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Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
e-mail:Jana.VanNess@aps.com
http://www.apsc.com

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

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RE: APS RATE CASE; DOCKET NO. E-01345A-03-0437

Dear Sir/Madame:

Pursuant to the Amended Procedural Order dated August 20, 2004, Arizona Public Service Company ('APS') hereby files its Settlement Direct Testimony of Steven M. Wheeler, Donald R. Robinson, David J. Rumolo and Steven M. Fetter in the above referenced docket.

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

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Compliance

Arizona Corporation Commission
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SETTLEMENT TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

September 27, 2004

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SETTLEMENT TESTIMONY OF STEVEN M. WHEELER ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Steven M. Wheeler. I am Executive Vice President of Customer Service and Regulation for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. DID YOU ALSO PARTICIPATE IN THE SETTLEMENT NEGOTIATIONS IN THIS MATTER?

A. Yes. I was the principal negotiator on behalf of APS.

Q. WHAT IS THE PURPOSE OF YOUR SETTLEMENT TESTIMONY?

A. My settlement testimony will first provide an overview of the Company's goals in the nearly four months of negotiations that led to the successful execution of a global settlement agreement with Commission Staff, the Residential Utility Consumer Office ("RUCO") and 19 other intervenors. I next explain why this settlement is both consistent with those goals and with the interests of our customers and that of the public.

I will also discuss the settlement process utilized in this proceeding and, more generally, the role of settlement in resolving complex litigation. In doing so, I hope to put this remarkable achievement into some perspective.

Lastly, I will describe the various Sections of the agreement itself and identify the appropriate APS witness (if other than myself) to respond to questions on that particular aspect of the settlement. Thus, in addition to myself, APS is presenting as witnesses in support of the settlement: Steven M. Fetter, a former Chairman of the Michigan Public Service Commission and also a former Managing Director of Fitch, Inc., one of the three major credit rating agencies; Donald G. Robinson, APS Vice President of Planning; and David J. Rumolo, APS Manager of Regulation and Pricing.

II. SUMMARY OF SETTLEMENT TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY IN SUPPORT OF THE PROPOSED SETTLEMENT?

A. Yes. APS had three primary goals going into this rate proceeding and in settlement discussions: (1) preserve its financial integrity so that it could continue to attract upon reasonable terms the capital investment necessary to serve the second fastest growing service area in America; (2) address the consequences of the Commission's "Track A" order in Decision No. 65154 (September 10, 2002), which Decision halted the divestiture of APS generation to Pinnacle West Energy Corporation ("PWEC"); and (3) receive clarification on fundamental regulatory issues affecting resource acquisition and system planning that had become increasingly uncertain in the years since the 1999 APS Settlement was approved by Decision No. 61973 (October 6, 1999). The settlement agreement filed by Commission Staff on August 18, 2004, was responsive to each of these goals to one degree or another.

The settlement also provides for numerous benefits to APS customers and to the people of Arizona. These include:

- a rate increase that, although significantly less than half of what the Company believes it could demonstrate through its testimony, moves each customer class closer to rates based on cost of service principles

- acquisition for the benefit of APS customers of some 1700 MW of PWEC generation at a significant discount to both cost and to its long-term economic value

- implementation of rate adjustment mechanisms, several of which had been approved previously, in whole or in part, in Decision No. 66567 (November 18, 2003), to smooth changes in rates over time and allow for customers to benefit when market prices for fuel or power drop

- an over 14-fold increase in the level of investment in Commission-approved energy efficiency and conservation, programs, including expansion of the existing low-income weatherization program, and a mechanism for funding even greater amounts of these types of programs, as well as demand-response programs, if the Commission finds them cost-effective and appropriate

- an RFP in 2005 that could increase APS renewable capacity by approximately 1100% and the energy it would receive from renewable resources also by at least some 1200%

- a mechanism to fund additional renewable energy commitments ordered by the Commission as a result of its ongoing review of the Environmental Portfolio Standard ("EPS")

- an expansion in the APS low-income rate discount and bill assistance programs to insulate the Company's eligible low-income customers from the proposed increase

- complete unbundling of rates to facilitate retail competition along with setting of rates for competitive electric services based on APS' cost of service so that competition will be based on the relative efficiency of the competitors and not on the arbitrage of an inefficient rate structure

- a means for competitive retail suppliers ("ESPs") to participate or for their customers to participate in energy efficiency, conservation and renewable energy programs called for under either the agreement or the existing EPS

- to promote the competitive wholesale market in the near term, a 1000 MW or greater competitive power solicitation will be held during 2005 in which no APS affiliate will be permitted to bid

- to provide the competitive merchant generation community greater assurance that they will be treated fairly after the 2005 RFP, a "self-build" moratorium until 2015 and a prohibition on the ability of an APS affiliate to bid in any subsequent solicitation for long-term APS resources without the participation of an independent monitor selected by the Commission

- to address long term development of the market and APS resource needs for the future, a series of workshops and, if appropriate, formal Commission rulemaking on competitive procurement processes, resource planning and infrastructure development

- confirmation that APS has clear authority to join a regional transmission organization ("RTO") or similar entity to facilitate more efficient wholesale competition

- implementation of a special rate structure recognizing the unique circumstances surrounding the receipt of electric service by Luke Air Force Base ("Luke"), which rate structure should also assist the ongoing efforts to prevent closure of Luke

- continued funding of nuclear decommissioning using a "greenfield" methodology in which the Palo Verde plant site is to be restored to its natural condition to the extent possible once the Palo Verde units are retired and dismantled

- an accounting mechanism that will allow for future funding of ongoing efforts by APS at bark beetle remediation, thus promoting both system reliability and community fire safety

- a dismissal of all pending litigation by APS against the Commission and release of all claims against either the State or its customers as a result of the Track A Order, including but not limited to the $234 million write-off taken by the Company under terms of the 1999 APS Settlement

Arizona law is full of repeated statements supporting the use of negotiated settlement rather than litigation to resolve disputes. The more complex the dispute, the more likely it is that the parties most affected can better negotiate than litigate a resolution having broad acceptance as being a fair solution to difficult problems. Indeed, the entire legislative process, with which several of the Commissioners are quite familiar, is essentially one of negotiation, debate and compromise.

The process utilized during the nearly four months of intense settlement negotiations was the most open, transparent and inclusive I have seen in my nearly thirty years of practice and appearances before this and other regulatory agencies, both in and outside of Arizona. Every view received fair and deliberate consideration by APS and all the other parties to these negotiations. No doubt as a result of these unprecedented efforts at inclusion and good faith negotiation, we ended up with an agreement that covers the broadest possible range of issues, some of which were wholly outside the scope of any of the litigation positions taken by the parties or which presented entirely new solutions to known issues. I also dare say that the breadth of support evidenced for this agreement is unheard of in this jurisdiction, and to my knowledge, anywhere in the country. Staff, RUCO, consumer groups (large and small, residential and commercial, as well as low-income), APS' competitors (both wholesale and retail), and environmental advocates (both proponents of increased energy efficiency/conservation and renewable resources) <u>all</u> have united in support of the proposed settlement – not because <u>any</u> of them received all that they pursued in litigation, but because <u>all</u> of them believe this agreement is a fair resolution of complicated issues by parties having often conflicting goals and interests and, perhaps more to the point, a better overall resolution of such issues than would likely be achieved through continued litigation.

As I discuss, however briefly, each of the Sections to the settlement, both the vast scope of the agreement and the delicate balance of compromises made to achieve it will become all the more evident. APS believes that each provision of the agreement serves an important purpose in the overall context of this settlement and is presenting a witness who can respond to any questions on such provisions. Each Company witness will also address, where relevant to a particular provision in the settlement, both the

Commissioner letters received during the course of negotiations and those received subsequent to the filing of the settlement on August 18th.

III. COMPANY OBJECTIVES IN SETTLEMENT

Q. WHAT WERE THE COMPANY'S PRIMARY OBJECTIVES DURING THE SETTLEMENT NEGOTIATIONS?

A. First and foremost, APS had to achieve a result that had a realistic chance of maintaining its financial integrity. For a capital intensive business, access to capital on reasonable terms is essential to fulfilling the Company's public service obligations to its customers. Second, as I noted in my Rebuttal Testimony and as was also discussed in the Rebuttal Testimony of the Company's President, Jack Davis, the continued division of the generating assets constructed to serve APS into two companies, APS and PWEC, and under two wholly different regulatory regimes was simply not sustainable over the long haul and had to be satisfactorily addressed. Finally, the Track A Order had clearly ended one vision of electric industry restructuring in Arizona, that which involved nearly total divestiture of existing generation and total reliance upon the competitive wholesale market for future generating resources. What was not clear was the regulatory structure that was to take its place. We needed prompt answers as to what were the "rules of the regulatory game" so that we could effectively plan for the future needs of our customers.

1. Financial Integrity

Q. WHAT IS YOUR DEFINITION OF "FINANCIAL INTEGRITY"?

A. There are numerous potential measures of a firm's financial integrity. Achieved return on common equity ("ROE") is one. Debt to equity ratio ("capital ratio") is another, while net cash flow from operations might be yet another way of assessing financial strength. As noted by Mr. Robinson in his Settlement Testimony, APS is currently earning less than any of the recommended ROEs in this docket, and even with the increase in rates called for under the settlement, will not achieve the settlement's proposed ROE. Cash indicators are also on the decline.

However, for an electric utility such as APS, access to public capital markets is most critical to the continued ability to provide reliable and economical service. Thus, I focus on the Company's credit rating, which takes into consideration a wide number of financial metrics, including those I have mentioned.

As is also explained in Mr. Robinson's and Mr. Fetter's settlement testimonies, as well as in their Rebuttal Testimonies and the Rebuttal Testimony of the Company's CFO, Don Brandt, credit ratings may be either "investment" or "non-investment" grade. The former carry lower interest rates, impose fewer restrictions on the Company in the form of what are called loan "covenants," and provide greater access to the market itself because many institutional investors such as pension funds cannot or will not invest in any non-investment grade security. When you are faced with <u>minimum</u> capital requirements of well over $2 billion in the next ten years, the annual cost in the form of just the higher interest rates associated with a loss of investment grade ratings can be as much as $100 million – a staggering sum (and one significantly higher than the overall revenue increase called for in the settlement), especially when you consider that this higher cost produces not one iota of additional reliability or service for customers. The covenant restrictions and the loss of a potential market of lenders within the institutional investment community, although less obvious than a higher coupon rate or greater underwriter fees, can impose significant hidden costs – hidden but equally burdensome to customers and equally unproductive in the effort to maintain and improve quality of service. For these reasons, minimum financial integrity requires the maintenance of an investment grade rating.

Q. WHAT ARE THE COMPANY'S CURRENT DEBT RATINGS?

A. APS is rated Baa-1 by Moody's Investment Service ("Moody's") and BBB by Standard & Poor's ("S&P") for its senior unsecured long-term debt. This is S&P's next to lowest investment-grade rating. Moreover, both Moody's and S&P have described the Company's prospects as "negative" since the filing of testimony by Staff and Intervenors in early February of 2004.

Q. WILL THE 3.77 PERCENT BASE RATE INCREASE CALLED FOR UNDER THE SETTLEMENT ALLOW APS TO MAINTAIN THE MINIMUM FINANCIAL INTEGRITY AS YOU HAVE DEFINED IT ABOVE?

A. I hope and believe so, at least as regards S&P, although it will likely be close even with such additional positives, from the credit perspective, as the inclusion of a power supply adjustment ("PSA") mechanism and the deferral of significant costs for bark beetle remediation. Certainly, we will not improve our position as had been originally hoped when the rate application was filed. Mr. Robinson and Mr. Fetter are the primary Company witnesses on this count, and I will defer to their opinions in the matter. I will note, however, that the filing of this settlement, even with the incredible degree of support shown for such settlement by the parties to this proceeding, has not resulted in a lifting of the "negative" outlook by either Moody's or S&P, let alone any improvement from what is pretty close to the bottom rung of the investment-grade ladder.

Q. I THOUGHT THE INCREASE WAS 4.21 PERCENT. WHY DID YOU REFERENCE 3.77 PERCENT IN YOUR LAST RESPONSE?

A. Section I to the agreement does refer to a 4.21 percent increase in rates. But nearly half a percent of that 4.21 percent is a temporary surcharge to recover previously incurred costs to implement the Commission's Retail Electric Competition Rules and related Commission orders. *See* Decision No. 61973 at Attachment 1, p. 4. That surcharge does not contribute to APS earnings or to any of its key credit metrics and thus would be ignored by ratings agencies. In addition, even the 3.77 percent base rate increase carries with it over half a percent in mandatory expenditure increases for energy efficiency and conservation programs, which if not expended must be refunded to APS customers. Thus, these additional revenues also contribute nothing to Company earnings or to key credit metrics. Indeed, if the energy efficiency and conservation programs are successful, as we hope they will be, they will put additional pressure on earnings and credit metrics, at least in the short run, by reducing Company revenues relative to its costs.

2. Unification of PWEC Reliability Assets with APS Generation

Q. WHY WAS THE ACQUISITION AND RATEBASING OF THE PWEC RELIABILITY GENERATION ASSETS BY APS SO IMPORTANT?

A. There are economic, financial, operational and equitable reasons why the acquisition and rate-basing of these assets by APS is appropriate and in the interests of both the Company and its customers. Mr. Robinson will address the economics of the PWEC assets and their financial impact upon APS. However, I would like to emphasize to the Commission that the Company's rebuttal testimony in this proceeding already indicated that the economic value of the PWEC assets was significantly greater than their June 30, 2004 book value and thus would produce equally significant economic benefits to APS customers even under the Company's original proposal. Those benefits are further increased by the nearly $150 million write-off of the rate base value of the PWEC assets called for under the settlement. I will now address those other factors to which I have alluded.

Q. BEFORE DOING SO, COULD YOU ANSWER THE FUNDAMENTAL QUESTION OF WHETHER THE PWEC ASSETS ARE, IN REGULATORY PARLANCE, "USED AND USEFUL"?

A. Yes. These assets are clearly being used by APS and will be useful in providing capacity and energy to APS customers.

Q. DIDN'T THE FINANCING ORDERS APPROVED BY THE COMMISSION IN LATE 2002 AND EARLY 2003 RESOLVE THIS PWEC ASSETS ISSUE WITHOUT THE NEED FOR APS TO ACTUALLY ACQUIRE AND RATE BASE THE PWEC GENERATION?

A. No. Although these two orders did resolve critical short-term liquidity problems, they did not address the underlying need to unify the two groups of generating assets, either from the perspective of their potential benefits to APS customers or as it would affect the Company. Rather, they bought time to more fully consider the unification issue in this proceeding.

Q. YOU ALSO MENTIONED OPERATIONAL REASONS FOR ACQUIRING AND RATEBASING THE PWEC ASSETS IN ADDITION TO THE ECONOMIC, EQUITABLE AND FINANCIAL CONSIDERATIONS. COULD YOU ELABORATE?

A. Yes, but before I do, let me emphasize that the operational circumstances I will discuss next are nowhere of the same degree of materiality as the earlier considerations. Indeed, having demonstrated that acquiring and rate-basing the PWEC assets, especially under the terms of the present settlement: (1) are a good deal for APS customers; (2) resolve issues left unaddressed by Decision No. 65154; and (3) provide a cornerstone for restoring some significant degree of financial stability to the whole enterprise, one might argue that also raising these operational factors is "beating a dead horse." But in point of fact, the inability to jointly dispatch the APS and PWEC generation for APS customers during the non-Track B months of October through May would cost APS customers as estimated $14 million during 2005 alone. This is because maintaining separate dispatch "stacks" for APS and PWEC is less efficient than using a single "stack" for both APS customers and off-system sales. Also, from a management perspective, the need to maintain duplicative management structures is both inefficient and harmful to effective corporate governance/oversight. See Rebuttal Testimony of Jack E. Davis at 23-25.

Q. **WHAT ARE THE EQUITABLE ARGUMENTS TO WHICH YOU REFER?**

A. These were discussed at length in both my Direct and Rebuttal Testimonies, as well as in the Rebuttal Testimony of Jack Davis. For the sake of brevity, I will merely reference them. See Direct Testimony of Steven M. Wheeler at 14-16 and Rebuttal Testimony of Steven M. Wheeler at 58-65; see also Rebuttal Testimony of Jack E. Davis at 13-20 and 23-25.

3. Resource Acquisition and Planning Uncertainty

Q. **DESCRIBE THE NATURE OF THE RESOURCE ACQUISITION AND RESOURCE PLANNING UNCERTAINTIES SOUGHT TO BE CLARIFIED BY THE COMPANY'S RATE APPLICATION AND, IN FACT, SO CLARIFIED IN THE PRESENT SETTLEMENT.**

A. These are discussed at some length in both my original Direct Testimony and in my Rebuttal Testimony. In essence, APS asked for clear, unambiguous answers to the following questions:

1. For whom does it have the obligation to plan to provide generation?
2. In meeting its obligation to provide adequate and reliable generation service, can APS build or acquire new utility-owned generation or is it limited to only seeking "Track B-like" PPAs?

3. Will any new generation constructed or acquired by APS to serve retail customers be regulated on a cost-of-service basis?

4. Does APS presently have sufficient authority from the Commission to join WestConnect or some similar FERC-regulated transmission entity?

Q. HOW DOES THE SETTLEMENT ADDRESS AND RESOLVE THESE REGULATORY UNCERTAINTIES?

A. These issues are addressed in Articles II and X of the agreement. Essentially, APS has the obligation to plan to serve all customers within its designated service area, although as is also indicated in Paragraph 81 of the agreement, the Company must be cognizant of direct access and the potential for direct access customers in planning its future resource needs. Moreover, such obligation to serve is subject to prospective modification by state policymakers acting in the public interest. Second, APS can build or acquire new utility-owned generation, albeit subject to specific limitations set forth in the settlement. And, subject to one adjustment for the early termination of the APS/PWEC Track B contract, the PWEC units were included in rates on a traditional cost-of-service basis. Both of these latter aspects of the agreement confirm the pre-existing regulatory regime in Arizona, one that had only been drawn into question by some of the language in the Track A and Track B Orders. Finally, the settlement (Paragraph 85) acknowledges the Company's existing authorization to join an RTO or similar FERC-regulated entity.

IV. <u>CUSTOMER AND PUBLIC INTEREST BENEFITS DERIVED FROM THE PRESENT SETTLEMENT</u>

Q. DO YOU BELIEVE THE PROPOSED SETTLEMENT PROVIDES SIGNIFICANT BENEFITS TO CUSTOMERS AND THE PUBLIC?

A. Absolutely. These benefits are both substantive and procedural. By substantive benefits, I mean benefits derived from specific provisions of the settlement itself. Procedural or process benefits refer to the general public policy in support of fairly negotiated settlements between and among well-represented and largely representative parties – "well represented" in the sense that all parties had access to legal and technical expertise during the course of negotiations – "largely representative" in the sense that the signatories to the agreement represent every major affected group.

1. Substantive Benefits of the Settlement

Q. WHAT ARE THE SUBSTANTIVE BENEFITS TO APS CUSTOMERS AND THE PUBLIC FROM THE SETTLEMENT?

A. I listed the principal benefits in my Summary, and many of them are more or less obvious to those that are familiar with rate case and other electric utility industry issues. But I realize that this testimony will be read by more than just the usual "rate case veterans," and thus I will briefly explain them in the order originally listed. Please note that such order is not intended to necessarily provide a ranking of the relative importance of the benefit. The importance of a particular benefit will vary considerably depending upon the affected constituency and the public policy values of the reader. Some might believe environmental considerations to be primary, while others would look to customer or firm economics, and yet others focus on the impact of the settlement on competition or infrastructure development.

a. <u>Reduced Size of Increase (Section I)</u>

The proposed base rate increase of 3.77 percent compares positively, from the customer standpoint, to the 9.33 percent base rate increase originally proposed, and yet the two figures are not directly comparable in certain aspects. The latter encompassed barely over $1 million for DSM, while the former allows, even mandates, some $10 million per year for energy efficiency and conservation, with another $6 million in approved DSM expenditures to be recovered through the DSM adjustment mechanism discussed later in my testimony. The 9.33 percent figure reflected a rate base value for the PWEC generation at approximately $850 million, while the 3.77 percent cuts that down to just $700 million. This reduction not only affected the size of the present rate increase but will also produce literally hundreds of millions of dollars of future savings to APS customers over the remaining service life of this generation, as is again discussed in the Settlement Testimony of Mr. Robinson.

The 3.77 percent base rate increase (or 4.21 percent including the CRCC surcharge) follows on the heels of eight consecutive rates decreases from 1996 through 2003 and nine rate decreases since 1991. And you would have to go back to the mid-1980s before APS rates were lower than they will be even after approval of the settlement's proposed increase. I would also note that Salt River Project, which shares the Metro-Phoenix service area with the Company but does not serve higher cost rural areas and enjoys all the advantages of being a governmental entity, has raised its rates nearly 8 percent since 2001.

b. <u>Write-off of Rate-Based PWEC Assets (Section II)</u>

The positive impact of the $148 million write-off on APS customers has been discussed above. However, I would like to emphasize Mr. Robinson's Settlement Testimony, which indicates that with this write-off, APS customers are getting an effective 31% discount on these assets compared to their original cost and close to a 50% discount to their market value. Thus, the PWEC assets will represent a tremendous bargain for APS customers for many years even aside from their reliability and price stability benefits.

c. Rate Adjustment Mechanisms (Sections IV, VII, VIII, XIII, and XVI)

To some, these rate provisions might appear to be mechanisms that primarily benefit APS. But although APS certainly believes itself to be an important part of the "public" for purposes of determining whether a particular regulatory action is in "the public interest," such rate mechanisms benefit customers and the public interest by allowing electric prices to more closely mirror costs. As was clearly seen in California, when electric prices do not respond quickly enough to reflect changes in underlying costs, the inevitable results are first uneconomic use of the product and then shortages, both chronic and acute. And by allowing for more periodic price adjustments, these rate mechanisms tend to better smooth out cost fluctuations (both up and down) than would be the case if prices were adjusted only in a massive general rate case every couple of years – and at a significantly lower administrative cost than a general rate case. They also provide a means to expand and contract the funding of utility programs that themselves have been found by the Commission to be in the public interest, such as energy efficiency and renewable energy. Finally, one of the adjustment mechanisms, the "Returning Customer Direct Access Charge" ("RCDAC") prevents smaller Standard Offer customers of APS from being harmed by the "unannounced" return of larger customers from direct access service. This again was a major issue in California when the "meltdown" of the wholesale market caused competitive retail suppliers to return their customers *en masse* to the incumbent utility, thus exacerbating the situation already facing these utilities.

d. Energy Efficiency and Conservation (Section VII)

The Commission's interest in and support for DSM has waxed and waned over the years. In 1991, the Commission created the Energy Efficiency and Solar Energy ("EEASE") Fund Surcharge to promote conservation and renewable energy programs. *See* Decision No. 57649 (December 6, 1991). The original commitment was a relatively modest $4 million per year, split between both DSM and solar energy. The EEASE program was scheduled to dramatically increase as a result of Decision No. 58644 (June 1, 1994), with funding rising over a three-year period to a minimum of $14 million per year and a maximum of $18 million per year just for DSM. By the time of Decision No. 59601 (April 24, 1996), the Commission's interest in DSM was beginning to be refocused on renewable energy. The EEASE Fund Surcharge was abolished, and $7 million was included in the System Benefits Charge ("SBC") component of APS base rates, with no more than $4 million and no less than $3 million for DSM. By 1999, the Company's traditional rebate-based DSM programs had almost entirely been replaced by what were termed "market transformation" programs, which sought to provide customers, builders and vendors with information concerning DSM available in the marketplace, but then depended upon market forces and customer preferences for actual adoption of DSM initiatives. Indeed, the only specific mention of DSM in the 1999 APS Settlement was the preservation of $500,000 for low-income weatherization. The dismantling of the Company's traditional DSM programs was complete when in Decision No. 62406 (May 4, 2000), the Commission ordered almost all remaining DSM funding to be redirected to the acquisition of those renewable resources required by the EPS.

However, the present Commission has clearly expressed a renewed interest in DSM, as can be seen by the letter in this docket of Chairman Spitzer dated May 14, 2004, as well as the ongoing generic docket workshops on the subject and the public pronouncements of other Commissioners. The nearly 14-fold increase in required DSM-related spending over a three-year period, as called for in Section VII, is wholly consistent with this renewed Commission interest in energy efficiency and conservation.

As can be seen in the Preliminary [DSM] Plan attached as Appendix B to the settlement, the parties anticipate the adoption by the Commission of energy efficiency and conservation programs targeted at schools and other public institutions. This, along with certain rate design modifications discussed in Mr. Rumolo's testimony, as well as the very significant overall decrease in the settlement revenue requirement compared to the Company's original request, are, I believe, responsive to some of the budgetary concerns expressed by our school district customers and reflected in Commissioner Mundell's Memorandum dated May 6, 2004. However, the real solution to those concerns was and is a legislative solution. In that regard, the last session of the Arizona Legislature removed the "cap" on so-called "excess utilities funding," thus largely obviating the near-term budgetary impact of utility costs increases, including electric increases.

One of the distinctive features of the current settlement, and a very significant concession on the part of the Company, is the lack of net lost revenue recovery as part of DSM "costs." "Net lost revenues" represent the difference between the revenues lost by APS as a result of introducing a specific conservation program (e.g., energy-efficient lighting) and the costs avoided by APS as a result of the same program. The Commission had previously allowed net lost revenues in response its consideration of the Public Utilities Regulatory Policies Act ("PURPA") ratemaking standards, which included the removal of disincentives to the implementation of energy efficiency and conservation programs. The Commission was required by PURPA to consider, but not necessarily adopt, these standards. *See* Decision No. 58643 (June 1, 1994). Under Section VII, APS is permitted to earn a "performance award" of up to 10% of program costs, depending upon the success of the DSM program in achieving predetermined program goals. This performance award will fall far short of recouping net lost revenues, and thus consumers will receive significantly more in direct DSM benefits under this settlement. Of course, APS will reflect the impact of the energy efficiency programs resulting from the settlement, both on revenues and costs, in future general rate proceedings. And APS is also permitted to seek prospective recovery of net lost revenues in other forums before the Commission, just as other parties to the settlement reserved the right to pursue their DSM proposals (to the extent different from those contained in Section VII of the agreement) in such forums.

Another important feature of the settlement is the requirement for Commission approval of both a preliminary DSM plan (Paragraph 47) and a final plan (Paragraph 48). The final plan will be submitted after review by and input from a stakeholder collaborative (Paragraph 54), but final responsibility for the plan's content and implementation will remain with the Company. And Staff, although a participant in the collaborative process, will continue to provide the Commission with an independent recommendation concerning the appropriateness of the plan's specific component programs, as will other collaborative participants, including APS. The concept of Commission approval and control over the very substantial financial commitment to DSM contained in the settlement was very important to APS and many other parties to the agreement because it permits the Commission to determine the scope, design, objectives and budgetary limits on plan components before any funds can be counted toward the DSM funding amounts called for in the settlement. Even after the final plan is approved, it is anticipated that the Company, or for that matter other members of the collaborative or interested members of the general public, may submit additional programs or substantive revisions to existing approved programs to the Commission for its approval. Yet another customer safeguard is the requirement that any unspent DSM funding authorized in APS base rates will be refunded to customers through the DSM adjustment mechanism. See Paragraph 51.

Finally, I would add that the specific provisions in Section VII are in addition to the opportunity for DSM resources to compete on a "level playing field" based on reliability, cost and other factors in the more general RFP called for in Section IX. This fair, but not preferential, treatment of DSM under Section IX is critical to the continued transformation of DSM from utility-sponsored subsidy programs to a truly commercialized competitive market alternative to traditional supply-side resources.

e. Renewable Energy RFP (Section VIII)

Mr. Robinson is the primary witness on resource acquisition, including renewables. He can provide the details of the how and why of much of this provision. But to touch on this subject in the context of my discussion of the overall public benefits contained in the settlement, I will note that pursuant to Section VIII of the agreement, APS will solicit at least 100 MW of renewable energy resources in 2005. These resources would produce at least 250,000 MWH of renewable energy. This would be in addition to the Company's present portfolio of just under 9 MW of renewable resources (21,500 MWH annually) acquired pursuant to the EPS. The definition of "renewable energy" is somewhat broader than that presently used by the EPS in that it includes small hydro, hydrogen (either directly or in fuel cells), and geothermal resources.

Here, the focus is on obtaining resource diversity as a hedge against volatile fossil fuel prices rather than on promoting specific technologies or fostering Arizona-only resources with the sort of in-state preference required by the EPS. Thus, there is a minimum energy requirement for individual resources of 25,000 MW per year and a "cap" of 125% of market on the price APS can pay for these resources. These restrictions will tend to favor new wind and biomass resources, as well as small hydro and geothermal projects. As such, this provision of the agreement is consistent with the thoughts expressed by Chairman Spitzer in his letter dated May 14, 2004. However, solar and other lower load factor resources are free to compete on the basis of cost and reliability. And, of course, any manner of renewable resource can compete in the general RFP called for in Section IX of the agreement, thus giving renewable resources a third opportunity to become a part of the Company's future resource portfolio.

Section VIII also creates a new rate adjustment mechanism to fund the EPS itself, whether as it currently exists or as it may be modified by the Commission. The present surcharge fixed by Rule 1616 is too inflexible to meet even present EPS goals, and even if the Commission were to amend Rule 1616 in that regard, it is difficult to imagine that a single surcharge could fit the specific EPS funding requirements of all the utilities subject to the EPS, which will also include the ESPs after this year.

f. Low-Income Programs (Sections VII and XII)

The agreement increases the discount available to eligible low-income APS customers under Rate Schedules E-3 and E-5 by between 30% and 40%, depending on usage. (As a general proposition, the discount is structured to encourage conservation by eligible customers.) APS will also increase the funding to promote these discounted rates by some 50%. Assuming that eligible customers take advantage of these rates, they should experience a net rate decrease under the settlement. Incidentally, this was a good example of an issue that was not addressed in the litigation testimony of any party to the rate case but which did end up as an element to the eventual agreement.

As part of the Company's DSM spending commitment in Section VII of the settlement, the existing low-income weatherization program will see its funding ceiling raised by 100%, including up to $250,000 in direct customer bill assistance. APS will submit this expanded low-income program for the same Commission review and approval as is generally required by Section VII of the agreement for other energy efficiency and conservation programs.

g. Retail and Wholesale Competition (Sections II, VII, VIII, IX, X, XIII, XIV, XVII and XIX)

As can be seen by the numerous Sections cited above, the negotiators of the settlement were extremely mindful of the potential impact (positive or negative) any agreement might have on the development of retail and wholesale electric competition. Indeed, Commissioner Gleason's letter dated May 10, 2004 specifically asked the parties to consider such competitive issues during negotiations.

I will first address those portions of the agreement relevant to retail competition and retail competitors such as Strategic Energy and Constellation, both signatories of this settlement, and then turn to wholesale competition. In doing so, I will only give the highlights from a public policy standpoint, as Mr. Robinson and Mr. Rumolo are the Company's lead witnesses on resource acquisition and rate design issues.

One of the key elements of the settlement's rate design proposal (Section XIX) is the total unbundling of each element of the Company's standard retail rates. See Paragraphs 125 and 126. Again, Mr. Rumolo can discuss the "how" of this process, but I can say that it is critical to efficient and fair retail electric competition that competitive electric services (e.g., generation, metering, billing, etc.) be separately priced so that retail customers can directly compare the prices for such services with those offered by the Company's retail competitors, present and future. It is equally important that competitive electric services provided by APS be priced as closely as possible to the Company's cost of providing those services. See Paragraphs 119 and 121. That is because offering competitive electric services below cost makes it more difficult for competitors to match or beat the incumbent's price even if the competitor can actually provide that service at a lower cost. Offering competitive services at higher than cost artificially encourages customers to choose an APS competitor even if APS is, in fact, the lower cost supplier of the service. This not only increases the total cost to society of producing the service in question, which is a drag on overall economic efficiency, it means that when an APS customer takes that competitive service from a competitor, APS loses more revenue than its avoided cost, thus increasing the pressure to increase the price for non-competitive services and for the remaining Standard Offer customers. This is the very issue of "shopping credits" noted by Commissioner Gleason in his May 10th letter.

Other provisions of the settlement favorable to retail electric competition are perhaps less obvious because they are contained within Sections of the agreement that, unlike Section XIX, do not specifically address competitive services. For example, in Section II, APS agrees to forego any future "stranded cost" recovery for the PWEC generation to be acquired by APS (Paragraph 8) and also allows competing retail suppliers within the Phoenix Metro area equal access to generation at cost-based rates from West Phoenix CC-4 and CC-5 during so-called "must run" hours (Paragraph 15). In Sections VII and VIII, both the DSM (Paragraph 53) and EPS programs (Paragraph 65) are expanded to encompass direct access customers and their suppliers. Section X, Paragraph 82 discusses the role of the Electric Competition Advisory Group in addressing other competitive issues, including the resale by APS to ESPs of "revenue cycle services" (metering, meter reading and billing) and the application of the Company's various Service Schedules (Section XIV, Paragraph 102) to direct access customers. Paragraph 95 of Section XIII clarifies the operation of the RCDAC in a manner favorable to returning (to Standard Offer) customers. While at first blush this does not appear to be an ESP issue, in fact, the ease of customers' return to Standard Offer greatly impacts their willingness to try retail access in the first instance. Finally, Section XVII's provisions to seriously address the issues affecting distributed generation (reliability, safety and economics) may also allow APS customers another competitive option.

Section IX is obviously at the core of the settlement's wholesale competition provisions and the reason for the support of the agreement by many in the Arizona merchant power community, including the Arizona Competitive Power Alliance. The four central features of this Section are: (1) APS would agree to a "self-build" moratorium until 2015; (2) APS would issue a 2005 RFP for at least 1000 MW of long-term resources, with no participation by PWEC; (3) APS would also agree to a Commission-appointed independent monitor should PWEC or any other APS affiliate wish to participate in any future competitive solicitation for long-term resources; and (4) the Staff would conduct a series of workshops, with the potential for eventual rulemaking, on power procurement issues. The last three of these provisions to the agreement are hopefully self-explanatory, both as to their impact on competition and in their relation of Commissioner Gleason's May 10^{th} letter, and thus I will only elaborate on the "self-build" moratorium (Paragraphs 74-76).

By "self-build," the agreement refers to the ability of APS to construct new regulated generation. It does not preclude APS from acquiring existing generation or, obviously, from entering into long-term PPAs with either merchant generators or other generation-owning utilities. And, the moratorium is not absolute. That would be too risky to both APS and its customers should it turn out that the competitive wholesale market is not able or willing to provide adequate power at reasonable prices. Thus, APS can apply to the Commission for permission to "self-build" under the specific circumstances set forth in Paragraph 75. There are also exclusions to the self-build moratorium for renewable generation, reliability-must run generation, and distributed generation (below 40 MW) because these sorts of resources do not materially impact the overall wholesale generation market, further other public policy objectives, or are so reliability-related that APS believes it must retain the unfettered ability to construct such resources as and when appropriate.

h. Luke Discount (Section XIX, Paragraph 120)

Mr. Rumolo is the rate design expert, and so I will allow him to discuss the rationale for and calculation of the \$2.74/kW/Mo. discount referenced in this Paragraph of the agreement. However, as the Company's chief policy witness and its primary negotiator, I can say that APS is very mindful of the key role played by Luke in this community and the continued threats to its survival in the ongoing review of military bases throughout the country. We believe this provision of the settlement is consistent with the stated desire of community leaders that Arizona do what it can to preserve Luke's competitiveness in the base review process. And although the other large military installation in the Company's service area, Yuma Marine Corps Air Station ("YMCAS"), is not similarly situated to Luke from a service configuration perspective, and thus would not qualify for the discount, APS has had and will continue to have discussions with YMCAS as to how it can best manage its energy costs.

i. Palo Verde Decommissioning (Section XV)

The settlement preserves the existing end-assumptions concerning funding for Palo Verde decommissioning. Specifically, the Commission has repeatedly approved the funding necessary to restore the Palo Verde site to its original state, to the greatest extent possible. APS believes this provision of the settlement to be consistent with this Commission's commitment to environmental and natural resource issues.

j. Bark Beetle Remediation (Section XVIII)

APS will be permitted no current recovery of the presently-ongoing costs of bark beetle remediation efforts. It will, however, defer these costs without return until the Company's next rate proceeding. Even then, only prudently-incurred costs will be recoverable from APS customers. As the Commission is aware, bark beetles have killed or will kill approximately three quarters of a million trees in or immediately adjacent to APS right-of-ways. These dead trees are a threat to APS power lines and are a constant fire hazard to the communities surrounding them. To the extent that Arizona officials are able to secure federal funds to cover all or a portion of these remediation costs, APS will directly credit these funds against any bark beetle cost deferrals.

k. Dismissal of Litigation and the Company's Claim for Restitution of the $234 Million 1999 APS Settlement Write-Off (Sections VI and XX)

APS will dismiss with prejudice all of its litigation against the State of Arizona and the Commission. This includes both its appeal of the Track A Order (Decision No, 65154) and a separate breach of contract claim relating to the 1999 APS Settlement. In addition, the Company will release any claim for restitution of the $234 million write-off its took in the 1999 APS Settlement in anticipation of the divestiture of APS generation and the other benefits of the 1999 APS Settlement, most of which APS never received. Unlike most of the other provisions of the agreement, which either are only binding for purposes of this proceeding or for finite periods, these represent permanent "give-ups" by APS.

2. Administrative Process Benefits of the Settlement

Q. FIRST OF ALL, AND IRRESPECTIVE OF THE MERITS OF THE PRESENT SETTTLEMENT, IS IT PROPER FOR A UTILITY RATE CASE TO BE RESOLVED AMONG THE PARTIES BY STIPULATION OR SETTLEMENT RATHER THAN THROUGH ADVERSARIAL LITIGATION?

A. Yes. The Arizona Administrative Procedure Act specifically provides for the settlement of contested cases, which is defined as including Commission rate proceedings. *See* A.R.S. §§ 41-1061 (D) and 41-1001 (4). The Commission itself has promulgated a formal settlement policy for utility rate cases. Neither of these should be surprising. There is a long-recognized public policy in Arizona—and all around the country for that matter—favoring the settlement of disputes, both public and private. This public policy recognizes that settlements avoid costly and protracted litigation. They also often yield creative and collaborative results for the parties that likely would not result from litigation. Moreover, parties are more likely to accept and effectively implement solutions that they had a direct hand in shaping and to which they have given a large degree of "buy-in" as opposed to solutions that are imposed upon them from above. Even non-unanimous settlements can result in significant public policy benefits by narrowing the scope of issues and still providing for creative resolution of other matters.

Q. IS THE PROPOSED SETTLEMENT OF THIS APS RATE CASE SIMILAR TO A SETTLEMENT OF A TYPICAL CIVIL DISPUTE?

A. Although both arise from negotiations of the parties, they are actually quite different, as one might expect given the differences between Commission rate determinations and civil actions between two private parties. In court proceedings, the parties come to an agreement amongst themselves, usually without a review by the court and usually without developing an evidentiary record to support the settlement. In contrast, in negotiated settlements of a rate proceeding, like the APS settlement, the parties typically file testimony, an evidentiary hearing takes place, and the parties present witnesses for cross examination. Thus, unlike a typical court case, the settlement of a rate case is presented to the Commission with an extensive record so that the Commission can determine whether a settlement agreement is in the public interest. This permits the Commission to fulfill its constitutional duty to be just and reasonable while still giving the appropriate weight, which I believe should be considerable, to the comprehensive extent of this settlement's substantive provisions, the openness of the process, and the tremendous effort required to align these many ordinarily adverse interests – interests representing literally every component of the public.

Q. WAS THE PROCESS UTILIZED BY THE PARTIES TO NEGOTIATE THE PRESENT SETTLEMENT ALSO DIFFERENT THAN THAT USED IN CIVIL COURT PROCEEDINGS IN THAT IT WAS UNUSUALLY OPEN, DELIBERATIVE AND FAIR TO ALL PARTICIPANTS?

A. Absolutely. During previous settlement negotiations in which I have taken part over the past thirty years, APS has approached or has been approached by one or more of the major parties, usually Staff. These parties undertake some preliminary negotiations to determine whether there is any likelihood that they can agree. If these preliminary discussions are successful, the original parties ask selected additional parties to join in the negotiations – selected in the sense that one generally approaches the other parties in the order of their likely receptiveness to the process. It is the hope that by proceeding in this manner, the overall settlement process will build a certain internal momentum that may bring in yet more parties, including those that originally may not have been interested in settlement. This process has been effective over the years in producing many settlements that the Commission has approved as being in the public interest, including settlements that provided the long series of APS rate decreases to which I previously alluded and settlements whose approval by the Commission has been upheld by Arizona courts as being in the public interest despite frenzied assaults on them by Enron and others.

In this instance, however, all intervenors to the APS rate case were invited to participate as equally-important negotiating parties from the initial filing by Staff of its Notice at the end of March. Most accepted that invitation and actively participated. These included all the customer representatives, both large and small. They included APS competitors, both retail and wholesale. They included environmental and renewable energy advocates. And of course, the participants included Commission Staff. Those parties that did not actively participate (although often in attendance) were either: (1) parties that were merely monitoring the proceedings from the beginning and had no position on any of the substantive issues in the case; or (2) parties that declined to actively participate or that relied on other participating parties to generally represent their interests in the negotiations. No party opposed the conduct of the settlement negotiations.

All substantive negotiations were conducted as a group, and at the beginning of each group meeting, the parties brought everyone up to speed with any developments since the last meeting, including a summary of any bilateral discussions between or among individual parties. The latter were encouraged to allow for the exchange of information between parties and to seek clarification of and justification for specific negotiating positions taken by various parties. Parties were also encouraged to provide detailed written responses to others' proposals rather than mere cursory rejections of any proposal. As a result, the parties communicated rather than simply arguing. Although the process was drawn out longer than in other settlement negotiations, in part because of the desire to bring everyone along at the same pace, it is hard to argue with success. And the stunning breadth of support shown for this settlement by parties not only adverse to the Company on most issues but also adverse to each other, as well as the scope of the eventual agreement on a multitude of seemingly intractable issues, constitute "success" by any definition of the term.

V. <u>OTHER PROVISIONS OF THE SETTLEMENT</u>

Q. ARE THERE OTHER SECTIONS OF THE AGREEMENT THAT YOU HAVE NOT ADDRESSED IN YOUR PRIOR TESTIMONY?

A. Yes, although only a few are substantive.

Q. COULD YOU ELABORATE?

A. Yes. For example, before Section I even begins, there is a listing of the signatories to the agreement and an abbreviated description of the process used in arriving at this settlement and the generic goals of the parties in such settlement. In addition to the overall increase in base rates, Section I also has a "fair value" rate base and return figures in order to comply with Arizona's unusual, perhaps unique, "fair value" provisions in Article 15, Section 14 of the Arizona Constitution. Section II, although generally about the rate-basing of the PWEC assets, has provisions governing what is to be done during the time between Commission approval of the settlement and the actual transfer of the PWEC generation to APS, however long that period may be. The Section also prevents parties to the settlement from supporting it before the Commission but then opposing its actual implementation at FERC. Section III has the cost of capital figures used in arriving at the return on fair value rate base.

Q. DO THE COST OF CAPITAL FIGURES IN SECTION III HAVE ANY OTHER SIGNIFICANCE?

A. Yes. They are used in the subsequent determination of an "Allowance for Funds Used During Construction" or "AFUDC." AFUDC is essentially a capitalized financing cost included under Commission and FERC regulations in the final plant-in-service amounts for major utility construction projects.

Q. WOULD YOU PLEASE CONTINUE?

A. Certainly. Section IV deals with the Power Supply Adjuster ("PSA"). Mr. Robinson and Mr. Rumolo are the witnesses who can explain the need for and impact of the PSA, as well as the mechanics involved in the PSA's actual operation. Thus, I will resume my discussion of the settlement beginning with Section V.

Section V to the agreement deals with depreciation. Because depreciation is one of those expenses determined solely by order of regulators, depending on which regulator has jurisdiction, it is required that the Commission specifically approved the depreciation rates for all property not under exclusive FERC jurisdiction. Mr. Robinson is the Company's settlement witness on the details of this particular Section.

Section XI sets forth the Competition Rules Compliance Charge ("CRCC"). This surcharge rate mechanism was called for in the 1999 APS Settlement as a means to recover the significant costs APS would incur to implement the Retail Electric Competition Rules and related Commission orders. The CRCC was also later approved in concept by this Commission in Decision No. 66567. Section XI determines the amount of such costs through June 30, 2004, the length of the recovery period, and the per kWh surcharge figure to be used until either the amount indicated is recovered or for five years, whichever occurs first. It also establishes the procedures for a true-up of any minor over- or under-recovery of the June 30, 2004 level of deferred costs.

Section XXI addresses the process by which the settlement will be considered by the Commission, in addition to the process by which a party to the settlement can withdraw from the settlement and the circumstances warranting such withdrawal. It also provides for all parties, excepting Staff, to support the aggrieved party's efforts to seek rehearing on the issue prompting its withdrawal from the settlement.

Finally, Section XXII contains the usual lawyer "boilerplate" that in my experience is common to settlement agreements. Perhaps the two most important of these are the continued commitment by the parties to keep confidential the actual settlement negotiations (Paragraph 140), as contrasted with the <u>results</u> of such negotiation, which are and should be fully public, and the "support and defend" language of Paragraph 143.

The former provision is to protect the integrity of the settlement process. This requires that the actual deliberative negotiations of the parties be kept confidential even after settlement is reached. This is because to do so would compromise the settlement process by way of a "chilling" effect on the willingness and ability of future parties to engage in the frank exchange of ideas and the "give and take" inherent in any compromise of strongly-held positions.

The latter provision (Paragraph 143) prevents a settling party from enjoying the benefits received under the agreement from the compromises of others, while seeking to undermine before the Commission (or a reviewing court) those provisions of the overall agreement that required the settling party to itself compromise one or more positions. Such mutuality of obligation is so obviously both necessary and equitable that I do not believe it requires further explanation or justification.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Although APS is a proponent of settlement as a way of creatively and effectively resolving multi-faceted proceedings such as rate cases, I could not truthfully say that the Company had a high degree of optimism going into these negotiations. This was not because the Company had not presented an overwhelmingly persuasive case for rate relief in general and for rate-basing of the PWEC assets in particular, but because of the very size of the gulf separating several of the parties on a wide number of issues, in addition to the number and complexity of those issues. That we were able to eventually succeed is both a tribute to the quality of Staff's leadership throughout the long and arduous settlement process and a testament to the ability of this diverse (to say the least) and large group of parties to grasp the possibility for and to appreciate the value of reaching settlement.

This settlement addresses three of the Company's fundamental objectives - objectives that have remained unchanged from the day this case was filed in late June of 2003. But is does far more than just that. The agreement is good for competition, for the environment, for resource diversity and reliability, and for customer equity. APS is pleased to be a part of this historic agreement and urges its prompt approval by the Commission.

Q. DOES THAT CONCLUDE YOUR DIRECT SETTLEMENT TESTIMONY?

A. Yes.

SETTLEMENT TESTIMONY OF DONALD G. ROBINSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

September 27, 2004

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SETTLEMENT TESTIMONY OF DONALD G. ROBINSON ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald G. Robinson. I am Vice President of Planning for Arizona Public Service Company ("APS" or "Company"). My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY SUBMIT DIRECT AND REBUTTAL TESTIMONY IN THIS MATTER?

A. Yes, I did.

Q. ARE YOUR RESPONSIBILITIES STILL THE SAME AS WHEN YOU PREVIOUSLY SUBMITTED TESTIMONY?

A. For the most part, yes. While I retain responsibility for Corporate Planning, Resource Planning, Budgets, Forecasts, Energy Risk Management and New Business Ventures, I also have assumed responsibility for Resource Acquisitions. Thus, I am responsible for oversight of the Company's future long-term resource acquisitions, including requests for proposals and other solicitations.

Q. DID YOU PARTICIPATE IN THE SETTLEMENT NEGOTIATIONS?

A. Yes, I did.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will first testify to the overall impacts on the Company's financial results and projections should the Arizona Corporation Commission ("Commission") accept the proposed settlement agreement without material modification. As part of that discussion, I also will provide an overview of the reaction of the financial markets to the settlement. Second, I will address specific sections of the settlement, including those dealing with (a) the write-off associated with the Pinnacle West Energy Corporation ("PWEC") generating assets being transferred to APS and put into rate base ("PWEC Assets"); (b) cost of capital and return on equity; (c) the power supply adjustment mechanism ("PSA"); (d) changes made to the Company's depreciation schedules for jurisdictional property; (e) future competitive procurement of long-term power resources; (f) the request for renewable proposals; (g) nuclear decommissioning; and (h) the deferral of bark beetle remediation costs.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR SETTLEMENT TESTIMONY?

A. Yes. The settlement was reached after extensive and detailed negotiations involving essentially all of the parties to the case. One of the Company's primary goals going into this rate proceeding was to preserve its financial integrity so that it could continue to attract the capital required to maintain reliable service to our customers. Although I believe the settlement should permit APS to maintain investment grade credit ratings, it does not provide APS the ability to improve those ratings, nor does it leave room for any further material decline in the Company's financial ratios. It also will not allow the Company to actually earn the agreed to return on common equity ("ROE"). For these reasons, the reactions of the financial markets to the settlement were mixed, with some entities being neutral to marginally positive, and others expressing concerns about the modest level of the rate increase proposed in the settlement. Steve Fetter addresses the reaction of the market in more detail in his Settlement Testimony.

The settlement adopts a PSA similar to adjustment mechanisms approved by the Commission in other proceedings and to the PSA approved by the Commission in

APS' PSA proceeding (*see* Decision No. 66567 (November 18, 2003)). The PSA is critical to the Company's and, I believe, the financial market's, ability to accept the low base rate increase. As discussed in greater detail in my Rebuttal Testimony and in the Rebuttal Testimony filed by APS Witness Pete Ewen, fuel and purchased power will make up almost half of the total Company operating expenses in 2005. This increasing exposure to forward gas and power prices, coupled with high price volatility, further illustrates the importance of the proposed PSA.

Although APS already had the lowest overall depreciation rates in Arizona, the settlement further extends the service lives of many APS assets as recommended by Staff while adopting the jurisdictional net salvage allowance proposed by APS. This extension of service lives explains why the Company's agreement to forego stranded costs on the PWEC assets also represents a significant concession.

I also discuss two procurement processes that the Company will be implementing before the end of 2005 as a result of the settlement. First, the Company will conduct a 2005 solicitation for at least 1000 MW of long-term resources, with deliveries to begin in 2007. PWEC will not participate in this solicitation. The settlement also places restrictions on the Company's right to self-build generation through 2015.

Second, the Company will conduct a special RFP in 2005 seeking at least 100 MW and 250,000 MWh per year of various renewable resources for delivery beginning in 2006. In addition, the Company has agreed to seek to acquire 10% of its future incremental nameplate capacity needs from such renewables.

Finally, my testimony discusses the issues of nuclear decommissioning and the deferral for bark beetle remediation costs.

III. FINANCIAL IMPACTS RESULTING FROM THE PROPOSED SETTLEMENT AGREEMENT

Q. HAVE YOU FORECASTED THE IMPACT ON APS' FINANCIAL RESULTS IF THE COMMISSION ADOPTS THE SETTLEMENT?

A. Yes, I have. I believe the implementation of the settlement should allow APS to maintain its investment grade credit ratings but it would not allow for any improvement in those ratings. Moreover, as Mr. Fetter testifies, the Company would have very little room for any further material degradation in its financial ratios. This is not a desirable situation for any electric utility, let alone one with the second fastest growing service area in the United States. This growth, expected to be 15-20% over the next five years, will require substantial capital expenditures by the Company over the next several years for infrastructure maintenance and expansion if it is to continue to provide reliable electric service.

Because of the marginal financial indicators, the implementation of the PSA and the ratebasing of the PWEC Assets will be of critical importance to maintaining the Company's current investment grade credit ratings. Both of these elements of the settlement provide the financial markets with some added certainty that the Company will be able to meet its financial obligations. For example, Standard & Poor's ("S&P") stated the following in its report on the settlement:

> [T]he settlement agreement that [APS] reached with 21 parties related to its electric rate case is constructive from a business risk perspective, but does little to strengthen the utility's financial profile.
>
> * * *
>
> The agreement, most significantly, would allow the utility to rate-base 1,790 MW of merchant capacity at a value of $700 million, net of a $148 million disallowance, owned by unregulated affiliate [PWEC].
>
> * * *

> Also, very significantly, the settlement calls for the establishment of a fuel adjustment mechanism, which would include a sharing mechanism with ratepayers and be reset annually to track future fuel and purchased power expenses for subsequent recovery.

Standard & Poor's, "Research: Arizona Public Service's Proposed Rate Settlement is Reasonably Constructive," August 20, 2004.

Q. WHAT ARE THE FINANCIAL RESULTS FROM THE PROPOSED SETTLEMENT AGREEMENT?

A. On Schedule DGR-1-S, I have updated the relevant information using the same format as Schedule A-2 from the Company's original filing to reflect the financial results under the settlement. Although the Company does not currently anticipate any significant negative impact on its ability to access funds to undertake its planned infrastructure investments, the inability to improve its credit ratings limits the Company's ability to effectively control financing costs if interest rates rise.

The following summarizes the financial results based on the settlement:

- The Company's net income under the settlement drops approximately 20% in 2005.
- The Company's return on average common equity would fall to 9.2% in 2005.
- The Company's debt to capital ratio would be 56% in 2005.
- The funds from operations to average total debt ratio would be 17.9% in 2005.
- The pre-tax interest coverage ratio would be 2.8x in 2005.
- The funds from operation interest coverage ratio would be 3.7x in 2005.

As Mr. Fetter testifies, while these measures for 2005 appear to be consistent with APS' current BBB rating level (based upon S&P's recently-revised financial targets), S&P has maintained its Negative outlook on APS because it does not see meaningful improvement in APS' financial profile resulting from the settlement.

Q. HOW DID THE COMPANY FORECAST THE FINANCIAL RESULTS SHOWN ON SCHEDULE DGR-1-S?

A. The Company started with Schedule A-2, which is part of the Commission's standard filing requirements, and then it made the necessary adjustments to reflect the settlement.

Q. WHAT KEY CHANGES DID YOU MAKE FOR THE PROPOSED SETTLEMENT AGREEMENT?

A. We made the following key changes:

- Reduced base revenues to reflect the proposed base rate increase of 3.77% and the 0.44% CRCC recovery.
- Adjusted depreciation and amortization expenses to be consistent with the settlement.
- Included the additional DSM expenses required by the settlement.

As I stated previously, I believe the resulting financial results will keep the Company with a marginal investment grade rating.

IV. SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

A. PWEC Asset Treatment

Q. WHAT DOES THE SETTLEMENT PROVIDE WITH RESPECT TO THE PWEC ASSETS?

A. The settlement provides that the dedicated PWEC Assets, *i.e.,* Redhawk CC-1 and CC-2, West Phoenix CC-4 and CC-5, and Saguaro CT-3, will be acquired by APS and put into rate base. The PWEC Assets will have an original cost rate base value of $700 million, which represents a $148 million rate base disallowance from the original cost of these assets as of December 31, 2004. As the settlement notes, this disallowance is intended to reflect a reasonable estimate of the remaining value of the APS-PWEC Track B contract.

Q. HOW WILL THE TRANSFER OF THE PWEC ASSETS FROM PWEC TO APS BE ACCOMPLISHED?

A. The Company plans to transfer the PWEC Assets in the most tax efficient manner possible, which means that the Company will attempt to eliminate or minimize any taxes resulting from the transfer of the PWEC Assets. At this time, the Company is evaluating two primary forms of transfer. The first would be to transfer the PWEC Assets to APS via a distribution of the assets from PWEC to Pinnacle West Capital Corporation ("PWCC") followed by a contribution of these same assets from PWCC to APS. The second approach under consideration would be the sale of the PWEC Assets to APS. Although there are other potential forms of transfer, the Company currently believes that one of these approaches will be the most tax-efficient.

Q. HOW DOES THE COMPANY VIEW THE WRITE-OFF OF THE RATE BASE VALUE OF THE PWEC ASSETS?

A. The Company considers the write-off of the rate base value of the PWEC assets to be a significant concession. The Company's rebuttal testimony in this case showed that the economic value of these assets was much greater than their June 30, 2004 book value. This means that APS customers would have received significant benefits even under the Company's original proposal. These substantial benefits are further increased with the write-off of $148 million. In fact, the total increased benefits to customers from APS concessions in the settlement is almost $250 million.

B. Cost of Capital

Q. WHAT DOES THE PROPOSED SETTLEMENT AGREEMENT PROVIDE WITH RESPECT TO COST OF CAPITAL?

A. The settlement requires APS to use a capital structure of 55% long-term debt and 45% common equity for ratemaking purposes. The settlement also incorporates a return on common equity of 10.25% and an embedded cost of long-term debt of 5.8%. Also, the capital structure assumes that the $500 million in debt authorized in Decision No. 65796 (April 4, 2003) becomes a permanent part of APS' capitalization and that the balance of the PWEC assets acquisition is financed on the same 55/45 basis.

Q. HOW DOES THE SETTLEMENT CAPITAL STRUCTURE COMPARE TO APS' ACTUAL CAPITAL STRUCTURE?

A. The 55/45 capital structure incorporated for ratemaking purposes in the Proposed Settlement Agreement is approximately half way between the actual capital structure of APS as of the end of the 2002 test year (at 50/50) and the minimum equity ratio (40%) mandated by Decision No. 65796.

Q. HOW DOES THE 10.25% ROE INCORPORATED IN THE SETTLEMENT COMPARE TO GRANTED ROE'S AROUND THE COUNTRY?

A. According to Regulatory Research Associates ("RRA"), the ROE included in the settlement is lower than the average granted ROE for at least the last 15 years in the United States for major electric utilities. *See* RRA, "Regulatory Study," February 6, 2004. The average ROE granted in 2003 was 10.97%, in 2002 it was 11.16%, and the average for the last 10 years was 11.28%. *See* RRA, "Major Rate Case Decisions—January-June 2004 Regulatory Study," July 8, 2004. The average ROE granted to electric utilities for the first half of 2004 was 10.63%. In light of APS' rapidly growing service area and the anticipated increases in interest rates, the Company believes that the ROE incorporated into the settlement is at the low end of the reasonable range.

Q. DO YOU BELIEVE APS WILL ACTUALLY EARN 10.25% UNDER THE PROPOSED SETTLEMENT RATE?

A. No. As I testified previously, APS expects to earn a ROE of 9.2% in 2005. When this actual anticipated ROE is compared to other recent ROEs granted to utilities with lower growth rates, it becomes even clearer that the 10.25% ROE is at a minimum acceptable level.

C. The Power Supply Adjustment Mechanism.

Q. PLEASE DESCRIBE THE KEY ELEMENTS OF THE PSA INCLUDED IN THE SETTLEMENT.

A. The PSA included in the settlement incorporates many of the elements approved by the Commission in Decision No. 66567. Specifically, the settlement PSA includes the following key elements:

- The PSA includes both fuel and purchase power.
- The adjustor rate will initially be set at zero and not adjusted for the first time until April 1, 2006; the maximum adjustment in any one year will be plus or minus $0.004 per kilowatt hour ("kWh") with any additional amounts carried over.
- APS and its customers will share in the costs or savings on a 90% customers/10% APS basis.
- Subject to certain limited exceptions, customers will receive the benefits of all off-system sales.
- The Commission and its Staff retain the ability to review the prudence of all fuel and power purchases at any time and any costs flowed through the PSA will be subject to refund if the Commission finds that such costs were not prudently incurred.
- APS will provide detailed and certified monthly reports to the Commission and RUCO encompassing an extensive amount of information relating not only to the PSA calculations, but also to the APS generating units and to its power and fuel purchases. Certain information may be provided confidentially.
- The minimum life of the PSA will be five years from the date that rates under the proceeding go into effect. Within four years, APS shall file a report that addresses the various aspects of the PSA and provides recommendations regarding the continuation of the PSA. After the five-year period, the Commission may abolish the PSA without a rate case but will incorporate provisions to address any under-recovery or over-recovery existing at the time of the termination.
- The base cost of fuel and purchased power reflected in APS' base rates will be $0.020743 per kWh.
- APS will file a plan of administration describing how the PSA will operate as part of its compliance filing in this docket.

Q. WHAT ARE THE BENEFITS OF THE PSA PROPOSED IN THE SETTLEMENT?

A. The PSA is critical to the Company's willingness to accept the low base rate increase included in the settlement. As the Company explained in detail in the PSA proceeding (Docket No. E01345A-02-0403) and in the Rebuttal Testimony filed by myself and Mr. Ewen in this proceeding, APS is increasingly dependent on natural gas, both to run its own generating facilities and through its rapidly increasing dependence on purchased power, which is predominantly gas-fired. For example, as we explained in the Rebuttal Testimony, between 1991 (the year following the Company's last full-blown general rate case) and 2005, APS' energy needs from gas-fired generating facilities and purchased power will have gone from 9% to approximately 28%. As a result, gas and purchased power will constitute 56% of the Company's total fuel and purchased power expenses by 2005, the first full year for which the proposed PSA will be effective. And fuel and purchased power expense will have gone from constituting one-third of all APS operating expenses in 1991 to almost one-half in 2005.

At the same time that APS is becoming more dependent on natural gas and purchased power, prices for both have become more volatile. As explained in my Rebuttal Testimony and in the Rebuttal Testimony of Mr. Ewen, for example, the average natural gas price for delivery at the San Juan Basin has ranged from \$1.40 per MMBTU to \$10.16 per MMBTU since 1998. At the SoCal Border, the gas price has ranged from \$1.40 per MMBTU to \$59.42 per MMBTU during the same timeframe. Both APS' increasing dependence on natural gas and the increasing volatility of natural gas prices clearly require the implementation of a PSA.

Q. WHAT IS THE MOST SIGNIFICANT MODIFICATION MADE IN THE SETTLEMENT TO DECISION NO. 66567?

A. The most significant change, which is also the most essential change, is the inclusion of fuel costs. Because the Company will continue to own generation (and, in fact, if the settlement is approved, will own more generation), we must be able to recover fuel costs in a timely manner. Moreover, gas tolling arrangements have become a much more common purchased power attribute. Under such arrangements, APS, the purchased power buyer, will provide the gas fuel used by the seller. Although in actuality a component of purchased power expense, this gas fuel is classified for accounting purposes as a fuel expense.

APS customers realize the benefit from net power supply costs when both fuel and purchased power are included, and APS is kept whole on changes to its total fuel and purchased power costs. In addition, APS believes it is important to optimize the mix of fuel and purchased power used to serve native load customers. Implementing a PSA provides the appropriate incentive for APS and ensures that customers receive the lowest cost energy in the future.

Q. THE SETTLEMENT ADOPTS A PROPOSED 90/10 SHARING. CAN YOU EXPLAIN WHY?

A. As I explained in my Rebuttal Testimony, the Company believes that it should be entitled to recover all of its prudent costs of providing service to its customers, including fuel and purchased power costs. Because certain parties raised the issue of incentives, however, the Company agreed to the 90/10 sharing in the spirit of compromise.

Q. ARE THERE ANY OTHER FEATURES INCLUDED IN THE PSA TO PROTECT CUSTOMERS FROM PRICE VOLATILITY?

A. Yes. The settlement recognizes the importance of APS being proactive in developing a forward hedge strategy for fuel and purchased power expenses, and that the prudent and direct costs of such hedging should be recovered through the PSA. Given the volatility of natural gas and power prices in today's market and APS' increasing dependence on natural gas and purchased power, forward hedges can protect both the customer and APS from some portion of financial risk of price uncertainty without sacrificing reliability of supply. For that reason, forward hedge costs are important to include in each annual calculation of fuel and purchased power costs.

The settlement also limits the amount of the annual adjustment under most circumstances, which helps smooth changes in rates over time. That limit is 4 mils per kWh, or roughly 5% for a typical residential customer.

Q. IN LIGHT OF THE ABOVE DISCUSSION, PLEASE SUMMARIZE APS' POSITION ON THE PSA.

A. APS firmly believes that the implementation of a PSA for both purchased power and fuel is critical to the future economic stability of the Company and to its agreement to the settlement, and to its customers. This is especially true in light of the Company's rapidly increasing dependence on natural gas to meet customer demand and the increasing volatility of natural gas prices. The PSA set forth in the settlement appropriately balances the interests of the Company and its customers and has broad support among all of the stakeholder groups.

D. Depreciation

Q. DOES THE SETTLEMENT INCLUDE ANY CHANGES TO DEPRECIATION?

A. Yes, it does. Specifically, although APS already had the lowest overall depreciation rates (and longest service lives) in Arizona, the settlement adopts the service lives proposed by Staff, while retaining APS' proposed jurisdictional next salvage allowance.

E. Competitive Procurement of Power

Q. UNDER THE SETTLEMENT, APS AGREES TO TAKE CERTAIN STEPS INTENDED TO PROMOTE COMPETITION. PLEASE BRIEFLY IDENTIFY THOSE STEPS.

A. The settlement includes a number of provisions designed to promote both wholesale and retail competition. With respect to promoting wholesale competition, there are three primary provisions in the settlement. First, APS will not pursue any self-build option for new generation with an in-service date before January 1, 2015 unless expressly authorized by the Commission. Second, APS will issue an RFP or other solicitation no later than the end of 2005 for at least 1000 MW long-term future resources for delivery starting in 2007. In addition to the activities that APS will undertake, Commission Staff will initiate workshops on resource planning to focus on infrastructure development and competitive procurement.

These provisions, which are set out in Section IX of the settlement, were key to the merchant community's willingness to support the acquisition and ratebasing of the PWEC Assets and to their general support of the settlement. They also respond to Commissioner Gleason's question in his May 10, 2004 letter regarding principles to address wholesale competition and provide customers with a choice of suppliers.

Q. PLEASE EXPLAIN THE SELF-BUILD RESTRICTION IN MORE DETAIL.

A. The self-build restriction precludes APS from building new generation with an in-service date before January 1, 2015, with certain exceptions intended to ensure reliability, encourage the development of a diverse resource base, or both. For purposes of the settlement, exceptions to the definition of "self-build" include:

- the acquisition of a generating unit or an interest in such a unit from a non-affiliated merchant or utility;
- the acquisition of temporary generation needed for system reliability;
- distributed generation of less than 50 MW per location;
- renewable resources; and

- the uprating of APS generation.

Q. ARE THERE ANY OTHER EXCEPTIONS TO THE SELF-BUILD MORATORIUM?

A. Although it is not truly an exception to the self-build moratorium, APS may seek Commission authorization to self-build under certain circumstances. In fact, the settlement expressly provides that the self-build moratorium does not excuse APS from its obligation to prudently acquire resources to meets customers needs. A part of that obligation is to seek Commission approval if the competitive market cannot reasonably meet APS customers' needs.

APS also believes that the option to seek Commission authorization was a critical element of the self-build moratorium because it provides the Company with a safety net in case the market cannot or will not provide the energy and capacity needed to meet customers' needs at reasonable cost.

Q. WHAT MUST APS SHOW IN ORDER TO RECEIVE COMMISSION AUTHORIZATION TO SELF-BUILD NEW GENERATION RESOURCES?

A. Specifically, APS must submit a filing that addresses the following:

- The Company's specific unmet needs for additional long-term resources;
- The Company's efforts to secure long-term resources from the competitive wholesale market (*i.e.*, RFPs or other solicitations conducted);
- The reasons why the Company believes its efforts were unsuccessful;
- The extent to which the self-build request is consistent with Company resource plans and competitive resource acquisition Commission rules or orders coming from the workshop process described below; and
- The anticipated life-cycle cost of any proposed self-build option as compared to available alternatives.

Q. YOU MENTIONED THAT APS WILL CONDUCT A COMPETITIVE POWER PROCUREMENT IN 2005. PLEASE PROVIDE MORE DETAIL ABOUT THAT PROCUREMENT PROCESS.

A. APS will issue an RFP or other competitive solicitation(s) by the end of 2005 for long-term future resources of not less than 1000 MW for delivery starting in 2007. For purposes of the settlement, long-term resources include any acquisition of generating facility (or an interest in one) or any PPA with a term of at least five years. No APS affiliate (including PWEC) may participate in the 2005 solicitation(s), and no APS affiliate will participate in solicitations after 2005 unless an independent monitor is appointed. APS also retains the ability to enter into bilateral contracts with non-affiliates for long-term resources.

Q. IS APS OBLIGATED TO PURCHASE AS A RESULT OF THIS SOLICITATION?

A. No, APS is not obligated to accept any specific proposal or combination of proposals submitted in response to this solicitation. This provides the Company with, in effect, assurance that bidders will not unreasonably mark up their proposals. It also allows APS to maintain a balanced portfolio of long-term and shorter-term resources if market conditions warrant.

Q. ARE THERE ANY OTHER IMPORTANT ELEMENTS OF THE SETTLEMENT'S COMPETITIVE POWER PROCUREMENT?

A. Yes. There are two other key provisions I would like to discuss. First, I want to reemphasize that in addition to the special renewables RFP discussed below, all renewable resources, distributed generation and DSM proposals will be evaluated in a manner consistent with other proposals. This provides another opportunity for such resources to participate in the market and further encourages the development of such resources.

Second, the settlement provides that the Commission Staff will initiate and conduct workshops open to all interested parties on resource planning issues. Those workshops will focus on developing needed infrastructure, as well as developing a flexible, timely and fair competitive procurement process. The workshops also will address whether and, if so, to what extent the process should include consideration of a diverse portfolio of short, medium and long-term purchased power, utility-owned generation, renewables, DSM and distributed generation. If found necessary, the workshops may be followed by a rulemaking. In the meantime and unless otherwise authorized by the Commission, APS will continue to use its Secondary Procurement Protocol, which was submitted to the Commission on April 4, 2003 as required by the Track B order.

F. Renewables Procurement

Q. ARE YOU DISCUSSING ALL OF THE PROVISIONS OF SECTION VIII OF THE SETTLEMENT?

A. No, I am not. Mr. Wheeler discusses the first element of this section of the settlement, the Environmental Portfolio Standard ("EPS"). My testimony will address renewables procurement, the second element of this section.

Q. WHAT IS INCLUDED IN THE SETTLEMENT WITH RESPECT TO RENEWABLES PROCUREMENT?

A. The principal element of the settlement relating to renewables procurement is APS' commitment to conducting a special RFP in 2005 that would seek at least 100 MW and at least 250,000 MWh of the following types of renewable resources for delivery starting in 2006: biomass/biogas; wind; small hydropower (under 10 MW); hydrogen (other than from natural gas); and geothermal. In addition, APS would seek to acquire, through the 2005 RFP or other solicitations, at least ten percent (10%) of its annual incremental peak capacity needs from renewable resources.

Q. PLEASE EXPLAIN HOW THE RENEWABLES RFP INTERSECTS WITH THE EPS AND OTHER APS PROCUREMENT ACTIVITIES.

A. As the Commission knows, the EPS was founded primarily as an environmental program that would promote development of specific types of in-state renewable resources. For example, the EPS' solar technology requirements were intended to encourage development of a natural resource that is abundant in Arizona, but that cannot yet be economically used to meet large portions of demand. The renewables RFP contemplated in the settlement would coordinate with and supplement the EPS but would not displace APS' requirements under the EPS as it exists today or as modified in the future. The renewables RFP also will have environmental benefits and encourage the development of Arizona resources, but its primary focus will be on providing additional resource diversity as a hedge against future fossil fuel (primarily gas) price volatility. In addition to the special opportunity created for renewable resources in the renewables RFP, such resources also will be able to participate in the competitive procurement RFP previously discussed.

Q. **ARE THERE ANY CONDITIONS ON THE RENEWABLE RESOURCES TO BE SOLICITED UNDER THIS SECTION OF THE SETTLEMENT, INCLUDING IN THE 2005 RFP OR FUTURE SOLICITATIONS?**

A. Yes, there are. The principal conditions are as follows:

- Although resources need not provide firm capacity, the degree of the resource's firmness will be considered in determining the capacity value to assign to each resource.
- Individual resources must be deliverable to the APS system, directly or through displacement, and must be capable of providing at least 20,000 MWh of renewable energy annually.
- Purchased power agreements ("PPAs") for renewable resources must be for at least five years and may be for as long as 30 years.
- Prices for the renewable resources may not vary with the price of natural gas or electricity.
- The cost for renewable resources is capped at 125% of market for conventional resources on a levelized cost per MWh basis.
- Costs for renewable resources are recovered through a combination of the PSA and the EPS, depending on the type of resource procured, the availability of EPS funding and the price of the resource compared to market. The settlement expressly recognizes that the costs of wind energy (and other renewables that are near market price) may be recovered through

the PSA, which responds to Chairman Spitzer's May 14, 2004 comment regarding the use of wind energy as a component of purchased power contracts to serve load.

- Although renewable resource procurement shall be subject to the Commission's customary prudence review, the fact that a renewable resource exceeds market price shall not alone render such purchase imprudent.

Q. ARE THERE ANY OTHER IMPORTANT POINTS YOU WOULD LIKE TO MAKE ABOUT THE RENEWABLES RFP?

A. Yes. As it has done with prior RFPs it has conducted, APS will circulate a draft of the renewables RFP before the formal solicitation begins and will hold a meeting for potential participants and other interested parties to solicit comments on the draft RFP. If APS fails to acquire at least 100 MW of renewable resources through the renewables RFP by the end of 2006, APS will submit a report to the Commission explaining the circumstances for the shortfall and recommending actions to resolve any identified issues.

Q. WILL THE RENEWABLES RFP PROVISIONS RESTRICT IN ANY WAY THE COMMISSION'S ABILITY TO MODIFY OR EXPAND THE EPS?

A. No.

G. Nuclear Decommissioning

Q. PLEASE SUMMARIZE THE PROVISIONS RELATING TO NUCLEAR DECOMMISSIONING.

A. The settlement preserves the existing assumptions concerning funding for the decommissioning of Palo Verde Nuclear Generating Station ("Palo Verde"). The proposal is based on a detailed study performed by LaGuardia & Associates, one of the nation's most experienced and respected nuclear consulting firms, and a firm whose studies have been accepted by the Commission in prior decisions. The study uses the "greenfield" methodology adopted by the Commission in 1988 and used ever since. *See* Decision No. 55931 (April 1, 1988). As explained in the Company's rebuttal testimony, the "greenfield" methodology presumes that following the termination of the operating license for the three Palo Verde units, the above-grade, site structures, facilities and supporting systems would be dismantled and the site regraded to resemble a condition close to its natural state. *See* Rebuttal Testimony of Thomas LaGuardia at p. 7, lines 17-29.

H. Bark Beetle Remediation.

Q. PLEASE EXPLAIN APS' PROPOSED ADJUSTMENT FOR BARK BEETLES?

A. As I explained in my rebuttal testimony, Arizona has, to date, experienced an eight-year drought that has weakened the Ponderosa pine forest trees to the extent that they became susceptible to infestation by bark beetles. It is projected that there are nearly one million dead or dying trees caused by this infestation within falling distance of APS power lines that will need to be removed over the next three to five years to protect the transmission and distribution system, ensure community safety and avoid the possibility of causing devastating forest fires.

Q. THE COMPANY PROPOSED IN ITS REBUTTAL TESTIMONY TO INCLUDE THE BARK BEETLE REMEDIATION COSTS AS AN ADJUSTMENT. WHAT APPROACH DOES THE SETTLEMENT TAKE?

A. Although APS views the bark beetle remediation as an extension of its nationally recognized vegetation management program, it proposed the use of an adjustment because of the unique circumstances surrounding the need for extensive remediation due to the bark beetle infestation. The settlement does not adopt the adjustment mechanism proposed by the Company, however, instead allowing the deferral without a return of the reasonable and prudent incremental costs that the Company incurs for bark beetle remediation. The Commission will determine in the Company's next general rate proceeding the reasonableness, prudence and appropriate allocation between distribution and transmission, as well as an appropriate amortization period, for these costs.

If the state is successful in securing federal funds for this problem, the Company will credit any funds it receives against the deferrals.

Q. WHY IS THIS DEFERRAL IMPORTANT?

A. Because of the low rate increase contained in the settlement and the accompanying minimal financial results, the Company would not be able to recognize these costs as a current expense without creating pressure on its financial condition. Moreover, the removal of dead and dying trees caused by bark beetle infestation is critical to the continuing reliability of the APS transmission and distribution system.

As the Federal Energy Regulatory Commission pointed out in its recent report, "*Utility Vegetation Management and Bulk Electric Reliability Report from the Federal Energy Regulatory Commission*" (September 7, 2004) ("Vegetation Report"), one of the four primary causes of the August 14, 2003 midwest blackout was inadequate vegetation management (tree pruning and removal). Vegetation Report at 1. That blackout is not the only one caused by tree contacts. The report recommended that federal, state and local land managers develop streamlined procedures that would allow utilities to correct "danger" trees that threaten transmission lines. Vegetation Report at 3, 18. The FERC also encouraged federal and state regulators to be "sensitive to requests for rate adjustments in order to recover reasonable reliability and security related expenses such as those for vegetation management." Vegetation Report at 17.

V. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. This settlement is the result of significant negotiations between virtually all of the parties. APS believes that the settlement provides a reasonable and appropriate resolution to a complex and difficult proceeding. The financial results should maintain an investment grade rating for the Company as long as the proposed adjustment clauses are approved.

Q. DOES THIS CONCLUDE YOUR PREFILED SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY PROJECTIONS OF OPERATIONS
Projected Years
(Thousands of Dollars)

Line No.	Description	Projected Year: Present Rates 12/31/2004 After Write-off	Projected Year: Present Rates 12/31/2004 Before Write-off	Projected Year: Present Rates 12/31/2005	Projected Year: Proposed Settlement Rates 12/31/2005	Line No.
1.	Gross Revenues	$ 2,127,246	$ 2,127,246	$ 2,201,061	$ 2,292,035	1.
2.	Revenue Deductions & Operating Expenses	1,851,238	1,762,866	1,844,677	1,881,374	2.
3.	Operating Income	276,008	364,380	356,384	410,661	3.
4.	Other Income and (Deductions)	4,004	4,004	(8,411)	(8,411)	4.
5.	Interest Expense	148,683	148,683	167,344	165,422	5.
6.	Net Income	$ 131,329	$ 219,701	$ 180,629	$ 236,828	6.
7.	Earned Per Average Common Share*	N/A	N/A	N/A	N/A	7.
8.	Dividends Per Common Share*	N/A	N/A	N/A	N/A	8.
9.	Payout Ratio*	N/A	N/A	N/A	N/A	9.
10.	Return on Average Invested Capital	6.0%	7.8%	6.7%	7.7%	10.
11.	Return on Year End Capital	5.9%	7.7%	6.5%	7.5%	11.
12.	Return on Average Common Equity	6.1%	10.1%	7.1%	9.2%	12.
13.	Return on Year End Common Equity	6.0%	10.1%	7.1%	9.1%	13.
14.	Times Bond Interest Earned-Before Income Taxes	2.1	2.8	2.4	2.8	14.
15.	Times Total Interest & Preferred Dividends Earned-After Income Taxes	1.6	2.1	1.8	2.1	15.
16.	Adjusted Return on Avg. Common Equity	4.9%	8.9%	7.1%	9.2%	16.
17.	Adjusted Debt to Total Capital				56%	17.
18.	Funds From Operations to Avg. Total Debt				17.9%	18.
19.	Pre-tax Interest Coverage Ratio				2.8	19.
20.	Funds From Operations Interest Coverage Ratio				3.7	20.

SETTLEMENT TESTIMONY OF

DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

September 27, 2004

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REBUTTAL TESTIMONY OF DAVID J. RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is David J. Rumolo.

Q. ARE YOU THE SAME DAVID RUMOLO WHO HAD PREVIOUSLY PROVIDED DIRECT AND REBUTTAL TESTIMONY IN THIS DOCKET?

A. Yes, I am. However, since those testimonies were filed, my title has changed. My title is now Manager, Regulation and Pricing.

Q. WHAT WAS THE NATURE YOUR PREVIOUSLY FILED TESTIMONY?

A. My Direct Testimony focused on APS' proposed revisions to the Company's Service Schedules. Service Schedules are the part of our tariff that contains the rules and regulations concerning provision of electric service. These rules and regulations include general policies on billing and collections, service establishment, etc., as well as specific policies on matters such as line extensions or curtailment. My Rebuttal Testimony commented on the direct testimony of several parties in this docket and focused on the Service Schedules, General Service rate schedules, and the rate adjustment mechanisms that would apply to retail sales.

II. SUMMARY OF SETTLEMENT TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE THE TESTIMONY YOU ARE FILING IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT ("AGREEMENT"OR "SETTLMENT")?

A. Yes, my testimony addresses three specific aspects of the Settlement. First, I describe the rate design aspects of the Agreement, including the proposed modifications to the residential and non-residential rates beginning with the unbundling of services in accordance with the Retail Electric Competition Rules ("Competition Rules"). The proposed rates for residential customers and key rates for non-residential customers are attached to the Agreement as Appendix J. Second, my testimony describes two of the adjustment mechanisms that will become part of the APS electric tariff – the Transmission Cost Adjustment ("TCA") and the Returning Customer Direct Access Charge ("RCDAC"). The other adjustment mechanisms described in the Agreement, including the Power Supply Adjustment ("PSA"), the Demand Side Management Adjustment Charge ("DSMAC") and the Competition Rules Compliance Charge ("CRCC"), are addressed in the Settlement Testimonies of Steven M. Wheeler and Donald G. Robinson. Third, my testimony describes and explains the modifications to APS' Service Schedules to which the parties to the Agreement have reached concurrence.

III. RATE DESIGN

1. *Rate Unbundling*

Q. UNDER THE RATE DESIGNS DESCRIBED IN THE AGREEMENT, WILL APS OFFER UNBUNDLED RETAIL RATES TO CUSTOMERS?

A. Yes, the APS retail electric tariff will include unbundled rate schedules in accordance with the R14-2-1606(C)(2). The unbundled rates separate competitive electric services such as generation, metering, and meter reading from non-competitive services such as distribution service and system benefits.

Q. HOW WERE THE UNBUNDLED RATES AND THE RATE ELEMENTS DEVELOPED?

A. In general, the rate elements were developed based on cost of service principles. For example, in all classes, the revenue cycle service elements (metering, meter reading, and billing) were based on the results of the Company's cost of service study. For General Service customers, the cost of service study results were also used to develop the generation component of the unbundled Standard Offer Service rate. As I explain later, this was critical because General Service customers are the customers most likely to consider Direct Access Service.

Q. HOW WILL THE RATE ELEMENTS BE DISPLAYED ON APS' TARIFF SHEETS?

A. We will show both the listed unbundled elements and a display of the "rolled up" rates for customers who desire to purchase all electric service elements from APS. We elected to provide the rolled up information for sake of simplicity so customers who do not wish to elect Direct Access options can also see their rate in a bundled format that is similar to current rate formats.

Q. WHY DIDN'T APS UNBUNDLE RATES PRIOR TO THIS FILING?

A. As a result of the 1999 APS Settlement Agreement which provided for "across the board" changes to rate designs, APS' current rate designs did not lend themselves to unbundling since they were not sufficiently cost based. It would have been necessary to alter rate levels and designs before the rates could have been unbundled. Instead the Commission authorized APS to provide a second page, the Competitive Services Information page or "page 2" for each billing showing the difference between the Standard Offer Service billing amount and what the APS-only portion of the bill would have been under Direct Access Service. The rates being proposed at this time have been developed in a manner that is more conducive to unbundling.

Q. WITH THE UNBUNDLED RATES PROPOSED IN THE AGREEMENT, WILL "PAGE 2" OF THE BILLS THAT CUSTOMERS CURRENTLY RECEIVE, AS DISCUSSED IN DECISION NO. 61973, STILL BE NEEDED?

A. In the absence of full rate unbundling, the purpose of "page 2" is to provide a customer the information needed to determine whether he or she should consider taking Direct Access Service. It was sufficient for that purpose but was not the complete unbundling of rates such as we have under the Agreement. The new bill format will provide customers with the billing element information in accordance with R14-2-1612. Therefore, "page 2" would be redundant, perhaps even confusing, and it will be eliminated.

Q. WILL APS' RETAIL RATES, AS PROPOSED IN THE AGREEMENT, BE 100% COST BASED?

A. No, they will not be totally cost based, although they will be closer to cost. Cost-based pricing has several aspects including charges based on class revenue requirements, pricing based on individual rate schedule cost allocations and pricing based on cost-based billing elements within rate schedules. Moving from current rates to rates that are totally cost based would result in significant rate shock to some customer classes and residential customers. For example, 100% cost-based pricing would result in an increase in residential customer rates that would be significantly higher than the increases described in the Agreement. However, the Agreement provides that certain billing elements, namely revenue cycle services and, in the case of General Service rates, generation charges will be cost based.

Q. PLEASE DESCRIBE HOW THE RATES WERE UNBUNDLED IF THE CLASS REVENUE TARGETS WERE NOT THEMSELVES TOTALLY COST BASED.

A. For residential rate schedules, we designed the revenue cycle services to be cost based. The distribution components of the residential rates are also cost based. The generation component was computed as the residual or the difference between the summation of the cost-based components and the targeted rate schedule revenue level. The targeted revenue level was established for each rate schedule through the settlement negotiations. For General Service Schedules E-32, E-34 and E-35, the revenue cycle services and generation cost elements were established at cost with the distribution element computed as the residual between the targeted revenue and the cost-based elements.

Q. WHY WERE THE COMPUTATIONS FOR RESIDENTIAL AND GENERAL SERVICE CUSTOMERS PERFORMED DIFFERENTLY?

A. The computations were performed differently because the residential customers rates are set to generate revenue levels which are below fully embedded cost of service while the General Service customers rates generate revenue levels that are higher than cost of service. The methodologies provide proper price signals for the generation and other competitive service elements to General Service customers while preserving the financial integrity of the "wires" business through recovery, in the aggregate, of the total allowable costs associated with that segment of service.

Q. IN YOUR OPINION, WILL THE RATES THAT HAVE BEEN DESCRIBED IN THE AGREEMENT PROMOTE RETAIL ELECTRIC COMPETITION?

A. Yes I believe they will. For residential customers, APS should be able to fully recover the revenue cycle services and distribution costs through cost-based charges even if a customer chooses an alternative energy supplier. For General Service customers, the generation and revenue cycle services elements are cost based which provides customers with the appropriate pricing information on which to make decisions on competitive services. At the same time, the pricing of the distribution elements provide the revenue stream for operating a safe and reliable electric system.

2. Residential Rates

Q. PLEASE DESCRIBE APS' CURRENT RESIDENTIAL RATE SCHEDULES AND HOW THEY WILL CHANGE AS A RESULT OF THE AGREEMENT.

A. APS currently has five residential schedules. Schedule E-10 is a non-time differentiated schedule that is frozen to new customers. Schedule E-12 is a non-time differentiated schedule that is open to new customers. Schedule ET-1 is a time of use ("TOU") rate. ECT-1R is also a TOU rate but includes a demand-based price element to encourage customers to utilize demand-side management to lower electric bills. Schedule EC-1, which includes a non-TOU demand-based price element, and like Schedule E-10, has been frozen to new customers for many years. Under the Agreement, customers on frozen Schedules E-10 and EC-1 will see an average increase of 4.82% while customers on E-12, ET-1 and ECT-1R will see an average increase of 3.8%. These differentials are consistent with the trends indicated in our cost of service analysis. The frozen rates will continue until the next rate case, at which time they will be eliminated.

Q. HAD APS PROPOSED TO ELIMINATE SCHEDULES E-10 AND EC-1 IN THIS RATE CASE?

A. Yes. The two frozen rates generate a rate of return that is significantly lower than the other residential rate schedules and are superfluous in that customers can take the same type of service under currently available schedules. These rate schedules have been frozen since 1991 as a result of Decision No. 57649 and APS believed that it would have been appropriate to eliminate them now. However, as a result of the compromises reached in developing the Agreement, we can support continuing these rates until the next rate case. The Agreement provides APS with a firm commitment to eliminate these underperforming rates and, during the interim until the rates are eliminated, customers will be provided information to help them select an appropriate rate for the future. Also, the Agreement provides a slightly higher increase to customers served on the frozen rates which may speed voluntary migration to the other open rates.

Q. PLEASE DESCRIBE THE CHANGES THAT WILL OCCUR IN RESIDENTIAL RATES.

A. In general, the basic structures of the residential rates are unchanged. Maintaining the current rate structure was a guiding principle in developing the residential rates under the Agreement. This provides for continuity of rate design which tends to reduce the likelihood of dramatic changes in customers' bills. For Schedules E-10 and E-12, which are based on inverted blocks, the same number and size of billing blocks are maintained. The inverted design provides price incentives that encourage energy conservation and are generally consistent with current usage patterns. This conservation incentive addresses a rate design objective mentioned in Commission Mundell's May 6, 2004 Memorandum. The definitions of the summer/winter seasons in the residential schedules are not changed and the existing TOU features are maintained in Schedules ET-1 and ECT-1R. Obviously, the unbundled billing elements are a new aspect, but when the unbundled elements are rolled up, the resulting bundled Standard Offer Service rate schedules are quite similar in structure to current rate schedules.

One difference between current rates and the bundled version of the proposed rates is the treatment of the basic service charge. Basic service charges do not vary with usage and cover the costs of services that do not vary with usage such as metering, meter reading, billing, and customer accounting. Currently, basic service charges are listed as flat monthly charges. When rates change or when customers connect or disconnect in mid-billing cycle, the billing system must be programmed to pro rate the basic service charge. To simplify the billing systems, the basic service charge will be expressed as a per-day charge which eliminates the need to first pro rate a portion of the bill and then explain pro-ration to customers.

Also, franchise fees (i.e., franchise taxes) have been removed from base rates and will be billed to customers at the appropriate franchise fee depending on the customer's location. Thus, franchise fees will be handled in a manner similar to transaction privilege taxes.

Finally, an experimental TOU program will be initiated in which residential customers can opt from three TOU on-peak periods, the current 9AM to 9PM, 7AM to 7PM, or 8AM to 8PM. This potential TOU enhancement will provide customers with additional flexibility and options that are not available today. TOU enhancement was an objective mentioned in Commissioner Hatch-Miller's May 14, 2004 letter. The experimental nature of the program, as well as metering equipment limitations, will limit the participation to 10,000 customers. The Agreement requires that APS will file a report with Staff on the experimental program 12 months after a decision on the rate case is adopted.

3. Non-Residential Rates

Q. PLEASE PROVIDE AN OVERVIEW OF APS' EXISTING NON-RESIDENTIAL RATE SCHEDULES.

A. APS currently has a fairly large group of overlapping non-residential rate schedules. Some of these schedules are for specific types of end use and are referred to as "classified" schedules. Examples of classified schedules include E-20 (houses of worship), E-36 (power plant station use), E-38 (agricultural irrigation pumping), street lighting, and partial requirements service. Most General Service customers are served on Schedule E-32 which is the rate for non-classified service under 3,000 kW. There are also several non-classified TOU General Service rates but these were instituted on an experimental basis and participation is limited. Customers over 3,000 kW generally take service under Schedule E-34 or its TOU companion, Schedule E-35. APS' General Service schedules have evolved over time as new rate concepts are instituted. However, some of the schedules, such as Schedule E-32, have origins in the four power companies that were merged to form APS in the early 1950s. These four companies served different types of non-residential loads in different parts of the state. Combining all these disparate customer uses into a single "catch-all" General Service rate schedules, i.e., E-32, has greatly contributed to the rate's complexity over the years. Simplifying E-32 was a major policy objective in this case.

Q. DOES THE AGREEMENT PROVIDE FOR FREEZING OR ELIMINATING ANY OF THE NON-RESIDENTIAL RATE SCHEDULES?

A. Yes. Schedule E-20 will be frozen to new customers, and the existing TOU rates E-22, E-23 and E-24 will frozen and eliminated in the next rate case. Schedule E-21 which is currently frozen will also be eliminated in the next APS rate case. Similarly, Schedule E-38 and the TOU option E-38-8T will continue to be frozen and will be eliminated in the next rate case.

Q. WHY ARE EXISTING SCHEDULES BEING FROZEN AT THIS TIME AND ELIMINATED IN THE NEXT RATE CASE?

A. The frozen schedules tend to be schedules that are significantly underperforming, i.e. the class rates of return are much lower than other General Service schedules, or are schedules with very limited participation. They also are based, in part, on specific non-residential end uses of electricity. Such rate distinctions are seldom good rate design. As an element of the Settlement, APS recognizes that eliminating the schedules now could result in greatly disproportionate bill increases to some customers. Therefore, the Agreement allows for increasing these frozen rates slightly more than the overall increase to APS revenue that the Agreement provides. Customers served under the frozen schedules will be provided information on alternative rates prior to the next APS rate case.

Q. DOES FREEZING THE GENERAL SERVICE TOU RATES REDUCE THE RATE OPTIONS THAT ARE AVAILABLE TO CUSTOMERS?

A. No, in the original rate filing and subsequent rebuttal filings, APS has proposed that a new General Service TOU rate be adopted. The Agreement recognizes the introduction of the new TOU option. New customers who can take advantage of TOU pricing or customers who opt to leave existing TOU rates but wish TOU service will be served under the new rate which is designated E-32 TOU.

Q. PLEASE DESCRIBE WHAT CHANGES TO SCHEDULE E-32 ARE ADDRESSED IN THE AGREEMENT.

A. As I mentioned earlier, Schedule E-32 is the most commonly used General Service rate schedule. In fact, over 90% of General Service customers are served under Schedule E-32. Because Schedule E-32 covers a wide variety of customers ranging from billboard lighting to manufacturing and warehousing facilities, the proposed schedule contemplated in the Agreement provides for simple energy-only rates for customers with loads of 20 kW or less and load factor sensitive rates for customers with loads over 20 kW. The 20 kW dividing line was used because that is the point at which metering requirements change under the Competition Rules.

The current E-32 rate is quite complex and it is somewhat difficult for customers to understand. Therefore, a simplified rate has been proposed. For customers 20 kW or less, the bundled rate consists of two energy blocks and a basic service charge. For customers over 20 kW, the bundled version of the rate will consist of a basic service charge, two demand blocks and two load factor based energy blocks. The rate design for customers over 20 kW was developed with careful consideration of load factor and the relationship between capacity rate elements and energy rate elements so that efficient use of the APS system is encouraged but yet lower load factor customers, such as some school facilities, will not experience disproportionately high increases in their energy costs. In that regard, I note that these sorts of school district concerns were raised in Commissioner Mundell's May 6th memo.

Q. WHAT CHANGES HAVE BEEN PROPOSED FOR THE RATE SCHEDULES USED FOR GENERAL SERVICE CUSTOMERS WITH LOADS OVER 3,000 KW?

A. The general structure of Schedules E-34 and E-35 for bundled service is very similar to the existing schedules. The rates have been modified to allow for the availability of voltage-based discounts. Customers who are served directly from the transmission system or at primary distribution voltage levels will receive a lower rate than customers who are served at secondary voltage levels. This reflects the lower investment required to serve customers who receive service at higher voltage levels.

The Agreement also provides for a specific discount made available to Luke Air Force Base ("Luke") that recognizes that service to Luke is provided under a somewhat unique arrangement in that a government-owned and operated substation is immediately adjacent to the APS-owned substation that is the delivery point to Luke. Therefore, service to Luke requires no APS-owned primary system poles or wires which lowers the investment required to serve the base, thus justifying some rate differential.

Q. WILL ALL GENERAL SERVICE CUSTOMERS HAVE THE ABILITY TO RECEIVE VOLTAGE BASED DISCOUNTS?

A. Yes, voltage options will be available to customers served under any non-frozen metered General Service schedule. However, from a practical standpoint, only large and technically sophisticated customers or customers who have unique situations would likely opt for transmission or primary service. Transmission or primary voltage service shifts the responsibility for ownership and maintenance of transformers and other equipment to the customer and most General Service customers do not have or want the ability to take on that responsibility.

Q. PLEASE DESCRIBE ANY OTHER SIGNIFICANT NON-RESIDENTIAL RATE SCHEDULE CHANGES.

A. The most obvious change is the unbundling of the rate schedules. Other changes include modifying time of use seasons for General Service TOU customers served under non-frozen rates to be the same as residential customers. The new summer TOU season will be from the first billing cycle in May to the last billing cycle in October. Currently, the summer General Service TOU summer season begins in June. The on-peak time periods for General Service TOU rates will continue to be 11AM to 9PM.

The rate schedules for dusk to dawn lighting (Schedule E-47) and street lighting (Schedule E-58) will be extensively modified. Because customers are seeking more options in selecting light fixtures and poles, the rate schedules will be converted to a menu format so that customers can pair up combinations of fixtures and poles to meet architectural or special lighting requirements. The menu approach also simplifies future modifications to the rate schedules as new hardware becomes available. The existing lighting rate schedules generate rates of return that are significantly lower than the system rate of return. Therefore, the Agreement provides for a 5% revenue increase compared to adjusted test year revenue levels, which still leaves those customers well below the system average return.

IV. <u>TRANSMISSION COST ADJUSTER ("TCA")</u>

Q. PLEASE DESCRIBE THE TCA.

A. The TCA is a mechanism that will allow APS to adjust the transmission cost element of retail rates.

Q. WHY IS THE TCA NEEDED?

A. Historically, transmission costs have been embedded in the bundled price of energy. The Federal Energy Regulatory Commission ("FERC") requires that utilities like APS provide open access to transmission systems in order to prevent impediments to competition. FERC promulgated rules that required utility companies to file a tariff that defined rules, regulations and charges for transmission service. In compliance with FERC requirements, APS filed an Open Access Transmission Tariff ("OATT"). FERC requires that utilities that provide Standard Offer Service in states with retail competition purchase transmission service from themselves for Standard Offer customers under the OATT just like any other energy service provider ("ESP"). The TCA will allow APS to pass on changes in OATT costs to retail customers when FERC approves OATT changes. As I explain later, without such a mechanism, ESPs would be at a competitive disadvantage.

Also, when a Regional Transmission Organization ("RTO") is formed, APS will purchase transmission service for standard offer customers under the rates, terms, and conditions of the RTO. These costs will become a new cost element that is beyond the control of APS. This was recognized by the Commission in formulating the Competition Rules. A.A.C. R12-2-1609.G acknowledges that costs incurred in the establishment and operations of transmission organizations should be recovered by transmission system users. The TCA is the mechanism that will ensure that cost recovery occurs in an even-handed fashion. The Plan of Administration for the TCA will be filed by APS as part of the compliance filing that is described in the Agreement.

Q. DOES THE TCA HELP FURTHER RETAIL COMPETITION?

A. I believe it does in that it puts the transmission component of cost on the same footing for all retail competitors. When the scheduling coordinator for an ESP purchases transmission service, the service will be priced at the then effective OATT charges. If APS' Standard Offer Service rates include transmission cost components based on something lower than the then-effective OATT charges, ESPs would be at a competitive disadvantage.

V. <u>RETURNING CUSTOMER DIRECT ACCESS CHARGE</u>

Q. PLEASE DESCRIBE THE RCDAC.

A. The 1999 APS Settlement Agreement provided for several adjustment clauses. Section 2.6.(2) of that agreement provided for an adjuster to recover the costs associated with customers who leave Standard Offer Service or a special contract for a competitive generation supplier but who later wish to return to Standard Offer Service. In May 2002 APS filed an application (Docket No. E-01345-A-02-0403) with the Commission seeking approval of the adjustment clauses including a charge to recover costs associated with customers returning to Standard Offer Service. The charge was labeled the Returning Customer Direct Access Charge or "RCDAC". Hearings were held in April 2003 and the Commission issued Decision No. 66567 in November 2003. The Decision approved the adjustment mechanisms, including the RCDAC with certain modifications. The Agreement incorporates the modifications in the description of the RCDAC, as well as some clarifications sought by ESPs.

Q. PLEASE DESCRIBE THE KEY ELEMENTS OF THE RCDAC.

A. The RCDAC is designed so that current Standard Offer customers will not experience increased costs due to customers returning to Standard Offer Service from Direct Access Service. The most likely source of increased costs would be power supply. Direct Access customers will not be included in APS resource plans, and if a large Direct Access customer or aggregated group of customers returns to Standard Offer Service, APS may need to make costly short term power supply purchases to adequately cover the increased Standard Offer load. The additional load would be incorporated in the normal power supply planning cycle in the future so the RCDAC is, by definition, a short term charge. The Agreement describes three key RCDAC elements: 1) the charge applies only to individual customers or aggregated groups of customers whose load is three megawatts or greater, 2) the charge does not apply to a customer or aggregated group who provides APS with one year's notice of intent to return to Standard Offer Service, and 3) the RCDAC rate schedule will include a breakdown of the individual components of the potential charge, definitions of the components, and a general framework that describes the way in which the RCDAC will be calculated. These elements are essentially the modifications to APS' original adjustment mechanism that were described in Decision No. 66567. The Plan of Administration for the RCDAC will also be filed in APS' compliance filing.

VI. SERVICE SCHEDULES

Q. WHAT IS THE PURPOSE OF SERVICE SCHEDULE 1?

A. Service Schedule 1 is entitled "Terms and Conditions for Standard Offer and Direct Access Services". It contains details on the conditions under which APS provides retail service to customers and includes topics such as the process and charges related to establishment of service; grounds for refusal of service such as unsafe conditions; establishment of credit by customers including security deposits; billing and collections policies; service responsibilities of the customer and APS; access to meters and APS equipment; easements; metering; and service termination.

Q. WHY DID APS PROPOSE CHANGES IN SERVICE SCHEDULE 1 IN THE CURRENT RATE APPLICATION?

A. As part of the rate case, APS determined that it was timely to review and update all the service schedules, including Service Schedule 1. Teams were formed that included APS staff members who are involved in daily customer contact and application of the rules and regulations and the teams developed recommended changes. This process included reviewing and updating the fees and charges found in Schedule 1.

Q. CAN THE CHANGES IN SCHEDULE 1 RESULT IN INCREASED COSTS TO CUSTOMERS?

A. Yes, customers who request services as described in Schedule 1 may see increased costs compared to current charges, and a few new charges have been instituted. However, the total revenue increase from all the changes is only $70,000 per year. An important point that must be recognized is that virtually all charges in Schedule 1 are avoidable by customers. For example, the after hours charge can be avoided by the customer if the customer requests connection work during normal working hours. After hours work by APS crews can result in overtime pay and it is only appropriate that the customer requesting special service be responsible for the cost of that service. Also, the increased charges found in Schedule 1 are necessary to recover costs that would otherwise be recovered from customers not using the service.

Q. WHAT ARE SERVICE SCHEDULE 2 AND 5 AND HOW WERE THEY MODIFIED UNDER THE TERMS OF THE AGREEMENT?

A. Service Schedule 2 describes the terms and conditions for energy purchases by APS from qualified cogeneration and small power production facilities. Schedule 5 is the APS curtailment plan. The Agreement makes no changes to these schedules. However, the schedules will be filed with the Compliance Plan under the Agreement because the schedules will be reformatted so that they will be consistent with the revised format and appearance of the other service schedules.

Q. PLEASE DESCRIBE SERVICE SCHEDULE 3.

A. Service Schedule 3 is APS' Line Extension Policy. The policy describes the terms of conditions under which APS extends electric service to new individual customers and to new subdivisions.

Q. ARE THE REVISIONS TO SCHEDULE 3 FOUND IN THE AGREEMENT THE SAME AS THOSE PROPOSED IN APS' FILING?

A. Not entirely. One of the most significant changes proposed by APS was to change the policy for extension of service to individual residential customers from a footage basis to a construction allowance basis. APS proposed to replace the footage allowance to a specific dollar amount which would better recognize differences in construction costs. However, as part of the rate case settlement, APS agreed to maintain the current footage based policy for individual customer extensions.

The Agreement provides for other modifications to Schedule 3 that better reflect today's world of direct access and nearly universal dual fuel (electric and gas) availability. For example, the economic feasibility studies that are used to evaluate residential extensions beyond the free allowance, subdivision extensions, and General Service extensions will be based on the costs and revenues associated with delivery service, excluding generation and transmission. This change ensures that Standard Offer Service customers compared with Direct Access customers are treated equally. Another change in the economic feasibility study is that the studies will no longer be based on the assumption that customers' energy sources will be all-electric (even if known to be dual-fuel) but rather will reflect the actual subdivision circumstances. Today, virtually all new residential subdivisions provide customers with energy source options if gas is available in the area.

Q. PLEASE DESCRIBE THE CHANGES TO SCHEDULE 4 AND SCHEDULE 15 AS PROPOSED IN THE AGREEMENT.

A. Schedule 4 describes APS' totalizing policy. Totalizing (the summation of loads for more than one meter) can result in lower bills for customers if they meet the totalizing criteria. Totalizing of a customer's load from adjacent service entrance sections for billing purposes is permitted under specific instances as described in Schedule 4. The proposed changes to the Schedule include making totalizing available to residential customers, modifying the descriptions of remote totalizing, and adding language regarding the removal of totalizing equipment. The proposed changes are largely administrative in nature and are designed to clarify the Company's existing totalizing policy.

Schedule 15 also addresses specific metering circumstances. The revisions to the Schedule provide clarification and definition regarding customer responsibilities such as contributions in aid of construction and communications equipment availability when a customer requests special metering.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 7.

A. Schedule 7 describes APS' Electric Meter Testing and Maintenance Plan. The changes adopted in the Agreement conform the plan to current industry practices including monitoring the performance of solid state metering.

Q. PLEASE DESCRIBE THE SCHEDULE 10 AND THE PROPOSED CHANGES TO THE SCHEDULE.

A. Schedule 10 details the terms and conditions for Direct Access Service. It addresses many issues such as billing, processing Direct Access Service requests, payments and collections, and metering. Schedule 10 has not been modified since originally filed in 1998 as a response to the Commission's Competition Rules. The proposed changes to Schedule 10 adopt the modifications proposed by APS as amended in Staff's testimony filed in the rate case. These modifications clarify language in the original filing and make the Schedule consistent with current provisions of the Competition Rules.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The retail rate changes that are incorporated in the Agreement are the result of hard negotiations among the parties to the Agreement. I believe the resulting rates are fair and reasonable and reflect reasonable compromises and they should be approved by the Commission.

SETTLEMENT TESTIMONY OF STEVEN M. FETTER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

September 27, 2004

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**SETTLEMENT TESTIMONY OF
STEVEN M. FETTER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**

DOCKET NO. E-01345A-03-0437

I. *INTRODUCTION*

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter, and my business address is P.O. Box 475, Rumson, NJ 07760.

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

A. I am President of REGULATION UnFETTERED, an energy advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London, as Group Head and Managing Director of the Global Power Group. Prior to my time at Fitch, I served as Chairman of the Michigan Public Service Commission.

Q. PLEASE BRIEFLY DESCRIBE YOUR ROLE AS PRESIDENT OF REGULATION UnFETTERED.

A. I formed an energy advisory firm to use my financial, regulatory, legislative and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include electric and gas utilities, a non-utility energy supplier, international financial services and consulting firms, and investors.

Q. **PLEASE BRIEFLY DESCRIBE FITCH'S BUSINESS DURING YOUR TENURE THERE.**

A. ~~Fitch is the third largest full service credit rating agency in the United~~ States and the largest European rating agency. It is one of four Nationally Recognized Statistical Rating Organizations recognized by the U.S. Securities and Exchange Commission.

Q. **WHAT WAS YOUR ROLE DURING YOUR EMPLOYMENT WITH FITCH?**

A. As Group Head and Managing Director of the Global Power Group within Fitch, I served as group manager of the combined 18-person New York and Chicago Utility Team. I also was responsible for interpreting the impact of regulatory and legislative developments on utility credit ratings. In early April 2002, I left Fitch to start REGULATION UnFETTERED.

Q. **HOW LONG WERE YOU EMPLOYED BY FITCH?**

A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant shortly after I resigned.

Q. **PLEASE DESCRIBE YOUR SERVICE ON THE MICHIGAN PUBLIC SERVICE COMMISSION ("MPSC").**

A. I was appointed as a Commissioner to the three-member MPSC in October 1987 by Democratic Governor James Blanchard. In January 1991, I was promoted to Chairman by incoming Republican Governor John Engler, who reappointed me in July 1993.

Q. PLEASE DESCRIBE YOUR OTHER PRIOR PROFESSIONAL EXPERIENCE.

A. From October 1979 until March 1982, I was employed as an appellate litigation attorney for the National Labor Relations Board in Washington, D.C. From March 1982 through January 1983, I served as assistant legal counsel to Michigan Governor William Milliken. From January 1983 until August 1985, I began as legal counsel within the Michigan Senate and later was appointed Senate Majority General Counsel. From August 1985 until October 1987, I started as executive assistant to the Deputy Under Secretary at the U.S. Department of Labor in Washington, D.C. and later was Acting Associate Deputy Under Secretary of Labor. As I previously stated, I served on the MPSC from 1987 until 1993.

During my time on the MPSC, I served as Chairman of the Board of Directors of the National Regulatory Research Institute ("NRRI") at Ohio State University, the regulatory research arm of the 51 state and District of Columbia public utility commissions. In 2002, I was appointed by the President of the National Association of Regulatory Utility Commissioners ("NARUC") to serve as a public member on the NRRI Board – a 20-member board that includes ten state public utility commissioners. I also served on the Keystone Center Energy Board, after having participated in the Keystone Center Dialogues on Financial Markets and Energy Trading, and on Regional Transmission Organizations.

I have been an adjunct professor of legislation at American University's Washington College of Law. In addition, I have been a member of the following organizations: the NARUC Executive, Natural Gas, and International Relations Committees; the Steering Committee of the U.S. Environmental Protection Agency / State of Michigan Relative Risk Analysis Project; the Federal Energy Regulatory Commission ("FERC") Task Force on Natural Gas Deliverability; and the International Advisory Council of Eisenhower Fellowships. In 1991, I traveled to Japan as an Eisenhower Fellow to study the Japanese utility structure, and, in 1992, I was a NARUC Fellow at the Kennedy School of Government at Harvard University.

Q. **HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE REGULATORY OR LEGISLATIVE BODIES?**

A. Since 1990, I have on numerous occasions testified before the U.S. Senate, the U.S. House of Representatives, federal courts and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric utility restructuring, utility securitization bonds, and nuclear energy. I also submitted Rebuttal Testimony in this docket.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

II. ***SUMMARY***

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

A. In this Settlement testimony, I discuss certain aspects of the settlement agreement that is under consideration by the Arizona Corporation Commission ("ACC" or "Commission") for review and approval. Specifically, from my perspective as a former state utility commission chairman and former head of the utility ratings practice at a major credit rating agency, I focus on the importance of settlements to the regulatory process and the benefits that can flow from them; the reasonableness of the 10.25% return on equity provision included within this settlement agreement; and the reaction of the Wall Street financial community, which generally appeared to view the settlement as a constructive resolution of the issues pending within the rate case, but also had some concern about the settlement's immediate impact on APS' financial condition. Finally, I conclude by explaining why I believe that approval of the settlement would represent a positive step for the regulatory environment within Arizona and why such approval could have a positive effect on the credit profiles of other regulated utilities operating within the Commission's jurisdiction.

III. *IMPORTANCE OF REGULATORY SETTLEMENTS*

Q. BASED ON YOUR EXPERIENCE AS A STATE REGULATOR AS WELL AS YOUR TENURE AT FITCH, DO YOU HAVE AN OPINION AS TO THE VALUE OF SETTLEMENTS TO THE REGULATORY PROCESS?

A. Yes I do. I have always believed that, in the context of a contested proceeding, if a settlement could be achieved among truly adversarial parties representing diverse interests, such an agreement would hold out a strong likelihood of representing a fair resolution of the contested proceeding. If the adversarial relationships of the parties are sufficient to ensure that all reasonable points of view will be represented in negotiations, the end result will in the vast majority of cases represent good public policy. While I was Chairman of the MPSC, the presence of MPSC staff at the negotiating table along with utility personnel and residential, commercial and industrial consumer interests provided me with substantial comfort that the end result would likely be better than any resolution the MPSC would impose upon the parties.

Q. WHY IS THAT?

A. Litigation tends to frame and present issues in terms of "either/or." Compromise or alternative resolutions are not usually offered for fear that they would detract from a party's litigation positions. Yet it is precisely these sorts of compromises and alternatives that quite often represent both the fairest and most constructive solution to complex problems. Also, in the context of a litigated rate case, the battle over the large economic issues (e.g., ROE or rate base) tends to obscure the concerns of parties such as low-income consumers or environmental groups not possessing the resources of, say, the utility or staff. On the other hand, these same parties can play an important and constructive role in settlement negotiations, as was evident in this case.

Q. WAS YOUR TRACK RECORD AT THE MPSC WITH REGARD TO SETTLEMENTS CONSISTENT WITH THE POINT OF VIEW YOU HAVE EXPRESSED HERE?

A. Yes, very much so. The most pressing issues I faced during my six years as a Commissioner and then Chairman at the MPSC were the financial condition of the state's two largest utilities, one electric (Detroit Edison) and the other electric and gas (Consumers Power), and the resulting effect on customers and the prospects for reliable service. Detroit Edison was reeling financially from construction expenditures at its Fermi nuclear plant and Consumers Power's abandonment of its Midland nuclear facility had placed it in a position where, without extraordinary rate relief, it likely would have had to file for bankruptcy.

In 1988, the MPSC approved a five-year rate settlement agreement for Detroit Edison that allowed the company to return to a degree of financial health during the term of the agreement and thereafter. With regard to Consumers Power, parties to a number of proceedings related to the abandonment of the Midland nuclear plant and its transition to a cogeneration facility negotiated during virtually my entire six-year tenure on the MPSC before bringing to the MPSC a global settlement of pending issues. The MPSC's approval of that major settlement agreement allowed Consumers Power to also return to financial health. While these were the two most important settlements approved during my tenure, there were many other regulatory settlements that the MPSC also reviewed and approved during my time as a commissioner.

Q. BASED ON THAT HISTORY, WHAT IS YOUR VIEW OF SUCH SETTLEMENT AGREEMENTS?

A. I am a strong proponent of regulatory staff working with regulated utilities and customer intervenor groups to effectuate settlements for consideration by public utility commissions. As the MPSC said in Consumers Power Co., 126 PUR4th 170 (Mich.PSC, 1991), a result devised by the parties to a case was "more likely to fit their needs and circumstances," while conserving "the scarce resources of the parties and the [MPSC]." This is especially the case where, as the ACC is doing here, a hearing is convened to allow the regulators independently to consider evidence to ensure that the public interest is being served if the agency were to approve the settlement.

Other key state utility commissions hold the same view. "There is a strong public policy in California favoring settlement in utility cases"[1] and, in my experience, the same point of view is held by the New York Public Service Commission.

Q. HOW DOES THE SEQUENCE OF EVENTS IN THIS PROCEEDING LEADING UP TO THE SETTLEMENT AGREEMENT ALIGN WITH YOUR VIEWS ON SETTLEMENT AGREEMENTS?

A. I think they line up well. I thought the letters provided by members of the Commission encouraging the parties to explore settlement options, either on a complete or partial basis, were a good idea and wholly consistent with the mindset of my MPSC colleagues and myself.

In addition, having reviewed the record in this proceeding, I believe that the public interest was protected by the substantial diversity of opinion within

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[1] Leonard Saul Goodman, The Process of Ratemaking (Vienna, VA: Public Utilities Reports, Inc., 1998) p.87.

the many parties' filed testimony as well as the differing interests they are charged with representing on a daily basis. Indeed, a neutral observer, "The Arizona Republic," described the parties that negotiated the settlement agreement as a "truly mixed bag of folks who managed to find common ground [, including] APS, Corporation Commission staff, a consumer watchdog office, private companies and environmentalists [who] haggled over the terms for five months."[2] Even Strategic Energy, an APS competitor, publicly praised the proposed rate case settlement as "a major boost to the state's open access market."[3]

APS witness Steve Wheeler provides a detailed overview of the settlement process. *See* Settlement Testimony of Steve Wheeler, at 28-30. That description and my review of the record, taken as a whole, demonstrate that the sequence of events leading up to the settlement agreement were consistent with good regulatory policy and procedures and the wide range of parties signing the agreement provides significant evidence that the public interest is embodied within the settlement agreement's terms. Accordingly, I believe that the ACC should place substantial weight on the rate case settlement agreement pending before it. After a hearing to ensure that neither substantive nor procedural irregularities indicating a denial of

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[2] "Light It Up!," The Arizona Republic, August 25, 2004, www.azcentral.com.

[3] "APS Settlement May Boost Competition in Arizona, Strategic Says," Platts Commodity News, August 27, 2004.

due process exist, I encourage the Commission to approve the agreement as negotiated. And, similarly, I caution that, if the agreement were to be rejected by the Commission without a rationale that the parties viewed to be at least arguably valid, such action would send a very negative message. Not only would the Wall Street financial community communicate a negative message to its constituencies – all of whom are important to APS' day-to-day financial operations, but the almost two dozen parties that labored for five months to achieve the agreement would likely never put in that kind of effort again to attempt to resolve key regulatory issues outside an adversarial contested case process.

Q. HOW WOULD YOU HAVE REACTED TO AN ACC REJECTION WHILE YOU WERE AT FITCH?

A. Prior to such rejection, I would have already communicated to both the Fitch utility team and also the debt investor community that the settlement agreement, based on its nearly unanimous support, was likely to be found in the public interest and that I expected the ACC to approve it. After disapproval, I would communicate to those same groups that I believed a major opportunity for constructive regulatory action had been missed.

IV. *REASONABLENESS OF THE RETURN ON EQUITY PROVISION*

Q. DO YOU HAVE AN OPINION AS TO WHETHER THE 10.25% RETURN ON EQUITY THAT HAS BEEN NEGOTIATED BY THE PARTIES IS REASONABLE?

A. Yes I do. While some degree of variations in risk exist between particular states or regions due to special circumstances within those locales, I believe there is sufficient similarity in the overall risk profile of the entire U.S. regulated utility sector to draw parallels among return on equity findings among all state utility commissions. To allow such assessment to be easily made, Regulatory Research Associates, a respected regulatory analysis firm based in Jersey City, NJ, periodically publishes such comparisons. I have included RRA's most recent report on "Major Rate Case Decisions: January – June 2004," issued on July 8, 2004, as an attachment to my testimony (SMF-1-S).

Q. WHAT DOES RRA'S DATA SHOW?

A. For the first six months of 2004, the average electric equity return authorized by state utility commissions was 10.63% based upon eight rate case decisions. The range of returns spanned from 12% at the top end to 10.25% at the bottom. The median of the eight results is 10.50%. In addition, focusing solely on the second quarter of 2004, there were five return on equity determinations: two at 10.50% and three at 10.25%.

Q. BASED UPON THIS DATA, DO YOU HAVE AN OPINION ABOUT THE 10.25% RETURN ON EQUITY PROVISION INCLUDED WITHIN THE SETTLEMENT?

A. Yes I do. While I have noted the potential for regional and individual utility variations, I see that the eight return on equity determinations came from states as varied in demographics and location as Wisconsin, Nevada, Wyoming, Kentucky, Indiana and Idaho. From my experience as a state regulator and bond rater, I am comfortable with this sample set of locales and results as a rough comparable benchmark. Based upon the return on equity average and median I calculated for the first half of 2004, as well as the most recent second quarter 2004 results – and supplemented by the fact that the settlement was negotiated by individuals representing all key utility and consumer interests, I believe that the 10.25% negotiated return on equity for APS represents the lower boundary of a reasonable result – actually at the bottom of the range of recent public utility commission determinations -- that merits the approval of the Commission.

V. *WALL STREET'S REACTION TO THE SETTLEMENT*

Q. HOW WOULD YOU CHARACTERIZE THE RATING AGENCIES' REACTION TO THE SETTLEMENT THAT WAS NEGOTIATED?

A. As one would expect from a settlement that resulted from negotiations that included a number of parties with a diverse range of interests, the rating agency community welcomed resolution of the contentious issues dividing the parties but had continuing concerns about APS' future financial condition. For example, Standard & Poor's ("S&P"), a key credit rating agency, described the rate case settlement agreement between APS and 21 parties as "constructive from a business risk perspective" but noted that it did "little to strengthen the utility's financial profile."[4]

S&P also stated that "the rate increase will not likely inject sufficient incremental revenue into the company to shore up a financial condition that is somewhat pressured at the current rating level." S&P also focused on the lessening of uncertainty for APS going forward as a positive aspect of the balance that was struck:

> From a business risk perspective,...the settlement would resolve a significant degree of uncertainty that has hovered over APS and its parent Pinnacle West Capital Corp....since the state of Arizona began restructuring the electric industry in the late 1990s,...most significantly [allowing] the utility to rate-base 1,790 MW of merchant capacity [owned by Pinnacle West Energy Corp].

Also, as I noted in my rebuttal testimony, credit rating agencies believe that a regulated utility's credit profile is strengthened when the company has access to a fuel and purchased power adjustment mechanism. S&P highlighted this aspect of the settlement agreement as well:

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[4] S&P Research: "Arizona Public Service's Proposed Rate Settlement Is Reasonably Constructive," August 20, 2004.

> [V]ery significantly, the settlement calls for the establishment of a fuel adjustment mechanism, which would include a sharing mechanism with ratepayers and be reset annually to track future fuel and purchased power expenses for subsequent recovery.

Finally, the modest impact of the settlement on APS' financial health is also illustrated by the fact that S&P and its competitors, Moody's and Fitch, have all maintained their Negative outlooks[5] on APS, indicating that the company will still have work to do to improve its financial situation, notwithstanding the 4.21% rate increase provided for within the settlement agreement. For example, on September 15, 2004, Moody's stated,

> In light of the recently proposed rate case settlement, it is unlikely that the rating would change in an upward direction in the near-term. Longer term the rating could be positively affected by an improvement in regulatory predictability, rate increases or cost savings that result in sustained increases in cash flow and reduced leverage.[6]

It is important to note that the goal I argued for in my rebuttal testimony -- maintenance of APS' credit ratings at investment grade levels – is supported by the settlement. I have reviewed the financial ratios included in APS witness Don Robinson's testimony and I believe that those measures are consistent with APS' current BBB corporate rating status.

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[5] A Negative outlook indicates that an issuing utility's current credit ratings may be lowered in the near to intermediate future timeframe, though it is not necessarily a precursor to a ratings change.

[6] Moody's Credit Opinion: "Arizona Public Service Company," September 15, 2004.

The Company's forecast for 2005 of total debt to total capital percentage of 56% and funds from operations to total debt measure of 17.9% are both slightly below the midpoint for the BBB category for a utility with a Business Profile of 5 (APS' current ranking). APS' funds from operations interest coverage would be 3.7x (times) in 2005, at the upper end of the BBB category. These measures taken together equate with APS' current rating level.

While S&P justifies its Negative outlook by referring to "APS' pressured financial profile that the settlement agreement does not appear to address to any meaningful degree," the rating agency goes on to say that:

> [T]he support that the settlement, if approved largely as proposed, lends to the risk profile of [Pinnacle West's] overall operations may compensate for this weakness sufficiently for [S&P] to consider less stringent financial ratios as appropriate benchmarks for the ratings.

Thus, S&P's view is consistent with the assessment I state above.[7]

Q. WHAT WAS THE REACTION FROM THE EQUITY ANALYSTS?

A. Similar sentiments indicating the pros and cons of the settlement agreement were expressed by the major Wall Street equity analysts:

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[7] S&P reiterated its mixed views about the settlement on September 20, 2004: "The settlement is generally responsive to APS' requests, particularly the proposal to rate-base the merchant generating assets constructed in Arizona by its non-regulated affiliate [Pinnacle West] and to implement a fuel and purchased power mechanism. However, the rate increase falls nearly $100 million short of APS' original request of $175 million. As a result, it remains unclear whether the settlement, if implemented, is sufficiently constructive to support cash flow and capitalization ratios at levels consistent with current ratings." S&P Research Summary: "Arizona Public Service Co.," September 20, 2004.

Goldman Sachs: Pinnacle West "stock has been priced at levels implying a very constructive rate outcome and the news of a fairly modest rate increase (agreed to in the settlement) caused the stock to drop 3.1%....In our view, the settlement was a reasonable compromise...." (Goldman Sachs Research: "Pinnacle West Capital Corp.," August 19, 2004.)

Merrill Lynch: "While regulatory certainty and [Pinnacle West's] growth territory could merit a premium,...the rate case settlement initially looks to have fallen somewhat short in terms of earnings power." (Merrill Lynch Flash Note: "Pinnacle West Capital – Settlement News Priced-In, Downgrading to Neutral Following APS Rate Settlement," August 19, 2004.)

Morgan Stanley: "We believe settlement demonstrates a supportive regulatory action for [Pinnacle West]. But in such a fast growth territory, [Pinnacle West] needs a regulatory regime that will allow timely recovery of infrastructure investments." (Morgan Stanley Equity Research: "PNW Reaches Settlement in Major Rate Case," August 19, 2004.)

Credit Suisse First Boston: "We believe rate case resolution eliminates a large overhang and are attracted by [Pinnacle West's] underlying growth and regulatory visibility. However, we are concerned the market got ahead of itself recently...." (Credit Suisse

> First Boston Equity Research: "You Can't Always Get What You Want," August 19, 2004.)
>
> **Lehman Brothers**: "While we believe the proposed settlement is a favorable outcome for the company..., we would have preferred more cash increases as opposed to depreciation life adjustments which give up cash." (Lehman Brothers Equity Research: "Pinnacle West Capital – Right in Time," August 19, 2004.)
>
> **UBS**: "We think the agreement is adequate and timing beneficial as rates could be in place before the end of the year...with much improved visibility on this high profile case, we believe [Pinnacle West's] overall risk profile has declined..." (UBS Investment Research: "Pinnacle West Capital Co.: Uncertainty Abating," August 19, 2004.)

Q. WHAT DO YOU CONCLUDE FROM THESE STATEMENTS?

A. These comments reflect that there is no shortage of opinions from Wall Street as to whether the APS rate case settlement is a positive or negative development, or a little of both. It is abundantly clear that the agreement incorporates provisions that fall within both of these categories, but that the overall feeling within the financial community is that approval of the settlement by the Commission would be a constructive step. To my mind, these comments provide further evidence that the settlement agreement has struck a fair balance among APS and the other 21 parties to the proceeding.

Q. WHY ARE THESE FINANCIAL COMMUNITY COMMENTS RELEVANT TO THE COMMISSION'S CONSIDERATION OF THE SETTLEMENT?

A. As I described in my earlier rebuttal testimony, the views of Wall Street equity analysts and the determinations of credit rating agencies are crucial for the ongoing operations of a regulated utility. It would not be an overstatement to say that APS' ability to access capital – both equity and long-and-short-term debt – on reasonable terms on a timely basis is within the discretion of the entities quoted above. When you have capital needs measured in the billions of dollars, as APS does, and an obligation to serve the public with an essential commodity, like APS, such access is vital. Accordingly, I believe that the Commission should give serious consideration to these views as well as the parties' determination that the settlement agreement provides a fair distribution of the quantitative and qualitative benefits and detriments within the rate case and represents an appropriate resolution to the proceeding.

VI. *__ARIZONA REGULATORY ENVIRONMENT__*

Q. ASIDE FROM THE EFFECTS ON APS OF RESOLVING THE UNCERTAINTIES FACING IT WITHIN THE RATE CASE AND THUS STABILIZING ITS CREDIT PROFILE, DO YOU FORESEE ANY OTHER POTENTIAL POSITIVE CREDIT IMPLICATIONS

RESULTING FROM APPROVAL OF THE SETTLEMENT AGREEMENT BY THE COMMISSION?

A. Yes I do. As I previously explained in my Rebuttal Testimony, an important element of the credit evaluation of public utilities is an assessment of regulation. For that reason, I noted that credit rating analysts would closely monitor this proceeding to see whether an improving trend would become evident. In my mind, and based upon the Wall Street reactions I just noted, review and approval of the settlement in this proceeding would be viewed as a constructive step by the financial community. Continuation of such positive movement with regard to regulatory policy and procedure within Arizona could have favorable credit rating implications, not only for APS, but potentially for all utilities subject to the rate making authority of the Commission.

Q. **CONVERSELY, HOW WOULD REJECTION OF THE SETTLEMENT BE PERCEIVED BY WALL STREET?**

A. As I discussed earlier, I believe that the reaction would be distinctively negative. When a settlement has the kind of broad support you see here, and the near total absence of opposition, there is a clear expectation by the financial community that regulators – after careful consideration – will look favorably on such an agreement. Rejection of the settlement under these circumstances would, I believe, lead the financial community to echo my views were I still head of the Fitch utility team: a golden opportunity for positive regulatory progress in Arizona had been missed.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes it does.

Regulatory Study
July 8, 2004

MAJOR RATE CASE DECISIONS--JANUARY-JUNE 2004

For the first six months of 2004, the average electric equity return authorization by state commissions was 10.63% (eight determinations), down modestly from the 10.97% average in calendar-2003. The average gas equity return authorization for the first two quarters of 2004 was 10.84% (seven determinations), down slightly from the 10.99% average in calendar-2003. During the first half of 2004, there was one telecommunications equity return authorization, 10%.

In recent years there have been relatively few equity return determinations. The reasons include: industry restructuring/intensifying competition; more efficient utility operations; technological improvements; relatively low inflation and interest rates; accelerated depreciation/amortization programs; the increased utilization of "black box" settlements; and, the use of performance, or price-based, regulation. As the number of equity return determinations has declined, the average authorized return now has less of a relationship to the return that the typical electric, gas, or telecommunications company has an opportunity to earn. In addition, electric industry restructuring in many states has led to the unbundling of rates, with commissions authorizing return and revenue requirement parameters for distribution operations only, thus complicating data comparability. The tables included in this study are extensions of those contained in the January 22, 2004 Regulatory Study entitled *Major Rate Case Decisions--January 2002-December 2003--Supplemental Study*. Refer to that report for information concerning individual rate case decisions that were rendered in 2002 and 2003.

The table on page 2 shows annual average equity returns authorized since 1994, and by quarter since 1998, in major electric, gas, and telecommunications rate decisions, followed by the number of determinations during each period. The tables on page 3 present the composite industry data for items in the chronology of this and earlier reports, summarized annually since 1994, and quarterly for the most recent six quarters. The individual electric, gas, and telecommunications cases decided in the first six months of 2004 are listed on pages 4 and 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the adopted capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. A case is generally considered "major" if the rate change initially requested was $5 million or greater, or the authorized rate change was at least $3 million. Gas rate requests that are considered in conjunction with major electric requests are recorded and reported as individual cases, regardless of size.

Average Equity Returns Authorized January 1994 - June 2004

(Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities	Telephone Utilities
1994	Full Year	11.34 (31)	11.35 (28)	11.81 (11)
1995	Full Year	11.55 (33)	11.43 (16)	12.08 (8)
1996	Full Year	11.39 (22)	11.19 (20)	11.74 (4)
1997	Full Year	11.40 (11)	11.29 (13)	11.56 (5)
1998	1st Quarter	11.31 (4)	— (0)	11.30 (1)
	2nd Quarter	12.20 (1)	11.37 (3)	— (0)
	3rd Quarter	11.80 (2)	11.41 (3)	— (0)
	4th Quarter	11.83 (3)	11.69 (4)	— (0)
1998	Full Year	11.66 (10)	11.51 (10)	11.30 (1)
1999	1st Quarter	10.58 (4)	10.82 (3)	13.00 (1)
	2nd Quarter	10.94 (4)	10.82 (3)	— (0)
	3rd Quarter	10.63 (8)	— (0)	— (0)
	4th Quarter	11.08 (4)	10.33 (3)	— (0)
1999	Full Year	10.77 (20)	10.66 (9)	13.00 (1)
2000	1st Quarter	11.06 (5)	10.71 (1)	11.50 (1)
	2nd Quarter	11.11 (2)	11.08 (4)	— (0)
	3rd Quarter	11.68 (2)	11.33 (5)	11.25 (1)
	4th Quarter	12.08 (3)	12.50 (2)	— (0)
2000	Full Year	11.43 (12)	11.39 (12)	11.38 (2)
2001	1st Quarter	11.38 (2)	11.16 (4)	— (0)
	2nd Quarter	10.88 (2)	10.75 (1)	— (0)
	3rd Quarter	10.78 (8)	— (0)	— (0)
	4th Quarter	11.50 (6)	10.65 (2)	— (0)
2001	Full Year	11.09 (18)	10.95 (7)	— (0)
2002	1st Quarter	10.87 (5)	10.67 (3)	— (0)
	2nd Quarter	11.41 (6)	11.64 (4)	— (0)
	3rd Quarter	11.06 (4)	11.50 (3)	— (0)
	4th Quarter	11.20 (7)	10.78 (11)	— (0)
2002	Full Year	11.16 (22)	11.03 (21)	— (0)
2003	1st Quarter	11.47 (7)	11.38 (5)	— (0)
	2nd Quarter	11.16 (4)	11.36 (4)	— (0)
	3rd Quarter	9.95 (5)	10.61 (5)	— (0)
	4th Quarter	11.09 (6)	10.84 (11)	— (0)
2003	Full Year	10.97 (22)	10.99 (25)	— (0)
2004	1st Quarter	11.00 (3)	11.10 (4)	10.00 (1)
	2nd Quarter	10.40 (5)	10.50 (3)	— (0)
2004	Year-To-Date	10.63 (8)	10.84 (7)	10.00 (1)

Electric Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.29 (30)	11.34 (31)	45.15 (30)	1,116.9 (40)
1995	Full Year	9.44 (30)	11.55 (33)	45.90 (30)	455.7 (43)
1996	Full Year	9.21 (20)	11.39 (22)	44.34 (20)	-5.6 (38)
1997	Full Year	9.16 (12)	11.40 (11)	48.79 (11)	-553.3 (33)
1998	Full Year	9.44 (9)	11.66 (10)	46.14 (8)	-429.3 (31)
1999	Full Year	8.81 (18)	10.77 (20)	45.08 (17)	-1,683.8 (30)
2000	Full Year	9.20 (12)	11.43 (12)	48.85 (12)	-291.4 (34)
2001	Full Year	8.93 (15)	11.09 (18)	47.20 (13)	14.2 (21)
2002	Full Year	8.72 (20)	11.16 (22)	46.27 (19)	-475.4 (24)
2003	1st Quarter	9.07 (6)	11.47 (7)	49.94 (5)	48.2 (7)
	2nd Quarter	9.07 (4)	11.16 (4)	49.46 (4)	116.2 (5)
	3rd Quarter	8.22 (5)	9.95 (5)	46.09 (5)	69.6 (5)
	4th Quarter	9.07 (5)	11.09 (6)	52.17 (5)	210.4 (5)
2003	Full Year	8.86 (20)	10.97 (22)	49.41 (19)	444.4 (22)
2004	1st Quarter	8.94 (3)	11.00 (3)	44.94 (3)	-711.2 (5)
	2nd Quarter	7.64 (5)	10.40 (5)	45.27 (5)	627.0 (10)
2004	Year-To-Date	8.13 (8)	10.63 (8)	45.15 (8)	-84.2 (15)

Gas Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.51 (32)	11.35 (28)	48.12 (27)	422.9 (42)
1995	Full Year	9.64 (16)	11.43 (16)	49.98 (15)	-61.5 (31)
1996	Full Year	9.25 (23)	11.19 (20)	47.69 (19)	193.4 (34)
1997	Full Year	9.13 (13)	11.29 (13)	47.78 (11)	-82.5 (21)
1998	Full Year	9.46 (10)	11.51 (10)	49.50 (10)	93.9 (20)
1999	Full Year	8.86 (9)	10.66 (9)	49.06 (9)	51.0 (14)
2000	Full Year	9.33 (13)	11.39 (12)	48.59 (12)	135.9 (20)
2001	Full Year	8.51 (6)	10.95 (7)	43.96 (5)	114.0 (11)
2002	Full Year	8.80 (20)	11.03 (21)	48.29 (18)	303.6 (26)
2003	1st Quarter	8.97 (4)	11.38 (5)	50.69 (4)	35.9 (6)
	2nd Quarter	9.09 (3)	11.36 (4)	50.32 (3)	14.2 (5)
	3rd Quarter	8.54 (4)	10.61 (5)	45.74 (4)	89.5 (6)
	4th Quarter	8.64 (11)	10.84 (11)	51.06 (11)	120.5 (13)
2003	Full Year	8.75 (22)	10.99 (25)	49.93 (22)	260.1 (30)
2004	1st Quarter	8.52 (4)	11.10 (4)	45.61 (4)	82.3 (7)
	2nd Quarter	8.24 (3)	10.50 (3)	46.98 (3)	95.9 (9)
2004	*Year-To-Date*	8.40 (7)	10.84 (7)	46.20 (7)	178.2 (16)

Telephone Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.91 (12)	11.81 (11)	57.46 (11)	-236.6 (16)
1995	Full Year	9.81 (8)	12.08 (8)	55.02 (7)	-264.0 (14)
1996	Full Year	9.65 (2)	11.74 (4)	56.00 (2)	-348.2 (11)
1997	Full Year	9.57 (5)	11.56 (5)	55.84 (5)	-154.4 (7)
1998	Full Year	9.37 (1)	11.30 (1)	52.00 (1)	-323.3 (13)
1999	Full Year	11.34 (1)	13.00 (1)	66.90 (1)	-570.1 (19)
2000	Full Year	9.52 (2)	11.38 (2)	56.59 (2)	-390.4 (14)
2001	Full Year	9.61 (1)	— (0)	— (0)	-130.0 (8)
2002	Full Year	— (0)	— (0)	— (0)	7.7 (4)
2003	1st Quarter	— (0)	— (0)	— (0)	— (0)
	2nd Quarter	— (0)	— (0)	— (0)	-27.6 (1)
	3rd Quarter	— (0)	— (0)	— (0)	-35.0 (1)
	4th Quarter	— (0)	— (0)	— (0)	— (0)
2003	Full Year	— (0)	— (0)	— (0)	-62.6 (2)
2004	1st Quarter	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)
	2nd Quarter	— (0)	— (0)	— (0)	— (0)
2004	Year-To-Date	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)

* Number of observations each period indicated in parentheses.

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/13/04	Madison Gas and Electric (WI)	9.37 (G)	12.00	55.91	12/04-A	11.7
2/18/04	United Illuminating (CT)	---	---	---	---	5.2 (B)
2/26/04	Pacific Gas and Electric (CA)	---	---	---	---	-799.0 (B)
3/2/04	PacifiCorp (WY)	8.42	10.75	44.95	9/02-YE	22.9
3/26/04	Nevada Power (NV)	9.03	10.25	33.97	5/03-YE	48.0
2004	***1ST QUARTER AVERAGES/TOTAL***	**8.94**	**11.00**	**44.94**		**-711.2**
	OBSERVATIONS	**3**	**3**	**3**		**5**
4/13/04	Aquila-MPS (MO)	---	---	---	---	14.5 (B)
4/13/04	Aquila-L&P (MO)	---	---	---	---	3.3 (B)
5/5/04	Wisconsin Electric Power (WI)	---	---	---	12/04-A	59.0
5/18/04	PSI Energy (IN)	7.30	10.50	44.44 *	9/02-YE	107.3
5/20/04	Rochester Gas & Electric (NY)	---	---	---	---	7.4 (1)
5/25/04	Idaho Power (ID)	7.85	10.25	45.97	12/03-A	25.3
5/27/04	Pacific Gas & Electric (CA)	---	---	---	12/03-A	274.0 (B)
5/27/04	Sierra Pacific Power (NV)	9.26	10.25	35.77	7/03-YE	46.7 (B)
6/30/04	Kentucky Utilities (KY)	7.00 (G)	10.50	51.58	9/03-YE	46.1 (B,2)
6/30/04	Louisville Gas and Electric (KY)	6.79 (G)	10.50	48.60	9/03-YE	43.4 (B,3)
2004	***2ND QUARTER AVERAGES/TOTAL***	**7.64**	**10.40**	**45.27**		**627.0**
	OBSERVATIONS	**5**	**5**	**5**		**10**
2004	***YEAR-TO-DATE AVERAGES/TOTAL***	**8.13**	**10.63**	**45.15**		**-84.2**
	OBSERVATIONS	**8**	**8**	**8**		**15**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/13/04	AmerenUE (MO)	---	---	---	---	13.0 (B)
1/13/04	Madison Gas and Electric (WI)	9.37 (G)	12.00	55.91	12/04-A	1.0
1/13/04	Public Service Co. of New Mexico (NM)	8.16	10.25	47.77	9/02-YE	22.0 (B)
1/21/04	Aquila (NE)	---	---	---	---	6.2 (I,B)
2/9/04	City Gas Co. of Florida (FL)	7.36	11.25	36.77 •	9/04-A	6.7 (I)
2/19/04	Wisconsin Gas (WI)	---	---	---	12/04-A	26.0
3/16/04	Southwest Gas (CA)	9.17	10.90	42.00	12/03-A	7.4 (4)
2004	***1ST QUARTER AVERAGES/TOTAL***	**8.52**	**11.10**	**45.61**		**82.3**
	OBSERVATIONS	**4**	**4**	**4**		**7**
4/5/04	Interstate Power and Light (MN)	9.05	11.00	47.15	12/02-A	0.2 (I)
4/22/04	Aquila Networks-MPS (MO)	---	---	---	---	2.6 (B)
4/22/04	Aquila Networks-L&P (MO)	---	---	---	---	0.8 (B)
5/20/04	Rochester Gas & Electric (NY)	---	---	---	---	7.2 (1)
5/25/04	TXU-Gas (TX)	8.26	10.00	49.80	12/02-YE	12.0
5/27/04	Pacific Gas & Electric (CA)	---	---	---	12/03-A	52.0 (B)
6/23/04	Northwest Natural Gas (WA)	---	---	---	---	3.5 (B)
6/30/04	Southern Indiana Gas and Electric (IN)	7.41	10.50 (B)	44.00 •	9/03-YE	5.7 (B)
6/30/04	Louisville Gas and Electric (KY)	---	---	---	---	11.9 (B)
2004	***2ND QUARTER AVERAGES/TOTAL***	**8.24**	**10.50**	**46.98**		**95.9**
	OBSERVATIONS	**3**	**3**	**3**		**9**
2004	***YEAR-TO-DATE AVERAGES/TOTAL***	**8.40**	**10.84**	**46.20**		**178.2**
	OBSERVATIONS	**7**	**7**	**7**		**16**