4.07	66.44	84.14	6.03	70.30	86.42	5.59	69.34	84.52	6.81	70.81	85.98	5.70
Mean (Excludes Cholla (1) Four Corners (1,2,3))	67.02	85.47	5.24	64.91	84.34	5.24	68.72	86.25	5.27	67.83	84.16	6.63	69.16	85.72	5.63
Mean (Cholla (1) Four Corners (1,2,3))	83.49	85.47	10.29	80.59	82.27	13.38	84.94	87.98	8.47	84.09	88.02	8.62	86.50	88.44	6.43
Median (Includes Cholla (1) Four Corners (1,2,3))	67.45	88.54	4.07	65.38	85.20	3.84	70.44	88.61	3.18	68.45	86.66	4.94	71.07	87.98	5.45
Median (Excludes Cholla (1) Four Corners (1,2,3))	66.75	88.75	3.56	64.41	85.83	3.11	69.45	88.34	3.02	67.96	85.60	4.89	68.17	87.47	5.07
Median (Cholla (1) Four Corners (1,2,3))	85.03	87.59	10.44	81.20	81.79	12.18	86.12	89.61	8.11	86.31	88.87	8.84	86.38	89.61	6.09
Standard Deviation (Includes Cholla (1) Four Corners (1,2,3))	12.43	9.35	5.65	13.42	9.59	8.86	11.85	8.64	7.16	11.86	10.18	6.95	11.47	7.33	4.21
Standard Deviation (Excludes Cholla (1) Four Corners (1,2,3))	11.82	9.60	5.71	12.97	9.85	8.81	11.31	8.94	7.46	11.31	10.48	7.24	10.66	7.52	4.42
Standard Deviation (Cholla (1) Four Corners (1,2,3))	7.58	7.61	2.03	9.22	7.54	5.79	4.54	5.85	1.84	5.25	6.46	2.71	5.78	5.38	1.22
Count (Includes Cholla (1) Four Corners (1,2,3))	41.00	41.00	41.00	41.00	41.00	41.00	41.00	41.00	41.00	43.00	43.00	43.00	42.00	42.00	42.00
Count (Excludes Cholla (1) Four Corners (1,2,3))	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	39.00	39.00	39.00	38.00	38.00	38.00
Count (Cholla (1) Four Corners (1,2,3))	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**B-New**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Cholla (2,3))	77.54	87.22	6.11	77.72	87.44	5.63	75.26	87.53	5.59
Mean (Excludes Cholla (2,3))	77.82	87.31	5.78	77.76	87.50	5.34	75.30	87.40	5.47
Mean (Cholla (2,3))	73.00	80.27	11.17	77.17	84.73	10.07	74.59	89.15	6.96
Median (Includes Cholla (2,3))	78.75	88.04	4.42	78.17	88.40	4.21	76.94	88.73	4.17
Median (Excludes Cholla (2,3))	78.75	87.93	4.72	77.96	88.29	4.20	76.94	88.51	4.19
Median (Cholla (2,3))	79.51	96.30	11.17	81.04	93.55	10.07	77.03	94.65	7.24
Standard Deviation (Includes Cholla (2,3))	11.18	8.50	6.71	10.41	7.94	5.49	12.23	8.02	5.41
Standard Deviation (Excludes Cholla (2,3))	10.76	7.47	5.36	10.24	7.41	4.63	12.26	7.71	5.03
Standard Deviation (Cholla (2,3))	17.32	29.52	10.92	13.41	19.88	7.82	12.19	15.95	4.83
Count (Includes Cholla (2,3))	104.00	104.00	104.00	205.00	205.00	205.00	345.00	345.00	345.00
Count (Excludes Cholla (2,3))	98.00	98.00	98.00	193.00	193.00	193.00	325.00	325.00	325.00
Count (Cholla (2,3))	6.00	3.00	3.00	12.00	6.00	6.00	20.00	10.00	10.00
Standard Error (Includes Cholla (2,3))	1.10	0.84	0.66	0.73	0.56	0.38	0.66	0.43	0.29
Standard Error (Excludes Cholla (2,3))	1.09	0.76	0.54	0.74	0.53	0.33	0.68	0.43	0.28
Standard Error (Cholla (2,3))	7.74	20.87	7.73	4.04	8.89	3.50	2.80	5.32	1.61
Skewness (Includes Cholla (2,3))	-0.32	-0.29	0.75	(0.13)	(0.36)	0.78	-0.41	-0.45	0.78
Skewness (Excludes Cholla (2,3))	-0.26	-0.25	0.59	(0.06)	(0.32)	0.74	-0.40	-0.43	0.76
Skewness (Cholla (2,3))	-1.13	-1.63	0.00	(0.87)	(1.33)	(0.00)	-0.60	-1.03	-0.17

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**B-New**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	1995			1996			1997			1998			1999		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Cholla (2,3))	69.52	87.99	4.37	69.56	87.69	5.43	70.42	85.49	6.36	76.74	89.51	5.11	77.71	88.55	4.73
Mean (Excludes Cholla (2,3))	69.81	87.37	4.52	69.63	87.14	5.54	70.26	85.05	6.61	76.77	89.48	5.07	77.73	88.78	4.38
Mean (Cholla (2,3))	64.84	98.13	2.01	68.48	96.70	3.71	73.04	92.85	2.35	76.27	90.00	2.21	77.27	84.80	10.21
Median (Includes Cholla (2,3))	73.19	89.02	3.36	72.11	90.79	4.41	72.71	87.04	4.40	75.00	90.04	4.14	77.30	89.23	3.91
Median (Excludes Cholla (2,3))	73.19	88.29	3.54	72.65	89.30	4.50	71.75	86.20	4.63	75.00	90.04	4.14	77.30	89.23	3.51
Median (Cholla (2,3))	64.84	98.13	4.75	68.48	96.70	3.71	73.04	77.85	2.35	76.27	90.00	2.21	77.27	84.80	10.21
Standard Deviation (Includes Cholla (2,3))	15.75	8.26	3.36	15.53	9.39	4.64	12.89	8.64	6.63	10.16	5.76	3.66	8.65	7.06	3.46
Standard Deviation (Excludes Cholla (2,3))	15.78	8.10	3.41	15.98	9.39	4.76	13.28	8.70	6.76	10.44	5.78	3.67	8.74	6.89	3.08
Standard Deviation (Cholla (2,3))	20.52	0.53	3.50	5.82	1.27	0.95	1.05	0.92	0.82	5.52	7.78	0.05	9.81	12.02	6.15
Count (Includes Cholla (2,3))	34	35	34	34	35	34	34	35	34	34	35	34	34	35	34
Count (Excludes Cholla (2,3))	32	33	32	32	33	32	32	33	32	32	33	32	32	33	32
Count (Cholla (2,3))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

Group:	**B-New**
Plant Query-Design:	
Unit Type	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	2000			2001			2002			2003			2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Cholla (2,3))	79.26	87.75	5.11	76.43	86.57	6.44	77.22	88.25	5.80	77.20	87.01	6.29	77.96	86.40	6.23
Mean (Excludes Cholla (2,3))	79.04	87.80	5.01	75.94	86.38	6.26	77.30	88.15	5.87	78.27	88.04	4.96	77.71	85.76	6.50
Mean (Cholla (2,3))	82.75	87.00	6.64	83.60	89.50	9.01	75.90	89.85	4.63	60.63	70.65	26.92	82.08	96.95	1.97
Median (Includes Cholla (2,3))	79.86	87.59	3.87	77.83	88.81	4.36	77.95	87.76	5.21	78.68	90.00	4.10	78.86	87.61	3.97
Median (Excludes Cholla (2,3))	79.86	87.59	3.35	76.30	88.81	4.09	78.39	87.76	5.50	78.68	90.00	3.99	78.39	87.01	4.68
Median (Cholla (2,3))	82.75	87.00	6.64	83.60	89.50	9.01	75.90	89.85	4.63	60.63	70.65	26.92	82.08	96.95	1.97
Standard Deviation (Includes Cholla (2,3))	7.87	5.61	3.89	12.14	9.17	8.33	10.06	5.74	4.40	13.66	10.75	8.77	10.24	8.49	6.94
Standard Deviation (Excludes Cholla (2,3))	7.88	5.55	3.99	12.38	9.38	8.56	10.36	5.67	4.53	12.10	8.12	4.48	10.51	8.32	7.07
Standard Deviation (Cholla (2,3))	9.57	9.19	0.17	4.03	6.08	3.92	3.06	9.12	1.34	31.42	34.58	30.89	1.60	1.91	0.54
Count (Includes Cholla (2,3))	33	34	33	31	32	31	34	35	34	33	34	33	34	35	34
Count (Excludes Cholla (2,3))	31	32	31	29	30	29	32	33	32	31	32	31	32	33	32
Count (Cholla (2,3))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Four Corners (4,5))	73.57	83.43	7.84	72.53	82.35	8.68	71.76	82.41	8.57
Mean (Excludes Four Corners (4,5))	72.46	83.51	7.59	71.09	82.12	8.42	70.22	82.06	8.31
Mean (Four Corners (4,5))	82.43	82.83	9.89	83.83	84.23	10.74	83.99	85.16	10.64
Median (Includes Four Corners (4,5))	72.99	86.64	5.87	73.15	84.61	6.73	72.56	85.30	6.28
Median (Excludes Four Corners (4,5))	72.78	86.45	5.76	72.34	83.24	5.89	71.63	84.35	5.60
Median (Four Corners (4,5))	89.55	89.70	9.89	87.55	88.20	10.74	87.55	88.20	10.64
Standard Deviation (Includes Four Corners (4,5))	9.47	9.52	7.41	10.39	9.33	7.84	11.92	9.67	7.85
Standard Deviation (Excludes Four Corners (4,5))	8.23	8.92	7.50	9.50	9.19	8.14	11.29	9.62	7.97
Standard Deviation (Four Corners (4,5))	14.42	14.57	5.39	10.52	10.59	3.48	9.66	9.81	4.63
Count (Includes Four Corners (4,5))	54.00	54.00	54.00	106.00	106.00	106.00	178.00	178.00	178.00
Count (Excludes Four Corners (4,5))	48.00	48.00	48.00	94.00	94.00	94.00	158.00	158.00	158.00
Count (Four Corners (4,5))	6.00	6.00	6.00	12.00	12.00	12.00	20.00	20.00	20.00
Standard Error (Includes Four Corners (4,5))	1.30	1.31	1.02	1.01	0.91	0.76	0.90	0.73	0.59
Standard Error (Excludes Four Corners (4,5))	1.20	1.30	1.09	0.99	0.95	0.84	0.90	0.77	0.64
Standard Error (Four Corners (4,5))	6.45	6.52	2.41	3.17	3.19	1.05	2.22	2.25	1.06
Skewness (Includes Four Corners (4,5))	0.18	(1.01)	0.80	(0.18)	(0.72)	0.74	(0.20)	(0.90)	0.88
Skewness (Excludes Four Corners (4,5))	(0.12)	(0.99)	0.73	(0.39)	(0.37)	0.93	(0.37)	(0.71)	1.02
Skewness (Four Corners (4,5))	(1.48)	(1.41)	-	(1.06)	(1.13)	-	(1.11)	(0.93)	-

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	1995			1996			1997			1998			1999		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Four Corners (4,5))	69.63	84.05	7.74	67.42	79.70	8.92	72.44	84.07	8.72	72.22	82.16	9.84	73.12	83.59	8.22
Mean (Excludes Four Corners (4,5))	67.47	82.67	8.09	65.78	79.09	9.05	72.00	84.65	7.54	70.49	81.53	9.47	71.73	83.19	7.87
Mean (Four Corners (4,5))	86.99	95.06	4.94	80.48	84.55	7.85	75.93	79.45	18.21	86.06	87.19	12.82	84.23	86.79	10.98
Median (Includes Four Corners (4,5))	69.36	88.16	4.75	69.59	80.69	5.35	73.02	87.11	5.57	72.18	84.81	8.00	74.26	85.68	6.70
Median (Excludes Four Corners (4,5))	69.00	86.01	4.75	68.12	80.07	4.99	73.02	87.11	5.57	69.98	82.75	6.56	71.03	84.47	5.31
Median (Four Corners (4,5))	86.99	95.06	4.94	80.48	84.55	7.85	75.93	79.45	18.21	86.06	87.19	12.82	84.23	86.79	10.98
Standard Deviation (Includes Four Corners (4,5))	16.10	10.72	8.00	14.41	11.24	8.91	11.70	9.41	8.73	12.27	9.58	6.71	10.60	7.12	5.84
Standard Deviation (Excludes Four Corners (4,5))	15.76	10.58	8.44	14.42	11.67	9.43	11.87	8.95	6.93	11.87	10.00	7.04	10.42	7.46	6.12
Standard Deviation (Four Corners (4,5))	1.18	1.19	1.19	5.06	7.27	3.49	13.63	15.99	19.31	3.88	1.02	1.03	1.94	1.70	1.46
Count (Includes Four Corners (4,5))	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Count (Excludes Four Corners (4,5))	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Count (Four Corners (4,5))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1986
Net Dependable Capacity (MW)	100-200

	2000			2001			2002			2003			2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Four Corners (4,5))	72.95	81.38	7.36	67.62	78.43	11.34	73.87	84.08	6.99	74.64	84.57	7.24	72.28	81.69	9.30
Mean (Excludes Four Corners (4,5))	71.64	81.11	7.13	65.03	77.27	11.13	73.55	85.10	6.00	72.75	83.81	7.33	71.08	81.61	9.44
Mean (Four Corners (4,5))	83.40	83.55	9.18	85.80	86.52	12.79	76.50	75.90	14.97	89.76	90.63	6.45	81.90	82.38	8.25
Median (Includes Four Corners (4,5))	74.22	81.76	5.77	70.18	78.91	9.04	74.61	87.97	4.83	72.26	87.12	5.49	72.91	84.11	7.28
Median (Excludes Four Corners (4,5))	73.96	81.76	4.66	68.89	77.07	6.86	74.61	87.97	4.50	71.14	86.05	5.49	72.91	84.11	7.28
Median (Four Corners (4,5))	83.40	83.55	9.18	85.80	86.52	12.79	76.50	75.90	14.97	89.76	90.63	6.45	81.90	82.38	8.25
Standard Deviation (Includes Four Corners (4,5))	9.15	6.93	6.34	13.35	12.39	11.74	9.27	10.45	7.19	8.56	6.86	6.73	11.04	10.95	8.31
Standard Deviation (Excludes Four Corners (4,5))	8.43	6.76	6.71	12.09	12.82	12.57	7.61	9.07	6.64	6.94	6.87	7.13	10.15	10.63	8.74
Standard Deviation (Four Corners (4,5))	10.65	10.92	0.62	4.24	4.01	3.03	24.03	21.78	8.59	2.83	3.20	2.38	17.93	18.46	5.20
Count (Includes Four Corners (4,5))	18	18	18	16	16	16	18	18	18	18	18	18	18	18	18
Count (Excludes Four Corners (4,5))	16	16	16	14	14	14	16	16	16	16	16	16	16	16	16
Count (Four Corners (4,5))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**D-Balance Draft**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1970-1980
Net Dependable Capacity (MW)	650-850

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Navajo (1,2,3))	78.15	84.66	6.07	75.66	84.13	6.31	72.62	84.11	6.76
Mean (Excludes Navajo (1,2,3))	77.92	83.36	6.69	74.67	82.67	6.99	71.96	82.90	7.41
Mean (Navajo (1,2,3))	79.32	91.11	2.99	80.51	91.23	2.97	75.92	90.07	3.58
Median (Includes Navajo (1,2,3))	79.17	86.01	3.33	77.07	86.34	3.89	74.90	86.66	4.22
Median (Excludes Navajo (1,2,3))	78.41	83.54	4.33	75.21	84.42	4.72	74.35	86.10	4.82
Median (Navajo (1,2,3))	80.80	93.80	2.94	81.30	93.05	3.07	77.35	91.15	3.36
Standard Deviation (Includes Navajo (1,2,3))	11.40	9.87	5.89	13.68	10.29	6.39	16.79	10.64	7.37
Standard Deviation (Excludes Navajo (1,2,3))	12.30	9.89	6.28	14.60	10.40	6.81	17.95	10.87	7.90
Standard Deviation (Navajo (1,2,3))	5.20	7.11	0.93	5.92	6.00	1.13	8.53	6.93	1.70
Count (Includes Navajo (1,2,3))	54.00	54.00	54.00	106.00	106.00	106.00	178.00	178.00	178.00
Count (Excludes Navajo (1,2,3))	45.00	45.00	45.00	88.00	88.00	88.00	148.00	148.00	148.00
Count (Navajo (1,2,3))	9.00	9.00	9.00	18.00	18.00	18.00	30.00	30.00	30.00
Standard Error (Includes Navajo (1,2,3))	1.57	1.36	0.81	1.34	1.00	0.62	1.26	0.80	0.55
Standard Error (Excludes Navajo (1,2,3))	1.85	1.49	0.95	1.57	1.11	0.73	1.48	0.90	0.65
Standard Error (Navajo (1,2,3))	1.84	2.51	0.33	1.44	1.45	0.27	1.58	1.29	0.32
Skewness (Includes Navajo (1,2,3))	(0.27)	(0.41)	1.40	(0.31)	(0.64)	1.14	(0.41)	(0.72)	1.04
Skewness (Excludes Navajo (1,2,3))	(0.12)	(0.05)	1.13	(0.11)	(0.50)	1.00	(0.40)	(0.88)	0.98
Skewness (Navajo (1,2,3))	(0.85)	(1.13)	0.15	(0.40)	(0.91)	(0.26)	(0.50)	(0.47)	0.40

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**D-Balance Draft**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1970-1980
Net Dependable Capacity (MW)	650-850

	1995			1996			1997			1998			1999		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Navajo (1,2,3))	65.92	82.90	7.39	66.73	83.82	6.82	69.53	85.65	7.53	70.55	84.04	8.02	69.32	82.68	7.47
Mean (Excludes Navajo (1,2,3))	63.76	80.56	8.10	67.57	84.38	7.50	70.12	85.36	7.54	70.48	82.63	8.96	68.15	81.29	8.47
Mean (Navajo (1,2,3))	76.74	94.60	3.81	62.54	81.02	3.40	66.59	87.09	7.46	70.92	91.06	3.31	75.17	89.66	2.45
Median (Includes Navajo (1,2,3))	72.01	88.95	4.47	69.60	87.08	5.68	72.60	85.63	4.76	74.37	89.56	3.94	71.72	84.42	4.28
Median (Excludes Navajo (1,2,3))	67.79	88.18	5.18	73.20	88.17	5.77	73.79	85.54	4.56	76.09	89.12	4.37	71.04	83.78	5.56
Median (Navajo (1,2,3))	77.17	97.09	2.91	62.68	81.03	2.82	63.50	87.74	5.87	73.88	95.19	3.51	73.06	88.52	2.60
Standard Deviation (Includes Navajo (1,2,3))	21.29	14.60	11.16	18.75	8.38	5.93	18.74	7.35	7.64	21.55	13.55	10.64	20.34	9.62	7.46
Standard Deviation (Excludes Navajo (1,2,3))	22.77	14.84	12.13	20.44	8.88	6.23	20.47	7.32	8.27	23.64	14.16	11.47	22.08	9.67	7.81
Standard Deviation (Navajo (1,2,3))	3.30	4.85	2.11	5.50	5.48	2.61	5.81	8.95	4.19	6.00	8.22	1.30	6.55	6.58	0.95
Count (Includes Navajo (1,2,3))	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Count (Excludes Navajo (1,2,3))	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Count (Navajo (1,2,3))	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

D-Balance Draft

Group:	
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1970-1980
Net Dependable Capacity (MW)	650-850

	2000			2001			2002			2003			2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Navajo (1,2,3))	78.07	86.09	6.38	71.49	81.77	5.82	76.50	83.49	6.87	77.86	84.17	5.66	79.98	86.32	5.68
Mean (Excludes Navajo (1,2,3))	77.02	84.60	7.10	68.21	79.67	6.32	75.83	81.22	7.62	78.41	83.83	6.05	79.53	85.05	6.38
Mean (Navajo (1,2,3))	83.30	93.56	2.77	85.71	90.86	3.65	79.87	94.86	3.12	75.15	85.88	3.69	82.26	92.70	2.16
Median (Includes Navajo (1,2,3))	79.93	89.59	4.57	72.94	86.65	4.52	75.64	81.57	3.56	77.93	85.03	3.29	82.47	88.18	3.13
Median (Excludes Navajo (1,2,3))	78.55	88.39	5.01	70.71	83.25	4.75	74.48	79.27	7.51	78.41	85.51	2.34	82.39	87.22	3.14
Median (Navajo (1,2,3))	82.67	94.56	2.73	82.42	88.35	4.28	77.51	95.85	3.39	72.69	84.54	3.99	82.55	96.12	1.45
Standard Deviation (Includes Navajo (1,2,3))	10.61	9.51	5.40	12.67	13.23	7.79	11.75	10.50	5.76	10.04	8.20	5.72	12.71	11.02	6.20
Standard Deviation (Excludes Navajo (1,2,3))	11.34	9.70	5.66	11.27	13.68	8.56	12.71	9.99	6.05	10.78	8.56	6.22	13.78	11.23	6.57
Standard Deviation (Navajo (1,2,3))	2.80	3.16	0.40	8.30	6.15	2.66	4.59	2.16	0.70	5.55	7.33	0.59	5.82	8.72	1.50
Count (Includes Navajo (1,2,3))	18	18	18	16	16	16	18	18	18	18	18	18	18	18	18
Count (Excludes Navajo (1,2,3))	15	15	15	13	13	13	15	15	15	15	15	15	15	15	15
Count (Navajo (1,2,3))	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**E-PWRs Greater than 600MW**
Plant Query Design:	
Unit Type	Nuclear
Date Range	1980-1989
Net Dependable Capacity (MW)	>600

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	90.57	89.64	2.82	90.16	89.26	3.27	87.60	86.91	5.29
Mean (Excludes Palo Verde)	90.80	89.95	2.73	90.20	89.40	3.34	87.41	86.84	5.57
Mean (Palo Verde)	88.44	86.56	3.68	89.84	87.94	2.68	89.49	87.53	2.66
Median (Includes Palo Verde)	91.76	90.20	1.43	91.17	90.04	1.34	89.98	88.50	2.17
Median (Excludes Palo Verde)	92.01	90.76	1.31	91.35	90.16	1.27	90.03	88.66	2.20
Median (Palo Verde)	89.13	87.40	3.67	89.555	87.65	2.53	87.90	86.20	2.34
Standard Deviation (Includes Palo Verde)	8.77	8.05	3.88	9.60	8.08	5.79	12.36	10.90	8.70
Standard Deviation (Excludes Palo Verde)	8.81	7.96	3.85	9.83	8.17	5.96	12.77	11.23	8.97
Standard Deviation (Palo Verde)	8.59	8.70	1.60	7.22	7.20	1.30	7.14	7.00	1.32
Count (Includes Palo Verde)	96.00	96.00	96.00	193.00	193.00	193.00	323.00	323.00	323.00
Count (Excludes Palo Verde)	87.00	87.00	87.00	175.00	175.00	175.00	293.00	293.00	293.00
Count (Palo Verde)	9.00	9.00	9.00	18.00	18.00	18.00	30.00	30.00	30.00
Standard Error (Includes Palo Verde)	0.90	0.83	0.40	0.69	0.58	0.42	0.69	0.61	0.48
Standard Error (Excludes Palo Verde)	0.95	0.86	0.41	0.74	0.62	0.45	0.75	0.66	0.53
Standard Error (Palo Verde)	3.04	3.08	0.57	1.75	1.75	0.32	1.33	1.30	0.25
Skewness (Includes Palo Verde)	(0.40)	(0.21)	1.07	(0.31)	(0.29)	1.00	(0.58)	(0.44)	1.08
Skewness (Excludes Palo Verde)	(0.41)	(0.30)	1.11	(0.35)	(0.28)	1.04	(0.62)	(0.49)	1.13
Skewness (Palo Verde)	(0.24)	(0.29)	0.02	0.12	0.12	0.33	0.67	0.57	0.72

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

E-PWRs Greater than 600MW

Group:	Nuclear
Plant Query Design:	1980-1990
Unit Type	>600
Date Range	
Net Dependable Capacity (MW)	

	1995			1996			1997			1998			1999		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Palo Verde)	80.996	81.281	6.4055	82.812	81.874	11.373	83.4988	82.9194	9.01281	87.7897	87.4764	6.5	87.7897	87.4764	6.5
Mean (Excludes Palo Verde)	80.699	81.203	6.7882	82.269	81.377	12.263	82.749	82.4283	9.6431	87.3277	87.16	6.98214	87.3277	87.16	6.98214
Mean (Palo Verde)	83.967	82.06	2.8333	88.06	86.683	2.7633	90.7467	87.6667	2.92	92.41	90.64	2	92.41	90.64	2
Median (Includes Palo Verde)	81.64	82.39	4.01	85.305	84.635	5.35	85.965	85.595	2.575	89.94	89.11	1.73	89.94	89.11	1.73
Median (Excludes Palo Verde)	80.995	81.65	4.035	84.62	85.72	6.24	85.21	85.75	2.41	89.985	89.24	1.69	89.985	89.24	1.69
Median (Palo Verde)	84.4	82.63	1.87	86.3	83.55	1.85	86.79	84.46	2.76	87.8	86.73	1.73	87.8	86.73	1.73
Standard Deviation (Includes Palo Verde)	13.878	13.669	4.01	13.939	14.166	21.133	13.9371	13.5191	13.2525	17.0329	11.7426	13.8103	17.0329	11.7426	13.8103
Standard Deviation (Excludes Palo Verde)	14.497	14.326	3.5244	14.361	14.595	22.033	14.3011	14.0061	13.925	17.6999	12.1287	14.471	17.6999	12.1287	14.471
Standard Deviation (Palo Verde)	4.4558	3.5792	2.6878	8.8719	9.496	1.8298	7.78021	7.01325	0.39509	8.00208	7.52939	0.47634	8.00208	7.52939	0.47634
Count (Includes Palo Verde)	33	33	31	32	32	32	32	32	31	33	33	31	33	33	31
Count (Excludes Palo Verde)	30	30	28	29	29	29	29	29	28	30	30	28	30	30	28
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

E-PWRs Greater than 600MW

Group:	Nuclear
Plant Query Design:	1980-1990
Unit Type	>600
Date Range	
Net Dependable Capacity (MW)	

	2000			2001			2002			2003			2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Palo Verde)	91.2534	89.8769	2.08034	89.1572	90.0169	2.58452	90.9734	89.7303	2.03786	89.5547	88.4625	3.68034	91.005	90.6856	2.74967
Mean (Excludes Palo Verde)	91.1193	89.7855	2.09308	89.2648	90.4379	2.75071	90.6197	89.4397	2.1708	89.9483	88.7607	3.81154	91.8183	91.6603	2.2137
Mean (Palo Verde)	92.55	90.76	1.97	88.1167	85.9467	1.03333	94.3933	92.54	0.93	85.75	85.58	2.54333	83.1433	81.2633	7.57333
Median (Includes Palo Verde)	90.87	89.66	0.95	93.725	92.38	1.03	91.68	90.025	1.415	91.48	90.155	1.14	91.87	92	1.745
Median (Excludes Palo Verde)	91.05	90.41	0.945	93.79	93.75	1.06	91.35	90.04	1.45	91.79	90.27	1.015	92.54	92.79	1.47
Median (Palo Verde)	90.25	88.66	2.12	87.79	86.29	0.32	92.03	89.95	0.25	87.47	85.88	2.45	84.59	82.81	8.32
Standard Deviation (Includes Palo Verde)	8.27144	7.73059	3.03155	14.4546	9.57541	6.2633	8.62887	7.79123	1.99026	9.4294	8.44795	6.90854	8.78499	8.07806	2.74333
Standard Deviation (Excludes Palo Verde)	8.49488	7.90722	3.19256	15.1608	9.89744	6.56798	8.81964	7.95148	2.03057	9.25707	8.41418	7.29509	8.54176	7.47582	2.21919
Standard Deviation (Palo Verde)	6.88445	7.04866	1.11261	4.33923	4.72437	1.43932	6.76218	6.53217	1.39083	12.4296	10.0634	0.89366	8.5127	9.05957	2.51456
Count (Includes Palo Verde)	32	32	29	32	32	31	32	32	28	32	32	29	32	32	30
Count (Excludes Palo Verde)	29	29	26	29	29	28	29	29	25	29	29	26	29	29	27
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**E-PWRs Greater than 1000MW**
Plant Query Design:	
Unit Type	Nuclear
Date Range	1980-1989
Net Dependable Capacity (MW)	>1000

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	90.46	89.47	3.02	90.53	89.42	2.93	87.86	86.80	5.26
Mean (Excludes Palo Verde)	90.73	89.85	2.93	90.62	89.62	2.97	87.65	86.70	5.61
Mean (Palo Verde)	88.44	86.56	3.66	89.84	87.94	2.57	89.49	87.53	2.56
Median (Includes Palo Verde)	92.27	90.38	1.51	91.55	90.03	1.27	89.98	88.52	2.17
Median (Excludes Palo Verde)	92.67	91.54	1.33	92.22	90.42	1.16	90.12	88.80	2.27
Median (Palo Verde)	89.13	87.40	3.76	89.56	87.65	2.66	87.90	86.20	2.45
Standard Deviation (Includes Palo Verde)	9.12	8.16	4.18	9.65	8.04	4.67	12.36	11.37	9.95
Standard Deviation (Excludes Palo Verde)	9.22	8.08	4.19	9.94	8.15	4.84	12.87	11.83	10.45
Standard Deviation (Palo Verde)	8.59	8.70	1.66	7.22	7.20	1.21	7.14	7.00	1.31
Count (Includes Palo Verde)	78.00	78.00	78.00	156.00	156.00	156.00	262.00	262.00	262.00
Count (Excludes Palo Verde)	69.00	69.00	69.00	138.00	138.00	138.00	232.00	232.00	232.00
Count (Palo Verde)	9.00	9.00	9.00	18.00	18.00	18.00	30.00	30.00	30.00
Standard Error (Includes Palo Verde)	1.04	0.93	0.48	0.77	0.65	0.38	0.76	0.70	0.62
Standard Error (Excludes Palo Verde)	1.12	0.98	0.51	0.85	0.70	0.41	0.85	0.78	0.69
Standard Error (Palo Verde)	3.04	3.08	0.59	1.75	1.75	0.29	1.33	1.30	0.24
Skewness (Includes Palo Verde)	(0.59)	(0.33)	1.08	(0.32)	(0.22)	1.06	(0.52)	(0.45)	0.93
Skewness (Excludes Palo Verde)	(0.63)	(0.63)	1.14	(0.48)	(0.29)	1.13	(0.58)	(0.53)	0.96
Skewness (Palo Verde)	(0.24)	(0.29)	(0.19)	0.12	0.12	(0.22)	0.67	0.57	0.25

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**E-PWRs Greater than 1000MW**
Plant Query Design:	
Unit Type	Nuclear
Date Range	1980-1990
Net Dependable Capacity (MW)	>1000

	1995			1996			1997			1998			1999		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	81.28	81.36	7.32	82.61	81.52	11.88	81.89	81.31	9.93	89.63	87.35	5.96	89.84	86.61	3.45
Mean (Excludes Palo Verde)	80.94	81.28	7.95	81.90	80.84	13.00	80.88	80.48	10.81	89.28	86.94	6.54	89.44	86.04	3.76
Mean (Palo Verde)	83.97	81.96	2.69	88.06	86.79	2.94	89.64	87.67	2.88	92.41	90.64	1.65	92.98	86.04	1.32
Median (Includes Palo Verde)	82.36	82.63	4.06	85.31	84.64	4.87	84.68	84.25	2.63	90.03	89.11	2.55	89.58	87.31	1.17
Median (Excludes Palo Verde)	82.00	83.19	4.40	84.62	85.72	6.08	83.84	84.03	2.52	90.76	89.24	2.74	89.54	87.40	1.12
Median (Palo Verde)	84.40	82.63	1.68	86.30	83.55	2.39	86.79	84.46	2.76	87.80	86.73	1.72	89.98	87.40	1.32
Standard Deviation (Includes Palo Verde)	14.81	14.75	13.37	14.68	15.02	22.86	14.55	14.07	22.83	13.80	12.57	12.40	5.81	6.76	5.29
Standard Deviation (Excludes Palo Verde)	15.66	15.64	14.15	15.27	15.63	24.06	15.08	14.64	24.12	14.44	13.12	13.14	5.76	6.69	5.60
Standard Deviation (Palo Verde)	4.46	3.73	2.68	8.87	9.37	1.72	8.35	7.01	0.44	8.00	7.53	0.94	6.37	6.69	0.23
Count (Includes Palo Verde)	27	27	25	26	26	27	26	26	27	27	27	25	26	26	24
Count (Excludes Palo Verde)	24	24	22	23	23	24	23	23	24	24	24	22	23	23	21
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	23	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

E-PWRs Greater than 1000MW

Group:	Nuclear
Plant Query Design:	1980-1990
Unit Type	>1000
Date Range	
Net Dependable Capacity (MW)	

	2000			2001			2002			2003			2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	91.29	89.77	2.23	90.69	91.72	2.82	91.42	90.09	2.15	89.45	88.27	3.92	90.48	90.05	2.99
Mean (Excludes Palo Verde)	91.12	89.64	2.27	91.03	92.47	3.04	91.04	89.76	2.31	89.71	88.63	4.14	91.43	91.17	2.33
Mean (Palo Verde)	92.55	90.78	1.95	88.12	85.95	1.16	94.39	92.60	1.02	87.42	85.50	2.39	83.14	81.46	7.57
Median (Includes Palo Verde)	90.63	88.80	1.08	93.87	93.91	0.85	92.02	90.09	1.45	92.97	89.95	1.16	91.69	92.00	1.92
Median (Excludes Palo Verde)	90.69	88.91	0.98	94.12	94.66	0.84	92.03	90.04	1.49	93.26	90.68	1.04	93.69	92.79	1.47
Median (Palo Verde)	90.25	88.66	2.12	87.79	86.29	1.20	92.01	90.13	0.52	87.47	91.44	2.45	84.59	82.81	8.32
Standard Deviation (Includes Palo Verde)	8.11	7.71	3.25	14.89	8.85	6.96	8.00	7.10	2.08	10.06	8.97	7.52	9.52	8.60	2.95
Standard Deviation (Excludes Palo Verde)	8.38	7.92	3.48	15.79	9.05	7.41	8.20	7.24	2.13	10.27	9.00	8.03	9.38	8.05	2.40
Standard Deviation (Palo Verde)	6.88	7.09	1.14	4.34	4.72	0.94	6.77	6.50	1.33	9.84	8.32	1.13	8.51	9.32	2.51
Count (Includes Palo Verde)	26	26	24	26	26	25	26	26	25	26	26	24	26	26	24
Count (Excludes Palo Verde)	23	23	21	23	23	22	23	23	22	23	23	21	23	23	21
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Comparison of APS Weighted Baseload Generation (Combined NCF and EAF) vs. Relevant Comparison Groups for the Period 1995-2004

Categories for Comparison are:	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	1995-2004 Group Performance	1995-2004 APS Performance	APS 1995-2004 Vs Group 1995-2004 Average Yearly MHWs	Formula
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Steam Mid - Coal	A-Old	1963	200	670	EAF	85.39	87.09	99,499	
Steam Mid - Coal	B-New	1980	260	520	EAF	87.40	89.15	79,709	
Steam Large - Coal	C-Pressurized	1973	750	226	EAF	82.06	85.16	61,316	
Steam Large - Coal	D-Balance Draft	1973	750	315	EAF	82.90	90.07	197,746	
								438,270	(b)
Nuclear	E-PWRs	1986	>600	1,108	NCF (3)	87.41	89.49	201,635	(a)

Variable Nuclear Production Costs	5.37 Per MWH					
Variable Coal Production Costs	16.80 Per MWH					
Purchase Power Minus Nuclear Prod Costs:	45.54 Per MWh (1)	(c)	Calc Benefit / (Burden) 2005 Dollars Annual	$	9,182,472	e = (a) * (c)
Purchase Power Minus Coal Prod Costs:	34.11 Per MWh (2)	(d)	Calc Benefit / (Burden) 2005 Dollars Annual	$	14,949,443	f = (b) * (d)
			Total Nuclear Calc Benefit / (Burden) x 10yrs.	$	91,824,720	= e * 10
			Total Coal Calc Benefit / (Burden) x 10yrs.	$	149,494,434	= f * 10

(1) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Nuclear $/MWh
(2) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh
(3) 87.41% Capacity Factor is based upon the Average NCF of all PWR Greater than 600 MW

Comparison of APS Weighted Baseload Generation NCF only vs. Relevant Comparison Groups for the Period 1995-2004

Categories for Comparison are:	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	1995-2004 Group Performance	1995-2004 APS Performance	APS 1995-2004 Vs Group 1995-2004 Average Yearly MHWs	Formula
		(1)	(2)	(3)	(4)	(5)	(6) 7	(7)	(8)
Steam Mid - Coal	A-Old	1963	200	670	NCF	64.78	78.82	823,997	
Steam Mid - Coal	B-New	1980	260	520	NCF	75.30	74.60	(31,770)	
Steam Large - Coal	C-Pressurized	1973	750	228	NCF	70.22	83.99	272,686	
Steam Large - Coal	D-Balance Draft	1973	750	315	NCF	71.96	75.92	109,365	
								1,174,278	(b)
Nuclear	E-PWRs	1986	>600	1,108	NCF (3)	87.41	89.49	201,635	(a)

Variable Nuclear Production Costs	5.37 Per MWH					
Variable Coal Production Costs	16.80 Per MWH					
Purchase Power Minus Nuclear Prod Costs:	45.54 Per MWh (1)	(c)	Calc Benefit / (Burden) 2005 Dollars	$	9,182,472	e = (a) * (c)
Purchase Power Minus Coal Prod Costs:	34.11 Per MWh (2)	(d)	Calc Benefit / (Burden) 2005 Dollars	$	40,054,752	f = (b) * (d)
(1) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Nuclear $/MWh			Total Nuclear Calc Benefit / (Burden) x 10yrs.	$	91,824,720	= e * 10
(2) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh			Total Coal Calc Benefit / (Burden) x 10yrs.	$	400,547,519	= f * 10

(3) 87.41% Capacity Factor is based upon the Average NCF of all PWR Greater than 600 MW

Comparison of APS Weighted Baseload Coal Generation EAF vs. Relevant Comparison Groups for the Periods 2002-2004 and 2005 Only

Categories for Comparison are:

	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	2002-2004 Group Performance	2002-2004 APS Performance	2002-2004 Group Performance	2005 Only APS Performance	APS 2002-2004 Vs Coal 2002-2004 Average Yearly MHW's	APS Coal 2005 Only Benefit With Jacobs' Nuclear Disallowance	Formula
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Steam Mid - Coal	A - Small Old	1963	168	670	EAF	85.36	88.09	85.36	92.28	160,533	406,061	
Steam Mid - Coal	B- Small New	1979	260	520	EAF	87.31	85.82	87.31	90.60	(68,006)	149,885	
Steam Large - Coal	C- Large Pressurized	1970	750	226	EAF	83.51	82.83	83.51	86.35	(13,326)	56,295	
Steam Large - Coal	D - LG Balance Draft	1975	750	315	EAF	83.36	91.11	83.36	88.53	213,774	142,643	
										292,975	754,884	(a)

Variable Coal Production Costs	$ 16.80	Per MWH	
Weighted Purchased Power Costs	$ 50.91	Per MWH	
Purchased Power Minus Coal Prod Costs	$ 34.11	*Per MWH	(b)

* Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh

Jacobs' Nuclear Disallowance		$ (17,373,000)	
Calc Benefit / (Burden) 2005 Dollars	$ 9,993,367	$ 25,749,082	c = (a) * (b)
Total Calc Benefit / (Burden)	$ 9,993,367	$ 8,376,082	
Total Calc Benefit / (Burden) x 3 yrs.	$ 29,980,102		= c * 3 yrs.

Comparison of APS Weighted Baseload Coal Generation NCF vs. Relevant Comparison Groups for the Periods 2002-2004 and 2005 Only

Categories for Comparison are:	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	2002-2004 Group Performance	2002-2004 APS Performance	2002-2004 Group Performance	2005 Only APS Performance	APS 2002-2004 Vs Coal 2002-2004 Average Yearly MHW's	APS Coal 2005 Only Benefit With Jacobs' Nuclear Disallowance	Formula
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Steam Mid - Coal	A - Small Old	1963	168	670	NCF	68.56	85.17	68.56	90.95	975,041	1,314,021	
Steam Mid - Coal	B- Small New	1979	260	520	NCF	77.82	73.00	77.82	84.10	(219,324)	286,099	
Steam Large - Coal	C- Large Pressurized	1970	750	226	NCF	72.46	82.42	72.46	85.95	197,308	267,123	
Steam Large - Coal	D - LG Balance Draft	1975	750	315	NCF	77.92	79.32	77.92	84.20	38,613	173,284	
										991,639	2,040,528	(a)

Variable Coal Production Costs	$ 16.80	Per MWH	
Weighted Purchased Power Costs	$ 50.91	Per MWH	
Purchased Power Minus Coal Prod Costs	$ 34.11	*Per MWH	(b)

* Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh

Jacobs' Nuclear Disallowance		$ (17,373,000)	
Calc Benefit / (Burden) 2005 Dollars	$ 33,824,808	$ 69,602,401	c = (a) * (b)
Total Calc Benefit / (Burden)	$ 33,824,808	$ 52,229,401	
Total Calc Benefit / (Burden) x 3 yrs.	$ 101,474,425		= c * 3 yrs.

Comparison of APS Weighted Baseload Coal Generation (EAF) 2005 Only vs. Relevant Comparison Groups for the Period 1999-2004

Categories for Comparison are:	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	1999-2004 Group Performance	2005 Only APS Performance	APS Coal Benefit With Jacobs' Nuclear Disallowance	Formula
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Steam Mid - Coal	A - Small Old	1963	168	670	EAF	85.13	92.28	419,094	
Steam Mid - Coal	B- Small New	1979	260	520	EAF	87.50	90.60	141,379	
Steam Large - Coal	C- Large Pressurized	1970	750	226	EAF	82.12	86.35	83,837	
Steam Large - Coal	D - LG Balance Draft	1975	750	315	EAF	82.67	88.53	161,661	
								805,970	(a)

Variable Coal Production Costs	$ 16.80	Per MWH	
Weighted Purchased Power Costs	$ 50.91	Per MWH	
Purchased Power Minus Coal Prod Costs:	$ 34.11	*Per MWH	(b)

Jacobs' Nuclear Disallowance	$ (17,373,000)	(d)
Calc Benefit / (Burden) 2005 Dollars	$ 27,491,653	c = a * b
Total Calc Benefit / (Burden)	$ 10,118,653	= (d) - c
Total Calc Benefit / (Burden) x 6 yrs.	$ 164,949,916	= c * 6 yrs.

* Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh

REBUTTAL TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. David J. Rumolo.

Q. ARE YOU THE SAME DAVID J. RUMOLO WHO SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A. Yes I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony addresses several areas. First, I comment on the non-rate design elements of the direct testimony filed by the Arizona Corporation Commission Staff ("Staff") and the Residential Utility Consumer Office ("RUCO") regarding cost of service allocations, pro forma adjustments, and the Demand Side Management ("DSM") Adjustment Mechanism. I sponsor an operating income adjustment to the Company's Service Schedule 1. Second, I provide comments on the rate design recommendations of Staff, RUCO, Arizonans for Electric Choice and Competition ("AECC"), Kroger, Federal Executive Agencies ("FEA"), the Distributed Energy Alliance of Arizona ("DEAA") and the Arizona Interfaith Coalition on Energy ("AICE"). Third, I am providing testimony regarding the phase out of frozen rates as provided for in Decision No. 67744. Fourth, my testimony discusses the concept of hook-up fees as a tool to finance system growth and includes a discussion of marginal costs. Fifth, I sponsor two alternative Plans of Administration for the Power Supply Adjustor ("PSA") mechanism. These plans implement the modifications to the

PSA that are discussed in the testimony of APS witnesses Don Robinson, Pete Ewen, and also Staff Witness John Antonuk. Finally, I sponsor calculations that include determining the jurisdictional splits of revenue requirements that are discussed in the Rebuttal Testimony of APS witnesses Froggatt, and Rockenberger.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. Yes. My rebuttal testimony compares production cost allocations proposed by Staff and energy allocation methods proposed by AECC with the methods used in the APS rate case filing. I conclude that the alternative methods shift cost responsibility between customer classes but when the alternatives are combined, the class revenue responsibilities are not that different from those proposed by APS. The alternative methods can shift cost responsibility within a class. My testimony notes that alternative rate designs proposed by intervenors can result in higher rate increases for lower load factor customers. My testimony rebuts rate design arguments of DEAA and note that some of DEAA's arguments simply cannot be factually supported. I also discuss the concept of hook-up fees and conclude that not only are such fees an expensive way to finance plant additions, but that this is a complicated issue and that such a policy decision should involve other parties who may not be participating in this rate case but who will be impacted by the policy. Therefore, I agree with Staff and RUCO that the hook-up fee discussion should occur in the context of generic workshops for all utilities.

III. NON- RATE DESIGN TESTIMONY OF STAFF, RUCO AND INTERVENORS

Q. HAVE YOUR REVIEWED THE DIRECT TESTIMONY FILED BY ACC STAFF, RUCO AND INTERVENORS IN THIS CASE?

A. Yes, I have.

Q. DO YOU HAVE ANY COMMENTS TO OFFER ON THE DIRECT TESTIMONY?

A. Yes, I do. First, I will address the testimony of Staff Witness Brosch regarding demand allocation methods.

Q. DOES STAFF WITNESS BROSCH PROPOSE UTILIZING A DEMAND ALLOCATION METHOD THAT ALLOCATES PRODUCTION COSTS AMONG THE RETAIL CLASSES THAT IS DIFFERENT THAN PROPOSED BY APS IN ITS FILING?

A. Yes. In our filing, APS allocated production demand based on a coincident peak method, specifically, the 4CP method that allocates capacity costs to each jurisdiction and to each customer class within the ACC jurisdiction based on the class contribution to the APS peak during the summer months. Staff Witness Brosch 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.

Q. WHY DID APS ELECT TO USE THE 4CP METHOD?

A. The 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 we were directed to use by the Federal Energy Regulatory Commission ("FERC") in previous federal rate case litigation. Because of the magnitude of the requested revenue increase in this case, I was concerned that adopting an alternative demand allocation method for customer class allocations could introduce a higher degree of rate shock to some customers.

Q. HAVE YOU PERFORMED ANY ANALYSIS OF THE CUSTOMER CLASS ALLOCATION METHOD PROPOSED BY MR. BROSCH?

A. Yes. We compared the results of the cost of service study that was the basis of our filing with the results of a cost of study that utilized the 4CP method for the jurisdictional allocation, i.e. the allocation of costs between retail and "all other" and then used the Peak and Average method for the allocation of production demand costs to the retail customer classes.

Q. WHAT WERE THE RESULTS OF YOUR COMPARISON OF THE TWO METHODS?

A. The retail cost allocations shifted between customer classes when the Peak and Average method was used with more costs shifted to general service customers and reduced cost allocation to residential customers. More costs were also shifted to irrigation and lighting service customers. The results of the studies are presented in Attachment DJR-1RB.

Q. WOULD YOU PLEASE EXPLAIN ATTACHMENT DJR-1RB?

A. Yes. The exhibit compares the relative rates of return, based on the revenue requirements requested in APS filing for each customer class under a 4CP allocation method and the method proposed by Staff Witness Brosch. Required rate increases, again based on the APS requested overall increase (less the RES surcharge) of 21.1 %, if each customer class contributed allocated costs of service and earned the same rate of return, under the 4CP and 4CP/Peak and Average methods are also displayed. For example, to achieve a levelized rate of return of 8.73%, which is the requested jurisdiction rate of return on original cost rate base, the residential customer class would experience a 27.1% increase and the general service class would experience a 14.9% increase under the 4CP method. Under the 4CP/Peak and Average method, the residential class would experience a 25.2 % increase while the general service class would experience a 16.3 % increase.

Q. WHAT DID YOU CONCLUDE AS A RESULT OF YOUR COMPARISON?

A. I concluded that, in this rate case, the two methods yield very similar results for the two largest customer classes, i.e. residential and general service. Within the general service class and for the irrigation and lighting classes, the 4CP/Peak and Average method for production demand allocation results in higher revenue requirements than the 4CP method.

Q. IN HIS TESTIMONY, STAFF WITNESS DITTMER PROPOSES A $19,000 ADJUSTMENT TO APS REVENUES RELATED TO A CHANGE IN SERVICE SCHEDULE 1 RELATED TO PAPERLESS BILLS. DO YOU AGREE WITH THAT ADJUSTMENT?

A. Yes, I do.

Q. DO YOU HAVE ANY COMMENTS ON THE DIRECT TESTIMONY OF RUCO'S WITNESSES?

A. Yes. RUCO Witness Diaz Cortez (Direct testimony at pages 38-40) proposed to disallow the APS modification to the Demand Side Management ("DSM") mechanism that would provide for interest accrual on the DSM spending in excess of the $10 million included in base rates. APS has requested the interest accrual for future recovery because the recovery of DSM expenditures in excess of the base amount occurs in years following the expenditures, thus APS incurs carrying costs until the recovery occurs. Therefore, the recovery of interest on the un-recovered DSM costs is appropriate. While RUCO Witness Diaz Cortez is correct that interest accrual was not explicitly addressed by the parties to the settlement agreement approved in Decision No. 67744 ("Settlement Agreement"), the APS proposal is consistent with other adjustment mechanisms such as the PSA that were part of the Settlement Agreement. I believe that not including the interest component for this adjustment mechanism to be merely a drafting oversight. In any event, it is only reasonable for APS to collect interest associated

with DSM costs since APS is required to make DSM investments and then file for approval to collect the funds on an after-the-fact basis in the following year.

IV. RATE DESIGN TESTIMONY

Q. HAVE YOU REVIEWED THE RATE DESIGN TESTIMONY FILED BY STAFF AND INTERVENORS ON SEPTEMBER 1, 2006?

A. Yes, I have.

Q. PLEASE PROVIDE A SUMMARY OF YOUR UNDERSTANDING OF THE TESTIMONY THAT WAS PROVIDED.

A. My comments focus on the overall rate designs and general rate levels. Obviously, Staff, RUCO and others offer rate designs based on revenue levels that are lower than the revenue level that was requested by APS. In general, the testimony filed on September 1 focused on how the increased revenue requirement should be allocated to the customer classes. For example, AECC offers demand rate alternatives that recover additional revenue requirements thorough demand charges as compared to the APS proposed rate designs. AECC also recommends that APS adopt an energy allocation method that recognizes the hourly variations in energy costs. The witnesses for Kroger and the FEA suggest demand rate alternatives similar to the alternatives recommended by AECC. These demand alternative proposals will produce relative rate increases for low load factor customers that will be higher than high load factor customers. Additionally, these witnesses that represent general service customers recommend that residential rates be increased more than the increases for the general service customers.

Staff does not offer specific rate designs for all schedules but provide recommendations regarding rate modifications, service schedule modifications,

and the phase-out of frozen rates.

Q. DOES APS OBJECT TO STAFF'S RECOMMENDATIONS REGARDING THE PHASE OUT OF FROZEN RATE SCHEDULES?

A. Staff's recommendations provide for a longer phase out period, one year for residential customers and six months for general service customers, than in the APS phase out plan. APS accepts Staff's recommendation for the longer time frame provided that the interim rates are revenue neutral compared to the rates to which the customer will be transferred.

Q. DO YOU HAVE ANY OTHER COMMENTS ON STAFF'S PROPOSED RATE DESIGNS?

A. Yes, Staff has recommended that the rate designs for the new residential time of use rates (Schedules ET-2 and ECT-2R) that were approved earlier this year be revenue neutral compared to Schedules ET-1 and ECT-1R. Any rate design alternatives proposed in this case should also be revenue neutral. We are gathering information on customers' usage patterns as customers opt for these new rates but during the interim period, revenue neutrality should be maintained.

Q. DID STAFF HAVE ANY SPECIFIC RECOMMENDATIONS FOR THE GENERAL SERVICE RATE SCHEDULES?

A. Yes, Staff suggested that the demand component of Schedule E-32 not be increased significantly. Staff also suggested that APS examine breaking up Schedule E-32 into usage divisions in its next rate case. I agree with these suggestions.

Q. STAFF HAS ALSO RECOMMENDED SOME CHANGES TO PROPOSED SCHEDULE 3. PLEASE COMMENT ON THOSE CHANGES.

A. We agree with Staff's changes, except for the recommendation regarding the timing of field audits, and have incorporated changes into a revised schedule.

Field audits are required at the end of 18 months in the case of Residential Homebuilder Subdivision extensions since that time period determines if additional advances are required. For other types of extensions, advances are made at the time the extension agreement is executed. Therefore, the field audits are not needed. We have also increased the construction allowance for multifamily housing projects from $500 to $1000 per unit and modified the provisions for refunds in Residential Custom Home "Lot Sale" Development extensions to allow for refunds. The revised Schedule 3 is attached and marked Attachment DJR–2RB. The revised schedule also corrects formatting and typographic errors in the original document. A redlined version that compares the final document with the version found in the testimony of Staff Witness Erin Andreasen is attached as Attachment DJR-3RB.

Q. PLEASE COMMENT ON RUCO'S PROPOSED RATE DESIGNS.

A. RUCO's designs follow the rate designs that were a result of the Settlement Agreement and are generally an "across the board" approach. I believe that, because of the high energy costs that comprise a significant part of the increase requested in this case, an across the board approach will induce rate inequities that we attempted to eliminate in the process of rate unbundling.

Q. HAVE YOU PERFORMED AN ANALYSIS OF AECC'S RECOMMENDATION REGARDING THE USE OF AN HOURLY ALLOCATION FACTOR FOR THE FUEL AND PURCHASED POWER ELEMENT OF BASE RATES?

A. Yes, we have. The results of that analysis are summarized in Attachment DJR – 1RB. If retail rates were designed strictly based on cost of service and all customer classes earned the same rate of return, residential rates would increase by approximately 27.1% based on the assumptions in the APS cost of service

study that utilized the 4CP production cost allocator. General Service rates would increase by approximately 14.9%. If the only change to the APS cost of service model was adoption of the AECC proposed energy allocator, residential rates would increase by 28.8% and general service rates would increase by 13.1%.

Q. HAVE YOU MODELED THE IMPACT OF COST OF SERVICE STUDY MODIFICATIONS RECOMMENDED BY STAFF AND AECC?

A. Yes, we combined the change in the production demand allocation method recommended by Staff Witness Brosch with the AECC energy allocation method. The impact on the results of the cost of service model for the combined recommendations is also found on Attachment DJR-1RB. It can be seen that, on a class basis, the two recommendations tend to offset each other and produce results similar to the APS original filing. Within the classes, the combined method tends to favor high load factor customers but the impact is less favorable than adopting the AECC energy allocation method alone. For example, in the APS base case, the required rate increase for large industrial customers served under Rate Schedule E-34 was 24.6 %. Adopting the Staff production plant method, the increase would be 31.9 %. The AECC modification to the study results in a required increase of 21.4 %. Under the combined modification study, the required rate increase would be 28.8% for Schedule E-34. APS' proposed rate increase for customers served under Schedule E-34 was 24.6% excluding the EIC.

Q. YOU MENTIONED THAT SOME OF THE RATE ALTERNATIVES PROPOSED BY INTERVENORS IN THIS CASE RESULT IN LOWER INCREASES FOR HIGH LOAD FACTOR CUSTOMERS. WHAT DO YOU MEAN BY LOAD FACTOR?

A. Load factor is a measurement of peak demand to average hourly demand. For example, if a customer had a demand of 10 kW and used that demand level for 24 hours per day for the entire month, the customer's monthly load factor would be

100%. If the customer's average demand was 5 kW, the monthly load factor would be 50%.

Q. HOW DOES LOAD FACTOR INFLUENCE A CUSTOMER'S BILL?

A. If a customer is billed on a rate with an explicit demand charge such as Schedule E-32 for loads over 20 kW, higher load factors tend to result in a bill with lower average cents per kWh since the demand component of the bill gets spread over more kWh. For example, a customer with a 50 kW load and a 50 per cent load factor would consume 18,250 kWh. A customer with a 50 kW load and a 30 per cent load factor would consume approximately 10,950 kWh. The demand charge for these two customers would be the same. But, as a percentage of the total bill, the demand component is higher for the low load factor customer. Therefore, in designing rates, the balance of revenue recovery between the demand and energy components of the rate can impact similarly sized customers differently.

Q. IN THE LAST APS RATE CASE THAT RESULTED IN THE SETTLEMENT AGREEMENT APPROVED IN DECISION NO. 67744, WAS THE RATE DESIGN EMPHASIS ON THE DEMAND OR ENERGY CHARGE COMPONENTS OF MOST RATES?

A. The last case included generation additions that require recovery of capacity costs. These costs are recovered through increased demand charges. Also, in unbundling our retail rates, we modified the rates to better reflect cost of service including segregating capacity, energy, and customer components. This also tended to increase demand charges. As a result, customers with low load factors tended to experience greater percentage bill increases than customers with high load factors. In fact, some high load factor customers actually saw a bill reduction as a result of Decision No. 67744. The current rate case is largely driven by higher fuel costs which impacts the energy portion of rates. Therefore, the

increase tends to have greater impact on higher load factor customers.

Q. DO YOU HAVE ANY COMMENTS ON THE RATE DESIGN TESTIMONY OF KROGER WITNESS STEPHEN BARON?

A. Kroger Witness Baron recommends acceptance of the APS 4CP allocation method for production plant. His testimony recommends that revenue increases for the generation and delivery components of Rate Schedule E-32 be split equally across the demand blocks for the delivery component and across demand and energy equally for the generation component. I disagree with these recommendations, especially on the generation component. Additionally, Mr. Baron claims that the cost of service study does not support the proposed APS change. I disagree with this statement. The cost of service study is based on increased fuel charges. Our base fuel charge has increased from slightly more than 2 cents per kWh to over 3 cents per kWh. The increased fuel and purchased power expense account for approximately 16% of the total 21% increase requested by APS in this case. Recovery of these increased energy costs through increased energy charges is appropriate and consistent with cost of service principles.

Q. FEA WITNESS GOINS RECOMMENDS INCREASING THE DISCOUNTS FOR PRIMARY AND TRANSMISSION VOLTAGE LEVEL CUSTOMERS. DO YOU AGREE WITH THIS RECOMMENDATION?

A. Dr. Goins recommendation is consistent with the results of the APS cost of service if that is the only consideration, and rates for all classes are set at equal rates of return. I do not disagree with the recommendation but it must be recognized that this recommendation results in slightly higher bills to customers who are not eligible for the discount.

Q. DO YOU HAVE ANY COMMENTS ON THE RATE DESIGN TESTIMONY OF DEAA WITNESS MURPHY?

A. Yes. Generally, Mr. Murphy's arguments are the same he made in the last APS rate case regarding his dislike for demand rates and cost-based rate making because his perception is that cost-based rates are a disincentive to distributed generation. He also is very selective in discussing the "Bonbright" principles on rate-making. I will agree with Mr. Murphy on one point. The APS rate designs for large partial requirements service customers are complex. APS Witness Greg DeLizio's testimony provides a discussion regarding new, less complex partial requirements rates that APS is proposing to offer customers with Commission approval in this rate case.

Q. MR. MURPHY DISCUSSES APS GENERAL SERVICE RATES AND COMPARES THE RATES TO THE RATES OF SALT RIVER PROJECT ("SRP"). WOULD YOU LIKE TO COMMENT ON HIS DISCUSSION?

A. Yes. Mr. Murphy's testimony excludes some important facts. APS has approximately 108,000 general service customers. Approximately 86,000 of those customers have loads under 20 kW. 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. This is the exact concept that Mr. Murphy espouses and we apply it to 80% of our general service customers. We also offer a time of use companion rate that has a similar rate design, i.e. no explicit demand charge for customers under 20 kW. Mr. Murphy discusses the SRP Time of Use ("TOU") 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. In fact, the SRP E-36 rate design is very similar to the APS rate design prior to Decision No. 67744.

Q. IN HIS TESTIMONY, MR. MURPHY ASSERTS THAT 96% OF NON-RESIDENTIAL CUSTOMERS HAVE PRICING THAT IS BASED ON DEMAND AND ENERGY BILLING UNITS. (TESTIMONY AT PG 6 LINES 12-14). IS THAT CORRECT?

A. No, that is not correct. I believe that Mr. Murphy is suggesting that all general service customers served under Schedule E-32 are billed on demand. That is simply wrong. As I noted earlier in my testimony, 80% of our general service customers are under 20 kW and are not billed based on demand. In the same testimony cite, Mr. Murphy states that over 8% of residential customers are billed on demand/energy billing determinants. While the correct number is under 8%, I will not argue the point. However, Mr. Murphy neglects to note an important fact. The 67,000 residential customers who are served on demand/energy rates have opted for those rates voluntarily. These customers understand capacity charges and are likely adopting measures to reduce demand.

Q. PLEASE COMMENT ON MR. MURPHY'S DISCUSSION OF THE "BONBRIGHT" PRINCIPLES.

A. First, I wish to clarify a misconception that may be drawn from Mr. Murphy's testimony. Therein, Mr. Murphy implies that the "Bonbright principles" are in order of importance (testimony at pg. 9 lines 6-7). The Bonbright text states, "The sequence of the eight items is not meant to suggest any order of relative importance." (Principles of Public Utility Rates, James C. Bonbright, pg. 291). I will agree with Mr. Murphy that revenue stability is important to utilities. It is also important to customers because a financially stable and healthy utility has better access to capital markets. Mr. Murphy also cites "freedom from controversy" as one of the Bonbright principles, but he does not include the entire cite, which reads: "Freedom from controversies as to proper interpretation." (Emphasis added.) I believe this to mean that rates are designed so they can be

applied consistently across the customer base of similar customers.

I also must point out that the Bonbright text recognizes that the "principles" can be somewhat ambiguous and overlapping and the text acknowledges there are three primary objectives. The three primary objectives are: 1) the revenue requirement objective; 2) a fair-cost apportionment objective; and 3) the optimum use objective under which rates are designed to discourage wasteful use while "promoting use that is economically justifiable in view of the relationships between costs incurred and benefits received."

I believe that the primary objectives yield rate designs as proposed by APS in which capacity costs are generally recovered through demand charges, energy costs through energy charges and customer-based costs through customer or basic service charges. I disagree with Mr. Murphy's allegations that APS' customers do not understand capacity charges. As I noted earlier, we have a significant number of residential customers who voluntarily participate in demand based rates, we work with our general service customers so that they understand demand charges and how they can proactively work to reduce demand, and in fact, the intervenors in this case who represent general service customers are endorsing demand charges that are higher than those proposed by APS.

Q. MR. MURPHY AND MR. TANNER OF AICE CLAIM THE APS IS ELIMINATING A SERIES OF RATES THAT COULD BE BENEFICIAL TO CERTAIN CUSTOMERS IN THIS CASE. IS THAT CLAIM CORRECT?

A. No, it is not. First, we are not eliminating Schedule E-20 which is available only to houses of worship. That rate schedule was frozen as part of the Settlement Agreement in Decision No. 67744. The Settlement Agreement 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 implements the actions of the Commission in the last case. These rates were limited participation rates that were established on an experimental basis several years ago. We now offer Schedule E-32 TOU which is open to all customers who can take advantage of lower off peak prices. New houses of worship whose primary hours of operation are evenings or weekends can likely save relative to our standard general service rate schedule.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE RATE DESIGN TESTIMONY SUBMITTED BY STAFF AND INTEVENORS IN THIS CASE?

A. Disregarding the issue of overall revenue levels, I believe that the testimony is generally supportive of the rate designs currently used by APS and adjusted in this case. The testimony provides recommendations that "fine tune" the APS rate designs generally to the benefit of a targeted customer group. I believe that the testimony is supportive of the concept that rate design has as much "art" as science as long as the "art" is supported by reasonable cost of service principles. While adjusting the balance between demand and energy charges can be supported by cost of service analyses, I think the customer impact aspect of rate changes is also important. In that regard, I could support modifying Schedules E-34 and E-35 as suggested by AECC, i.e., converting the transmission revenues to a capacity charge in lieu of the current energy charge but recovering the same revenue level, and adjusting the unbundled generation charge balance between capacity and energy. I do not support changing the E-32 rate design as proposed by AECC et al. As mentioned above, our rate unbundling and moving rates closer to cost of service increased demand charges for E-32 customers and low load factor customers experienced larger than average increases. The E-32 customer class is very non-homogeneous, and customers on the rate schedule range from

small users such as railroad crossing signals to very large commercial establishments and industrial users. The average load factor is under 40% and only 4% of customers have load factors greater than 70%. On the other hand, customers served under our industrial rate schedules, E-34 and E-35, have average load factors of approximately 70% and tend to have much less load factor disparity than E-32 customers. Therefore, rate design changes tend to impact customers on a more equal basis. The E-32 rate design proposed by APS in this case tends to spread the increase on a more even basis across a broad customer group than then the revisions suggested by intervenors.

V. FROZEN RATE ELIMINATION PLAN

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE SCHEDULE CHANGES REGARDING ELIMINATION OF FROZEN RATE SCHEDULES?

A. Decision No. 67744 provided for the elimination of frozen rate schedules in the next APS rate case and we are doing so in this case. APS has and will continue to communicate the proposed rate schedule changes to customers on frozen rates. Communications include bill notices and direct contact with affected customers. In my Direct Testimony, I described our plan for the frozen rate elimination. We proposed that customers on Schedule E-10 be transferred to Schedule E-12 if the customer does not opt for an alternative rate option. The default rate for Rate Schedule EC-1 customers will be Schedule ECT-1R. However, because most meters installed for Schedule EC-1 customers cannot provide the time of use billing determinants required by Schedule ECT-1R, we proposed an interim Schedule EC-1 that would continue until meter exchanges take place. As I stated in my Direct Testimony in these proceedings, APS proposed transferring E-10 customers to the E-12 rate schedule and transferring EC-1 customer to ECT-1R if

the customer does not select an alternate rate within a six month period after the frozen rate schedules are eliminated.

Q. DO YOU PROPOSE ANY CHANGES OR UPDATES TO THE TRANSITION PLAN DESCRIBED IN YOUR DIRECT TESTIMONY?

A. Yes. After in-house discussion with APS Customer Service personnel, it was agreed that the original plan could be more 'customer friendly' with the goal of easing or transitioning E-10 and EC-1 customers to new rates. This revised plan includes requesting approval of an interim rate for customers on Schedule E-10.

Q. HAS APS DESIGNED AN INTERIM RATE FOR CUSTOMERS ON THE FROZEN E-10 RATE?

A. Yes. An interim rate for E-10 customers is attached as Attachment DJR-4RB. The interim rate was designed to collect the same revenue level as would be collected if the Schedule E-10 customers were transferred to Schedule E-12.

Q. PLEASE DESCRIBE ANY ADDITIONAL DETAILS REGARDING THE E-10 AND EC-1 TRANSITION PLAN.

A. Upon further examination of bill frequency and bill impact data, we believe that some Schedule E-10 customers might prefer to transfer to a TOU rate option. To aid E-10 customers in the selection process and provide some guidance to customers that haven't selected a rate during the transition period, APS proposes customers using more than 1,000 kWh/month (calculated annual average) be placed on Schedule ET-1 as the default rate. ET-1, also known as the Time Advantage Rate, is our most commonly used residential TOU rate. For the Schedule EC-1 customers that haven't selected a new rate, APS proposes that customers consuming more than 1,000 kWh/month (annual average) be placed on Schedule ECT-1R. For E-10 and EC-1 customers using less than 1,000 kWh/month (annual average), the default rate will be Schedule E-12. These rate

selections should result in the lowest rate impact due to elimination of the frozen rates.

Q. ARE THERE METERING IMPLICATIONS TO ELIMINATION OF FROZEN RATE SCHEDULES?

A. Yes. A customer's rate selection may require a meter exchange. For example, a meter exchange will likely be required if an E-10 customer requests to be transferred to a TOU rate schedule. Similarly, a new meter will be required for Schedule EC-1 customers who select a TOU schedule. The need of meter exchanges is another factor in the need for a transition time period.

Q. ARE THERE TRANSITION PLANS FOR GENERAL SERVICE CUSTOMERS ON FROZEN TIME OF USE RATES?

A. Yes. Customers on frozen experimental TOU rates E-21, E-22, E-23 and E-24 will receive a direct mail letter communicating the results of a rate comparison between E-32 and E-32 TOU. Customers will receive the letter within one month after the approval of the rate case.

At least three times during the transition period following the approval of the rate case, APS will conduct an outbound phone call campaign to convey the results of the rate comparison and discuss features of each rate. At the end of the transition period, APS will again call to inform customers they have been defaulted to E-32 TOU if the customer has not selected a new rate.

Q. APS IS ALSO ELIMINATING RATE SCHEDULE E-38. TO WHICH RATE WILL THOSE CUSTOMERS BE TRANSFERRED?

A. At the time frozen rates are eliminated, customers on agricultural irrigation rates E-38 and the TOU option E-38-8T will be transferred to rate schedule E-221. E-221 is a Water Pumping Service TOU rate. E-38 and E-38-8T customers will be given a bill comparison if requested. They will also be provided information on

E-32, E-32 TOU and E-221 at the aps.com website.

Q. EARLIER IN YOUR TESTIMONY YOU DESCRIBED CERTAIN MODIFICATIONS THAT STAFF HAS PROPOSED TO THE TRANSITION PLAN. DO YOU AGREE THAT STAFF'S PROPOSED MODIFICATIONS ARE BASED LARGELY ON THE PLAN PROPOSED BY APS?

A. Yes, Staff proposed modifications consist of time extensions to the APS plan and APS is supportive of those modifications.

VI. HOOK-UP FEES

Q. SEVERAL COMMISSIONERS REQUESTED THAT APS EXAMINE THE CONCEPT OF USING HOOK-UP FEES AS A METHOD OF RAISING CAPITAL TO MEET GROWTH. HAVE YOU DONE SO?

A. Yes, we have looked at the concept. However, hook-up fees have wide ranging ramifications, and we believe that if the Commission is considering the use of hook-up fees by utilities, the examination should be done in the context of a generic workshop as suggested by RUCO Witness Diaz Cortez and Staff Witness Andreasen. This is an industry-wide issue that should involve at least gas, electric, telephone and water companies as well as those who would be impacted by such a significant change.

Q. HAVE YOU IDENTIFIED ISSUES THAT SHOULD BE ADDRESSED IN THE GENERIC WORKSHOPS?

A. Yes. Among the significant policy issues that should be examined are: 1) 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; 2) what would be the impact on housing affordability; 3) 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; 4) what are the long term impacts on the financial health of

regulated companies; 5) what are the short and long term rate impacts to customers; 6) should the amount of the hook-up fee include tax effects (i.e. gross-up vs. self pay); 7) could existing customers be responsible for hook-up fees; and 8) what would be the impact on homebuilders and the construction industry. The generic workshops should include all utilities, not just APS.

Q. WOULD YOU PLEASE DESCRIBE WHAT IS MEANT BY A HOOK-UP FEE?

A. It is important to understand the use of the term "hook-up fee." It is used in several different contexts. In some instances, the term is used to describe a service initiation fee which is primarily an administrative cost. In the context of this testimony and the questions raised by the Commissioners, the term is used in the context of a capital addition funding mechanism. A hook-up fee is a means to provide capital for infrastructure additions. Hook-up fees are also sometimes called "impact fees" or "cost of development fees." Typically, new customers pay a fee designed to recover the incremental or marginal investment required for the utility to provide service. Hook-up fees are often used by municipalities to fund water or wastewater system additions such as pipelines, water supplies or treatment plants. They are rarely used in the electric utility industry as a capital funding tool and to my knowledge, only by municipalities or other public power entities.

Q. PLEASE DESCRIBE THE TAX CONSEQUNCES OF CONTRIBUTED CAPITAL.

A. When an investor-owned utility receives contributed capital, an immediate income tax liability is created because the payment is considered taxable income. So, for example, if hook-up fees generated $820 million over at ten year period (assuming $2,000 per customer, 42,000 customers per year), approximately $320

million would be paid in additional current income taxes leaving $500 million to fund capital projects. If the objective was to have the full $820 million available, the hook-up fee would need to be "grossed-up" to account for the tax liability to $1.34 billion. This would, of course, significantly raise the hook-up fee paid by customers. This $320 million tax impact actually reduces the Funds from Operations ("FFO") which is a key financial indicator used by the investment community to assess the financial health of APS.

Q. WHY WOULD THE $82 MIILLION ANNUAL HOOK-UP FEE REVENUE REDUCE THE COMPANY'S FFO?

A. It is my understanding that under Generally Accepted Accounting Principles (GAAP), funds received from contributions in aid of construction, hook-up fees etc., are booked to reduce capital expenditures. They are not booked as revenues to the Company. So, the $82 million per year would not directly flow into the calculation that determines the Company's FFO. But the $30 million per year of increased current income taxes decreases the Company's FFO.

Q. HAS APS PERFORMED ANY ANALYSIS OF THE LONG TERM RATE IMPACTS OF THE USE OF HOOK-UP FEES?

A. Yes, our financial modeling group performed some preliminary analyses. Assuming hookup fees would generate $82 million annually, incremental rate impacts due to decreased debt and rate base would be very small, totaling an average of 0.3% per year over a ten year period. These rate impacts are more than offset by the cumulative cost of the hook-up fees. In my example, new customers would contribute $820 million to achieve $400 million in rate benefits over the ten-year period. Therefore, it appears that hook-up fees are an expensive vehicle for financing system improvements.

Q. IF HOOK-UP FEES REPRESENT SUCH AN EXPENSIVE WAY TO FINANCE NEW ADDITIONS, WHY ARE HOOK-UP FEES USED BY SMALL WATER UTILITES AND MUNICIPALITIES?

A. Hook-up fees are often used if a utility has limited access to capital markets such as in the case of small privately owned water companies. Customer or developer contributions may be the only readily available capital source for projects such as new water wells or treatment facilities. Municipal utilities, on the other hand, do not face the significant tax consequences of contributed capital that a utility such as APS would face. Also, private water companies often gross-up contributed capital to cover tax consequences. This make the hook-up fee more effective for the utility but even more expensive to consumers.

Q. IF THE COMMISSION WERE TO ORDER APS TO ADOPT A HOOK-UP FEE APPROACH, HOW COULD THE FEE BE DEVELOPED?

A. There are many approaches to hook-up fee development and fee development would be a key element to be explored in workshops. For example, one of the first decisions is to identify the capital expenditures that would be the target of the hook-up fee. APS invests considerable capital each year in distribution facilities to meet customer growth. We also have increasing capital requirements for transmission plant and could have significant capital needs for generation plant additions or improvements as well as general plant additions such as computer systems and facilities. The basic concept behind typical hook-up fee analysis is based on some form of marginal or incremental cost analysis. For example, APS' distribution capital expenditures for new customers are approximately $5,000 per meter set. However, new customers will pay rates that include an imbedded cost element. Therefore, it is reasonable to "credit" the incremental cost with the cost included in base rates. The average book investment is approximately $1,500 per customer. Therefore, the hook-up charge would be $3,500 per customer. Hook-up

fees would be developed for each customer class. Residential hook-up fees would likely be a per customer charge. Because the general service customer group is very non-homogeneous, it is more difficult to state hook-up fees in terms of a per customer charge. General Service hook-up fees would likely be expressed in terms of connected kW load. The water system analogy utilizes service or meter size to determine hook-up fees for different types of customers.

Q. COULD HOOK-UP FEES BE APPLICABLE TO EXISTING CUSTOMERS?

A. Typically, hook-up fees are applicable only to new service applications, e.g. a new subdivision or new home or business. I might add that it is not always easy to determine whether a customer is "new," especially in the case of businesses. However, an argument could be made that a form of hook-up fee should be collected from existing customers who request a change of service or who change service locations. For example, if an existing home has a 200 ampere service and the customer is constructing a large addition that will require that the service be upgraded to 400 amperes, an impact fee could be assessed.

Q. YOU HAVE ONLY DISCUSSED THE APPLICATION OF HOOK-UP FEES FOR THE WIRES PART OF THE BUSINESS. HOW COULD YOU CALCULATE HOOK-UP FEES TO FUND GENERATION RESOURCES?

A. Generation marginal costs are typically developed based on the "peaker deferral method" which computes the cost of the next kW of peaking capacity or a generation planning approach. In either case, the marginal cost is developed on a per kilowatt basis. To develop a per customer hook-up, it would be necessary to assume a coincident peak load per customer class and convert the per kW marginal cost to a customer basis. For example, assume the next unit of generation required as a system resource has a cost of $2,200 per kW. The rate

base value of the existing generation fleet is approximately $480 per kW. Therefore, a hook-up charge for generation would be valued at approximately $1,720 per kW. The average residential customer's coincident peak demand is approximately 3.5 kW. Therefore, a generation cost hook-up fee would be approximately $6,000 per kW for new resources. When combined with the distribution facilities fee described above, the total hook-up fee for a customer could be $9,500.

Q. HOW COULD YOU DETERMINE A HOOK-UP FEE FOR TRANSMISSION SYSTEM ADDITIONS?

A. Because transmission charges are regulated by FERC, it may not be possible to include transmission system additions in a hook-up fee computation for retail customers. Many transmission system additions are made for reliability reasons, and it may be more appropriate to recover reliability project costs from all customers, not just new customers.

Q. HAVE YOU REVIEWED COMMISSIONER MAYES LETTER DATED AUGUST 31, 2006 REGARDING HOOK-UP FEES?

A. Yes I have. Commissioner Mayes raises some important issues regarding hook-up fees, and the generic workshop suggested by RUCO and Staff would be the best venue to discuss these points to allow for input from all stakeholders including all regulated utilities, homebuilders, and the general public.

Q. IN HER AUGUST 31, 2006 LETTER, COMMISSION MAYES ASKED SPECIFIC QUESTIONS REGARDING HOOK-UP FEES. CAN YOU RESPOND?

A. Yes, the first question asks about the facilities that were included or excluded in the $1,650 per residential customer and $4,900 per commercial customer budgetary estimates that were provided to Staff in a data request response. These

estimates are the direct costs for local facilities. Local facilities include the wires, poles, manholes, and switching cabinets within a subdivision or development. The budget estimates exclude backbone facilities such as main feeders, capacitor banks, duct banks, switching cabinets, substations, and engineering, inspection, warehousing and other overhead costs.

The second question raised by Commissioner Mayes requested comments on the benefits and drawbacks of including generation costs in a hook-up fee. The primary benefit is that the hook-up fee is another source of capital available to the utility, albeit an expensive source. The largest drawbacks are the financial impact on the Company because of the tax consequences and the impact on customers due to the potential size of the generation element in the fee. Another drawback is that the generation element of the hook-up fee could vary depending on the resource acquisition cycle. The per kW cost of a base load generation unit is very different than a peaking unit so the period hook-up fee calculations could vary based on the next expected generation source. Staff Data request EAA 4-18 asked for a hook-up fee for full costs of growth. We interpreted full costs to include generation and assumed the next unit of generation is a base load unit. Although retail competition exists in Arizona, utilities are the providers of last resort and therefore have responsibility to plan for and obtain adequate generation resources to meet that responsibility. Therefore, it may be appropriate to include the cost of generation in hook-up fees.

Commissioner Mayes' third question requested the impact of sample hook-up fees on the Company capital budget. As noted above, a $2,000 per customer hook-up fee would generate approximately $500 million after tax over a ten-year period. APS Witness Don Brandt notes in his Rebuttal Testimony that the non-generation

capital budget is approximately $8.6 billion over the next ten years. Finally, the letter asked about the issue of rural vs. subdivision development. We make no distinction in our rates or policies between rural and subdivision development, and in our service territory it often becomes difficult to distinguish between the two. Each has unique system planning and construction aspects. I believe it may be possible to distinguish between rural and subdivisions as far as hook-up fees but from a practical perspective, it may difficult to differentiate the two. For example, the local facilities cost for a subdivision in a rural area may be the same as an urban subdivision, but the backbone system improvements may be significantly more expensive.

VII. POWER SUPPLY ADJUSTMENT

Q. APS WITNESSES ROBINSON AND EWEN DISCUSS CHANGES TO THE POWER SUPPLY ADJUSTMENT MECHANISM. IF ADOPTED, WOULD THESE CHANGES NECESSITATE MODIFICATIONS TO THE PLAN OF ADMINISTRATION?

A. Yes. We have modified the currently approved PSA Plan of Administration ("POA") to reflect proposed changes to the PSA. Attachment DJR-5 RB is a POA that encompasses the modifications to the PSA as proposed by APS and described in the testimony of APS Witness Robinson. Attachment DJR–6 RB is a Plan that reflects our understanding of the proposed PSA mechanism as described by Staff Witness John Antonuk and uses the assumptions regarding the proposal described by APS witnesses Don Robinson and Pete Ewen.

VIII. JURISDICTIONAL CALCULATIONS

Q. WERE YOU RESPONSIBLE FOR JURISDICTIONAL ALLOCATIONS THAT ARE FOUND IN ATTACHMENTS TO THE REBUTTAL TESTIMONY OF OTHER APS WITNESSES?

A. Yes. I am sponsoring the ACC jurisdictional columns on the Adjustments to

Schedules C-1 and C-2 which are attached to APS Witness Froggatt's Rebuttal Testimony, as well as the ACC jurisdictional columns on the Adjustments to Schedules B-1, B-2, and B-3 which are attached to APS Witness Rockenberger's Rebuttal Testimony. These jurisdictional allocations have been calculated using the same factors that were used in APS' January 31, 2006 filing and were presented in my Direct Testimony.

IX. CONCLUSIONS

Q. PLEASE SUMMARIZE THE CONCLUSIONS REACHED IN YOUR TESTIMONY.

A. First, I note that the key issue of rate design changes is customer impact. While strictly adhering to cost of service principles for rate design may benefit one group of customers, it may negatively impact a larger group of customers. I do agree that the rate designs proposed by APS could be "fine tuned" by making some of the modifications such as collecting transmission costs through demand charges from the largest customer. Cost of service is a valuable guide in rate design but it not the only factor to consider. Impacts on individual customer's bills should also be a significant consideration. Second, I believe that while hook-up fees have fairly widespread usage by municipalities and small water companies, the tax consequences offset any advantages for taxable entities. This and several other aspects of hook-up fees can and should be addressed in the context of generic workshops involving all utilities

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY

COMPARISON OF RATES OF RETURN, OPERATING INCOME AND % REVENUE REQUIREMENT INCREASE UNDER ALTERNATIVE ALLOCATION METHODS

	4 CP as Filed			4 CP Juris. & Avg. & Pk.			4 CP With Fuel Allocated on Hourly Energy Costs			4 CP Juris. & Avg. & Pk. With Fuel Allocated on Hourly Energy Costs		
	ROR	$ Return	% Inc.	ROR	$ Return	% Inc.	ROR	$ Return	% Inc.	ROR	$ Return	% Inc.
GE-1												
Total Retail	2.59%	115,904,477	21.1%	2.59%	115,904,477	21.1%	2.59%	115,904,477	21.1%	2.59%	115,904,477	21.1%
Total Residential	1.52%	37,745,444	27.1%	1.87%	45,634,943	25.2%	1.04%	25,878,910	28.8%	1.38%	33,768,410	27.0%
Total General Service	3.91%	73,368,581	14.9%	3.55%	67,766,451	16.3%	4.49%	84,276,708	13.1%	4.12%	78,674,578	14.5%
Water Pumping	9.30%	2,370,299	-1.2%	3.06%	1,032,844	15.0%	10.18%	2,592,733	-2.9%	3.72%	1,255,278	13.3%
Street Lighting	2.05%	1,053,936	42.1%	0.50%	279,931	56.7%	3.27%	1,676,705	34.5%	1.61%	902,700	49.1%
Dusk to Dawn	5.78%	1,366,217	17.8%	4.82%	1,190,307	24.7%	6.26%	1,479,420	14.9%	5.28%	1,303,510	21.8%
GE-2												
Total General Service	3.91%	73,368,581	14.9%	3.55%	67,766,451	16.3%	4.49%	84,276,708	13.1%	4.12%	78,674,578	14.5%
E-20 (Church Rate)	8.47%	623,406	0.9%	6.94%	544,374	6.4%	8.05%	592,380	2.3%	6.54%	513,348	7.9%
E-30, E-32 (0-20 kW)	3.56%	13,469,005	21.2%	5.55%	19,087,411	11.8%	3.76%	14,238,295	20.4%	5.78%	19,856,702	11.0%
E-32 (21-100 kW)	4.88%	22,897,254	13.4%	5.66%	25,610,610	10.3%	5.17%	24,248,930	12.4%	5.96%	26,962,286	9.3%
E-32 (101-400 kW)	6.12%	25,165,747	7.2%	5.42%	23,011,520	9.5%	6.55%	26,903,570	6.1%	5.83%	24,749,344	8.3%
E-32 (401-999 kW)	6.12%	13,966,498	6.6%	3.89%	9,859,517	13.7%	6.84%	15,606,206	4.8%	4.54%	11,499,226	11.8%
E-32 (1,000+ kW)	-0.20%	-359,838	27.4%	-1.18%	-2,244,824	32.4%	0.63%	1,119,832	24.9%	-0.40%	-765,154	29.9%
E-34	0.07%	86,584	24.6%	-1.45%	-1,848,944	31.9%	1.19%	1,380,609	21.4%	-0.44%	-554,919	28.8%
E-35	-2.79%	-2,480,075	24.9%	-5.57%	-6,253,214	38.9%	0.21%	186,885	18.4%	-3.20%	-3,586,254	32.5%
GE-3												
Total Residential	1.52%	37,745,444	27.1%	1.87%	45,634,943	25.2%	1.04%	25,878,910	28.8%	1.38%	33,768,410	27.0%
Residential E-10	1.42%	2,103,917	26.1%	1.28%	1,914,459	26.8%	1.12%	1,653,718	27.2%	0.98%	1,464,260	27.9%
Residential E-12	3.18%	25,297,678	19.5%	3.50%	27,405,534	18.0%	2.80%	22,247,713	20.8%	3.11%	24,355,569	19.4%
Residential EC-1	0.44%	351,017	30.6%	0.35%	277,932	31.1%	-0.02%	-18,326	32.3%	-0.11%	-91,411	32.8%
Residential ET-1	0.83%	10,137,772	31.2%	1.33%	15,863,466	28.3%	0.26%	3,146,087	33.4%	0.74%	8,871,782	30.6%
Residential ECT-1R	-0.06%	-144,940	33.6%	0.07%	173,551	32.8%	-0.48%	-1,150,281	35.2%	-0.35%	-831,790	34.4%

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following policy governs the extension of overhead and underground electric facilities rated up to 21kV to customers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Backbone Infrastructure means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

b. Conduit Only Designs mean a line extension request where the developer is only requesting the conduit layout and design to serve the project. Local distribution facilities such as transformers and services will be installed at a later date when lot sales occur.

c. Corporate Business & Industrial Developments means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

d. High Rise Residential means residential multi-family developments built with four or more floors, usually using elevators for accessing floors.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Master Planned Community Developments means developments that consist of a number of separately subdivided parcels for different "Residential Homebuilder Subdivisions". Developments may have a variety of uses including residential, commercial, and public use facilities.

g. Mixed Use Residential Developments means buildings that consist of both residential and commercial use, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

h. Residential Custom Home "Lot Sale" Developments means any tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

i. Residential Homebuilder Subdivisions means any tract of land which has been divided into four or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

j. Residential Multi-family Developments means developments consisting of apartments, condominiums, or townhouse developments.

k. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

l. System Improvement Costs means the costs of system additions over and above what is required to serve the customer, where such additions provide additional capacity for other customers.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Residential extensions will be made to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. An allowance of $5,000 per home will be credited against the total construction cost, as determined by Company. Any additional cost will be paid by the applicant, as a refundable advance prior to Company extending facilities.

1.1.2 Where an advance is required, Company will issue the applicant an Advance Certificate. If, within five (5) years of issuance, a lateral extension is made off the original line extension, the applicant may present his/her Advance Certificate to Company for a potential refund. Refunds will be issued when the Advance Certificate is presented for payment and the connection of the subsequent applicant has been verified. In no event will refunds exceed the original advance. Refunds will be determined as shown in the example:

EXAMPLE:

First applicant's estimated cost for a line extension	$22,000
First applicant allowance	$ 5,000
First applicant's advance	$17,000
Second applicant's estimated cost for a lateral off the original extension	$ 3,000
Second applicant's allowance	$ 5,000
Refund to first applicant upon presentation of Advance Certificate and verification	$ 2,000

1.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

1.2.1 Extensions will be made to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant(s) signs an extension agreement. If approved by Company, a per lot allowance of $5,000 may be credited against the total construction cost, which may include applicable backbone system costs as determined by Company (minus street light and system improvement costs). Any additional construction cost in excess of the per lot allowance will be paid by applicant as a non-refundable contribution in aid of construction.

1.2.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and requires the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.2.3 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

1.2.4 The following provides examples of the application of the policy:

EXAMPLE 1:

The following example illustrates a case in which the allowance is adequate to cover the subdivision's construction costs. It is assumed that the applicant builds all of the homes in the 18 month period.

Estimated Construction Cost	$450,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$ 0

EXAMPLE 2:

Example #2 illustrates a case in which the construction costs exceed the allowance and the applicant completes all homes in the subdivision. The total construction cost exceeds the allowance by $150,000 and the applicant provides the non-refundable contribution in aid of construction when the extension agreement is executed. If the applicants completes all 100 homes within the 18 month period after the execution date of the extension agreement, no additional funds are advanced by the applicant.

Estimated Construction Cost	$650,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$150,000

EXAMPLE 3:

The following example illustrates a case in which two events occur. First, the allowance does not adequately cover the required construction. This results in the requirement that the applicant provide a non-refundable contribution in aid of construction. This payment is due at the time the extension agreement is signed by the applicant.

The second event illustrated in this example is the applicant does not sell sufficient homes in the development in the 18 month period following the extension agreement execution date. In the example, at the end of the 18 month period, the applicant has completed 35 homes. Since there are 65 homes left to be completed the applicant must provide a refundable advance of $325,000. This advance will be eligible for refund during the subsequent 42 months as additional homes are completed. Any un-refunded advance remaining at the end of the refund period becomes a non-refundable contribution in aid of construction.

Estimated Construction Cost	$650,000
Number of Homes Planned	100
Potential Allowance Refundable Advance	$500,000
Non Refundable Contribution	$150,000
Assumed Number of Completed Homes	35
Allowance Credited (35 x $5000)	$175,000
Potential Amount Remaining Eligible For Refund	$325,000

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

Extensions will be made to residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure. The payment of the advance is due at the time the extension agreement is executed and subject to refund as specified in Section 4.1.

1.3.1 Line extensions and/or equipment installations will be made for each permanent customer upon request for service, and an allowance of $5,000 will be credited against the construction cost for each installation as determined by Company (minus streetlight and system improvements costs). Any additional construction cost will be paid as a non-refundable contribution in aid of construction.

1.3.2 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant(s) based on the project scope, or location, or financial condition of the applicant(s), or where organizational structure of the applicant(s) warrants, as determined by Company. Advances are subject to refund as specified in Section 4.2.

1.3.2 The costs for the installed infrastructure and the extensions and equipment installations needed to provide service to each permanent customer less any applicable credits will be used in determining the development's Economic Feasibility.

1.3.3 Company will provide "conduit only" designs provided applicant makes a non-refundable contribution in aid of construction in the amount equal to the estimated cost of preparation, in addition to the costs for any materials, field survey and inspections that may be required.

1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

Extensions will be made to master planned community developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

1.4.1 Line extensions and equipment installation for backbone infrastructure to serve a Master Planned Development will be made in advance of application for service by permanent customers. A per lot allowance of $1,000 will be credited against the backbone infrastructure cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid by applicant as a non-refundable contribution at the time the extension agreement is executed.

Line extensions and equipment installations will be made for each residential subdivision within the planned development in advance of application for service by permanent customers. The cost of the extensions and equipment installations needed to provide service will be used in determining the cost for the development. A per lot allowance of $4,000 will be credited against the "subdivision" cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

1.4.2 Company reserves the right to disallow the credit and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.4.3 The residential extension examples provided in 1.2.4 would be applicable to residential developments within a Master Planned Community. Extensions to multi-family developments or commercial developments would be made in accordance with the applicable sections of this Service Schedule. The

following example illustrates the policy application for the entire project.

EXAMPLE 4:

Example #4 illustrates a case in which the applicant of the Master Planned Community requests an extension of backbone infrastructure and individual residential developers request extensions for residential subdivisions. The applicant makes a refundable contribution in aid of construction at the time the extension agreement is executed. The individual subdivision will be handled in a manner consistent with the subdivision examples found in Section 1.2.4.

Estimated Backbone Cost	$2,500,000
Number of Homes	1000
Potential Allowance Refundable Advance	$1,000,000
Non Refundable Contribution	$1,500,000
Estimated Subdivision Cost	$600,000
Number of Homes	200
Total Allowance	$800,000
Non-Refundable Contribution	$0

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

1.5.1 Extensions will be made to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers. If approved by Company, a per completed unit allowance of $1,000 may be credited against the total construction cost, including any applicable backbone infrastructure costs as determined by the company, (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

1.5.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and require the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.5.3 Company reserves the right to disallow the credit and collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.6 HIGH RISE AND MIXED USE RESIDENTIAL DEVELOPMENTS

1.6.1 Extensions will be made to high rise and mixed use developments where the residential units are privately owned and either individually metered or master

metered in accordance with Section 6.12.3.

1.6.2 In general, APS will provide service to these type of developments at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical distribution facilities within the building.

1.6.3 Extensions will be on the basis of Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

1.6.4 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

2.0 NON-RESIDENTIAL

2.1 General service line extensions and equipment installations will be made to all applicants not meeting the definition of Residential or as provided for in Section 2.4, or Section 3.0 of this Schedule. General service line extensions and equipment installations will be made on the basis of Economic Feasibility or on a revenue basis as described in Section 2.2. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer. Extensions that are economically feasible as determined by the revenue basis as described in Section 2.2 or by the economic feasibility analysis described in this section are provided free to the customer. Extensions will be provided to customers that do not meet the economic feasibility determination provided the customer signs an extension agreement and advances as much of the construction cost and/or agree to pay a facilities charge to make the extension economically feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to the refund provisions of Section 4.0.

2.2 A revenue basis extension will be made to customers or applicants except those specified in Sections 2.4, 3.1, 3.2, or 3.3, when the extension does not exceed a total construction cost of $25,000.

2.2.1 Such extension shall be free to the customer where the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

2.4 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.4.1 Extensions will be made to business and industrial park developments in advance of application for service by permanent customers, provided applicant(s) make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

2.4.2 The costs for the installed infrastructure and the cost of the extensions and equipment installations needed to provide service to each permanent customer will be used in determining the development's Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service, provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

2.4.3 For extensions and equipment installations which meet the conditions specified in Section 2.4.1, Company, after special study and at its option, may install its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 2.1. Such customers or applicant(s) must sign an extension agreement and advance as much of the construction cost and/or pay a non-refundable contribution (facilities charge) to make the extension economically feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to refund as specified in Section 4.1.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost at the time the extension advance is executed. Advances are subject to refund as specified in Section 4.3. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, the customer ~~shall make a non-refundable contribution~~ in advance of installation or construction equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

3.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is

doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 4.4.

4.0 REFUNDS

4.1 ECONOMIC FEASIBILITY BASIS REFUNDS

Customer advances over $50.00 are subject to full or partial refund. At the end of eighteen months from the date Company facilities are energized, Company will obtain actual closing costs and actual first year distribution revenues and determine if the company is receiving the required minimum rate of return. If this results in an advance lower than the amount advanced by customer, Company will refund the difference between the amount advanced and the amount that would have been advanced using actual closing costs and distribution revenues. In no event shall the amount of any refund exceed the amount originally advanced. Subsequent refund studies will be performed at one year intervals for an additional four years using actual distribution revenues for the year. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

Customer advances over $50.00 are subject to refund based on the number of permanently connected customers during the five year refund period commencing on the extension agreement's execution date. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.3 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.4 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial based on the Economic Feasibility Basis as specified in Section 3.3. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.5. GENERAL REFUND CONDITIONS

4.5.1 Customer advances of $50.00 or less are not subject to refund.

4.5.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

4.5.3 Any unrefunded advance balance shall become nonrefundable five (5) years from the execution or the effective date of the agreement.

4.5.4 Company reserves the right to withhold refunds to any customer or developer who is delinquent on any account, agreement, or invoice and apply these refund amounts to past due bills.

5.0 UNDERGROUND CONSTRUCTION

5.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

5.1.1 The extension meets feasibility requirements as specified in Sections 1.0, 2.0, or 3.0.

5.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

5.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

5.1.4 In lieu of customer or applicant(s) providing these services and equipment, the company may provide and the customer or applicant(s) will make a non-refundable contribution equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than APS' contractors, which Claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

5.2 Where it is determined that three phase service is required to serve the customer, customer may be required to make a nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

6.0 GENERAL CONDITIONS

6.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department and in accordance with this Schedule.

6.2 POINT OF DELIVERY

6.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

6.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

6.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

6.3 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVA demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVA specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

6.4 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

6.5 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

6.6 OWNERSHIP

Except for customer-owned facilities, all electric facilities, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

6.7 MEASUREMENT AND LOCATION

6.7.1 Measurement must be along the proposed route of construction.

6.7.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

6.7.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

6.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

6.9 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non-refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

6.10 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

6.11 RELOCATIONS AND/OR CONVERSIONS

6.11.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

6.11.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make a non-refundable contribution equal to the total cost of relocation.

6.11.3 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2.0 or 3.0.

6.12 MASTER METERING

6.12.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.12.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered

unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 6.12.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.12.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.12.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.12.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

6.12.4 Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

6.13 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2.0 or 3.0.

6.14 STUDY AND DESIGN DEPOSIT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction, otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

6.15 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

6.16 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

6.17 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

6.18 EXTENSION AGREEMENTS

All line extensions or equipment upgrades requiring payment by the customer shall be in writing and signed by both the customer and Company.

6.19 ADDITIONAL PRIMARY FEED

When specifically requested by the customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the request's feasibility and the customer may be required to pay a nonrefundable contribution in aid of construction for the added cost as well as the applicable rate for the additional feed requested.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following policy governs the extension of overhead and underground electric facilities rated up to 21kV to customers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Backbone Infrastructure means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

b. Conduit Only Designs mean a line extension request where the developer is only requesting the conduit layout and design to serve the project. Local distribution facilities such as transformers and services will be installed at a later date when lot sales occur.

c. Corporate Business & Industrial Developments means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

d. High Rise Residential means residential multi-family developments built with four or more floors, usually using elevators for accessing floors.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Master Planned Community Developments means developments that consist of a number of separately subdivided parcels for different "Residential Homebuilder Subdivisions". Developments may have a variety of uses including residential, commercial, and public use facilities.

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g. Mixed Use Residential Developments means buildings that consist of both residential and commercial use, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

h. Residential Custom Home "Lot Sale" Developments means any tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home. Separate line extensions and equipment

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installations may be needed to provide service to each permanent customer.

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i. Residential Homebuilder Subdivisions means any tract of land which has been divided into four or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

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j. Residential Multi-family Developments means developments consisting of apartments, condominiums, or townhouse developments.

k. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

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l. System Improvement Costs means the costs of system additions over and above what is required to serve the customer, where such additions provide additional capacity for other customers.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Residential extensions will be made to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. An allowance of $5,000 per home will be credited against the total construction cost, as determined by Company. Any additional cost will be paid by the applicant, as a refundable advance prior to Company extending facilities.

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1.1.2 Where an advance is required, Company will issue the applicant an Advance Certificate. If, within five (5) years of issuance, a lateral extension is made off the original line extension, the applicant may present his/her Advance Certificate to Company for a potential refund. Refunds will be issued when the Advance Certificate is presented for payment and the connection of the subsequent applicant has been verified. In no event will refunds exceed the original advance. Refunds will be determined as shown in the example:

EXAMPLE:

First applicant's estimated cost for a line extension	$22,000
First applicant allowance	$ 5,000
First applicant's advance	$17,000
Second applicant's estimated cost for a lateral off the original extension	$ 3,000
Second applicant's allowance	$ 5,000
Refund to first applicant upon presentation of Advance Certificate and verification	$ 2,000

1.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

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Extensions will be made to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant(s) signs an extension agreement. If approved by Company, a per lot allowance of $5,000 may be credited against the total construction cost, which may include applicable backbone system costs as determined by Company (minus street light and system improvement costs). Any additional construction cost in excess of

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the per lot allowance will be paid by applicant as a non-refundable contribution in aid of construction.

1.2.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and requires the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.2.3 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

1.2.4 The following provides examples of the application of the policy:

EXAMPLE 1:

The following example illustrates a case in which the allowance is adequate to cover the subdivision's construction costs. It is assumed that the applicant builds all of the homes in the 18 month period.

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Estimated Construction Cost	$450,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$ 0

EXAMPLE 2:

Example #2 illustrates a case in which the construction costs exceed the allowance and the applicant completes all homes in the subdivision. The total construction cost exceeds the allowance by $150,000 and the applicant provides the non-refundable contribution in aid of construction when the extension agreement is executed. If the applicants completes all 100 homes within the 18 month period after the execution date of the extension agreement, no additional funds are advanced by the applicant.

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Estimated Construction Cost	$650,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$150,000

EXAMPLE 3:

The following example illustrates a case in which two events occur. First, the allowance does not adequately cover the required construction. This results in the requirement that the applicant provide a non-refundable contribution in aid of construction. This payment is due at the time the extension agreement is signed by the applicant.

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The second event illustrated in this example is the applicant does not sell sufficient homes in the development in the 18 month period following the extension agreement execution date. In the example, at the end of the 18 month period, the applicant has completed 35 homes. Since there are 65 homes left to be completed the applicant must provide a refundable advance of $325,000. This advance will be eligible for refund during the subsequent 42 months as additional homes are completed. Any un-refunded advance remaining at the end of the refund period becomes a non-refundable contribution in aid of construction.

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Estimated Construction Cost	$650,000
Number of Homes Planned	100
Potential Allowance Refundable Advance	$500,000
Non Refundable Contribution	$150,000
Assumed Number of Completed Homes	35
Allowance Credited (35 x $5000)	$175,000
Potential Amount Remaining Eligible For Refund	$325,000

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

Extensions will be made to residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure. The payment of the advance is due at the time the extension agreement is executed and subject to refund as specified in Section 4.1.

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1.3.1 Line extensions and/or equipment installations will be made for each permanent customer upon request for service, and an allowance of $5,000 will be credited against the construction cost for each installation as determined by Company (minus streetlight and system improvements costs). Any additional construction cost will be paid as a non-refundable contribution in aid of construction.

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1.3.2 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant(s) based on the project scope, or location, or financial condition of the applicant(s), or where organizational structure of the applicant(s) warrants, as determined by Company. Advances are subject to refund as specified in Section 4.2.

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1.3.2 The costs for the installed infrastructure and the extensions and equipment installations needed to provide service to each permanent customer less any applicable credits will be used in determining the development's Economic Feasibility.

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Company will provide "conduit only" designs provided applicant makes a non-refundable contribution in aid of construction in the amount equal to the estimated cost of preparation, in addition to the costs for any materials, field survey and inspections that may be required.

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1.3.4 The examples provided in 1.2.4 would also be applicable to "lot sale" developments.

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1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

Extensions will be made to master planned community developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

1.4.1 Line extensions and equipment installation for backbone infrastructure to serve a Master Planned Development will be made in advance of application for service by permanent customers. A per lot allowance of $1,000 will be credited against the backbone infrastructure cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid by applicant as a non-refundable contribution at the time the extension agreement is executed.

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Line extensions and equipment installations will be made for each residential subdivision within the planned development in advance of application for service by permanent customers. The cost of the extensions and equipment installations needed to provide service will be used in determining the cost for the development. A per lot allowance of $4,000 will be credited against the "subdivision" cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

1.4.2 Company reserves the right to disallow the credit and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.4.3 The residential extension examples provided in 1.2.4 would be applicable to residential developments within a Master Planned Community. Extensions to multi-family developments or commercial developments would be made in accordance with the applicable sections of this Service Schedule. The following example illustrates the policy application for the entire project.

EXAMPLE 4:

Example #4 illustrates a case in which the applicant of the Master Planned Community requests an extension of backbone infrastructure and individual residential developers request extensions for residential subdivisions. The applicant makes a refundable contribution in aid of construction at the time the extension agreement is executed. The individual subdivision will be handled in a manner consistent with the subdivision examples found in Section 1.2.4.

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Estimated Backbone Cost	$2,500,000
Number of Homes	1000
Potential Allowance Refundable Advance	$1,000,000
Non Refundable Contribution	$1,500,000

Estimated Subdivision Cost	$600,000
Number of Homes	200
Total Allowance	$800,000
Non-Refundable Contribution	$0

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

1.5.1 Extensions will be made to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers. If approved by Company, a per completed unit allowance of $1,000 may be credited against the total construction cost, including any applicable backbone infrastructure costs as determined by the company, (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

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1.5.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and require the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

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1.5.3 Company reserves the right to disallow the credit and collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.6 HIGH RISE AND MIXED USE RESIDENTIAL DEVELOPMENTS

1.6.1 Extensions will be made to high rise and mixed use developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 6.12.3.

1.6.2 In general, APS will provide service to these type of developments at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical distribution facilities within the building.

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Extensions will be on the basis of Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

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1.6.3 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

2.0 NON-RESIDENTIAL

2.1 General service line extensions and equipment installations will be made to all applicants not

meeting the definition of Residential or as provided for in Section 2.4, or Section 3.0 of this Schedule. General service line extensions and equipment installations will be made on the basis of Economic Feasibility or on a revenue basis as described in Section 2.2. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer. Extensions that are economically feasible as determined by the revenue basis as described in Section 2.2 or by the economic feasibility analysis described in this section are provided free to the customer. Extensions will be provided to customers that do not meet the economic feasibility determination provided the customer signs an extension agreement and advances as much of the construction cost and/or agree to pay a facilities charge to make the extension economically feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to the refund provisions of Section 4.0.

2.2 A revenue basis extension will be made to customers or applicants except those specified in Sections 2.4, 3.1, 3.2, or 3.3, when the extension does not exceed a total construction cost of $25,000.

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2.2.1 Such extension shall be free to the customer where the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

2.4 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.4.1 Extensions will be made to business and industrial park developments in advance of application for service by permanent customers, provided applicant(s) make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

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The costs for the installed infrastructure and the cost of the extensions and equipment installations needed to provide service to each permanent customer will be used in determining the development's Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service, provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

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2.4.3 For extensions and equipment installations which meet the conditions specified in Section 2.4.1, Company, after special study and at its option, may install its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 2.1. Such customers or applicant(s) must sign an extension agreement and advance as much of the construction cost and/or pay a non-refundable contribution (facilities charge) to make the extension economically

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feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to refund as specified in Section 4.1.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost at the time the extension advance is executed. Advances are subject to refund as specified in Section 4.3. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, the customer, in advance of installation or construction, equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

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3.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 4.4.

4.0 REFUNDS

4.1 ECONOMIC FEASIBILITY BASIS REFUNDS

Customer advances over $50.00 are subject to full or partial refund. At the end of eighteen months from the date Company facilities are energized, Company will obtain actual closing costs and actual first year distribution revenues and determine if the company is receiving the required minimum rate of return. If this results in an advance lower than the amount advanced by customer, Company will refund the difference between the amount advanced and the amount that would have been advanced using actual closing costs and distribution revenues. In no event shall the amount of any refund exceed the amount originally advanced. Subsequent refund studies will be performed at one year intervals for an additional four years using actual distribution revenues for the year. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

Customer advances over $50.00 are subject to refund based on the number of permanently connected customers during the five year refund period commencing on the extension agreement's execution date. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.3 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.4 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial based on the Economic Feasibility Basis as specified in Section 3.3. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.5. GENERAL REFUND CONDITIONS

4.5.1 Customer advances of $50.00 or less are not subject to refund.

4.5.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

4.5.3 Any unrefunded advance balance shall become nonrefundable five (5) years from the execution or the effective date of the agreement.

4.5.4 Company reserves the right to withhold refunds to any customer or developer who is delinquent on any account, agreement, or invoice and apply these refund amounts to past due bills.

5.0 UNDERGROUND CONSTRUCTION

5.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

5.1.1 The extension meets feasibility requirements as specified in Sections 1.0, 2.0, or 3.0.

5.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

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5.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

5.1.4 In lieu of customer or applicant(s) providing these services and equipment, the company may provide and the customer or applicant(s) will make a non-refundable contribution equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other

than APS' contractors, which Claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

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5.2 Where it is determined that three phase service is required to serve the customer, customer may be required to make a nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

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6.0 GENERAL CONDITIONS

6.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department and in accordance with this Schedule.

6.2 POINT OF DELIVERY

6.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

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6.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

6.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

6.3 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVA demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVA specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

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6.4 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

6.5 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

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6.6 OWNERSHIP

Except for customer-owned facilities, all electric facilities, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

6.7 MEASUREMENT AND LOCATION

6.7.1 Measurement must be along the proposed route of construction.

6.7.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

6.7.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

6.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

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6.9 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non-refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

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6.10 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

6.11 RELOCATIONS AND/OR CONVERSIONS

6.11.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

6.11.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make a non-refundable contribution equal to the total cost of relocation.

6.11.3 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2.0 or 3.0.

6.12 MASTER METERING

6.12.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.12.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 6.12.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

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6.12.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

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6.12.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.12.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

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6.13 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2.0 or 3.0.

6.14 STUDY AND DESIGN DEPOSIT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost

estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction, otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

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6.15 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

6.16 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

6.17 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

6.18 EXTENSION AGREEMENTS

All line extensions or equipment upgrades requiring payment by the customer shall be in writing and signed by both the customer and Company.

6.19 ADDITIONAL PRIMARY FEED

When specifically requested by the customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the request's feasibility and the customer may be required to pay a nonrefundable contribution in aid of construction for the added cost as well as the applicable rate for the additional feed requested.

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RATE SCHEDULE E-10
RESIDENTIAL SERVICE
INTERIM CLASSIC RATE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule E-10 prior to December 6, 1991.

This rate schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.253 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.09205 per kWh for the first 400 kWh, plus $0.12607 per kWh for the next 400 kWh, plus $0.12966 per kWh for all additional kWh	$0.09501 per kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.056 per day

RATE SCHEDULE E-10
RESIDENTIAL SERVICE
INTERIM CLASSIC RATE

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

Metering	$0.080	per day
Meter Reading	$0.055	per day
Billing	$0.062	per day
System Benefits Charge:	$0.001860	per kWh
Transmission Charge:	$0.00476	per kWh
Delivery Charge:	$0.03288	per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.05255 per kWh for the first 400 kWh, plus $0.08657 per kWh for the next 400 kWh, plus $0.09016 per kWh for all additional kWh	$0.05551 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Rate Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

RATE SCHEDULE E-10
RESIDENTIAL SERVICE
INTERIM CLASSIC RATE

ADJUSTMENTS (cont)

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Rate Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS Proposed Power Supply Adjustment Plan of Administration

APS Proposed Power Supply Adjustment Plan of Administration

General Description

The purpose of the Power Supply Adjustment ("PSA") is to track changes in Arizona Public Service Company's ("APS") cost of obtaining power supplies. This is done by making an annual adjustment to the cost of fuel and purchased power embedded in APS' base rates. The PSA applies to all fuel and purchased power costs incurred on or after April 1, 2005. The costs/savings are shared on a 90 percent customer/10 percent APS basis ("90/10 Sharing"). The PSA currently has five different accounts: 1) an Annual Tracking Account, 2) an Annual Adjustor Account, 3) a Paragraph 19(d) Balancing Account, 4) a Surcharge Account for any surcharge approved by the Arizona Corporation Commission ("Commission") and if applicable 5) a Interim Adjustor Account for any approved Interim Adjustor rate.

Entries are made each month into the Annual Tracking Account. These entries reflect 90 percent of the difference between incurred fuel and purchased power costs and the sum of costs collected through the base cost of fuel and purchased power rate ($0.0XXXXX established in Decision No. XXXXX).

The results of the PSA are applied to customer bills through the Adjustor Rate. The Adjustor Rate is applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. It is applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes. The Adjustor Rate must remain within a plus or minus $0.004 per kWh annual bandwidth that limits the amount it can increase or decrease in a year. Examples of applying the two bandwidths are as follows:

1. Assume that the Adjustor Rate was set at *negative* $0.002 per kWh. The following year, the calculation of the new Adjustor Rate would indicate a new rate of *positive* $0.003 per kWh. However, since that rate would constitute a change of $0.005 from the prior year's Adjustor Rate, the new Adjustor Rate would be set at $0.002 per kWh. That new rate would meet the limit of $0.004 from the base level.

2. Assume that the Adjustor Rate was set at $0.003 per kWh. The following year, the calculation of the new Adjustor Rate would indicate a new rate of $0.005 per kWh. The annual change is less than $0.004, so the new Adjustor Rate would be set at $0.005 per kWh.

The Adjustor Rate is reset on February 1 each year and is effective with the first billing cycle in February unless suspended by the Commission. It is not prorated. APS will submit a publicly available report to the Commission that shows the calculation of the new Adjustor Rate. The amount expected to be recovered or refunded through the Adjustor Rate is entered into the Annual Adjustor Account.

Any recoverable or refundable amounts outside of the bandwidth are recorded in the Paragraph 19(d) Balancing Account and will carry over to the subsequent year or years. The carryover amount shall not be subject to further sharing. Surcharges may be approved by the Commission to recover/refund amounts in the Paragraph 19(d) Balancing Account. Amounts approved for collection through surcharges will be removed from the Paragraph 19(d) Balancing Account.

Definitions

Adjustor Rate – A per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the prior calendar year's fuel and purchased power costs. This annual adjustment is limited to a maximum change of plus or minus 4 mills in a year.

Annual Adjustor Account – An annual schedule/account that shows/records the amount that is available to be recovered through the PSA (after the 90/10 Sharing mechanism is applied); the amount that can be collected through the applicable Adjustor Rate; and also tracks/records the collections per month and the monthly ending balance remaining to be collected.

Annual Tracking Account – An annual schedule/account that tracks/records on a monthly basis APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the base cost.

Base Cost of Fuel and Purchased Power – The fuel and purchased power cost embedded in the base rates approved by the Commission in APS' most recent rate case. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh.

Interim Adjustor Account – A schedule/account that shows/records the revenue collected by the Interim Adjustor rate and the associated fuel and purchased power supply costs that the collected revenue offsets.

ISFSI –Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

PacifiCorp Supplemental Sales – The PacifiCorp Supplemental Sales agreement is a long- term contract from 1990, which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Paragraph 19(d) Balancing Account – A schedule/account that shows/records the amount (after the application of the Adjustor Rate) remaining to be refunded or collected through either a Surcharge, or through the next year's Adjustor Rate . This includes any interest accruals on the account's balance.

PSA – The Power Supply Adjustment mechanism used to update the Base Cost of Fuel and Purchased Power each year for fluctuations in APS' actual cost of fuel and purchased power.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

Surcharge – A per kWh charge that can be applied to customer bills after Commission approval to collect, or refund, an amount for the purpose of reducing the balance in the Paragraph 19(d) Balancing Account. It can be either a positive or negative charge.

Surcharge Account – A schedule/account that shows/records any Surcharge approved, including the amount, timing, rate, and whether interest is applied; and that tracks/records collections per month and the monthly ending balance remaining to be collected.

System Book Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included.

System Book Off-System Sales Revenue – The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale – The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

Calculations

Schedule 1. Annual Tracking Account

1. Enter the monthly Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales. Add these two items together to produce the monthly Total Native Load Energy Sales. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.

2. Enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue. Subtract the System Book Off-System Sales Revenue from the System Book Fuel and Purchased Power Costs to produce the monthly Net Native Load Power Supply Costs. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.

3. To calculate the Retail Power Supply Costs, divide the Retail Energy Sales by the Total Native Load Energy Sales and then multiply the product by the Net Native Load Power Supply Costs.

Directly-assigned power supply costs and related energy sales from applicable Special Contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.

4. The amount recovered by the power supply costs embedded in base rates has to be calculated in order to determine the monthly (over)/under collection. To calculate the monthly Base Rate Power Supply Revenue, multiply the Retail Energy Sales by the Base Cost of Fuel and Purchased Power.

5. Subtract the Base Rate Power Supply Revenue from the Retail Power Supply Costs to get the monthly Pre-90/10 Sharing (Over)/Under Collection amount.

6. Enter the month's 90/10 Sharing Exclusion total. This is the current month's purchased renewable resource cost that is embedded in the System Book Fuel

and Purchased Power Costs which is not covered by the Environmental Portfolio Standard ("EPS") surcharge. Also include the demand costs of Purchased Power Agreements ("PPA") that were acquired through a competitive process.

7. The Post 90/10 Sharing (Over)/Under Collection amount is calculated by multiplying the Pre-90/10 Sharing (Over)/Under Collection amount less the 90/10 Sharing Exclusion by 90 percent. Then the 90/10 Sharing Exclusion amount is added back in to the product of the multiplication to get the Post 90/10 Sharing (Over)/Under Collection.

8. Enter any transfers to the Interim Account Adjustor if such an account is currently active.

9. An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

10. Add the Post-90/10 Sharing (Over)/Under Collection, Transfer to Interim Adjustor Account and Interest amounts together to get the month's Tracking Account Balance.

Schedule 2. Annual PSA Adjustor Rate Calculation

1. Enter the Tracking Account Balance from Schedule 1.

2. Add the Annual Adjustor Account Balance from Schedule 3, the Paragraph 19(d) Balancing Account Balance from Schedule 4, and the Surcharge Account Balance (if a Surcharge has terminated) from Schedule 5 to determine the Total (Credit)/Charge Amount.

3. The Computed Adjustor Rate is calculated by dividing the Total Credit/Charge Amount by the Projected Energy Sales (kWh) for the next 12 months. The Computed Adjustor Rate is then compared to the plus or minus $0.004 per kWh bandwidth. The Projected Energy Sales amount will exclude E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA.

4. The Adjustor Rate Bandwidth Upper Limit is $0.004 per kWh plus the Current Adjustor Rate. The Adjustor Rate Bandwidth Lower Limit is $(0.004) per kWh plus the Current Adjustor Rate.

5. If the Computed Adjustor Rate is inside the bandwidth, the Computed Adjustor Rate becomes the Applicable Adjustor Rate. It is then applied to customer monthly bills for the next 12 months.

6. If the Computed Adjustor Rate is outside the bandwidth, the Applicable Adjustor Rate can be no higher than the upper limit of the bandwidth and no lower than the lower limit of the bandwidth.

7. The Applicable Adjustor Rate is multiplied by the projected Energy Sales to calculate the amount to be carried forward to the Annual Adjustor Account.

8. If the amount to be carried forward to the Annual Adjustor Account is less than the Total (Credit)/Charge Amount used to calculate the Applicable Adjustor Rate, then the difference is carried forward to the Paragraph 19(d) Balancing Account.

Schedule 3. Annual Adjustor Account

1. The Adjustor Rate from Schedule 2 is entered on Schedule 3 in February. The Amount Carried Forward to Annual Adjustor Account is entered as the Beginning Balance.

2. Each month, the Adjustor Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Adjustor Rate. The revenue is subtracted from the Beginning Balance.

3. Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Schedule 4. Paragraph 19(d) Balancing Account

1. The Amount Carried Forward to Paragraph 19(d) Balancing Account from Schedule 2 is entered as the Beginning Balance.

2. Each month, interest is applied based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

3. Whenever the Commission approves a Surcharge, the amount to be collected through the surcharge is subtracted from the balance.

APS is required to make a filing for a Surcharge in the following circumstances. If the size of the Paragraph 19(d) Balancing Account, as shown in the monthly reports filed with the Commission, reaches plus or minus $50 million APS has up to 45 days from the end of the month in which this limit was exceeded to either file a request for Commission approval of a Surcharge or an explanation of why such a Surcharge is not necessary. Should APS seek to recover or refund an amount from the Paragraph 19(d) Balancing Account, the timing and manner of recovery, or refund, and whether interest will be allowed to accrue on the Surcharge balance, will be addressed at that time.

Schedule 5. Surcharge Account

1. The approved Surcharge Rate is entered on Schedule 5 in the month it takes effect. The timing of the Surcharge and whether interest is applied are indicated on the schedule. The approved Surcharge amount is entered as the Beginning Balance.

2. Each month, the Surcharge Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Surcharge Rate. The revenue is subtracted from the Beginning Balance.

3. If interest is authorized, it is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Schedule 6. Interim Adjustor Account

1. If applicable, the approved Interim Adjustor Rate is entered on Schedule 6 in the month it takes effect. The revenue from the approved Interim Adjustor Rate is also entered and then the fuel and purchased power costs offset by the Interim Adjustor rate revenue is moved into the account from Schedule 1 where it is shown as a reduction to the balance in the Tracking Account.

Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The Annual Tracking Account, Annual Adjustor Account, Paragraph 19(d) Balancing Account, Surcharge Account and if applicable, Interim Adjustor Account calculations, including all input and outputs.
2. Total power and fuel costs.
3. Customer sales in both MWh and thousands of dollars by customer class.
4. Number of customers by customer class.
5. A detailed listing of all items excluded from the PSA calculations.
6. A detailed listing of any adjustments to the adjustor reports.
7. Total off-system sales revenues.
8. System losses in MW and MWh.
9. Monthly maximum retail demand in MW.
10. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:

1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller:

1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

Information on economy interchange purchases may be aggregated.

C. Information on off-system sales shall include the following items:

1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.

2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.

F. A summary of unplanned outage costs by resource type.

G. Provide the data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

Allowable Costs

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components presently include the following Federal Energy Regulatory Commission ("FERC") accounts:

1. 501 Fuel (Steam)
2. 518 Fuel (Nuclear) less ISFSI regulatory amortization
3. 547 Fuel (Other Production)
4. 555 Purchased Power
5. 557 Broker Fees (Other Expenses)
6. 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since

origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
XXXX Annual Tracking Account
XXXX XXXX
($ in thousands)

Line No.	Month	(a) PSA Retail [1] Energy Sales (MWh)	(b) Native Load [2] Wholesale Energy Sales (MWh)	(c) Native Load Energy Sales (MWh)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book [4] Off-System Sales Revenue	(f) Net Native Load Power Supply Cost	(g) PSA Retail Power Supply Cost	(h) Base Rate Power Supply Cost	(i) Pre 90/10 Sharing (Over)/Under Collections	(j) 90/10 Sharing Exclusions	(k) Post 90/10 Sharing (Over)/Under Collections	(l) Transfer to Interim Adjustor Account	(m) Interest [5]	(n) Tracking Account Balance
				(a + b)			(d - e)	(a/c * f)	(a * 0.0XXXXX)	(g - h)		((i -j)* 0.9) + j)		(n * rate/12)	(k + l + m)
1	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	May	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	June	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	July	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	August	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12.5	January interest													$ -	
13	Total	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Interest Rate [5]		4.38%												

[1] PSA Retail Energy Sales are the calendar month's kWh sales. Cumulative Retail Energy Sales of XXXXXX MWhs under rate schedule E-36 were excluded from the PSA Calculations.
[2] Includes traditional sales-for-resale and Pacificorp supplemental sales.
[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 XXXXXX, ISFSI and mark-to-market accounting adjustments.
[4] Includes off-system revenue less mark-to-market accounting adjustments.
[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.
Definitions of commonly used terms for this filing are included in the PSA Plan of Administration. Any new terms will be defined on this page.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
XXXX Year End PSA Adjustor Rate Calculation
($ in thousands)

Line No.				
	PSA Adjustor Rate Calculation			
1	Annual Tracking Account Balance (From Schedule 1) [1]		$ -	
2	Annual Adjustor Account Balance (from Schedule 3) [1 2]		$ -	
3	Paragraph 19d Balancing Account Balance (from Schedule 4) [1]		$ -	
4	Surcharge Account Balance after surcharge termination (from Schedule 5) [1]		$ -	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			$ -
6	Projected Energy Sales without E-3, E-4 and E-36 (MWh)	-		
7	Computed Adjustor Rate ($/kWh) (Line 5 / Line 6)		$ -	
8	Current Adjustor Rate ($/kWh)	$ -		
9	Difference between Current Adj. Rate and Computed Adj. Rate (Line 7 - Line 8)	$ -		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit ($/kWh) (Line 8 + .004)		$ 0.004000	
11	Adjustor Rate Bandwidth Lower Limit ($/kWh) (Line 8 + .004)		$ (0.004000)	
12	Applicable Adjustor Rate for February 1, 2007($/kWh)			$ -
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			$ -
14	Amount Carried Forward to Paragraph 19d Balancing Account (Line 5 - Line 13)			$ -

[1] Includes interest for January.

[2] Because the actual amount of revenue to be received in January from the adjustor rate is not available at the time of filing this schedule, the Annual Adjustor Account Balance used here contains estimated revenue for January. The difference between estimated and actual revenue for January is included in the February numbers in the new year's Annual Adjustor Account.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
XXXX Annual Adjustor Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December	200X January
1	Annual Adjustor Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [1]		-	-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Revenue True-up from January Estimate [2]		$ -											
5	Less Revenue from Applicable Adjustor Rate (Ln. 1 * Ln. 2) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Monthly Interest ([Line 3 + Line 4] * [4.38% / 12]) [4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance (Ln. 3 + Ln. 4 - Ln. 5 + Ln. 6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Sales amounts are for energy billed beginning with the first billing cycle of February 2006.

[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calcuation because the actual amount was not available at the time of filing that schedule.

[3] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

[4] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
XXXX Paragraph 19d Balancing Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Amounts Removed due to Authorized Surcharge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest ([Line 1- Line 2] * [4.38% / 12]) [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Ending Balance (Ln. 1 - Ln. 2 + Ln. 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
XXXX Surcharge Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Surcharge Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs)		-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Less: Revenue from Surcharge Rate (Line 1 * Line 2) [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Monthly Interest (Line 3 * [4.38% / 12]) [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Ending Balance with Interest (Line 3 - Line 4 + Line 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

[2] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
XXXX Interim Adjustor Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Interim Adjustor Rate	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs)	-	-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Less: Revenue from Interim Adjustor Rate (Line 1 * Line 2)[1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Transfer from the Annual Tracking Account (Schedule 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Ending Balance (Line 3 - Line 4 + Line 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

Proposed Power Supply Adjustment Plan of Administration using Staff's Approach

Proposed Power Supply Adjustment Plan of Administration using Staff's Approach

General Description

The purpose of the Power Supply Adjustment ("PSA") is to track changes in Arizona Public Service Company's ("APS") cost of obtaining power supplies. This is done by making an annual adjustment to the cost of fuel and purchased power embedded in APS' base rates through the combination of a Prospective Adjustor Rate and Adjustor Rate. The Prospective Adjustor is designed to recover/refund the difference between the base rate fuel and purchased power cost and the actual costs. It is based on the difference between APS' fuel and purchased power costs forecast for the coming year and the base fuel and purchased power rate embedded in APS' effective rates. The Adjustor Rate will recover on an after the fact basis differences between the forecast and actual fuel and purchased power costs in addition to any applicable account balances.

The PSA applies to all fuel and purchased power costs incurred on or after April 1, 2005. This version of the PSA Plan of Administration applies to the fuel and purchased power costs incurred after Decision No. XXXXX was issued on XXXXX XX, XXXX. The costs/savings that are in excess of the forecast balance are shared on a 90 percent customer/10 percent APS basis ("90/10 Sharing"). The PSA has four different accounts: 1) an Annual Tracking Account, 2) an Annual Adjustor Account, 3) a Paragraph 19(d) Balancing Account, and 4) a Surcharge Account for any surcharge approved by the Arizona Corporation Commission ("Commission").

Entries are made each month into the Annual Tracking Account. These entries reflect 90 percent of the difference between incurred fuel and purchased power costs and the sum of costs collected through both the base cost of fuel and purchased power rate ($0.0XXXXX per kWh established in Decision No. XXXXX) and the Prospective Adjustor. The results of the PSA are applied to customer bills through the Adjustor Rate and the Prospective Adjustor Rate. The Adjustor Rate and the Prospective Adjustor are applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and are adjusted annually. They are applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The Adjustor and Prospective rates are reset on February 1 of each year. The new Adjustor and Prospective Adjustor rates are effective with the first billing cycle in February unless suspended by the Commission. They are not prorated.

APS will submit a publicly available report to the Commission that shows the calculation of the new Adjustor Rate. The amount expected to be recovered or refunded through the Adjustor Rate is entered into the Annual Adjustor Account. Any recoverable or refundable amounts over the amount collected by the Adjustor Rate are recorded in the Paragraph 19(d) Balancing Account and will carry over to the subsequent year or years.

The carryover amount shall not be subject to further sharing. Surcharges may be approved by the Commission to recover/refund amounts in the Paragraph 19(d) Balancing Account. Amounts approved for collection through surcharges will be removed from the Paragraph 19(d) Balancing Account and transferred to a Surcharge Account.

The Prospective Adjustor rate calculation will be filed with the Commission by September 30th each year. The Commission Staff will review the forecast on which the rate is based and make a recommendation to the Commission within 45 days. The Commission will determine whether to approve the rate. If the Commission has not acted on the rate by December 31st it will take effect with the first February billing cycle, and it will be subject to refund.

Definitions

Adjustor Rate – A per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the difference between the prior calendar year's actual fuel and purchased power costs and the cost recovery from both the base fuel rate of $0.0XXXXX per kWh and the Prospective Adjustor.

Annual Adjustor Account – An annual schedule/account that shows/records the amount that is available to be recovered through the PSA (after the 90/10 Sharing mechanism is applied); the amount that can be collected through the applicable Adjustor Rate; and that also tracks/records the collections per month and the monthly ending balance remaining to be collected.

Annual Tracking Account – An annual schedule/account that tracks/records on a monthly basis APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the base cost with the Prospective Adjustor.

Base Cost of Fuel and Purchased Power – The fuel and purchased power cost embedded in the base rates approved by the Commission in APS' most recent rate case. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh.

Prospective Adjustor – A per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the difference between the coming year's forecast power supply costs and the base cost of fuel and purchased power of $0.0XXXXX per kWh.

ISFSI –Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

PacifiCorp Supplemental Sales – The PacifiCorp Supplemental Sales agreement is a long- term contract from 1990, which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Paragraph 19(d) Balancing Account – A schedule/account that shows/records the amount (after the application of the Adjustor Rate) remaining to be refunded or collected through either a Surcharge or through the next year's Adjustor Rate. This includes any interest accruals on the account's balance.

PSA – The Power Supply Adjustment mechanism used to update the Base Cost of Fuel and Purchased Power each year for fluctuations in APS' actual cost of fuel and purchased power.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

Surcharge – A per kWh charge that can be applied to customer bills after Commission approval to collect, or refund, an amount for the purpose of reducing the balance in the Paragraph 19(d) Balancing Account. It can be either a positive or negative charge.

Surcharge Account – A schedule/account that shows/records any Surcharge approved, including the amount, timing, rate, and whether interest is applied; and that tracks/records collections per month and the monthly ending balance remaining to be collected.

System Book Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included.

System Book Off-System Sales Revenue – The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale – The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

Calculations

Schedule 1. Prospective Adjustor Rate Calculation

1. Enter the Projected Fuel and Purchased Power Costs for the coming year.
2. Enter the Projected Off-System Sales Revenue for the coming year.
3. Enter the PSA Adjustments to Fuel and Purchased Power Costs for the coming year.
4. Add the Projected Fuel and Purchased Power Costs, Projected Off-System Sales Revenue and the PSA Adjustments to Fuel and Purchased Power Costs together to get the Net Fuel and Purchased Power Costs.
5. Enter the Projected Native Load Sales (kWh), excluding the E-3, E-4, E-36 sales for the coming year.
6. Divide the Net Fuel and Purchased Power Costs by the Projected Native Load Sales to get the Projected Average Net Fuel Cost.
7. Enter the Authorized Base Fuel Rate.
8. Subtract the Authorized Base Fuel Rate from the Projected Average Net Fuel Cost to get the Prospective Adjustor Rate for the coming year.
9. Multiply the Prospective Adjustor Rate by the Projected Native Load Sales to get the Projected Prospective Adjustor Collections for the coming year.
10. The Prospective Adjustor Rate will be used on the coming year's Annual Tracking Account as described below.

Schedule 2. Annual Tracking Account

1. Enter the monthly Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales. Add these two items together to produce the monthly Total Native Load Energy Sales. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.

2. Enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue. Subtract the System Book Off-System Sales Revenue from the System Book Fuel and Purchased Power Costs to produce the monthly Net Native Load Power Supply Costs. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.

3. To calculate the Retail Power Supply Costs, divide the Retail Energy Sales by the Total Native Load Energy Sales and then multiply the product by the Net Native Load Power Supply Costs.

Directly-assigned power supply costs and related energy sales from applicable Special Contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.

4. The amount recovered by the power supply costs embedded in base rates has to be calculated in order to determine the monthly (over)/under collection. To calculate the monthly Base Rate Power Supply Recovery, multiply the Retail Energy Sales by the Base Cost of Fuel and Purchased Power.

5. The Prospective Adjustor Recovery is calculated by multiplying the Retail Energy Sales by the applicable Prospective Adjustor rate.

6. Subtract the Base Rate Power Supply Recovery and the Prospective Adjustor Recovery from the Retail Power Supply Costs to get the monthly Pre-90/10 Sharing (Over)/Under Collection amount.

7. Enter the month's 90/10 Sharing Exclusion total. This is the current month's purchased renewable resource cost that is embedded in the System Book Fuel and Purchased Power Costs and is not covered by the Environmental Portfolio Standard ("EPS") surcharge. Also include the demand costs of Purchased Power Agreements ("PPA") that were acquired through a competitive process.

8. The Post-90/10 Sharing (Over)/Under Collection amount is calculated by multiplying the Pre-90/10 Sharing (Over)/Under Collection amount less the 90/10 Sharing Exclusion by 90 percent. Then the 90/10 Sharing Exclusion

amount is added back in to the product of the multiplication to get the Post 90/10 Sharing (Over)/Under Collection.

9. An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

10. Sum the Post-90/10 Sharing (Over)/Under Collection, the Interest and the prior months Tracking Account Balance to get the current month's balance.

Schedule 3. Annual PSA Adjustor Rate Calculation

1. Enter the Tracking Account Balance from Schedule 2, the Annual Adjustor Account Balance from Schedule 4, the Paragraph 19(d) Balancing Account Balance from Schedule 5, and the Surcharge Account Balance (if a Surcharge has terminated) from Schedule 6. Add all of these balances together to determine the Total (Credit)/Charge Amount.

2. The Applicable Adjustor Rate is calculated by dividing the Total (Credit)/Charge Amount by the Projected Energy Sales (kWh) for the next 12 months. The Projected Energy Sales amount will exclude E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA.

3. The Applicable Adjustor Rate is then applied to customer monthly bills for the next 12 months.

4. The Applicable Adjustor Rate is multiplied by the projected Energy Sales to calculate the amount to be carried forward to the Annual Adjustor Account.

5. If the amount to be carried forward to the Annual Adjustor Account is less than the Total (Credit)/Charge Amount used to calculate the Applicable Adjustor Rate, then the difference is carried forward to the Paragraph 19(d) Balancing Account.

Schedule 4. Annual Adjustor Account

1. The Adjustor Rate from Schedule 3 is entered on Schedule 4 in February. The Amount Carried Forward to Annual Adjustor Account is entered as the Beginning Balance.

2. Each month, the Adjustor Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Adjustor Rate. The revenue is subtracted from the Beginning Balance.

3. Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Schedule 5. Paragraph 19(d) Balancing Account

1. The Amount Carried Forward to Paragraph 19(d) Balancing Account from Schedule 3 is entered as the Beginning Balance.

2. Each month, interest is applied based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

3. Whenever the Commission approves a Surcharge, the amount to be collected through the surcharge is subtracted from the balance.

APS is required to make a filing for a Surcharge in the following circumstances. If the size of the Paragraph 19(d) Balancing Account, as shown in the monthly reports filed with the Commission, reaches plus or minus $50 million, APS has up to 45 days from the end of the month in which this limit was exceeded to either file a request for Commission approval of a Surcharge or an explanation of why such a Surcharge is not necessary. Should APS seek to recover or refund an amount from the Paragraph 19(d) Balancing Account, the timing and manner of recovery, or refund, and whether interest will be allowed to accrue on the Surcharge balance, will be addressed at that time.

Schedule 6. Surcharge Account

1. The approved Surcharge Rate is entered on Schedule 6 in the month it takes effect. The timing of the Surcharge and whether interest is applied are indicated on the schedule. The approved Surcharge amount is entered as the Beginning Balance.

2. Each month, the Surcharge Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Surcharge Rate. The revenue is subtracted from the Beginning Balance.

3. If interest is authorized, it is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest

rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The Annual Tracking Account, Annual Adjustor Account, Paragraph 19(d) Balancing Account, and Surcharge Account calculations, including all input and outputs.
2. Total power and fuel costs.
3. Customer sales in both MWh and thousands of dollars by customer class.
4. Number of customers by customer class.
5. A detailed listing of all items excluded from the PSA calculations.
6. A detailed listing of any adjustments to the adjustor reports.
7. Total off-system sales revenues.
8. System losses in MW and MWh.
9. Monthly maximum retail demand in MW.
10. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:

1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller:

1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.

4. The total cost of energy.

Information on economy interchange purchases may be aggregated.

C. Information on off-system sales shall include the following items:

1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.

2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.

F. A summary of unplanned outage costs by resource type.

G. Provide the data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

Allowable Costs

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components presently include the following Federal Energy Regulatory Commission ("FERC") accounts:

1. 501 Fuel (Steam)
2. 518 Fuel (Nuclear) less ISFSI regulatory amortization

3. 547 Fuel (Other Production)
4. 555 Purchased Power
5. 557 Broker Fees (Other Expenses)
6. 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
XXXX PSA Prospective Adjustor Rate Calculation
($ in thousands)

Line No.	**PSA Prospective Adjustor Rate Calculation**				
1	XXXX Projected Fuel and Purchased Power Costs	$	-		
2	XXXX Projected Off-System Sales Revenue	$	-		
3	XXXX PSA Adjustments to Fuel and Purchased Power Costs [1]	$	-		
4	Net Fuel and Purchased Power Cost	$	-		
5	XXXX Projected Native Load Sales, excluding E-3, E-4, E-36 (kWhs)		-		
6	XXXX Projected Average Net Fuel Cost				-
7	Authorized Base Fuel Rate				-
8	Prospective Adjustor Rate for XXXX				-
9	XXXX Projected Prospective Adjustor Collections			$	-

[1] Includes costs associated with E-36, ISFSI and mark-to-market accounting adjustments.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
XXXX Annual Tracking Account
XXXX XXXX
($ in thousands)

Line No.	Month	(a) PSA Retail[1] Energy Sales (MWh)	(b) Native Load[2] Wholesale Energy Sales (MWh)	(c) Native Load Energy Sales (MWh)	(d) System[3] Book Fuel and Purchased Power Costs	(e) System Book[4] Off-System Sales Revenue	(f) Net Native Load Power Supply Cost	(g) PSA Retail Power Supply Cost	(h) Base Rate Power Supply Recovery	(i) Prospective Adjustor Recovery	(j) Pre 90/10 Sharing (Over)/Under Collections	(k) 90/10 Sharing Exclusions	(l) Post 90/10 Sharing (Over)/Under Collections	(m) Interest[5]	(n) Tracking Account Balance
				(a + b)			(d - e)	(a/c * f)	(a * 0.0XXXX)	(a * 0.0XXXX)	(g - h - i)		((j -k)* 0.9) + k)	(m * rate/12)	(l + m + n)
1	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	May	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	June	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	July	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	August	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Total	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Interest Rate[5]		4.38%												

[1] PSA Retail Energy Sales are the calendar month's kWh sales. Cumulative Retail Energy Sales of XXXXXX MWhs under rate schedule E-36 were excluded from the PSA Calculations.
[2] Includes traditional sales-for-resale and Pacificorp supplemental sales.
[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 XXXXXX, ISFSI and mark-to-market accounting adjustments.
[4] Includes off-system revenue less mark-to-market accounting adjustments.
[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.
Definitions of commonly used terms for this filing are included in the PSA Plan of Administration. Any new terms will be defined on this page.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
XXXX Year End PSA Adjustor Rate Calculation
($ in thousands)

Line No.	**PSA Adjustor Rate Calculation**			
1	Annual Tracking Account Balance (From Schedule 2) [1]		$ -	
2	Annual Adjustor Account Balance (from Schedule 4) [1,2]		$ -	
3	Paragraph 19d Balancing Account Balance (from Schedule 5) [1]		$ -	
4	Surcharge Account Balance after surcharge termination (from Schedule 6) [1]		$ -	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			$ -
6	Projected Energy Sales without E-3, E-4 and E-36 (MWh)	-		
7	Applicable Adjustor Rate for February 1, XXXX ($/kWh)			$ -
8	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 7)			$ -
9	Amount Carried Forward to Paragraph 19d Balancing Account (Line 5 - Line 8)			$ -

[1] Includes interest for January.

[2] Because the actual amount of revenue to be received in January from the adjustor rate is not available at the time of filing this schedule, the Annual Adjustor Account Balance used here contains estimated revenue for January. The difference between estimated and actual revenue for January is included in the February numbers in the new year's Annual Adjustor Account.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
XXXX Annual Adjustor Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December	200X January
1	Annual Adjustor Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [1]	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Revenue True-up from January Estimate [2]		$ -											
5	Less Revenue from Applicable Adjustor Rate (Ln. 1 * Ln. 2) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Monthly Interest ([Line 3 + Line 4] * [4.38% / 12]) [4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance (Ln. 3 + Ln. 4 - Ln. 5 + Ln. 6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Sales amounts are for energy billed beginning with the first billing cycle of February 2006.

[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calcuation because the actual amount was not available at the time of filing that schedule.

[3] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

[4] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
XXXX Paragraph 19d Balancing Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Amounts Removed due to Authorized Surcharge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest ([Line 1- Line 2] * [4.38% / 12]) [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Ending Balance (Ln. 1 - Ln. 2 + Ln. 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
XXXX Surcharge Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Surcharge Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs)	-	-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Less: Revenue from Surcharge Rate (Line 1 * Line 2) [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Monthly Interest (Line 3 * [4.38% / 12]) [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Ending Balance with Interest (Line 3 - Line 4 + Line 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

[2] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

REBUTTAL TESTIMONY OF JAMES LEVINE

On Behalf of Arizona Public Service Company

DOCKET NO. E-01345A-05-0816

September 15, 2006

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

I. BACKGROUND

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Jim Levine. I am the Executive Vice President Generation for Arizona Public Service Company ("APS" or "Company"). In this capacity, I have overall responsibility for the safe and reliable operations of the Company's fleet of generating units.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE?

A. I received a Bachelor of Science degree in Mechanical Engineering from Tri-State University in Angola, Indiana, in 1972. From 1972 to 1975, I worked as a field engineer for Westinghouse Electric Corporation in their Power Generation Service Division. From 1975 to 1981, I worked as a supervisor in the Operations, Engineering, and Maintenance departments for the Connecticut Yankee Atomic Power Company at the Connecticut Yankee Atomic Power Station. From 1981 to 1989, I worked in various positions of increasing responsibility at the Arkansas Power and Light Company's Arkansas Nuclear One (ANO) nuclear power plant. In my last position at Entergy, I was the Executive Director, Nuclear Support.

In September 1989, I joined APS as the Vice President of Nuclear Production for the Palo Verde Nuclear Generating Station ("Palo Verde"). In this role I was responsible for the day-to-day operations of Palo Verde. In September 1996, I

was named the Senior Vice President Nuclear for APS. In this role, I was responsible for all nuclear-related activities associated with the operation of Palo Verde. In 1999, I was named to my current position of Executive Vice President Generation for APS.

With regard to my industry experience, I served as a member of the Advisory Council of the National Academy and the Institute of Nuclear Power Operations' ("INPO") Industry Review Group for Evaluation and Assessment. This group advises and oversees the nuclear industry's comprehensive program of independent, performance evaluations and assessments to high standards of safety and reliability. I currently serve as Chairman of INPO's National Nuclear Accrediting Board, which formally verifies and accredits or rejects the operations, maintenance and technical training programs for key positions at each member's nuclear utility. I am also a member of the Nuclear Energy Institute's ("NEI") Nuclear Strategic Issues Advisory Committee. I serve as Chairman of NEI's Risk Informed Regulatory Working Group and I am a member of the Materials Executive Oversight Group. In May 1999, I was appointed by Governor Hull to the Arizona Radiation Regulatory Hearing Board, and I serve in that capacity today.

Q. ARE THERE OTHER WITNESSES TESTIFYING ON BEHALF OF APS IN REBUTTAL TO THE GDS REPORT?

A. Yes. Steven Wheeler, Executive Vice President, Customer Service & Regulation, will address the issue of GDS' recommendation regarding a nuclear performance standard, as well as other policy issues. Robert Denton, the former President and Chief Executive Officer of Constellation Nuclear, which owned

and operated the Calvert Cliffs and Nine Mile Point nuclear plants will testify on the prudence of certain outages and contracting practices in the utility industry. Roger Mattson, a former senior official at the Nuclear Regulatory Commission ("NRC"), will testify regarding the differences between NRC regulatory practices and the prudence standard applicable to this proceeding, the NRC's views regarding nuclear performance standards, and the prudence of the outages at Units 2 and 3 in October 2005 due to a question posed by the NRC. George Fitzpatrick, the chief executive of Harbourfront Group, Inc., with over 30 years experience in performing statistical analyses for electric and gas utilities, will testify regarding GDS' recommendation that the Commission adopt a nuclear performance standard, as well as the appropriateness of GDS' disallowance recommendation in light of both Palo Verde's past performance and the performance of APS' other baseload plants. Finally, Peter Ewen, APS' Manager of the Revenue and Fuel Analysis and Forecasts Department, will testify regarding the appropriateness of a number of the disallowance calculations contained in GDS' report, the appropriateness of GDS' recommendation that certain costs should not be considered in establishing base fuel costs in the pending rate case, and the performance of APS' baseload coal plants versus the normalized amounts included in the Company's base rates.

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

A. On February 2, 2006, APS filed with the Commission an application for approval of a Power Supply Adjuster ("PSA") surcharge. APS' application is being adjudicated before the Commission in Docket No. E-01345A-06-0063. APS is seeking recovery of replacement power costs that were incurred as a

result of various short notice outages and forced outages at Palo Verde. The actual recovery of these costs would be through the Power Supply Adjustment mechanism.

My testimony addresses APS' operation of Palo Verde and responds to certain conclusions and recommendations set forth in the report of the Staff's consultant, GDS Associates, Inc. ("GDS") and in the testimony of GDS' Vice President, William R. Jacobs, Jr.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Not in a formal proceeding, but I have appeared before the Commission on several occasions to discuss Palo Verde related issues.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony will demonstrate the following:

- Safe operation of the Palo Verde units is our overriding priority and Palo Verde has operated safely.
- Over the last 10 years, Palo Verde has performed well in comparison to other nuclear plants.
- The Integrated Performance Improvement Program that APS is currently implementing at Palo Verde is an aggressive effort to return Palo Verde performance to the level of excellence it achieved during the last decade.
- GDS' recommendation to disallow $15.344 million in replacement power costs in connection with the forced outage of Units 2 and 3 in October

2005 is not appropriate. As NRC Regional Administrator, Bruce Mallet told the Commission during his appearance on January 25, 2006, this outage (1) was caused by a new question that the NRC asked; (2) Palo Verde personnel took the correct action in taking the units out of service when the question could not be immediately answered; and (3) it was not an issue that Palo Verde should have reasonably addressed before the NRC raised it. Moreover, the original design was determined to be adequate and the units returned to service nine days later without any change to the equipment. Finally, Palo Verde performed equipment maintenance during the outage that would otherwise have caused a unit to be taken out of service, and thereby avoided between $4.4 million and $7.0 million in future replacement power costs.

- GDS' recommendation to disallow $1.134 million in replacement power costs associated with a delay in start-up following an August 2005 Unit 1 outage because of an operator's error should be rejected. In light of Palo Verde's excellent performance over the past decade this one error should not be a basis for a finding of imprudence. Moreover, GDS has not presented an analysis of why Palo Verde actions were imprudent but has simply relied on Company self-critical documents developed with the full benefit of hindsight.
- GDS' criticism of Palo Verde's storage of the Unit 1 Diesel Generator A governor, the failure of which led to a three-day outage in March of 2005, is inappropriate. GDS' recommendation is inappropriate because the actual cause of the governor failure was not determined and Palo Verde personnel complied with the manufacturer's storage instructions. Nor

could Palo Verde personnel have detected the problem through a pre-installation inspection. Additionally, this outage predates the PSA and has no bearing on this case.

- APS' actions in connection with pursuing potential remedies against vendors whose equipment caused certain of the 2005 outages have been appropriate.
- The Company is willing to file the report recommended by GDS in its fourth recommendation regarding plant performance, although confidential information would be made available for review only. Moreover, the Company cannot commit to provide INPO data, or even to make INPO data available, without INPO's consent. The Company has informed INPO of GDS' recommendation, and will supplement this testimony upon receiving INPO's response. With respect to GDS' fifth and sixth recommendations, the Company is willing to file such reports. However, although GDS referred to other nuclear plants that "have been successful in managing aging equipment issues" in its fifth recommendation, and to "other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts," in its sixth recommendation, GDS stated in data request responses that it was unaware of any plants with these characteristics and recommended that APS contact INPO. We will do so, but the extent to which APS can file the recommended reports will depend on the results of the contact with INPO.

III. OPERATING PHILOSOPHY

Q. COULD YOU PLEASE EXPLAIN APS' ROLE IN OPERATING PALO VERDE?

A. Palo Verde is jointly owned by seven companies. They are: APS (29.1%); Salt River Agricultural Improvement and Power District (17.5%); Southern California Edison Company (15.8%); El Paso Electric Company (15.8%); Public Service Company of New Mexico (10.2%); Southern California Public Power Authority Association (5.9%); and Department of Water and Power City of Los Angeles (5.9%).

APS is the licensed operator and the operating agent for Palo Verde on behalf of Palo Verde's owners. In this regard, APS manages the employees and contractors working at Palo Verde, and makes all decisions with regard to the safe and reliable operation of the station such as scheduling maintenance and refueling outages, shutting a unit down for an outage when an issue arises, and re-starting a unit after an outage. APS confers, and receives approval from the other owners on a number of things, including all major capital projects such as steam generator replacements and turbine upgrades.

Q. ARE THERE DIFFERENCES BETWEEN OPERATING A NUCLEAR POWER PLANT AND OTHER POWER PLANTS?

A. Absolutely. Certain aspects of regulation can greatly impact a nuclear unit's performance. Nuclear stations are licensed and regulated by the NRC. As a condition of its license, each station is required to designate strict plant operating standards, plant designs and technical specifications that must be complied with to meet the license standards. If an anomalous situation occurs,

technical specifications require that certain actions must be performed and conditions met within specific timeframes in order to continue to operate the unit. In some cases, when these predetermined timeframes cannot be met, the technical specifications require that the unit be taken out of service. NRC regulations, radiological conditions, and prescriptive operating procedures require the unit to follow a specific process for shutdown, outages and restart.

Since nuclear power plants are strictly regulated to assure their safety, the operating requirements are vastly different from those applicable to coal or gas-fired plants of similar size. For example, the radiological conditions of the plant are highly controlled and monitored, and access to specific areas is restricted during normal plant operations. When a nuclear plant is taken out of service, access to certain areas is restricted until radiological, temperature and other conditions are met. Despite Palo Verde's success in minimizing the effect of radiological conditions on outages, the ability of employees to work during outages is still more restricted than comparable maintenance or repair in a fossil station.

Each U.S. nuclear station contains multiple systems as well as engineering practices and operational features that create redundancy -- or multiple barriers -- to ensure safe operations. Regulations and maintenance practices in nuclear stations are in place to replace, repair and ensure the safety margin of the primary and secondary systems. That means that the unit may be down-powered or removed from service to repair a system that does not directly impact the operations or output of the plant but rather, to ensure the safe operation of the

back-up systems. Palo Verde has specific operating and maintenance procedures (and corresponding training for personnel) that control plant operation. These procedures cover not only normal plant operation, but a multitude of other conditions – such as emergency and abnormal operations. As a result, plant operators have extremely limited discretion in how the plant is to be operated in any specific condition. For example, in one of the outages discussed below, we had to shut down two of the Palo Verde units (the third was already in a steam generator replacement outage) when the NRC posed a question that raised doubt about whether a safety system would function adequately if called upon in the event of an extremely unlikely but theoretically possible accident. By contrast, fossil units do not have strict technical specifications that require the unit to be taken out of service under such circumstances. Nuclear unit shutdown under normal conditions takes about one day. From shutdown conditions to returning to the grid takes about two days, and return to 100 percent power takes an additional one to two days. In contrast, return of a gas or coal plant to service can be achieved in as little as, or less than, one day.

IV. HISTORICAL PERFORMANCE

Q. HOW HAS PALO VERDE PERFORMED OVER THE LAST DECADE?

A. Over the last decade, Palo Verde has performed very well. For the 13th year in a row, Palo Verde in 2004 was the most productive single power station in the country, producing more than 28 million megawatt-hours. From 1995 through 2004, the 10-year average capacity factor for all three Palo Verde units was 89.5% compared with an industry average of 82% and with a pressurized water

reactor (PWR) average of 87%. This was far superior to the 75% capacity factor anticipated when the units were designed and built. As Mr. Fitzpatrick addresses in his testimony, this superior performance resulted in a net benefit to APS and its customers of over $90 million during the period of 1995 to 2004 as compared to the average performance of pressurized water reactors of greater than 600 megawatts.

V. PERFORMANCE DURING 2005

Q. HOW WOULD YOU CHARACTERIZE PALO VERDE'S PERFORMANCE IN 2005?

A. Palo Verde generated 25,803,512 MWh of electricity, the greatest output of any station in the United States. However, in 2005 Palo Verde admittedly fell short of our own very high standards. For example, our 2005 internal goal for production was 28 million megawatt hours and we finished the year about 10 percent short of that goal. Also, our year-end capacity factor goal was 86 percent, and we achieved a plant-wide capacity factor of 77.4 percent. So in terms of production and capacity factor we fell about 10 percent shy of our high targets in 2005.

Q. CAN YOU PROVIDE AN EXPLANATION FOR WHY PALO VERDE DID NOT MEET THE COMPANY'S HIGH PERFORMANCE EXPECTATIONS?

A. Yes, the decrease in performance is directly related to the greater than typical number and duration of plant outages that we experienced in 2005. In several instances these outages necessitated repairs and/or inspections that required the affected unit to remain out of production for a period of time. These outages

were not the result of imprudence. Prudence only requires that reasonable actions be taken based on information that was or should have been known at the time of an action, without the use of hindsight. As Mr. Denton and Dr. Mattson explain in their testimony, prudence does not depend on the results achieved, and certainly does not require perfection.

Q. DO YOU AGREE WITH THE STAFF CONSULTANT GDS' RELIANCE ON THE PLANT'S 2005 CAPACITY FACTOR TO SHOW THAT PERFORMANCE IN 2005 WAS "POOR" (GDS, P. 8)?

No. GDS claims that plant performance was poor because of low capacity factor, yet it acknowledges that the bulk of the outages that cause the low capacity factor were prudent. For example, Unit 1's capacity factor was only 66%. However, this was due in large part to the 77 day steam generator replacement outage, which GDS describes in its report as "a complex outage that was well planned and executed." Thus, the only Unit 1 outages challenged equal five days of Unit 1 outage time, three of which predate the PSA, and two days for a reactor trip upon startup of Unit 1 in August.

Q. GDS ALSO COMMENTS ON THE COMPANY'S PERFORMANCE IMPROVEMENT PLAN. DO YOU AGREE WITH THOSE COMMENTS?

A. GDS describes the Performance Improvement Plan as "a comprehensive plan with substantial resources and the full backing and commitment of APS management." (GDS, p. 10). I agree with this description and assure the Commission that the plan has my full commitment and that of all the Company's senior management. It is our goal to return Palo Verde's performance to the sustained level of excellence at which it performed for a decade, and we are

working as hard as possible to achieve that goal as quickly as possible. I appreciate and share in GDS' optimism that the plan "will be successful in improving the performance of Palo Verde to the desired level." (GDS, p. 11)

Q. WERE THERE ANY SAFETY ISSUES RELATED TO ANY OF THE 2005 OUTAGES?

A. No. In keeping with the conservative philosophy with which we operate Palo Verde, in each case the affected unit was promptly shut down until the problem could be repaired or the issue appropriately analyzed. As you will recall, Dr. Bruce Mallet, the NRC's Regional Administrator for Region IV also addressed this issue in his January 26, 2006 appearance before the Commission. Dr. Mallet stated:

> First and foremost, the licensee, Arizona Public Service, has operated the Palo Verde nuclear plant in a safe and secure condition. They have ensured the protection of the public health and safety. And they have ensured the protection of the environment. They have also responded to emergent plant conditions and emergency events with safety as a primary focus.

(Transcript at 6-7.) I would note that GDS also observed that "[n]one of the outages investigated resulted in or from unsafe operations and, in fact, demonstrated that APS was willing to shut down the plant when any safety conditions were identified. Palo Verde was safely operated throughout 2005." (GDS, p. 18) Operating the plant with safety as a primary focus is how we always have operated the plant and how we always will operate Palo Verde.

VI. 2005 OUTAGES CHALLENGED BY GDS AS IMPRUDENT

Q. BEFORE ADDRESSING THE OUTAGES THAT GDS CLAIMS WERE CAUSED BY IMPRUDENT APS CONDUCT, WOULD YOU EXPLAIN WHAT IS MEANT BY A FORCED OUTAGE?

A. A forced outage can be of two types. The first is an immediate outage where the unit "trips" (i.e., automatically begins to shut down) or an equipment issue requires immediate removal from service, and plant personnel respond. The second type is the situation where the plant's technical specifications require that actions be performed or conditions met within a specified time frame in order to continue to operate the unit. If required actions cannot be taken or specific conditions met within the pre-determined time frame, the unit must be removed from service. These situations often involve the need to make what is known as an operability determination.

Q. WHAT IS AN "OPERABILITY DETERMINATION"?

A. The NRC defines "operable/operability" as the condition when a safety-related system, subsystem, train, component or device is capable of performing its specified safety functions, and when "all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication and other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s)." NRC Inspection Manual, Part 9900, addressing operability determinations, defines an operability declaration as "a decision by a senior licensed operator on the operating shift crew that there is a reasonable expectation that a SSC [a safety system, structure or component] can perform its specified safety function." See Section 3.7 of Part 9900. The

NRC emphasizes that the "reasonable expectation" standard is a high standard. See Section 3.9. The NRC further states that "determinations of operability are appropriate whenever a review, TS [technical specification] surveillance, or other information calls into question the ability of SSCs to perform specified safety functions." Significantly, an SSC may be deemed inoperable even though there is no current need for the SSC to operate and even if it is highly unlikely that the SSC will be called upon to operate. Such operability determinations resulted in the outages at Units 2 and 3 in October of 2005.

Q. GDS RECOMMENDS A DISALLOWANCE FOR THE FORCED OUTAGE AFFECTING UNITS 2 AND 3 BETWEEN OCTOBER 11 AND OCTOBER 20, 2005. WHAT WAS THE ISSUE THAT CAUSED THIS OUTAGE?

A. It arose during a follow-up inspection that the NRC was conducting to address the Company's response to the "yellow" finding related to the pipe void issue the Company identified in 2004. During the inspection, one of the inspectors asked a question about the possibility of air ingestion into piping after what is called a recirculation actuation signal. A detailed explanation of how the containment spray system and emergency core cooling systems work in the event of a loss of coolant accident and the Company's response to the NRC inspector's question is set forth in the testimony of Dr. Roger Mattson. In summary, however, it was a new question that, as the NRC's Regional Administrator Bruce Mallet acknowledged in his appearance before the ACC on January 26, 2006, the NRC had never asked before, (Transcript at 43), not during Palo Verde's licensing nor during the subsequent almost two decades of operation.

Q. WHY WOULD SUCH A QUESTION REQUIRE THE PLANT TO SHUT DOWN?

A. The question went to the adequacy of what is referred to as the design basis of the plant. As Dr. Mallet explained in his appearance before the Commission, the NRC's question required the plant to make an operability determination which required the plant to be shut down.

> In the October [2005] time frame, when we raised this issue about the design flaw, it was a new question, okay, one that we hadn't come across before, nor had they [APS] 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 over simplifying – so that would put us in a condition we don't believe is within our design. If you can't answer [the] NRC, and we [APS] can't answer it within this certain time frame, we have to shut the plant down by our technical specifications until we get it resolved. And that's what they did . . . . All I can say in this case is that it was a question we raised and they did the right thing when they couldn't answer the question. . . .
>
> (Transcript at pp. 45-46.)

Q. SHOULD APS HAVE ANTICIPATED THE NRC'S QUESTION?

A. No. Commissioner Mayes asked this same question of Dr. Mallet who responded that "we didn't determine that they should have found it beforehand." (Transcript at 46.) Without getting too far into the technical detail Dr. Mattson provides in his testimony, the basic reason we would not have asked ourselves this question earlier is because the plant was in conformity with its design basis based on the static calculations the NRC had accepted back when it issued the license for the Palo Verde units. When the NRC inspection team asked the question that required going beyond these static calculations and required dynamic calculations – the "new question" that NRC Regional Administrator Mallet was referring to – we had to retain expert help to do those calculations.

Because we could not assure ourselves (i.e., make the operability determination) that the system would perform properly in the hypothetical situation the NRC inspector posed, we had no choice but to take the plant out of service while the expert work was being performed. We obtained the services of a premier expert in hydrodynamics who did the analysis and confirmed that the original design would perform as intended. The NRC promptly accepted this analysis, and the plant returned to service as quickly as possible, i.e., nine days, and without any change to plant equipment.

Q. DO YOU AGREE WITH GDS' ASSERTION THAT APS SHOULD HAVE IDENTIFIED THE NRC INSPECTOR'S CONCERN IN 2004, AND THAT THEREFORE, THE OCTOBER 2005 OUTAGE WAS AVOIDABLE?

A. I do not agree with GDS' claim nor apparently does the senior NRC official involved. As noted above, Dr. Mallet told the Commission that "we didn't determine that they should have found it beforehand." (Transcript at 46.) In fact, Dr. Mallet asked Mr. Pruett, a Region IV Branch Chief, and one of the principal NRC officials responsible for NRC oversight of Palo Verde to correct him if he was incorrect. Mr. Pruett did not add anything. (Transcript at 46.)

Q. DID DR. MALLET ALSO STATE THAT AN UPCOMING REPORT TO BE ISSUED THE NEXT DAY WOULD MAKE THE NRC'S CONCLUSIONS FINAL WITH RESPECT TO THE REFUELING WATER TANK OUTAGE?

A. Yes, and while that report is critical of the Company in a number of respects, it does not contradict the remarks that Dr. Mallet made to the Commission about the new nature of the question the NRC posed and his conclusion that this was not a question the Company should have considered previously. Had the NRC

believed otherwise, it would have issued a violation on this point, and while the report does contain some minor violations for other matters, it does not issue a violation for failure to properly assess the extent of condition associated with the voided pipe issue.

Q. GDS ALSO STATES IN ITS REPORT THAT GDS PERSONNEL SPOKE WITH MR. WARNICK, ONE OF THE NRC RESIDENT INSPECTORS, AND THAT MR. WARNICK TOLD GDS THAT THE OUTAGE WAS AVOIDABLE. IS MR. WARNICK WRONG?

A. First, unlike the remarks of Mr. Warnick's superior, Dr. Mallet, there is no transcript of what Mr. Warnick told GDS. Second, Mr. Warnick was not a member of this inspection team. Third, assuming that Mr. Warnick said that the outage was avoidable, in NRC parlance, that does not mean that APS should have foreseen the question or that it acted imprudently. As described in detail in Dr. Mattson's testimony, the NRC does not focus on prudence, but uses hindsight to identify lessons learned from events in order to constantly improve the safety of nuclear plants. In hindsight, the outage may have been avoidable if, back at the time the NRC initially licensed the plant, the NRC had asked the question in the same way the inspector posed the question in 2005. However, as GDS acknowledges, such hindsight is impermissible in a prudence review.

Q. GDS QUOTES EXTENSIVELY FROM THE NRC'S JANUARY 26, 2006 INSPECTION REPORT TO SUPPORT ITS CLAIM OF IMPRUDENCE. IS GDS' RELIANCE ON THAT REPORT APPROPRIATE?

A. No. Not surprisingly, that report does not contradict Dr. Mallet's representation to this Commission that the NRC did not determine that APS should have found the issue before the NRC raised it in 2005. Indeed, Dr. Mallet signed the cover letter forwarding the report to me, and page i of the report states that it was

"Approved By: Bruce Mallet, Regional Administrator." It only makes sense to read that report in a manner that is consistent with Dr. Mallet's statements to this Commission.

Q. WAS ANY OTHER WORK PERFORMED ON UNIT 2 DURING THE REFUELING WATER TANK OUTAGE?

A. Yes. When we are required to shut down a unit due to unforeseen events, we always try to perform as much work as possible in order to improve equipment reliability, maximize plant performance, and shorten future outages.

Q. PLEASE DESCRIBE THE WORK THAT WAS PERFORMED ON UNIT 2.

A. Palo Verde performed the following work on Unit 2:

- Replaced Thrust Bearing Oil Seal on RCP 1A
- Replaced Thrust Bearing Oil Seal on RCP 2A
- Performed Complete Oil Change Out on RCPs 1A and 2A
- Replaced Inboard and Outboard Oil Seals for "A" Main Feedwater Pump
- Replaced Control Circuit Resistor for "A" Auxiliary Feedwater Pump
- Repaired Steam Leak on "A" Heater Drain Pump
- Replaced Main Generator Excitation Bushings
- Repaired RU-151
- Performed EW Heat Exchanger Thermal Performance Test

Q. DID THE PERFORMANCE OF THIS WORK PREVENT OR REDUCE THE LENGTH OF A LATER OUTAGE?

A. Yes. The oil leakage from the thrust bearing oil seals on reactor coolant pumps ("RCPs") 1A and 2A had decreased to the point that Palo Verde in all likelihood

would have had to shut down Unit 2 prior to the unit's next outage to replace the oil seals. Therefore, when Unit 2 was shut down due to the issues with the refueling water tank, we decided that we should use the opportunity to replace these oil seals.

Q. DID GDS PROVIDE ANY CONCLUSIONS REGARDING OUTAGES DUE TO OIL LEAKAGE FROM THE RCP OIL SEALS?

A. Yes. GDS analyzed other outages based on this same problem of oil leakage from the RCP oil seals, and concluded in its report (p. 39) that Palo Verde's actions regarding the oil seals have been "reasonable and prudent."

Q. WAS THE OIL LEAKAGE FROM THE UNIT 2 RCPS THE SAME AS FOR THE OUTAGES THAT GDS ANALYZED?

A. Yes. All of the outages occurred due to the same issue of oil leakage from RCP oil seals.

Q. WHAT AMOUNT OF REPLACEMENT POWER COSTS DID PALO VERDE AVOID BY PERFORMING THE WORK ON THE RCP OIL SEALS DURING THE REFUELING WATER TANK OUTAGE?

A. Palo Verde avoided a minimum of $4.4 million and potentially $6.1 million by performing this work on the RCPs during the October outage. The details of these calculations are addressed in Peter Ewen's testimony. It is difficult to know precisely when the outage would have occurred, but I believe, based on the performance of the oil seals at the time of their replacement in October 2005, had the seals not been replaced as part of the RWT outage, we would have had to shut down Unit 2 shortly thereafter in order to replace the seals.

Palo Verde also performed maintenance on the Unit 2 main generator excitation bushings. Had this work not been performed during the October outage, it likely would have also caused an independent outage, and Unit 2 would have had to shut down. Nonetheless, this work would have been performed in concurrence with the work on the RCP oil seals. Therefore, the performance of the main generator excitation bushing maintenance in October did not avoid any replacement power costs separate from the costs avoided by the RCP maintenance discussed above.

Q. DID PALO VERDE PERFORM ANY ADDITIONAL WORK ON UNIT 2 THAT PREVENTED A LATER OUTAGE OR REDUCTION IN POWER?

A. Yes. The work listed above that was performed on a main feedwater pump and a heater drain pump in October would likely have required a reduction of power in Unit 2 to replace various seals on the pumps had the work not been performed during this outage. Using the same methodology above used to calculate the values for the RCPs, the avoided replacement power costs due to the work performed on the main feedwater pump and the heater drain pump increases the total replacement power costs avoided for all maintenance on Unit 2 from $6.1 million to $7.0 million. The details of these calculations are described in Peter Ewen's testimony.

Q. WAS ANY OTHER WORK PERFORMED ON UNIT 3 DURING THE REFUELING WATER TANK OUTAGE?

A. Yes. As stated above, when we must shut down a unit due to unforeseen events, we perform maintenance in order to improve equipment reliability and maximize plant performance. In the case of Unit 3, as with Unit 2, we

performed a variety of such tasks. However, we cannot say definitively that any of these tasks would have directly shortened or prevented later outages, but could have been accomplished during the normal course.

Q. DO YOU AGREE WITH GDS' RECOMMENDATION THAT $7.672 MILLION FOR UNIT 2 AND $7.672 MILLION FOR UNIT 3 SHOULD BE DISALLOWED FOR THE REFUELING WATER TANK OUTAGE?

A. No. The question posed by the NRC was a new question. We responded promptly and appropriately by shutting down Units 2 and 3 when we could not immediately answer the question and assure ourselves that we did not have a safety issue. Once the question was adequately resolved, we started up Units 2 and 3 without any change to plant equipment. Therefore, GDS' recommendation of any amount of disallowance for this outage is inappropriate. Additionally, Peter Ewen's rebuttal testimony provides further corrections to these numbers recommended by GDS.

Q. GDS ALSO CHALLENGES THE PRUDENCE OF PALO VERDE'S ACTIONS IN CONNECTION WITH A REACTOR TRIP AT UNIT 1 IN AUGUST 2005. WOULD YOU DESCRIBE THE EVENTS OF THIS OUTAGE?

A. On August 26, 2005, Palo Verde was in the process of starting up Unit 1 following the outage to repair the Unit 1 Diesel Generator B voltage regulator. At about 2% reactor power during the startup, the Secondary Control Room Operator switched the system that controls the level in the steam generator to automatic. The operator did not believe the automatic control was adequately maintaining the level in the steam generator, so the operator switched the system to manual control. However, as GDS acknowledges, the operator failed to request concurrence from the Control Room Supervisor when he shifted to

manual operation. In attempting to maintain proper level in the steam generator, the operator altered the level setpoint and switched between manual and automatic control several times. These attempts, combined with the expansion of the water in the steam generator due to rising temperatures, were unsuccessful, and the reactor ultimately tripped due to a high level in the steam generator.

Q. HOW HAS PALO VERDE PERFORMED WITH RESPECT TO UNPLANNED REACTOR TRIPS?

A. As Dr. Mattson shows in Attachment RJM-3RB of his rebuttal testimony, over time Palo Verde has performed as well as or better than similar plants based on NRC's "Unplanned Scrams" performance indicator. In fact, during the quarter in which this trip occurred, the average "Unplanned Scrams" value at Palo Verde was lower than the average for all pressurized water reactors and for reactors in Peer Group 2.

Q. IS THE EVOLUTION OF SWITCHING TO AUTOMATIC STEAM GENERATOR LEVEL CONTROL A FREQUENT OCCURRENCE?

A. No. This evolution only occurs during startup. Very few startups occur at Palo Verde each year, and each unit has six different crews of operators with several operators on each crew who can perform the evolution. Additionally, a modification was made in 2004 to change from an analog to digital system. All of these factors combine such that each operator only rarely performs this evolution of switching to automatic control, and it could be years between performances of this evolution for a specific operator.

Q. HOW HAS PALO VERDE RESPONDED TO THIS EVENT?

A. We have learned from this event and have performed corrective actions to try to prevent the reoccurrence of a similar event. These corrective actions include additional training, clarification of procedures, and modifications to the system. These actions do not suggest that Palo Verde was imprudent, but only that Palo Verde is willing to respond to problems. It would have been imprudent not to have made these or similar changes based on the knowledge we had following this outage. These actions are part of the "continuous improvement" environment that exists in the nuclear industry.

Q. WHAT IS YOUR REACTION TO GDS' CLAIM THAT THE OPERATORS SHOULD HAVE RECEIVED MORE TRAINING ON THIS EVOLUTION?

A. Following a reactor trip that involves some element of human error, it is always easy to speculate, using hindsight, that additional training should have been performed on the specific issue that would have prevented the error. Nuclear power plants are complex systems that involve complex evolutions. We 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.

Q. ON PAGES 25-26 OF ITS REPORT, GDS LISTS THE DIRECT CAUSES AND ROOT CAUSES AND THEN CONCLUDES THAT THE OUTAGE WAS IMPRUDENT BASED ON THE ROOT CAUSE REPORT. DO YOU AGREE WITH THIS APPROACH?

A. No. A root cause evaluation is a self-critical document that takes full advantage of hindsight. We perform the evaluation in order to better understand an event and to ensure that it does not recur. The causes listed on pages 25-26 are based on hindsight. This is not the standard of prudence. Additionally, GDS simply

recites portions of the root cause report and concludes (without any analysis) on page 26 that "[t]he 8/26/05 reactor trip and resulting outage extension would have been avoided with prudent operation and management." As stated above, critical comments in a root cause evaluation are not based on a standard of prudence. Therefore, GDS' conclusion, based solely on the root cause report, is insufficient to show imprudence.

Q. PAGE 26 OF THE GDS REPORT STATES THAT THE NET REPLACEMENT POWER COST DUE TO THE REACTOR TRIP IS $1.260 MILLION. DOES APS AGREE WITH THIS AMOUNT?

No. The correct value is $1.162 million, as explained in Peter Ewen's rebuttal testimony.

Q. GDS RECOMMENDS 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." DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. First, and most importantly, Palo Verde took appropriate actions regarding the outages that occurred prior to April 2005. Additionally, as the ACC Staff has indicated in other testimony, the prudence of any outages prior to April 2005 (before the PSA) does not have any bearing on the rate case.

The ACC Staff presented its position through the direct testimony of John Antonuk, the President of The Liberty Consulting Group, who testified regarding an audit his company performed with the ACC Staff on the "management and operations of fuel and purchased-power functions of APS." The testimony (p. 23) regarding 2005 fuel and energy costs discusses GDS'

recommendations of disallowances, and questions whether Mr. Antonuk has considered the impact of the outages in these proceedings. Mr. Antonuk responded by stating that APS witness Ewen's "normalization did not rely upon actual 2005 performance of any generating unit, including Palo Verde." Therefore, Mr. Antonuk concluded that "it is not necessary to make any further adjustment to the Ewen normalization in order to remove the effects of below standard performance of Palo Verde or any other generating units during 2005."

Q. IF GDS' RECOMMENDATION REGARDING THE PRE-APRIL 2005 OUTAGES HAS NO BEARING ON THE RATE CASE, WHY ARE YOU ADDRESSING THIS ISSUE IN YOUR TESTIMONY?

A. GDS contends in its report (p. 24) that "[t]his outage was the result of imprudence and 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." I disagree with this statement and believe that it is important that the Commission understand that we were not imprudent with respect to this outage.

Q. PLEASE DESCRIBE THIS OUTAGE INVOLVING THE UNIT 1 EMERGENCY DIESEL GENERATOR A GOVERNOR IN MORE DETAIL.

A. On March 17, 2005, the Unit 1 Diesel Generator A failed to reach full speed during a post-maintenance retest. We investigated the problem and determined that the governor (which controls the speed of the diesel generator) should be replaced. Palo Verde's technical specifications require that the plant be shut down in order to perform the necessary retests following replacement of the governor. Therefore, Unit 1 was shut down and we performed the retests.

Q. DID PALO VERDE INVESTIGATE THE CAUSES OF THE PROBLEM WITH THE GOVERNOR?

A. Yes. We performed a Root Cause Investigation ("RCI") to evaluate the problems with the governor which led to this outage. The RCI is provided in part as Attachment 10 to the GDS report.

Q. WHAT WERE THE CONCLUSIONS OF THE ROOT CAUSE INVESTIGATION?

A. The RCI (p. 15) determined that the direct cause of the governor failure was "oil contamination of the lube oil in the governor actuator." Additionally, the RCI (p. 3) identifies the three most probable root causes as water introduced during refurbishment that was not completely drained, governor storage drained of oil in the Palo Verde warehouse, and water introduced during oil change. Nonetheless, the RCI (p. 15) clearly states that "[n]o root cause could be found for this event." Therefore, Palo Verde does not know for certain what led to the problems with the governor.

Q. WHY DO YOU DISAGREE WITH GDS' CLAIM REGARDING STORAGE OF THE GOVERNOR?

A. Palo Verde properly stored the governor in accordance with the manufacturer's recommendations. Woodward Governor Company, the manufacturer of the governor, recommends the following (Attachment JML-1RB): "Mechanical hydraulic governors and actuators should be stored in a clean and dry condition; any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years." The governor was stored in Palo Verde warehouse Level B storage, and meets these conditions. Furthermore, the manufacturer only recommends examination every five years.

The governor at issue was rebuilt and shipped to Palo Verde in July 2000, and was installed in April 2001, much shorter than the five year recommendation.

Q. GDS ALSO ASSERTS THAT "STORAGE OF THE GOVERNOR DRAINED OF OIL IN A WAREHOUSE THAT WAS NOT CLIMATE CONTROLLED IS NOT A GOOD PRACTICE." IS THIS ACCURATE?

A. No. As discussed above, Palo Verde stored the governor in accordance with the instructions from the manufacturer and did not come close to the five year limit before a recommended examination.

Q. GDS ALSO STATES THAT THIS OUTAGE "WAS AVOIDABLE BY ENSURING THAT THE . . . PRE-INSTALLATION INSPECTION OF THE RE-FURBISHED GOVERNOR [WAS] COMMENSURATE WITH THE IMPORTANCE OF THIS EQUIPMENT." DO YOU AGREE WITH THIS STATEMENT?

A. No. Palo Verde personnel inspected the governor as it was installed and could not have detected any internal rust. Following this outage, the faulty governor was sent to Engine Systems Inc. ("ESI") for testing and failure analysis. ESI's report is provided as Attachment JML-2RB. Following its receipt inspection, ESI stated (p. 1) that "[t]he internal inspection with the top cover removed indicated the governor internals were clean and in very good condition." The rust in the governor was only identified after a "disassembly inspection" by ESI (p. 2). This rust would only have been identified during a pre-installation inspection had Palo Verde dismantled the governor. It is not reasonable to require Palo Verde personnel to disassemble a component before installation. In fact, this disassembly would only increase the possibility of contaminating the equipment.

Q. WHAT IS YOUR CONCLUSION REGARDING THIS OUTAGE?

A. Palo Verde personnel stored the governor in accordance with the manufacturer's recommendations. Additionally, the only inspection that would have revealed any rust would have required disassembling the governor. It is unreasonable to require this, and would likely cause more problems than it would correct. Furthermore, the exact cause for the oil contamination that we believe led to the problems with the governor is unknown. Since Palo Verde properly stored and inspected the governor, the outage cannot be attributed to imprudent actions by Palo Verde.

VII. PALO VERDE CONTRACTS WITH VENDORS

Q. ARE YOU FAMILIAR WITH THE RECOMMENDATION BY GDS THAT THE COMMISSION ADDRESS THE ISSUE OF "THE DEGREE TO WHICH APS HAS SOUGHT APPROPRIATE LEGAL REMEDIES OR OTHER REMEDIES" AGAINST VENDORS WHOSE EQUIPMENT CAUSED CERTAIN OF THE 2005 OUTAGES?

A. Yes, GDS' report states that "[w]e have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent." (GDS, p. 3). The specific outages that GDS identified as being the result of "faulty vendor supplied equipment" were (1) the February 16 – February 19, 2005 Unit 1 outage caused by a reactor coolant pump oil seal o-ring being made of the wrong material; (2) the May 22 – June 24, 2005 Unit 3 outage due to improperly manufactured pressurizer heaters supplied by Framatome–ANP and its subcontractor Thermocoax; and (3) the August 22 – August 25, 2005 Unit 2 outage caused by an error in core protection calculator system software provided by Westinghouse.

Q. HAS APS TAKEN ANY STEPS TO OBTAIN A REMEDY FROM THESE VENDORS?

A. Yes. APS obtained replacement o-rings from the vendor at no charge. Similarly, Westinghouse corrected the software error at no charge. The contracts in question precluded the recovery of consequential damages in these two instances. In the case of the Framatome – ANP pressurizer heaters, to date APS has recovered $3.1 million, including $2.7 million to offset the cost of the new heaters from other vendors and the original design costs, as well as a $400,000 credit for future purchases from Framatome – ANP. The remaining claims (relating to the recovery of replacement power costs) will be submitted to non-binding mediation. If mediation is unsuccessful, APS has retained the right to litigate the issue.

Q. WHY DID APS ENTER INTO CONTRACTS WITH WESTINGHOUSE AND THE O-RING MAKER THAT PRECLUDED RECOVERY OF CONSEQUENTIAL DAMAGES?

A. My understanding is that equipment vendors, particularly in the nuclear industry but also with respect to power plant equipment generally, will not enter into contracts that permit recovery of consequential damages. That is especially true where, as here, the potential consequential damages would be vastly disproportionate to the value of the equipment or service provided. For example, the o-ring seals in question cost $90.

Such limitations however, are not applicable in all instances (such as where conduct of a vendor is deemed to be willful or grossly negligent). This is why, without discussing the nature of APS' litigation strategy, that APS believes that it has a claim for recovery of replacement power costs in the case of Framatome

– ANP pressurizer heaters. In contrast, in the case of the Westinghouse computer error and the case of the o-ring made of the wrong material, we had no evidence to suggest that those vendors had done anything willful or grossly negligent. Given the relatively small number of vendors for much of the equipment and many of the services needed at nuclear power plants, it would be counterproductive and highly detrimental from a business standpoint for APS to bring claims against vendors without having a reasonable factual basis to do so.

VIII. OTHER GDS RECOMMENDATIONS

Q. HAVE YOU REVIEWED ADDITIONAL GDS RECOMMENDATIONS?

A. Yes.

Q. DO YOU HAVE ANY COMMENTS ON THOSE RECOMMENDATIONS?

A. Yes. GDS' fourth recommendation states the following:

> The Commission should order APS to file a semi-annual report with the Commission's Docket Control, describing the plant performance levels, explaining any negative reporting by NRC and INPO Inspectors, and, finally, providing details of the corrective actions taken by the utility. This report should also include information on the replacement cost of power resulting from forced outages of the Palo Verde units. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.

As noted above, the Company is willing to file the report recommended by GDS in its fourth recommendation regarding plant performance, although confidential information would be made available for review only. Moreover, the Company cannot commit to provide INPO data, or even to make INPO data available,

without INPO's consent. The Company has informed INPO of GDS' recommendation, and will supplement this testimony upon receiving INPO's response.

GDS' fifth recommendation states the following:

> Effective programs must be developed to deal with aging equipment issues. The Palo Verde units are now 20 years old and age related problems will become more numerous. The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.

Palo Verde is willing to file the report in GDS' fifth recommendation, but requested GDS' input regarding "nuclear plants that have been successful in managing aging equipment issues." In response to data request APS/Staff/TBD 2.42, GDS stated that it had not identified specific plants with successful programs in managing aging equipment issues, and suggested that APS contact INPO for a list of such plants. We will do so, but obviously the extent to which APS can file the recommended report will be dependent upon the results of the contact with INPO.

GDS' sixth recommendation states the following:

> Procedures for 1) receipt inspection of materials and 2) verification of materials and equipment prior to installation should be improved. Two of the 2005 outages could have been avoided with better inspection of parts and components prior to installation. The Commission should

> order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde.

One of the two 2005 outages that GDS states "could have been avoided with better inspection of parts" is likely the March 2005 outage regarding the diesel generator governor. As discussed above, Palo Verde disagrees with GDS' conclusion that Palo Verde was imprudent with respect to this outage. Nonetheless, Palo Verde is willing to file the report in GDS' sixth recommendation, but requested input from GDS regarding "other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts." In response to data request APS/Staff/TBD 2.43, GDS stated that it had "not identified specific plants with successful programs in management of installation of incorrect parts." GDS recommended that APS contact INPO for a list of such plants. We will do so, but obviously the extent to which APS can file the recommended report will be dependent upon the results of the contact with INPO.

IX. CONCLUSIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. Palo Verde has been a valuable asset to APS and the people of Arizona for many years. Although we were disappointed in 2005 results, GDS' characterization of Palo Verde's 2005 performance as "poor" is inappropriate, particularly in light

of GDS' recognition that most of the 2005 outages were prudently incurred. On the other hand, we appreciate GDS' recognition that the plant was safely and conservatively operated during 2005 as well as its confidence that the Performance Improvement Plan is well-designed to return the plant to its prior excellent performance level.

As to the specific outages that GDS challenges, as NRC Regional Administrator Mallet told the Commission when he appeared before it in January, the October 2005 outages at Units 2 and 3 were caused by the NRC raising a new question, and Palo Verde acted appropriately in shutting the units down until the question could be answered. The question was not one which Palo Verde personnel should reasonably have anticipated because the plant was in conformity with its design basis based on the calculations NRC accepted when it issued the Palo Verde license. Palo Verde quickly addressed the question and returned Units 2 and 3 to service without any change to plant equipment. Additionally, Palo Verde performed equipment maintenance during the outage that prevented a later unplanned outage, and thereby avoided between $4.4 million and $7.0 million in future replacement power costs.

With respect to the August Unit 1 reactor trip, I do not contest that the trip was due to certain errors made by our personnel. However, it is an operation infrequently performed and Palo Verde's historic performance in terms of numbers of reactor trips is as good as or better than the industry norm. Such an isolated event does not constitute imprudence.

GDS' contentions that the March Unit 1 outage resulting from the failure of a diesel generator governor would have been avoided if Palo Verde had stored the governor differently or done a better pre-installation inspection are not supported by the facts. Palo Verde more than met the governor manufacturer's storage directions, and GDS provides no support for its assertion that Palo Verde's storage requirements did not conform to good industry practice. The rust in question could have been detected only if Palo Verde fully disassembled the governor. To do so would not have been reasonable. Finally, GDS' recommendation is inconsistent with the fact that the 2005 Palo Verde outages have no bearing on the rate case as those costs were not reflected in APS' normalization calculations.

With respect to GDS' recommendation that the Commission address whether APS is appropriately pursuing vendors whose equipment caused some of the 2005 outages, we have done so and are continuing to do so. Both Westinghouse and the o-ring vendor corrected their errors. To date, we have obtained over $3 million from Framatome and are pursuing our claims for replacement power costs where there is a contractual basis upon which to do so. With respect to GDS' recommendations regarding the filing of various reports, APS is willing to do so where feasible, e.g., where there are other plants against which to compare as discussed above with respect to GDS' fifth and sixth recommendations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment JML-1RB

WOODWARD GOVERNOR COMPANY
SERVING PRIME MOVER CONTROL AND ACCESSORY MARKETS
ENGINE CONTROLS
1000 East Drake Road • P.O. Box 1519 • Fort Collins, Colorado 80522-1519
Telephone 303 482-5811 • Fax 303 498-3058 • Telex 4-5691
ESTABLISHED 1870

Frank Amend
Engine Systems Incorporated/Power Control Services
Post Office Box 1928
Rocky Mount, NC 27802-1928

Reference: Oil Changes and Governor Refurbishment

Dear Frank,

I am writing this letter to explain Woodward Governor Company's recommendations on governor oil change and refurbishment cycle times.

Since the most important variable affecting governor life is the environment in which it operates, Woodward Governor Company has no precise guidelines for governor maintenance. However, we offer the following general recommendations which could be incorporated into preventative maintenance specifications for nuclear applications:

Oil Change Interval: Woodward Governor Company recommends that mechanical actuator/governor oil should be changed at the second or third refueling outage. If there has been no indication of problems with the unit (specifically water and/or rust), this interval can be extended. If problems do occur, Woodward Governor Company recommends the interval to be shortened to every first or second refueling outage and/or until the problem's root cause has been identified and corrected.

Overhaul Interval: Woodward Governor Company recommends that mechanical hydraulic governors and actuators be refurbished every five (5) to ten (10) years.

Shelf Life: Mechanical hydraulic governors and actuators should be stored in a clean and dry condition; any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years.

As Woodward Governor Company has chosen Engine Systems Incorporated/Power Control Services to qualify, support, and market controls for nuclear applications, I request that you inform the nuclear industry of these latest guidelines. If any questions develop within the nuclear industry pertaining to these guidelines, Woodward Governor Company requests that they be direct to your organization.

Regards,

Steve Thompson
Nuclear Coordinator/Contract Review

Attachment JML-2RB

ENGINE SYSTEMS, INC.
175 Freight Road, Rocky Mount, NC 27804
P.O. Box 1928, Rocky Mount, NC 27802-1928
Telephone: 252/977-2720
Fax: 252/446-3830

Engine Systems Inc.

Document Number: 8000367-FA
Revision 0, June 06, 2005

Failure Analysis

For

Woodward EGB-50PLS Governor Assembly

P/N 9903-254

S/N 1524051

For

Arizona Public Service Company
Palo Verde Nuclear Generating Station

PO #500285962

ESI IWO 8000367

Prepared By:		Date: 06 Jun 2005
Technical Review:		Date: 06/06/2005
Approved By:		Date: 6/8/05
Quality Review:		Date: 6/8/05

REV	DATE	PAGE	PARA	DESCRIPTION

Overview

Palo Verde Generating station experienced a fail to start on one of their Cooper KSV Emergency Diesel Generators. The start failure occurred upon startup following maintenance activities performed during an LCO. The maintenance activities performed included replacement of air control valves associated with the fuel control cylinder. Following replacement, an engine start was attempted during which the engine cranked over at approximately 100 RPM for a 15 second duration and did not start. A typical start of this unit cranks at 100 RPM for approximately 3 seconds, the engine starts and accelerates to rated speed in less than 10 seconds total duration.

The engine fuel system on the Cooper KSV includes the Woodward EGB-50PLS, the fuel control cylinder and mechanical linkage to the right hand and left hand banks of the engine. During normal engine operation, the fuel cylinder is in the collapsed condition and the terminal shaft of the EGB governor controls the fuel rack travel to the right and left hand banks of the engine. If the engine controls require the engine to be shut down, the fuel control cylinder extends and overrides the governor shaft position and forces the engine fuel to minimum level. The fuel control cylinder is pneumatically operated. Refer to Attachment #1 for control linkage layout.

Visual inspections following the failure revealed that the fuel control cylinder was collapsed and the fuel rack position was approaching the minimum fuel level of approximately 10mm rack length. This is not sufficient fuel to support engine startup. Further investigation indicated that the fuel rack and fuel control cylinder were easily moved by hand; this is not expected as there typically is resistance to movement encountered.

It was suspected that there was an internal failure of the EGB-50PLS which would not allow the fuel racks to be moved to the run position. The governor was removed and sent to ESI for test and failure analysis.

Receipt Inspection:

The governor assembly was received at ESI and visually inspected prior to performing tests or disassembly. The following conditions are noted:

External:

- The pallet for the governor assembly was broken.
- Outside oily (indicating unit had been on its side at some point during shipment).
- Indicator pointer and scale on left side marked with grease
- Indicator pointer on right side faded
- Woodward Governor P/N: 9903-254
- Woodward Governor S/N: 1524051
- Governor knob position: Droop: **0.4**; Speed: **13.42**; Load Limit: **Max**

Internal:

- The internal inspection with the top cover removed indicated the governor internals were clean and in very good condition.

Test As Received:

The EGB-50PLS governor was initially filled with 15W40 oil as required on Woodward Governor Specification TSP 883 Sheet 32. At the request of the site representative, Mr. A.T.Fernandez (Palo Verde Mechanical Maintenance Engineer), the governor was started without purging to determine the amount of time required to build oil pressure and move the terminal shaft to the maximum fuel position. This was found to be 2.87 seconds @ 72.2° F with a corresponding oil pressure of 520 PSIG. The governor was allowed to run to reach the required operational test temperature. The unit was stopped and a repeat of the fast start was performed with the unit in a hot condition. The time was found to be 1.34 seconds @ 180° with 520 PSIG pressure. After completion of this testing, the standard Woodward functional test was performed.

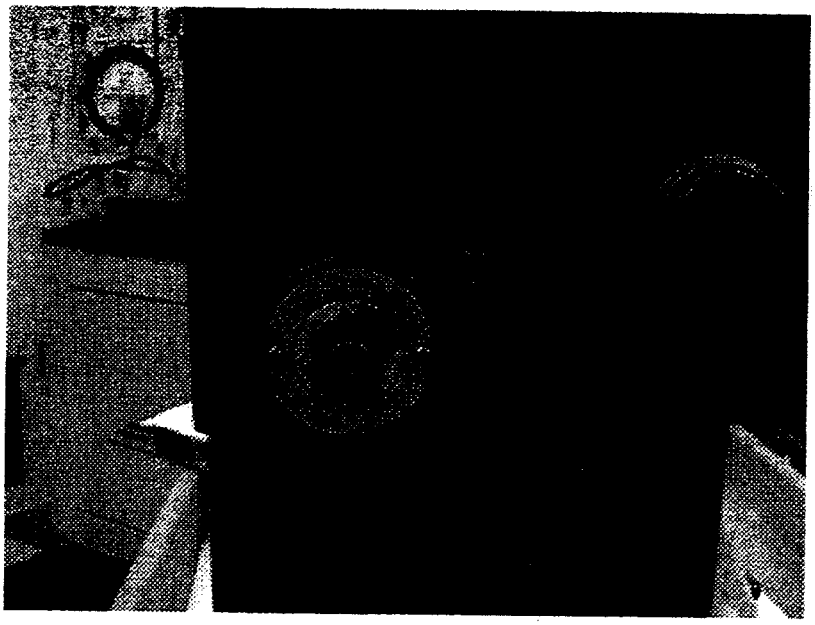
The P/N 9903-254 EGB-50PLS governor is required to be tested in accordance with Woodward Governor test specification TSP 883 Sheets 32 & 33. The governor performed satisfactorily and no out of tolerance conditions were reported. See Attachment #2 for completed test record sheets.

Following testing, the governor was allowed to sit overnight and a repeat of the quick start was performed. The initial governor temperature was 71.9°F. For this test the governor was driven at a speed of 135 RPM (approximate drive speed during engine start) and oil pressure developed to 520 PSIG in 3.68 Seconds.

Disassembly Inspection:

The governor was disassembled and the following conditions were discovered:

- No internal damage.
- A small amount of foreign material (rust) found in the sump pocket area. (see accompanying photos).
- Slight rusting found in accumulator area and on accumulator springs.
- Foreign material (rust) found in the lower end of the base area near the seal retainer (see accompanying photos).
- The drive shaft sealing area found scored from the seal. This is considered to be normal wear.
- The seal retainer has rust on lower drive end. (see accompanying photos).
- A small amount of Teflon tape found in the site glass during cleaning.



Photograph #1

Left Side View

Note grease residue around scale and pointer

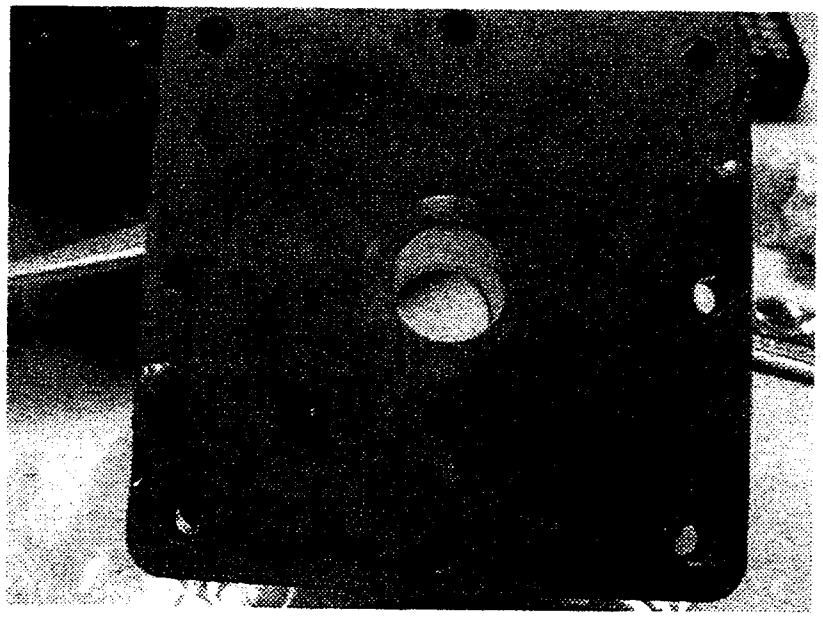
Photograph #2

Right Side View

Photograph #3

Oil Seal Retainer Area

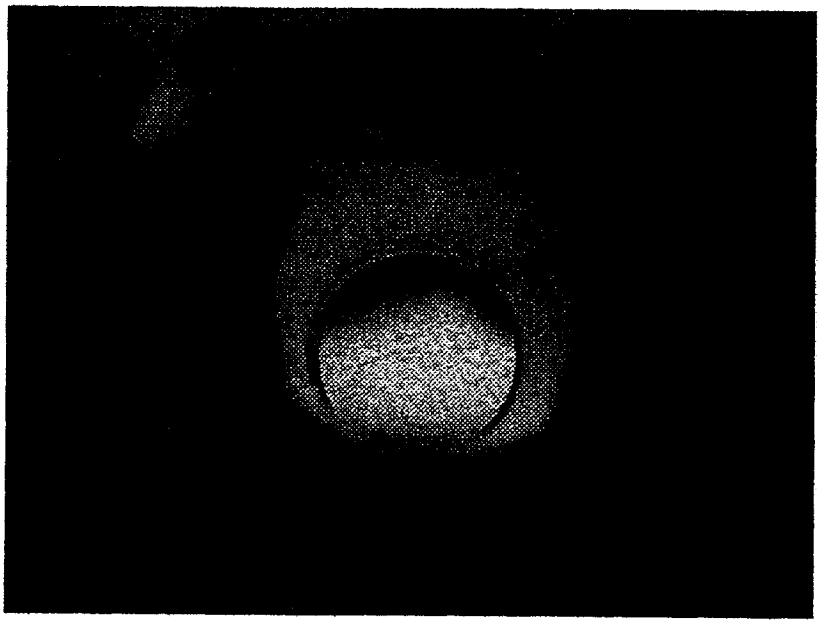
Note foreign material presence



Photograph #4

Base

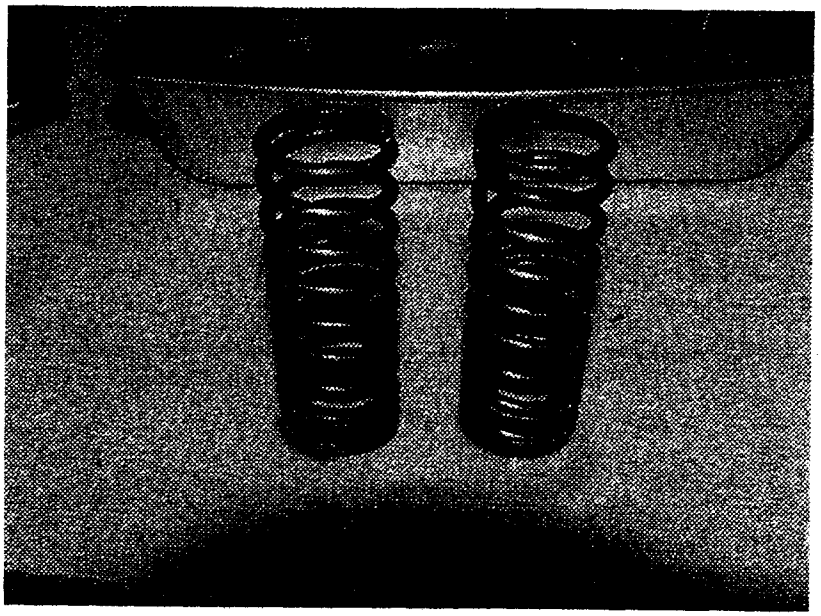
Note discoloration due to rust contamination



Photograph #5

Base bore

Note foreign material on surface



Photograph #6

Accumulator Springs

Note discoloration due to rust contamination

Photograph #7

Oil Seal Retainer

Note foreign material presence

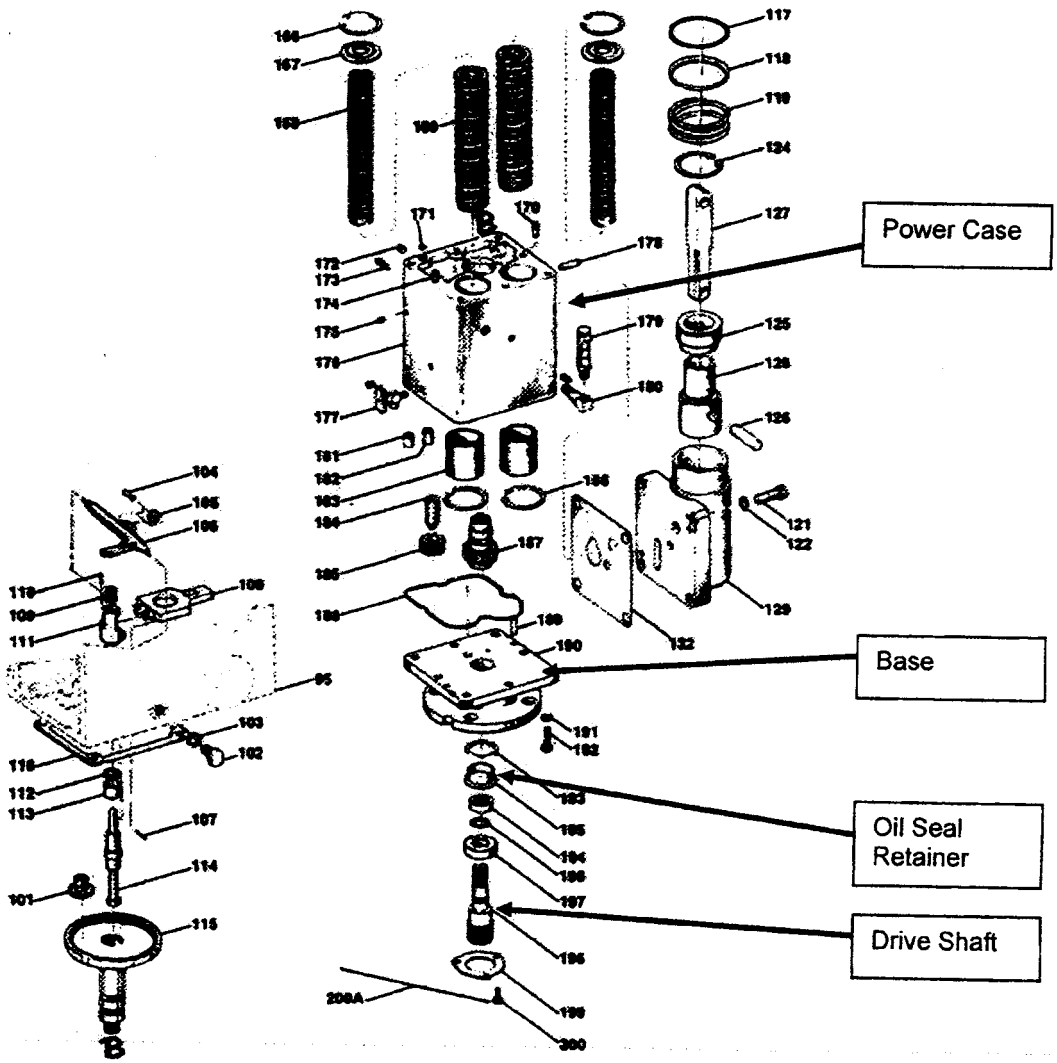


Figure #1
EGB Power Case

Conclusion:

The condition of the EGB-50PLS governor was in an operable state when received at Engine Systems. The Test As received was performed in accordance with manufacturer's instructions with no malfunctions or otherwise out of specification performance. Additional testing was performed to confirm that the governor was capable of developing sufficient work capacity to properly position the fuel racks during startup.

During disassembly and internal inspections there was evidence of foreign material presence in the power case. Based on the condition of the components and the location of the contaminants, it is not expected to have adversely influenced the performance of the governor assembly.

No indications were found to contribute to the fail to start issue.

E-01345A-05-0816

PART 1 OF 2
BAR CODE # 0000061601

To review Part 2 please see:

BAR CODE #0000059991