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Application
E-01345A-11-0224

PART 3 OF 3
BAR CODE # 0000126068

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PART 1 OF 3 BAR CODED #0000126066

PART 2 OF 3 BAR CODED #0000126067

Daniel T. Froetscher

TESTIMONY OF DANIEL T. FROETSCHER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

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TESTIMONY OF DANIEL T. FROETSCHER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Daniel T. Froetscher. I am Arizona Public Service Company's (APS or Company) Vice President for Energy Delivery and my address is 400 North 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I earned a Bachelor of Applied Sciences degree and a Bachelor of Arts degree from Northern Arizona University. I began employment with APS in 1980 and have served in numerous management and leadership capacities during my tenure with the Company, including as the Southeast Division Manager and the General Manager of Rural Arizona Delivery. I was made Vice President for Energy Delivery in October 2008.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am responsible for all facets of energy delivery throughout APS's 35,000 square-mile service territory, including operation and maintenance of the company's transmission and distribution system, service restoration, new construction and planning.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes the key functions of the Energy Delivery organization and how they contribute to the provision of safe, reliable and cost-effective service to APS customers. I identify representative programs, initiatives and expenditures made during the 2010 test year, discuss APS's overall performance in key operational areas and describe how such programs and performance benefit APS customers and communities. Portions of my testimony also bridge into the Customer Service organization, a part of the Company primarily

responsible for direct interactions with customers, such as handling customer inquiries and transactions, reading meters and preparing monthly billing statements. My testimony concludes by describing Energy Delivery's planned capital expenditures for the 18-month post-Test Year period and supports the following pro-forma adjustments: Emergency/Storm, Asset Management, Customer Growth, Smart Grid, Community Power Project, Other Customer & Technology, AMI Meters and IT & Facilities.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Since APS's last rate case, Energy Delivery performed to the highest standards in the key operational areas of safety, reliability, compliance, meeting customer demands for new service and technology and responding to government mandates. Energy Delivery improved already high levels of safety, reliability and customer satisfaction. And it effectively planned and executed the deployment of new technologies and investments in critical and essential distribution infrastructure. Importantly, Energy Delivery performed at this level while managing the associated costs. Indeed, while the performance measures noted above have improved, Energy Delivery has steadily reduced its capital and operations and maintenance (O&M) spending since the Company's last rate case.

The ever present need to provide safe and reliable electric service lies at the core of Energy Delivery's mission and requires significant investment in APS's distribution system. APS is mindful of the observations in the Liberty Consulting Group's February 2011 Benchmarking Study ("Study"). There, Liberty made clear that diminishing reliability performance trends across the industry are "...the direct result of yesterday's lack of investment."[1] Although sacrificing

[1] Study, p. 10.

distribution investments may result in short term lower rates, the risks to reliability and safety, as well as the prospect of overall higher rates in the long term, render such a decision unwise.

Furthermore, although Arizona's current pace of economic growth is slower than the historical norm, this will not always be the case. Electrical infrastructure is not a short term proposition. Careful planning and sufficient investment today and tomorrow will ensure that Arizona is not caught flatfooted when growth does escalate. Indeed, without such distribution investment, growth may have nowhere to take root. Any perceived lack of confidence in a community's underlying infrastructure—including its electrical infrastructure—would likely deter businesses from expanding or relocating to Arizona. Continued capital investment in the distribution infrastructure—upgrading facilities to meet the needs of customers for today and tomorrow—is critical. APS has a careful and considered plan in place that reflects appropriate levels of investment to support an expanding Arizona economy.

III. INTRODUCTION TO APS ENERGY DELIVERY

Q. WHAT IS ENERGY DELIVERY?

A. Energy Delivery is a business unit within APS responsible for delivering electricity from generating stations to customers in a safe, reliable, affordable and environmentally-friendly manner. Functional areas include Asset Management and Planning, Construction, Operations and Maintenance. Energy Delivery is responsible for APS's transmission and distribution systems.

Q. PLEASE DESCRIBE THE SERVICE TERRITORY FOR WHICH ENERGY DELIVERY IS RESPONSIBLE.

A. APS's service territory encompasses almost 35,000 square miles of distribution service area, overlaying all or part of 11 of the state's 15 counties. In 2008, the Edison Electric Institute ranked APS as having the 4th largest service territory out of 155 ranked utilities. Within this area, APS serves more than 1.1 million retail customers using infrastructure that includes more than 28,000 miles of distribution lines, over 6,000 miles of transmission lines, 417 substations, 295,000 transformers and more than 500,000 power poles and structures. Although often thought of as urban, APS's service territory is in fact a mix of urban and rural communities. With one of the lowest customer densities in the United States—ranking 36th out of the 40 utilities benchmarked by the Liberty Consulting Group[2]—and a large service territory that includes a variety of elevations, terrain and climate, Energy Delivery encounters a multitude of operational and cost challenges.

IV. PERFORMANCE IN KEY OPERATIONAL AREAS

Q. YOU MENTIONED THE IMPORTANCE OF SAFETY. PLEASE ELABORATE.

A. Safety has long been a priority at APS and is identified as a Core Value within the Company's Strategic Framework. Many of our employees work with electric lines or facilities that are either energized or could become energized in an instant. Further, we have a responsibility to our customers and the general public to provide electric service in a safe, responsible fashion. While the present business and regulatory climate pushes greater efficiency and productivity, these added demands cannot come at the expense of safety; one accident is too many. Therefore, we begin and end every day—and every customer connection and

[2] Study, p. 8.

interaction—with safety foremost and continue to emphasize a zero-accident culture.

Q. PLEASE PROVIDE SOME EXAMPLES OF SAFETY-RELATED INITIATIVES THAT HELP DRIVE SAFETY PERFORMANCE?

A. Investment in safety—both employee and public safety—is no small endeavor. Employee safety is rooted in a number of key areas: employee training and skill development, effective policy development and execution, root cause analysis and other essential tools designed to train, instruct and enhance organizational performance.

Journeyman lineman and journeyman electrician employees, for example, participate in regular training programs throughout the year. These may be programs designed to increase skill sets (e.g., hot stick training), improve crew safety, efficiency and planning (e.g., Tailboard and Crew Foreman training), or familiarize field personnel with new equipment and procedures (e.g., Lineman's Academy and grounding procedures). Other programs are designed to deal with environmental hazards. For example, we provide annual dog bite prevention training for meter reading and customer service personnel; and, in an organization that puts over 18.6 million miles annually on the road serving its customers, we routinely review and practice defensive driving techniques. Energy Delivery also has an aggressive Fatigue Management program, essentially mandating that its employees, after a certain threshold of hours working on the job, be relieved from further work responsibilities and secure mandatory rest—a program that has enhanced both employee and public safety considerably. The number and scope of employee safety-related programs and initiatives are impressive and founded in providing employees the right training, tools and structure to keep themselves safe.

We take our responsibilities interacting with the public seriously as well. APS has three full-time Public Safety Consultants whose principal responsibilities are to interface with contractors, builders and the general public on issues that present any prospective risk or concern. Examples include working through clearance issues between buildings and overhead power lines, instructing and guiding contractors on proper adherence to state Blue Stake laws, Occupational Safety and Health Administration (OSHA) clearance requirements, or changes and modifications to regulations involving overhead cranes and safe working distances from energized electrical equipment.

Additional public outreach and training occurs through our "Weenie Wagon", a mobile, instructional device designed to demonstrate the hazards of electricity to schools, youth groups, fire and police agencies, etc. Annually, APS makes more than 120 presentations to more than 6,000 attendees, advocating for greater understanding and respect for the dangers of electricity.

Finally, several company initiatives serve a dual purpose of increasing public safety and improving service reliability. For example, APS inspects aged wood poles at routine intervals for termite damage and wood rot, and either replaces suspect poles, or "stubs" them with an adjacent, supporting pole. APS also periodically inspects pad-mounted equipment, including switching cabinets and transformers, and replaces damaged, leaking or rusted equipment. And APS annually inspects all of its 28,000 miles of distribution infrastructure, looking for potential key public safety and reliability-related issues and making repairs.

Q. WHAT ARE THE RESULTS OF ENERGY DELIVERY'S SAFETY EFFORTS?

A. Clearly, no single program or initiative is solely responsible for driving safety improvement. Rather, it is the combination of programs, initiatives,

communications and heightened awareness that has helped Energy Delivery improve its overall safety performance.

In connection with our emphasis on zero accidents (a part of APS's corporate "Got Safety? Get Zero" safety program), Energy Delivery and Customer Service together experienced 44 OSHA recordable injuries in 2010, more than a 20% improvement over its previous best performance and reflecting a solid 2nd quartile performance within the industry when compared against 2009 EEI data. APS has enjoyed similar improvements in the number of Lost Work Time incidents and the number of Lost Work Time days recorded—both indications that the number and severity of injuries has decreased. Energy Delivery and Customer Service achieved this safety record by actively emphasizing safety at all levels. The strong and continued emphasis on eliminating safety risks caused by human performance, efforts towards eliminating unwanted events and strong management and employee commitment to safety have produced measurable results.

Q. WHAT ROLE DOES RELIABILITY PLAY IN ENERGY DELIVERY'S RESPONSIBILITIES?

A. Other than safety, strengthening reliability—which includes managing the assets associated with delivering energy to our customers and planning the infrastructure needed to do the same—is Energy Delivery's most important responsibility. Electricity is an essential public commodity, particularly in an age when so many technologies, especially information technologies, are dependent upon reliable electric service. Feedback from our customers and others is clear: reliable service helps drive customer satisfaction.

Reliable service requires investments in the existing distribution system that maintain, upgrade and expand the system across the state. Over time, equipment

reaches the end of its life, becomes obsolete or fails. Storms and unplanned third party events (such as vehicle accidents, wildfires, etc.) may also damage or destroy facilities. And new and upgraded utility infrastructure provides the additional capacity needed to meet the growth-related needs of businesses and communities. In each of these situations, Energy Delivery must repair, replace and/or upgrade equipment. Managing existing assets and effectively deploying new and upgraded assets in a cost-conscious manner to keep customer rates as low as possible is Energy Delivery's most complex challenge. It takes the innovation, imagination and engagement of our entire workforce to successfully balance these competing demands.

Q. WHAT ARE SOME OF THE MAINTENANCE PROGRAMS APS PERFORMS TO MAINTAIN OR IMPROVE RELIABILITY?

A. APS's strong reliability record results from its comprehensive maintenance and asset management programs. APS implements 39 programs annually to maintain and improve service reliability throughout the Company's entire distribution system. They include: (i) maintaining transformers, circuit breakers, and relays in substations; (ii) performing thermographic, acoustic and corona inspections of substation and distribution line equipment; and (iii) patrolling, repairing, refurbishing and replacing aged overhead and underground equipment and distribution line component parts. Let me provide specific examples.

Under one annual maintenance program, APS ranks all distribution feeders in its system and performs a thorough end-to-end line patrol. During the patrol, we perform maintenance as necessary, such as replacing broken or suspect cross-arms, insulators and poles. We further maximize the efficiency of these patrols by simultaneously inspecting the patrolled facilities for public safety hazards.

A related program involves replacing failed or failing underground cable. APS incurs millions of dollars every year responding to, trouble-shooting, and repairing cable faults on its system. In 2010, APS repaired 1,372 cable faults and replaced over 68 miles of underground cable. In 2011, APS anticipates spending approximately $13 million as part of its cable replacement program. Such work directly improves reliability. Over the past decade, the cable replacement program has reduced the average customer interruption frequency due to cable faults by nearly 61%.

Another activity includes adding wildlife protection guards to substation and distribution equipment. Adding these guards not only accomplishes their primary purpose of protecting wildlife, but it also helps eliminate outages.

Finally, distribution reliability depends upon an effective vegetation management and tree-trimming program. Vegetation has long been cited as one of the leading contributors to distribution system power outages. APS spends approximately $8 million annually on distribution level vegetation management, typically pruning or removing over 69,000 trees along 11,000 miles of overhead distribution.

Q. WHAT IMPACT HAVE ENERGY DELIVERY'S PROJECTS HAD ON RELIABILITY?

A. During the 2010 Test Year, APS maintained and improved upon its already strong history of reliable performance. Reliability is typically measured by using four standard industry metrics: (i) SAIFI (System Average Interruption Frequency Index)—a measure of the average number of interruptions a customer experiences in a year; (ii) SAIDI (System Average Interruption Duration Index)—a measure of the number of interrupted minutes a customer experiences in a year; (iii) CAIDI (Customer Average Interruption Duration Index)—a measure of the number of minutes an average service interruption lasts; and (iv)

MAIFI (Momentary Average Interruption Frequency Index)—a measure of the number of momentary interruptions a customer experiences in a year.

APS has achieved excellent performance under each of these metrics. For instance, APS has reduced its SAIFI by nearly 44% since 2001. Indeed, according to the Liberty Benchmarking Study, APS "rates far better than the industry average" on SAIFI and importantly, the "favorable gap is growing with time."[3] Similarly, Energy Delivery's pro-active maintenance programs have successfully reduced APS's SAIDI by nearly 33% since 2001. By comparison, the industry is seeing an upward trend (declining performance) in SAIDI ratings.[4] Moreover, APS's CAIDI rating is "far better than the industry average," with APS appearing in the top quartile of its industry peers.[5] Finally, although little historical data regarding MAIFI exists, APS nonetheless "remains well below the industry in the number of momentary outages."[6]

Q. PLEASE DESCRIBE APS'S RELIABILITY PERFORMANCE IN THE CONTEXT OF ITS INDUSTRY AND SERVICE AREA.

A. Liberty Consulting reported that "[w]e would of course expect APS to appear very favorably on a bulk, national basis because of its location."[7] Although I am not certain what that quote means, we believe that our large service territory, with a complex mix of some urban but mostly rural communities, presents a challenge larger than Liberty acknowledges. The Electric Power Research Institute (EPRI) in *Distribution Reliability Indices Tracking Within the United States, 2003*, noted that:

> Service territories generally include urban, suburban, or rural, or more likely, some combination of all of these. Distribution systems designed for rural areas are generally made up of smaller

[3] Study, p. 10.
[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] *Id.* at p. 9.

> substations with long radial circuits extending for many miles with little redundancy and few circuit ties. In contrast, systems in dense urban areas often deploy grid like systems and incorporate larger substations often with redundant facilities, shorter circuit lengths, and multiple feeds.
>
> Circuit distance alone is a substantial reliability issue; longer circuits have inherently more interruptions. This is due to the fact that more circuit length equates to more exposure and more potential points of failure.[8]

As the 36th least dense utility of the 40 utilities that Liberty Consulting benchmarked, APS is keenly aware of what EPRI calls a "substantial reliability issue" caused by long circuits and the reality of "little redundancy and few circuit ties." That APS nonetheless achieved the gains it did in SAIFI and SAIDI over the past decade, and resides in the 1st Quartile in terms of overall reliability, illustrates the strength of APS's commitment to reliability.

Q. CAN YOU IDENTIFY WHY APS'S RELIABILITY NUMBERS COMPARE SO FAVORABLY TO ITS INDUSTRY PEERS?

A. Yes, APS agrees with Liberty Consulting that "today's national reliability trends are a direct result of yesterday's lack of investment. Distribution has consistently been the least preferred area for investment and we are now seeing the results."[9] The reliability lesson taught by the Study is that investment in reliability today pays significant dividends tomorrow. APS invests not only in infrastructure to meet demand, but has also leveraged our comprehensive maintenance program to achieve this separation from the industry average.

Q. HAVE RELIABILITY IMPROVEMENTS CONTRIBUTED IN OTHER AREAS?

A. Yes, customer service, among others. APS places a high priority on service to its customers as evidenced by the continuous improvement in APS's J.D. Powers Reliability and Power Quality scores. J.D. Powers considers, among other

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[8] *Distribution Reliability Indices Tracking Within the United States*, EPRI, Palo Alto, CA: 2003.
[9] Study, p. 10.

factors, power quality and reliability in developing customer satisfaction data.[10] Liberty Consulting relied on J.D. Powers' customer satisfaction work in its Study, noting that "APS's position vis-à-vis other [investor owned utilities] is particularly interesting; the Company ranks 4th of 89. Also of interest is the trend of performance, which exhibits a steady improvement. APS has risen to mid-top quartile from mid-second quartile just three years ago."[11]

Q. DOES APS FACE ANY RELIABILITY CHALLENGES?

A. Yes, Liberty Consulting noted that although APS's "performance in minimizing the duration of an outage (CAIDI) is far better than the industry average, coming recently into the top quartile," "the Company's CAIDI is drifting upwards. This trend suggests that its restoration performance is slipping. Given its performance versus the industry, it is hard to criticize such a condition, but the Company may wish to examine this trend."[12] APS is mindful of this trend in CAIDI. I note, however, that our efforts to reduce the number of outages each customer experiences has resulted in decreasing the average annual duration of outages experienced by our customers (SAIDI) by over 33% during the last decade. In addition, the rise in APS's customer satisfaction rating, as demonstrated by J.D. Powers' ranking, suggests that APS's attention to outage frequency reflects its customers' values.

Q. PLEASE EXPLAIN HOW CUSTOMER GROWTH AND NEW DEMAND IMPACT ENERGY DELIVERY.

A. Although growth in Arizona has slowed over the past couple of years, most prognosticators anticipate that strong residential and commercial growth will return to the state. For an electric utility company, the return of strong growth presents several challenges, not all of which are immediately obvious. Clearly, as

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[10] Study, p. 9.
[11] *Id.* at p. 9.
[12] *Id.* at p. 10.

new customers request service, APS must be in a position to serve them in a safe, efficient and timely manner. Each new customer, however, places an "upstream" demand on the system. Although this demand is only incremental, and nearly invisible when looking at only one new customer at a time, it can have a tremendous impact in the aggregate. That impact primarily occurs on the servicing utility's distribution feeders, substations, capacitors, regulators and other equipment necessary to ensure that customers receive electricity of sufficient capacity and voltage to meet their needs. In many respects, the careful planning and investments APS makes today helps determine whether APS facilitates—or impedes—the coming resumption of economic growth in Arizona.

Q. PLEASE EXPLAIN SOME OF THE CAPITAL INVESTMENTS ENERGY DELIVERY MADE DURING THE TEST YEAR TO HELP MEET NEW DEMAND AND LAY THE FOUNDATION FOR ECONOMIC GROWTH RESUMING IN ARIZONA.

A. During 2010, APS added over 7,600 new residential and commercial meter sets to its system. To serve those new customers, APS's system needed approximately $19 million in new distribution transformers, along with $37 million in other service and extension costs, such as poles, conductors, switchgear, etc. Although the vast majority of new customer requests are smaller in scale, projects like the development of CityScape—a commercial project intended to help revitalize downtown Phoenix and create jobs—were constructed in 2010. Similarly, Energy Delivery extended service to the West Data Center of Cox Communications, a large local employer that in the past has provided significant contributions to Arizona's economy. Other new customer construction projects, large and small, are brought on line daily in communities across the state.

These new customers demand safe, reliable electric service. But the provision of such service is not limited solely to the local facilities needed to serve the new

customer. APS must make significant, sometimes less visible, investment upstream that accounts for the new load to continue providing the capacity, voltage support and operating flexibility all customers need. Downtown Phoenix, for example, benefitted from APS's development of the Evans Churchill substation, a critical infrastructure addition necessary to serve CityScape, TGen, and the expansion of facilities by the University of Arizona and Arizona State University. The addition of the Flores substation in the town of Congress alleviated incremental, but increasingly apparent, voltage and capacity problems stemming from the previous service feed from Wickenburg. And APS constructed the new Arica substation in Eloy in large part to provide improved service to the prison facility in that community. Each of these projects is absolutely essential to providing the reliable service APS customers expect and need in order to further their businesses and strengthen their communities.

Q. YOU MENTIONED THE IMPORTANCE OF MEETING CUSTOMER DEMANDS FOR NEW TECHNOLOGY, PLEASE ELABORATE.

A. Innovative technologies, such as smart meters, distributed renewable generation and electric/hybrid vehicles rank as a top priority for APS, our regulators and our customers. They offer tremendous potential benefits while posing a series of challenges for APS. For example, our customers are increasingly interested in electric/hybrid vehicles and the widespread deployment of distributed renewable generation, such as rooftop solar panels. Although APS is excited about both prospects, they place different demands on distribution systems that must be simultaneously considered and may present integration issues. Moreover, innovative technologies can dramatically increase the dynamic, two-way nature of a utility's power flow, potentially changing the day-to-day operational characteristics of a distribution system. Other challenges exist as well, including cost, cyber security and technology-related training for employees.

The benefits and challenges of such technologies raise many questions. How can we safely leverage these technologies to maximize cost and efficiency? Can they assist in power restoration? What dynamics do they create on a traditional power delivery system? Do they help offset traditional utility demand (e.g., solar) or add to it (e.g., electric vehicles), and if so, during what parts of the day? These and other similar questions are being considered throughout the electric industry. Although these technologies pose challenges, at APS, we also see them as opportunities to help us better understand the dynamics of and prepare for a changing technological landscape and electric grid. We look forward to exploring these opportunities with our customers.

Q. PLEASE GIVE AN EXAMPLE OF A NEW TECHNOLOGY THAT ENERGY DELIVERY HAS IMPLEMENTED?

A. APS has long focused on investing in new customer tools that empower customers to better manage their energy use. For instance, APS has offered Time of Use (TOU) pricing for our customers since the 1970s. APS currently has the highest penetration of TOU in the United States with over 50% of our customers on one of our TOU rates. In recent years, and in conjunction with implementing our Automated Metering Infrastructure (AMI or "smart meters"), TOU offerings have expanded in variety and scope, and now include super peak and peak event pricing.

Similarly, smart meters help our customers better manage their energy consumption and facilitate the use of power during off-peak times. Such tools help customers control their costs by enabling them to access information about their individual energy use and profiles via aps.com on a "day behind" basis. This represents an unprecedented degree of access to timely and relevant energy use information. Our customers seem to think so as well; more than 170,000 customers have created such web-based home profiles to date.

Smart technology offers even more opportunities for the future. The primary purpose of smart technology is to improve reliability, empower customers with the tools to better manage their energy use and facilitate the integration of alternative energy. It is a long-term effort that will improve system efficiency and help us maintain excellent reliability. For example, the ACC-approved Home Energy Information pilot involves deploying "smart thermostats" that permit direct control over certain appliances and display real-time energy consumption and pricing in customers' homes. With this voluntary pilot, APS seeks to not only assess customer interest in such technologies, but also evaluate how effectively these technologies change consumer behavior and electrical system demand. Over time and properly developed, APS believes that these kinds of tools will result in a more dynamic and efficient electrical system spurred largely by customer interest and behavioral changes.

Demand response is another area within which technology and innovation have converged to meet both customer and utility needs. APS's callable demand response program is designed to shed as much as 100 MW of load on a per-event basis through 2012 by incentivizing customers to change their behaviors during a specific event. This program offers pricing incentives to participants, and more than 3,300 commercial and industrial customers have enrolled to date. A parallel residential program similarly seeks to change energy consumption behaviors during callable events and has so far attracted more than 600 participants.

Q. YOU HAVE DESCRIBED A NUMBER OF TECHNOLOGICAL INITIATIVES THAT OFFER INCREASED INFORMATION AND CONTROL TO CUSTOMERS. WHAT IS HAPPENING FROM A TECHNOLOGY STANDPOINT ON YOUR SYSTEM?

A. APS has deployed innovative technology on its system with increasing frequency over the past few years. One of our most visible examples is the APS-developed Transformer Oil Analysis and Notification (TOAN) system. The TOAN system

monitors transformer oil data on a near real-time basis to evaluate and identify any potential abnormalities. Possessing this information so quickly lets the Company prevent otherwise catastrophic transformer fires. In fact, in the past two years, APS identified the need to take two major switchyard or substation transformers out of service before a failure occurred, permitting APS to actively manage system alternatives and take necessary action. The Edison Electric Institute (EEI) recognized APS's TOAN program in 2008 with its prestigious Edison Award, reflecting APS's outstanding contributions to the advancement of the electrical industry both nationally and worldwide.

APS's system is also becoming increasingly automated through the use of smart meters and other emerging technologies. In Flagstaff, APS continues to install a variety of different technologies ranging from automated switches to self-isolating devices to advanced communication systems. We anticipate that these technologies will provide substantial benefits to customers, principally in the area of reducing the duration and scope of power outages. Indeed, APS estimates that its customers have already experienced 500,000 fewer outage minutes due to self-isolating equipment that APS installed on two feeders in Flagstaff. In 2011, we will continue to monitor technology results in Flagstaff and will expand these technology demonstrations to a new pilot area in north Phoenix. APS plans other demonstration projects in the areas of volt-var optimization and distribution fault anticipation. And APS continues to integrate its smart meter outage notification capabilities with its Distribution Outage Management System for effective power outage reporting and more efficient and smarter outage response.

Flagstaff is also home to the Commission-approved Community Power Project. The Project involves installing on the same feeder both (i) an estimated 1.5 MW of residential and commercial rooftop and utility scale greenfield solar; and (ii)

500 kW of lithium-ion battery storage technology. The Project is intended to demonstrate the benefits and challenges associated with coupling high penetrations of distributed generation (solar) with distribution automation, smart meters and battery storage. In conjunction with the Department of Energy (DOE) and in part through a DOE grant, the project will result in a future High Penetration Solar Deployment study.

Finally, one should not lose sight of the tremendous success that APS has achieved in its distributed energy incentive programs. To date, more than 11,000 customers have participated, enabling APS to surpass 60 MW of customer-owned solar energy on its distribution system as of early 2011. We project that number to exceed 400 MW by 2015. These numbers reveal that residential rooftop solar has displaced generation that APS would have otherwise had to produce or acquire from other sources.

Q. ON TOP OF PURSUING EACH OF THESE GOALS, YOU MENTIONED ENERGY DELIVERY'S OBJECTIVE OF PROVIDING AFFORDABLE ELECTRIC SERVICE. PLEASE DESCRIBE THE IMPORTANCE OF COST MANAGEMENT IN ENERGY DELIVERY'S OPERATIONS.

A. Cost management has played—and will continue to play—a significant role in APS's business. Like all electric utilities, the costs of equipment and materials essential to our business (e.g., copper, steel, aluminum and other commodities) continue to escalate. With a growth rate close to triple the national average for more than a decade, material costs have affected APS more heavily than many of our peer utilities because more growth means more customers and a need for additional infrastructure to serve those customers. And although growth has slowed for the time being, APS must still fulfill its commitment of meeting the highest reliability standards while preparing for a resumption of growth in Arizona.

To meet that obligation, Energy Delivery has planned and is constructing distribution construction projects during the post-Test Year period designed to meet its planning and reliability responsibilities. These projects, however, will cost money—and represent the essence of the cost management challenge for the Delivery organization. Energy Delivery assesses system deficiencies, needs and weaknesses and only includes in its work plan those projects that specifically contribute to service reliability and/or system capacity. Balancing strategic system investments with cost management will also require organizational improvements in work processes, project management and performance measures. Energy Delivery is in the midst of a multi-year effort to produce just such operational improvements with a program we call SOAR (Standardize, Organize, Automate, Review). SOAR emphasizes maximizing effectiveness and efficiencies in planning, construction, operations and maintenance. Process improvement such as SOAR will be crucial to successfully manage costs while ensuring that the delivery system is sufficiently constructed to meet customer needs.

Q. DOES ENERGY DELIVERY FACE ANY PARTICULAR CHALLENGES THAT MAY IMPACT COST MANAGEMENT EFFORTS?

A. Successfully meeting the principles identified above—safety, reliability, compliance and meeting customers' demands for new service and technology—constitutes a challenging opportunity that drives costs. Tension exists between our aim to keep customer costs down and making the investments needed to meet our customers' needs and fulfill critical policy goals. Another challenge lurks, however, that, although not unique to APS, is particularly important in today's climate: our aging workforce.

It is only through our people, our employees, that we will be successful in achieving Energy Delivery's goals. Energy Delivery is not alone in facing large

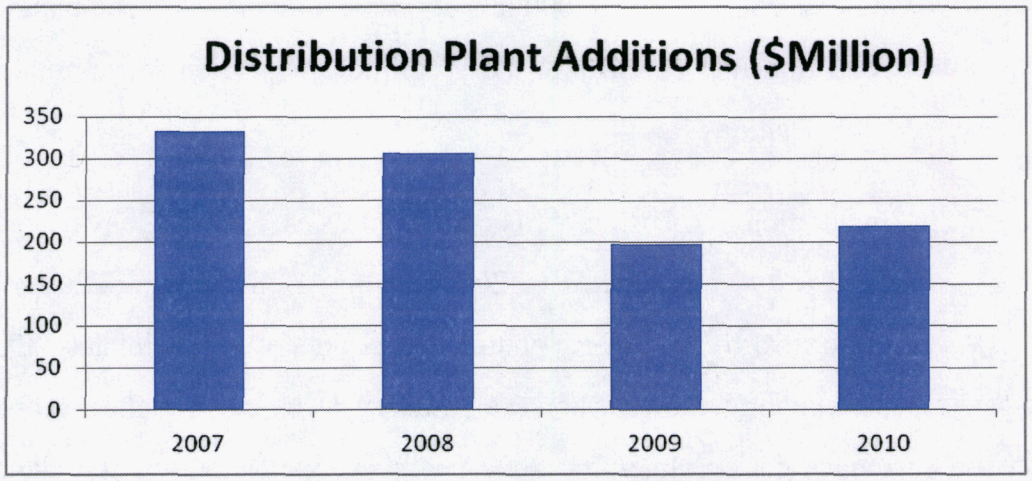
workforce turnover as the "baby boomer" generation begins to retire. Approximately 38% of Energy Delivery's regular employees qualify for retirement in the next five years, and that number will only grow. In response, we will continue recruiting and training new employees qualified to manage our existing system and its "older" technologies. At the same time, we seek creative employees with the innovative and entrepreneurial spirit we need to embrace emerging technologies. Our emphasis on workforce development flows not just from the need to capture the skills of retiring employees, but to develop new skill sets able to deal with emerging technologies, cost pressures and higher customer expectations. Although tackling this challenge may exert upward pressure on O&M costs in the short term, it is critical; without the investment and commitment of an engaged workforce, we cannot be successful.

Working together, we will continue to perform at high levels while forging the kind of vigorous, mentoring leadership and engaged workforce that can absorb and manage change. Given the spectrum of challenges facing Energy Delivery, that is a key driver of our future success.

V. TEST YEAR EXPENDITURES

Q. PLEASE PROVIDE MORE DETAIL ON ENERGY DELIVERY'S PLANT ADDITIONS DURING THE TEST YEAR?

A. As Arizona's economy began to slow in 2007, Energy Delivery took a hard look at its operations as part of APS's overall commitment to cost management. With the goal of carefully calibrating capital expenditures to the predicted slowdown in new customer growth, Energy Delivery embraced a rigorous process for reviewing new construction projects. As a result, Energy Delivery reduced its plant additions by a cumulative total of 33% from 2007 to 2010 as shown in the following chart:



This downward spending trajectory represents a systematic and disciplined effort to correctly scale capital expenditures with needs. Energy Delivery's total addition to distribution plant in service during the 2010 Test Year was approximately $219 million. Critically, this Test Year figure reflects the culmination of these cost cutting measures, translating into compounded savings for APS customers.

Q. HOW HAS ENERGY DELIVERY MANAGED ITS O&M BUDGET DURING THE TEST YEAR?

A. The slowing economy also prompted Energy Delivery to scrutinize its O&M expenditures. Since late 2007, Energy Delivery aggressively managed work load to work force in anticipation of the slowdown in the local new customer construction market. As a result of evaluating people, process and technologies, Energy Delivery adjusted during the last three-and-a-half years by, among other items, reducing the total workforce by approximately 460 people, or 23% of Energy Delivery's total employees. In combination with this reduction, Energy Delivery also reduced the number of its vehicles by 20%.

In addition to workforce reductions, Energy Delivery strengthened overtime management by evaluating work prioritization, scheduling and work load. This

process resulted in 250,000 less overtime hours in 2010 compared to 2007, a 44% reduction that saved almost $13 million, equivalent to approximately 140 full time positions.

In addition to focusing on its own employees, Energy Delivery reduced its use of third-party contractors. In 2007, Energy Delivery's monthly average of work performed by third-party contractors peaked at approximately 30,000 hours. As the economy slowed, however, Energy Delivery brought that work in-house to reduce costs. Since the 2007 peak, Energy Delivery has reduced the monthly average to approximately 1,000 hours per month, all but eliminating our reliance on third-party contractors. In 2010, Energy Delivery sent approximately $17 million less in distribution work to third-party contractors than in 2007. This represents a reduction of over 94%, again equivalent to approximately 150 full time positions.

Streamlining its workforce, reducing overtime and bringing work in-house represent a few of the cost cutting measures Energy Delivery employed in response to the slowing economy. In the aggregate, these efforts to reduce O&M paid off. In 2007, APS's Distribution O&M was approximately $94.5 million. With just inflation alone since that time—over 5% as measured by the Consumer Price Index—Distribution O&M should have increased to $99.4 million. But it did not. By 2010, and after adding almost 44,000 meter sets, Energy Delivery reduced its O&M expenditure by $2.4 million ($7.4 million as adjusted for inflation) for a Test Year O&M expenditure of $92 million.

In sum, Energy Delivery carefully stepped down spending as new customer growth slowed beginning in 2007. Again, it was a delicate balancing act in which APS fulfilled its obligation to serve those new customers that did emerge, but

also protected customers' interests by keeping expenditures low. Critically, Energy Delivery balanced these objectives while also improving reliability and safety as discussed earlier. Because the 2010 Test Year contains these reductions in expenditures, APS customers will benefit from Energy Delivery's cost management efforts.

Q. HOW DO ENERGY DELIVERY'S O&M EXPENDITURES COMPARE TO THOSE OF ITS PEER UTILITIES?

A. Liberty Consulting and Concentric Energy Advisors separately evaluated Energy Delivery's O&M in light of industry norms. Liberty found that although APS experienced sharp increases in distribution O&M in 2007 and 2008, APS's per customer distribution O&M was competitive and consistently falls in the 2nd quartile.[13] Concentric echoed this finding and provided additional detail in a report attached to the testimony of APS witness Jeff Guldner. Concentric first noted that the 2007 and 2008 spikes in distribution O&M resulted from a one-time severance payment, vegetation management expenses and the Bark Beetle infestation in Arizona.[14] Concentric also considered APS's distribution O&M in light of how much of APS's distribution system resides underground, a factor which typically increases O&M expense per circuit mile. Despite having the second-highest percentage of underground distribution system in the industry, APS has been in the second or third quartile of distribution O&M, "demonstrating the Company's success at managing costs in this area."[15] Concentric concluded by noting that on a per customer basis, APS's distribution O&M is competitive against both Liberty's base and high growth panels.[16] The following chart demonstrates the trajectory of APS's Distribution O&M over the past few years.

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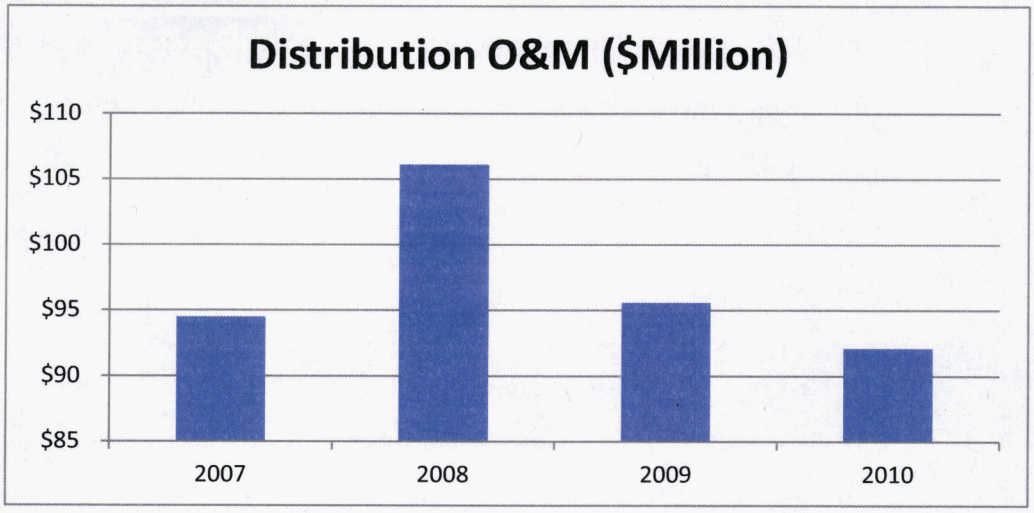
[13] Study, p. 27.
[14] *See* Concentric Energy Advisors Report, p. 18.
[15] *Id.* at 27.
[16] *Id.*



Q. BASED UPON ENERGY DELIVERY'S EXPERIENCES AND PERFORMANCE SINCE APS'S LAST RATE CASE, WHAT LESSONS WILL ENERGY DELIVERY CARRY INTO THE POST-TEST YEAR PERIOD AND BEYOND?

A. As I stated earlier, meeting customer demands and furthering energy policy objectives are key challenges for APS going forward. Moreover, APS is obligated to be ready for the growth that will occur as Arizona's economy revives. Managing these challenges depends in large part on system performance, in one word—*reliability*. Energy Delivery must plan, construct and maintain the APS system to lock in current levels of system performance, while ensuring that as it continually expands, the system is sufficiently reliable and has the capacity to meet future customer and community needs. It is the level of investment we make today that will determine whether APS contributes to and facilitates economic growth in Arizona, or whether business leaders can point to a lack of electric infrastructure if they seek to justify a decision to expand into another state.

In contributing to the resumption of economic growth in Arizona, however, Energy Delivery will bring its disciplined approach to cost management. Energy Delivery will deepen its focus on operational efficiency, seek improved ways of

doing business and continue its rigorous review of what projects to implement, and when. Energy Delivery's performance in the past few years demonstrates that it knows how to balance needed investments with cost management. The post-Test Year expenditures detailed below reflect that balance.

VI. POST TEST YEAR EXPENDITURES

A. *Total Capital Expenditures for Distribution.*

Q. WHAT LEVEL OF PLANT ADDITIONS DOES ENERGY DELIVERY EXPECT THROUGH JUNE 30, 2012?

A. Energy Delivery plans to add a total of $433 million in distribution and IT & facilities plant by June 30, 2012 as summarized in Attachment DTF-1. These additions contribute $159 million to the Company's Post-Test Year Plant adjustment.[17] APS Witness Jason La Benz describes additional details of the adjustment, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes and interest expense.

Q. PLEASE PROVIDE MORE DETAIL ON WHAT MAKES UP THE DISTRIBUTION CAPITAL SPENDING FOR 2011 AND 2012.

A. Attachment DTF-2 itemizes APS's Post-Test Year capital expenditures by specific categories. The first category concerns expenditures related to emergencies and storms and includes costs associated with both the labor and equipment required to replace facilities damaged by uncontrollable events. Examples include storm damage, cars hitting poles and equipment breaking unexpectedly, among others.

The second category involves planned outlays for asset management. This category reflects those costs that APS will incur in proactively extending the life of its distribution system by replacing end-of-life or obsolete equipment. For instance, Energy Delivery intends to spend approximately $2.8 million replacing

[17] *See* SFR B-2, page 2, column K

or stubbing aging or rotted wooden poles during the Post-Test Year period. Similarly, Energy Delivery has budgeted approximately $9 million to patrol, upgrade and replace, as appropriate, overhead facilities, particularly high SAIFI feeders. This line patrol and replacement program reflects APS's strong commitment to reliability and contributes to the reliability successes detailed earlier in my testimony. Energy Delivery's dedication to reliability also underlies its plan to incur $26 million in replacing underground cable during the Post-Test Year period. The benefits to date of replacing this underground cable—a 61% drop in the average customer interruption frequency over the past decade—make clear that leaving this cable in the ground would inevitably erode the reliability of APS's distribution system.

The final category of Post-Test Year capital expenditures arises out of installing facilities to serve anticipated local customer growth.[18] For instance, a clear area of sustained and to-be-accelerating growth is the West Valley (e.g., Goodyear, Avondale, Buckeye). As subdivisions and commercial centers develop, electrical distribution backbone infrastructure is needed—and needs to be in place in advance of customer needs. At APS's Sarival substation, two existing 20 MVA transformers will be replaced with two new 41 MVA substation transformers—adding capacity to ensure the reliably supply of energy to the anticipated West Valley growth. New feeder exits at APS's Granite Reef substation perform a similar function and will aid continued growth in North Scottsdale.

Neither the Sarival nor Granite Reef substation projects are tied to specific new customers. Instead, they represent the sometimes less visible infrastructure investments that APS must install to provide the capacity, voltage support and

[18] Attachment DTF-2 identifies customer growth-related expenditures under the headings 12 kV Lines, Distribution Subs, Relocates, Service and Extensions and Transformers.

operating flexibility that customers need. Without these investments, and the other expenditures contemplated under the new customer category, APS risks hindering anticipated growth in Arizona.

Q. ARE THERE OTHER DISTRIBUTION CAPITAL COSTS THAT THE COMPANY WILL INCUR SUBSEQUENT TO THE TEST YEAR THROUGH JUNE 30, 2012?

A. Yes. As I discuss earlier in my testimony, innovative technologies are a priority for both our customers and APS. We plan on investing $25.5 million as part of our Smart Grid demonstration projects, furthering our investment in substation equipment and distribution asset health monitoring; we essentially seek operating characteristic feedback before equipment may fail similar to our highly effective TOAN system. We also plan on further automating our distribution system in both Flagstaff and Phoenix, thereby improving outage responsiveness and reducing customer outage scope and duration. (*See* the schedule of costs outlined in Attachment DTF-3).

Commission-approved pilot programs in the smart home and electric vehicle areas will also be conducted, and we'll be installing an estimated 317,000 AMI meters during this time period at a cost of approximately $53.7 million (*see* the schedule of costs outlined in Attachment DTF-4).

Technology extends beyond the field distribution system as well. A projected $18.3 million in other customer and technology initiatives is planned, including a pre-pay energy services pilot, the consolidation of a number of software applications in our Call Center designed to improve our responsiveness to and handling of customer telephone inquiries, and technology to leverage our AMI system in power outage reporting, transformer loading and voltage monitoring and energy diversion detection. More detail on these project costs are included in my Attachment DTF-3.

B. *Total Capital Expenditures for Information Technology and Facilities*

Q. MR. FROETSCHER, EARLIER YOU STATE THAT THE COMPANY WILL BE MAKING INVESTMENTS IN INFORMATION TECHNOLOGY AND FACILITIES. PLEASE ELABORATE ON THESE INVESTMENTS.

A. Yes, APS will make substantial investments in both information technology and the Company's facilities. As detailed in Attachment DTF-5, the Company will invest over $102 million during the Post-Test Year period. One critical project encompassed by this figure involves rebuilding the Company's Deer Valley Operations Center at a cost of approximately $34 million. Deer Valley, the Company's principal Phoenix-based campus, will be upgraded to facilitate certain functions critical to APS's core operations, including APS Energy Control Center and the Metro Dispatch Headquarters and Call Center. Other related, key expenditures during the Post-Test Year period include upgrading Information Technology Disaster Recovery hardware and software, enhancing aps.com and leasing vehicles. The total adjustment to the test year APS proposes to include as an original cost rate base pro forma adjustment for (i) distribution capital expenditures; and (ii) information technology and facilities by June 30, 2012 is $433 million.

Q. IS APS REQUESTING AN INCREASE IN TRANSMISSION RELATED-COSTS IN THIS RATE CASE?

A. No. Distribution-related cost recovery is subject to the ACC's jurisdiction, whereas transmission-related costs are generally subject to FERC's jurisdiction. FERC reviews the prudency and pricing of APS's transmission service through the Company's Annual Informational Filing. My testimony focuses on APS's distribution system and the need for cost recovery of the distribution system related costs including Post-Test Year plant additions.

VII. CONCLUSION

Q. THANK YOU, MR. FROETSCHER. DO YOU HAVE ANY CONCLUDING REMARKS?

A. APS will only be ready for the resumption of strong growth in Arizona by continuing to make the sound distribution investments today that it made leading up to and during the Test Year. It is those types of investments—which resulted from diligent study and careful analysis—that permit me to highlight the successes in safety and reliability identified above. But it is the context of these successes that is truly remarkable: Energy Delivery achieved such strong reliability and safety numbers *while reducing capital and O&M expenditures* since the last rate case.

Those reductions are not small either. Since the last rate case, Energy Delivery reduced its capital expenditures by 33%. And it reduced its O&M expenditure by $2.4 million despite adding almost 44,000 meters sets and in the face of over 5% inflation. APS customers benefit from those reductions in this rate case.

Looking forward, the distribution investments planned for the Post-Test Year period will permit Energy Delivery to build upon its strong record on safety and reliability. And these investments will continue the installation of new technologies that not only empower customers with more knowledge and control, but create operational efficiencies with cost savings that compound over time. We look forward to unlocking the opportunities afforded by these investments and building upon Energy Delivery's record.

ARIZONA PUBLIC SERVICE COMPANY
Distribution, Smart Grid, AMI, IT and Facilities
Capital Post Test Year Additions - Summary
Test Year Ending 12/31/2010

Line	Description		$000
1.	Emergency/Storm	Attachment DTF-2	$ 16,875
2.	Asset Management	Attachment DTF-2	68,901
3.	Customer Growth		
4.	Transformers	Attachment DTF-2	29,747
5.	Service & Extensions	Attachment DTF-2	62,006
6.	12 kV Lines	Attachment DTF-2	21,078
7.	Distribution Substation	Attachment DTF-2	18,624
8.	Relocates	Attachment DTF-2	14,427
9.	Smart Grid Demonstration Projects	Attachment DTF-3	25,530
10.	Community Power Project	Attachment DTF-3	2,233
11.	Other Customer & Technology	Attachment DTF-3	18,290
12.	AMI Meters	Attachment DTF-4	53,700
13.	IT & Facilities Plant Additions	Attachment DTF-5	101,573
14.	Total Post Test Year Plant Additions		$ 432,984

Distribution Capital Post Test Year Additions $000

Line #	Category	Capital Identified in Accounting System to be Placed in Service	Additional Capital Dollars to be Placed In Service	Total Capital Dollars to be Placed In Service
	Emergency Storm			
1.	Total Storm	$ 3,336	$ 1,298	$ 4,634
2.	Unplanned Emergency	4,197	8,045	12,241
3.	**Total Emergency Storm**	**7,533**	**9,343**	**16,875**
	Asset Management			
4.	General Reliability	283	695	978
5.	Wood Pole Replacement - Includes line patrol replacement work	3,082	(232)	2,850
6.	Service Poles - Bark Beetle	97	97	194
7.	Network Monitoring Equipment	238	931	1,170
8.	Substation Aged Equipment Replacement (Includes Planned Replacement)	264	2,648	2,913
9.	Service Replacements	584	7,176	7,760
10.	Overhead Planned Replacements -Includes High SAIFI line patrol replacement work	1,206	8,137	9,344
11.	AT Switch Replacement	1,034	(698)	336
12.	12kV Metal Clad Sub Switch Gear Replacement	3,586	(37)	3,549
13.	Capacitor Bank Radio Controls	307	78	384
14.	UG Transformer Replacement	78	4,987	5,065
15.	UG Cabinet Replacement	704	4,150	4,854
16.	Underground Cable Replacement	6,800	19,013	25,813
17.	Underground Network Cable Replacement	0	2,921	2,921
18.	Transformer Replacement - Distribution	441	183	624
19.	Franchise Elections	-	146	146
20.	**Total Asset Management**	**18,705**	**50,197**	**68,901**
	12 kV Lines			
21.	Sub Distribution General Projects (Base)	12,844	2,103	14,947
22.	New Feeders	8,032	(2,027)	6,005
23.	Distribution State Land ROW Renewals	-	646	646
24.	Distribution Tribal Land ROW Leases - No agreements made	-	-	-
25.	Efficiency Savings (2% of Total DAI) 2009 LRF was 5% of Total DAI	-	(521)	(521)
26.	**Total 12 kV Lines**	**20,876**	**201**	**21,078**
	Distribution Subs			
27.	69kV Activity Within Substation	379	2,673	3,052
28.	Additional Transformers	1,472	1,165	2,637
29.	New Substations (Includes Land)	4,623	3,426	8,048
30.	Transformer Upgrades	3,760	(1,768)	1,992
31.	Forestry/Landscaping	174	791	965
32.	Unplanned Sub Walls (Aesthetics)	713	1,216	1,928
33.	**Total Distribution Subs**	**11,121**	**7,503**	**18,624**
	Relocates			
34.	Highway Relocations	9,450	**2,697**	**12,147**
35.	PV Conversion	-	974	974
36.	Other Conversions	2,355	(1,049)	1,306
37.	**Total Relocates**	**11,805**	**2,622**	**14,427**
	Service and Extensions			
38.	Service & Line Extensions - Residential	12,038	24,780	36,819
39.	Service & Line Extensions - Residential - Non -Residential	24,407	135	24,542
40.	Streetlights & Dusk to Dawn	2,805	2,340	5,145
41.	Forfeited Refundable Advances (CIAC)	-	(4,500)	(4,500)
42.	**Total Service and Extensions**	**39,251**	**22,755**	**62,006**
	Transformers			
43.	Transformers	-	29,747	29,747
44.	**Total Transformers**	**-**	**29,747**	**29,747**
45.	**Total Post Test Year**	**$ 109,290**	**$ 122,368**	**$ 231,658**

Smart Grid Capital Post-Test Year Additions

($ in Millions)

Line No.	Eighteen Month Capital Forecast		Total
1.	**Smart Grid Demonstration Projects**		
2.	Smart Circuit Automation		
3.	Flagstaff	$	4.873
4.	Metro		9.824
5.	Asset Monitoring		
6.	Substation Health Monitoring		3.412
7.	Distribution Asset Monitoring		1.228
8.	Customer Pilots		
9.	Home Energy Information Pilot		1.299
10.	Electric Vehicles		1.722
11.	Solar Demonstration		
12.	Chase		1.659
13.	USAC		1.513
14.	**Total**		**25.530**
15.			
16.	**Community Power Project**		
17.	Battery Storage		2.233
18.			
19.			
20.	**Other Customer & Technology Initiatives**		
21.	Marketing Systems & Products		
22.	Click Fox		0.248
23.	CRM/MKIS		1.195
24.	Proactive Alerts		0.419
25.	Streamlining Options		0.543
26.	Customer Interaction Scorecard		0.236
27.	Contact Center		4.647
28.	Leveraging AMI		1.936
29.	Merging of Products		0.945
30.	Prepay Energy Services		1.836
31.	Strategic IT		6.285
32.	Total		18.290
33.			
34.	**Grand Total (14+17+32)**	**$**	**46.053**

ARIZONA PUBLIC SERVICE COMPANY

AMI Post Test Year Additions
Test Year Ending 12/31/2010

Line No.	Calendar Year 2011	AMI Meter Order/Delivery Quantities	Residential AMI Meters (90% of Monthly Purchase)	General Service AMI Meters (10% of Monthly Purchase)	Residential AMI Meter Cost (@$146/meter)	General Service AMI Meter Cost (@ $380/meter)	Total AMI Meter Cost
		A	B	C	D=Bx$146	E=Cx$380	F=D+E
1.	January	18,000	16,200	1,800	$2,365,200	$684,000	$3,049,200
2.	February	18,000	16,200	1,800	2,365,200	684,000	3,049,200
3.	March	18,000	16,200	1,800	2,365,200	684,000	3,049,200
4.	April	18,000	16,200	1,800	2,365,200	684,000	3,049,200
5.	May	18,000	16,200	1,800	2,365,200	684,000	3,049,200
6.	June	18,000	16,200	1,800	2,365,200	684,000	3,049,200
7.	July	18,000	16,200	1,800	2,365,200	684,000	3,049,200
8.	August	18,000	16,200	1,800	2,365,200	684,000	3,049,200
9.	September	18,000	16,200	1,800	2,365,200	684,000	3,049,200
10.	October	18,000	16,200	1,800	2,365,200	684,000	3,049,200
11.	November	18,000	16,200	1,800	2,365,200	684,000	3,049,200
12.	December	18,000	16,200	1,800	2,365,200	684,000	3,049,200
13.	Total	216,000	194,400	21,600	$28,382,400	$8,208,000	$36,590,400
14.							
15.	Calendar Year 2012						
16.	January	18,000	16,200	1,800	$2,365,200	$684,000	$3,049,200
17.	February	18,000	16,200	1,800	2,365,200	684,000	3,049,200
18.	March	17,000	15,300	1,700	2,233,800	646,000	2,879,800
19.	April	16,000	14,400	1,600	2,102,400	608,000	2,710,400
20.	May	16,000	14,400	1,600	2,102,400	608,000	2,710,400
21.	June	16,000	14,400	1,600	2,102,400	608,000	2,710,400
22.	Total	101,000	90,900	10,100	$13,271,400	$3,838,000	$17,109,400
23.							
24.						**Total AMI Meter Post Test Year Proforma =**	**$53,699,800**

IT and Facilities Capital Post Test Year Additions

Line No.	WA#	Project Description	Purpose	Project Cost to Date 12/31/10	Cost to Complete	Total Project Cost	Estimated In-Service Date
1.	P138020	DV Ops Cntr Phase I - DVN1	Program/Design the demo and rebuild of the DVN1 Building. Critical Operations to be included: ECC, MDH/DOMS and the Customer Call Ceeter with supporting functions. Remove and Replace HVAC, Electrical, controls systems and all lighting. Add a Central Plant, UPS, APU systems.	$ 7,324,739	$ 26,834,601	$ 34,159,340	12/30/2011
2.	T25957	Disaster Recovery Program Phase 1	To enhance IS Disaster Recovery strategy and establish program to implement and progess it, to ensure sufficent disaster recovery infrastructure and support processes are in place in the event of a major site disaster impacting the DV or 502 Data Centers.	$ 6,063,877	$ 140,289	$ 6,204,167	3/1/2011
3.	Budget	Automobile Lease Purchase	Purchase of remaining asset value after lease period ends	$ -	$ 5,714,232	$ 5,714,232	12/30/2011
4.	T26461	PSFSCM Upgrade 9.1	Define the future roadmap of PeopleSoft Portal application in accordance with HR Web Strategy. The long term vision is to integrate Sharepoint with core PeopleSoft HCM applications so that all HR employee and leader information and tools are accessed through one site. Upgrade PeopleSoft Human Capital Management (HCM) applications from version 8.9 to 9.1 (or 9.2 if available). (HR, Benefits, Payroll, Time and Labor, Employee and Manager Self Service, COBRA, Recruiting, etc.)	$ 1,036,401	$ 3,178,683	$ 4,215,084	6/1/2012
5.	Budget	CSS - APS.com Enhancements (Redesign, Mobile and Automation)	Strategic Business Requirement to support customer demands for information and functionality on company web page	$ -	$ 3,871,201	$ 3,871,201	12/30/2011
6.	Budget	Contact Center	Single source solution-Cisco Unified Contact Center Enterprise (UCCE)	$ -	$ 3,473,618	$ 3,473,618	12/30/2011
7.	T25434	EMS PI Historian	Implement PI Historian for EMS including software, hardware, and displays. Provide replacement for Spectrum Historical Reporting application.	$ 2,297,427	$ 212,606	$ 2,510,033	12/30/2011
8.	Budget	Digital / Video Wall Map MDH	$40M has been spent on a new distribution operations center and we intend to remove paper maps. We need a digital display technology that will work to replace paper.	$ -	$ 2,406,422	$ 2,406,422	12/30/2011
9.	T25610	DWDM Replacement	Design/implement robust multiplexing network by using Dense Wavelength Division Multiplexing (DWDM). Replace existing DWDM nodes with Cisco nodes, increase system bandwidth, speed, reliability, segregate process and business applications by using wavelength technology, and physical separation.	$ 1,788,911	$ 165,548	$ 1,954,458	12/30/2011
10.	Budget	Prepaid Metering	Business Unit strategy to provide ACC approved new product. Modifications to AMI and CIS to allow customers to prepay with proper customer tracking and notification.	$ -	$ 1,569,406	$ 1,569,406	12/30/2011
11.	Budget	Telegraph Pass(Remodel/Replace/Evaluate)	New Telegraph Pass Comm house and transition of equipment/comms from Yuma's location. Existing risk factors include degrading facilities which may no longer be able to support communications for transmission or generation.	$ -	$ 1,546,806	$ 1,546,806	3/1/2012
12.	Budget	EMS Network Concentrator Upgrades	Upgrades to concentrators as Smartgrid expands.	$ -	$ 1,464,779	$ 1,464,779	12/30/2011
13.	T26578	Maximo Phase 3	Continue the implementation of the T&D functionality into new Maximo 7 system. This phase will focus encapsulating ODL functionality in Maximo and configuring the system to set Protective Relays as Assets.	$ 601,112	$ 421,822	$ 1,022,934	12/30/2011
14.	Budget	HMI Upgrade - West Phoenix PP	Replace aging Fossil plant Operator Interface stations with next generation hardware and software.	$ -	$ 1,046,271	$ 1,046,271	12/30/2011
15.	Budget	Home area network	The project is part of a comprehensive approach to reduce energy usage. It is part of a residential demand response and energy efficiency program that includes a technical assessment of in-home devices that will provide customers with transparent information regarding their energy use and associated costs.	$ -	$ 1,011,568	$ 1,011,568	3/1/2012
16.	Budget	Plug in hybrid electric vehicle	Support of Electric vehicles at redesigned DVN1	$ -	$ 1,011,568	$ 1,011,568	3/1/2012
17.	Budget	TranZ 2012 capital improvements	This funding request is meant to provide funding for making changes that are of capital in nature, but are not specified as of yet. These changes will no doubt come forward and will be required changes as opposed to simple improvements in process or efficiency. Historically the dollars for this kind of change have been to address software and occasionally hardware needs that arise from regulatory, financial reporting, or urgent business opportunities.	$ -	$ 1,011,568	$ 1,011,568	3/1/2012

IT and Facilities Capital Post Test Year Additions

Line No.	WA#	Project Description	Purpose	Project Cost to Date 12/31/10	Cost to Complete	Total Project Cost	Estimated In-Service Date
18.	T26583	Zoning - Process Network Separation	This project will separate process control networks from business networks.	$ 1,039,614	$ 96,207	$ 1,135,821	12/30/2011
19.	T26223	Carol Springs-Greens Peak-Signal Pe	Replace microwave equipment and antenna systems to meet performance objectives, Carol Springs Electronic Station to Greens Peak and Signal Peak	$ 849,462	$ 78,610	$ 928,072	12/30/2011
20.	T26231	SOAR Scorecard and DWH	This project will develop a data warehouse for reporting on all T&D historical data using specialized query and reporting tools. The source of the data will be from systems including Maximo, Primavera, DOMS, OIS, TOAN, EMS, HR data, Accounting Data, KPI's and GIS. This system will allow customized data mining and complex data views.	$ 788,272	$ 72,947	$ 861,220	12/30/2011
21.	Budget	Thermostat Pilot	The project is part of a comprehensive approach to reduce energy usage. It is part of a residential demand response and energy efficiency program that includes a technical assessment of in-home devices that will provide customers with transparent information regarding their energy use and associated costs.	$ -	$ 1,011,568	$ 1,011,568	3/1/2012
22.	T25594	Transmission GIS/Vegetation Managem	Leverage the O&M collection of LIDAR vegetation and transmission data (separate, but related project) by creating a system that stores and provides the base foundation infrastructure and tools to access and maintain this data.	$ 644,044	$ 59,600	$ 703,644	12/30/2011
23.	Budget	Bill on Read date	Business need added funcationality to current systems to maintain operational efficiency	$ -	$ 873,636	$ 873,636	12/30/2011
24.	Budget	Mainframe Storage Refresh	Additional disk storage media for on-going enterprise data growth.	$ -	$ 818,508	$ 818,508	6/1/2012
25.	P152950	Casa Grande - Service Center T.I. H	Upgrade and Replacement: HVAC, Energy Ventialor Recovery Units, ceiling system, lighting system and restroom fixtures	$ 823,156	$ 76,176	$ 899,332	12/30/2011
26.	Budget	CSS - Change Control Board (CIS)	Placeholder for enhancements made to the CIS applications that are geared towards reducing O&M costs for the Business, improve customer satisfaction, and improve revenue	$ -	$ 832,818	$ 832,818	3/1/2012
27.	Budget	Windows 7	Engineer, develop, build, test and implement the Windows 7 OS workstation enterprise wide.	$ -	$ 941,643	$ 941,643	12/30/2011
28.	Budget	SurePay / AutoPay Upgrade	The Web Infrastructure project is an initiative aimed at keeping up with growth of the enterprise web environment in terms of servers, storage, licensing and further consolidation of web server environment.	$ -	$ 837,016	$ 837,016	12/30/2011
29.	T26343	PMAC Upgrade	This project is to replace the existing application and improve the usability of the PMAC relay setting's data being stored in the database. This will add more structure to the data so that it can be integrated with the new Maximo system and support the growing reporting needs of the Asset Management Group. This will also improve performance and other application limitations due to old technology.	$ 8,764	$ 210,065	$ 218,829	12/30/2011
30.	T26530	ECM Records Management	This is to update the ECM infrastructure to the latest version 4.0 to 4.5 and to install the Records Manager tool.	$ 171,055	$ 15,830	$ 186,885	12/30/2011
31.	T26584	Informatica ETL Mappings Implementa	Replace Sagent with new ETL tool (Informatica) for more functionality and better performance.	$ 138,739	$ 12,839	$ 151,578	12/30/2011
32.	Budget	Directory Services Optimization	Upgrade of current system functionality. This will collapse the many desperate AD's into a common environment.	$ -	$ 209,254	$ 209,254	12/30/2011
33.	Budget	Distributed Tape Refresh	Current System Improvements and Upgrades	$ -	$ 613,881	$ 613,881	6/1/2012
34.	Budget	DVO Telephony	Upgrade of telephone system in non-CHQ location for additional functionality	$ -	$ 511,568	$ 511,568	6/1/2012
35.	Budget	Fossil Generation Information Management System	Fossil Generation Information Management System	$ -	$ 523,135	$ 523,135	12/30/2011
36.	T26317	800mhz TTA	Upgrade/replace existing tower top amplifiers & receiver mulit-couplers at 6 APS microwave/radio sites state wide	$ 132,932	$ 12,302	$ 145,234	12/30/2011

IT and Facilities Capital Post Test Year Additions

Line No.	WA#	Project Description	Purpose	Project Cost to Date 12/31/10	Cost to Complete	Total Project Cost	Estimated In-Service Date
37.	Budget	TranZ .NET conversion 2012	Current System Improvements and Upgrades	$ -	$ 511,568	$ 511,568	6/1/2012
38.	Budget	System Health Indicator Program	Implement a solution that automates documenting & reporting System Health at a site & across plants. Integrate data from supporting systems Maximo, Smart Signal, NewCO, Vibrations, TapRoot, etc into a weighted algorithm to calc overall system health	$ -	$ 544,061	$ 544,061	12/30/2011
39.	T26459	DDO Digital Wall Map	Printing/plotting enhancements, system planning requirements, ICCP (the protocol for passing information from one control system to another) analogs, PMAC (APS's Protective Metering and Control Department) integration and Maximo devices, switching plans, equip locations, cap bank integration, continue DOMS - EMS integration for Distribution SCADA (Supervisory Control and Data Acquisition - the system that facilitates retrieval of data from field devices and remote control of same) devices, get symbology we currently have operating correctly , Vista Switch Gear & ATO's symbology for what we have, more device properties from external sources into DOMS.	$ 371,919	$ 34,418	$ 406,337	12/30/2011
41.	Budget	Budget/Planning Application	Business based need for improved budget and planning software to facilitated various reviews of budget performance and fudiciary discipline	$ -	$ 511,568	$ 511,568	6/1/2012
42.	Budget	TranZ .NET conversion from VB6 and improvement of MTM process	This project is meant to upgrade the base technology from Microsoft VB6 to Microsoft .NET allowing for reduced cost for future upgrades and eliminate growing risk from Microsoft's focus turning away from older VB6 technology .	$ -	$ 523,135	$ 523,135	12/30/2011
43.	T26314	One Maximo	Consolidate the three Maximo environments and databases used in Generation (four Corners, Cholla, & Gas/Oil plants).	$ 521,169	$ 48,230	$ 569,399	12/30/2011
44.	Budget	InsideAPS enhancements and eOn sites retirements	This project is to consolidate the various old legacy eOn websites, it also includes migration of all Newsline articles from old legacy technology to InsideAPS along with various small enhancements that have been requested by corporate communications.	$ -	$ 209,254	$ 209,254	12/30/2011
45.	Budget	Customer Interaction Scorecard	Business need added funcationality to current systems to maintain operational efficiency	$ -	$ 517,566	$ 517,566	3/1/2012
46.	Budget	Replace non-Smartzone/P25 Capable Radios in Metro Phoenix	Excluding upgrades being done under the 2 Way Radio Enhandcement project (1509), this project will replace the remaining analog 2 Way radios that will not operate on a APCO P25 system. These radios are also at end of life and are no longer supported by the manufacturer.	$ -	$ 476,448	$ 476,448	3/1/2012
47.	Budget	Flagstaff CSO	Community Joint Office - Buildout Customer Service Office with City of Flagstaff's City Building. Timing based on City of Flagstaff's approval.	$ -	$ 470,822	$ 470,822	12/30/2011
48.	Budget	HR Common Retirement (Expand TIBCO HR Service)	This project is to leverage the investment of the TIBCO HR Service for all apps requiring data from PeopleSoft HCM. Currently many databases house HR Data. This project will track these and work with the business/IT teams to migrate to the new Service.	$ -	$ 423,563	$ 423,563	6/1/2012
49.	Budget	TranZ .NET conversion from VB6 and improvement of Trade Capture process	This project is intended to update the technology from Microsoft VB6 to Microsoft .NET to enable not only future business needs as we evolve but to enable IT to do so much more effectively using the technological advancements in place today.	$ -	$ 418,508	$ 418,508	12/30/2011
50.	Budget	Security Improvements - Generation (Saguaro and Yucca)	These are security improvement projects for Generation that moved to IT for funding / implementation.	$ -	$ 408,045	$ 408,045	12/30/2011
51.	Budget	DMC Phase 2 - integrate with Resource Planning	Continuation of Water Resource Planning "Decision Modeling Center" build-out	$ -	$ 303,470	$ 303,470	3/1/2012
52.	T26554	PowerPlant Enhancements 2010 Phase	Phase 2 of PowerPlant 10.2.1 installation, to develop additional enhancement priorities identified in the IS Requirements Specification & additional interfaces, controls, and further automation of manual tasks performed by Accounting.	$ 117,001	$ 10,827	$ 127,829	12/30/2011
53.	Budget	Push e-billing integration	Purchase and implement a Matter Management and eBilling solution for the Legal Dept.	$ -	$ 354,049	$ 354,049	3/1/2012
54.	T26229	Mt Elden Cholla Microwave	Replace microwave equipment and antenna systems to meet performance objectives, Mt Eldon Electronic Station to Cholla.	$ 260,299	$ 24,088	$ 284,387	12/30/2011

IT and Facilities Capital Post Test Year Additions

Line No.	WA#	Project Description	Purpose	Project Cost to Date 12/31/10	Cost to Complete	Total Project Cost	Estimated In-Service Date
55.	Budget	Commitment Control and CWP	Business based need for improved budget and planning software to facilitated various reviews of budget performance and fudiciary discipline	$ -	$ 358,097	$ 358,097	6/1/2012
56.	T26511	Fossil Generation - KPI (Metrics)	Implement a system to accumulate, update, and display reports for Fossil Generation.	$ 106,972	$ 9,899	$ 116,871	12/30/2011
57.	Budget	IDM Improvements Phase 2	IS Infrastructure uses Identity Lifecycle Manager & in-house software to de-provision users for separations/transfers. The project is to consolidate/eliminate redundant software, leverage ILM more effectively & build for future implementations	$ -	$ 353,653	$ 353,653	3/1/2012
58.	Budget	EMS Real Time Upgrades	The current version of the OHM database used by APS is at end of life with the Pure Safety Organization and will no longer be supported as of December 31, 2010. Evaluation of the current OHM database has identified that the current version has many outdated analysis and reporting functions leaving our regulatory and compliance programs at risk of incorrectly interpreting the data. In addition, an evaluation through the LEAN process has identified that the current OHM system does not support the electronic forms processing and increased medical analysis and reporting necessary to ensure compliance in NRC, OSHA, and DOT regulatory programs.	$ -	$ 313,881	$ 313,881	12/30/2011
59.	Budget	DV IDF Redesign	Implement an enterprise wide Purchasing & Inventory Management system that supports the new Supply Chain processes.	$ -	$ 321,250	$ 321,250	6/1/2012
60.	Budget	Deer Valley to Biscuit Flat via Rose Garden and Adobe (Statewide Fiber buildout Program)	OASIS/OATI processes continue to evolve and require system changes to stay in line with new requirements. The methodology for designating and undesignating use of transmission for own load is being modified. It is far too early to know how it will impact us specifically, but it will require further automation and integration with software packages, TranZ and PCI.	$ -	$ 308,729	$ 308,729	1/1/2012
61.	Budget	Websense upgrade	Foundation Infrastructure required to supprot "critical business functions"	$ -	$ 303,470	$ 303,470	3/1/2012
62.	Budget	Remote location Update	Tenant improvements- recently renewed leased space in Washington DC for Government liasion. Timing- coinicides with lease renewal.	$ -	$ 293,640	$ 293,640	6/1/2012
63.	Budget	OATI Based Changes to own load transmission utilization	We currently have applications like email, calendar, and contacts available on mobile devices. We are working towards a device agnostic solution that will enable us to move towards a thin client solution for all users. Taking this approach further and based on many requests from business units (eg: Fossil to access plant information) we are proposing this project to enable intranet access on mobile devices like IPhones, Droids, Blackberries thus extending the trusted platform to a broad range of applications and use cases.	$ -	$ 261,568	$ 261,568	12/30/2011
64.	Budget	CHQ	Replacment of Electrical transfer switches at CHQ. Timing- based on failures and planned useful life of equipment.	$ -	$ 296,095	$ 296,095	12/30/2011
65.	Budget	FileNet and Sharepoint Integration	To help with integration of FileNet & SharePoint. With SharePoint rollout/asking people to move completed documents to eDocs, we have been asked to provide tools to ease the transfer from one system to another. This project will at third party integration	$ -	$ 313,881	$ 313,881	12/30/2011
66.	Budget	Enhance single-sign-on solutions for non-Microsoft integrated technologies and for SaaS solutions while maintaining compliance with tiers of information sensitivity and potential re-authentication requirements. (D13, D17)	This initiative leverages the AMI data to provide proactive customer alerts via voice, text and e-mail. Customers would have the ability to opt in for outage, usage and pricing alerts. The alerts proactively provide the customers with the information they are looking for, eliminating the need for the customer to call in for status updates or information.	$ -	$ 252,892	$ 252,892	3/1/2012
67.	Budget	Union Dues - APTMS Enhancements	Current System Improvements and Upgrades	$ -	$ 278,181	$ 278,181	3/1/2012
68.	Budget	Maximo Enhancements	Allow for necessary work required to maintain application integrity. Several enhancements have been identified for Phase 1,2 and 3 as the business has been using the products. OA's will be generated and this could be broken into several projects based on priority.	$ -	$ 261,568	$ 261,568	12/30/2011
69.	Budget	Coolidge	Flooring. SE Divison Emergency Op's Center. Flooring is Beyond planned useful life	$ -	$ 9,104	$ 9,104	3/1/2012
70.	P155480	CHQ L-1, Remodel Gallery to Allow T	Demolition and remodeling of the open gallery, the TA receoption area, entry points and 1 meeting room.	$ 255,790	$ 23,671	$ 279,461	12/30/2011

IT and Facilities Capital Post Test Year Additions

Line No.	WA#	Project Description	Purpose	Project Cost to Date 12/31/10	Cost to Complete	Total Project Cost	Estimated In-Service Date
71.	Budget	EMS CIP Optimization	There are many areas where our CIP compliance is maintained by manual processes. This project is to implement automated tools/methods where possible to automate artifact generation and reduce compliance risk.	$ -	$ 240,642	$ 240,642	12/30/2011
72.	T26505	Synchronization Time Clock Replacem	Engineer and upgrade the current synchronization equipment to support the SONET network operations. The addition of the new synchronization equipment will provide redundancy, take advantage of the technology to allow the equipment to better determine a source of synchronization, and provide better alarming and reporting of the health and status of the synchronization system.	$ 6,417	$ 594	$ 7,010	12/30/2011
73.	T26542	Matter Management eBilling	Replace internally developed Access database for Law Dept with Practice/Matter Management and e-Billing software that will bring information from various databases, speadsheets, and documents into one matter centric collaboration tool.	$ 220,123	$ 20,370	$ 240,493	12/30/2011
74.	T26441	Decision Modeling Center	This project will develop and implement the tools required for the Water Resource Planning department: a web mapping application that will enable users access to a view-only GIS web service/mapping tool and a water modeling application, which will provide the ability to simulate and display water resource scenarios and data.	$ 81,482	$ 174,944	$ 256,425	12/30/2011
75.	Budget	Power Gem	Renewal for GIS Enterprise License Agreement, renewed every 3 years and will cover APS' entire installed software base of Environmental Systems Research Institute (ESRI) GIS software, and unlimited licenses.	$ -	$ 209,254	$ 209,254	12/30/2011
76.	Budget	SOUTHERN YD	Paving & Landscaping - Improvements to newly purchased property; dust control and useability. Timing- purchased in 2010 .	$ -	$ 247,599	$ 247,599	6/1/2012
77.	Budget	SQL 2000 Obsolescense	Mainstream support for SQL server (2000) version ended 4/8/2008. Once the Extended Support ends, the product will be outside of the supported security patching level, thus exposing the company network environment to additional security risks.	$ -	$ 209,254	$ 209,254	12/30/2011
78.	Budget	DVF	Fire Detection and Alarm System Replacement based on failures and planned useful life.	$ -	$ 121,388	$ 121,388	3/1/2012
79.	T26398	APS Mapping Application Replacement	This project is for a solution using advancements by ESRI & Telvent to meet current needs. APS GIS is the provider of land & distribution facility data to DOMS & web map services including AMI, EIN, Wildfire, MATS & field data for the GIS field map viewer	$ 201,446	$ 18,642	$ 220,088	12/30/2011
80.	T26079	Aruba 802.11 Security Enhancements	Implement a more secure SSID for wireless users. Also instal redundent Airwave controllers	$ 173,460	$ 16,052	$ 189,512	12/30/2011
81.	T26400	Decoupling Project	Implement Cisco Voice Gateways to decouple Call Manager solution from the Nortel PBX, to provide access to pulic switched telephone network and eliminate PBX dependencies. Modify APS Telephone Management System to access Call Manager database to input long distance authorization codes.	$ 113,320	$ 10,487	$ 123,807	12/30/2011
82.	Budget	Firewall Replacement & Manageability Improvements	This project will assist with hardware obsolescence replacements as well as allocate resources to make tuning and process improvements that would help the performance and reliability of the system.	$ -	$ 104,627	$ 104,627	12/30/2011
83.	Budget	Maximo Phase 2	Enhance single-sign-on solutions for non-Microsoft integrated technologies and for SaaS solutions while maintaining compliance with tiers of information sensitivity and potential re-authentication requirements. (D13, D17)	$ -	$ 104,627	$ 104,627	12/30/2011
84.	Budget	Implement automation of user/sites management for SharePoint	Procure and implement SharePoint administration tools that will allow automation of user management and sites management for SharePoint.	$ -	$ 104,627	$ 104,627	12/30/2011
85.	Budget	SOUTHERN YD SECURITY	Security & Fencing - Improvements to newly purchased property; access control, security and useability. Timing- purchased in 2010 .	$ -	$ 104,627	$ 104,627	12/30/2011

IT and Facilities Capital Post Test Year Additions

Line No.	WA#	Project Description	Purpose	Project Cost to Date 12/31/10	Cost to Complete	Total Project Cost	Estimated In-Service Date
86.	Budget	Implement Intranet Access for mobile devices that use GoodLink/ActiveSync/Blackberry.	We have apps available on mobile devices & working on a thin client solution for all users. Based on requests from business units this project will allow intranet access on mobile devices extending the trusted platform to a broad range of apps/use cases	$ -	$ 104,627	$ 104,627	12/30/2011
87.	Budget	Purchase SharePoint migration tool, Backup/restore tool, rebuild legacy websites using sharepoint	Purchase of SharePoint Migration tool and next tier backup / storage tool (due to growth), retirement of legacy websites, creating new SharePoint sites, retirement of SharePoint 2003 and 2007 sites.	$ -	$ 101,157	$ 101,157	3/1/2012
88.	Budget	Goodyear CSO	Remodel - Customer Service Office jointly with new City of Goodyear building. This project has been moved to future years based on City of Goodyear's development plan.	$ -	$ 104,627	$ 104,627	12/30/2011
89.	T26596	Zoning Process Network Separation	This project will separate process control networks from business networks.	$ 91,527	$ 8,470	$ 99,997	12/30/2011
90.	P157207	Conference Room Upgrades L3 & L15	Purchase and installation of the new conference room tables, seating and Audio Video equipment.	$ 73,540	$ 6,805	$ 80,346	12/30/2011
91.	T26451	EAI Infrastructure Upgrade SS Gen	Continuation effort to restructure the EAI Corporate Domains (environments).	$ 72,809	$ 6,738	$ 79,547	12/30/2011
92.	Budget	Deer Valley Sub	Substation Control House Roofing Replacement. Replacments are scheduled on 30 year intervals based on maintained useful life.	$ -	$ 43,943	$ 43,943	12/30/2011
93.	T26467	PowerPlant Enh for IFRS	Enhance the PowerPlant application to capture the necessary data and interface to PeopleSoft for compliance with International Financial Reporting Standards.	$ 69,299	$ 6,413	$ 75,712	12/30/2011
94.	T26298	Power Backup - Falcon Crest	Upgrade batteries and charging systems at mountain top communications sites.	$ 31,250	$ 2,892	$ 34,142	12/30/2011
95.	Budget	GIS GIS DB Changes- UFO-ID. Merge, ST Geom	To change to static unique ID data relationships in our Geodatabases. The relationships currently use an Object ID to relate to each other. This is a SW-generated ID that changes when certain functions are executed.	$ -	$ 62,776	$ 62,776	12/30/2011
96.	T26299	Power Backup - Yuma SC	Upgrade batteries and charging systems at mountain top communications sites.	$ 6,776	$ 627	$ 7,404	12/30/2011
97.	Budget	DVM	HVAC- Replace 7 units. Units beyond planned useful life	$ -	$ 58,671	$ 58,671	3/1/2012
98.	T26300	Power Backup - Childs Mtn	Upgrade batteries and charging systems at mountain top communications sites.	$ 13,282	$ 1,229	$ 14,512	12/30/2011
99.	T25576	Black Peaks ES	Upgrade batteries and charging systems at mountain top communications sites	$ 46,880	$ 4,338	$ 51,218	12/30/2011
100.	Budget	Willow Creek Sub	Substation Control House Roofing Replacement. Replacments are scheduled on 30 year intervals based on maintained useful life.	$ -	$ 36,416	$ 36,416	3/1/2012
101.	Budget	Pwr Backup - Signal Peak	Replace the obsolescence charging system and batteries	$ -	$ 10,463	$ 10,463	12/30/2011
102.	Budget	PWR - Mt Elden	Replace the obsolescence charging system and batteries	$ -	$ 36,619	$ 36,619	12/30/2011
103.	Budget	32 St Sub	Substation Control House Roofing Replacement. Replacments are scheduled on 30 year intervals based on maintained useful life.	$ -	$ 32,370	$ 32,370	3/1/2012
104.	Budget	Tuba City RES	Flooring & Remodel -Housing provided to area sericeman. Flooring and Furnishings are beyond their planned useful life	$ -	$ 20,231	$ 20,231	3/1/2012
105.	T26157	Power Backup Program - Mt Elden	Upgrade batteries and charging systems at mountain top communications sites.	$ 28,642	$ 2,651	$ 31,293	12/30/2011
106.	Budget	Coldwater Sub	Substation Control House Roofing. Restore has been determined as O&M per Accounting. Restorations are are scheduled every 10 years over 30 year life span.	$ -	$ 11,509	$ 11,509	12/30/2011
107.	V1258	PV U2 OSB L4 AO Briefing Room Remod	Remodel existing facility based on business unit growth and usage need changes	$ 10,923	$ 1,011	$ 11,934	12/30/2011
108.	**Total IT and Facilities Capital Post-Test Year Additions**					**$ 101,572,939**	

William E. Avera

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF

WILLIAM E. AVERA

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-____

June 2011

DIRECT TESTIMONY OF WILLIAM E. AVERA

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DIRECT TESTIMONY OF WILLIAM E. AVERA
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-_____)

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Arizona Corporation Commission ("ACC" or the "Commission") my independent assessment of the fair rate of return on equity ("ROE") for the jurisdictional electric utility operations of Arizona Public Service Company ("APS" or "Company"). In addition, I also examined the reasonableness of APS's capital structure, considering both the specific risks faced by the Company and other industry guidelines.

A. Summary of Conclusions

Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR APS?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that APS be authorized an ROE in the range of 10.75 percent to 11.75 percent, with the midpoint being 11.25 percent. My findings were based on the following conclusions:

- In order to reflect the risks and prospects associated with APS's jurisdictional utility operations, my analyses focused on a proxy group of other utilities with comparable investment risks;

- Consistent with the fair value rate base standard, and the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;

- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the discounted cash flow ("DCF") approach and capital asset pricing model ("CAPM") to estimate a fair ROE for APS. These methods are forward-looking and can be applied under the fair value rate base standard without adjustments;

- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.6 percent to 11.60 percent range, or 10.75 percent to 11.75 percent after incorporating a minimal adjustment to account for the impact of common equity flotation costs;

- Investors view existing and proposed cost recovery and revenue adjustment mechanisms as supportive of APS's financial integrity, but there is no evidence that these provisions alone will result in a measurable change in the Company's investment risk or ROE relative to the proxy companies;

- The reasonableness of an 11.25 percent ROE for APS is also supported by the greater investment risks implied by:
    - The Company's low credit rating,
    - The pressures of funding significant capital expenditures,
    - The potential for continued regulatory lag,
    - Exposures to nuclear uncertainty, and
    - The expected upward trend in long-term capital costs.

- As reflected in the testimony of Mr. Jeff Guldner APS is requesting a fair ROE of 11.00 percent to balance customer impact during these challenging economic times with the Company's

need to maintain is financial integrity and access to capital. This 11.00 percent ROE falls below the midpoint of my recommended range and, in my professional opinion, represents a reasonable rate of return on common equity for APS; and,

- Taken together, these factors more than offset any arguable impact attributable to the implementation of the Company's existing and proposed adjustment mechanisms.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR ROE RECOMMENDATION IN THIS CASE?

A. My recommendation was reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;

- Providing APS with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs;

- Strengthening APS's financial integrity is imperative to ensure that the Company has the capability to maintain an investment grade rating while confronting the pressures associated with funding substantial infrastructure development and ensuring APS's ability to respond effectively to unforeseen events, and,

- The ROE estimates developed in my testimony, as well as the weighted cost of capital requested by APS, can and should be applied to fair value rate base, without adjustment, since the estimation methods are forward-looking and based on returns required on market values. Lowering the ROE when determining the reasonable return on fair value would amount to simply another way of reducing the Company's fair value rate base.

Q. HOW DID YOU CONDUCT YOUR ANALYSIS OF THE COST OF EQUITY SO THAT THE RESULT CAN BE APPLIED TO THE FAIR VALUE RATE BASE WITHOUT ADJUSTMENT?

A. I implemented the DCF and CAPM methods using forward-looking expectations applied to current market values that are consistent with a fair value rate base standard. My DCF approach used expected dividend yields and forecasted growth rates based on professional security analysts' current expectations. My application of the CAPM was based on expected dividend yields and growth forecasts underlying the expected return on the broad market. I did not employ risk premium estimates based on historical returns nor did I reference comparable earnings on original cost investment. By using forward-looking approaches that estimate the cost of equity based on current market values, the resulting reasonable ROE range is consistent with my understanding of the constitutional requirements in Arizona. Thus, the 11.00 percent return that APS selected from the lower end of my reasonable range can be applied under the fair value rate base standard without further adjustments.

Q. IS ATTRITION A LEGITIMATE CONSIDERATION IN ESTABLISHING APS' RATES FOR ELECTRIC UTILITY SERVICE?

A. Yes. Regulatory lag is prevalent in Arizona and attrition remains a major concern of the investment community. If the impact of attrition is ignored, the Company will be denied an opportunity to earn investors' required rate of return. My testimony demonstrates that:

- APS is undertaking a huge capital investment program in order to meet the growing requirements of customers. A continuation of regulatory lag would prevent the Company from achieving timely cost recovery, which would erode the Company's credit metrics;
- In evaluating the Company's requested ROE, the Commission should consider the economic reality that APS's actual returns have fallen systematically short of the allowed ROE;

- Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles:
  - To be fair to investors and to benefit customers, a regulated utility must have an opportunity to actually earn a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk;
  - Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation;
  - Denying APS the opportunity to earn a sufficient return through the impact of attrition is the economic equivalent of taking the capital value of existing investors.
- APS's proposed cost and revenue adjustment mechanisms represents a logical approach to attenuate the impact of attrition.

Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that a common equity ratio of approximately 54 percent represents a reasonable basis from which to calculate APS's overall rate of return. This conclusion was based on the following findings:

- APS's requested capitalization is consistent with the Company's need to strengthen its credit standing and financial flexibility as it seeks to raise additional capital to fund significant system investments and meet the requirements of its growing service territory;
- APS's proposed common equity ratio is consistent with the range of capitalizations maintained by the firms in my utility proxy group;
- My conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks and the pressures of funding significant capital investments, as well as the impact of off-balance sheet commitments such as purchased power agreements;

- Regulatory support for higher equity levels is necessary to maintain APS's financial flexibility and preserve the Company's capacity to fund investments that will ensure reliable service and facilitate further development of electric utility infrastructure in Arizona.

B. Qualifications

Q. WHAT ARE YOUR QUALIFICATIONS?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface

Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states, including the ACC.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. Attachment

WEA-1 contains a resume presenting the details of my experience and qualifications.

C. Overview

Q. WHAT IS THE PRACTICAL TEST OF THE REASONABLENESS OF THE ROE USED IN SETTING A UTILITY'S RATES?

A. The ROE compensates equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to (1) fairly compensate the utility's investors, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the organization, finances, and operations of APS from my participation in prior proceedings before the ACC. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to APS and its parent company, Pinnacle West Capital Corporation ("Pinnacle West"). I also reviewed

[1] Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required rate of return for APS, and they form the basis of my analyses and conclusions.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first reviewed the operations and finances of APS, as well as general conditions in the electric utility industry and the capital markets. With this as a background, I described the conceptual principles underlying investors' required rate of return and then conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the DCF approach and CAPM. From the cost of equity range indicated by my analyses, a rate of return on equity was selected taking into account the fair value rate base standard used in this jurisdiction and the economic requirements and specific risks and potential challenges for APS's electric utility operations in Arizona.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to my analyses, this section briefly reviews the operations and finances of APS, along with the risks and prospects for the utility industry. An understanding of these fundamental factors is essential in developing an informed opinion about investor expectations and requirements that form the basis of a fair rate of return.

A. Arizona Public Service Company

Q. BRIEFLY DESCRIBE APS.

A. The principal subsidiary of Pinnacle West, APS is primarily engaged in the generation, transmission, and distribution of electric power to approximately 1.1 million customers in 11 of Arizona's 15 counties. In addition to providing retail electric utility service, the Company also sells electric power at wholesale to municipalities and other utilities. During the adjusted test year, retail energy sales amounted to 27.7 million megawatt-hours ("MWh") hours. Sales to residential customers comprised approximately 51.2 percent of retail revenues from base rates, while sales to non-residential customers comprised approximately 48.8 percent of retail revenues from base rates.[3] In addition, APS had total depreciable assets of approximately $13.7 billion,[4] with operating revenues totaling approximately $3.2 billion.[5]

The Company owns approximately 6,290 MW of generating facilities, including its 29.1% interest in the three nuclear units of the Palo Verde Nuclear Generating Station ("Palo Verde"), with a total capacity of approximately 1,146 MW. In 2010, nuclear generation accounted for approximately 27 percent of the electric energy provided by APS, with coal at 37 percent, and natural gas at 12 percent. In addition to its own generating capacity, APS relied on purchased power for the remaining 24 percent of its 2010 energy needs. APS's transmission and distribution facilities consist of approximately 17,000 pole miles of overhead lines and over 17,400 miles of underground lines.

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[3] APS Rate Filing, Schedule H-2.
[4] Ibid, Schedule A-4.
[5] Ibid, Schedule E-2.

The Company's retail electric operations are subject to the jurisdiction of the Commission, with transmission operations being regulated by FERC. Additionally, APS's nuclear facilities are subject to licensing and oversight by the Nuclear Regulatory Commission ("NRC"). While the Commission originally approved rules to restructure Arizona's electric utility industry in 1999, it effectively halted this process following the Western energy crisis in 2000-2001. Although future legal and regulatory developments surrounding industry restructuring remain unresolved, at the time of this filing there are no active regulated competitors providing unbundled energy or other utility services to APS's customers. However, APS does face increasingly significant competition from distributed generation, both customer-owned and that provided by unregulated third parties.

Q. DOES APS ANTICIPATE THE NEED TO ACCESS THE CAPITAL MARKETS GOING FORWARD?

A. Most definitely. APS will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission and distribution facilities. In order to keep pace with the infrastructure needs of its service territory, APS anticipates construction expenditures totaling approximately $3.3 billion over the next three years alone.[6] As Fitch noted, "Compound annual growth in capital expenditures is estimated at 14% during 2010–2012.[7] Support for APS's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

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[6] Pinnacle West Capital Corp., *2010 Form 10-K Report* at p. 63.

[7] Fitch Ratings, Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Full Ratings Report* (Jun. 11, 2010).

Q. HOW ARE FLUCTUATIONS IN APS'S OPERATING EXPENSES CAUSED BY VARYING FUEL AND POWER MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A. APS recovers variations in purchased power and fuel costs through a power supply adjustor ("PSA"). Under the PSA, the base fuel rate is established based on annual projections for the following year filed with the Commission. Monthly differences between the actual costs for purchased power and fuel and the base fuel rate are deferred for future recovery or refund. At year-end, the deferred balance is either charged to or credited back to customers over the coming year. As a result, deviations in actual versus projected costs are collected on a one-year lagged basis. In the event that APS experiences unexpected volatility in power costs, it can apply to the Commission for consideration of a mid-year surcharge to address extenuating circumstances.

The PSA continues to provide for a sharing mechanism, under which APS must absorb as much as the first 10 percent of costs above the base fuel rate and may retain up to 10 percent of savings when actual costs fall below projected levels. Adjustments are limited to the sum of the prior year's total PSA plus or minus $0.004 per kilowatt-hour ("kWh"), with additional amounts being recorded in a balancing account for future recovery. However, APS is proposing to remove the PSA sharing in this case.

Q. WHAT CREDIT RATINGS HAVE BEEN ASSIGNED TO APS?

A. Currently, APS is assigned a corporate credit rating of "BBB-" by Standard & Poor's Corporation ("S&P"). Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "Baa2", with Fitch Ratings Ltd. ("Fitch") assigning a "BBB-" issuer default rating. The "BBB-" ratings assigned by S&P and Fitch represent the lowest rung on the ladder of the

investment grade scale, and any downgrade would place the Company in the same category as speculative, or "junk" securities.

B. Risks for APS

Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY INDUSTRY EVOLVED?

A. Implementation of structural change, along with other factors impacting the economy and the industry, has caused investors to rethink their assessment of the relative risks associated with utilities. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. In December 2009, S&P observed with respect to the industry's future that:

> Looming costs associated with environmental compliance, slack demand caused by economic weakness, the potential for permanent demand destruction caused by changes in consumer behavior and closing of manufacturing facilities, and numerous regulatory filings seeking recovery of costs are some of the significant challenges the industry has to deal with.[8]

Similarly, Moody's noted:

> [A] sustained period of sluggish economic growth, characterized by high unemployment, could stress the sector's recovery prospects, financial performance, and credit ratings. The quality of the sector's cash flows are already showing signs of decline, partly because of higher operating costs and investments.[9]

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[8] Standard & Poor's Corporation, "U.S. Regulated Electric Utilities Head Into 2010 With Familiar Concerns," *RatingsDirect* (Dec. 28, 2009).

[9] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

More recently, Moody's concluded, "we also see the sector's overall business and operating risks increasing."[10]

Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in fuel costs due to ongoing price volatility in the spot markets, and investors recognize the potential for further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. Coal has historically provided relative stability with respect to fuel costs, but prices experienced significant volatility over the 2007 – 2009 time period. Similarly, the Energy Information Administration ("EIA"), which is a statistical agency of the U.S. Department of Energy ("DOE"), reported that the weighted-average price paid for uranium oxide equivalent in 2008 was $45.88 per pound, representing an increase of 40 percent compared to 2007 price levels and coming on the heels of a 76 percent price increase during the previous year.[11] The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.

While current expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. For example, heightened uncertainties in the Middle East have led to sharp increases in petroleum prices,

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[10] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).
[11] Energy Information Administration, *2008 Uranium Marketing Annual Report* (May 26, 2009).

and the potential ramifications of the Japanese nuclear accident on the future cost and availability of nuclear generation in the U.S. have not been lost on investors. S&P observed that "short-term price volatility from numerous possibilities ... is always possible,"[12] while Moody's concluded that utilities remain exposed to fluctuations in energy prices, observing, "This view, that commodity prices remain low, could easily be proved incorrect, due to the evidence of historical volatility."[13]

Q. DOES THE PSA COMPLETELY SHIELD APS FROM EXPOSURE TO FLUCTUATIONS IN POWER SUPPLY COSTS?

A. No. The investment community views the Company's ability to periodically adjust retail rates to accommodate fluctuations in fuel costs as an important source of support for APS's financial integrity. Nevertheless, they also recognize that there can still be a lag between the time APS actually incurs the expenditure and when it is recovered from ratepayers. As a result, APS is not insulated from the potential need to finance deferred fuel costs.[14] Indeed, despite the significant investment of resources to manage fuel procurement, investors are aware that the best that APS can do is to recover something less than its actual costs during times of rising fuel costs. In other words, APS earns no return on deferred fuel costs and is exposed to disallowances for imprudence in its fuel procurement.

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[12] Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).

[13] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[14] Moody's has noted that the Company's financial metrics have been negatively impacted in the past as a result of power cost deferrals. Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Opinion* (Dec. 17, 2007).

Q. WHAT OTHER FINANCIAL PRESSURES IMPACT INVESTORS' RISK ASSESSMENT OF THE COMPANY?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[15] As Moody's observed:

> [W]e also see the sector's overall business risk and operating risks increasing, owing primarily to rising costs associated with upgrading and expanding the nation's trillion dollar electric infrastructure.[16]

As noted earlier, investors anticipate that APS will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company.

Q. ARE ENVIRONMENTAL CONSIDERATIONS ALSO AFFECTING INVESTORS' EVALUATION OF ELECTRIC UTILITIES?

A. Yes. Utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities."[17] While the momentum for carbon emissions legislation has slowed, expectations for eventual regulations continue to pose uncertainty. Fitch recently concluded,

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[15] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).
[16] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).
[17] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

"Prospects of costly environmental regulations will create uncertainty for investors in the electricity business in 2011."[18] With respect to APS specifically, Fitch noted that, "Spending in the generation category is expected to outpace transmission and distribution, driven in large part by investment in environmental remediation equipment."[19] The imperative of meeting evolving emissions standards implies significant capital expenditures for those utilities, such as APS, that rely significantly on coal-fired generation.

Q. WHAT OTHER CONSIDERATIONS AFFECT INVESTORS' EVALUATION OF APS?

A. In evaluating an investment in the Company, investors would also consider the fact that Palo Verde accounts for approximately 18 percent of APS's company-owned generation capacity – its largest single generating resource. S&P observed that APS is "highly exposed to nuclear power availability and operations."[20] While customers benefit from the advantages of fuel cost savings and diversity that nuclear power confers, investors also associate nuclear facilities with risks that are not encountered with other sources of generation. These concerns have been exacerbated by the events at the Fukushima Daiichi nuclear complex in Japan, as S&P recently noted:

> Standard & Poor's Ratings Service believes that the failure of the back-up safety systems will heighten scrutiny of the systematic risks for U.S. nuclear power generators. We aren't taking any rating actions at this time. Still, the failures and their consequences raise the likelihood of greater costs and enhanced

[18] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010)
[19] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Full Ratings Report* (Jun. 11, 2010).
[20] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).

regulatory oversight for existing U.S. facilities. A renewed public focus on the inherent risks of nuclear power will demand as much. This could result in delays in license-extension approvals and deteriorating economics for new plant construction. At the same time, closure of nuclear power plants, either due to increased costs or regulatory action, might significantly affect U.S. electricity supply and have substantial capital spending implications for utilities.[21]

C. Impact of Capital Market Conditions

Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. The deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of December 2010, the Dow Jones Utility Average stock index remained approximately 25 percent below the previous high reached in May 2008. This prolonged sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry is not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives in September 2008 as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

[21] Standard & Poor's Corporation, "The U.S. Nuclear Power Industry Looks At Japan And Awaits More Scrutiny," *Global Credit Research* (Mar. 16, 2011).

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[22]

Similarly, an October 1, 2008 *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[23] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions had increased the cost of capital for utilities.[24]

While conditions have improved significantly since the depths of the crisis, investors have nonetheless had to confront ongoing fluctuations in share prices and stress in the credit markets. As the Wall Street Journal noted in February 2010:

> Stocks pulled out of a 167-point hole with a late rally Friday, capping a wild week reminiscent of the most volatile days of the credit crisis. ... It was a return to the unusual relationships, or correlations, seen at major flash points over the past two years when investors fled risky assets and jumped into safe havens. This market behavior, which has reasserted itself repeatedly since the financial crisis began, suggests that investment decisions are still

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[22] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

[23] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).

[24] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).

> being driven more by government support and liquidity concerns than market fundamentals.[25]

In response to renewed capital market uncertainties initiated by unrest in the Middle East, the natural disaster in Japan, ongoing concerns over the European sovereign debt crisis, and questions over the sustainability of economic growth, investors have repeatedly fled to the safety of U.S. Treasury bonds, and stock prices have experienced renewed volatility.[26] The dramatic rise in the price of gold and other commodities also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. With respect to electric utilities, Fitch observed that, "the outlook for the sector would be adversely affected by significantly higher inflation and interest rates."[27] Moody's recently concluded:

> Over the past few months, we have been reminded that global financial markets, which are still receiving extraordinary intervention benefits by sovereign governments, are exposed to turmoil. Access to the capital markets could therefore become intermittent, even for safer, more defensive sectors like the power industry.[28]

Uncertainties surrounding economic and capital market conditions heighten the risks faced by electric utilities, which, as described earlier, face a variety of operating and financial challenges.

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[25] Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010).

[26] The Wall Street Journal recently reported that the Dow Jones Industrial Average experienced its largest drop since August 2010, which marked the fourth triple-digit move in less than two weeks. Tom Lauricella and Jonathan Cheng, "Dow Below 12000 on Mideast Worries – Troubles in Europe and China Add to Jitters," *Wall Street Journal* C1 (March. 11, 2011).

[27] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010).

[28] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

Q. HOW DO INTEREST RATES ON LONG-TERM BONDS COMPARE WITH THOSE PROJECTED FOR THE NEXT FEW YEARS?

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the EIA:

TABLE WEA-1
INTEREST RATE TRENDS

	Current (a)	2012	2013	2014	2015
30-Yr. Treasury					
Value Line (b)	4.4%	4.9%	5.2%	5.5%	6.0%
IHS Global Insight (c)	4.4%	4.7%	5.0%	5.1%	6.0%
Blue Chip (d)	4.4%	4.8%	5.2%	5.4%	5.5%
AAA Corporate					
Value Line (b)	5.0%	5.6%	6.0%	6.3%	6.5%
IHS Global Insight (c)	5.0%	5.2%	6.0%	6.2%	6.8%
Blue Chip (d)	5.0%	5.4%	5.8%	6.1%	6.3%
S&P (e)	5.0%	6.1%	5.7%	5.9%	6.3%
AA Utility					
IHS Global Insight (c)	5.2%	5.4%	6.3%	6.4%	7.2%
EIA (f)	5.2%	5.5%	6.4%	7.0%	7.4%

(a) Based on monthly average bond yields for the six-month period Oct. 2010 - Mar. 2011 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 25, 2011).
(c) IHS Global Insight, *U.S. Economic Outlook* at 19 (Feb. 2011).
(d) *Blue Chip Financial Forecasts,* Vol. 29, No. 12 (Dec. 1, 2010).
(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Pouring Water On Troubled Oil," *RatingsDirect* (Mar. 8, 2011).
(f) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2012-2015 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR APS?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. The fact remains that the electric utility industry requires significant new capital investment. Given the importance of reliable electric utility service, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case. Similarly, the Company's capital structure must also preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In this section, I develop capital market estimates of the cost of equity. First, I address the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of equity for benchmark groups of comparable risk firms. In recognition of the fair value rate base standard in Arizona, I have applied the DCF and CAPM in a forward-looking manner and I have avoided applying historical risk premium and comparable earnings approaches. Finally, I examine the issue of flotation costs, which are properly considered in evaluating a fair ROE.

A. Economic Standards

Q. WHAT ROLE DOES THE RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with

investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky.[29] Following bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY FOR A UTILITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

[29] That being said, even secured long-term debt is effectively "junior" to long-term cost commitments necessary to operate the underlying business such as power agreements, fuel contracts and certain leases. The magnitude of these non-debt obligations can affect the cost of all forms of capital, including equity.

Q. DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF EQUITY FOR APS?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

B. Comparable Risk Proxy Groups

Q. HOW DID YOU IMPLEMENT THESE QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR APS?

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A. In order to reflect the risks and prospects associated with APS's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by The Value Line Investment

Survey ("Value Line") as electric utilities with: (1) an S&P corporate credit rating of "BBB-" to "BBB+", (2) a Value Line Safety Rank of "2" or "3", (3) a Value Line Financial Strength Rating of "B" to "B++", and (4) a market capitalization of $1.6 billion or greater. In addition, I eliminated three utilities (FirstEnergy Corp., Northeast Utilities, and Progress Energy, Inc.) that otherwise would have been in the proxy group, but are not appropriate for inclusion because they are currently involved in a major merger or acquisition. These criteria resulted in a proxy group composed of twenty-one companies, which I will refer to as the "Utility Proxy Group."

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR APS?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair ROE is relative risk, not the particular business activity or degree of regulation. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to

investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk.

Q. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER REQUIRED RETURNS FOR NON-UTILITY COMPANIES?

A. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." [30] It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[31]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or

[30] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[31] *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 391, 1944).

similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY PROXY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry or the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example, Value Line recently observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years.[32]

Because the Non-Utility Proxy Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY PROXY GROUP?

A. My comparable risk proxy group of non-utility firms was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or

[32] The Value Line Investment Survey at 445 (Mar. 12, 2010).

greater; (4) have a beta of 0.85 or less; and, (5) have investment grade credit ratings from S&P.

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE TO EVALUATE INVESTORS' RISK PERCEPTIONS?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Although the credit rating agencies are not immune to criticism, their rankings and analyses are widely cited in the investment community and referenced by investors.[33] Investment restrictions tied to credit ratings continue to influence capital flows, and credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a

[33] While the ratings agencies were faulted during the financial crisis for failing to adequately assess the risk associated with structured finance products, investors continue to regard corporate credit ratings as a reliable guide to investment risks.

stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUPS COMPARE WITH APS?

A. Table WEA-2 compares the Utility Proxy Group with the Non-Utility Proxy Group and APS across four key indicators of investment risk. Because the Company does not have publicly traded common stock, the Value Line risk measures shown reflect those published for the Company's parent, Pinnacle West:

TABLE WEA-2
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Beta
Utility Group	BBB	3	B+	0.74
Non-Utility Proxy Group	A	1	A+	0.70
APS	BBB-	3	B+	0.70

Q. DO THESE COMPARISONS INDICATE THAT INVESTORS WOULD VIEW THE FIRMS IN YOUR PROXY GROUPS AS RISK-COMPARABLE TO THE COMPANY?

A. Yes. As discussed earlier, APS is assigned a corporate credit rating of "BBB-" by S&P, which falls below the average corporate credit rating for the Utility Proxy Group. Meanwhile, the average Value Line Safety Rank and Financial Strength Rating for the Utility Proxy Group are identical to the values assigned to the Company's parent, while the average beta value for the Utility Proxy Group suggests somewhat greater risk than investors would associate with APS. Considered together, a comparison of these objective measures, which consider of a broad spectrum of risks, including financial and business position, and exposure to firm-specific factors, indicates that investors would likely conclude that the overall investment risks for APS are comparable to, or greater than, those of the firms in the Utility Proxy Group.

With respect to the Non-Utility Proxy Group, its average credit ratings, Safety Rank, and Financial Strength Rating suggest less risk than for APS, with its 0.70 average beta indicating identical risk. While the impact of differences in regulation is reflected in objective risk measures, my analyses conservatively focus on a lower-risk group of non-utility firms.

C. Discounted Cash Flow Analyses

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where:
- P_0 = Current price per share;
- P_t = Expected future price per share in period t;
- D_t = Expected dividend per share in period t;
- k_e = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[34]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. WHAT FORM OF THE DCF MODEL DID YOU USE?

A. I applied the constant growth DCF model to estimate the cost of equity for APS, which is the form of the model most commonly relied on to establish the cost of equity for traditional regulated utilities and the method most often referenced by regulators. Other forms of the general, or non-constant DCF model, such as "two-stage" or "multi-stage" analyses can be used to estimate the cost of equity.

[34] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

However, these approaches generally require several very specific assumptions regarding investors' expected cash flows that must occur at given points in the future. This makes the results of non-constant growth DCF applications sensitive to changes in assumptions, and therefore subject to greater controversy in a rate case setting.

While the complexity of non-constant DCF models may impart an aura of accuracy, there is no evidence that investors' current view of electric utilities anticipates a series of discrete, clearly defined stages. As a result, there is no discernable transition that would support use of the multi-stage DCF approach to evaluate a fair rate of return for APS. Moreover, to the extent that each of these time-specific suppositions about future cash flows do not reflect what real-world investors actually anticipate, the resulting cost of equity estimate will be biased. Indeed, the benchmark for growth in a DCF model is <u>what investors expect</u> when they purchase stock. Unless we replicate investors' thinking, we cannot uncover their required returns and thus the market cost of equity. In practice, applying a non-constant DCF model would lead to error if it ignores the views of real-world investors.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The

final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. HOW WAS THE DIVIDEND YIELD FOR THE UTILITY PROXY GROUP DETERMINED?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Attachment WEA-2. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 2.1 percent to 5.9 percent.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. ARE HISTORICAL GROWTH RATES LIKELY TO BE REPRESENTATIVE OF INVESTORS' EXPECTATIONS FOR ELECTRIC UTILITIES?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical

conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for electric utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the electric utility industry or the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of electric utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[35] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the electric utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the

[35] For example, the payout ratio for electric utilities fell from approximately 80% historically to on the order of 60%. The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 4, 2011 at 2237).

source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[36]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[37]

The fact that investment advisory services focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts

[36] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).
[37] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

actually use.[38] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[39]

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[40]

Q. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY PROXY GROUP?

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on Attachment WEA-2.[41]

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[38] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[39] *Id.* at 88.
[40] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.
[41] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

Q. SOME ARGUE THAT ANALYSTS' ASSESSMENTS OF GROWTH RATES ARE BIASED. DO YOU BELIEVE THESE PROJECTIONS ARE INAPPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or

pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is similarly irrelevant if investors share the analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[42]

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

[42] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006).

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. WHAT IS THE PURPOSE OF THE "SV" TERM?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE UTILITY PROXY GROUP?

A. The sustainable, "br+sv" growth rates for each firm in the proxy group are summarized on Attachment WEA-2, with the underlying details being presented on Attachment WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations.

Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. WHAT COST OF EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY PROXY GROUP USING THE DCF MODEL?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of equity estimates are shown on Attachment WEA-2.

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF results must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As noted earlier, the average S&P corporate credit rating for the Utility proxy Group is "BBB", with APS being rated "BBB-". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.0 percent in March 2011.[43] It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[44]

[43] Moody's Investors Service, www.credittrends.com.
[44] *Southern California Edison Company*, 92 FERC ¶ 61,070 at p. 22 (2000).

Similarly, in its August 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[45]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[46]

The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[47] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[48]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 7.16 percent over the period 2012-2015:

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[45] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[46] *Id.*
[47] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[48] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

TABLE WEA-3
IMPLIED BBB BOND YIELD

	2012-15
Projected AA Utility Yield	
IHS Global Insight (a)	6.33%
EIA (b)	6.58%
Average	6.45%
Current BBB - AA Yield Spread (c)	0.71%
Implied Triple-B Utility Yield	**7.16%**

(a) IHS Global Insight, *U.S. Economic Outlook* at 19 (Feb. 2011).
(b) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).
(c) Based on monthly average bond yields for the six-month period Oct. 2010 - Mar. 2011.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb more than 100 basis points through the period 2012-2016.[49]

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As shown on Attachment WEA-2, eight low-end DCF estimates ranged from 0.7 percent to 6.5 percent. Five of these values were below current utility bond yields, with cost of equity estimates below 7.0 percent being less than the yield on triple-B utility bonds expected during the period 2012-2015. In light of the risk-return tradeoff principle and the test applied in *SoCal Edison*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and the

[49] *Blue Chip Financial Forecasts*, Vol. 29, No. 12 (Dec. 1, 2010) & Vol. 30, No. 3 (Mar. 1, 2011).

upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. DO YOU ALSO RECOMMEND EXCLUDING ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?

A. Yes. The upper end of the cost of common equity range produced by the DCF analysis presented in Attachment WEA-2 was set by estimates of 18.8 percent and 17.1 percent for ITC Holdings Corp. I determined that, when compared with the balance of the remaining estimates, these values should be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[50]

Q. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As shown on Attachment WEA-2 and summarized in Table WEA-4, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates ranging from 9.3 percent to 11.40 percent:

[50] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

TABLE WEA-4
DCF RESULTS –UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.2%
IBES	11.0%
Zacks	10.9%
br+sv	9.5%

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY PROXY GROUP?

A. I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the proxy group of utilities. The results of my DCF analysis for the Non-Utility Proxy Group are presented in Attachment WEA-4, with the sustainable, "br+sv" growth rates being developed on Attachment WEA-5. As shown on Attachment WEA-4 and summarized in Table WEA-5, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates on the order of at least 12 percent:

TABLE WEA-5
DCF RESULTS – NON-UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.9%
IBES	12.4%
Zacks	12.5%
br+sv	12.1%

Q. DO THE HIGHER DCF ESTIMATES FOR THE NON-UTILITY PROXY GROUP DEMONSTRATE THAT THE RISKS OF THESE COMPANIES ARE GREATER THAN APS?

A. No. While we are accustomed to associating higher risk with higher returns, DCF estimates of investors' required rate of return do not always produce that

result. Performing the DCF calculations for the Non-Utility Proxy Group produced ROE estimates that are higher than the DCF estimates for the Utility Proxy Group, even though the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and Beta – are lower than the risks investors associate with the Utility Proxy Group and APS. The actual cost of equity is unobservable, and DCF estimates may depart from these values because investors' expectations may not be captured by the inputs to the ROE model, particularly the assumed growth rate. Nevertheless, regulators have relied upon DCF calculations for years in evaluating a fair ROE. The divergence between the DCF estimates for the Utility and Non-Utility Proxy Groups suggests that both should be considered to ensure a balanced end-result.

D. Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity both among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as

$$R_j = R_f + \beta_j(R_m - R_f)$$

where:
R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF EQUITY?

A. Application of the CAPM to the Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Attachment WEA-6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500 Composite Index.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-years' growth using the rate discussed subsequently $(1 + g)$ to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the consensus earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 354 individual firms, current estimates imply an average growth rate over the next five years of 10.5 percent. Combining this average growth rate with a year-ahead dividend yield of 2.3 percent results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.8 percent. Subtracting a 4.5 percent risk-free rate based on the average yield

on 30-year Treasury bonds produced a market equity risk premium of 8.3 percent.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. ... Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[51]

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A. A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[52]

Because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

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[51] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).
[52] *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at p. 85 (footnote omitted).

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[53] Accordingly, my CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups.

Q. WHAT COST OF EQUITY ESTIMATE WAS INDICATED FOR THE UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. The average market capitalization of the Utility Proxy Group is $6.3 billion. Based on data from *Morningstar*, this means that the theoretical CAPM cost of equity estimate must be increased by 74 basis points to account for the industry group's relative size. As shown on Attachment WEA-6, adjusting the theoretical CAPM result to incorporate this size adjustment results in an average indicated cost of common equity of 11.40 percent.

Q. WHAT COST OF COMMON EQUITY WAS INDICATED FOR THE NON-UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

[53] *Id.* at Table C-1.

A. As shown on Attachment WEA-7, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.0 percent.

Q. SHOULD THE CAPM APPROACH BE APPLIED USING HISTORICAL RATES OF RETURN?

A. No. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely than it is today. This incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.[54]

E. Flotation Costs

[54] FERC has previously rejected CAPM methodologies based on historical data because whatever historical relationships existed between debt and equity securities may no longer hold. *See Orange & Rockland Utils., Inc., 40 F.E.R.C. P63,053, at pp. 65,208 -09 (1987), aff'd, Opinion No. 314, 44 F.E.R.C. P61,253 at 65,208.*

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN DETERMINING THE ROE FOR APS?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds that a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for

indirectly, with an upward adjustment to the cost of common equity being the most logical mechanism.

Q. HAS PINNACLE WEST RECENTLY ISSUED ADDITIONAL COMMON EQUITY?

A. Yes. Pinnacle West closed on the sale of 6.9 million shares of common stock in April 2010, with the net proceeds raising approximately $252.8 million of additional equity capital. Pinnacle West contributed all of the net proceeds from this common stock offering into APS in the form of equity infusions.[55] Thus, in addition to flotation costs associated with past equity issues, APS also incurred issuance costs associated with Pinnacle West's recent sale of new common shares.

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF COMMON EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. While there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *New Regulatory Finance* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[56]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation

[55] Pinnacle West Capital Corporation, *2010 Form 10-K Report* at 51.
[56] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

cost percentage of 3.6 percent,[57] with Pinnacle West incurring issuance costs equal to 3.57 percent of the gross proceeds from its April 2010 public offering.

Issuance costs are a legitimate consideration in setting the ROE for a utility, and applying these expense percentages to a representative dividend yield for a utility of 4.5 percent implies a flotation cost adjustment on the order of 15 to 45 basis points.

IV. RETURN ON EQUITY FOR APS

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting the conclusions of my evaluation of a fair ROE for APS, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of APS's requested capital structure.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW APS AN ADEQUATE RETURN ON FAIR VALUE RATE BASE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While APS remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with ongoing capital expenditure requirements,

[57] Application of Yankee Gas Services Company for a Rate Increase, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

uncertain economic and financial market conditions, future environmental compliance costs, and the potential for continued energy price volatility. As discussed earlier, APS faces a number of potential challenges that might require the relatively swift commitment of considerable capital resources in order to maintain the high level of service to which its customers have become accustomed. For example, mandated shutdowns of generating facilities in response to security threats or a catastrophic event elsewhere in the U.S. would impose significant reliance on wholesale power markets to meet energy shortfalls. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on APS. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing APS an adequate return on the fair value of its investment.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING ACCESS TO CAPITAL FOR APS?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to the

Company's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects."[58] S&P has also emphasized the need for regulatory support, concluding, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[59] Similarly, Moody's concluded:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[60]

With respect to APS specifically, the investment community has noted ongoing challenges posed by regulatory uncertainty.[61] Of particular concern to investors is the impact of regulatory lag and cost-recovery on the APS's ability to earn its authorized ROE and maintain its financial metrics, with Fitch noting:

> In Fitch's opinion, the regulatory compact in Arizona will continue to be the key determinant of APS's creditworthiness. Implementation of effective regulatory policies to ameliorate regulatory lag and provide APS a reasonable opportunity to earn

[58] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).
[59] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).
[60] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).
[61] *See e.g.*, Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (Feb. 25, 2011).

its authorized ROE will be critical to the utility's future credit ratings.[62]

Q. WHAT ARE THE IMPLICATIONS OF THE COMPANY'S RELATIVE CREDIT STANDING?

A. In a recent report by S&P ranking U.S. regulated utilities from strongest to weakest, APS was ranked 150 out of the total 185 companies with investment grade credit ratings.[63] During the financial crisis Fitch observed that, "'flight to quality' is selective within the [utility] sector, favoring companies at higher rating levels."[64] Because of the weaker overall credit standing associated with APS, there is little backstop in the event of a crisis and reduced flexibility to respond to other challenges, such as increased capital outlays or renewed energy market volatility.

The negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. In light of APS's present ratings, an inadequate rate of return imposed in this proceeding would further pressure APS's financial flexibility and credit standing. Strengthening financial integrity is imperative to ensure the capability to maintain existing ratings while confronting potential challenges.

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

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[62] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Full Ratings Report* (Jun. 11, 2010).

[63] Standard & Poor's Corporation, "Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest," *RatingsDirect* (Apr. 7, 2011).

[64] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

A. Yes. While providing a return on fair value that is sufficient to maintain APS's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* decision, it is also in customers' best interests.[65] Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN APS'S REQUESTED CAPITAL STRUCTURE?

A. APS's capital structure is presented in the testimony of Witness Jim Hatfield. As

[65] The end result requirement of the *Hope* case was affirmed in the *Duquesne* case cited earlier and in the more recent *Verizon Comm. Et al v. FCC*, 535 U.S. 467 (2002).

summarized in his testimony, the common equity ratio used to compute APS's overall rate of return was approximately 54 percent in this filing.

Q. WHAT WAS THE AVERAGE BOOK VALUE CAPITALIZATION MAINTAINED BY THE UTILITY PROXY GROUP?

A. As shown on Attachment WEA-8, common equity ratios at December 31, 2010 ranged from 25.3 percent to 63.8 percent and averaged 45.5 percent for the firms in the Utility Proxy Group.

Q. WHAT OTHER BENCHMARKS ARE RELEVANT IN ASSESSING APS'S CAPITAL STRUCTURE UNDER THE FAIR VALUE RATE BASE STANDARD?

A. To be able to raise capital, companies must pay returns that are competitive at the current market prices of their securities, not the embedded book value of the mix of stocks and bonds. Reference to market values is also consistent with the underlying premise of the fair value rate base standard.[66] As a result, the market value capitalizations for the firms in the Utility Proxy Group also serve as a benchmark in evaluating APS's proposed capital structure.

As shown on Attachment WEA-9, at year-end 2010, the market value capitalizations for the firms in the Utility Proxy Group implied an average common equity ratio of 53.8 percent.

Q. WHAT CAPITALIZATION IS REPRESENTATIVE FOR THE UTILITY PROXY GROUP GOING FORWARD?

A. As shown on Attachment WEA-8, Value Line expects that the average book value common equity ratio for the Utility Proxy Group of 48.5 percent over its

[66] The U.S. Supreme Court in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989) noted that the purpose of fair value ratemaking is to provide a fair return on the market value of plant. Using a market value capital structure would seem to be more consistent with this objective than original cost given that Arizona is a fair value jurisdiction.

three-to-five year forecast horizon. On a market value basis, the average capitalization for this group of electric utilities implies an average common equity ratio of 54.1 percent (Attachment WEA-9).

Q. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER ELECTRIC UTILITY OPERATING COMPANIES?

A. Attachment WEA-10 displays capital structure data at year-end 2010 for the group of electric utility operating companies owned by the firms in the Utility Proxy Group. As shown there, common equity ratios for the electric utility operating companies corresponding to the Utility Proxy Group ranged from 26.5 percent to 62.9 percent and averaged 51.5 percent.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating economic and financial market uncertainties, and ongoing regulatory risks. Taken together, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, including times of adverse capital market conditions.

Moody's has repeatedly warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the

opportunity to strengthen the balance sheet as a buffer against future uncertainties.[67] More recently, Moody's concluded:

> From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative ratings actions.[68]

Similarly, S&P noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[69] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance in 2010," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[70]

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating the Company's financial risk. For example, power purchase agreements ("PPA") typically obligate the utility to make specified minimum contractual payments. As a result, when a utility enters into a PPA, the fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage. Because investors consider the debt impact of such fixed obligations

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[67] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[68] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

[69] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality In A Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[70] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the resulting debt equivalent, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels. These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks.[71]

As discussed earlier, a significant portion of the Company's power requirements are currently obtained through long-term purchased power contracts. These contractual payment obligations, along with the sale-leaseback agreements associated with Unit 2 of Palo Verde, are fixed commitments with debt-like characteristics and are properly considered when evaluating the financial risks implied by APS's capital structure. S&P reported that it adjusts Pinnacle West's capitalization to include $1.1 billion in imputed debt from off-balance sheet obligations associated with lease agreements, post-retirement benefit obligations, and PPAs.[72] Unless the Company takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken APS's creditworthiness, implying a higher required rate of return to compensate investors for the greater risks.

Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO APS'S PROPOSED CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that a capital structure consisting of approximately 54 percent common equity represents a reasonable mix of capital sources from which to calculate APS's overall rate of return. The Company's

[71] See, *e.g.*, Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008)
[72] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).

requested common equity ratio of approximately 54 percent is entirely consistent with the range of book value capitalizations for the proxy companies and other electric operating companies, and is essentially identical to the average market value capital structure for the Utility Proxy Group based on year-end 2010 data and Value Line's near-term projections. Because the purpose of fair value ratemaking is to provide a reasonable return on the value of the utility's rate base, reference to market values is relevant in evaluating APS's capital structure.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

The Company's proposed capital structure is consistent with industry benchmarks and reflects APS's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of APS's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the need to accommodate the additional exposures associated with the Company's resource mix, and the importance of supporting continued investment in system improvements, even during times of adverse industry or market conditions. S&P noted that the Company's credit rating could decline if APS "is unable to maintain or improve its capital

structure,"[73] while Moody's cited the need for a reduction in financial leverage to stabilize APS's credit standing.[74]

C. Implications of Attrition

Q. WHAT CAUSES ATTRITION?

A. Attrition is the deterioration of actual return below the allowed return that occurs when the relationships between revenues, costs, and rate base used to establish rates (e.g., using a historical test year) have changed by the time rates go into effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return even if the utility is operating efficiently. Similarly, when growth in the utility's investment outstrips the rate base used in the test year, the earned rate of return will fall below the allowed return through no fault of the utility's management. These imbalances are exacerbated as the regulatory lag increases between the time when the data used to establish rates is measured and the date when the rates go into effect.

Q. WHY IS IT NECESSARY TO ADDRESS THE IMPACT OF ATTRITION?

A. Investors are concerned with what they can expect in the future, not what they might expect in theory if a historical test year were to repeat. To be fair to investors and to benefit customers, a regulated utility must have an <u>opportunity to actually earn</u> a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk. In other words, it is the end result in the future that determines whether or not the *Hope* and *Bluefield* standards are met.

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[73] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).

[74] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007).

Q. HAS THE INVESTMENT COMMUNITY RECOGNIZED THE RISKS ASSOCIATED WITH ATTRITION AND LAG IN ITS EVALUATION OF APS?

A. Yes. S&P noted that, "Regulatory lag, or the time that a company takes to pass on higher costs to customers, has typically been higher than sector averages, and is expected to persist because the company continues to require high levels of capital investment."[75] Similarly, Moody's noted, "APS's ability to earn reasonable returns has been limited due to significant regulatory lag," and concluded that the uncertain timing of rate case decisions by the ACC "causes APS to map to a factor in the Ba range for its Regulatory Framework."[76] Fitch has also cited the potential that regulatory lag could produce "significant deterioration" in credit metrics and result in rating downgrades.[77] More recently, Fitch concluded:

> Earnings attrition due to regulatory lag is a primary risk factor for APS investors. If left unaddressed, post-2011 earned returns could track significantly below authorized levels, resulting in weakening credit metrics and potential credit rating downgrades.[78]

Fitch observed that, "Implementation of effective regulatory policies to ameliorate regulatory lag and provide APS a reasonable opportunity to earn its authorized ROE will be critical to the utility's future credit ratings.[79]

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[75] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).
[76] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (Feb. 25, 2011).
[77] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Credit Analysis* (Jan. 23, 2008).
[78] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Credit Analysis* (Jun. 11, 2010).
[79] *Id.*

Similarly, the February 28, 2011 Benchmarking Study prepared by the Liberty Consulting Group concluded that APS's earned returns have fallen significantly below benchmark levels.[80] As the study concluded:

> The graph below shows APS [return on average equity] falling consistently well below the average returns of each of the base, expanded growth and nuclear comparative panels from 2002-2009.[81]

Q. WHAT ARE THE WAYS TO DEAL WITH ATTRITION?

A. For many utilities, the widespread adoption of pass-through clauses for fuel, purchased power, and other costs that were rising rapidly in the late 1970's and early 1980's has helped to partially offset the impact of attrition. The use of future test years and other forward-looking mechanisms is also useful in ameliorating the impact of attrition, as is accelerated depreciation and inclusion of CWIP in rate base, particularly where financing an expensive generating plant addition is undermining a utility's financial indicators. Many jurisdictions have developed methods to attenuate regulatory lag, such as allowing interim rates, putting rates into effect subject to refund, as well as accelerating the administrative process to allow faster rate decisions. As a result of these measures, combined with the fall-off of inflation, growth, and new construction across the electric utility industry, attrition ceased to be a major regulatory issue for most utilities by the mid-1980s.

Q. WOULD THE DECOUPLING MECHANISM PROPOSED BY APS HELP TO ATTENUATE ATTRITION?

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[80] Liberty Consulting Group, "Benchmarking Study of Arizona Public Service Company's Operations, Cost, and Financial Performance," Docket No. E-01345A-08-0172 (Feb. 28, 2011) at 41-42 ("Benchmarking Study").
[81] *Id.*

A. Yes. Decoupled rate structures are another tool to better match a utility's revenues with the underlying costs of providing service. By improving a utility's ability to recover its fixed costs between rate cases, mechanisms, such as the Efficiency and Infrastructure Account ("EIA") mechanism proposed by APS, help to reduce attrition by addressing the impact of at least one cause; namely, declining customer sales.

Q. IS IT REASONABLE TO CONSIDER ATTRITION IN ESTABLISHING RATES FOR APS?

A. Yes. Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles. That end result would maintain the utility's financial integrity, ability to attract capital and offer investors fair compensation for the risk they bear. Given the past timing of rate relief and the dynamics faced by APS, there is every reason to believe that attrition would lead to under-earning the allowed ROE if the impact of regulatory lag and rising costs and capital requirements is ignored.

Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation. The Supreme Court has reaffirmed that the end result test must be applied to the actual returns that investors expect if they put their money at risk to finance utilities.[82] This end result can only be achieved for APS if the ROE is sufficient

[82] *Verizon Communications, et al v. Federal Communications Commission, et al*, 535 U.S. 467 (2002). While I cannot comment on the legal significance of this case, I found the economic wisdom of looking to the reasonable expectations of actual investors compelling. I understand that as a fair value state, Arizona law may have requirements beyond the *Hope* and *Bluefield* end-result tests. But economic logic and common sense confirm that a utility cannot attract capital on reasonable terms if investors expect future returns to fall short of those offered by comparable investments.

to offset the impact of attrition. Thus, whatever the Commission ultimately determines to be investors' required return, the only way to achieve that end result is to set the ROE at a level that is sufficient to give APS an opportunity to actually earn investors' required rate of return in the future.

Indeed, not allowing the Company an opportunity to earn a sufficient return is the economic equivalent of taking the capital value of existing investors.

Q. HOW DOES NOT ALLOWING APS AN ACTUAL OPPORTUNITY TO EARN ITS COST OF CAPITAL RESULT IN TAKING VALUE FROM APS INVESTORS?

A. In real world capital markets, investors have many competing places to put their money. If the money that is dedicated to utility public service does not have an opportunity to earn a return commensurate with that available from alternatives of equivalent risk in the capital markets, investors are not being adequately compensated for the use of their money and bearing risk. Since the capital dedicated to utility service cannot be withdrawn from public service, its economic value to investors is reduced by the amount necessary to make the utility investment competitive with alternative investments on the open market.[83] This reduction in economic value necessary to bring the rate of earnings on utility investment into line with market opportunities of commensurate risk constitutes a taking of investors' capital by the governmental authority setting rates.

[83] Individual owners of utility bonds and stocks can sell their claims on future cash flows to other investors, but they cannot withdraw the underlying capital from the utility. The government will not allow capital that is invested in utility rate base to be withdrawn. Therefore, the governmental authority having control over the rates must be set them as to allow that capital to earn of return that is competitive with the earnings available other opportunities of commensurate risk. Failing to allow such a return constitutes a taking of the economic value of the capital dedicated to public utility service.

We can observe how inadequate returns reduce economic value in the marketplace. Consider a bond issued by a risky entity. Generally the bond is sold to the public at close to face value ($1000) and can be traded in the market. Whoever owns the bond will receive the coupon payments over the life of the bond and receive the $1000 principal repayment at maturity. As the level of interest rates vary or the risk of the cash flow promises from the issuer of the bond change, so will the market value of the bond. If the risk increases that the promised payments will not be made in full, the value of the bond drops in the capital market. Only by lowering the price that investors must pay for the bond can the expected return be made competitive with other opportunities in the capital markets. If an investor owns the bond and does not sell it when the risk increases, the economic value of their investment is reduced as the market price declines.

Similarly, capital that is dedicated to public service in the rate base of APS has its value affected by the risks and prospects of APS relative to other opportunities in the capital market. Since the money invested in APS's fair value rate base cannot be withdrawn, the effect of not having an opportunity to earn returns commensurate with the underlying risk causes the economic value of its securities to fall. This reduction in value due to an inadequate opportunity to earn a return commensurate with risk is the economic equivalent of the government taking value from the private property of investors without compensation.

D. Impact of Adjustment Mechanisms

Q. HOW ARE FLUCTUATIONS IN ENERGY COSTS FOR APS ACCOMMODATED IN RATES?

A. Concerns over the risks associated with energy price volatility and rising costs have become increasingly pronounced in the industry. The Company's retail electric rates contain a fuel and purchased power adjustment clause ("PSA"), whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The ACC requires periodic filings and hearings to establish the amount of price adjustments under the PSA and also provides for deferral and subsequent recovery or refund of variances between the estimated cost of fuel and purchased power and the actual costs incurred. Under the existing PSA, APS defers 90 percent of the difference between retail fuel and purchased power costs and the Base Fuel Rate. As discussed earlier, the Company absorbs as much as 10 percent of the retail fuel and purchased power costs above the Base Fuel Rate and retains up to 10 percent of the benefit from the retail fuel and purchased power costs that are below the Base Fuel Rate. The PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

As a result, while the PSA mechanism is supportive of APS's financial integrity, there can be a lag between the time the Company actually incurs power cost expenditures and when they are recovered from ratepayers. Thus, APS is not entirely shielded from the need to finance deferred power supply costs. Thus, while the PSA is a valuable means of mitigating the risks associated with energy cost volatility, they do not eliminate them.

Q. DOES APS OPERATE UNDER OTHER COST RECOVERY MECHANISMS?

A. Yes. The ACC has approved a recovery mechanism to track the costs that APS incurs in providing transmission services, as well as costs related to energy

efficiency programs and renewable energy standards. APS is also proposing the implementation of a revenue decoupling mechanism, the EIA, and an Environmental and Reliability Account ("ERA") mechanism for environmental and generation capacity additions, which will provide APS a more timely recovery of the revenue requirement associated with qualified investments made by APS.

Q. WHAT WOULD BE THE EFFECT OF APS'S TWO NEW PROPOSED MECHANISMS FROM INVESTORS' PERSPECTIVE?

A. Revenue decoupling mechanisms address the investment community's heightened concerns over the risks associated with declining consumption by helping to preserve a utility's opportunity to collect the level of revenues per customer it was authorized when rates were established. APS's distributed generation, energy conservation and efficiency programs may be desirable, but as S&P noted, "policy objectives can sometimes increase utilities' uncertainty and credit risk."[84] S&P went on to conclude that, "efficiency programs that lack decoupling may carry a higher level of credit risk."[85] Because utility revenues and cash flow typically depend on sales volume, a utility will be unable to recover its fixed costs on a timely basis, if at all, to the degree that usage is declining. Regulatory mechanisms, such as the EIA proposed by APS, are essential to mitigate regulatory lag while ensuring that conservation efforts do not undermine the utility's financial integrity and credit standing.

Q. WOULD APPROVAL OF APS'S PROPOSED EIA AND ERA MECHANISMS IMPLY THAT ITS INVESTMENT RISKS ARE LOWER

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[84] Standard & Poor's Corporation, "When Energy Efficiency Means Lower Electric Bills, How Do Utilities Cope?," *RatingsDirect* (Mar. 9, 2009).
[85] *Id.*

THAN FOR THE COMPANIES IN THE PROXY GROUPS USED IN YOUR QUANTITATIVE ANALYSES?

A. No. Adjustment clauses and cost trackers, along with rate design measures and other mechanisms designed to break the link between a utility's revenues from customer usage, have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and regulatory lag, and in light of the importance of advancing other public interest goals such as energy conservation, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers in favor of reducing consumption through decoupling and other adjustment mechanisms. As Fitch observed:

> An emerging regulatory trend for integrated electric utilities is the initiation of electricity revenue decoupling in response to the recent softness of demand and state policies that include ambitious energy-efficiency targets.[86]

While not always directly analogous to the specific mechanisms approved or proposed for APS, the objective is similar; namely, to allow the utility an opportunity to earn a fair rate of return and mitigate exposure to attrition in an era of rising costs and declining consumption. Reflective of this industry trend, the companies in the Utility Proxy Group operate under a variety of cost adjustment mechanisms. As summarized on Attachment WEA-11, these mechanisms range from riders to recover bad debt expense and post-retirement

[86] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010," *Global Power North America Special Report* (Dec. 4, 2009). Fitch observed that electric revenue decoupling had been initiated or was allowed in California, Ohio, Vermont, New York, and Maryland, with pilot programs in Wisconsin and Idaho, while 18 states have approved the implementation of revenue decoupling for gas utilities.

employee benefit costs to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures.

For example, the utility operations of Constellation Energy, Inc. benefit from energy adjustment clauses and revenue decoupling, as well as trackers for costs associated with conservation and demand-side management programs. Similarly, Edison International Inc. and Pacific Gas and Electric Company also operate under numerous balancing account mechanisms that cover a significant portion of revenue requirements and effectively dampen the impact of fluctuations in electric sales on their ability to recover the costs of providing service. Similarly, the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether.

Q. IS THERE A DOWNSIDE TO REVENUE DECOUPLING MECHANISMS FROM AN INVESTOR PERSPECTIVE?

A. Yes. The investment community does not view mechanisms to address revenue stabilization, such as weather mitigants or rate design mechanisms that shift away from volumetric recovery of fixed costs, as entirely positive. This is because, while such measures dampen the volatility of a utility's revenues, they also largely preclude the prospects of greater earnings due to higher consumption. This double-edged sword was noted by S&P in the context of weather adjustment clauses:

> Some LDCs are reluctant to pursue such provisions, because they don't want to forego the upside earnings potential of a significantly colder-than-normal winter.[87]

[87] Standard & Poor's Corporation, "Natural Gas Distribution," *Industry Surveys* at 18 (Nov. 29, 2001).

Similarly, Moody's warned that "it is unclear, at this time, as to whether these cost riders/trackers may prove to have hidden consequences over the long-term horizon."[88] Thus, investors would also consider the loss of upside potential in evaluating the impact of decoupling mechanisms.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO YOUR EVALUATION OF A FAIR ROE FOR APS?

A. While the EIA and ERA mechanisms proposed for APS would be supportive of the Company's financial integrity and credit ratings, there is certainly no evidence to suggest that these provisions would justify any adjustment to the ROE range determined earlier. First, APS's investment risks are comparable to or greater than those of the proxy groups used to estimate the cost of equity. For example, the "BBB-" corporate credit rating assigned to APS indicates slightly *more* risk than the "BBB" average for the Utility Proxy Group.

As demonstrated above, utilities across the U.S. that APS competes with for new capital – including those in the Utility Proxy Group used to estimate the cost of equity – are increasingly availing themselves of similar adjustments. As a result, the impact of utilities' ability to mitigate the risk of declining revenues and cash flows is already reflected in the capital market estimates discussed earlier, and no separate adjustment to APS's ROE is necessary or warranted. While the adjustment mechanisms approved and proposed for APS address the built-in disincentives associated with increasing capital expenditures and fluctuating energy demand by attenuating exposure to declining revenues, this leveling of the playing field only serves to address factors that could otherwise impair APS's opportunity to collect its authorized revenues.

[88] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (January 2009).

E. Return on Equity Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, I used both the DCF and CAPM methods to estimate a fair ROE for APS. These methods were applied in a forward-looking manner to be consistent with the Arizona fair value rate base standard. In order to reflect the risks and prospects associated with APS's jurisdictional utility operations, my analyses focused on a proxy group of twenty-one other utilities with comparable investment risks. Consistent with the fair value rate base standard, and the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy.

My application of the constant growth DCF model considered four alternative growth measures based on projected earnings growth and the sustainable, "br+sv" for each firm in the respective proxy groups. In addition, I evaluated the reasonableness of the resulting DCF estimates and eliminated low- and high-end outliers that failed to meet threshold tests of economic logic. My CAPM analyses were based on forward-looking data that best reflects the underlying assumptions of this approach. The results of my alternative analyses are summarized in Table WEA-6, below:

TABLE WEA-6
SUMMARY OF QUANTITATIVE RESULTS

DCF	Utility	Non-Utility
Earnings Growth		
Value Line	11.2%	11.9%
IBES	11.0%	12.4%
Zacks	10.9%	12.5%
br + sv	9.5%	12.1%
CAPM	11.4%	10.0%

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE RANGE FOR APS?

A. Considering the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity is in the 10.6 percent to 11.60 percent range. After incorporating a minimal adjustment for flotation costs of 15 basis points to my "bare bones" cost of equity range, I concluded that my analyses indicate a fair ROE in the 10.75 percent to 11.75 percent range. In light of capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, these considerations indicate that an ROE in the range of 10.75 to 11.75 percent is reasonable.

Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting the Company's financial position so that APS remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of maintaining the Company's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers.

As discussed in the testimony of Mr. Jeff Guldner, APS is requesting an ROE of 11.00 percent in this case. Because the Company's requested ROE falls below the 11.25 percent midpoint of my recommended range it represents a reasonable compromise between balancing the impact on customers and the need to provide APS with a return that is adequate to compensate investors, maintain financial integrity, and attract capital. The reasonableness of an 11.00 percent ROE is reinforced by the economic reality that APS's actual returns have fallen systematically short of the allowed ROE, and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

V. FAIR VALUE RATE OF RETURN

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section examines the alternatives the Commission might consider for rate of return to fair value based on the economic and financial realities facing APS in this case. It is clear that "backing into" the fair value rate of return to yield the same revenue requirement as original cost ratemaking has been rejected by the Arizona Court of Appeals in *Chaparral City Water Company, v. Arizona Corporation Commission ("Chaparral")*[89] and subsequent Commission orders. It is also clear that the Commission feels it has the flexibility to apply fair value principals in a manner that fits the facts and circumstances of the utility and achieves regulatory objectives.[90] In the UNS Electric decision the Commission repeated the regulatory benchmark: "that a utility should be provided with rates that will allow it an opportunity to earn a return that is comparable to those of

[89] CA-CC-05-0002 (February 13, 2007). My discussion of this and other court cases and Commission orders cited in this section is as an economist and financial analysts, not as an attorney.
[90] UNS Electric Decision 71914 (Sept. 30, 2010), p. 42.

similarly situated enterprises."[91] Also, in the UNS Electric decision, the Commission explicitly rejected any "a one size fits all approach" to return on fair value.[92]

This section of my testimony will first demonstrate that it is in the customers' interest to grant APS rates that will allow it an ***actual*** opportunity to earn a return that is comparable to similarly situated entities. Given the history of APS being unable to earn its allowed return as documented in the Benchmarking Study discussed earlier in my testimony, the Commission should adopt ratemaking methods that offset earnings attrition. The return to fair value is a tool the Commission could use to offset the effects of attrition and support continued recovery of financial resilience. Second, this section examines methods beyond those advocated in other cases by witnesses before this Commission to find a return to fair value increment consistent with economic and financial realities of APS. These approaches would achieve the key regulatory policy objectives in this case – maintaining APS's access to capital markets and financial integrity, so as to protect APS customers, as well as the customers of other Arizona utilities and the economy of Arizona, from the adverse effects that would result if APS were to lose its investment grade credit rating.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO USE THE FAIR VALUE RETURN TO SUPPORT APS'S FINANCIAL INTEGRITY?

A. Due to recent constructive decisions, APS has recovered from its precarious financial position. RUCO witness Dr. Ben Johnson correctly warned in the last

[91] Id., p. 44.
[92] Id., p. 51.

rate case (pp. 16-22) that APS customers, customers of other Arizona utilities, and the economy of the state would suffer if APS were to be driven deeper into financial distress. Dr. Johnson urged the Commission to show that it understands the severity of APS's financial weakness and demonstrate to the investment community that it supports APS's efforts to maintain an investment grade bond rating. The recent financial crisis highlights the importance of regulatory support, as lower rated companies can be denied access to capital during times of financial market turmoil.

Giving a reasonable measure of return to the fair value increment would provide a clear signal that the Commission is willing to use the regulatory tools at its disposal to support APS's efforts to maintain investment grade ratings and improve its credit standing. By approving the ERA and the EIA, the Commission will address possible drags on APS's ability to earn its allowed return, but those features do not increase return. Moreover, as documented earlier, the utilities in the Utility Proxy Group enjoy similar mechanisms, while the low-risk firms in the Non-Utility Proxy Group are able to adjust their prices without regulatory intervention. Therefore, to assure that APS has realistic opportunity to earn a return comparable to the similarly situated entities in the Utility and Non-Utility Proxy Groups, a return to fair value should be used to offset anticipated attrition.

Q. ARE THE METHODS YOU HAVE USED TO ESTIMATE A FAIR VALUE ROE APPLICABLE ONLY TO ORIGINAL COST RATE BASE?

A. No. Most, but not all, utility proceedings apply the cost of capital to original cost rate base.[93] However, in my consulting and teaching outside of the utility regulatory arena, the cost of capital concept is applied to investment bases other than original cost. For example, cost of capital is applied to fair market values in valuing businesses and in capital budgeting. Indeed, a widely accepted authority in the valuation literature, Dr. Shannon P. Pratt, CFA, has written:

> Cost of capital estimation is at once the most critical and the most difficult element of most business valuations and capital expenditure decisions.[94]

In his authoritative text, Pratt discusses the same DCF and CAPM approaches applied by the witnesses in this and other utility rate cases. In the entire book devoted to the cost of capital, Dr. Pratt devotes only a few paragraphs to utility rate setting while detailing many other contexts in which the cost of capital concept is applied to an investment base other than original cost.

A recent and widespread application of standard ROE methods to a rate base other than original cost in the regulatory arena is in the area of telephone regulation. The Federal Communication Commission ("FCC") established a method of setting rates for unbundled network elements ("UNEs") pursuant to the Telecommunications Act of 1996 using a method termed Total Element Long-Run Incremental Cost ("TELRIC"). In the TELRIC method, the cost of capital is applied to a rate base derived from the cost of replicating the

[93] Although in my experience, Arizona is unique in having the fair value standard established in the state constitution, other states have used variations of fair value rate base at various times pursuant to legislative statutes. For example, when the PUCT was first established in 1975, the legislation provided for fair value rate base. The Texas Legislature subsequently eliminated the fair value language for electric and telephone utilities. For gas utilities in Texas, the Texas Railroad Commission has the option of using a fair value rate base.

[94] Shannon Pratt, CFA, *Cost of Capital: Estimation and Applications* (1998), Preface, p. xvii.

incumbent telephone companies' network using current technologies. This forward-looking measure of investment value departs significantly from original cost for most telephone companies. In *Verizon Communications v. FCC, et al.*, 535 U.S. 476 (May 13, 2002) ("*Verizon*"),[95] the U.S. Supreme Court upheld this application of the cost of capital to TELRIC rate base, rather than to original cost. I have been involved in a number of UNE cases in many states, and the cost of capital estimated using DCF and/or CAPM methods has been routinely applied to the current value rate base by state commissions and the FCC.

Q. WOULD INVESTORS RECEIVE ANY "WINDFALL" IF APS IS GRANTED THE OPPORTUNITY TO EARN A RETURN ON A RATE BASE THAT EXCEEDS ORIGINAL COST?

A. No. Equity investors expect that they will benefit when the value of an investment rises above the price originally paid; indeed, the expectation of an increase in investment value is one of the two sources of cash flow in the DCF model. For corporations in both the non-utility and utility sectors there is often a significant difference between the original cost (less depreciation) of equity investment as reflected on the balance sheet and the value that equity garners in the market as common stock. The conventions of Generally Accepted Accounting Principles do not equate to the concept of economic value in the marketplace. It is incorrect to state that the appreciation in the value of an investment is not attributable to the funds supplied by investors or that it is "cost-free" to investors. As will be discussed later, when the cost of capital for a company is estimated in the competitive sector, the market value weights of debt

[95] *In the Matter of Petition of Worldcom, Inc. Pursuant to Section 252(E)(5) for Preemption of the Jurisdiction of the Virginia State Corp. Comm'n regarding Interconnection Disputes with Verizon Va. Inc.*, 18 F.C.C.R. 17,722 (August 29, 2003).

and equity, rather than book value weights, are used to account for investors' market value not reflected in book value. The claim of debt holders may be limited to the amount they have loaned to the business, but their claim is senior to equity investors. While equity investors have a junior claim on the value of the corporation, their claim is open-ended. As a result, any residual value after meeting the obligations to debt investors inures to the benefit of equity investors.[96] But to say that the appreciation did not come from investors' funds is economic nonsense. Without the original investment, the subsequent appreciation would not have been possible.

Outside the world of original cost utility ratemaking, there is no link between the concepts of original cost and the cost of capital. Indeed, in *Verizon* the U.S. Supreme Court observed that the linkage between original investment and rate base is not unbroken in the regulatory arena:

> "Cost" as used in calculating rate base under the traditional cost-of-service method did not stand for all past capital expenditures, but at most for those that were prudent, while prudent investment itself could be denied recovery when unexpected events rendered investment useless. *Duquesne Light Co. v. Barasch, 488 U.S. 299, 312, 102 L. Ed. 2d 646, 109 S. Ct. 609 (1989).*[97]

The *Duquesne* case cited by the U.S. Supreme Court compared the fair value standard to the outcome of competitive markets where investors received the gains (or losses) derived from their investments:

> [The] fair value standard mimics the operation of the competitive market. To the extent utilities' investment in plant are good ones

[96] There may be equity claimants who are senior to common stock investors, *e.g.*, preferred stock. These claimants are ignored in this discussion since APS only has debt and common stock investors.
[97] *Verizon* at 10.

> (because their benefits exceed their costs) they are rewarded with an opportunity to earn an "above cost" return, that is, a fair return on the current "market value" of the plant. To the extent utilities' investments turn out to be bad ones (such as plants that are canceled and so never used and useful to the public), the utilities suffer because the investments have no fair value and so justify no return.[98]

Clearly, the capital appreciation of investments that result in market value exceeding book value is not a "cost-free" asset, but is instead the fruit of the equity investors' commitment of capital and risk-bearing.

Q. IS ANY ADDITIONAL RETURN ON AN INCREMENT OF RATE BASE ABOVE ORIGINAL COST EXCESSIVE?

A. No. Although this incremental value was not separately financed, it has what economists understand as opportunity cost because it requires that investors forgo other opportunities to leave their funds invested in the utility. That value increment is the private property of investors and it is being used to serve the public in the utility. Any argument that it is "cost-free" ignores the opportunity cost principle and would be akin to saying that homeowners have no ownership claim to the appreciation in the value of their home because they have no explicit financing cost.[99]

Q. IS A ZERO PERCENT RETURN ON THE FAIR VALUE INCREMENT APPROPRIATE IN THIS CASE?

A. No. A zero percent return would be economically and financially equivalent to "backing into the fair value return" based on the return to original cost. As observed by the court in *Chaparral,* granting the same return as original cost

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[98] *Duquesne Light Co. v. Barasch, 488 U.S. 299, 312, 102 L. Ed. 2d 646, 109 S. Ct. 609 (1989),* pp. 308-09.

[99] In an original cost jurisdiction, utility investors understand that earnings will be tied to original cost with the *Hope* and *Bluefield* protections.

would render the provisions of the Arizona Constitution without any economic effect. APS investors in a fair value regulatory regime would have the same compensation as an original cost jurisdiction.

Q. IS IT LOGICAL TO LIMIT THE RETURN TO FAIR VALUE INCREMENT TO A RISK-FREE TREASURY YIELD ADJUSTED FOR INFLATION, AS IT IS SOMETIMES ARGUED BEFORE THIS COMMISSION?

A. No. Because the return from the fair value increment is not risk-free, risk-free Treasuries yields are not a reasonable benchmark. A utility is not granted a guaranteed return, only an opportunity to earn the allowed return (including any fair value increment). As documented in the Benchmarking Study and in the testimony in this case, APS has consistently earned significantly less than the allowed return due to attrition. One surrogate for the required risky return would be the yield on utility bonds, rather than risk-free Treasury bonds. As noted earlier, the average yield on triple-B rated utility bonds in March 2011 was approximately 6.00 percent.

Q. IS A BOND YIELD THE MOST ECONOMICALLY RELEVANT RETURN BENCHMARK FOR THE FAIR VALUE INCREMENT?

A. No. The inflation-adjusted cost of equity would be more consistent with the economics of the fair value increment. The fair value increment is the difference between the fair value rate base and the original cost rate base. As discussed above, debt investors have a specified claim against the company's value and cash flow. The capital structure applied to the original cost rate base considers the debt claims and they are provided for by the use of the embedded cost of debt applied to the debt percentage of the capital structure. After the debt claims are satisfied, the residual inures to the benefit of equity holders. As a result, the

equity cost estimate is the proper economic benchmark for the return to the fair value increment. Therefore, my 11.25 percent recommended ROE (or the 11.00 percent ROE requested by APS) could be the starting point with a forward-looking inflation estimate subtracted. This equity return is consistent with the economic reality that equity investors retain the residual value after debt claims have been satisfied. Therefore, the top of the range of reasonable returns to the fair value increment should be the inflation adjusted equity return.

Q. SHOULD THE METHOD OF DERIVING THE RETURN TO FAIR VALUE RATE BASE RECOMMEDED BY RUCOIN CHAPARRAL CITY WATER DECISION NO. 70441 (JULY 28, 2008) BE APPLIED IN THIS CASE?

A. No. The capital structure should be adjusted to recognize market values. Since the fair value rate base in this case is an average of current value and original cost, so also should the capital structure be the average of original cost and market value. Specifically, APS's adjusted original cost capital structure of approximately 54 percent common equity and 46 percent long-term debt should be averaged with the market value capital structure of 56 percent equity and 44 percent debt for Pinnacle West, as identified in Attachment WEA-9 to my Direct Testimony. The resulting capital structure would be 55 percent equity and 45 percent debt.[100]

Market value capital structures are used in the competitive sector and have been used in UNE cases in determining the cost of capital to be applied to the current value TELRIC rate base. Indeed, in 2002 Dr. Johnson and I both testified in a UNE case for Southwestern Bell Telephone before the Missouri Public Service Commission in Docket TO-2002-222. He recommended the use of an original

[100] Computed as (54%+56%)/2 and (44% + 46%)/2, respectively.

cost capital structure and I recommended a market value capital structure. In its August 6, 2002 Order, the Missouri Public Service Commission adopted Dr. Johnson's original cost capital structure recommendation and accepted my cost of debt and cost of equity recommendations based on the DCF and CAPM. On June 17, 2004, the U.S. District Court for the Western District of Missouri (Central Division) issued an order finding that the use of book value capital structure "is at odds with the TELRIC methodology" and that market value capital structure should be used in calculating the cost of capital for UNE rates.[101]

Q. IS ANY ADJUSTMENT TO THE COST OF EQUITY NECESSARY TO AVOID DOUBLE-COUNTING INFLATION?

A. There is a reasonable argument that the cost of equity estimates presented in my testimony incorporate market methods of the DCF and CAPM for non-utility companies, where the values of investment can change over time with inflation and other influences. On the other hand, some, but not all of the inputs to the fair value rate base incorporate inflation and may be expected to do so in the future. I believe it may be reasonable to apply a reduction to the equity return to avoid double-counting inflation. But to produce a reasonable return on fair value rate base, as the FCC and most states have done in the TELRIC cases, the market value capital structure must first be incorporated into the return to fair value rate base, as I have recommended above.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

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[101] *Southwestern Bell Telephone L.P., d/b/a SBC Missouri v. Missouri Public Service Commission, et al.,* Case No. 03-04148-CV-C-NKL (June 17, 2004) at 8.

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

Director, Economic Research Division,
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to

Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

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"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

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"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

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"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

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"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend Yield			Growth Rates				Cost of Equity Estimates			
	Company	Price	Dividends	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	Ameren Corp.	$ 26.91	$ 1.54	5.7%	-2.0%	-1.7%	4.0%	2.5%	3.7%	4.0%	9.7%	8.2%
2	American Elec Pwr	$ 34.92	$ 1.86	5.3%	3.5%	4.0%	4.0%	4.9%	8.8%	9.3%	9.3%	10.2%
3	CenterPoint Energy	$ 15.58	$ 0.79	5.1%	2.5%	4.9%	5.5%	4.5%	7.6%	10.0%	10.6%	9.5%
4	Cleco Corp.	$ 32.62	$ 1.12	3.4%	8.0%	3.0%	7.0%	4.1%	11.4%	6.4%	10.4%	7.6%
5	CMS Energy	$ 18.88	$ 0.86	4.6%	7.0%	5.9%	6.0%	4.7%	11.6%	10.5%	10.6%	9.3%
6	Constellation Energy	$ 30.90	$ 0.96	3.1%	6.0%	9.9%	9.9%	4.7%	9.1%	13.0%	13.0%	7.8%
7	DTE Energy Co.	$ 48.18	$ 2.30	4.8%	5.5%	5.8%	5.0%	3.6%	10.3%	10.6%	9.8%	8.3%
8	Edison International	$ 35.81	$ 1.29	3.6%	-1.0%	5.0%	5.0%	4.7%	2.6%	8.6%	8.6%	8.3%
9	Great Plains Energy	$ 19.25	$ 0.85	4.4%	6.0%	8.9%	9.0%	2.1%	10.4%	13.3%	13.4%	6.5%
10	Hawaiian Elec.	$ 24.04	$ 1.24	5.2%	11.5%	7.0%	8.6%	4.2%	16.7%	12.2%	13.8%	9.4%
11	IDACORP, Inc.	$ 36.77	$ 1.20	3.3%	5.5%	4.7%	4.7%	5.0%	8.8%	8.0%	8.0%	8.2%
12	Integrys Energy Group	$ 49.24	$ 2.72	5.5%	9.5%	7.9%	10.4%	3.1%	15.0%	13.4%	15.9%	8.6%
13	ITC Holdings Corp.	$ 67.71	$ 1.39	2.1%	14.0%	16.7%	15.0%	13.7%	16.1%	18.8%	17.1%	15.7%
14	Pepco Holdings	$ 18.21	$ 1.08	5.9%	0.5%	7.0%	4.3%	2.0%	6.4%	12.9%	10.2%	7.9%
15	PG&E Corp.	$ 43.00	$ 1.92	4.5%	6.0%	6.2%	7.7%	6.7%	10.5%	10.7%	12.2%	11.1%
16	Pinnacle West Capital	$ 42.31	$ 2.10	5.0%	6.0%	6.4%	5.8%	3.7%	11.0%	11.4%	10.8%	8.6%
17	Portland General Elec.	$ 23.23	$ 1.07	4.6%	3.0%	4.7%	5.2%	3.7%	7.6%	9.3%	9.8%	8.3%
18	PPL Corp.	$ 24.58	$ 1.40	5.7%	4.0%	-5.0%	-5.0%	7.2%	9.7%	0.7%	0.7%	12.9%
19	TECO Energy	$ 17.81	$ 0.84	4.7%	8.0%	6.1%	5.3%	6.1%	12.7%	10.8%	10.0%	10.8%
20	Westar Energy	$ 25.68	$ 1.28	5.0%	8.5%	6.5%	5.3%	4.6%	13.5%	11.5%	10.3%	9.6%
21	Wisconsin Energy	$ 29.37	$ 1.06	3.6%	7.5%	8.5%	8.0%	5.5%	11.1%	12.1%	11.6%	9.2%
	Average (g)								**11.2%**	**11.0%**	**10.9%**	**9.5%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Mar. 25, 2011).
(b) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).
(c) *Thomson ReutersCompany in Context Report* (Apr. 4, 2011).
(d) www.zacks.com (retrieved Mar. 22, 2011).
(e) See Attachment WEA-3.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

BR + SV GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		----------	2015	----------			Adjustment			--------- "sv" Factor --------			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Ameren Corp.	$2.50	$1.54	$36.50	38.4%	6.8%	1.0188	7.0%	2.7%	0.0104	(0.2167)	-0.23%	**2.5%**
2	American Elec Pwr	$3.75	$2.10	$36.00	44.0%	10.4%	1.0287	10.7%	4.7%	0.0097	0.2000	0.19%	**4.9%**
3	CenterPoint Energy	$1.30	$0.90	$9.75	30.8%	13.3%	1.0253	13.7%	4.2%	0.0051	0.5125	0.26%	**4.5%**
4	Cleco Corp.	$2.75	$1.60	$28.50	41.8%	9.6%	1.0265	9.9%	4.1%	-	0.1231	0.00%	**4.1%**
5	CMS Energy	$1.75	$1.10	$14.75	37.1%	11.9%	1.0300	12.2%	4.5%	0.0063	0.3140	0.20%	**4.7%**
6	Constellation Energy	$3.25	$1.00	$47.75	69.2%	6.8%	1.0250	7.0%	4.8%	0.0083	(0.1938)	-0.16%	**4.7%**
7	DTE Energy Co.	$4.25	$2.70	$46.50	36.5%	9.1%	1.0200	9.3%	3.4%	0.0086	0.1913	0.16%	**3.6%**
8	Edison International	$3.25	$1.40	$40.25	56.9%	8.1%	1.0285	8.3%	4.7%	-	(0.0063)	0.00%	**4.7%**
9	Great Plains Energy	$1.75	$1.20	$23.50	31.4%	7.4%	1.0231	7.6%	2.4%	0.0241	(0.1190)	-0.29%	**2.1%**
10	Hawaiian Elec.	$2.00	$1.30	$18.00	35.0%	11.1%	1.0220	11.4%	4.0%	0.0098	0.2653	0.26%	**4.2%**
11	IDACORP, Inc.	$3.10	$1.40	$36.50	54.8%	8.5%	1.0303	8.8%	4.8%	0.0181	0.0875	0.16%	**5.0%**
12	Integrys Energy Group	$4.00	$2.72	$42.75	32.0%	9.4%	1.0141	9.5%	3.0%	0.0033	0.1000	0.03%	**3.1%**
13	ITC Holdings Corp.	$5.50	$1.75	$35.50	68.2%	15.5%	1.0553	16.4%	11.1%	0.0398	0.6359	2.53%	**13.7%**
14	Pepco Holdings	$1.55	$1.12	$21.60	27.7%	7.2%	1.0210	7.3%	2.0%	0.0126	(0.0286)	-0.04%	**2.0%**
15	PG&E Corp.	$4.25	$2.20	$36.25	48.2%	11.7%	1.0384	12.2%	5.9%	0.0332	0.2368	0.79%	**6.7%**
16	Pinnacle West Capital	$3.50	$2.30	$38.25	34.3%	9.2%	1.0339	9.5%	3.2%	0.0418	0.1000	0.42%	**3.7%**
17	Portland General Elec.	$2.00	$1.20	$23.75	40.0%	8.4%	1.0327	8.7%	3.5%	0.0385	0.0500	0.19%	**3.7%**
18	PPL Corp.	$2.75	$1.60	$23.75	41.8%	11.6%	1.0511	12.2%	5.1%	0.0575	0.3667	2.11%	**7.2%**
19	TECO Energy	$1.75	$1.00	$13.25	42.9%	13.2%	1.0289	13.6%	5.8%	0.0075	0.3690	0.28%	**6.1%**
20	Westar Energy	$2.40	$1.44	$24.00	40.0%	10.0%	1.0207	10.2%	4.1%	0.0275	0.2000	0.55%	**4.6%**
21	Wisconsin Energy	$2.50	$1.40	$20.25	44.0%	12.3%	1.0215	12.6%	5.5%	-	0.4600	0.00%	**5.5%**

UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		---------- 2010 ----------			---------- 2015 ----------			Chg	-------- 2015 Price --------				---- Common Shares ----		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2010	2015	Growth
1	Ameren Corp.	50.9%	$15,185	$7,729	53.0%	$17,600	$9,328	3.8%	$35.00	$25.00	$30.00	0.822	240.40	256.00	1.27%
2	American Elec Pwr	46.5%	$29,185	$13,571	50.5%	$35,800	$18,079	5.9%	$55.00	$35.00	$45.00	1.250	481.00	500.00	0.78%
3	CenterPoint Energy	26.2%	$12,199	$3,196	29.0%	$14,200	$4,118	5.2%	$25.00	$15.00	$20.00	2.051	424.70	430.00	0.25%
4	Cleco Corp.	48.5%	$2,718	$1,318	55.0%	$3,125	$1,719	5.5%	$40.00	$25.00	$32.50	1.140	60.75	60.75	0.00%
5	CMS Energy	29.5%	$9,473	$2,795	34.0%	$11,100	$3,774	6.2%	$25.00	$18.00	$21.50	1.458	249.60	255.00	0.43%
6	Constellation Energy	62.8%	$12,468	$7,830	67.5%	$14,900	$10,058	5.1%	$50.00	$30.00	$40.00	0.838	199.00	209.00	0.99%
7	DTE Energy Co.	48.7%	$13,811	$6,726	47.5%	$17,300	$8,218	4.1%	$70.00	$45.00	$57.50	1.237	170.00	176.00	0.70%
8	Edison International	46.5%	$21,185	$9,851	45.0%	$29,100	$13,095	5.9%	$50.00	$30.00	$40.00	0.994	325.81	325.81	0.00%
9	Great Plains Energy	49.2%	$5,868	$2,887	48.5%	$7,500	$3,638	4.7%	$25.00	$17.00	$21.00	0.894	135.71	155.00	2.69%
10	Hawaiian Elec.	50.7%	$2,841	$1,440	52.0%	$3,450	$1,794	4.5%	$30.00	$19.00	$24.50	1.361	95.52	99.00	0.72%
11	IDACORP, Inc.	49.8%	$2,807	$1,398	50.5%	$3,750	$1,894	6.3%	$50.00	$30.00	$40.00	1.096	47.90	52.00	1.66%
12	Integrys Energy Group	56.8%	$5,119	$2,907	54.0%	$6,200	$3,348	2.9%	$55.00	$40.00	$47.50	1.111	77.35	78.50	0.30%
13	ITC Holdings Corp.	30.9%	$3,614	$1,117	33.5%	$5,800	$1,943	11.7%	$115.00	$80.00	$97.50	2.746	50.72	54.50	1.45%
14	Pepco Holdings	52.5%	$8,000	$4,200	48.0%	$10,800	$5,184	4.3%	$25.00	$17.00	$21.00	0.972	225.00	240.00	1.30%
15	PG&E Corp.	47.4%	$21,793	$10,330	54.0%	$28,100	$15,174	8.0%	$55.00	$40.00	$47.50	1.310	370.60	420.00	2.53%
16	Pinnacle West Capital	49.6%	$6,687	$3,317	53.5%	$8,700	$4,655	7.0%	$50.00	$35.00	$42.50	1.111	101.43	122.00	3.76%
17	Portland General Elec.	49.7%	$3,100	$1,541	50.0%	$4,275	$2,138	6.8%	$30.00	$20.00	$25.00	1.053	75.21	90.00	3.66%
18	PPL Corp.	40.0%	$20,620	$8,248	51.5%	$26,700	$13,751	10.8%	$45.00	$30.00	$37.50	1.579	485.00	580.00	3.64%
19	TECO Energy	40.8%	$5,318	$2,170	47.5%	$6,100	$2,898	6.0%	$25.00	$17.00	$21.00	1.585	214.90	220.00	0.47%
20	Westar Energy	46.4%	$5,181	$2,404	45.5%	$6,500	$2,958	4.2%	$35.00	$25.00	$30.00	1.250	112.13	125.00	2.20%
21	Wisconsin Energy	49.0%	$7,765	$3,805	48.0%	$9,825	$4,716	4.4%	$45.00	$30.00	$37.50	1.852	233.80	233.80	0.00%

(a) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2015 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2014-16 BVPS.

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		(a)	(a)	(b)	(c)	(d)	(e)	(e)	(e)	(e)
		Dividend	Growth Rates				Cost of Equity Estimates			
	Company	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	3M Company	2.39%	7.0%	11.9%	11.3%	12.9%	9.4%	14.3%	13.7%	15.3%
2	Abbott Labs.	3.67%	10.0%	8.9%	9.0%	15.0%	13.7%	12.6%	12.7%	18.7%
3	Alberto-Culver	1.02%	15.0%	9.4%	12.5%	8.4%	16.0%	10.4%	13.5%	9.4%
4	AT&T Inc.	6.09%	5.5%	5.7%	7.0%	5.4%	11.6%	11.8%	13.1%	11.5%
5	Automatic Data Proc.	2.93%	8.0%	10.6%	10.8%	9.5%	10.9%	13.5%	13.7%	12.4%
6	Bard (C.R.)	0.77%	9.5%	10.9%	11.8%	18.1%	10.3%	11.7%	12.6%	18.9%
7	Baxter Int'l Inc.	2.45%	10.0%	9.6%	9.3%	15.5%	12.5%	12.1%	11.8%	17.9%
8	Becton, Dickinson	1.97%	9.5%	9.9%	10.8%	9.0%	11.5%	11.9%	12.8%	11.0%
9	Bristol-Myers Squibb	5.11%	8.5%	1.8%	2.0%	5.7%	13.6%	6.9%	7.1%	10.8%
10	Brown-Forman 'B'	1.90%	7.5%	10.9%	13.0%	10.6%	9.4%	12.8%	14.9%	12.5%
11	Chubb Corp.	2.55%	2.5%	8.7%	9.8%	8.0%	5.1%	11.3%	12.4%	10.5%
12	Church & Dwight	0.97%	12.0%	11.8%	12.0%	10.3%	13.0%	12.8%	13.0%	11.3%
13	Coca-Cola	2.80%	9.5%	8.7%	9.0%	9.9%	12.3%	11.5%	11.8%	12.7%
14	Colgate-Palmolive	2.76%	11.0%	9.3%	9.2%	18.1%	13.8%	12.1%	12.0%	20.8%
15	Commerce Bancshs.	2.22%	7.0%	7.0%	7.0%	7.9%	9.2%	9.2%	9.2%	10.1%
16	ConAgra Foods	3.92%	10.5%	7.7%	8.0%	8.1%	14.4%	11.6%	11.9%	12.0%
17	Costco Wholesale	1.24%	7.5%	13.3%	12.9%	8.2%	8.7%	14.5%	14.1%	9.5%
18	Cullen/Frost Bankers	2.96%	4.5%	8.5%	8.0%	5.7%	7.5%	11.5%	11.0%	8.6%
19	CVS Caremark Corp.	1.42%	9.5%	10.1%	12.0%	7.8%	10.9%	11.5%	13.4%	9.2%
20	Ecolab Inc.	1.41%	12.0%	13.2%	13.2%	19.6%	13.4%	14.6%	14.6%	21.0%
21	Exxon Mobil Corp.	2.26%	6.0%	12.1%	8.4%	13.5%	8.3%	14.4%	10.7%	15.7%
22	Gen'l Mills	3.02%	9.5%	7.7%	8.0%	9.3%	12.5%	10.7%	11.0%	12.3%
23	Heinz (H.J.)	3.85%	6.5%	7.0%	8.0%	13.9%	10.4%	10.9%	11.9%	17.8%
24	Hormel Foods	2.01%	10.5%	10.0%	9.3%	10.7%	12.5%	12.0%	11.3%	12.7%
25	Int'l Business Mach.	1.77%	13.0%	11.5%	9.3%	20.4%	14.8%	13.3%	11.1%	22.2%
26	Johnson & Johnson	3.44%	4.5%	6.0%	5.8%	10.8%	7.9%	9.4%	9.2%	14.2%
27	Kellogg	3.14%	9.5%	8.6%	9.0%	9.7%	12.6%	11.7%	12.1%	12.9%
28	Kimberly-Clark	4.09%	6.5%	7.5%	8.7%	18.6%	10.6%	11.6%	12.8%	22.7%
29	Kraft Foods	3.71%	8.0%	8.4%	8.0%	10.7%	11.7%	12.1%	11.7%	14.4%
30	Lilly (Eli)	5.64%	-2.5%	-6.4%	-5.3%	8.4%	3.1%	-0.8%	0.3%	14.0%
31	Lockheed Martin	3.78%	10.0%	8.1%	6.8%	20.3%	13.8%	11.9%	10.6%	24.1%
32	McCormick & Co.	2.24%	8.5%	9.6%	9.5%	13.3%	10.7%	11.8%	11.7%	15.6%
33	McDonald's Corp.	3.25%	9.5%	9.8%	9.3%	10.7%	12.8%	13.1%	12.6%	13.9%
34	McKesson Corp.	0.98%	10.0%	14.2%	11.0%	11.7%	11.0%	15.2%	12.0%	12.7%
35	Medtronic, Inc.	2.47%	7.5%	8.8%	8.4%	11.7%	10.0%	11.3%	10.9%	14.1%
36	Microsoft Corp.	2.26%	12.5%	11.3%	11.7%	15.3%	14.8%	13.6%	14.0%	17.5%
37	NIKE, Inc. 'B'	1.49%	9.5%	10.9%	12.5%	12.2%	11.0%	12.4%	14.0%	13.7%
38	Northrop Grumman	2.82%	12.5%	11.0%	11.1%	7.9%	15.3%	13.8%	13.9%	10.7%
39	PepsiCo, Inc.	2.91%	11.0%	8.9%	9.5%	14.5%	13.9%	11.8%	12.4%	17.4%
40	Pfizer, Inc.	4.50%	5.0%	2.8%	3.5%	7.0%	9.5%	7.3%	8.0%	11.5%
41	Procter & Gamble	3.01%	8.0%		9.2%	7.2%	11.0%	11.9%	12.2%	10.3%
42	Raytheon Co.	3.02%	10.0%		10.0%	8.6%	13.0%	11.0%	13.0%	11.6%
43	Stryker Corp.	1.26%	12.5%		11.4%	13.6%	13.8%	12.2%	12.7%	14.9%
44	Sysco Corp.	3.47%	8.0%	10.0%	9.7%	14.2%	11.5%	13.5%	13.2%	17.6%
45	TJX Companies	1.28%	13.5%	14.5%	14.4%	11.1%	14.8%	15.8%	15.7%	12.4%
46	United Parcel Serv.	2.59%	9.0%	11.7%	11.5%	17.9%	11.6%	14.3%	14.1%	20.5%
47	Verizon Communic.	5.63%	4.0%	6.2%	14.9%	5.7%	9.6%	11.8%	20.5%	11.3%
48	Walgreen Co.	1.68%	11.5%	13.4%	13.0%	8.4%	13.2%	15.1%	14.7%	10.1%
49	Wal-Mart Stores	2.16%	10.0%	10.7%	11.3%	9.9%	12.2%	12.9%	13.5%	12.1%
50	Waste Management	3.52%	5.5%	9.6%	11.0%	5.2%	9.0%	13.1%	14.5%	8.7%
	Average (f)						**11.9%**	**12.4%**	**12.5%**	**12.1%**

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) *Thomson Reuters Company in Context Report* (Jan. 28, 2011).
(c) www.zacks.com (retrieved Jan. 31, 2011).
(d) See Attachment WEA-5.
(e) Sum of dividend yield and respective growth rate.
(f) Excludes highlighted figures.

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	Company	(a) 2014 EPS	(a) 2014 DPS	(a) 2014 BVPS	b	r	(b) Adjust. Factor	(c) Adj. r	br	(d) "sv" Factor s	(e) "sv" Factor v	"sv" Factor sv	br + sv
1	3M Company	$7.60	$3.10	$40.05	59.2%	19.0%	1.0818	20.5%	12.2%	0.0106	0.6731	0.71%	12.9%
2	Abbott Labs.	$5.70	$2.18	$22.05	61.8%	25.9%	1.0384	26.8%	16.6%	(0.0197)	0.7900	-1.56%	15.0%
3	Alberto-Culver	$2.35	$0.55	$17.85	76.6%	13.2%	1.0315	13.6%	10.4%	(0.0330)	0.6033	-1.99%	8.4%
4	AT&T Inc.	$3.25	$2.00	$24.05	38.5%	13.5%	1.0327	14.0%	5.4%	(0.0001)	0.4656	-0.01%	5.4%
5	Automatic Data Proc.	$3.45	$1.60	$22.95	53.6%	15.0%	1.0786	16.2%	8.7%	0.0111	0.7039	0.78%	9.5%
6	Bard (C.R.)	$7.75	$0.85	$31.45	89.0%	24.6%	1.0255	25.3%	22.5%	(0.0564)	0.7754	-4.37%	18.1%
7	Baxter Int'l Inc.	$5.85	$1.50	$22.90	74.4%	25.5%	1.0560	27.0%	20.1%	(0.0633)	0.7224	-4.57%	15.5%
8	Becton, Dickinson	$7.65	$2.20	$34.10	71.2%	22.4%	1.0306	23.1%	16.5%	(0.1030)	0.7216	-7.43%	9.0%
9	Bristol-Myers Squibb	$2.35	$1.54	$11.65	34.5%	20.2%	1.0263	20.7%	7.1%	(0.0212)	0.6671	-1.42%	5.7%
10	Brown-Forman 'B'	$4.50	$1.48	$20.40	67.1%	22.1%	1.0372	22.9%	15.4%	(0.0640)	0.7368	-4.71%	10.6%
11	Chubb Corp.	$7.00	$1.60	$64.85	77.1%	10.8%	1.0184	11.0%	8.5%	(0.0319)	0.1632	-0.52%	8.0%
12	Church & Dwight	$5.80	$1.00	$39.25	82.8%	14.8%	1.0465	15.5%	12.8%	(0.0414)	0.6075	-2.52%	10.3%
13	Coca-Cola	$4.95	$2.48	$18.20	49.9%	27.2%	1.0479	28.5%	14.2%	(0.0526)	0.8267	-4.34%	9.9%
14	Colgate-Palmolive	$7.20	$3.20	$13.25	55.6%	54.3%	1.0671	58.0%	32.2%	(0.1557)	0.9086	-14.15%	18.1%
15	Commerce Bancshs.	$3.35	$1.15	$32.10	65.7%	10.4%	1.0480	10.9%	7.2%	0.0240	0.2867	0.69%	7.9%
16	ConAgra Foods	$2.35	$1.00	$15.00	57.4%	15.7%	1.0288	16.1%	9.3%	(0.0217)	0.5385	-1.17%	8.1%
17	Costco Wholesale	$4.20	$0.95	$33.50	77.4%	12.5%	1.0315	12.9%	10.0%	(0.0301)	0.5939	-1.79%	8.2%
18	Cullen/Frost Bankers	$4.35	$2.10	$44.00	51.7%	9.9%	1.0382	10.3%	5.3%	0.0132	0.2667	0.35%	5.7%
19	CVS Caremark Corp.	$4.00	$0.56	$38.15	86.0%	10.5%	1.0268	10.8%	9.3%	(0.0395)	0.3642	-1.44%	7.8%
20	Ecolab Inc.	$3.60	$0.85	$14.45	76.4%	24.9%	1.0530	26.2%	20.0%	(0.0056)	0.7592	-0.43%	19.6%
21	Exxon Mobil Corp.	$9.35	$2.05	$45.50	78.1%	20.5%	1.0546	21.7%	16.9%	(0.0578)	0.5956	-3.44%	13.5%
22	Gen'l Mills	$3.15	$1.36	$11.95	56.8%	26.4%	1.0318	27.2%	15.5%	(0.0809)	0.7610	-6.16%	9.3%
23	Heinz (H.J.)	$4.10	$2.32	$14.65	43.4%	28.0%	1.0908	30.5%	13.3%	0.0085	0.7830	0.66%	13.9%
24	Hormel Foods	$2.10	$0.70	$13.55	66.7%	15.5%	1.0527	16.3%	10.9%	(0.0025)	0.6387	-0.16%	10.7%
25	Int'l Business Mach.	$18.00	$3.60	$48.75	80.0%	36.9%	1.0856	40.1%	32.1%	(0.1501)	0.7759	-11.65%	20.4%
26	Johnson & Johnson	$5.85	$2.65	$27.60	54.7%	21.2%	1.0378	22.0%	12.0%	(0.0185)	0.6846	-1.26%	10.8%
27	Kellogg	$5.10	$1.88	$9.95	63.1%	51.3%	1.0352	53.1%	33.5%	(0.2690)	0.8829	-23.75%	9.7%
28	Kimberly-Clark	$6.25	$2.75	$15.55	56.0%	40.2%	1.0140	40.8%	22.8%	(0.0506)	0.8363	-4.24%	18.6%
29	Kraft Foods	$3.00	$1.40	$24.00	53.3%	12.5%	1.0480	13.1%	7.0%	0.0716	0.5200	3.72%	10.7%
30	Lilly (Eli)	$3.40	$2.20	$15.60	35.3%	21.8%	1.0636	23.2%	8.2%	0.0032	0.6716	0.21%	8.4%
31	Lockheed Martin	$13.25	$3.50	$31.25	73.6%	42.4%	1.0882	46.1%	34.0%	(0.1663)	0.8188	-13.62%	20.3%
32	McCormick & Co.	$3.50	$1.36	$18.95	61.1%	18.5%	1.0649	19.7%	12.0%	0.0178	0.7293	1.30%	13.3%
33	McDonald's Corp.	$6.05	$3.00	$19.00	50.4%	31.8%	1.0303	32.8%	16.5%	(0.0734)	0.8000	-5.87%	10.7%
34	McKesson Corp.	$6.80	$0.72	$46.65	89.4%	14.6%	1.0421	15.2%	13.6%	(0.0380)	0.4957	-1.88%	11.7%
35	Medtronic, Inc.	$4.50	$1.18	$25.95	73.8%	17.3%	1.0597	18.4%	13.6%	(0.0326)	0.5848	-1.91%	11.7%
36	Microsoft Corp.	$3.35	$0.96	$10.75	71.3%	31.2%	1.0763	33.5%	23.9%	(0.1104)	0.7850	-8.66%	15.3%
37	NIKE, Inc. 'B'	$5.65	$1.50	$34.60	73.5%	16.3%	1.0643	17.4%	12.8%	(0.0085)	0.6358	-0.54%	12.2%
38	Northrop Grumman	$10.25	$2.50	$68.00	75.6%	15.1%	1.0293	15.5%	11.7%	(0.0783)	0.4868	-3.81%	7.9%
39	PepsiCo, Inc.	$6.40	$2.34	$24.00	63.4%	26.7%	1.0724	28.6%	18.1%	(0.0449)	0.8118	-3.64%	14.5%
40	Pfizer, Inc.	$2.05	$1.16	$13.00	43.4%	15.8%	1.0154	16.0%	7.0%	-	0.5273	0.00%	7.0%
41	Procter & Gamble	$5.25	$2.18	$29.45	58.5%		1.0230	18.2%	10.7%	(0.0495)	0.6900	-3.41%	7.2%
42	Raytheon Co.	$7.20	$2.00	$38.65	72.2%		1.0231	19.1%	13.8%	(0.0870)	0.5932	-5.16%	8.6%
43	Stryker Corp.	$5.35	$0.84	$32.75	84.3%		1.0660	17.4%	14.7%	(0.0144)	0.7213	-1.04%	13.6%
44	Sysco Corp.	$2.75	$1.10	$10.10	60.0%	27.2%	1.0502	28.6%	17.2%	(0.0385)	0.7756	-2.98%	14.2%
45	TJX Companies	$4.80	$0.80	$12.75	83.3%	37.6%	1.0374	39.1%	32.5%	(0.2565)	0.8355	-21.43%	11.1%
46	United Parcel Serv.	$5.50	$2.20	$19.30	60.0%	28.5%	1.0912	31.1%	18.7%	(0.0090)	0.8245	-0.75%	17.9%
47	Verizon Communic.	$3.05	$1.96	$18.95	35.7%	16.1%	1.0250	16.5%	5.9%	(0.0032)	0.6555	-0.21%	5.7%
48	Walgreen Co.	$3.65	$1.00	$21.15	72.6%	17.3%	1.0252	17.7%	12.8%	(0.0684)	0.6475	-4.43%	8.4%
49	Wal-Mart Stores	$6.05	$1.75	$23.40	71.1%	25.9%	1.0072	26.0%	18.5%	(0.1157)	0.7400	-8.56%	9.9%
50	Waste Management	$2.90	$1.60	$15.30	44.8%	19.0%	1.0079	19.1%	8.6%	(0.0515)	0.6600	-3.40%	5.2%

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)		(g)	(a)	(a)	(f)
		---- Common Equity ----			------- 2014 Price -------				---- Common Shares ----		
	Company	2009	2014	Chg.	High	Low	Avg.	M/B	2009	2014	Growth
1	3M Company	$12,764	$28,975	17.8%	$135.00	$110.00	$122.50	3.059	710.60	723.00	0.35%
2	Abbott Labs.	$22,856	$33,550	8.0%	$115.00	$95.00	$105.00	4.762	1,551.90	1,520.00	-0.41%
3	Alberto-Culver	$1,197	$1,640	6.5%	$50.00	$40.00	$45.00	2.521	98.26	92.00	-1.31%
4	AT&T Inc.	$102,339	$141,895	6.8%	$50.00	$40.00	$45.00	1.871	5,901.90	5,900.00	-0.01%
5	Automatic Data Proc.	$5,323	$11,700	17.1%	$85.00	$70.00	$77.50	3.377	501.70	510.00	0.33%
6	Bard (C.R.)	$2,194	$2,830	5.2%	$155.00	$125.00	$140.00	4.452	95.92	90.00	-1.27%
7	Baxter Int'l Inc.	$7,191	$12,600	11.9%	$90.00	$75.00	$82.50	3.603	600.97	550.00	-1.76%
8	Becton, Dickinson	$5,143	$6,985	6.3%	$135.00	$110.00	$122.50	3.592	237.08	205.00	-2.87%
9	Bristol-Myers Squibb	$14,785	$19,230	5.4%	$40.00	$30.00	$35.00	3.004	1,709.50	1,650.00	-0.71%
10	Brown-Forman 'B'	$1,895	$2,750	7.7%	$85.00	$70.00	$77.50	3.799	146.96	135.00	-1.68%
11	Chubb Corp.	$15,634	$18,800	3.8%	$85.00	$70.00	$77.50	1.195	332.01	290.00	-2.67%
12	Church & Dwight	$1,602	$2,550	9.7%	$110.00	$90.00	$100.00	2.548	70.55	65.00	-1.63%
13	Coca-Cola	$24,799	$40,035	10.1%	$115.00	$95.00	$105.00	5.769	2,303.00	2,200.00	-0.91%
14	Colgate-Palmolive	$3,116	$6,100	14.4%	$160.00	$130.00	$145.00	10.943	494.17	460.00	-1.42%
15	Commerce Bancshs.	$1,886	$3,050	10.1%	$50.00	$40.00	$45.00	1.402	87.26	95.00	1.71%
16	ConAgra Foods	$4,721	$6,300	5.9%	$35.00	$30.00	$32.50	2.167	441.66	420.00	-1.00%
17	Costco Wholesale	$10,018	$13,725	6.5%	$90.00	$75.00	$82.50	2.463	435.97	410.00	-1.22%
18	Cullen/Frost Bankers	$1,894	$2,775	7.9%	$65.00	$55.00	$60.00	1.364	60.04	63.00	0.97%
19	CVS Caremark Corp.	$35,768	$46,750	5.5%	$65.00	$55.00	$60.00	1.573	1,391.00	1,225.00	-2.51%
20	Ecolab Inc.	$2,001	$3,400	11.2%	$65.00	$55.00	$60.00	4.152	236.60	235.00	-0.14%
21	Exxon Mobil Corp.	$110,569	$191,000	11.6%	$125.00	$100.00	$112.50	2.473	4,727.00	4,200.00	-2.34%
22	Gen'l Mills	$5,175	$7,115	6.6%	$55.00	$45.00	$50.00	4.184	656.00	595.00	-1.93%
23	Heinz (H.J.)	$1,891	$4,700	20.0%	$75.00	$60.00	$67.50	4.608	318.06	321.00	0.18%
24	Hormel Foods	$2,124	$3,600	11.1%	$40.00	$35.00	$37.50	2.768	267.19	266.00	-0.09%
25	Int'l Business Mach.	$22,755	$53,650	18.7%	$240.00	$195.00	$217.50	4.462	1,305.30	1,100.00	-3.36%
26	Johnson & Johnson	$50,588	$73,850	7.9%	$95.00	$80.00	$87.50	3.170	2,754.30	2,675.00	-0.58%
27	Kellogg	$2,272	$3,230	7.3%	$95.00	$75.00	$85.00	8.543	381.38	325.00	-3.15%
28	Kimberly-Clark	$5,406	$6,220	2.8%	$105.00	$85.00	$95.00	6.109	417.00	400.00	-0.83%
29	Kraft Foods	$25,972	$42,000	10.1%	$55.00	$45.00	$50.00	2.083	1,477.90	1,750.00	3.44%
30	Lilly (Eli)	$9,524	$18,000	13.6%	$50.00	$45.00	$47.50	3.045	1,149.00	1,155.00	0.10%
31	Lockheed Martin	$4,129	$10,000	19.4%	$190.00	$155.00	$172.50	5.520	372.90	320.00	-3.01%
32	McCormick & Co.	$1,335	$2,555	13.9%	$75.00	$65.00	$70.00	3.694	131.80	135.00	0.48%
33	McDonald's Corp.	$14,034	$19,000	6.2%	$105.00	$85.00	$95.00	5.000	1,076.70	1,000.00	-1.47%
34	McKesson Corp.	$7,532	$11,480	8.8%	$100.00	$85.00	$92.50	1.983	271.00	246.00	-1.92%
35	Medtronic, Inc.	$14,629	$26,600	12.7%	$70.00	$55.00	$62.50	2.408	1,097.30	1,025.00	-1.35%
36	Microsoft Corp.	$39,558	$85,000	16.5%	$55.00	$45.00	$50.00	4.651	8,908.00	7,900.00	-2.37%
37	NIKE, Inc. 'B'	$8,693	$16,550	13.7%	$105.00	$85.00	$95.00	2.746	485.50	478.00	-0.31%
38	Northrop Grumman	$12,687	$17,000	6.0%	$145.00	$120.00	$132.50	1.949	306.87	250.00	-4.02%
39	PepsiCo, Inc.	$17,442	$36,015	15.6%	$140.00	$115.00	$127.50	5.313	1,565.00	1,500.00	-0.84%
40	Pfizer, Inc.	$90,014	$105,000	3.1%	$30.00	$25.00	$27.50	2.115	8,070.00	8,070.00	0.00%
41	Procter & Gamble	$63,099	$79,455	4.7%	$105.00	$85.00	$95.00	3.226	2,917.00	2,700.00	-1.53%
42	Raytheon Co.	$9,827	$12,375	4.7%	$105.00	$85.00	$95.00	2.458	383.20	320.00	-3.54%
43	Stryker Corp.	$6,595	$12,775	14.1%	$130.00	$105.00	$117.50	3.588	397.90	390.00	-0.40%
44	Sysco Corp.	$3,450	$5,700	10.6%	$50.00	$40.00	$45.00	4.455	590.03	565.00	-0.86%
45	TJX Companies	$2,889	$4,200	7.8%	$85.00	$70.00	$77.50	6.078	409.39	330.00	-4.22%
46	United Parcel Serv.	$7,630	$19,035	20.1%	$120.00	$100.00	$110.00	5.699	992.85	985.00	-0.16%
47	Verizon Communic.	$41,600	$53,439	5.1%	$60.00	$50.00	$55.00	2.902	2,835.70	2,820.00	-0.11%
48	Walgreen Co.	$14,376	$18,500	5.2%	$65.00	$55.00	$60.00	2.837	988.56	875.00	-2.41%
49	Wal-Mart Stores	$70,749	$76,025	1.4%	$100.00	$80.00	$90.00	3.846	3,786.00	3,250.00	-3.01%
50	Waste Management	$6,285	$6,800	1.6%	$50.00	$40.00	$45.00	2.941	486.12	445.00	-1.75%

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of year-end "r" for 2014 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Five-year rate of change.
(g) Average of High and Low expected market prices divided by 2013-15 BVPS.

CAPITAL ASSET PRICING MODEL

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.3%	
Growth Rate (b)	10.5%	
Market Return (c)		12.8%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Market Risk Premium (e)		8.3%
Utility Proxy Group Beta (f)		0.74
Utility Proxy Group Risk Premium (g)		6.1%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Unadjusted CAPM (h)		10.6%
Size Adjustment (i)		0.74%
Implied Cost of Equity (j)		**11.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for March 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.3%	
Growth Rate (b)	10.5%	
Market Return (c)		12.8%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Market Risk Premium (e)		8.3%
Non-Utility Proxy Group Beta (f)		0.71
Utility Proxy Group Risk Premium (g)		5.9%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Unadjusted CAPM (h)		10.4%
Size Adjustment (i)		-0.37%
Implied Cost of Equity (j)		**10.0%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved Jan. 28, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

BOOK VALUE CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2010 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	Ameren Corp.	47.1%	0.0%	52.9%	46.0%	1.0%	53.0%
2	American Elec Pwr	55.1%	0.2%	44.7%	49.5%	0.0%	50.5%
3	CenterPoint Energy	74.7%	0.0%	25.3%	71.0%	0.0%	29.0%
4	Cleco Corp.	51.7%	0.0%	48.2%	44.5%	0.5%	55.0%
5	CMS Energy	71.7%	0.0%	28.3%	65.5%	0.5%	34.0%
6	Constellation Energy	34.7%	1.5%	63.8%	31.5%	1.0%	67.5%
7	DTE Energy Co.	49.9%	2.1%	48.0%	52.5%	0.0%	47.5%
8	Edison International	51.9%	3.8%	44.3%	52.0%	3.0%	45.0%
9	Great Plains Energy	54.0%	0.6%	45.4%	51.0%	0.5%	48.5%
10	Hawaiian Elec.	47.3%	1.2%	51.5%	47.0%	1.0%	52.0%
11	IDACORP, Inc.	51.2%	0.0%	48.8%	49.5%	0.0%	50.5%
12	Integrys Energy Group	47.6%	0.0%	52.4%	45.0%	1.0%	54.0%
13	ITC Holdings Corp.	69.1%	0.0%	30.9%	66.5%	0.0%	33.5%
14	Pepco Holdings	46.6%	0.0%	53.4%	52.0%	0.0%	48.0%
15	PG&E Corp.	50.4%	1.1%	48.5%	45.0%	1.0%	54.0%
16	Pinnacle West Capital	49.3%	0.0%	50.7%	46.5%	0.0%	53.5%
17	Portland General Elec.	53.1%	0.0%	46.9%	50.0%	0.0%	50.0%
18	PPL Corp.	59.9%	0.0%	40.1%	47.5%	1.0%	51.5%
19	TECO Energy	59.4%	0.0%	40.6%	52.5%	0.0%	47.5%
20	Westar Energy	54.3%	0.4%	45.3%	54.0%	0.5%	45.5%
21	Wisconsin Energy	53.5%	0.4%	46.2%	51.5%	0.5%	48.0%
	Average	**53.9%**	**0.5%**	**45.5%**	**51.0%**	**0.5%**	**48.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).

MARKET VALUE CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2010 (a)			Value Line Projected (b)		
		(a)	(b)	(c)	(a)	(b)	(c)
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	Ameren Corp.	51.3%	0.0%	48.7%	50.8%	1.1%	48.1%
2	American Elec Pwr	48.1%	0.2%	51.7%	44.1%	0.0%	55.9%
3	CenterPoint Energy	57.7%	0.0%	42.3%	54.0%	0.0%	46.0%
4	Cleco Corp.	42.9%	0.0%	57.1%	41.1%	0.5%	58.4%
5	CMS Energy	59.4%	0.0%	40.6%	56.8%	0.4%	42.8%
6	Constellation Energy	40.7%	1.8%	57.5%	35.6%	1.1%	63.3%
7	DTE Energy Co.	46.3%	1.9%	51.8%	47.3%	0.0%	52.7%
8	Edison International	45.1%	3.3%	51.6%	52.1%	3.0%	44.9%
9	Great Plains Energy	54.3%	0.6%	45.1%	53.7%	0.5%	45.7%
10	Hawaiian Elec.	37.8%	1.0%	61.2%	39.7%	0.8%	59.4%
11	IDACORP, Inc.	44.8%	0.0%	55.2%	47.2%	0.0%	52.8%
12	Integrys Energy Group	39.4%	0.0%	60.6%	42.4%	0.9%	56.7%
13	ITC Holdings Corp.	44.3%	0.0%	55.7%	42.1%	0.0%	57.9%
14	Pepco Holdings	47.6%	0.0%	52.4%	52.7%	0.0%	47.3%
15	PG&E Corp.	37.9%	0.8%	61.2%	38.5%	0.9%	60.7%
16	Pinnacle West Capital	44.0%	0.0%	56.0%	43.8%	0.0%	56.2%
17	Portland General Elec.	50.2%	0.0%	49.8%	48.7%	0.0%	51.3%
18	PPL Corp.	49.2%	0.0%	50.8%	36.5%	0.8%	62.7%
19	TECO Energy	45.2%	0.0%	54.8%	40.9%	0.0%	59.1%
20	Westar Energy	49.7%	0.4%	49.9%	48.1%	0.4%	51.4%
21	Wisconsin Energy	23.1%	0.2%	76.7%	36.5%	0.4%	63.2%
	Average	**45.7%**	**0.5%**	**53.8%**	**45.4%**	**0.5%**	**54.1%**

(a) Debt outstanding computed by multiplying long-term debt ratio by total book capital, both as reported by The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).

BOOK VALUE CAPITAL STRUCTURE

ELECTRIC UTILITY OPERATING COS.

		At Fiscal Year-End 2010 (a)		
	Company	**Long-term Debt**	**Preferred**	**Common Equity**
1	AEP Texas Central Co.	54.9%	0.4%	44.7%
2	AEP Texas North Co.	54.3%	0.3%	45.4%
3	Ameren Illinois Co.	41.2%	0.0%	58.8%
4	Appalachian Power Co.	55.6%	0.3%	44.1%
5	Atlantic City Electric Co.	48.5%	0.4%	51.1%
6	Baltimore Gas & Electric Co.	43.8%	5.7%	50.4%
7	CenterPoint Energy Houston Electric, LLC	73.5%	0.0%	26.5%
8	Cleco Power	53.1%	0.0%	46.9%
9	Columbus Southern Power Co.	49.2%	0.0%	50.8%
10	Consumers Energy Co.	52.1%	0.5%	47.4%
11	Delmarva Power & Light Co.	47.6%	0.0%	52.4%
12	Detroit Edison Co.	52.1%	0.0%	47.9%
13	Hawaiian Electric Co.	43.5%	1.4%	55.0%
14	Idaho Power Co.	53.4%	0.0%	46.6%
15	Indiana Michigan Power Co.	54.1%	0.2%	45.7%
16	International Transmission Co.	40.0%	0.0%	60.0%
17	ITC Great Plains	38.8%	0.0%	61.2%
18	ITC Midwest	40.0%	0.0%	60.0%
19	Kansas City Power & Light	47.0%	0.0%	53.0%
20	Kansas Gas & Electric	43.0%	0.0%	57.0%
21	Kentucky Power Co.	55.8%	0.0%	44.2%
22	Kentucky Utilities Co.	47.0%	0.0%	53.0%
23	Louisville Gas & Electric Co.	41.4%	0.0%	58.6%
24	Michigan Elec. Transmission Co.	39.1%	0.0%	60.9%
25	Ohio Power Co.	46.1%	0.3%	53.6%
26	Pacific Gas & Electric Co.	49.2%	1.1%	49.7%
27	Portland General Elec.	53.1%	0.0%	46.9%
28	Potomac Electric Power Co.	51.9%	0.0%	48.1%
29	PPL Electric Utilities Corp.	43.1%	7.3%	49.6%
30	Public Service Co. of Oklahoma	53.4%	0.3%	46.3%
31	Southern California Edison Co.	45.3%	5.5%	49.2%
32	Southwestern Electric Pwr Co.	51.4%	0.1%	48.4%
33	Tampa Electric Co.	49.0%	0.0%	51.0%
34	Union Electric Co.	48.8%	0.0%	51.2%
35	Upper Penninsula Power Co.	37.1%	0.0%	62.9%
36	Westar Energy	38.1%	0.6%	61.4%
37	Wisconsin Electric Power Co.	39.2%	0.6%	60.2%
38	Wisconsin Public Service Corp.	42.3%	2.5%	55.2%
	Average	**47.8%**	**0.7%**	**51.5%**

(a) Company Form 10-K and Annual Reports.

COST RECOVERY MECHANISMS

UTILITY PROXY GROUP

	Company	Mechanism
1	Ameren Corp.	FCA; PGA; DSMA; TCR; BDR; Cost trackers for pensions & post-retirement benefits, vegetation management, infrastructure inspections
2	American Elect Pwr	FCA: ECA
3	CenterPoint Energy	PGA; RMD; TCR
4	Cleco Corp.	FCA
5	CMS Energy	FCA; PGA; RDM; Self-implementing rates to reduce regulatory lag
6	Constellation Energy	PGA; RDM; DSMA
7	DTE Energy Co.	FCA; PGA; RDM; BDR; Cost tracker for restoration costs
8	Edison International	FCA; RDM; ICR; ECA; Variety of balancing accounts cover a substantial portion of authorized revenue requirements
9	Great Plains Energy	FCA
10	Hawaiian Elec.	FCA; RDM; ICR; Pension cost tracker
11	IDACORP, Inc.	FCA; RDM (Fixed cost adjustment mechanism); DSMA
12	Integrys Energy Group	FCA; RDM; ICR; BDR
13	ITC Holdings Corp.	RDM (formula rates with true-up mechanism)
14	Pepco Holdings	FCA; PGA; RDM
15	PG&E Corp.	FCA; RDM; ICR; ECA; TCR; Variety of balancing accounts cover a substantial portion of authorized revenue requirements
16	Portland General Elec.	FCA; RDM; ICR
17	PPL Corp.	FCA; PGA; ECA; DSMA; TCR; ICR (smart meters); Universal service cost tracker
18	TECO Energy	FCA; PGA; ECA; DSMA
19	Westar Energy	FCA; ECA; Employee benefit cost tracker
20	Wisconsin Energy	FCA; PGA

BDR -- Bad Debt Cost Recovery Rider
DSMA -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Purchased Power Cost Adjustment Clause
ICR -- Infrastructure / Renewables Cost Recovery
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
TCR -- Transmission Cost Recovery Tracker

Source: 2010 Form-10K Reports.

Leland R. Snook

TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11- _____

June 1, 2011

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TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-XXXX)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Leland R. Snook. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Director of Rates and Pricing for Arizona Public Service Company ("APS" or "Company"). I have management responsibility for all aspects relating to rates, pricing, and revenue requirements.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My background and experience are set forth in Appendix A to this testimony.

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

A. My testimony will address the need to modernize the Company's rate structure by adopting a mechanism that will, among other things, allow APS to continue to actively promote energy efficiency and distributed energy programs. This new rate structure will align the Company's and customers' financial interests, resulting in a more reasonable opportunity for the Company to collect its fixed costs of providing service. The Arizona Corporation Commission ("Commission") approved a Decoupling Policy Statement on December 29, 2010, which provided guidance related to the form of decoupling utilities should seek to implement to help mitigate the effects of reduced sales due to energy efficiency ("EE") and renewable distributed generation ("DG"). Consistent with the policy statement, APS proposes that an Efficiency and Infrastructure Account ("EIA") mechanism be implemented in this proceeding to create the proper

business model for APS to actively encourage our customers to participate in EE and DG programs.

My testimony will also address APS's proposed Environmental and Reliability Account ("ERA") mechanism, which is intended to recover the revenue requirement of generation plant capacity acquisitions, efficiency projects and environmental improvement projects on a more concurrent basis between rate cases. Environmental regulation of power plants and their emissions by the federal government is becoming increasingly more stringent. Compliance with new environmental standards in many instances will require significant capital expenditures, beyond the levels that APS has currently made. The ERA mechanism will allow the Company to recover costs in the year after it is placed in service to reduce the impacts of regulatory lag on these required investments.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony describes why modernizing the APS rate structure in this proceeding is necessary given the ambitious Energy Efficiency Standard ("EES") and increasing DG requirements. APS recognizes that EE and conservation programs developed to meet the EES provide important customer and environmental benefits, including the ability of customers to reduce their electricity bills through direct participation in APS programs. In addition, reduced consumption will both decrease fuel costs and delay the need for additional expensive generation resources, which provides cost savings for all customers. APS supports the expansion of EE as a resource because it is a lower cost alternative today to help meet future energy requirements. However, without an evolution in the current rate structure, successful energy efficiency programs – even at levels below that set by the Commission in the EES – create a significant

disincentive for the utility with serious adverse financial impacts. For the EES to be sustainable in the long-term, it is essential to address this disincentive and better align the utility business model with the public interest using a modern complementary tool such as APS's proposed EIA.

Generally speaking, a utility has two types of costs: fixed and variable. Variable costs are those that change depending on the amount of energy produced, such as fuel costs. Fixed costs are those that do not fluctuate with the amount of energy produced and consumed, such as the carrying costs of plant assets, taxes and operations and maintenance expenses associated with generation, transmission, distribution and general plant investments. Under traditional ratemaking, the vast majority of each of these costs is collected through usage-based (or "volumetric") rates. In the 2010 Test Year, for residential customers APS collected approximately 27% of its fixed costs through a fixed charge (the basic service charge and kilowatt ("kW") demand charges[1]), while the remaining 73% was collected through kilowatt-hour ("kWh") rates. For commercial customers the percentages were 34% through fixed charges (basic service and kW charges) and 66% through kWh charges. Basic service charges alone were only approximately 16% for both residential and commercial customers. Under this rate design, the fixed costs a utility needs to recover depends heavily upon this throughput incentive to sell additional kWh. The more kWh a utility sells, the more revenue a utility will collect through volumetric rates, thereby recovering a greater portion of its fixed costs. Conversely, if the kWh sales are lower, the utility will recover a lower portion of its fixed costs of service. In a business model that addresses the objectives of EE and DG, the utility's and customer's incentives should be

[1] Demand charges (kW) also vary with the customer's actual demand, but have less variability than energy charges (kWh) depending on the applicable period of time that demand measurements are recorded or applicable demand ratchets where demands in previous periods, either time-of-day or monthly, still apply for a period of time.

aligned, but APS's present rate structure puts us at cross-purposes. In other words, APS's financial incentives are in conflict with what is best for the customer.

To address this inherent disincentive, APS is proposing its EIA, which is a revenue per customer decoupling mechanism consistent with the Commission approved policy statement. This method was the model preferred by the majority of stakeholders who participated in the Commission Decoupling Workshops and is the mechanism most commonly applied in other regulatory jurisdictions. My testimony will describe the EIA and discuss why this proceeding is the appropriate place to adopt a mechanism which modernizes the rate structure. I will also describe the benefits that will result from the implementation of the EIA for both customers and the utility.

Further, my testimony describes why the ERA should be implemented in this proceeding. Environmental regulations of coal-fired generating units continue to become more stringent and to be in compliance with new regulations may require significant capital spending. For instance, the Environmental Protection Agency ("EPA") has recently proposed a ruling that would require the Four Corners generating station participants to install nitrogen oxide ("NO_x") emission controls on each of the plant's five units, and additional mercury controls on Units 1-3. The capital expenditures required for compliance will have a time clock for completion. Due to the nature of the projects, APS proposes the ERA be adjusted annually to recover the carrying costs associated with (1) environmental improvement projects, (2) generation plant capacity additions or the construction of new generation and (3) efficiency projects. My testimony will explain the ERA mechanism and discuss why its adoption in this proceeding is necessary.

III. MODERNIZING THE RATE STRUCTURE

A. Background Information on the Decoupling Workshops

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE DECOUPLING WORKSHOPS AND THE PROCESS.

A. There were five ACC sponsored workshops held to discuss decoupling (Docket Nos. E-00000J-08-0314 & G-00000C-08-0314) – all of which allowed for open, collaborative discussions among participants. Stakeholders who participated in the workshops consisted of: Arizona Investment Council, Arizonans for Electric Choice and Competition ("AECC"), Commission Staff, Residential Utility Consumer Office ("RUCO"), Southwest Gas, Tucson Electric Power, UNS Gas, UNS Electric, Southwest Energy Efficiency Project ("SWEEP"), Western Resource Advocates ("WRA"), Natural Resources Defense Council ("NRDC") and Duncan Valley Electric Cooperative, Inc., Graham County Electric Cooperative, Inc., Mohave Electric Cooperative, Inc., Navopache Electric Cooperative, Inc., Trico Electric Cooperative, Inc. and Sulphur Springs Valley Electric Cooperative, Inc., collectively the ("Cooperatives"). Also, the Regulatory Assistance Project ("RAP") assisted in facilitating the workshop process and provided guidance on decoupling model mechanics.

To begin the workshops, presentations were made by RAP, SWEEP and NRDC that discussed the theory of decoupling, the types of mechanisms used throughout the country, various decoupling implementation strategies along with the merits and customer benefits associated with EE and decoupling. In the later workshops, at the request of the Commission, Lawrence Berkeley National Laboratories ("LBNL") presented their independent analyses of the effects of the EES on APS and Tucson Electric Power Company, both with and without a decoupling mechanism. LBNL concluded that if the EES could be achieved it would be greatly beneficial to customers, but would dramatically harm the financial

viability of the companies. If however, a companion decoupling mechanism was implemented, the rate impact of decoupling would be very modest by comparison to the customer bill savings resulting from EE programs to meet the EES. In total, customers' overall bills would still be reduced (and even more so if they participate in EE), while also aligning customers' and APS's interests in achieving the EES. Such a mechanism would modernize the rate structure by allowing APS to actively encourage customers to participate in EE and DG programs while stabilizing APS's financial condition between rate cases.

Q. WHAT RESULTED FROM THE DECOUPLING WORKSHOPS?

A. The workshops resulted in a unanimously-approved Commission Policy Statement issued December 29, 2010 providing guidance for the potential future implementation of a decoupling mechanism. The Policy Statement creates a framework for the type of mechanism, frequency of the adjustment, customer class inclusion and rate design options. For instance, in Policy Statement Number 4, a revenue per customer decoupling mechanism is suggested as being better suited than other alternative mechanisms to respond to customer growth typically experienced in Arizona. APS agrees with this observation.

When designing the APS proposed EIA mechanism, the Policy Statement was used to frame its creation. I will identify throughout my testimony where the mechanism is consistent with the Policy Statement and will also provide explanations for any differences.

B. Why Modernizing the APS Rate Structure is Necessary

Q. WHAT, IF ANY, FINANCIAL DISINCENTIVES ARE CREATED BY THE IMPLEMENTATION OF EE AND DG?

A. Currently, the vast majority of APS's revenues are collected through volumetric kWh energy charges. Therefore, the more energy a customer conserves or self-produces, the less fixed-cost recovery APS will receive. In essence, with the implementation of EE and DG, the historic volumetric pricing structure deprives APS from having a reasonable opportunity to earn its return authorized by the Commission. In the last APS rate case hearing (Decision No. 71448), APS Witness Jim Wontor estimated that the 3.75% EE target that was established in that rate case, would result in over $100 million in cumulative uncollected fixed costs from 2010 – 2012 (*see* Wontor Settlement Hearing Testimony at 1668). Based on measured and verified program results, the actual amount of uncollected fixed costs for 2010 was $17 million. If similar amounts were incurred in 2011 and 2012, the cumulative impact would be $119 million. As you can see, the 3.75% EE goal in Decision No. 71448 will result in a substantial amount of foregone cost recovery to APS. Absent a modernized regulatory mechanism, the EES would continue to significantly erode fixed cost recovery over the life of the EES, and would necessitate much more frequent rate case filings by APS to attempt to correct the increasing amounts of unrecovered fixed costs.

Mr. Jeff Schlegel on behalf of SWEEP correctly noted in the Decoupling Workshops that "in order to achieve the standard and in order to do so with the utilities as enthusiastic partners, I think you do have to address the financial disincentive" (*see* Decoupling Workshop transcripts on 4/15/2010 at 36). As well, then Commission Chairman Mayes pointedly asked Commission Staff if a 22% standard could be achieved without decoupling, to which the Director of the

Utilities Division Staff replied, "no" (*see* Decoupling Workshop transcripts on 4/16/2010 at 265). APS's proposed EIA mechanism will effectively address the financial disincentive. It changes the utility business model from a sales-driven model and aligns revenue with the number of customers – allowing for a greater portion of the fixed cost of service to be collected regardless of sales levels. The EIA would resolve the cross-purposes dilemma by aligning the Company's and customers' interests.

Q. ARE THERE OTHER METHODS THAT WOULD ACHIEVE SIMILAR RESULTS FOR APS?

A. Yes. For example, a rate design approach known as Straight Fixed-Variable ("SFV") would resolve the financial disincentive. In this rate design method, all fixed costs of service would be collected through fixed charges and only variable costs of service would be collected through usage charges. This approach would require very high basic service charges[2]. For example, the basic service charges for residential service would need to be raised to over $90 per month. General Service customers would experience even larger increases. This would be particularly burdensome for many residential and smaller commercial customers. Inherent to the SFV approach, there is a much lower incentive to participate in EE programs, since the bill savings would be equal to the reduced kWh energy sales times the lower energy charge. Because EE is presently the least cost resource alternative for APS, lower participation in EE programs would increase costs for all APS customers. I would add that APS is proposing a relatively modest increase in basic service charges in this case, but APS believes its proposal is less harmful to residential and small business customers and preserves an adequate incentive for EE.

[2] Basic Service Charges are used for illustrative purposes since they are the only absolute cost recovery component that does not vary with consumption. Demand charges (kW) would also improve fixed cost recovery as compared to energy charges (kWh).

Another method that would address the financial disincentive would be to establish a retail formula rate that is reset annually or an annual general rate case cycle. The first approach is more administratively challenging and the latter would likely prove to be very time consuming and expensive for all parties involved in the process.

The adoption of a future test year is also sometimes viewed as a potential remedy. However, although a future test year establishes a more synchronized starting point between the test period and the initial rate effective date, unless the approach provides for multi-year step increases like California, a future test year does not address the financial disincentives that would result between rate cases. Also, several states employ multiple regulatory tools that complement each other. For example, California has a multi-year future test year and a full decoupling mechanism.

Q. WHY IS IT NECESSARY TO IMPLEMENT THE EIA AT THIS TIME?

A. With the adoption of the EES, APS is at a crossroads. APS supports the Commission's EES, but needs the financial wherewithal and stability to implement such programs. APS believes EE is a resource and there are clear benefits in terms of resource cost savings to be obtained on behalf of customers. However, without a mechanism designed to help recover the fixed costs of service, it simply is not a sustainable path a utility can pursue. APS believes we are clearly beyond the tipping point (and would be even at levels much lower than that set by the standard) where there is an expectation the Commission should address this issue. The Policy Statement correctly acknowledged that now is the right time to modernize the rate structure, and APS is requesting to do so in this proceeding.

C. Customer Benefits Associated with the New Business Model

Q. HOW WILL THE EIA AFFECT PRICE SIGNALS TO CUSTOMERS?

A. Price signals to customers will be improved with the implementation of the EIA, which will actually better align APS's costs with the price customers pay, sending them a more meaningful price signal. The goal of the new business model and modern rate structure is to align the Company's and customers' interests by allowing customers to benefit from lower cost EE resources while allowing APS a reasonable opportunity to collect the established fixed-cost portion of its revenue requirement as determined in the rate case. Comparatively, without such a mechanism, any decrease in per customer sales due to EE and DG, will inherently cause an under-collection of fixed costs, resulting in earnings erosion. Therefore, a modern rate structure will make certain that customers as a whole pay the categories of fixed costs determined to be appropriate in a rate case. This sends a more appropriate price signal to customers, while increasing a utility's probability of recovery of previously approved fixed costs.

Q. HOW WILL THE IMPLEMENTATION OF A NEW BUSINESS MODEL AFFECT CUSTOMERS' BILLS?

A. The new business model will affect customers' bills in a positive way. If customers participate in EE, their overall bill will be reduced. If the EIA mechanism is implemented, all other things being equal, only a minimal charge will be passed onto customers. In APS's proposed approach, even non-participants will see lower overall bills in the long run as compared to an alternative where less EE was implemented, because today, EE is the lowest cost resource available.

Q. THE COMMISSION HAS RECEIVED MANY COMMENTS FROM CONSUMERS CONTENDING THAT DECOUPLING SOMEHOW "PUNISHES" THEM FOR CONSERVING ENERGY OR NEGATES THE BENEFITS OF SUCH CONSERVATION. DO YOU AGREE?

A. Absolutely not. As I noted in my response to the prior question, those customers who can and do conserve energy will receive lower bills irrespective of decoupling. And those who do not or cannot conserve will also benefit in the long term from the reduced fuel costs and deferred capital costs attributable to EE – benefits that LBNL estimated to be billions of dollars in excess of any charges attributable to a decoupling mechanism. Finally, allowing APS to recover its prudently incurred fixed costs of service cannot be fairly characterized as "punishing" anyone. This is what is done in every rate proceeding before the Commission. As discussed earlier, using formula rates or future test years would have a similar effect to decoupling, which shows that it is the ratemaking process that drives this need, not the "value" of conservation or energy efficiency. Decoupling modernizes the rate structure because it does not alter the end result of ratemaking but rather affects only the timing of cost recovery. Decoupling smoothes out the inevitable adjustments to rates necessitated by declining sales per customer in the face of continued customer growth. APS's proposed EIA mechanism essentially updates the customer billing determinants annually in a simple and straightforward manner, without having to litigate rate cases every year.

Q. YOU REFERENCED LBNL IN YOUR PREVIOUS ANSWER. HAS APS QUANTIFIED THE BENEFIT CUSTOMERS WILL RECEIVE FROM THE IMPLEMENTATION OF ITS PROPOSED EIA?

A. Not directly. As mentioned previously, the Commission asked LBNL to conduct a study to determine the net benefits associated with the implementation of the EES and decoupling. The results demonstrated that collectively, with the implementation of the EES, APS's customers will receive a net benefit of $4.6

billion as compared to a business as usual EE case and $8.9 billion benefit as compared to a case with no EE.[3] Implementing a companion mechanism to address the financial disincentives would reduce the benefit by less than 4% - a small fraction of the savings.[4] This "cost" of the mechanism merely reflects a timing of fixed cost collection rather than the magnitude of fixed costs. If a general rate case were assumed more frequent than the LBNL study the "cost" to customers from this mechanism would be less. Of course, APS customers that participate in EE programs will benefit to a much larger degree than customers who do not participate.

Q. WOULD IT BE POSSIBLE TO SIMPLY ILLUSTRATE HOW LBNL'S ANALYSIS DEMONSTRATES SUCH AN OVERWHELMING BENEFIT TO CUSTOMERS?

A. Yes. There is a perceived mystery regarding how customers will actually save money from energy efficiency if a rate mechanism is allowed that addresses the financial disincentive. However, using the average cost of EE programs today and comparing them to the average cost of a combined-cycle ("CC") gas generating resource will increase the transparency. APS presently estimates the cost of EE programs to be approximately $0.035 per kWh, and the cost of a CC to be approximately $0.10 per kWh on a twenty year life-cycle basis. LBNL's analysis of decoupling determined a mechanism such as APS's EIA would increase average rates cumulatively by approximately $0.0015 cents per kWh (approximately 1%) by 2020. LBNL's analysis used resource planning model assumptions on what resources APS would need to add without EE, and then compared how that would change if APS achieved the EES. The $8.9 billion in

[3] The $8.9 billion in net benefits is based on APS discussions with LBNL and is similar to the verbal testimony presented during the Commission's Decoupling Workshop.

[4] Please see the LBNL Study at page 27 where it references the net cost impact of decoupling for APS of $320 million. The calculated percentage is derived by dividing the decoupling impact by the $8.9 billion net benefit of EE.

customer savings is the difference, on a net present value basis, between these two scenarios. The modern rate mechanism allows APS to pursue the lower cost alternative[5] without a financial penalty.

Q. ARE THERE OTHER BENEFITS TO CUSTOMERS FROM THE PROPOSED EIA, SEPARATE FROM THE BENEFITS RELATED TO EE AND DG?

A. Yes, there are other benefits to customers. The EIA will also encourage rate stability by mitigating the impact of weather for customers. During the Decoupling Workshops, APS performed a historical analysis of the previous ten years to understand the hypothetical impact of a mechanism like APS's proposed EIA. This analysis showed that customers would have seen modest increases or decreases of 1.5%, primarily from weather driven variations. When annual use per customer increased, APS would have refunded money to customers through the mechanism. Conversely, when use per customer declined, a small surcharge would have been passed on to customers. Importantly, the mechanism in and of itself, separate and apart from EE and DG, removes the incentive to sell more energy. And the fact that the EIA mechanism would reset customer billing determinants annually should also help reduce the number of base rate cases that are filed, because such cases are often partly driven by the need to reset billing determinants to address a revenue deficiency.

D. APS's Proposed Efficiency and Infrastructure Account Mechanism

Q. IS APS PROPOSING A MECHANISM IN THIS PROCEEDING THAT IS CONSISTENT WITH THE COMMISSION'S POLICY STATEMENT ON DECOUPLING?

[5] After addressing the financial disincentive, EE would only costs approximately 37% of what a CC resource would cost over its lifetime; $0.035/kWh (EE) + $0.0015/kWh (EIA) = $0.0365/kWh versus $0.10/kWh(CC).

A. Yes. Consistent with the ACC Policy Statement, specifically Policy Statements 3 and 4, APS is recommending a non-fuel revenue per customer decoupling mechanism be implemented to help address the financial disincentives that occur due to reduced sales resulting from EE and DG.

Q. WHY IS APS PROPOSING A REVENUE PER CUSTOMER DECOUPLING MECHANISM TO ADDRESS THE EFFECTS OF REDUCED SALES?

A. A revenue per customer decoupling mechanism is the most appropriate mechanism for the following reasons:

- It modernizes the rate structure and aligns the Company's and customers' interests by updating customer billing determinants annually in a simple and straightforward manner;
- It is the most commonly applied form of decoupling within the electric and gas utility industries;
- It properly removes the link between volumetric sales and revenue collection, thus eliminating the disincentive associated with implementing EE programs and instead allows a utility to willingly engage in and promote EE programs; and
- It allows a utility to collect a greater portion of its authorized fixed cost of service (as determined within a rate case) associated with both existing and future customers regardless of sales levels.

As mentioned previously, other mechanisms would also work, such as SFV pricing, annual rate cases or formula rates. However, other mechanisms discussed in the workshop would not work as well for APS. For example, lost margin calculations are not a holistic solution, and would need to be derived separately

for both EE and DG. A lost margins approach will also result in more disputes around program Measurement, Evaluation and Reporting ("MER"), where the approach APS has taken removes the polarization from the MER discussion.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW THE EIA WILL WORK?

A. For a detailed description of the mechanism, a step by step calculation of the annual adjustment and what will be included in the annual compliance reports; please see the Efficiency and Infrastructure Account Plan of Administration, Attachment LRS-1.

Q. PLEASE DESCRIBE HOW FIXED COSTS ARE CALCULATED AND WHAT IS EXCLUDED.

A. In general terms, fixed costs are those that do not fluctuate in the short term with the amount of energy produced and consumed, including the carrying costs of plant assets, taxes and operations and maintenance expenses associated with generation, transmission, distribution and general plant investments. For APS this includes virtually all base rate costs, except for fuel and transmission costs, which are determined to be fixed cost in the most recent rate case cost of service study.[6] The fuel and transmission costs are excluded for the following reasons: (a) APS collects fuel costs through its Power Supply Adjustor ("PSA") mechanism and fuel costs do vary as sales levels change and (b) APS has a formula transmission rate that is updated annually with the Federal Energy Regulatory Commission ("FERC"). Other costs that vary in the short-term with sales levels are also excluded from the mechanism, primarily generation maintenance costs.[7]

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[6] APS's cost of service study generally uses the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual as a guide in classifying its costs as fixed or variable. APS witness Zachary Fryer discusses the specific results of the Company's cost of service study in this case.

[7] Costs included in the following FERC Accounts are deemed variable, per the APS Cost of Service Study, and are excluded from the calculation of fixed costs: 510, 512, 513, 521, 522, 528, 530, and 531.

Q. YOU INDICATED THAT 73% AND 66% OF APS'S FIXED COSTS FOR RESIDENTIAL AND COMMERCIAL CUSTOMERS, RESPECTIVELY, ARE RECOVERED THROUGH VOLUMETRIC RATES. IS THAT HIGH FOR AN ELECTRIC UTILITY?

A. No, it is typical for a capital intensive industry, particularly one with an obligation to serve. An everyday example most people can relate to, such as owning a car, may help provide some perspective. If you looked at the costs that do not change from month to month with the number of miles driven, those costs would be equivalent to fixed costs. For example, your monthly car payment, registration cost and insurance are obvious fixed costs. The costs of gasoline and oil changes are obvious variable costs that would vary with the number of miles driven. If an important component system requires replacement from general wear and tear, such as the air conditioner, transmission, tires, engine or water pump, it is a fixed cost in the short term if you intend to still use the car. In comparing this analogy to the utility system, these maintenance items would be viewed as fixed expenses that are required to keep your car running safely and reliably. Similar to the electric utility, the most significant variable cost of owning a car is the fuel, while most other costs are fixed in the short term when they occur.

Q. WHAT CUSTOMER CLASSES ARE INCLUDED IN THE EIA MECHANISM?

A. Policy Statement 11 stated that broad customer class participation in decoupling is preferred and APS agrees. The Policy Statement goes on to recognize that within any given utility there are customer classes that are not homogenous and may require other rate design options to address the under-recovery of fixed costs. Consistent with this, APS has included all customer classes in the EIA

mechanism, except for the following rate schedules: E-30, E-36 XL, E-47, E-58, E-59 and Contract 12.

Q. FOR THE CLASSES EXCLUDED FROM THE EIA ADJUSTMENT, PLEASE EXPLAIN WHY THEY WERE EXCLUDED AND HOW AND IF THEIR FIXED COSTS WILL OTHERWISE BE RECOVERED.

A. APS excluded those customer classes that have non-metered accounts, for instance street lighting. These classes are not metered because they have very little variability in their usage. Also any energy efficiency that would occur would be through fixture replacement, which would result in a different non-metered rate, but one that would still recover fixed costs. These customers are not able to otherwise participate in the Company's broader EE programs, are not associated with DG and are responsible for only a minuscule amount of the total retail revenue requirement. We are also excluding customers served under rate schedule E-36 XL. This rate schedule is designed for service to large gas-fired generation plants during machine start-up and these customers are not part of EE programs. Therefore, APS believes it is reasonable to exclude them from the mechanism.

Q. DURING THE WORKSHOP PROCESS, AECC STATED THAT LARGE CUSTOMERS SHOULD BE EXCLUDED FROM DECOUPLING. PLEASE EXPLAIN WHY YOU DID NOT EXCLUDE THEM.

A. Consistent with the intent of the policy statement, APS believes that broad customer participation in the EIA mechanism is necessary. APS does agree that large customers, particularly those served under rate schedules E-34 and E-35, have more of their fixed costs recovered through demand-related charges that are assessed on the basis of a customer's kW capacity demand over a given period rather than kWh energy charges assessed on the basis of energy consumed. However, demand charges have a variable element that can be affected through

energy efficiency. Additional modifications to the current rate design for rate schedules E-34 and E-35 would be required to make the rate design more of a SFV approach as a means to resolve the unrecovered fixed costs associated with the large customer class. That said, modifying the E-34 and E-35 rate designs to be more SFV is a possible solution for this customer class that would not necessarily be appropriate for residential and small commercial customer classes where the majority of costs are presently recovered in energy related charges. For these reasons, the Company included the large customers in the decoupling mechanism.

If, however, it is the Commission's desire to remove E-34 and E-35 customers from the mechanism, APS believes modification to the current rate design is necessary. For example, requiring a minimum demand in the Service Agreement or modifying what is commonly referred to as a demand "ratchet" would help address the unrecovered fixed cost concern. APS's present demand ratchet is 80% of the highest kW measured in the previous summer billing months (May to October) of the twelve month period ending with the current billing month. The customer pays the higher of the actual demand measured in the highest single fifteen minute period in the billing month or the demand ratchet. The ratchet could be strengthened from 80% to as much as 100% or the period of time the ratchet applies could be increased, for example from twelve months to twenty-four months. These modifications would be necessary to create something closer to a SFV pricing design.

Q. AECC ALSO STATED IN THE WORKSHOP THAT CUSTOMERS IN THE E-32 L CLASS SHOULD BE EXCLUDED. DO YOU AGREE?

A. No. While APS understands the argument to exclude rate schedules E-34 and E-35, if their rate design is appropriately modified, APS is opposed to excluding E-

32 L. There is a wide range of customers included in this rate class and changing their rate design to a complete SFV would not be consistent with the merits of the decoupling mechanism. As well, a modified SFV rate design for E-32 L's diverse customer mix could impact a large number of customers, where there are a large number of winners and losers within the rate class with significant rate increases or decreases, merely based on load factors.

Q. HOW WILL THE ANNUAL ADJUSTMENT BE APPLIED TO CUSTOMERS?

A. APS proposes to aggregate all of the differences between authorized and actual fixed cost recovery for each customer class included in the adjustor on an annual basis. This total amount of over or under-recovery of fixed costs will then be allocated to each eligible customer class on an equal percentage basis. This method of aggregating customer classes is consistent with Policy Statement 12, which proposes to blend and apply any adjustments to all customer classes equally to provide customers with greater rate stability. Please see APS's Efficiency and Infrastructure Account Plan of Administration, attached as Attachment LRS-1, and also Attachment LRS-2 for the proposed rate schedule, EIA-1.

Q. POLICY STATEMENT 13 STATES THAT "DECOUPLING ADJUSTMENTS APPLIED IN A MANNER TO ENCOURAGE ENERGY EFFICIENCY ARE PREFERRED, SUCH AS APPLYING DECOUPLING SURCHARGES TO RATES AND HIGHER-USAGE BLOCKS TO ENCOURAGE ENERGY EFFICIENCY, AND APPLYING DECOUPLING SURCREDITS TO REWARD CUSTOMERS WHO USE LESS ENERGY." DID APS COMPLY WITH THIS STATEMENT?

A. APS is very supportive of promoting energy efficiency and conservation through cost-based rate design. The Company currently has robust residential time-of-use ("TOU") rates – which have the highest customer participation rate in the US, over 50%. APS's only non-TOU residential rate schedules have inclining block

rates, which strongly encourages energy conservation. APS's existing rate designs comply with Statement 7, which suggests tailoring rate design options to encourage participation in energy efficiency. However, the suggested rate design philosophy for asymmetrical application of surcharges and credits in Statement 13 raises issues of practicality and equity for APS. Specifically, all but one of APS's residential rate schedules have uniform (flat) per kWh charges, thus there are no "initial" or "tail" blocks of usage that could be separately assessed a credit or surcharge. The single remaining residential schedule, E-12 (and its companion low-income rate schedule), already has a severely inclining tail block charge that APS would not recommend exacerbating by bearing the full brunt of any decoupling surcharge. Since APS has such a high adoption rate of TOU, it is also not necessary. TOU rates do not lend themselves to an inclining block design. Prices are based on costs incurred by APS that change both seasonally and over the course of a day. Inherently, TOU rates are sending customers the appropriate price signal. Adding inclining blocks to TOU rate schedules would make them overly complex and very confusing to customers.

What the EIA mechanism is attempting to accomplish is better recovery of fixed costs. It was the inclusion of such costs in the energy component of rates that caused the problem of unrecovered fixed costs in the first instance. APS believes using an equal percentage adjustment (based on Total Company revenues) to be fairer and more consistent with cost causation.

Q. THE POLICY STATEMENT RECOMMENDED CAPPING ANNUAL ADJUSTMENTS FOR INCREASES IN THE DECOUPLING ADJUSTMENT IN POLICY STATEMENT 14. PLEASE DESCRIBE THE MECHANICS OF THE CAP FOR APS'S PROPOSED DECOUPLING MECHANISM.

A. The Commission recommended the adoption of a cap to the annual surcharge to help moderate the adjustments. However, in the event of an over-collection, the

full amount should be credited to customers. APS's agrees it is reasonable to implement an annual cap on the adjustment if, and only if, any amount in excess of the cap can be deferred to a later period for collection. APS believes this concept is the intent of the Stakeholders who participated in the workshops (*see* Decoupling Workshop transcripts on 11/4/2010 at 136-137). If in any given year, the cap is exceeded APS proposes to defer that amount with interest until such time that it can be included in the annual adjustment without reaching the cap. Any deferred amount will be tracked as a separate line item in the annual EIA compliance report.

APS proposes a 3% annual cap on any surcharges. This cap will be calculated on total revenues. Although there is an argument for reciprocal limits on EIA credits (essentially banking some of the potential refund for a "rainy day"), APS's proposal, consistent with the Policy Statement, contains no such limit. For more information on the mechanics of the cap, please see the Efficiency and Infrastructure Account Plan of Administration in Attachment LRS-1.

Q. WHEN WOULD APS'S FIRST EIA ADJUSTMENT OCCUR?

A. The Settlement set forth a good faith effort for parties to complete this rate case within 12-months of a sufficiency finding, where rates would go into effect July 1, 2012. Consistent with this timing, APS proposes the first EIA adjustment be made the following year, coincident with the DSM Adjustor Clause in the first billing cycle in March of 2013, unless suspended by the Commission. The adjustment will be calculated using the fixed cost level established in the rate case applied against customer usage in 2012. The adjustment in the first year would normalize the actual recovery to reflect the new rates across the full year to compare to the full year's authorized fixed cost. Please see Attachment LRS-2 for a proposed rate schedule for the EIA-1.

E. Additional Considerations for Implementation

Q. IN THE WORKSHOPS, A REDUCTION TO A UTILITY'S RETURN ON EQUITY ("ROE") RELATED TO DECOUPLING WAS DISCUSSED. PLEASE DESCRIBE APS'S POSITION ON THIS.

A. Whether a utility has a decoupling mechanism or other tools in place that allows it to recover what would otherwise be unrecovered fixed cost is one of several factors that should be considered in the risk analysis undertaken when determining a Company's authorized return on equity. While implementing a decoupling mechanism will help a utility reduce the erosion in earnings between rate cases (by allowing a greater portion of its fixed cost to be recovered each year), it does not remove all or even most risk and therefore should not in itself require that the authorized ROE be lowered by any predetermined amount. To the contrary, perfunctorily lowering the authorized ROE simply because a decoupling mechanism is adopted to compensate the utility for what would otherwise be unrecovered cost merely exchanges one financial disincentive for another. The Policy Statement acknowledged this in Statement 6, which stated that "commitment to and early implementation of decoupling should precede significant decoupling-specific adjustments to cost of capital."

Ralph Cavanagh on behalf of NRDC opined in the workshops that adopting decoupling should not automatically result in a reduction to a utility's ROE:

> "If I were a commissioner, I wouldn't adjust the rate of return going in. Recognize the implicit notion there is that this is somehow a really sweet deal for the utilities and they should give something up in order to get it... [Utilities] are taking on all the risks of meeting the most aggressive energy efficiency standard in the country. And as you look ahead at what that is going to take, the management demands, effort that the company is going to have to make, it is hard for me to see an argument that the company ought to have to take a rate of return reduction as part of that package." (*See* Decoupling Workshop transcripts from 4/16/2010 at 182-184.)

APS Witness Dr. William Avera provides comprehensive testimony on APS's proposed ROE. In his analysis, Dr. Avera compares APS to a peer group of utilities to determine the appropriate ROE for APS. In the peer group, Dr. Avera found that there were multiple utilities that have both decoupling and an ROE that is at or in excess of APS's proposed ROE. Many utilities also have other mechanisms that achieve the same objective as a decoupling mechanism, such as an earnings adjustor or full future test years, but also have an authorized ROE that is at or in excess of APS's proposed ROE.

For these reasons, APS believes that the ROE set forth in Dr. Avera's testimony is appropriate to adopt and should not be lowered by a predetermined amount simply due to the adoption of APS's proposed EIA mechanism.

IV. ENVIRONMENTAL AND RELIABILITY ACCOUNT

A. Purpose of the Environmental and Reliability Account

Q. PLEASE DESCRIBE THE ENVIRONMENTAL AND RELIABILITY ACCOUNT MECHANISM AND WHY APS IS PROPOSING ITS IMPLEMENTATION IN THIS CASE?

A. APS is proposing the implementation of the ERA in this proceeding because increasingly stringent environmental rules will require the Company to invest a significant amount of capital to remain in compliance with environmental regulations. APS must receive timely recovery of these large capital investments to ensure safe, reliable, environmentally-compliant and cost effective baseload generation. The investments that APS proposes to include in the ERA are projects that are placed in service after new rates go into effect. Under traditional Arizona regulation, the cost of the projects would not be recovered by APS until the next general rate case. The time lag between when a project is placed into service and when the Company begins to recover the cost can be significant and would be detrimental to the Company's financial position by reducing cash flow and

increasing external capital requirements without a corresponding increase in revenues. The ERA would align the Company's and customers' economic interests. For example, absent the ERA, if APS purchased power in lieu of an investment, the recovery of purchased power cost is recovered on a more timely basis through the PSA mechanism, with no capital requirements on the Company, but perhaps at a higher cost to customers.

Additionally, as APS Witness Jeff Guldner describes in his testimony, having smaller periodic rate adjustments, allows for greater rate gradualism, which is more palatable to customers. In fact, the ERA has the potential to reduce the size and frequency of future general rate increase requests, since the ERA will annually include some of the capital expenditure costs that are recovered in base rate proceedings.

B. Mechanics of the Environmental and Reliability Account

Q. PLEASE DESCRIBE THE ERA IN MORE DETAIL.

A. The ERA is a mechanism that will allow APS to recover the carrying costs of environmental improvement projects necessary for compliance with current or prospective environmental standards required by federal, state, tribal or local laws or regulations, as well as generation plant capacity acquisitions or additions. The Environmental and Reliability Account Plan of Administration, Attachment LRS-3, further describes the "Qualified Investments" allowed under the mechanism. The ERA mechanism will address cost recovery for Qualified Investments which occur outside of a rate case and are therefore, not reflected in base rates. Annually, APS will calculate the ERA adjustment based on the investments that were actually placed in-service during the preceding calendar year, rather than forecasting plant. The Company believes this feature of the ERA complements its proposed post-Test Year plant adjustment proposed by APS witness Mark

Schiavoni in the case. The calculated adjustment will be applied on an equal percentage basis to all retail Standard Offer customers, except for customers served under rate schedule E-36 XL. These customers are served at market based rates, not from APS's generation fleet.

Q. WHAT ARE SOME BENEFITS OF IMPLEMENTING THE ERA?

A. The ERA will provide a number of service and rate benefits to customers. APS has the obligation to serve its customers with electric power that is safe, reliable, and environmentally responsible. To fulfill this obligation, APS must be able to raise enough capital for the necessary investments in generating facilities. By providing timely recovery of required environmental improvement projects and generation capacity acquisitions or additions between rate proceedings, the ERA will better enable APS to secure capital at a reasonable cost and make these capital investments. Thus, passing these savings onto customers.

Q. PLEASE DESCRIBE THE TYPES OF INVESTMENTS APS PROPOSES TO INCLUDE IN THE ERA.

A. As I indicated previously, APS's Environmental and Reliability Account Plan of Administration describes the Qualified Investments which APS proposes to recover of through the ERA. APS proposes to include:

- Environmental improvement projects which are designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for carbon dioxide (CO_2), sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC) and toxics

such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts; and

- Generation plant capacity acquisitions, efficiency projects or the construction of new generating plant. For example, APS's pending acquisition of Southern California Edison's share of Four Corners Units 4 and 5 would be Qualified Investments for inclusion in the ERA in the year following the close of the transaction.

Q. WHAT SPECIFIC TYPES OF COSTS WILL APS INCLUDE FOR RECOVERY THROUGH THE ERA?

A. The ERA will recover the revenue requirement or carrying costs of Qualified Investments, similar to the types of costs APS recovers for the AZ Sun projects that are currently collected in APS's Renewable Energy Surcharge. Items APS proposes to include in the ERA are:

- A return on ERA Qualified Investments based on the Company's Weighted Average Cost of Capital ("WACC") approved by the Commission in the Company's preceding general rate case;
- Depreciation expense;
- Income taxes;
- Property taxes;
- Deferred taxes and tax credits where appropriate; and
- Operations and maintenance ("O&M") expenses.

For more information regarding each of these components, please see the Environmental and Reliability Account Plan of Administration found at Attachment LRS-3.

Q. WILL THE COMMISSION'S ADOPTION OF THE ERA MECHANISM HAVE IMPACT ON THE SELF-BUILD MORATORIUM AGREED TO BY APS IN DECISION NO. 67744?

A. No, it will not.

C. Annual Implementation of the ERA Adjustment

Q. HOW WILL THE COMPANY'S PROPOSED ANNUAL ERA ADJUSTMENT PROCESS WORK?

A. Annually, on March 1, APS will submit its ERA Rate Filing. The filing will include the ERA percentage to be recovered from customers in that year, with supporting detail. The Environment and Reliability Account Plan of Administration, Attachment LRS-3, includes supporting compliance schedules that APS would include in the annual filing with the Commission. APS proposes the ERA rate become effective with the first billing cycle in April, unless suspended by the Commission.

Q. HOW WILL THE COMPANY SEPARATELY TRACK AND DOCUMENT ERA QUALIFIED INVESTMENTS?

A. In two ways. First, each ERA Qualified Investment will be classified in one or more of the FERC plant accounts listed in the Environmental and Reliability Account Plan of Administration upon going into service. Second, each ERA Qualified Investment will be tracked by a specific project number. Collectively, this will ensure that ERA costs are appropriately identified, tracked and documented.

Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE THE ERA RATE?

A. The ERA rate will be applied to customers' bills on an equal percentage. This will be calculated by dividing the total ERA revenue requirement by the annual Total Company Revenues, similar to the EIA adjustment calculation. For a proposed rate schedule, ERA-1, please see Attachment LRS-4.

Q. HOW WILL QUALIFIED INVESTMENTS RECOVERED THROUGH THE ERA BE ADDRESSED IN SUBSEQUENT RATE CASES?

A. ERA Qualified Investments that are recovered through ERA rates will be transferred to base rates and removed from the ERA when base rates are re-set within the context of a rate case.

Q. WILL THE ERA REPLACE THE ENVIRONMENTAL IMPROVEMENT SURCHARGE PREVIOUSLY APPROVED BY THE COMMISSION?

A. Yes. APS will collect costs through the ERA investments that would have otherwise been collected through the Environmental Improvement Surcharge ("EIS"). The current EIS is set at a nominal fixed amount and additionally is accounted for as a Contribution in Aid of Construction ("CIAC"). The ERA, in addition to functioning as a cost recovery mechanism for all environmental improvement projects, expands upon the EIS by including investments in generation capacity and generation acquisitions. This is an important enhancement that will allow APS more flexibility to meet its resource needs going forward.

Q. WILL THE COMMISSION HAVE OTHER OPPORTUNITIES TO REVIEW PROJECTS INCLUDED IN THE ERA?

A. Yes. The Commission will have multiple opportunities to review the projects included in the ERA. They can be reviewed annually in the ERA filing, as

discussed above. In addition, the Commission always has the opportunity to review all capital expenditures and costs within the context of a rate case to determine prudency. Further, with the adoption of the IRP Rules, the Commission has to acknowledge the Company's resource plan every two years. This filing allows the Commission review of APS's current and proposed resource mix and any external items, such as new environmental rules, that would affect generating resources.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The ACC has implemented an ambitious EES which essentially requires a new business model for APS that is not premised on increasing the volume of sales, and a corresponding mechanism that modernizes the rate structure to address the financial disincentives to APS and fully align the interests of APS and its customers. APS believes its proposed EIA mechanism is the appropriate complementary rate making tool to remove the financial disincentive. APS is fully supportive of EE for the long-term benefits that it provides to customers, but to achieve the results required, APS needs approval of the EIA mechanism to help maintain its financial condition without requiring fundamental changes to how or how often base rate cases are filed. This model provides an appropriate structure for updating rates between general rate cases. The EIA mechanism proposed by APS is the most commonly used form of decoupling throughout the nation, it removes the link between volumetric sales and revenue collection, eliminating the utility disincentive associated with implementing EE programs and will allow APS to, in Mr. Schlegel's words, be an "enthusiastic partner" to promote EE. This mechanism will allow APS to collect a greater portion of its fixed costs of service associated with both existing and future customers,

regardless of sales levels. Often, providing benefits to customers while also addressing the financial viability of a utility is a win-lose proposition – this is not the case with the EIA. Approval of this mechanism is clearly a win-win proposition for the Company and its customers.

The Policy Statement set forth guidelines for utilities to implement decoupling and APS has largely followed those guidelines in its proposed EIA model. To be able to meet aggressive EE and DG standards, APS needs this mechanism to be approved in this proceeding. ACC Staff said it best in the workshop that absent a mechanism to address the financial disincentive, a utility will likely be unable to achieve a 22% reduction in sales. *See* Decoupling Workshop transcripts on 4/16/2010 at 265. APS agrees.

Further, with increasingly stringent environmental rules, the implementation of the ERA will allow APS to invest the necessary capital in technologies to comply with these requirements. The ERA will provide for timely recovery of these necessary investments, thus reducing the lag between when a project is placed into service and when the Company begins to recover the cost. Importantly, the ERA will also promote greater rate gradualism for customers by providing for modest annual increases to customers' bills, as opposed to less frequent, larger increases that typically occurs when a company files for a rate case – rate gradualism is something that provides a benefit to both customers and the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Statement of Qualifications

Leland R. Snook

Leland R. Snook is Arizona Public Service Company's Director, Rates and Pricing. He has over 25 years experience in the electric utility business as a utility professional. Mr. Snook holds a Bachelor of Science Degree in Electrical Engineering from Texas Tech University and is a registered professional electrical engineer in the state of Arizona.

Mr. Snook's areas of expertise include development and analysis of electric utility revenue requirements, modeling of cost of service, rate schedule design, embedded and marginal cost analysis and formulation of utility service policies. Mr. Snook has previously testified before the Arizona Corporation Commission on customer service contract and rate schedule matters.

Mr. Snook has held his current position at Arizona Public Service Company for approximately three years. Prior to assuming that position, he served as the Director of Federal Regulation for APS. Before joining APS, Mr. Snook had a twenty-two year career with Tucson Electric Power Company, where he served in various professional and leadership roles.

Efficiency and Infrastructure Account ("EIA")
Plan of Administration

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1. General Description

This document describes the plan of administration for the EIA mechanism approved for Arizona Public Service Company ("APS" or "the Company") by the Arizona Corporation Commission ("ACC") on [insert date] in Decision No. XXXXX. The EIA mechanism provides for the recovery of all base rate costs except for fuel and transmission costs associated with residential and commercial and industrial customers to the extent that the actual costs recovered are greater or less than the amount initially authorized through base rates in Decision No. XXXXX.

2. Definitions

Customers – The number of annual customers will be equivalent to the average number of active meters for the calendar year.

Sales – Annual sales used for the EIA mechanism will be the calendar year billed kWh per FERC Form 1 (*i.e.* not weather normalized).

Fixed Costs – Base rate costs, except for fuel and transmission costs and costs recorded to FERC accounts 510, 512, 513, 521, 522, 528, 530, and 531, as established in the most recent rate case cost of service.

Actual Fixed Cost Recovery – The amount of fixed costs actually collected by the utility during the year. This amount is calculated by multiplying the Allowed Fixed Cost Revenue per Customer Rate (per kWh) established in the most recent rate case by the given year's sales.

Allowed Fixed Cost Recovery – The amount of fixed costs that the utility should have received during the year. This amount is determined by multiplying the average number of customers served during the calendar year by the Allowed Fixed Cost Revenue per Customer established in the most recent rate case.

Allowed Fixed Cost Revenue Requirement – This amount is determined within a rate case by subtracting fuel, transmission and other excluded costs from the overall total revenue requirement on a customer class basis.

Allowed Fixed Cost Revenue per Customer – The Allowed Fixed Cost Revenue Requirement is divided by the average number of customers within each class in the Test Year to determine the appropriate annual Allowed Fixed Cost Revenue per Customer amount, by class.

Allowed Fixed Cost Revenue per Customer Rate – The Allowed Fixed Cost Revenue per Customer is stated on a dollar basis (*see* above) and is also stated in terms of a class average Allowed Fixed Cost per Customer Rate on a per kWh basis. This is derived by dividing the total Allowed Fixed Cost Revenue Requirement by the adjusted Test Year sales on a class basis.

Annual EIA Adjustment – The difference between the Allowed Fixed Cost Recovery and the Actual Fixed Cost Recovery represents the adjustment to be either recovered or refunded in the mechanism in the subsequent twelve month period.

Total Company Revenues – The net amount annually recorded in FERC Form 1, in accounts titled "Sales to Ultimate Customers" and "Provision for Rate Refunds."

3. Calculation of the EIA Adjustment

The EIA Adjustment Percentage will be calculated annually as follows:

To determine Allowed Fixed Cost Revenue per Customer Rate per Class:

Allowed Fixed Cost Revenue Requirement ($000) ÷ Adjusted Test Years Sales (MWh) = Allowed Fixed Cost Revenue per Customer Rate ($/kWh)

To determine Allowed Fixed Cost Recovery per Class:

# of Customers * Allowed Fixed Cost Revenue per Customer ($) / 1000 = Allowed Fixed Cost Recovery ($000)

To determine Actual Recovery of Fixed Costs per Class:

Actual Annual Sales (MWh) * Allowed Fixed Cost Revenue per Customer Rate ($/kWh) = Actual Fixed Cost Recovery ($000)

To determine Annual EIA Adjustment, Sum All Classes:

$$\sum(\text{Allowed Fixed Cost Recovery (\$000)} - \text{Actual Fixed Cost Recovery (\$000)}) = \text{Annual EIA Adjustment (\$000)}$$

To determine the EIA Annual Adjustment Percentage:

$$\text{Annual EIA Adjustment (\$000)} / \text{Total Company Revenues (\$000)} = \text{EIA Adjustment Percentage (\%)}$$

The EIA Adjustment Percentage (%) is the factor applied to applicable customers' total bill excluding sales tax, transaction privilege tax, regulatory assessments, and franchise fees.

4. EIA Adjustment Annual Cap

APS will compare the Annual EIA Adjustment to the amount of Total Company Revenues collected. If the Annual EIA Adjustment results in a surcharge and the annual increase exceeds 3% of Total Company Revenues, any amount above the cap will be deferred for collection until the next adjustment period (but not to exceed the cap in the future). If, however, an over-collection occurs, the full amount shall be credited to customers and shall not be subject to the cap. If a balance occurs, it will be tracked and included in the annual compliance report. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 will be applied annually to any deferred balance.

5. Filing and Procedural Deadlines

APS will file the calculated Annual EIA Adjustment, including all supporting data, with the Commission for the previous year on February 1st (please see "Compliance Report" section for a description of the filed reports).

The Commission Staff and any interested parties shall have an opportunity to review the February 1st filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted by March 1st, the new EIA Adjustment Percentage proposed by APS will go into effect with the first billing cycle in March and will remain in effect for the following 12-month period.

6. Compliance Reports

APS will provide an annual report to Staff's Compliance Section and the Residential Utility Consumer Office detailing all calculations related to the EIA Adjustment Percentage. The reports will include at minimum the following:

1. The average number of APS customers;
2. The actual MWh sales by applicable customer classes;
3. The Allowed Fixed Cost Revenue per Customer ($) and the Allowed Fixed Cost Revenue per Customer kWh rate (¢/kWh);
4. The Test Year Fixed Costs ($000);
5. The Actual Fixed Cost Recovery in the previous year ($000);
6. The Allowed Fixed Cost Recovery in the previous year ($000);
7. The Annual EIA Adjustment ($000); and
8. The EIA Adjustment Percentage (%) to be in effect for the following 12-month period.

Attached is the compliance report that will be submitted annually.

Schedule 1: Efficiency and Infrastructure Account Adjustment
Effective XX/XX/20XX

Line No.	EIA Rate Calculation		$
1.	Total EIA Adjustment for Current Period (Schedule 4, line 6)	$	-
2.	Total Company Revenues (Schedule 4, line 1)		-
3.	% Increase Applied to Customer's Bills (line 1 / line 2)		0.0%

Note: This information is confidential until APS's FERC Form 1 has been filed.

Schedule 2: Test Year Data to Derive Fixed Costs

$ in Thousands

Line No.			$
	Residential		
1.	# of Residential Customers		-
2.	Residential Allowed Fixed Cost Revenue Requirement	$	-
3.	Residential Allowed Fixed Cost Revenue per Customer [1] (line 2 / line 1 * 1000)	$	-
4.	Residential Sales (MWh)		-
5.	Residential Allowed Fixed Cost Revenue per Customer Rate ($/kWh) (line 2 / line 4)	$	-
6.	Average Usage per Customer (kWh) (line 4 * 1000 / line 1)		-
	Commercial and Industrial [2]		
8.	# of C&I Customers		-
9.	C&I Allowed Fixed Cost Revenue Requirement	$	-
10.	C&I Allowed Fixed Cost Revenue per Customer [1] (line 9 / line 8 * 1000)	$	-
11.	C&I Sales (MWh)		-
12.	C&I Allowed Fixed Cost Revenue per Customer Rate ($/kWh) (line 9 / line 11)	$	-
13.	Average Usage per Customer (kWh) (line 11 * 1000 / line 8)		-

[1] The revenue per customer value is shown in actual dollars, not thousands.

[2] Excluding rate schedules E-30, E-36 XL and lighting schedules.

Schedule 3: Calculation of Current Period EIA Adjustment

$ in Thousands

Line No.	Residential		$
1.	# of Residential Customers		-
2.	Residential Allowed Fixed Cost Revenue per Customer (Schedule 2, line 3) [1]	$	-
3.	Total Allowed Fixed Cost Recovery (line 1 * line 2 / 1000)	$	-
4.	Residential Sales (MWh)		-
5.	Residential Allowed Fixed Cost Revenue per Customer Rate ($/kWh) (Schedule 2, line 5)	$	-
6.	Total Residential Actual Fixed Cost Recovery (line 4 * line 5)	$	-
7.	**Residential EIA Adjustment (line 3 - line 6)**	**$**	**-**
8.	Average Usage per Customer (kWh) (line 4 * 1000 / line 1)		-
	Commercial and Industrial		
9.	# of C&I Customers		-
10.	C&I Allowed Fixed Cost Revenue per Customer (Schedule 2, line 10) [1]	$	-
11.	Total Allowed Fixed Cost Recovery (line 9 * line 10 / 1000)	$	-
12.	C&I Sales (MWh)		-
13.	C&I Allowed Fixed Cost Revenue per Customer Rate ($/kWh) (Schedule 2, line 12)	$	-
14.	Total C&I Actual Fixed Cost Recovery (line 12 * line 13)	$	-
15.	**C&I EIA Adjustment (line 11 - line 14)**	**$**	**-**
16.	Average Usage per Customer (kWh) (line 12 * 1000 / line 9)		-
	Total		
17.	Total Sales (MWh) (line 4 + line 12)		-
18.	Total Actual Fixed Cost Recovery (line 6 + line 14)	$	-
19.	**Total Annual EIA Adjustment (line 7 + line 15)**	**$**	**-**
20.	**Total Allowed Fixed Cost Recovery (line 18 + line 19)**	$	-

[1]The revenue per customer value is shown in actual dollars, not thousands.

Schedule 4: Calculation of Annual Cap

$ In Thousands

Line No.	Annual Cap Calculation		$
1.	Total Company Revenues	$	-
2.	Allowed Cap %		3.0%
3.	Maximum Allowed Recovery (line 1 * line 2)	$	-
4.	Total Annual EIA Adjustment (Schedule 3, line 19)	$	-
5.	Total Deferred Balance from Previous Period (Schedule 5, line 4)		-
6.	Total EIA Adjustment for Current Period (line 4 + line 5)	$	-
7.	EIA Adjustment from Prior Period	$	-
8.	Total Incremental EIA Adjustment for Current Year (line 6 - line 7)	$	-
9.	Current Period Adjustment as % (line 8 / line 1)		0.0%
10.	Amount in Excess of Cap to Defer (line 6 - line 3)	$	-
11.	Total EIA Adjustment for Current Period (line 6 - line 10)	$	-

Note: This information is confidential until APS's FERC Form 1 has been filed.

Schedule 5: Annual Deferral Calculation

$ In Thousands

Line No.	Deferral Calculation		$
1.	Deferred Balance from Prior Period	$	-
2.	Annual Interest Rate[1]		0.0%
3.	Interest Accrued on Deferred Balance (line 1 * line 2)		-
4.	Total Deferred Balance (line 1 + line 3)	$	-

[1]The interest rate is the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15.

ADJUSTMENT SCHEDULE EIA-1
EFFICIENCY AND INFRASTRUCTURE ACCOUNT

APPLICATION

The Efficiency and Infrastructure Account ("EIA") shall be applied monthly to all retail Standard Offer or Direct Access service, except for E-30, E-36XL, E-47, E-58, E-59 and Contract 12. All provisions of the customer's currently applicable rate schedule will apply in addition to this adjustment charge. The EIA adjustment will be updated in billing cycle 1 of the March revenue month and will not be prorated. Details of how the adjustment is derived and administered can be found in the Efficiency and Infrastructure Account Plan of Administration approved by the ACC in Decision No. XXXXX.

RATE

The EIA charge will be applicable to the customer's total billed amount (which amount shall not be less than zero) including all other adjustors, except for the Environmental and Reliability Account, excluding sales tax, transaction privilege tax, regulatory assessments, and franchise fees.

EIA Charge: X.X%

Environmental and Reliability Account ("ERA")
Plan of Administration

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1. General Description

This document describes the plan for administering the Environmental and Reliability Account ("ERA") approved for the Arizona Public Service Company ("APS") by the Arizona Corporation Commission ("ACC" or "Commission") on [insert date] in Decision No. XXXXX. The ERA provides for the recovery of the revenue requirement effect of actual environmental or generation plant additions or efficiency projects made by APS and not already recovered in base rates approved in Decision No. XXXXX or recovered through another Commission approved adjustment. The ERA will be calculated annually based on the ERA Qualified Investments closed to plant-in-service during the preceding calendar year.

2. Definitions

ERA Qualified Investments – Investments in Qualified Environmental Improvement Projects and Qualified Generation Plant. Each ERA Qualified Investments must: (1) be classified in one or more of the FERC plant accounts as listed in section 3 of this document, or any other successor FERC account, upon going into service, (2) be tracked by a specific project number, and (3) exceed $500,000 in capital investment.

Qualified Environmental Improvement Projects - Projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for carbon dioxide (CO_2), sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC), and toxics such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts.

Qualified Generation Plant - Generation plant capacity acquisitions, existing generating plant efficiency projects or the construction of new generating plant.

Total Company Revenues – The net amount annually recorded in FERC Form 1, in accounts titled "Sales to Ultimate Customers" and "Provision for Rate Refunds."

3. Qualified FERC Accounts

1. Steam Production
   - FERC Account 310 – Land and Land Rights
   - FERC Account 311 – Structures and Improvements
   - FERC Account 312 – Boiler Plant Equipment
   - FERC Account 313 – Engines and Engine-Driven Generators
   - FERC Account 314 – Turbogenerator Units
   - FERC Account 315 – Accessory Electric Equipment
   - FERC Account 316 – Miscellaneous Power Plant Equipment

2. Nuclear Production
   - FERC Account 320 – Land and Land Rights
   - FERC Account 321 – Structures and Improvements
   - FERC Account 322 – Reactor Plant Equipment
   - FERC Account 323 – Turbogenerator Units
   - FERC Account 324 – Accessory Electric Equipment
   - FERC Account 325 – Miscellaneous Power Plant Equipment

3. Other Production
   - FERC Account 340 – Land and Land Rights
   - FERC Account 341 – Structures and Improvements
   - FERC Account 342 – Fuel Holders, Products, and Accessories
   - FERC Account 343 – Prime Movers
   - FERC Account 344 – Generators
   - FERC Account 345 – Accessory Electric Equipment
   - FERC Account 346 – Miscellaneous Power Plant Equipment

Please note this list may expand to include other accounts approved by the ACC in the future.

4. Calculation of ERA Revenue Requirement

The ERA Adjustment Percentage will recover capital expenditures and operations and maintenance ("O&M") costs for ERA Qualified Investments.

ERA Revenue Requirement used in calculating the ERA Adjustment Percentage will include: (1) Return on ERA Qualified Investments based on the Company's Weighted Average Cost of Capital ("WACC") approved by the Commission in the Company's

preceding general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits where appropriate and (6) associated O&M. ERA Qualified Projects and the ERA Revenue Requirement calculation will be submitted by the Company to the ACC in the form of Schedule 1 and Schedule 2 as attached to this document.

5. Calculation of ERA Adjustment Percentage

The ERA Adjustment Percentage to be applied to customers' bill (excluding Adjustment Schedule EIA, sales tax, transaction privilege tax, regulatory assessments and franchise fees) will equal a percentage calculated by dividing the total ERA Revenue Requirement by Total Company Revenues.

6. Filing and Procedural Deadlines

APS will file the calculated ERA Adjustment Percentage including all supporting data, with the Commission for the previous year on or before March 1st (please see "Compliance Report" section for a description of the filed reports).

The Commission Staff and interested parties shall have the opportunity to review the ERA filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted by April 1st, the new ERA Rate proposed by APS will go into effect with the first billing cycle in April (and will not be prorated) and will remain in effect for the following 12-month period.

7. Compliance Reports

APS will provide an annual report to Staff's Compliance Section and the Residential Utility Consumer Office detailing all calculations related to the ERA Adjustment Percentage. The reports will include at minimum the following:

1. List of Qualified Investments by;
    a. Project Tracking Number
    b. Project Name
    c. Project Purpose
    d. Plant In-service Date
    e. Project Cost
2. Adjustments to Plant including;
    a. Accumulated Depreciation
    b. Cumulative Deferred Tax/Tax Credits
3. Annual Depreciation of Plant in Service for Qualified Projects
4. Applicable Property Tax associated with Qualified Projects

5. Associated O&M Expense for Qualified Projects
6. Total Company Revenues
7. The Annual ERA Revenue Requirement ($000); and
8. The ERA Adjustment Percentage (%) to be in effect for the following 12-month period.

Attached is the compliance report that will be submitted annually.

Schedule 1: Qualified Investments for ERA Adjustment
Electric Plant in Service for Calendar Year 20XX

Line No.	Project Tracking Number	Project Name	Purpose	In-Service Date	Total Cost	ACC Jurisdictional
	A	B	C	D	E	F
	Environmental Improvement Projects					
1.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
3.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
4.		**Total**			**$ -**	**$ -**
	New Generation Capacity - Plant Construction					
5.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
6.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
7.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
8.		**Total**			**$ -**	**$ -**
	New Generation Capacity - Plant Acquisitions					
9.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
10.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
11.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
12.		**Total**			**$ -**	**$ -**
	Existing Generation Plant - Efficiency Projects					
13.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
14.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
15.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
16.		**Total**			**$ -**	**$ -**

Schedule 2: Revenue Requirement and Adjustor Calculation
Plant in Service for Calendar Year 20XX
Billing Period 4/1/20XX-3/30/XX

Line No.	ERA Calculation		
	Qualified Plant		
1.	Environmental Improvement Projects (Schedule 2, Line 4, Column F)	$	-
2.	New Generation Capacity - Plant Construction (Schedule 2, Line 8, Column F)	$	-
3.	New Generation Capacity - Plant Acquisition (Schedule 2, Line 12, Column F)	$	-
4.	Existing Generation Plant - New Efficiency Projects (Schedule 2, Line 16, Column F)	$	-
5.	Plant Balance - ERA Qualified Investments (Line 1 + Line 2 + Line 3 + Line 4)	$	-
	Adjustment to Plant		
6.	Accumulated Depreciation	$	-
7.	Cumulative Deferred Tax/Tax Credits	$	-
8.	ERA Net Plant (Line 5 - Line 6 - Line 7)	$	-
9.	Pre-tax Weighted Average Cost of Capital		0.00%
	Revenue Requirement		
10.	Composite Return on ERA Net Plant (Line 8 * Line 9)	$	-
11.	Annual Depreciation of Plant In Service	$	-
12.	Applicable Property Tax	$	-
13.	Associated O&M Expense	$	-
14.	Total ERA Revenue Requirement (Line 10 + Line 11 + Line 12 + Line 13)	$	-
15.	Total Company Revenues	$	-
16	ERA Adjustment Percentage (Line 14 / Line 15)		0.0%

Note: This information is confidential until APS's FERC Form 1 has been filed.

ADJUSTMENT SCHEDULE ERA-1
ENVIRONMENTAL AND RELIABILITY ACCOUNT

APPLICATION

The Envirnomental and Reliabity Account ("ERA") shall be applied monthly to all retail Standard Offer or Direct Access service, except for E-36XL. All provisions of the customer's currently applicable rate schedule will apply in addition to this adjustment charge. The ERA adjustment will be updated in billing cycle 1 of the April revenue month and will not be prorated. Details of how the adjustment is derived and administered can be found in the Envirnomental and Reliabity Account Plan of Administration approved by the ACC in Decision No. XXXXX.

RATE

The ERA charge will be applicable to the customer's total billed amount (which amount shall not be less than zero) including all other adjustors, except for the Efficiency and Infrastructure Account, excluding sales tax, transaction privilege tax, regulatory assessments, and franchise fees.

ERA Charge: X.X%

Zachary J. Fryer

TESTIMONY OF ZACHARY J. FRYER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

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TESTIMONY OF ZACHARY J. FRYER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-_____)

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Zachary J. Fryer. I am a Manager in the Regulation and Pricing Department for Arizona Public Service Company ("APS" or "Company"). I am primarily responsible for the development and coordination of the Company's regulatory filings that seek to recover an appropriate level of revenue. These filings are typically under the jurisdiction of the Arizona Corporation Commission ("ACC" or "Commission") or the Federal Energy Regulatory Commission ("FERC"). My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Business with a major in Accounting from the University of Arizona in 1993. From 1993 to 1998 I was employed primarily as a financial auditor. I joined the Company in November of 1998 as a staff accountant and have spent the past 13 years working for APS in the Accounting Operations Department as well as the Regulation and Pricing Department.

Prior to my promotion to Manager in the Regulation and Pricing Department in 2007, I was responsible for the generation accounting function at APS as a supervisor of that department. I am a Certified Public Accountant and maintain an expertise in financial analysis, embedded cost analysis and evaluation of utility revenue requirements.

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

A. My testimony addresses three general areas. The first area of my testimony discusses the Standard Filing Requirements ("SFR") schedules, including Schedule A-1. Schedule A-1 presents the overall increase in revenue requirements requested in this Application. Second, I discuss the Cost of Service Study prepared to functionalize, classify, and then allocate Test Year costs and revenues, first between wholesale and retail customers and then to the various classes of retail service. It is this cost allocation study that allows APS to determine the rate of return produced by each class and subclass of customer, as well as the unit costs APS incurs to provide different services to each customer group. Finally, I address the calculation of the fair value increment that helps to derive the appropriate rate of return to apply to the Company's Fair Value Rate Base ("FVRB"). This calculation is an integral component used in the derivation of the Company's proposed revenue requirement, and I refer to the dollar revenue requirement impact of this calculation as the "fair value increment." The approach and policy to determine the "fair value increment" is discussed in the testimonies of APS Witnesses William Avera and Jeff Guldner.

II. SUMMARY.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

My testimony addresses certain Standard Filing Requirements exhibits including Schedule A-1 that calculates the $95,493,000 increase in revenue requirements that is sought by the Company. This amount includes a $239,004,000 increase in non-fuel rates (which itself includes a transfer of revenue requirement from the Renewable Energy Surcharge ("RES") to base rates in the amount of $44,911,000) and a net decrease to the fuel-related component of rates in the

amount of $143,511,000. The components of the net base rate increase are as follows:

Non-fuel increase (excluding RES recovery transferred to base rates)	$194,093,000
RES recovery transferred to base rates	$ 44,911,000
LESS: decrease in base fuel rate	($143,511,000)
Net base rate increase proposed by APS	$ 95,493,000

If proposed rates are effective on July 1, 2012, customers will experience a $44,911,000 increase under the normal operation of the RES and $143,511,000 of savings under the normal operation of the Power Supply Adjustor ("PSA"). After, taking into consideration the transfer of recovery from the RES to base rates and the reclassification of PSA revenues to base fuel revenues as called for in the Commission-approved PSA Plan of Administration, the effective base rate revenue increase will be $95,493,000. This additional revenue will allow APS to earn a rate of return of 6.47% on a FVRB of $8,224,405,000. The additional revenue excluding "fair value increment" results in an 8.87% rate of return on an adjusted Original Cost Rate Base ("OCRB") of $5,720,277,000.

My testimony describes the Cost of Service Study that is used to support the Company's rate designs in the Company's application as well as the jurisdictional allocation of costs.

Finally, I will explain the calculation used to determine the fair value increment derived from the Company's FVRB. The mechanics of the calculation are based on those proposed by ACC Staff and adopted by the ACC in the 2007 Test Year rate filing made by APS that resulted in Decision No. 71448 (December 30, 2009).

III. STANDARD FILING REQUIREMENT SCHEDULES.

Q. ARE YOU SPONSORING ANY STANDARD FILING REQUIREMENTS ("SFR") SCHEDULES?

A. Yes. I am sponsoring SFR Schedules A-1, portions of B-1, B-2, C-1, C-2 and all the G schedules. Although not specifically required by the SFR, I am also sponsoring some additional schedules that are attached to my testimony and are designated as Schedule GJ (Attachment ZJF-1), Schedule GE-1 (Attachment ZJF-2), Schedule GE-2 (Attachment ZJF-3), and Schedule GE-3 (Attachment ZJF-4). I have also attached a SFR index that lists the APS witnesses responsible for preparation of the SFRs or elements of the SFRs (Attachment ZJF-5).

Q. PLEASE DESCRIBE THE PORTIONS OF THE SFRS THAT YOU ARE SPONSORING.

A. I am sponsoring portions of SFR Schedules A, B, C, and all of the G Schedules. In doing so, I rely on input from numerous witnesses. Moreover, I am sponsoring the allocation of rate base and expenses between Commission jurisdictional customers and other customers (the "jurisdictional splits"). These allocations are based on the results of the Cost of Service Study that are discussed in my testimony.

Schedule A-1 presents the requested overall increase in retail revenue requirements. Schedule A-1 demonstrates that the adjusted Test Year rate of return for ACC jurisdictional operations was 5.77% on a FVRB of $8,224,405,000. The rate of return on FVRB resulting from the requested increase of $95,493,000 is 6.47%.

The calculation of the Company's FVRB was based on the average of Original Cost Rate Base ("OCRB") and Reconstruction Cost New Less Depreciation ("RCND") rate base. This calculation has been accepted by the Commission for

decades as a reasonable determination in satisfying the requirement of completing a finding of fair value in order to establish new base rates. In addition to the determination of FVRB, Attachment ZJF-6 provides a detailed calculation of the fair value increment, discussed later in my Testimony. The net increase or bill impact to customers is further discussed in the testimonies of APS Witnesses Jeff Guldner and Charles Miessner. Although it is important to reflect the change in base rates, it is critical to recognize that the actual impact to customers does not equate to the base rate change due the presence of various other rate mechanisms, in this case the RES and the PSA.

Schedule B-1 provides the calculations of rate base for Total Company and ACC jurisdictional operations. The jurisdictional operations rate base calculations were developed through the Cost of Service Study.

I also sponsor portions of the C schedules that exhibit the pro forma adjustments to the Test Year and the jurisdictional splits of the pro forma adjustments between total Company and ACC jurisdictional operations. The sponsorship of the individual pro forma adjustments is noted on Schedule C-2.

The G schedules provide detailed information regarding the Company's Cost of Service Study. These schedules address existing and expected original cost rates of return by class, show pro forma adjusted amounts of Original Cost Rate Base and operating expenses allocated to ACC jurisdictional customers, and list the allocation factors used in preparing the study.

Q. WHY DID APS NOT USE FAIR VALUE RATE BASE IN THESE G SCHEDULES?

A. The form of the schedules set forth in the Commission's rules (A.A.C. R14-2-103) indicates that Original Cost Rate Base amounts are to be used. Had the Company used Fair Value Rate Base, the percent returns for all classes would be

less, but the overall conclusions to be drawn from the analysis would not significantly change.

Q. PLEASE FURTHER DESCRIBE THE SFR "G" SCHEDULES.

A. The following is a summary of these Schedules:

- SFR Schedule G-1 shows the rate-of-return at existing rates by customer class, based on the adjusted Test Year Cost of Service Study.
- SFR Schedule G-2 is similar to Schedule G-1, except it reflects returns by class that would result under APS's proposed rates.
- SFR Schedule G-3 shows the functionalized dollar amount and percentage of adjusted rate base allocated to each retail customer class.
- SFR Schedule G-4 shows the functionalized amount of operating expenses allocated to each retail customer class.
- SFR Schedule G-5 shows the amount of functionalized adjusted rate base allocated to ACC jurisdictional customers.
- SFR Schedule G-6 shows the amount of functionalized adjusted operating expense allocated to ACC jurisdictional customers.
- SFR Schedule G-7 lists the allocation factors used in preparing the Test Year Cost of Service Study.

Q. DO YOU SPONSOR ANY ADDITIONAL SCHEDULES RELATED TO THE COST OF SERVICE?

A. Yes. The following Schedules also relate to the study:

- Schedule GJ is a summary of the Cost of Service Study showing the jurisdictional separation of rate base costs, revenues, and operating expenses.
- Schedule GE-1 is a summary of the Cost of Service Study showing, by retail customer class, the allocation of total ACC allocated rate base costs, revenues, and operating expenses and the rate-of-return for each major customer class.

- Schedule GE-2 is a summary of the Cost of Service Study showing, by each general service subclass, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.
- Schedule GE-3 is a summary Cost of Service Study showing, by each residential subclass, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.

IV. COST OF SERVICE STUDY.

Q. DID THE COMPANY CONDUCT AN EMBEDDED COST OF SERVICE STUDY IN THE DEVELOPMENT OF ITS PROPOSED RATE SCHEDULES?

A. Yes. APS conducted an embedded Cost of Service Study using the twelve-month period ending December 31, 2010 as the test period ("Test Year"). That is, the Company analyzed its historical costs, customer class sales and load characteristics during this period and used those results to allocate the various items of plant and operating expenses to each customer class. This study was a major input for designing the Company's proposed rates. The study results provided an original cost rate of return for each customer class as well as the functionalization, classification, and allocation of costs.

Q. WHAT DO YOU MEAN BY EMBEDDED COSTS?

A. An embedded Cost of Service Study is based on the historical costs and operating experience of the utility during the selected Test Year with certain adjustments for normalizing and/or annualizing known and measurable changes. For example, known and measurable cost changes from the test year, such as labor costs, costs of employee benefits, taxes and fuel costs, are included as adjustments to the historical data.

Q. WAS THE USE OF A TWELVE-MONTH TEST YEAR ENDING DECEMBER 31, 2010 SUITABLE FOR THIS COST OF SERVICE STUDY?

A. Yes. In fact, it was specifically required by the Company's 2009 Settlement Agreement. The Company's analysis also includes a number of pro forma adjustments to the Test Year that reflect known and measurable changes to its cost of service that have occurred since the Test Year, as well as other adjustments to normalize the test period. The Company has included these pro forma adjustments in its analysis, in order to obtain a better relationship between revenues, expenses, and rate base at the time closer to when the proposed rates are expected to be in effect. For example, wages and salaries are updated through a pro forma adjustment to account for current salary levels and employee count.

Q. WHAT DO YOU MEAN BY "NORMALIZING" THE TEST YEAR INFORMATION?

A. Normalization refers to eliminating the effect of conditions or situations that would not ordinarily occur or be expected to occur in a normal Test Year, or that recur periodically but should be averaged out over a period of years. For example, the Company would normalize the revenue impact of an abnormally hot or cool summer to better reflect APS's revenue stream during average summer months. In this case, the weather normalization adjustment reflected milder than normal temperatures. The purpose of normalization is to produce a Test Year that will likely be more generally representative of conditions that will exist during the period in which the proposed rates will be in effect.

Q. HOW DO YOU TREAT PRO FORMA AND NORMALIZATION ADJUSTMENTS TO THE TEST YEAR IN YOUR COST OF SERVICE STUDY?

A. Other APS witnesses sponsor a number of pro forma adjustments that were incorporated into the Test Year used during the Cost of Service Study. APS

Witnesses Jason La Benz, Peter Ewen, and Charles Miessner list, by rate base, revenue, and expense category, the monetized amount of each proposed pro forma adjustment. These amounts were then functionalized, classified, and allocated to the retail and wholesale customer classes as part of the process in performing the Cost of Service Study. The adjusted Test Year Cost of Service Study reflects each of the Company's proposed pro forma adjustments.

Q. PLEASE DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY.

A. This study was prepared using industry accepted Cost of Service Functionalization, Classification, and Allocation principles, and is generally consistent with the historical APS practices that the Commission has approved in the past.

Functionalization refers to the process of attributing a particular rate base or expense item to a particular function – namely Production, Transmission, or Distribution – in the provision of electric service. An easy example is the assignment of the costs of building and operating the Company's power plants to the Production function.

Classification refers to the process of determining the factor or factors that drive the magnitude of the cost. For example, if a cost is driven by the amount of energy consumed, it is classified as Energy; if a cost is driven by the rate at which energy is consumed, it is classified as Demand; and if a cost is driven by the number of customers taking service on the APS system irrespective of either the demand or energy utilized, it is classified as Customer.

Allocation occurs once a cost has been functionalized and classified. This is the process in which allocation factors (such as peak demand contribution, energy or customers) are applied to spread the costs to particular jurisdictions, customer

classes, and rate schedules. A simple example is the allocation of energy-related costs by kilowatt-hour ("kWh") consumption to different customer classes.

In the Cost of Service Study, the expense and rate base items that comprise APS's costs were grouped into major categories, such as Plant in Service or Operating & Maintenance ("O&M") Expense. Each of these categories was first functionalized into Production, Transmission, or Distribution related costs, then classified as Demand, Energy, or Customer-related. Allocation factors based on kilowatts, kilowatt-hours and number of customers, or customer equivalents were then developed so that allocation of the functionalized and classified costs could be made to the state jurisdiction and to the various retail customer classes and sub-classes.

Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated between jurisdictions based on the average of the system peak demands occurring in the months of June, July, August, and September ("4CP") to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its cases before FERC and prevents the potential for "stranded" costs that cannot be recovered from either jurisdiction. It has also been accepted as the jurisdictional allocation methodology by the Commission for many years.

Within the ACC-jurisdictional customer classes, production costs were allocated based on the Average and Excess Demand ("AED") method, which effectively requires all customers to contribute to meeting the fixed costs the Company incurs when providing generation services and activities. This is consistent with

the directive of the Commission contained in Decision No. 69663 (June 28, 2007) at pages 70-71.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the Cost of Service Study. A portion of those costs which equate to the existing OATT revenues are brought back into the ACC jurisdictional cost of service.

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not be coincident with the system peak load. Thus, allocation of costs related to distribution substations and primary distribution lines are made based on non-coincident peak loads ("NCP"). Allocation of costs related to distribution transformers and secondary distribution lines are made based on the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP"). Each of these allocation methods has been used by APS and accepted by the ACC for many years.

Q. PLEASE EXPLAIN THE "ALL OTHER" OR NON-ACC JURISDICTIONAL SEGMENT OF YOUR COST OF SERVICE STUDY.

A. The "All Other" segment, which appears as a column in the Cost of Service Study, represents the rate base, expenses, and revenues associated with service to long-term firm FERC jurisdictional resale customers that APS serves, as well as long-term transmission services APS provides to a number of entities. Because APS plans and uses Company facilities in order to fulfill these obligations, APS has allocated and assigned a portion of APS production and distribution facilities to these non-jurisdictional customers in the same manner as it does to the Company's classes of retail jurisdictional customers in preparing the Cost of Service Study, except that for jurisdictional purposes, APS used a 4CP demand allocator for the reasons described earlier.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COST OF SERVICE STUDY.

A. APS makes sales to parties that are not traditional APS retail customers such as sales to Rate Schedule E-36 customers. In order to be certain that all the benefits of such transactions flow through to retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the entire margin or profit that APS realizes from these non-retail transactions is attributed to each class through the revenue credit, which benefits all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm, short-term transactions and a number of other small items, such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, and Other Electric Revenues, as revenue credits.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND RATE OF RETURN BASED ON THE ADJUSTED TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functions and the Demand, Energy, and Customer classifications for each class of retail business, the original cost rate of return for each class under both Test Year and proposed rates appears in the SFR "G" Schedules.

Q. BASED ON THE RESULTS OF YOUR ADJUSTED TEST YEAR COST OF SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

A. The "G", GJ, and GE Schedules plainly show that there are disparities in the rates of return that the different customer classes are providing to the Company. The residential class contributes less towards the Company's overall rate of return than does the general service class. Specifically, under current rates and adjusted operating expenses, the revenue from the residential class provides a rate of return of 6.08% while revenue from the general service class produces an 11.86%

rate of return. Overall, the rate of return provided by total retail revenues on an adjusted original cost rate base under current rates is 8.29%.

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES?

A. Yes. Various adjustors, surcharges, regulatory assessments, sales/transaction privilege taxes, and franchise fees are charged outside of base rates.

V. TRANSMISSION COSTS

Q. WOULD YOU EXPLAIN HOW TRANSMISSION COSTS WERE TREATED IN THE COST OF SERVICE STUDY?

A. Yes. Consistent with the methods adopted in our last rate cases, the revenue requirement for transmission services was computed based on the FERC-jurisdictional rates found in the APS Open Access Transmission Tariff ("OATT").

Q. HOW DID YOU ALLOCATE TRANSMISSION COSTS TO THE RETAIL CUSTOMERS CLASSES?

A. It is unnecessary to perform interclass allocation of transmission costs. These costs are directly assigned. The APS OATT provides the class rate elements for each of the FERC-regulated transmission and ancillary service costs. Under the requirements established in Decision No. 69663 (June 28, 2007) and upheld in Decision No. 71448 (December 30, 2009), the APS retail rates were re-structured so the transmission component of the rates reflects the OATT charges. In this application, the Company proposes that the FERC-regulated charges be removed from base rates and directly charged to customers through the transmission rate schedule, TCA-1, that would directly incorporate the Company's then-effective OATT charges. APS is proposing to modify the existing TCA-1 to reflect this change. Effectively, the new TCA-1 will reflect the transmission costs found in base rates today, plus the then-effective adjustment that reflects the increased or

decreased OATT charges. In other words, all transmission costs would be recovered through the TCA. No such costs would remain in base rates. When the FERC-regulated transmission rates are changed, APS will re-file the retail transmission rate schedule TCA-1 with the new charges. A copy of the proposed, revised rate schedule TCA-1 is included in the testimony of Charles Miessner.

VI. FAIR VALUE RATE OF RETURN.

Q. WHAT IS APS'S FAIR VALUE RATE BASE AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR 2010.

A. As can be seen on SFR Schedule A-1, APS's FVRB is $8,224,405 and the rate of return is 6.17% as reflected on SFR Schedule A-1, Line 5.

Q. HOW WAS THE FAIR VALUE RATE BASE DETERMINED?

A. To determine the FVRB, APS used the previously Commission-approved methodology of averaging the Original Cost Rate Base ("OCRB") and the Reconstructed Cost Net Depreciation Rate Base ("RCND").

Q. DID APS PERFORM AN INCREMENTAL CALCULATION TO ADDRESS THE APPROPRIATE LEVEL OF RETURN ON FAIR VALUE RATE BASE?

A. Yes. A calculation of the fair value increment was performed. See Attachment ZJF-6 and SFR Schedule A-1, Line 11.

Q. IS THIS TREATMENT CONSISTENT WITH THE METHOD USED IN APS'S LAST RATE CASE?

A. Generally, yes. In APS's most recent rate case, Decision No. 71448 (December 30, 2009), the Commission applied a 1.5% rate of return to calculate a weighted average cost of capital that was then used to determine the appropriate fair value increment. This method was proposed by ACC Staff consultant, Ralph Smith. The Company proposes a 1.0% rate of return in this case. This return component

is below that recommended by APS Witness Dr. William Avera for the reasons described by APS Witness Jeff Guldner.

Q. PLEASE EXPLAIN HOW THE FAIR VALUE INCREMENT WAS CALCULATED?

A. To determine the fair value increment, APS calculated the rate of return to be applied to the FVRB as follows (See Attachment ZJF-6 for detailed calculation):

- First, FVRB is divided into three components 1) the Fair Value Increment calculated by subtracting the OCRB from the FVRB to determine the portion of fair value rate base in excess of the OCRB; 2) Debt component of OCRB, calculated by multiplying the Company's adjusted Test Year debt percentage (46%) by the OCRB; 3) Equity component of OCRB, calculated by multiplying the Company's adjusted test year equity percentage (54%) by the OCRB.
- Next, a return component of 1.0% is applied to the Fair Value Increment.
- Using the 1.0% return for the Fair Value Increment, 6.38% return on the debt component and 11.0% on the equity component, a new weighted average cost of capital is calculated.

The fair value weighted average cost of capital is applied to the FVRB and is compared to the revenue requirement reflected on SFR Schedule A-1, Line 8. The difference between those two values results in the fair value increment of $40,883,000, reflected on SFR Schedule A-1, Line 9.

VII. CONCLUSION.

Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO COST OF SERVICE MATTERS IN THIS PROCEEDING?

A. The 2010 adjusted test year Cost of Service Study fully supports the Company's rate request reflected on Schedule A-1. The Cost of Service Study indicates that APS's current rate schedules produce rates of return for each customer class that vary greatly from each other and from the overall average and required rate of return. While moving to cost-based pricing is an appropriate goal, moderation in changes is appropriate. APS's approach to cost of service and rate design attempts to incorporate these goals to provide better price signals to customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

Line No.	AVERAGE & EXCESS Description	GJ ELECTRIC TOTAL (1)	GJ ACC JURISDICTION (2)	GJ ALL OTHER (3)
	SUMMARY OF RESULTS			
1	**DEVELOPMENT OF RATE BASE**			
2	ELECTRIC PLANT IN SERVICE	$12,598,371,933	$10,539,862,564	$2,058,509,369
3	GENERAL & INTANGIBLE PLANT	$1,057,732,085	$982,250,587	$75,481,498
4	LESS: RESERVE FOR DEPRECIATION	($5,218,999,716)	($4,528,867,636)	($690,132,080)
5	OTHER DEFERRED CREDITS	($1,266,301,000)	($1,192,469,776)	($73,831,224)
6	WORKING CASH	($101,350,672)	($84,458,112)	($16,892,560)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$335,128,869	$296,522,619	$38,606,250
8	ACCUM. DEFERRED TAXES	($1,931,062,000)	($1,567,901,808)	($363,160,192)
9	REGULATORY ASSETS	$560,583,000	$491,882,993	$68,700,007
10	DECOMMISSIONING FUND	$469,886,000	$458,475,866	$11,410,134
11	GAIN FROM DISP. OF PLANT	($22,882,000)	($22,104,012)	($777,988)
12	MISCELLANEOUS DEFERRED DEBITS	$143,172,000	$135,473,716	$7,698,284
13	CUSTOMER ADVANCES	($121,645,000)	($121,645,000)	$0
14	CUSTOMER DEPOSITS	($68,084,000)	($68,084,000)	$0
15	PROFORMA ADJUSTMENTS	$409,299,507	$401,339,475	$7,960,032
16	**TOTAL RATE BASE**	**$6,843,849,006**	**$5,720,277,476**	**$1,123,571,529**
17				
18	**DEVELOPMENT OF RETURN**			
19	REVENUES FROM RATES	$2,946,462,521	$2,862,997,305	$83,465,216
20	PROFORMA TO BASE REVENUES FROM RATES	$5,860,414	$5,860,414	$0
21	OTHER ELECTRIC REVENUE	$136,850,042	$121,013,337	$15,836,705
22	**TOTAL OPERATING REVENUES**	**$3,089,172,977**	**$2,989,871,056**	**$99,301,921**
23				
24	**OPERATING EXPENSES**			
25	OPERATION & MAINTENANCE	$1,735,768,826	$1,830,377,943	($94,609,117)
26	ADMINISTRATIVE & GENERAL	$216,234,381	$195,988,517	$20,245,864
27	DEPRECIATION & AMORT EXPENSE	$408,764,001	$360,155,041	$48,608,960
28	AMORTIZATION ON GAIN	($4,817,341)	($4,655,929)	($161,412)
29	REGULATORY ASSETS	($2,131,520)	($2,131,520)	$0
30	PROFORMA ADJUSTMENTS	($172,397,589)	($178,895,956)	$6,498,367
31	TAXES OTHER THAN INCOME	$134,467,497	$114,221,382	$20,246,115
32	INCOME TAX	$226,357,054	$200,455,694	$25,901,360
33	**TOTAL OPERATING EXPENSES**	**$2,542,245,309**	**$2,515,515,172**	**$26,730,138**
34				
35	**OPERATING INCOME**	**$546,927,668**	**$474,355,885**	**$72,571,783**
36				
37	**RETURN**	**$546,927,668**	**$474,355,885**	**$72,571,783**
38				
39	**RATE OF RETURN (PRESENT)**	**7.99%**	**8.29%**	**6.46%**
40				
41	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**1.04**	**0.81**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

Line No.	AVERAGE & EXCESS Description	GE-1 TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
	SUMMARY OF RESULTS						
1	**DEVELOPMENT OF RATE BASE**						
2	ELECTRIC PLANT IN SERVICE	$10,539,862,564	$6,199,293,105	$4,083,107,010	$93,350,948	$116,324,604	$47,786,897
3	GENERAL & INTANGIBLE PLANT	$982,250,587	$608,907,751	$353,616,322	$8,918,531	$8,002,038	$2,805,946
4	LESS: RESERVE FOR DEPRECIATION	($4,528,867,636)	($2,623,262,578)	($1,805,123,078)	($45,106,721)	($40,310,779)	($15,064,480)
5	OTHER DEFERRED CREDITS	($1,192,469,776)	($676,486,545)	($493,096,458)	($11,827,922)	($8,433,143)	($2,625,708)
6	WORKING CASH	($84,458,112)	($49,984,261)	($32,370,794)	($760,207)	($948,463)	($394,368)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$296,522,619	$160,699,985	$129,625,559	$2,986,090	$2,389,824	$821,161
8	ACCUM. DEFERRED TAXES	($1,587,901,808)	($946,860,525)	($580,140,677)	($12,074,828)	($20,130,857)	($8,694,921)
9	REGULATORY ASSETS	$491,882,993	$328,777,421	$152,382,518	$3,896,937	$4,896,468	$1,929,649
10	DECOMMISSIONING FUND	$458,475,866	$221,063,987	$229,543,198	$5,178,704	$2,273,135	$416,842
11	GAIN FROM DISP. OF PLANT	($22,104,012)	($12,019,915)	($9,685,951)	($281,449)	($98,393)	($18,306)
12	MISCELLANEOUS DEFERRED DEBITS	$135,473,716	$79,119,030	$53,766,108	$1,462,532	$868,286	$257,760
13	CUSTOMER ADVANCES	($121,645,000)	($64,471,850)	($53,356,771)	($3,649,350)	($167,029)	$0
14	CUSTOMER DEPOSITS	($68,084,000)	($37,446,200)	($29,395,742)	($592,315)	($464,170)	($185,573)
15	PROFORMA ADJUSTMENTS	$401,339,475	$232,401,691	$160,545,973	$4,157,328	$3,139,812	$1,094,672
16	**TOTAL RATE BASE**	**$5,720,277,476**	**$3,419,731,076**	**$2,159,417,218**	**$45,668,280**	**$67,341,332**	**$28,129,571**
17							
18	**DEVELOPMENT OF RETURN**						
19	REVENUES FROM RATES	$2,862,997,305	$1,466,220,472	$1,340,151,430	$27,003,618	$21,161,515	$8,460,270
20	PROFORMA TO BASE REVENUES FROM RATES	$5,860,414	$3,912,905	$2,448,578	($334,387)	($162,967)	($3,715)
21	OTHER ELECTRIC REVENUE	$121,013,337	$61,674,921	$56,525,049	$1,216,323	$1,167,525	$429,518
22	**TOTAL OPERATING REVENUES**	**$2,989,871,056**	**$1,531,808,298**	**$1,399,125,057**	**$27,885,554**	**$22,166,073**	**$8,886,073**
23							
24	**OPERATING EXPENSES**						
25	OPERATION & MAINTENANCE	$1,830,377,943	$944,559,847	$852,325,729	$21,406,382	$9,538,037	$2,547,949
26	ADMINISTRATIVE & GENERAL	$195,988,517	$121,052,052	$70,878,574	$1,797,873	$1,706,538	$553,479
27	DEPRECIATION & AMORT EXPENSE	$360,155,041	$210,089,575	$141,959,120	$3,413,869	$3,393,848	$1,298,629
28	AMORTIZATION ON GAIN	($4,655,929)	($2,517,130)	($2,055,137)	($58,940)	($20,846)	($3,875)
29	REGULATORY ASSETS	($2,131,520)	($1,159,097)	($934,029)	($27,140)	($9,488)	($1,765)
30	PROFORMA ADJUSTMENTS	($178,895,956)	($86,595,944)	($88,349,682)	($3,249,593)	($581,500)	($119,236)
31	TAXES OTHER THAN INCOME	$114,221,382	$68,268,854	$43,005,346	$916,769	$1,421,827	$608,587
32	INCOME TAX	$200,455,694	$70,245,750	$126,157,797	$920,107	$1,875,155	$1,256,884
33	**TOTAL OPERATING EXPENSES**	**$2,515,515,172**	**$1,323,943,907**	**$1,142,987,717**	**$25,119,326**	**$17,323,570**	**$6,140,652**
34							
35	**OPERATING INCOME**	**$474,355,885**	**$207,864,392**	**$256,137,340**	**$2,766,228**	**$4,842,504**	**$2,745,421**
36							
37	**RETURN**	**$474,355,885**	**$207,864,392**	**$256,137,340**	**$2,766,228**	**$4,842,504**	**$2,745,421**
38							
39	**RATE OF RETURN (PRESENT)**	**8.29%**	**6.08%**	**11.86%**	**6.06%**	**7.19%**	**9.76%**
40							
41	**INDEX RATE OF RETURN (PRESENT)**	**1.04**	**0.76**	**1.48**	**0.76**	**0.90**	**1.22**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

Line No.	AVERAGE & EXCESS Description	TOTAL GENERAL SVC (10)	E-20 (Church Rate) (11)	E-32 TOU (0-100kW) (12)	E-32 TOU (101-400kW) (13)	E-32 TOU (401+ kW) (14)	E-30, E-32 (0 - 100 kW) (15)	E-32 (101 - 400 kW) (16)	E-32 (401+ kW) (17)	E-34 (18)	E-35 (19)
		GE-2									
	SUMMARY OF RESULTS										
1	**DEVELOPMENT OF RATE BASE**										
2	ELECTRIC PLANT IN SERVICE	$4,083,107,010	$20,062,424	$10,407,593	$15,191,206	$60,548,429	$1,587,308,975	$992,009,068	$898,524,648	$225,506,548	$273,548,119
3	GENERAL & INTANGIBLE PLANT	$353,616,322	$1,497,816	$989,085	$1,338,535	$5,440,676	$141,288,394	$80,354,945	$75,004,636	$20,386,321	$27,335,914
4	LESS: RESERVE FOR DEPRECIATION	($1,805,123,078)	($8,511,220)	($4,673,942)	($6,760,906)	($27,424,383)	($687,175,075)	($437,625,366)	($399,548,232)	($102,898,131)	($130,505,822)
5	OTHER DEFERRED CREDITS	($493,096,458)	($1,732,190)	($1,473,030)	($2,132,097)	($8,641,165)	($170,918,756)	($114,210,397)	($114,008,386)	($32,719,494)	($47,060,943)
6	WORKING CASH	($32,370,794)	($170,159)	($78,791)	($114,589)	($453,422)	($12,922,994)	($7,958,244)	($7,016,568)	($1,699,210)	($1,956,819)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$129,625,559	$479,238	$376,727	$565,304	$2,336,282	$43,434,348	$30,952,751	$30,716,217	$8,625,123	$12,139,569
8	ACCUM. DEFERRED TAXES	($580,140,677)	($2,918,189)	($1,476,193)	($2,145,719)	($8,403,471)	($232,291,396)	($139,667,664)	($125,903,501)	($31,045,426)	($36,289,118)
9	REGULATORY ASSETS	$152,382,518	$789,824	$389,306	$479,462	$1,865,471	$70,858,050	$33,912,124	$28,849,802	$7,085,602	$8,152,876
10	DECOMMISSIONING FUND	$229,543,198	$576,593	$747,841	$1,151,294	$4,869,745	$64,589,508	$53,959,601	$56,383,668	$17,833,774	$27,431,172
11	GAIN FROM DISP. OF PLANT	($9,685,951)	($43,476)	($25,170)	($36,611)	($153,309)	($3,478,064)	($2,386,593)	($2,196,672)	($583,491)	($782,564)
12	MISCELLANEOUS DEFERRED DEBITS	$53,766,108	$234,607	$144,908	$203,488	$840,115	$20,344,905	$12,751,800	$11,817,023	$3,172,263	$4,257,600
13	CUSTOMER ADVANCES	($53,356,771)	($149,673)	($200,488)	($258,254)	($926,224)	($19,462,226)	($12,725,339)	($11,949,551)	($3,215,417)	($4,469,598)
14	CUSTOMER DEPOSITS	($29,395,742)	($82,459)	($110,455)	($142,279)	($510,283)	($10,722,286)	($7,010,746)	($6,583,343)	($1,771,464)	($2,462,427)
15	PROFORMA ADJUSTMENTS	$160,545,973	$763,414	$421,673	$595,469	$2,414,305	$61,927,828	$38,655,518	$35,107,778	$9,078,374	$11,581,613
16	**TOTAL RATE BASE**	**$2,159,417,218**	**$10,796,550**	**$5,439,067**	**$7,934,303**	**$31,602,764**	**$882,780,613**	**$521,011,467**	**$471,197,520**	**$117,735,373**	**$140,919,571**
17											
18	**DEVELOPMENT OF RETURN**										
19	REVENUES FROM RATES	$1,340,151,430	$3,759,314	$5,035,623	$6,486,512	$23,283,793	$488,828,869	$319,619,809	$300,134,494	$80,781,001	$112,262,015
20	PROFORMA TO BASE REVENUES FROM RATES	$2,448,578	$126,594	$51,489	($101,380)	($347,276)	$1,776,331	($2,304,531)	$3,883,807	($183,908)	($252,548)
21	OTHER ELECTRIC REVENUE	$56,525,049	$165,168	$179,003	$267,333	$1,120,199	$17,230,008	$13,386,728	$13,992,412	$4,122,181	$6,062,018
22	**TOTAL OPERATING REVENUES**	**$1,399,125,057**	**$4,051,076**	**$5,266,115**	**$6,652,465**	**$24,036,716**	**$507,835,208**	**$330,702,006**	**$317,790,713**	**$84,719,274**	**$118,071,485**
23											
24	**OPERATING EXPENSES**										
25	OPERATION & MAINTENANCE	$852,325,729	$2,810,968	$2,827,843	$3,868,894	$15,643,984	$284,254,320	$200,880,399	$200,465,395	$57,324,204	$84,249,922
26	ADMINISTRATIVE & GENERAL	$70,878,574	$307,649	$197,148	$266,072	$1,078,631	$28,445,647	$16,180,991	$14,994,866	$4,042,661	$5,364,910
27	DEPRECIATION & AMORT EXPENSE	$141,959,120	$650,497	$375,516	$543,023	$2,197,379	$53,884,307	$34,095,499	$31,493,927	$8,201,921	$10,517,050
28	AMORTIZATION ON GAIN	($2,055,137)	($8,988)	($5,419)	($7,916)	($33,173)	($728,677)	($505,027)	($469,378)	($125,890)	($170,670)
29	REGULATORY ASSETS	($934,029)	($4,192)	($2,427)	($3,530)	($14,784)	($335,394)	($230,142)	($211,828)	($56,267)	($75,464)
30	PROFORMA ADJUSTMENTS	($88,349,682)	($418,064)	($400,181)	($352,543)	($1,008,092)	($45,337,012)	($21,549,278)	($13,783,407)	($3,044,630)	($2,456,475)
31	TAXES OTHER THAN INCOME	$43,005,346	$215,866	$109,085	$159,365	$627,010	$17,036,578	$10,411,409	$9,391,517	$2,321,387	$2,733,128
32	INCOME TAX	$126,157,797	$71,096	$793,459	$770,105	$1,826,739	$57,602,205	$30,115,695	$24,552,793	$4,982,065	$5,443,641
33	**TOTAL OPERATING EXPENSES**	**$1,142,987,717**	**$3,624,832**	**$3,894,824**	**$5,243,470**	**$20,317,695**	**$394,821,973**	**$269,399,544**	**$266,433,886**	**$73,645,452**	**$108,606,042**
34											
35	**OPERATING INCOME**	**$256,137,340**	**$426,244**	**$1,371,291**	**$1,408,995**	**$3,719,021**	**$113,013,235**	**$61,302,461**	**$51,356,827**	**$11,073,822**	**$12,465,443**
36											
37	**RETURN**	**$256,137,340**	**$426,244**	**$1,371,291**	**$1,408,995**	**$3,719,021**	**$113,013,235**	**$61,302,461**	**$51,356,827**	**$11,073,822**	**$12,465,443**
38											
39	**RATE OF RETURN (PRESENT)**	**11.86%**	**3.95%**	**25.21%**	**17.76%**	**11.77%**	**13.25%**	**11.77%**	**10.90%**	**9.41%**	**8.85%**
40											
41	**INDEX RATE OF RETURN (PRESENT)**	**1.48**	**0.49**	**3.15**	**2.22**	**1.47**	**1.66**	**1.47**	**1.36**	**1.18**	**1.11**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

Line No.	AVERAGE & EXCESS Description	GE-3 TOTAL RESIDENTIAL (20)	GE-3 RESIDENTIAL E-12 (21)	GE-3 RESIDENTIAL ET-1 & ET-2 (22)	GE-3 RESIDENTIAL ECT-1 & ECT-2 (23)
	SUMMARY OF RESULTS				
1	**DEVELOPMENT OF RATE BASE**				
2	ELECTRIC PLANT IN SERVICE	$6,199,293,105	$1,860,099,673	$3,337,603,738	$1,001,589,694
3	GENERAL & INTANGIBLE PLANT	$608,907,751	$211,072,005	$310,091,653	$87,744,092
4	LESS: RESERVE FOR DEPRECIATION	($2,623,262,578)	($790,297,750)	($1,408,443,329)	($424,521,509)
5	OTHER DEFERRED CREDITS	($676,486,545)	($223,641,038)	($348,137,654)	($104,707,852)
6	WORKING CASH	($49,984,281)	($14,671,363)	($27,167,198)	($8,145,720)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$160,699,985	$48,704,200	$85,271,988	$26,723,797
8	ACCUM. DEFERRED TAXES	($946,860,525)	($291,243,794)	($506,045,448)	($149,571,283)
9	REGULATORY ASSETS	$328,777,421	$117,353,027	$166,533,568	$44,890,826
10	DECOMMISSIONING FUND	$221,063,987	$67,423,813	$115,002,344	$38,637,829
11	GAIN FROM DISP. OF PLANT	($12,019,915)	($3,411,706)	($6,560,269)	($2,047,939)
12	MISCELLANEOUS DEFERRED DEBITS	$79,119,030	$25,252,431	$41,554,828	$12,311,771
13	CUSTOMER ADVANCES	($64,471,850)	($21,737,904)	($32,808,081)	($9,925,866)
14	CUSTOMER DEPOSITS	($37,446,200)	($12,625,695)	($19,055,417)	($5,765,089)
15	PROFORMA ADJUSTMENTS	$232,401,691	$70,060,314	$124,937,719	$37,403,658
16	**TOTAL RATE BASE**	**$3,419,731,076**	**$1,042,336,213**	**$1,832,778,453**	**$544,616,410**
17					
18	**DEVELOPMENT OF RETURN**				
19	REVENUES FROM RATES	$1,466,220,472	$494,363,962	$746,122,218	$225,734,292
20	PROFORMA TO BASE REVENUES FROM RATES	$3,912,905	($998,200)	$1,198,055	$3,713,050
21	OTHER ELECTRIC REVENUE	$61,674,921	$18,866,889	$32,324,144	$10,483,889
22	**TOTAL OPERATING REVENUES**	**$1,531,808,298**	**$512,232,651**	**$779,644,417**	**$239,931,231**
23					
24	**OPERATING EXPENSES**				
25	OPERATION & MAINTENANCE	$944,559,847	$301,232,623	$487,258,008	$156,069,215
26	ADMINISTRATIVE & GENERAL	$121,052,052	$41,430,325	$62,025,101	$17,596,626
27	DEPRECIATION & AMORT EXPENSE	$210,089,575	$64,653,462	$111,898,804	$33,537,308
28	AMORTIZATION ON GAIN	($2,517,130)	($716,893)	($1,370,865)	($429,373)
29	REGULATORY ASSETS	($1,159,097)	($328,995)	($632,616)	($197,486)
30	PROFORMA ADJUSTMENTS	($86,595,944)	($32,246,136)	($43,166,999)	($11,182,809)
31	TAXES OTHER THAN INCOME	$68,268,854	$20,699,908	$36,656,406	$10,912,541
32	INCOME TAX	$70,245,750	$34,372,431	$28,910,241	$6,963,077
33	**TOTAL OPERATING EXPENSES**	**$1,323,943,907**	**$429,096,726**	**$681,578,081**	**$213,269,100**
34					
35	**OPERATING INCOME**	**$207,864,392**	**$83,135,924**	**$98,066,336**	**$26,662,131**
36					
37	**RETURN**	**$207,864,392**	**$83,135,924**	**$98,066,336**	**$26,662,131**
38					
39	**RATE OF RETURN (PRESENT)**	**6.08%**	**7.98%**	**5.35%**	**4.90%**
40					
41	**INDEX RATE OF RETURN (PRESENT)**	**0.76**	**1.00**	**0.67**	**0.61**

Standard Filing Requirements Index for Sponsorship

pA-1	Fryer		
A-2 A-3 A-4 A-5	La Benz Hatfield	Historical Projected	
B-1*	La Benz		
B-2* B-3*	La Benz La Benz/Guldner La Benz/Schiavoni La Benz/Edington La Benz/Froetscher La Benz	Columns Column Column Column Column Column	2 3 4 5 6 7
B-4 B-5	La Benz	Column	
C-1*	La Benz		
C-2*	La Benz La Benz/Guldner La Benz/Schiavoni La Benz/Edington La Benz/Froetscher La Benz Ewen Miessner	Columns Column Column Column Column Columns Columns Column	1-5 6 7 8 9 10-27 28-30 31-33
C-3	La Benz		
D-1 D-2 D-3	La Benz Hatfield	Historical Projected	
D-4	La Benz		

*Zachary Fryer sponsors the ACC jurisdictional amounts that are computed, via the Cost of Service Study.

E-1 E-2 E-3 E-4 E-5 E-6 E-7 E-8 E-9	La Benz	
F-1 F-2 F-3	La Benz Hatfield	Historical Projected
F-4	Hatfield	
G-1 G-2 G-3 G-4 G-5 G-6 G-7	Fryer	
H-1 H-2 H-3 H-4 H-5	Miessner	

Calculation of Fair Value Increment

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 3,382,856	46.06%	6.38%	2.94%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	3,961,248	53.94%	11.00%	5.93%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 7,344,104	100.00%		8.87%

	Capital Structure with 1.0% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 2,634,760	32.04%	6.38%	2.04%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	3,085,517	37.52%	11.00%	4.13%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	2,504,128	30.45%	1.00%	0.30%
11.	Total	$ 8,224,405	100.00%		6.47%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 8,224,405	$ 5,720,277
13.	Rate of Return	6.47%	8.87%
14.	Required Operating Income	$ 532,119	$ 507,389
15.	Adjusted Operating Income	$ 474,356	$ 474,356
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 57,763	$ 33,033
17.	Revenue Conversion Factor	1.6532	1.6532
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 95,494	$ 54,610
19.	Fair Value Increment	$ 40,883	

Jason C. La Benz

TESTIMONY OF JASON C. LA BENZ

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

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TESTIMONY OF JASON C. LA BENZ
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Jason C. La Benz. I am the Director of Financial Reporting for Arizona Public Service Company ("APS" or the "Company"), a subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"). I am responsible for the financial accounting, revenue and regulatory accounting, payroll, asset accounting, accounts payable, accounts receivable and cash control functions at Pinnacle West and APS. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Business with a major in Accounting from Arizona State University in 1982. I joined APS in May of 1982 as a staff accountant and have spent the last 29 years working for APS and Pinnacle West in Financial Accounting, Asset Accounting, Financial Planning, and the Tax Department.

Prior to my current position in Financial Reporting, I was responsible for the asset accounting function at APS as the leader of that department. I am a Certified Public Accountant and a member of the Edison Electric Institute's Corporate Accounting Committee.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony addresses the historical accounting information and pro forma adjustments required by the Standard Filing Requirements ("SFR") of the Arizona Corporation Commission ("ACC" or "Commission") in support of the

Company's rate case filing. I sponsor historical information for the twelve month period ending December 31, 2010, which was used as the test year in this proceeding (the "Test Year") and any prior years presented on the following SFR Schedules (APS Witness James Hatfield sponsors any projected information contained in these schedules):

- A-2 through A-5 – Summary Schedules
- B-1, B-3 through B-5 – Rate Base Schedules
- C-1 – Test Year Income Statements
- C-3 – Computation of Gross Revenue Conversion Factor
- D-1 through D-4 – Cost of Capital
- E-1 through E-9 – Financial Statements and Statistical Schedules
- F-1 through F-3 – Projections and Forecasts

I will also provide direct testimony on certain pro forma adjustments made to the Test Year on SFR Schedules B-2 and C-2. Specifically, I will be sponsoring the "Total Company" column for the following pro formas on SFR Schedule B-2:

- West Phoenix Unit 4 Regulatory Disallowance
- Adjust Rate Base for Post-Test Year Plant Additions
- Adjust Cash Working Capital for Cost of Service Pro Formas

Additionally, I will be sponsoring the "Total Company" columns for the following pro formas on SFR Schedule C-2:

- Remove Bark Beetle Remediation Amortization
- Remove Test Year Surcharges
- Include West Phoenix Unit 4 Regulatory Disallowance
- Include Interest Expense on Customer Deposits
- Adjust Depreciation Expense – 2010 Study
- Adjust for Post-Test Year Plant Additions
- Adjust Decommissioning and Spent Fuel Costs – 2010 Study
- Annualize Payroll Expense
- Normalize Employee Benefits
- Normalize Income Tax Expense / Interest Synchronization
- Annualize Property Tax Expense
- Annualize Severance Costs
- Amortize Childs-Irving Excess Decommissioning Costs
- Remove Schedule 3 Revenues
- Normalize Fossil Maintenance
- Normalize Nuclear Maintenance
- Annualize Four Corners Coal Reclamation Costs
- Adjust Cash Working Capital for Cost of Service Pro Formas

- Remove PWEC Loan Amortization
- Amortize Pension and OPEB Deferral
- Normalize Pole Attachment Revenues
- Remove Supplemental Executive Retirement Plan Benefits
- Remove Stock Compensation
- Remove Out of Period and Miscellaneous Items

These adjustments are consistent with prior filings and represent "normalizations" and "annualizations" as discussed later in my testimony. These operating income pro formas also include an income tax calculation at the current combined federal and state statutory income tax rates. The SFR Schedule C-2 pro formas that have a related Rate Base pro forma also include synchronization of interest expense. This interest expense is used in determining federal and state income tax expense.

I will discuss and explain the "Gross Revenue Conversion Factor" that is used to gross-up operating income to account for income taxes, as presented on SFR Schedule C-3. I will also present testimony concerning the capital structure of the Company and provide APS's actual overall cost of capital, as presented on SFR Schedules D-1 through D-4. (Mr. Hatfield will discuss the projected information on SFR Schedules D-1 through D-3). This discussion will include information on the cost of equity provided by Dr. William Avera, APS's return on equity ("ROE") witness, as well as the Company's cost of debt. In addition, I will sponsor the various schedules relating to the Company's financial statements on SFR Schedules E-1 through E-9. SFR Schedule E-6 refers only to "combination" utilities (e.g., electric and gas) and thus is not applicable to APS.

Finally, I will sponsor the Test Year data on SFR Schedules F-1 through F-3. These schedules also include projected income statements and projected changes in financial position. Once again, Mr. Hatfield will address and sponsor the projected information on those schedules.

III. HISTORICAL AND TEST YEAR ACCOUNTING DATA

Q. PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING.

A. My testimony covers historical accounting data, including the actual data for the Test Year. The majority of this information is disclosed directly or indirectly in both the consolidated APS and consolidated Pinnacle West audited financial statements, which are included in filings made with the Securities and Exchange Commission ("SEC") for the relevant years.

Additionally, all of the accounting information provided in my testimony complies with Generally Accepted Accounting Principles ("GAAP"). These are the principles that accounting professionals use to prepare financial statements. One major goal of GAAP is to make financial statements comparable from year to year, from industry to industry, and from jurisdiction to jurisdiction. In addition to GAAP, APS's accounting practices comply with other applicable utility accounting standards, such as the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, which this Commission has adopted. *See* A.A.C. R14-2-212(G)(2).

On January 1, 2010, APS adopted amended accounting guidance relating to Variable Interest Entities ("VIE"). This amended guidance significantly changed the consolidation model for VIE's and resulted in the consolidation of the Palo Verde ("PV") lessor trusts from which we lease a portion of PV Unit 2. Consistent with Decision Nos. 55120 (July 24, 1986) and 55320 (December 5,

1986), the PV leases have been accounted for as operating leases on APS's unconsolidated financial statements. The levelized lease expense (net of the gain amortization) is currently being recovered through rates. The Test Year financial information will continue to portray the operating lease treatment reflected on APS's unconsolidated financial statements.

In large part, my testimony supports the testimony of other APS witnesses. The direct testimony of Mr. Hatfield addresses financial projections to actual Test Year data. APS witness Zachary Fryer focuses on the jurisdictional allocation of APS revenues, costs, and Rate Base items for the actual Test Year and all pro forma adjustments. Dr. Avera's testimony addresses the Company's ROE.

A. *Summary Schedules*

Q. PLEASE DESCRIBE THE HISTORICAL INFORMATION ON SFR SCHEDULES A-2 THROUGH A-5.

A. These summary schedules provide the "Summary Results of Operations", the "Summary of Capital Structure", the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service" and "Summary Changes in Financial Position" for the Test Year and the prior two calendar years. These schedules also include projected information. I am sponsoring the historical data for the Test Year and prior calendar years. Mr. Hatfield is sponsoring the projected information on these schedules.

B. *Rate Base Schedules*

Q. PLEASE DESCRIBE THE INFORMATION ON SFR SCHEDULES B-1 THROUGH B-5.

A. These schedules provide summary and detailed information of our Original Cost and Reconstructed Cost New less Depreciation ("RCND") Rate Base, including the related pro formas needed to present an adjusted Rate Base as of the end of the Test Year. I am sponsoring the "Total Company" portion of these schedules and certain pro forma adjustments. Mr. Fryer is sponsoring the "ACC" portion,

and his testimony will present the allocation of "Total Company" figures to the ACC jurisdiction.

Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL COST RATE BASE PROPOSED BY APS.

A. As of December 31, 2010, APS is proposing a Total Company Adjusted Original Cost Rate Base ("OCRB") of $6,843,849,000. This represents an increase of $409,300,000 over the unadjusted amount. The amount of the adjusted OCRB allocated to the ACC jurisdiction is $5,720,277,000. The requested adjustments to the Test Year amounts are summarized in SFR Schedule B-2.

Q. WHAT IS MEANT BY THE TERMS "RCND" AND "RCN" AS USED IN YOUR TESTIMONY?

A. The Commission regulations define Reconstructed Cost New Less Depreciation or "RCND" as:

> An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contribution and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis (A.A.C. R14-2-103(A)(3)(n)).

Thus, Reconstructed Cost New ("RCN") refers to the estimated cost of utility property that would be incurred if APS were to reproduce or reconstruct the property as new, using current cost levels. RCND is the net amount that results after deducting accumulated depreciation and amortization (both of which are also restated in current dollars) from the RCN amount.

Q. WHAT DOES SFR SCHEDULE B-4 PRESENT?

A. SFR Schedule B-4 presents the RCN and RCND amounts of APS's utility properties. These amounts were determined using a Handy-Whitman RCN Study performed by the Company.

Q. BASED ON YOUR STUDY, WHAT IS THE RCN OF APS'S UTILITY PROPERTY DEVOTED TO SERVICE TO THE PUBLIC AS OF THE END OF THE TEST YEAR?

A. Total RCN for APS's utility property is approximately $26.4 billion. This total amount is shown in column (A) of SFR Schedule B-4, page 2 of 2.

Q. WOULD YOU PLEASE EXPLAIN HOW RCND WAS CALCULATED AS SHOWN ON SFR SCHEDULE B-4?

A. To arrive at RCND, RCN column (A) is multiplied by a "condition percent," also known as a net book value percent, which is shown in column (B). RCND is shown in column (C). The condition percent used to convert RCN to RCND is calculated by first taking the original cost less accumulated depreciation (net book value) for all depreciable plant for each FERC account. This amount is then divided by the original cost for each FERC account to arrive at the condition percent. In other words, the condition percent is the percentage that results when comparing original cost less accumulated depreciation to the original cost of plant in service.

For example, assume that distribution lines have an original cost of $400,000, and accumulated depreciation of $250,000. The original cost less accumulated depreciation would be $150,000, which is $400,000 minus $250,000. Also, assume the distribution lines were purchased in 1985 and have a RCN value of $632,000. Using these assumptions, the condition percent is calculated by dividing original cost less accumulated depreciation by original cost, or $150,000/$400,000, resulting in 37.5%. Multiplying RCN by the condition percent yields RCND. In this hypothetical, the RCND for these distribution lines would be $237,000 ($632,000 x 37.5%=$237,000).

Q. ARE THERE ANY OTHER RELATED ADJUSTMENTS NECESSARY TO DETERMINE FAIR VALUE RATE BASE?

A. Yes. Plant-related accumulated deferred income taxes ("ADIT") were also adjusted. Plant-related ADIT arises primarily as a result of differences between

book depreciation recorded for GAAP purposes and tax depreciation used for income tax purposes. Since RCND trending results in a change in accumulated book depreciation, a corresponding change was made to original cost ADIT. To make this adjustment, the Company trended plant-related ADIT using the relationship between the Original Cost less Depreciation and RCND.

Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE B-4A?

A. SFR Schedule B-4A shows the computation of adjusted jurisdictional RCND Rate Base as of December 31, 2010. Column (A) presents data for Total RCND Rate Base. Mr. Fryer provided the jurisdictional allocations of the RCND Rate Base split between "ACC" and "Other," which is presented in columns (B) and (C) respectively.

Q. HOW DID YOU ARRIVE AT THE AMOUNTS SHOWN ON LINES 11 THROUGH 24 OF SFR SCHEDULE B-4A?

A. The amounts shown on lines 11 through 29 of SFR Schedule B-4A for other Rate Base elements were obtained from SFR Schedule B-1, page 1 of 2, column (A). Consistent with past Commission practice, the RCND of these specific Rate Base elements are stated at their original cost levels, as these elements do not change in value with the passage of time.

Q. WOULD YOU PLEASE EXPLAIN LINES 29 AND 30 OF SFR SCHEDULE B-4A?

A. The amounts shown on line 29 represent the RCND Rate Base as of December 31, 2010. However, the end of Test Year data needs to be adjusted to more closely reflect the value of certain items of property when the proposed rates become effective. Therefore, it is necessary to also reflect the pro forma Rate Base adjustments in the RCND Rate Base. The RCND pro forma adjustments are shown in detail on SFR Schedules B-3. The total is shown on line 30 of SFR Schedule B-4A.

Q. WHAT IS THE TOTAL ADJUSTED RCND RATE BASE?

A. The total Company RCND Rate Base, as adjusted, is approximately $12.8 billion. This is shown on SFR Schedule B-4A, column (A), line 31.

Q. PLEASE EXPLAIN COMPUTATION OF WORKING CAPITAL ON SFR SCHEDULE B-5.

A. SFR Schedule B-5 outlines the computation of the allowance for working capital of $233,778,000 included in the Company's Rate Base. Working capital is a measure of investor funding of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations. Working capital includes materials and supplies, fuel inventories, prepayments and cash working capital. Working capital is an investment just like other capital requirements, such as power plants and transmission and distribution infrastructure; thus, it is part of APS's Rate Base. My testimony presents the calculation of the allowance for working capital, which includes a cash working capital component that is determined using a "lead/lag study." The lead/lag study is required by Decision No. 55931 (April 1, 1988).

Q. HOW WAS THE CASH WORKING CAPITAL CALCULATED?

A. APS calculated the cash working capital by performing a lead/lag study. A lead/lag study establishes the amount of investor funds used to maintain utility operations from the time expenditures are made to the time revenues are collected as a reimbursement for that utility service. The Company used the number of lead/lag study days derived from a calendar year 2010 study and applied this information to the Test Year income statement expenses.

In addition, the Company considered the pro forma adjustments to the Test Year income statement expenses and computed a Rate Base pro forma to reflect the related change in cash working capital (*see* the pro forma discussion in Section IV of my testimony).

C. *Test Year Income Statements*

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULE C-1.

A. SFR Schedule C-1 is a summary of the Company's adjusted Test Year income statement. I am sponsoring the actual Test Year data in the first column of SFR Schedule C-1, page 1. This information provides the baseline from which pro forma adjustments are made and shows operating income and net income for the Test Year.

Q. ARE YOU SPONSORING ANY OTHER RELATED SFR SCHEDULES?

A. Yes. I am sponsoring certain pro forma adjustments on SFR Schedule C-2, which presents pro forma adjustments to the Company's Test Year operating income. I will discuss these adjustments in detail later in my testimony (*see* section IV "Pro Forma Adjustments to Test Year"). I am also sponsoring SFR Schedule C-3, which shows the computation of the gross revenue conversion factor.

Q. PLEASE DESCRIBE SFR SCHEDULE C-3.

A. SFR Schedule C-3 calculates the factor applied to "gross-up" income to account for income taxes. The Company applies this factor to operating income to ensure income tax expense is reflected in the requested revenue requirement. The Gross Revenue Conversion factor of 1.6532 (shown on line 5) is an algebraic transformation of APS's composite federal and state income tax rate of 39.51 percent. This factor is used on SFR Schedule A-1 (line 7) to arrive at the increase or decrease in Revenue Requirements necessary to account for income taxes.

D. *Cost of Capital*

Q. PLEASE DISCUSS THE COST OF CAPITAL INFORMATION THAT YOU ARE SPONSORING.

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the Test Year in this schedule. SFR Schedule D-2

presents supporting detail for the long-term debt summarized on SFR Schedule D-1. SFR Schedule D-3 addresses preferred stock and is included in the Company's schedules for the sake of completeness. SFR Schedule D-3 is not directly applicable because APS did not have any outstanding preferred stock as of December 31, 2010. SFR Schedule D-4 addresses the Company's cost of common equity.

Q. WHAT IS THE COST OF CAPITAL THE COMPANY IS REQUESTING?

A. The company is requesting a weighted average cost of capital of 8.87% as set forth on SFR Schedule D-1.

Q. PLEASE DISCUSS IN MORE DETAIL THE COMPANY'S OUTSTANDING LONG-TERM DEBT AS OF THE END OF THE TEST YEAR.

A. At the end of the Test Year, approximately 81% of APS's outstanding long-term debt consisted of unsecured notes with a weighted average interest rate of approximately 6.6%. Most of the remaining long-term debt consisted of tax-advantaged pollution control bonds. This debt has a weighted average interest rate of approximately 5.3%. APS also has a small amount of interest expense related to capitalized lease obligations.

Q. WHAT WAS APS'S CAPITAL STRUCTURE AT THE END OF THE TEST YEAR?

A. APS's total long-term debt and common equity was approximately $7.21 billion. This amount includes approximately $3.38 billion in long-term debt (including current maturities) and approximately $3.82 billion in common equity. APS's adjusted capital structure at the end of the Test Year was approximately 46.06% debt and 53.94% equity.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE CAPITAL STRUCTURE?

A. I have applied two pro forma adjustments to the December 31, 2010 actual cost of capital. These adjustments remove impacts to equity of non-cash accounting

adjustments for pension and derivatives. Since these adjustments were small in comparison to total equity, there is no significant impact on the Company's capital structure.

Q. WHAT IS THE RETURN ON EQUITY THE COMPANY IS REQUESTING?

A. Dr. Avera concludes in his testimony that the fair rate of return on equity for APS ranges from 10.75% to 11.75%. For the purpose of this filing, the Company is proposing a return on common equity of 11.0%.

E. *Financial Statements and Statistical Schedules*

Q. PLEASE SUMMARIZE THE INFORMATION PRESENTED ON SFR SCHEDULES E-1 THROUGH E-9.

A. These schedules relate to historical financial and accounting information, as well as the notes to the financial statements. As noted earlier in my testimony, SFR Schedule E-6 is only required for combined electric and gas utilities and therefore does not apply to APS.

Q. PLEASE DISCUSS SFR SCHEDULES E-1 THROUGH E-4.

A. These schedules present APS's balance sheets, income statements, statements of cash flows and changes in stockholders' equity for the Test Year and the two prior calendar years. As discussed earlier, these financial statements continue to reflect APS's unconsolidated results, consistent with previous rate filings. The SEC Form 10-K filings reflect APS's consolidated financial statements, which include the consolidation of the PV lessor trusts from which APS leases a portion of PV Unit 2.

Q. PLEASE DISCUSS SFR SCHEDULE E-5.

A. SFR Schedule E-5 is a detailed statement of utility plant included in the Company's Rate Base, broken down by FERC account under the Uniform System of Accounts. The first page of SFR Schedule E-5 is a summary of gross plant in service, accumulated depreciation and amortization, nuclear fuel,

construction work in progress, and plant held for future use. The remainder of the schedule presents supporting detail for each FERC plant account.

Q. WHAT INFORMATION IS PROVIDED ON SFR SCHEDULE E-7?

A. SFR Schedule E-7 provides detailed information concerning APS's sales (in kWh), average number of customers, average kWh usage per customer, and average annual revenue per residential customer over the last three years, including the Test Year. This information is contained in or derived from APS's FERC Form 1 filings for the applicable periods. The information in SFR Schedule E-7 is separated by customer classes to show residential, commercial, industrial, irrigation, public street and highway lighting, other sales to public authorities, and sales for resale.

Q. PLEASE DISCUSS SFR SCHEDULE E-8.

A. SFR Schedule E-8 provides a breakdown of APS's tax expense incurred during the Test Year and the two prior calendar years for federal and state taxes.

Q. PLEASE DISCUSS SFR SCHEDULE E-9.

A. SFR Schedule E-9 presents the Company's SEC financial statements, including the footnotes, as filed with the Company's Form 10-K for 2010. The footnotes include, but are not limited to, the Company's accounting policies for depreciation, capitalized interest and income taxes. The footnotes also provide additional detailed information related to the income statements, the balance sheets and statements of cash flows.

F. *Projections and Forecasts*

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULES F-1 AND F-2.

A. SFR Schedule F-1 presents income statements for projected calendar years, compared with actual Test Year results, at present and proposed rates. SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years compared with the Test Year, at present and proposed

rates. I am sponsoring the historical Test Year data in the first column of each of these SFR Schedules. Mr. Hatfield will address the projected data on these same schedules.

Q. PLEASE DISCUSS SFR SCHEDULE F-3.

A. SFR Schedule F-3 presents projected annual construction expenditure requirements, by property classification, for three years subsequent to the Test Year. I am sponsoring the actual Test Year information. Again, Mr. Hatfield will address the projected data on this schedule.

IV. PRO FORMA ADJUSTMENTS TO TEST YEAR

A. *Types of Pro Forma Adjustments*

Q. WHAT ARE PRO FORMA ADJUSTMENTS?

A. Pro forma adjustments are adjustments made to a historical test year to reflect conditions during the period in which rates are to be in effect. Because the Company has used a historical test year, it is necessary to adjust recorded revenues and expenses for known and measurable changes. Pro forma adjustments commonly include normalizations, annualizations and out-of-period adjustments. All of the pro forma adjustments discussed in my testimony reflect Total Company amounts prior to any jurisdictional allocation and are reflected on either SFR Schedule B-2 or SFR Schedule C-2.

Q. WHAT ARE "NORMALIZATIONS"?

A. Normalization adjustments compensate or adjust for unusual levels of operations experienced during the Test Year period. These adjustments generally relate to items that are abnormal in amount or nonrecurring in nature and are made to better reflect what is believed to be an ongoing level of operations.

Q. WHAT ARE "ANNUALIZATIONS"?

A. Annualization adjustments recognize that some events occurring during the test period are ongoing and must be adjusted to reflect their impact over an entire

twelve-month period. One example of an annualization is for the payroll increases that happen during the Test Year. Since payroll costs will be higher on an ongoing basis than what was recorded during the Test Year, an adjustment must be made to reflect the prospective level of costs.

Q. WHAT IS AN "OUT-OF-PERIOD" ADJUSTMENT?

A. Out-of-period adjustments remove expenses or revenues properly recorded during the Test Year, but which are associated with operations from another year.

B. *Pro Forma Adjustment Descriptions*

1. Remove Bark Beetle Remediation Amortization.

Q. PLEASE DESCRIBE THIS ADJUSTMENT.

A. Decision No. 69663 (June 28, 2007) ordered amortization of these previously deferred costs over a three-year period beginning July 1, 2007. The total deferral balance at June 30, 2007 was $11,508,000, resulting in an annual amortization of $3,836,000. APS completed the recovery of these previously deferred costs on June 30, 2010. Because the Test Year contains amortization from January 1, 2010 through June 30, 2010 (6 months), a pro forma is necessary to remove the 6 months of amortization. This results in an increase to pre-tax operating income of $1,918,000 (*see* Attachment JCL-1 and SFR Schedule C-2, page 1, column 1).

2. Remove Test Year Surcharges.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR SURCHARGES AND ADJUSTORS.

A. The adjustment is made to exclude from revenue and expense the amounts collected during the Test Year under surcharges and adjustors outside of base rates; specifically, the Renewable Energy Surcharge ("RES"), Competition Rules Compliance Charge ("CRCC"), Demand Side Management Adjustment Charge ("DSMAC"), Transmission Cost Adjustment ("TCA") and Regulatory Assessment charges. These items are not collected as part of base rates, so they must be excluded from Test Year revenue in order to calculate new base rates.

The pro forma also removes from expense the associated costs incurred. This results in a reduction to pre-tax operating income of $7,307,000 (*see* Attachment JCL-2 and SFR Schedule C-2, page 1, column 2).

APS witness Pete Ewen sponsors the Power Supply Adjustor ("PSA") pro forma in his testimony.

3. West Phoenix Unit 4 Regulatory Disallowance.

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE.

A. This disallowance was recorded for regulatory purposes, but did not qualify as a disallowance for GAAP purposes. Consequently, a pro forma adjustment is needed to reduce Rate Base by the disallowed amount. Accordingly, the Rate Base reduction for the West Phoenix Unit 4 regulatory disallowance at December 31, 2010 is $8,729,000 (*see* Attachment JCL-3 and SFR Schedule B-2, page 1, column 2).

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE DEPRECIATION EXPENSE RELATED TO THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE?

A. Yes. The operating income pro forma reflects an annual reduction in depreciation expense. This results in an increase to pre-tax operating income of $329,000 (*see* Attachment JCL-4 and SFR Schedule C-2, page 1, column 3).

4. Include Interest Expense on Customer Deposits.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR INTEREST EXPENSE ON CUSTOMER DEPOSITS.

A. This pro forma adjustment reflects the annualized interest cost associated with customer deposits as an operating expense. This treatment conforms to the approach utilized by the Commission in the Company's previous rate cases. This adjustment was calculated by applying the 0.29 percent annual 2011 interest rate to the December 31, 2010 outstanding deposit balance. The annual interest rate is the rate required by APS Schedule 1 for customer deposits – the established one-

year Treasury Constant Maturities rate, effective on the first business day of each year (in this instance, January of 2011), as published on the Federal Reserve website. The result of this pro forma is a reduction to pre-tax operating income of $197,000 (*see* Attachment JCL-5 and SFR Schedule C-2, page 2, column 4).

5. Adjust Depreciation Expense – 2010 Study.

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO DEPRECIATION AND AMORTIZATION EXPENSE?

A. For this filing, APS witness Dr. Ronald White performed a 2010 Depreciation Study using data as of December 31, 2010. Using Dr. White's study, APS has updated depreciation rates from the rates authorized in Decision No. 71448 (December 30, 2009). APS is asking Commission approval of these depreciation rates in this proceeding. Please refer to Dr. White's testimony for further discussion. This pro forma adjustment reduces depreciation expense and thus results in an increase to pre-tax operating income of $28,646,000 (*see* Attachments JCL-6 and SFR Schedule C-2, page 2, column 5).

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?

A. No. APS is not requesting any change to the amortization rates authorized in Decision No. 71448.

6. Adjust for Post-Test Year Plant Additions.

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ACCOUNT FOR POST-TEST YEAR PLANT ADDITIONS?

A. APS witnesses Jeff Guldner (Vice President of Rates and Regulation), Daniel Froetscher (Vice President of Energy Delivery), Mark Schiavoni (Senior Vice President of Fossil Generation), and Randy Edington (Executive Vice President and Chief Nuclear Officer) address the details of the Company's capital investments in their respective testimonies. The Company is proposing to include plant additions that go into service after the Test Year, but before new base rates

are expected to be in effect. My testimony covers the mechanics of the pro formas, as discussed below:

Step 1: Construction Work in Progress ("CWIP") is extracted from the general ledger as of December 31, 2010 for non-transmission plant that is expected to go into service prior to July 1, 2012 (the proposed effective date for new rates);

Step 2: The forecast plant in service cost of each project that is expected to go into service prior to July 1, 2012 was compiled (both projects in CWIP at December 31, 2010 and projects that begin after December 31, 2010);

Step 3: The plant was classified by functional area: solar generation, fossil generation, nuclear generation; and distribution, general and intangible plant;

Step 4: Annual accumulated depreciation and amortization, net accumulated deferred income taxes and tax credits (where applicable) on pre-existing plant in service were offset against the post-Test Year plant additions adjustment;

Step 5: The sum of the forecast plant in service costs, less accumulated depreciation and net deferred income taxes is, presented by functional unit and included in the Rate Base pro forma adjustments that increases Rate Base at December 31, 2010 by $432,249,000 (See Attachment JCL-7 and SFR Schedule B-2, pages 1 and 2, columns 3-6);

Step 6: Operations and Maintenance costs ("O&M"), property and income taxes, and depreciation expenses were calculated and reflected as a

reduction to pre-tax operating income of $41,560,000 (See Attachment JCL-8 and SFR Schedule C-2, pages 2 and 3, columns 6-9).

APS will true-up this adjustment with actual plant placed in service, net of retirements, as necessary throughout the case.

7. Decommissioning and Spent Fuel Costs.

Q. PLEASE EXPLAIN THE NUCLEAR DECOMMISSIONING FUNDS AND WHAT IS MEANT BY A "QUALIFYING" DECOMMISSIONING FUND.

A. Like all nuclear power plants, Palo Verde eventually will need to be decommissioned, an expensive and time consuming process. Regulatory agencies throughout the country, including the Commission, have required that the cost of this eventual decommissioning be recovered from electricity customers over the life of the facility.

Most of the amounts collected from ratepayers that relate to decommissioning of a nuclear power plant can be deposited into a "qualified" decommissioning trust. A trust is "qualified" to the extent it meets certain requirements set forth in the Internal Revenue Code and related regulations. A qualified decommissioning trust is afforded significant income tax benefits versus other funding alternatives. This favorable tax treatment is twofold. First, contributions to a qualified decommissioning trust are deductible for federal income tax purposes in the year made to the extent these do not exceed the "ruling amount" approved by the U.S. Secretary of the Treasury in a private letter ruling. The plant owner must request from the Secretary a new schedule of ruling amounts upon each renewal of the operating license of the nuclear power plant. Furthermore, the investment earnings of the assets within the trust are taxed at a federal income tax rate of 20% versus 35% if the investment earnings occurred outside of the qualified trust.

The Nuclear Regulatory Commission ("NRC") and most state regulators prefer the external funding option both because of increased security of the funding for its intended purpose and because of the income tax benefits afforded qualified decommissioning trusts.

Q. PLEASE EXPLAIN THE NEED FOR A PRO FORMA ADJUSTMENT FOR NUCLEAR DECOMMISSIONING FUNDING AND THE CORRESPONDING EXPENSE.

A. In Decision No. 71448, APS was ordered, upon the later date of receiving NRC approval for the Palo Verde license extension or January 1, 2012, to file a request to adjust the System Benefit Charge ("SBC") to reflect the reduction in decommissioning funding obligations. The assumed funding periods for Units 1 and 3 have been increased to 2045 and 2047 respectively to reflect the twenty-year license extension approved by the NRC in April 2011. Under the terms of the sale-leaseback, the Palo Verde Unit 2 decommissioning fund is required to be fully funded by the end of the lease, which is 2015.

In addition to the NRC's approval of the license extension, two basic components associated with determining the annual amounts to deposit into the decommissioning fund have changed: earnings assumptions and new decommissioning study cost estimates.

The earnings assumption is used to determine how much the investments will grow between now and the time of decommissioning. APS is proposing to use an after-tax earnings assumption of 4.73% for Palo Verde Units 1 and 3. APS is also proposing to use an after-tax earnings assumption of 3.72% for Palo Verde Unit 2. The assumption for Units 1 and 3 was determined using pre-tax investment return assumptions for fixed income of 5.00% and pre-tax equity returns of 7.25%. Using a 60% stocks and 40% bonds asset allocation and the applicable tax rates for qualifying and non-qualifying funds, a 4.73% after-tax

earnings assumption was calculated. The Unit 2 assumption was also determined using a pre-tax investment return assumption for fixed income of 5.00%. The Company did not assume an equity return for Unit 2 due to the restrictions included in the terms of the sale leaseback agreement, which prohibit Unit 2 from holding equities after January 31, 2010. Therefore, the after-tax earnings assumption for Unit 2 is 3.72%.

Finally, the new decommissioning funding and expense estimates reflect a new study performed by TLG Services, Inc. The decommissioning costs in this study are presented in current year's dollars. An escalation rate of 4% is used to account for the inflation that will occur between now and the time of decommissioning. The escalation rate reflects expected increases in payroll and material costs.

Q. WHAT IS THE PRO FORMA ADJUSTMENT REQUIRED TO REFLECT NEW LEVELS OF DECOMMISSIONING TRUST FUNDING?

A. Based on the change in assumptions described above, the new annual level of funding required is $17,249,000. This results in an increase to pre-tax operating income of $7,183,000 (*see* Attachments JCL-9 and SFR Schedule C-2, page 4, column 10).

Q. IS SPECIFIC COMMISSION ACTION REQUIRED?

A. Yes. As previously stated, the owner of a nuclear power plant must request a new schedule of ruling amounts upon each renewal of the operating license of the plant from the U.S. Secretary of the Treasury. Treasury Regulation Section 1.468A-3 states that in the private letter ruling process, the applicant has the burden of proving that the proposed schedule of ruling amounts is consistent with the principles of the decommissioning fund provisions, and that it is based on reasonable assumptions. The Regulation goes on to state: "If a public utility commission established or approved the currently applicable rates for the

furnishing or sale by the taxpayer of electricity from the plant, the taxpayer can generally satisfy this burden of proof by demonstrating that the schedule of ruling amounts is calculated using the assumptions used by the public utility commission in its most recent order."

8. Annualize Payroll Expense.

Q. DID APS ANNUALIZE TEST YEAR PAYROLL?

A. Yes. This pro forma adjustment decreases Test Year expense mainly as a result of a decrease in employee levels. This pro forma adjustment annualizes the Test Year payroll and payroll tax expense to March 2011 employee and wage levels. It also reflects an estimated 1% increase in union wages that is currently under negotiation. This estimate will be updated to actual once the union negotiations are finalized. This results in an increase to pre-tax operating income of $519,000 (*see* Attachment JCL-10 and SFR Schedule C-2, page 4, column 11).

Q. DOES THIS TOTAL PAYROLL ADJUSTMENT ONLY AFFECT O&M?

A. Yes. This adjustment excludes capitalized payroll costs. This O&M adjustment was estimated by calculating the percentage of APS's O&M payroll to total payroll during the Test Year. The pro forma O&M payroll and payroll taxes were allocated to operations and maintenance based on the Test Year payroll amounts recorded for each of these activities.

9. Normalize Employee Benefits.

Q. PLEASE EXPLAIN THE NEED FOR THE EMPLOYEE BENEFIT PRO FORMA ADJUSTMENT.

A. This adjustment is necessary to appropriately recognize the costs associated with pension and Other Post-retirement Employee Benefits ("OPEB") plans, which are primarily medical benefits for eligible retirees. This adjustment is consistent with the adjustment recommended by Staff in Decision No. 69663 and used by the Company in Decision No. 71448.

Q. HOW WAS THE EMPLOYEE BENEFITS PRO FORMA ADJUSTMENT DETERMINED?

A. The total change in pension and OPEB expense is the difference between the Test Year expense and the 2011 level of that expense, as determined by our actuaries, Towers Watson. As noted below, this calculation resulted in an increase to employee benefits expense.

Q. HOW DID YOU DETERMINE THE AMOUNT OF INCREASED BENEFITS COSTS PROPERLY ALLOCABLE TO APS'S O&M?

A. An allocation factor was calculated and applied to the total change in benefit expenses. This allocation factor was determined by comparing APS's 2010 actual O&M employee benefits to the total employee benefit costs for Pinnacle West. This results in a decrease to pre-tax operating income of $8,148,000 (*see* Attachment JCL-11 and SFR Schedule C-2, page 4, column 12).

10. Normalize Income Tax Expense / Interest Synchronization.

Q. WHAT METHODOLOGY DID YOU USE TO DETERMINE THE FEDERAL AND STATE INCOME TAX PRO FORMA ADJUSTMENT?

A. The Company used a "top down" approach in computing cost-of-service income tax expense. This calculation, which was also adopted in Decision No. 69663, uses the statutory rate and estimated 2010 levels of various tax credits and other permanent tax items, reflecting the Company's best estimate of on-going income tax expense. It also considers the deduction of interest expense synchronization to the end of the Test Year's Rate Base. The total federal and state income tax pro forma increases income tax expense by $23,762,000 (*see* Attachment JCL-12 and SFR Schedule C-2, page 5, column 13).

11. Annualize Property Tax Expense.

Q. HAS APS PROPOSED AN ADJUSTMENT TO THE TEST YEAR AD VALOREM (PROPERTY) TAX?

A. Yes. An adjustment is appropriate to reflect December 31, 2010 plant values, the current state assessment ratios and the most current estimated composite tax rate.

Q. HOW WERE PROPERTY TAXES CALCULATED?

A. Property taxes were calculated using December 31, 2010 property values as filed with the Arizona Department of Revenue in April 2011. These property values were then multiplied by the most current approved assessment ratios. Finally, that assessed value is multiplied by the current estimated composite tax rate. APS will update the expected composite tax rate with the actual rate when it becomes available near the end of the third quarter of 2011. This adjustment results in a reduction to pre-tax operating income of $17,971,000 (*see* Attachment JCL-13 and SFR Schedule C-2, page 5, column 14).

12. Annualize Severance Costs.

Q. DID APS UNDERTAKE ANY PLANS TO REDUCE ITS WORKFORCE IN THE TEST YEAR?

A. Yes. From January 2010 through March of 2011, APS reduced its employee levels by approximately 260 positions through a non-voluntary severance program.

Q. HAS APS REFLECTED THE COSTS AND SAVINGS ASSOCIATED WITH THESE REDUCTIONS IN WORKFORCE?

A. Yes. The first year savings associated with the elimination of these positions will be approximately $23,446,000, of which approximately $11,475,000 will be savings to APS O&M. The remainder will be a reduction to capitalized construction costs and amounts billed to participants in jointly owned facilities.

The cost associated with severing positions through a non-voluntary severance program was approximately $10,099,000. Under GAAP, these expenses were charged to O&M in 2010. For ratemaking purposes however, the Company proposes that these expenses be amortized over a 3-year period for a yearly expense of approximately $3,366,000. This matches the cost of the employee reductions with the on-going savings. Similar amortization was requested in the Company's 2003 rate filing, but was not litigated as the case resulted in a

settlement which was approved under Decision No. 67744 (April 7, 2005). This workforce reduction results in a net increase to pre-tax operating income of $6,732,000 (*see* Attachment JCL-14 and SFR Schedule C-2, page 5, column 15).

Q. WHERE ARE THE SAVINGS RELATED TO THESE EMPLOYEE REDUCTIONS REFLECTED AS AN ADJUSTMENT TO TEST YEAR EXPENSE?

A. The Company has adjusted the Test Year as part of the "Annualize Payroll" adjustment to reflect these savings.

Q. DIDN'T APS ALSO ANNOUNCE REDUCTION IN CONTRACT EMPLOYEES AND THE ELIMINATION OF VACANT POSITIONS?

A. Yes. Contract employees were used to augment the Company's construction workforce, therefore elimination of these positions impacts post-Test Year capital construction costs but not O&M. The elimination of open positions would likewise not impact Test Year O&M because APS used only on-board employees to determine its adjustment to annualize payroll expense.

13. Amortize Childs-Irving Excess Decommissioning Costs.

Q. CAN YOU PLEASE DESCRIBE THIS PRO FORMA?

A. Yes. The decommissioning of the Childs-Irving hydroelectric power plant was completed in December 2010. The estimated cost of decommissioning this plant was collected through prior retail rates. The actual cost of decommissioning this plant was $2,678,000 less than the estimate. This pro forma reflects the Company's proposal to flow this benefit back to retail customers over a three-year period. This results in an increase to pre-tax operating income of $893,000. (*See* Attachment JCL-15 and SFR Schedule C-2, page 6, column 16).

14. Remove Schedule 3 Revenues.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE SCHEDULE 3 REVENUES?

A. Yes. Decision No. 71448 authorized APS to record the proceeds from the Company's line extension policy ("Schedule 3") as revenue during the period

from January 1, 2010 through either the earlier of December 31, 2012, or the conclusion of APS's next rate case. Thereafter, the Schedule 3 receipts will be recorded as CIAC unless the Commission orders otherwise. Because Schedule 3 proceeds were revenue in the Test Year but will not be revenue when new rates go into effect, a pro forma is needed to remove the Schedule 3 revenue recorded in the Test Year. This pro forma reduces pre-tax operating income by $18,660,000. (*See* Attachment JCL-16 and SFR Schedule C-2, page 6, column 17).

15. Normalize Fossil and Nuclear Maintenance.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMAS TO NORMALIZE NUCLEAR AND FOSSIL MAINTENANCE?

A. Yes. These pro formas adjust both planned maintenance time and unplanned outage time so that the level of maintenance expense included in the Test Year is consistent with an average year. These adjustments are necessary because outage time at each of the power plants in the Test Year for planned routine maintenance and unplanned forced outages is not indicative of the normal levels of availability. I have adjusted Test Year O&M expenses to normalize maintenance levels for the Company's production plant in service at December 31, 2010. This was done separately for the Company's nuclear facilities and its fossil facilities. The fossil generation maintenance adjustment increases pre-tax operating income by $4,397,000 and the nuclear generation maintenance adjustment decreases pre-tax operating income by $5,383,000. The O&M expense adjustments include the impacts of the outage time normalization for all of the units. (*See* Attachments JCL-17 and JCL-18 and SFR Schedule C-2, pages 6 and 7, columns 18 and 19).

Q. HOW DID YOU ADJUST THE OUTAGE TIME TO NORMALIZE THE TEST YEAR RESULTS?

A. I used two separate approaches for normalizing outage time. Planned maintenance for each generating plant is an average over the routine overhaul

cycle for the plant type. For example, the Company's coal plants are on a six-year overhaul cycle, which means that each of the coal units should experience a major overhaul once in every six-year period. The nuclear units are on an 18-month refueling cycle. Any single year, such as the Test Year, does not represent the average maintenance time and associated expense levels that can reasonably be expected when rates established in this case will be in effect.

Q. HOW DID YOU ADJUST THE MAINTENANCE EXPENSES TO NORMALIZE THE TEST YEAR RESULTS?

A. The maintenance expenses were normalized in a similar fashion to the outage time. For fossil generating units, normal maintenance levels are determined by averaging the maintenance expense at each power plant using the six-year average maintenance cycle. Normal Palo Verde expenses are based on historical expenses for a three-year period. Labor costs, including overtime costs, have been adjusted to reflect historical labor cost increases. Non-labor maintenance costs were adjusted to current cost levels using the Handy-Whitman cost indices.

16. Annualize Four Corners Coal Reclamation Costs.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE FOUR CORNERS COAL RECLAMATION COSTS?

A. Yes. This pro forma adjustment for Four Corners coal reclamation annualizes the estimate for final reclamation costs, the costs to account for growth, and the amortization period for Units 4 and 5. The estimate for final reclamation costs was revised based on a study performed by Marston as of August 2010. The estimate was increased due to the higher cost of materials and supplies, the use of dirt instead of ash filler, increased bond premiums, and higher demolition costs. The costs within this recent Marston study were presented on a 2010 dollar basis. Due to the long term nature of these costs, APS escalated the cost estimates for Units 1-3 through September 2012 and for Units 4 and 5 through June 2038. The Company also extended the amortization period for Units 4 and 5 from 2016 to

2038 in anticipation of an extended coal supply agreement with BHP Billiton. This results in a reduction to pre-tax operating income of $6,216,000 (*see* Attachment JCL-19 and SFR Schedule C-2, page 7, column 20).

Q. HOW WAS THE ESCALATION CALCULATED?

A. Total estimated costs from the Marston study were used to derive APS's share of Four Corners coal reclamation (in 2010 dollars). The reclamation costs for Units 1-3 are expected to be paid to BHP Billiton (the owner of the coal mine, who is responsible for the physical reclamation of the mine) in the third quarter of 2012 and therefore were inflated using an annual cost inflation rate of 2.5% over 1.75 years to adjust the 2010 dollar basis to the third quarter 2012. The final reclamation costs for Units 1-3 continue to be amortized through June 2016. The reclamation costs for Units 4 and 5 are inflated using an annual rate of 2.5% over 27.5 years to adjust the 2010 dollar basis to second quarter 2038, which is when the Company expects to pay this obligation. The final reclamation costs for Units 4 and 5 are amortized through June 2038.

Q. WHY IS THE ESCALATION AND AMORTIZATION PERIOD DIFFERENT FOR UNITS 1-3?

A. Due to the pending purchase of Southern California Edison's share of Units 4 and 5, APS is planning to shut down Units 1-3 if the transaction is consummated. The estimated shut down could occur as early as October 2012 The BHP Billiton coal supply agreement requires the Company to fully fund the final reclamation costs associated with these units prior to shut down. An amortization period this short would cause a significant increase to the amount recovered during this period. Therefore, the Company recommends amortizing the remaining costs over the original amortization period through June, 2016.

17. Adjust Cash Working Capital for Cost of Service Pro Formas.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO ADJUST CASH WORKING CAPITAL FOR COST OF SERVICE PRO FORMAS?

A. Yes. This is a Rate Base pro forma to adjust cash working capital to include the effects of the cost of service pro formas. As discussed earlier in my testimony, the cash working capital on SFR Schedule B-5 includes a cash working capital component determined using a lead/lag study. The expense levels in that study reflect the actual expense in the Test Year. This pro forma adjusts the study to take into consideration the cost of service pro formas which adjust actual Test Year levels of expense. This pro forma decreases Rate Base at December 31, 2010 by $14,220,000 (*see* Attachment JCL-20 and SFR Schedule B-2, page 3, column 7).

Q. ARE THERE ANY ADDITIONAL IMPACTS OF THIS RATE BASE PRO FORMA?

A. Yes. Since the Rate Base pro forma affects total Rate Base, there is a corresponding operating income pro forma necessary to reflect the income tax impacts of interest. This pro forma was calculated using the Rate Base adjustment above and the weighted cost of debt. This adjustment increases income tax expense by $165,000 (*see* Attachment JCL-21 and SFR Schedule C-2, page 7, column 21).

18. Remove PWEC Loan Amortization.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE PWEC LOAN AMORTIZATION?

A. Yes. Decision No. 65796 (April 4, 2003) authorized APS to issue non-secured debt in an amount up to $500 million and loan the proceeds to PWEC. That decision also required APS to charge PWEC a 2.64 percent interest premium, and defer that premium as long as the loan was outstanding. The loan was outstanding through April 2005 when the loan was repaid. In Decision No. 67744, the Commission ordered the Company to amortize the portion of the

premium deferred through December 31, 2004 over a five year period beginning April 1, 2005. The portion of the premium deferred after December 31, 2004 was ordered to be amortized over a five-year period beginning July 1, 2007. This pro forma removes both amortization amounts from the Test Year, since both will be fully amortized when new rates are expected to go into effect. This results in a reduction to pre-tax operating income of $2,107,000 (*see* Attachment JCL-22 and SFR Schedule C-2, page 8, column 22).

19. Amortize Pension and OPEB Deferral.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT TO AMORTIZE PENSION AND OPEB DEFERRAL?

A. Yes. Commission Decision No. 71448 allowed the Company to defer for future recovery a portion of its Pension and OPEB costs above or below the Test Year level ($23,949,000 in the prior case) in years 2011 and 2012, subject to the following limitations:

a. In 2011; the deferral cannot exceed the lower of $13,500,000 or 50% of the cost above the Test Year level (any amounts over $27,000,000 cannot be deferred); and

b. In 2012; the deferral cannot exceed $29,000,000 of the cost above Test Year level.

Using the 2011 level of expense as determined by our actuaries, Towers Watson, for both 2011 and 2012 deferral calculations, APS estimates a deferral balance of $26,219,000 at the time new retail rates are expected to go into effect (July 1, 2012). The Company proposes to recover this deferral balance over a three-year period. This adjustment results in a decrease to pre-tax operating income of $8,740,000 (*see* Attachment JCL-23 and SFR Schedule C-2, page 8, column 23).

20. Normalize Pole Attachment Revenues.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT TO NORMALIZE POLE ATTACHMENT REVENUES?

A. Yes. In April 2011, the U.S. Federal Communications Commission ("FCC") voted to revamp nationwide rules governing how broadband providers can attach their lines to utility poles, with the goal of making it faster and easier to deploy new service in underserved areas.

The FCC voted unanimously for the new pole-attachment rules, which require electric utilities to allow most broadband services to attach lines to poles within 148 days of a request, with a deadline of 178 days for putting wireless broadband antennas on top of utility poles. Pole owners, which also include some telecom providers, would have an extra 60 days for requests involving large numbers of poles.

The new rules also require pole owners to give all broadband providers the same pole attachment rate as other telecom carriers. This has the impact of lowering APS's other revenues, which are an offset to the Company's cost of service. This pro forma adjustment takes into consideration the new rates and lowers pre-tax operating income by $305,000 (*see* Attachment JCL-24 and SFR Schedule C-2, page 8, column 24).

21. Remove Supplemental Executive Retirement Plan Benefits.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN BENEFITS?

A. Yes. As discussed by APS witness Jeff Guldner, the Company proposes to remove the Test Year level of expense associated with the Supplemental Executive Retirement Plan Benefits ("SERP"). This results in an increase to pre-tax operating income of $8,492,000 (*see* Attachment JCL-25 and SFR Schedule C-2, page 9, column 25).

22. Remove Stock Compensation.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE STOCK COMPENSATION?

A. Yes. Also discussed by APS witness Jeff Guldner, the Company proposes to remove the Test Year level of expense associated with stock compensation. This results in an increase to pre-tax operating income of $12,421,000 (*see* Attachment JCL-26 and SFR Schedule C-2, page 9, column 26).

23. Remove Out of Period and Miscellaneous Items.

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE MISCELLANEOUS AND OUT OF PERIOD ITEMS?

A. Yes. In any Test Year, there are bound to be some items recorded that relate to periods other than the Test Year, or conversely, items recorded in other time periods that correctly belong in the Test Year. This adjustment, for the sake of simplicity, combines several smaller entries that fit this description. They are shown in aggregate in the pro forma. This adjustment results in a decrease to pre-tax operating income of $7,471,000 (*see* Attachment JCL-27 and SFR Schedule C-2, page 9, column 27).

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. No.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 1
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Remove Bark Beetle Remediation Amortization**
Adjustments to Test Year operations to remove 6-months of deferred bark beetle costs as authorized in Decision No. 69663.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	(1,918)
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	(1,918)
10.	**Operating Income (before income tax)**	**1,918**
11.	Current Income Tax Rate - 39.51%	758
12.	**Operating Income After Tax**	**$ 1,160**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 2
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Remove Test Year Surcharges and Adjustors**
Adjustment to Test Year operations to remove the Renewable Energy Standard, Competition Rules Compliance Charge, Demand Side Management Adjustment Clause, Transmission Cost Adjustor and Regulatory Assessment surcharges from both operating revenues and expenses.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	(192,761)
3.	Other electric revenue	-
4.	Total electric operating revenues	(192,761)
	Operating Expenses	
5.	Electric fuel and purchased power	(8,201)
6.	Operations and maintenance excluding fuel expenses	(177,253)
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	(185,454)
10.	**Operating Income (before income tax)**	**(7,307)**
11.	Current Income Tax Rate - 39.51%	(2,887)
12.	**Operating Income After Tax**	**$ (4,420)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 1, column 2
Total Company
(Thousands of Dollars)

Proforma Adjustment: **West Phoenix Unit 4 Regulatory Disallowance**
Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decision Nos. 67744 and 69663.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ (13,833)
2.	Less: Accumulated Depreciation and Amortization	(3,635)
3.	Net Utility Plant in Service	(10,198)
4.	Less:Total Deductions	(1,469)
5.	Total Additions	-
6.	**Total Rate Base**	**$ (8,729)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 3
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **West Phoenix Unit 4 Regulatory Disallowance**
Adjustments to Test Year operations to reflect depreciation of regulatory disallowance of West Phoenix Unit 4.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	(329)
8.	Other taxes	-
9.	Total Operating Expenses	(329)
10.	**Operating Income (before income tax)**	**329**
11.	Interest Expense	(257)
12.	Taxable Income	586
13.	Current Income Tax Rate - 39.51%	232
14.	**Operating Income After Tax**	**$ 97**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 2, column 4
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Interest Expense on Customer Deposits**
Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits using January 2011 interest rates.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	197
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	197
10.	**Operating Income (before income tax)**	**(197)**
11.	Current Income Tax Rate - 39.51%	(78)
12.	**Operating Income After Tax**	**$ (119)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 2, column 5
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Depreciation Expense - 2010 Study**
Adjustment to Test Year operations to reflect depreciation expense based on the 2010 depreciation study.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	28,646
8.	Other taxes	-
9.	Total Operating Expenses	28,646
10.	**Operating Income (before income tax)**	**(28,646)**
11.	Current Income Tax Rate - 39.51%	(11,318)
12.	**Operating Income After Tax**	**$ (17,328)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, pages 1 and 2, columns 3-6
Total Company
(Thousands of Dollars)

Pro forma Adjustment: **Post-Test Year Plant Additions**
Adjustment to Test Year rate base to include Post Test Year Plant Additions with an estimated in service date prior to 6/30/2012.

Line No.	Description	Solar Generation	Fossil Generation	Nuclear Generation	Distribution and General and Intangible	Total Company Amount
1.	Gross Utility Plant in Service	$ 277,411	$ 156,269	$ 120,103	$ 432,984	$ 986,767
2.	Less: Accumulated Depreciation and Amortization	5,799	133,240	95,937	269,239	504,215
3.	Net Utility Plant in Service	271,612	23,029	24,166	163,745	482,552
4.	Less: Total Deductions	3,979	12,583	29,329	4,412	50,303
5.	Total Additions	-				-
6.	**Total Rate Base**	**$ 267,633**	**$ 10,446**	**$ (5,163)**	**$ 159,333**	**$ 432,249**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, pages 2 and 3, columns 6-9
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Post-Test Year Plant Additions**
Adjustment to Test Year operations to include depreciation, interest expense and property taxes associated with Post-Test Year Plant Additions.

Line No.	Description	Solar Generation	Fossil Generation	Nuclear Generation	Distribution and General and Intangible	Total Company Amount
	Electric Operating Revenues					
1.	Revenues in base rates	$ -	$ -	$ -	$ -	$ -
2.	Surcharge revenue	-	-	-	-	-
3.	Other electric revenue	-	-	-	-	-
4.	Total electric operating revenues	-	-	-	-	-
	Operating Expenses					
5.	Electric fuel and purchased power	-	-	-	-	-
6.	Operations and maintenance excluding fuel expenses	1,785	-	-	-	1,785
7.	Depreciation and amortization	9,405	4,245	1,729	13,847	29,226
8.	Administrative and General	217	-	-	-	217
9.	Other taxes	978	950	735	7,669	10,332
10.	Total Operating Expenses	12,385	5,195	2,464	21,516	41,560
11.	**Operating Income (before income tax)**	**(12,385)**	**(5,195)**	**(2,464)**	**(21,516)**	**(41,560)**
12.	Interest Expense	7,868	307	(152)	4,684	12,707
13.	Taxable Income	(20,253)	(5,502)	(2,312)	(26,200)	(54,267)
14.	Current Income Tax Rate - 39.51%	(8,002)	(2,174)	(913)	(10,352)	(21,441)
15.	**Operating Income After Tax**	**$ (4,383)**	**$ (3,021)**	**$ (1,551)**	**$ (11,164)**	**$ (20,119)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 10
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Decommissioning and Spent Fuel Costs
Adjustment to Test Year operations to reflect udated decommissioning and spent fuel funding levels for Palo Verde due to license extension and updated study costs.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	(4,236)
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	(2,947)
8.	Other taxes	-
9.	Total Operating Expenses	(7,183)
10.	**Operating Income (before income tax)**	**7,183**
11.	Current Income Tax Rate - 39.51%	2,838
12.	**Operating Income After Tax**	**$ 4,345**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 11
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Annualize Payroll Expense
Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2011 employee levels for performance review and Union employees.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
5.		
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	(519)
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	(519)
10.	**Operating Income (before income tax)**	**519**
11.	Current Income Tax Rate - 39.51%	205
12.	**Operating Income After Tax**	**$ 314**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 12
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Normalize Employee Benefits**
Adjustment to Test Year operations to reflect the current December 2010 actuarial valuation of retirement program expenses.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	8,148
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	8,148
10.	**Operating Income (before income tax)**	**(8,148)**
11.	Current Income Tax Rate - 39.51%	(3,219)
12.	**Operating Income After Tax**	**$ (4,929)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 13
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Normalize Income Tax Expense/Interest Synchronization**
Adjustment to Test Year operations for top down income tax true-ups consistent with Decision Nos. 69663 and 71448 using the 12/31/2010 rate base and cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.

Line No.	Description	Total Company Amount
1.	Operating Income	$ -
2.	Interest and Other Net Deductions	(60,142)
3.	**Taxable Income**	**60,142**
4.	**Income Tax @ 39.51%**	**23,762**
5.	Deferred Tax	-
6.	**Net Income**	**$ (23,762)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 14
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Annualize Property Tax Expense
Adjustment to Test Year operations to annualize property taxes calculated using the 2011 anticipated tax assessment ratio and tax rate.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	17,971
9.	Total Operating Expenses	17,971
10.	**Operating Income (before income tax)**	**(17,971)**
11.	Current Income Tax Rate - 39.51%	(7,100)
12.	**Operating Income After Tax**	**$ (10,871)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 15
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Annualize Severance Costs**
Adjustment to Test Year operations to amortize the expense associated with employees severed in 2010 over a three year period.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	(6,732)
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	(6,732)
10.	**Operating Income (before income tax)**	**6,732**
11.	Current Income Tax Rate - 39.51%	2,660
12.	**Operating Income After Tax**	**$ 4,072**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 16
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Amortize Childs-Irving Excess Decommissioning Costs**
Adjustment to amortize the excess decommissioning costs for the Childs Irving Power Plant over a three year period.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	(893)
8.	Other taxes	-
9.	Total Operating Expenses	(893)
10.	**Operating Income (before income tax)**	**893**
11.	Current Income Tax Rate - 39.51%	353
12.	**Operating Income After Tax**	**$ 540**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 17
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Remove Schedule 3 Revenues**
Adjustment to remove revenues associated with Schedule 3 (line extensation policy) in the Test Year.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	(18,660)
4.	Total electric operating revenues	(18,660)
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	-
10.	**Operating Income (before income tax)**	**(18,660)**
11.	Current Income Tax Rate - 39.51%	(7,373)
12.	**Operating Income After Tax**	**$ (11,287)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 18
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Normalize Fossil Maintenance**
Adjustment to Test Year operations to reflect normalization of fossil production maintenance expense.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	(4,397)
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	(4,397)
10.	**Operating Income (before income tax)**	**4,397**
11.	Current Income Tax Rate - 39.51%	1,737
12.	**Operating Income After Tax**	**$ 2,660**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 19
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Normalize Nuclear Maintenance**
Adjustment to Test Year operations to reflect normalization of nuclear production maintenance expense.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	5,383
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	5,383
10.	**Operating Income (before income tax)**	**(5,383)**
11.	Current Income Tax Rate - 39.51%	(2,127)
12.	**Operating Income After Tax**	**$ (3,256)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 20
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Annualize Four Corners Coal Reclamation Costs
Adjustment to Test Year operations to reflect most recent Four Corners coal reclamation study.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	6,216
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	-
8.	Other taxes	-
9.	Total Operating Expenses	6,216
10.	**Operating Income (before income tax)**	**(6,216)**
11.	Current Income Tax Rate - 39.51%	(2,456)
12.	**Operating Income After Tax**	**$ (3,760)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 3, column 7
Total Company
(Thousands of Dollars)

Pro forma Adjustment: **Adjust Cash Working Capital for Cost of Service Pro Formas**
Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	-
4.	Less:Total Deductions	-
5.	Total Additions	(14,220)
6.	**Total Rate Base**	**$ (14,220)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 21
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Adjust Cash Working Capital for Cost of Service Pro Formas**
Adjustments to Test Year interest expense for cash working capital rate base pro forma adjustment.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	-
7.	Depreciation and amortization	
8.	Other taxes	-
9.	Total Operating Expenses	-
10.	**Operating Income (before income tax)**	-
11.	Interest Expense	(418)
12.	Taxable Income	418
13.	Current Income Tax Rate - 39.51%	165
14.	**Operating Income After Tax**	**$ (165)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 22
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Remove PWEC Loan Amortization and Interest**
Adjustment to Test Year operations to remove PWEC loan amortization and interest authorized in Decision Nos. 65796 and 67744.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	2,107
7.	Depreciation and amortization	-
10.	Other taxes	-
11.	Total Operating Expenses	2,107
12.	**Operating Income (before income tax)**	**(2,107)**
13.	Current Income Tax Rate - 39.51%	(832)
14.	**Operating Income After Tax**	**$ (1,275)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 23
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Amortize Pension/OPEB Deferral**
Adjustment to Test Year operations to reflect the recovery of the Pension/OPEB deferral authorized in Decision No. 71448 to be amortized over a three year period.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	8,740
7.	Depreciation and amortization	-
8,	Other taxes	-
9,	Total Operating Expenses	8,740
10,	**Operating Income (before income tax)**	**(8,740)**
11,	Current Income Tax Rate - 39.51%	(3,453)
12,	**Operating Income After Tax**	**$ (5,287)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 24
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Normalize Pole Attachment Revenues**
Adjustment to Test Year Other Electric Revenues to reflect change in FCC rules impacting pole attachment fees.

Line No.	Description	Total Company Amount
	Revenues	
1.	Revenues in Base Rates	$ -
2.	Surcharge Revenue	-
3.	Other Electric Revenue	(305)
4.	Total Electric Operating Revenues	(305)
	Other Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	
7.	Depreciation and amortization	
8.	Income taxes	-
9.	Other taxes	
10.	Total Operating Expenses	-
11.	**Operating Income (before income tax)**	**(305)**
12.	Current Income Tax Rate - 39.51%	(121)
13.	**Operating Income After Tax**	**$ (184)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 25
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Remove Supplemental Executive Retirement Plan Benefits**
Adjustment to Test Year operations to remove supplemental executive retirement benefits ("SERP").

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	(8,492)
7.	Depreciation and amortization	
8.	Other taxes	
9.	Total Operating Expenses	(8,492)
10.	**Operating Income (before income tax)**	**8,492**
11.	Current Income Tax Rate - 39.51%	3,355
12.	**Operating Income After Tax**	**$ 5,137**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 26
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Remove Stock Compensation**
Adjustment to Test Year operations to remove stock compensation.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ -
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	-
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	(12,421)
7.	Depreciation and amortization	
8.	Other taxes	
9.	Total Operating Expenses	(12,421)
10.	**Operating Income (before income tax)**	**12,421**
11.	Current Income Tax Rate - 39.51%	4,908
12.	**Operating Income After Tax**	**$ 7,513**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 27
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Remove Miscellaneous and Out of Period Items
Adjustment to Test Year operations to remove legal accrual reserve, bad debt reversal accrual, grant reserve, benchmark study costs, branding costs and non-recurring payroll expense.

Line No.	Description	Total Company Amount
	Electric Operating Revenues	
1.	Revenues in base rates	$ (7,000)
2.	Surcharge revenue	-
3.	Other electric revenue	-
4.	Total electric operating revenues	(7,000)
	Operating Expenses	
5.	Electric fuel and purchased power	-
6.	Operations and maintenance excluding fuel expenses	3,000
7.	Depreciation and amortization	-
8.	Administrative and General	(2,529)
9.	Other taxes	-
10.	Total Operating Expenses	471
11.	**Operating Income (before income tax)**	**(7,471)**
12.	Current Income Tax Rate - 39.51%	(2,952)
13.	**Operating Income After Tax**	**$ (4,519)**

Ronald E. White

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E–01345A–11–XXXX

June 2011

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DIRECT TESTIMONY
OF
DR. RONALD E. WHITE
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-XXXX

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am Chairman and a Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member

of the American Economic Association, the Financial Management Association, the Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979 as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty jurisdictions, including several appearances in Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communications Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Attachment REW–1.

II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by Arizona Public Service Company (APS or Company) to conduct a 2011 depreciation rate study for plant subject to the jurisdiction of the Arizona Corporation Commission (ACC). The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates. Depreciation rates currently used by APS were approved by the ACC pursuant to a settlement agreement in Docket No. E–01345A–08–0172. (Decision No. 71448, dated December 30, 2009).

III. DEVELOPMENT OF DEPRECIATION RATES

Q. WOULD YOU PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regula-

tion, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. It can be shown that, given the same financing requirements and the same dividend payout ratio, an increase in internal cash generation will accelerate per–share growth in earnings, dividends, and book value over the business life of a firm. Financial theory provides that the marginal cost of external financing will be reduced by these enhanced measurements of financial performance. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. WHAT ARE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors which should be considered are the age of plant retirements, the portion of retirements that will be reused, changes in the method of removing plant, the type of plant to be retired in the future, inflation expectations, the shape of the projection life curve, and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements

that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

IV. 2011 Depreciation Rate Study

Q. DID APS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2011 DEPRECIATION STUDY?

A. Yes. Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1971 through 2010. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The database used in conducting the 2008 study in Docket No. E–01345A–08–0172.was updated for the current study by appending additional plant and net salvage transactions for activity years 2008–2010 and age distributions of surviving plant at December 31, 2010. The accuracy and completeness of the assembled database was verified for activity years 2008 through 2010 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2008 were verified in the 2008 study. Age distributions of surviving plant at December 31, 2010 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2010 were used in the 2011 study to derive appropriate net salvage rates. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR APS PLANT AND EQUIPMENT?

A. Yes. As discussed in Attachment REW–2, all plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function can be expressed as a survivorship function, which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category. Plant accounts classified in Steam, Nuclear and Other Production were identified by unit and treated as life–span categories in the 2011 study.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR APS PLANT AND EQUIPMENT?

A. Yes. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2011 study for transmission, distribution and general plant categories to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate.

Future net salvage rates for steam production facilities were adjusted and approved in Docket No. E–01345A–05–0816 et al. for estimated terminal dismantlement costs based on costs per kW derived in dismantling studies conducted in 2002

for the Navajo and Four Corners generating stations. This treatment was retained in the 2008 study and approved in Decision No. 71448. APS subsequently retained an independent contractor to develop a cost estimate for the demolition and abatement of the Four Corners Generating Station. The estimated cost at December 31, 2009 for dismantling Four Corners and a cost $40 per kW estimated for all other steam generating stations were used in the current depreciation study to formulate average and future net salvage rates.[1]

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Statement C of Attachment REW–2 provides a comparison of APS recorded, computed and redistributed reserves at December 31, 2010. The recorded reserve was $4,209,736,678 or 38.2 percent of the depreciable plant investment. The corresponding computed reserve is $3,367,619,454 or 30.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $842,117,224 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study. Statement D of Attachment REW–2 provides an estimate of the investment and net salvage components of the rebalanced reserves.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES FOR APS?

A. Yes. It is the opinion of Foster Associates that a redistribution of recorded reserves is again appropriate for APS. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

[1] A cost of $39 per kW for Navajo and $40 per kW for all other steam generating stations was approved in Decision No. 71448. An estimated cost of $40 per kW was used for Navajo in the current study to establish consistency with other plant units.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserves (net of amortizable accounts) to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

Q. DID FOSTER ASSOCIATES CONSIDER THE ANTICIPATED PURCHASE OF FOUR CORNERS UNITS 4 & 5 AND THE SUBSEQUENT SHUTDOWN OF UNITS 1–3 IN REBALANCING RESERVES FOR STEAM PRODUCTION PLANTS?

A. Yes. Rebalanced reserves for Units 1–3 were set equal to computed reserves derived from a 2012 estimated year of shutdown. Estimated dismantlement costs for Units 1–3 were added to the estimated dismantlement costs for Units 4 & 5 and reserves were rebalanced over all steam production units. This treatment marginally increases the unrecovered investment of plant units other than Four Corners and allocates the unrecovered investment of Units 1–3 over the longer estimated average remaining lives of other steam units.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR APS.

A. Current depreciation rates were developed for each primary account using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique.

The formulation of an account accrual rate using the currently approved system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where both the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR APS?

A. No. Depreciation rates recommended in the 2008 study for all depreciable plant categories were derived from a system composed of the straight–line method, vintage group procedure, remaining–life technique. This change in procedure from broad group to vintage group was recommended by Foster Associates (and approved by the ACC) to more nearly achieve the goals and objectives of depreciation accounting.

Depreciation rates recommended in the 2011 study were developed using the currently approved system. It is the opinion of Foster Associates that this system will remain appropriate for APS, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern. It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS FOSTER ASSOCIATES IS RECOMMENDING FOR APS IN THE 2011 STUDY.

A. Table 2 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended in the 2011 depreciation study.

	Accrual Rate			2011 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.35%	2.84%	-0.51%	$59,943,328	$50,825,171	($9,118,157)
Nuclear	2.77%	1.44%	-1.33%	72,235,832	37,539,055	(34,696,777)
Other	3.00%	2.62%	-0.38%	43,949,098	38,279,711	(5,669,387)
Transmission	2.27%	2.40%	0.13%	2,337,578	2,477,081	139,503
Distribution	2.26%	2.37%	0.11%	104,066,081	109,307,181	5,241,100
General Plant	5.25%	5.90%	0.65%	22,836,498	25,639,197	2,802,699
Total	2.77%	2.40%	-0.37%	$305,368,415	$264,067,396	($41,301,019)

Table 2. Current and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.40 percent. Depreciation expense is currently accrued at rates that composite to 2.77 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.37 percentage points.

A continued application of current rates would provide annualized depreciation expense of $305,368,415 compared with an annualized expense of $264,067,396 using the rates developed in this study. The proposed 2011 expense reduction is $41,301,019. The computed change in annualized accruals includes a reduction of $62,327,472 attributable to an amortization of a $842,117,224 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2011 study.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

2007 - Present Foster Associates, Inc.
Chairman

1996 - 2007 Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Testifying Witness

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public

Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company;

testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing how third–party reimbursements should be recorded and treated in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light

Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for

conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power

Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

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Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee.

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

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Speaker

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

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Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

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Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

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The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

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An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Attachment REW–2

2011 Depreciation Rate Study

aps

Arizona Public Service Company

Prepared by
Foster Associates, Inc.

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EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for utility plant owned and operated by Arizona Public Service Company (APS). The report contains recommended 2011 depreciation rates and parameters for: a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. Work on the study commenced in January 2011 and progressed through April, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers, Florida office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by APS were approved by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–08–0172. (Decision No. 71448, dated December 30, 2009). With the exception of Account 370.01 (Meters – Electronic), parameters (*i.e.*, projection curves, projection lives and future net salvage rates used to derive the approved rates were developed in the Company's 2008 depreciation study.[1] The Decision further provided that "... upon the later date of receiving Nuclear Regulatory Commission approval for the Palo Verde license extension or January 1, 2012, APS is authorized to adjust depreciation rates used for recording depreciation expense on the Palo Verde generating unit to reflect such license extension, and APS shall file a request to adjust the System Benefit Charge ('SBC') to reflect the corresponding reduction in the decommissioning trust funding obligations. APS is also required to provide a depreciation rate study in its next rate case"[2]

The principal findings and recommendations developed in the current study

[1] The settlement agreement provided that the prior approved rate of 3.68 percent would be retained for Account 370.01 rather than adopting the Company's proposed five–year amortization.
[2] Docket No. E–01345A–08–0172, Decision No. 71448, §XI, p. 10.

are summarized in Section IV of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides a computation of the estimated future net salvage rate for steam production facilities. Statement G contains the computation of terminal dismantlement costs for steam production facilities. Statement H provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains current and proposed statistics including average service life, average remaining life, and average net salvage rates.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Field visits and discussions with APS operations and plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been approved, APS is currently using a depreciation system composed of the straight–line method, vintage group procedure, remain-

ing–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

Proposed Depreciation Rates

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the current study.

	Accrual Rate			2011 Annualized Accrual		
Function	Current	Proposed	Diff.	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.35%	2.84%	-0.51%	$59,943,328	$50,825,171	($9,118,157)
Nuclear	2.77%	1.44%	-1.33%	72,235,832	37,539,055	(34,696,777)
Other	3.00%	2.62%	-0.38%	43,949,098	38,279,711	(5,669,387)
Transmission	2.27%	2.40%	0.13%	2,337,578	2,477,081	139,503
Distribution	2.26%	2.37%	0.11%	104,066,081	109,307,181	5,241,100
General Plant	5.25%	5.90%	0.65%	22,836,498	25,639,197	2,802,699
Total	2.77%	2.40%	-0.37%	$305,368,415	$264,067,396	($41,301,019)

Table 1. Current and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.40 percent. Depreciation expense is currently accrued at rates that composite to 2.77 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.37 percentage points.

A continued application of current rates would provide annualized depreciation expense of $305,368,415 compared with an annualized expense of

$264,067,396 using the rates developed in this study. The proposed 2011 expense reduction is $41,301,019. The computed change in annualized accruals includes a reduction of $62,327,472 attributable to an amortization of a $842,117,224 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2011 study.

Of the 170 plant accounts included in the 2011 study, Foster Associates is recommending rate reductions for 97 accounts and rate increases for 73 accounts.

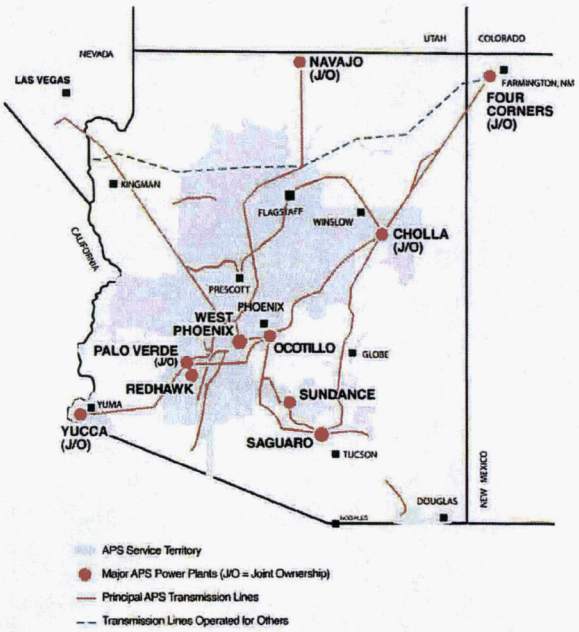
COMPANY PROFILE

GENERAL

Arizona Public Service Company is the largest subsidiary of Pinnacle West Capital Corporation. APS provides electric service to more than 1.1 million customers in 11 of Arizona's 15 counties.

Incorporated in 1920 under the laws of the state of Arizona, APS employs more than 6,600 employees, including employees at jointly–owned generating facilities for which APS serves as the generating facility manager.

In addition to the Palo Verde Nuclear Generating Station, APS owns and operates six natural–gas plants, one oil plant, two coal–fired plants, and an increasing array of renewable energy power generation.



APS has built an infrastructure consisting of more than 30,000 miles of transmission and distribution lines and 400 substations.

GENERATING RESOURCES

The Palo Verde Nuclear Generating Station is owned by a consortium of seven utilities in the Southwest and is operated by APS. Its three units are capable of generating nearly 4,000 megawatts of electricity. APS owns or leases 29.1 percent of the plant.

The five–unit, 2060 megawatt Four Corners Power Plant, located on the Navajo Indian Reservation, is owned by APS and five other utilities in the Southwest. The plant is operated by APS and fueled by low–sulfur coal from the nearby Navajo mine.

The 1027 megawatt Cholla Power Plant is located in northeastern Arizona. APS operates the plant and owns Units 1, 2 and 3, which are capable of producing 647 megawatts of electricity. PacifiCorp owns the 380 megawatt Unit 4. Cholla is fueled by coal from the McKinley Mine in New Mexico.

The Navajo Power Plant is located in northern Arizona on the Navajo Indian Reservation near Page. The plant's three 750 megawatt coal–fueled, steam–electric generating units are owned by a partnership of five utility companies and

the U.S. Bureau of Reclamation. APS owns 14 percent of the plant, which is operated by Salt River Project.

The Redhawk Power Station, which began operating in mid–2002, is comprised of two identical 492 megawatt natural gas–fueled combined–cycle units. The plant is owned and operated by APS.

The natural gas–fueled West Phoenix Power Plant has seven generating units: two combustion turbine units and five units that employ combined–cycle technology. Owned and operated by APS, West Phoenix generates about 950 megawatts of electricity.

Ocotillo is a natural gas–fueled Power Plant owned and operated by APS. Located in Tempe, Arizona, the plant has two steam and two combustion turbine units that are capable of generating about 330 megawatts.

The natural gas–fueled Saguaro Power Plant, located north of Tucson, has two steam units and three combustion turbine units. APS owns and operates all five of the generating units that have a combined capacity of about 395 megawatts available to the APS system.

Sundance Generating Station in Coolidge, Arizona is the newest member of the APS fleet. APS purchased the 420 megawatt station in the spring of 2005. The simple–cycle, natural gas–fueled station consists of 10 quick–start combustion turbines.

APS operates the natural gas–fueled Yucca Power Plant located near Yuma in southwestern Arizona. The Company owns six combustion turbine units that produce nearly 243 megawatts for APS customers.

APS has one oil–only power plant, Douglas, located in the town of Douglas, Arizona with a 16 megawatt capacity.

Since 1996, APS has completed a number of solar projects around the state. The current capacity of their solar plants is about five megawatts.

Transmission and Distribution Facilities

Transmission facilities consist of approximately 5,992 pole miles of overhead lines and approximately 49 miles of underground lines, 5,769 miles of which are located in Arizona. APS shares ownership of some of its transmission facilities with other companies.

Distribution facilities consist of approximately 11,098 miles of overhead lines and approximately 17,417 miles of underground primary cable, all of which are located in Arizona.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation rates used by APS for its steam, nuclear, other production, transmission, distribution and general plant categories. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2011 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribu-

tion to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by APS provides aged transactions for all plant accounts.

Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1971 through 2010. Detailed accounting transactions were extracted from the CPR system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The database used in conducting the 2008 study was updated for the current study by appending additional plant and net salvage transactions for activity years 2008–2010 and age distributions of surviving plant at December 31, 2010. The accuracy and completeness of the assembled database was verified for activity years 2008 through 2010 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2008 were verified in the 2008 study. Age distributions of surviving plant at December 31, 2010 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2010 were used in the 2011 study to derive appropriate net salvage rates. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the ex-

pected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2011 APS depreciation study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival func-

tions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), the concept of retirement dispersion is interpreted differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts classified in Steam, Nuclear and Other Production were identified by unit and treated as life–span

categories in the 2011 study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Future net salvage rates for steam production facilities were adjusted and approved in Docket No. E–01345A–05–0816 et al. for estimated terminal dismantlement costs based on costs per kW derived in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. This treatment was retained and approved in the 2008 study. APS subsequently retained an independent contractor to develop a cost estimate for the demolition and abatement of the Four Corners Generating Station. The estimated cost at December 31, 2009 for dismantling Four Corners and the prior approved cost of $40 per kW estimated for all other steam generating stations were used in the current depreciation study to formulate average and future net salvage rates.[2] Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for steam production facilities. The distinction between average and future net salvage rates is shown in Statement E.

[2] A cost of $39 per kW for Navajo and $40 per kW for all other steam generating stations was approved in Decision No. 71448. An estimated cost of $40 per kW was used for Navajo in the current study to establish consistency with other plant units.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2011 study for transmission, distribution and general plant categories to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of estimated average net salvage rates is shown in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be

identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is again appropriate for APS. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current study) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserves (net of amortizable accounts) to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2010. The recorded reserve was $4,209,736,678 or 38.2 percent of the depreciable plant investment. The corresponding computed reserve is $3,367,619,454 or 30.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $842,117,224 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Statement D provides an estimate of the investment and net salvage components of the rebalanced reserves.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not alter the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2011 study were developed using the currently approved system composed of the straight–line method, vintage group procedure, remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that this system will remain appropriate for APS, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the

straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate these plant categories.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage parameters recommended for a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2011 depreciation accruals based upon the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2010.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a computation of the estimated future net salvage rate for steam production facilities.
- Statement G contains the computation of terminal dismantlement costs for steam production facilities.
- Statement H provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by the Company for the mix of investments recorded on December 31, 2010. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	3.15%	0.39%	3.54%	2.33%	0.27%	2.60%
312.00 Boiler Plant Equipment	2.95%	0.39%	3.34%	2.48%	0.35%	2.83%
314.00 Turbogenerator Units	2.93%	0.38%	3.31%	2.69%	0.35%	3.04%
315.00 Accessory Electric Equipment	2.47%	0.32%	2.79%	2.29%	0.27%	2.56%
316.00 Miscellaneous Power Plant Equipment	3.81%	0.58%	4.39%	3.01%	0.41%	3.42%
Total Steam Production Plant	2.96%	0.39%	3.35%	2.50%	0.34%	2.84%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	2.63%	0.01%	2.64%	1.33%	0.01%	1.34%
322.00 Reactor Plant Equipment	2.84%	0.05%	2.89%	1.50%	0.05%	1.55%
323.00 Turbogenerator Units	2.75%	0.01%	2.76%	1.44%	0.02%	1.46%
324.00 Accessory Electric Equipment	2.54%	0.01%	2.55%	1.19%	0.01%	1.20%
325.00 Miscellaneous Power Plant Equipment	2.88%	0.04%	2.92%	1.47%	0.04%	1.51%
Total Nuclear Production Plant	2.74%	0.03%	2.77%	1.41%	0.03%	1.44%
OTHER PRODUCTION						
341.00 Structures and Improvements	2.67%	0.23%	2.90%	2.89%	-0.13%	2.76%
342.00 Fuel Holders, Products and Accessories	3.04%	0.15%	3.19%	3.09%	-0.14%	2.95%
343.00 Prime Movers	2.61%	0.09%	2.70%	2.57%	-0.10%	2.47%
344.00 Generators and Devices	3.21%	0.14%	3.35%	3.32%	-0.60%	2.72%
345.00 Accessory Electric Equipment	2.79%	0.13%	2.92%	2.74%	-0.12%	2.62%
346.00 Miscellaneous Power Plant Equipment	2.92%	0.15%	3.07%	3.35%	-0.15%	3.20%
Total Other Production Plant	2.88%	0.12%	3.00%	2.92%	-0.30%	2.62%
TRANSMISSION PLANT						
352.02 Structures and Improvements	2.45%		2.45%	2.67%		2.67%
353.00 Station Equipment	2.29%		2.29%	2.31%	0.11%	2.42%
354.00 Towers and Fixtures	1.78%		1.78%	1.84%		1.84%
355.00 Poles and Fixtures	2.03%	0.40%	2.43%	1.86%	0.37%	2.23%
356.00 Overhead Conductors and Devices	1.72%	-0.33%	1.39%	1.75%	0.33%	2.08%
Total Transmission Plant	2.27%		2.27%	2.29%	0.11%	2.40%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.51%	0.06%	1.57%	1.57%	0.07%	1.64%
362.00 Station Equipment	2.16%	-0.21%	1.95%	2.19%	-0.20%	1.99%
364.01 Poles, Towers and Fixtures - Wood	2.26%	-0.04%	2.22%	2.29%	-0.02%	2.27%
364.02 Poles, Towers and Fixtures - Steel	2.75%	0.16%	2.91%	2.55%	0.26%	2.81%
365.00 Overhead Conductors and Devices	1.89%	-0.19%	1.70%	1.98%	-0.08%	1.90%
366.00 Underground Conduit	1.46%	0.07%	1.53%	1.57%	0.08%	1.65%
367.00 Underground Conductors and Devices	2.76%	0.10%	2.86%	2.63%	0.09%	2.72%
368.00 Line Transformers	1.66%	0.07%	1.73%	1.68%	0.07%	1.75%
369.00 Services	2.20%		2.20%	2.20%	0.10%	2.30%
370.01 Meters - Electronic	3.68%		3.68%	6.24%	-0.03%	6.21%
370.03 Meters - AMI	3.82%		3.82%	6.53%		6.53%
371.00 Installations on Customers' Premises	1.75%	0.19%	1.94%	2.34%	0.34%	2.68%
373.00 Street Lighting and Signal Systems	1.47%	0.13%	1.60%	1.72%	0.13%	1.85%
Total Distribution Plant	2.23%	0.03%	2.26%	2.32%	0.05%	2.37%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.05%	0.11%	2.16%	2.19%	0.13%	2.32%
391.CM Office Furn. and Equip. - Computer	10.19%	0.01%	10.20%	12.08%	0.02%	12.10%
397.00 Communication Equipment	4.72%		4.72%	5.35%		5.35%
Total Depreciable	5.29%	0.04%	5.33%	6.09%	0.05%	6.14%
Amortizable						
391.FE Office Furn. and Equip. - Furniture	← 20 Year Amortization →			← 20 Year Amortization →		
393.00 Stores Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
395.00 Laboratory Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
398.00 Miscellaneous Equipment	← 24 Year Amortization →			← 24 Year Amortization →		
Total Amortizable	4.94%		4.94%	4.93%	-0.02%	4.91%
Total General Plant	5.22%	0.03%	5.25%	5.86%	0.04%	5.90%
TOTAL UTILITY	2.67%	0.10%	2.77%	2.35%	0.05%	2.40%
STEAM PRODUCTION (by Unit)						
Cholla						
311.00 Structures and Improvements	1.63%	0.18%	1.81%	2.87%	0.14%	3.01%
312.00 Boiler Plant Equipment	1.97%	0.23%	2.20%	3.23%	0.23%	3.46%
314.00 Turbogenerator Units	2.21%	0.21%	2.42%	3.38%	0.17%	3.55%
315.00 Accessory Electric Equipment	1.67%	0.18%	1.85%	2.44%	0.13%	2.57%
316.00 Miscellaneous Power Plant Equipment	2.29%	0.27%	2.56%	3.11%	0.20%	3.31%
Total Cholla	1.95%	0.22%	2.17%	3.13%	0.20%	3.33%
Cholla Unit 1						
311.00 Structures and Improvements	2.29%	0.20%	2.49%	3.60%	0.17%	3.77%
312.00 Boiler Plant Equipment	3.61%	0.37%	3.98%	4.22%	0.26%	4.48%
314.00 Turbogenerator Units	1.44%	0.13%	1.57%	4.59%	0.24%	4.83%
315.00 Accessory Electric Equipment	2.50%	0.24%	2.74%	3.65%	0.19%	3.84%
316.00 Miscellaneous Power Plant Equipment	2.15%	0.21%	2.36%	3.45%	0.19%	3.64%
Total Cholla Unit 1	2.95%	0.30%	3.25%	4.22%	0.24%	4.46%
Cholla Unit 2						
311.00 Structures and Improvements	2.02%	0.19%	2.21%	2.81%	0.15%	2.96%
312.00 Boiler Plant Equipment	1.62%	0.17%	1.79%	2.51%	0.17%	2.68%
314.00 Turbogenerator Units	2.21%	0.19%	2.40%	3.11%	0.17%	3.28%
315.00 Accessory Electric Equipment	1.50%	0.14%	1.64%	2.30%	0.13%	2.43%
316.00 Miscellaneous Power Plant Equipment	2.06%	0.21%	2.27%	3.25%	0.20%	3.45%
Total Cholla Unit 2	1.72%	0.17%	1.89%	2.60%	0.17%	2.77%
Cholla Unit 3						
311.00 Structures and Improvements	1.54%	0.19%	1.73%	2.19%	0.10%	2.29%
312.00 Boiler Plant Equipment	1.67%	0.22%	1.89%	3.40%	0.25%	3.65%
314.00 Turbogenerator Units	2.57%	0.27%	2.84%	3.04%	0.15%	3.19%
315.00 Accessory Electric Equipment	1.55%	0.20%	1.75%	2.16%	0.12%	2.28%
316.00 Miscellaneous Power Plant Equipment	2.00%	0.27%	2.27%	2.48%	0.15%	2.63%
Total Cholla Unit 3	1.81%	0.23%	2.04%	3.17%	0.22%	3.39%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Cholla Common						
311.00 Structures and Improvements	1.55%	0.17%	1.72%	2.94%	0.15%	3.09%
312.00 Boiler Plant Equipment	2.07%	0.29%	2.36%	3.32%	0.25%	3.57%
314.00 Turbogenerator Units	2.20%	0.13%	2.33%	2.67%	0.13%	2.80%
315.00 Accessory Electric Equipment	2.22%	0.26%	2.48%	2.96%	0.18%	3.14%
316.00 Miscellaneous Power Plant Equipment	2.60%	0.33%	2.93%	3.16%	0.22%	3.38%
Total Cholla Common	1.92%	0.24%	2.16%	3.13%	0.20%	3.33%
Four Corners						
311.00 Structures and Improvements	5.32%	0.63%	5.95%	0.68%	0.36%	1.04%
312.00 Boiler Plant Equipment	4.42%	0.58%	5.00%	0.81%	0.51%	1.32%
314.00 Turbogenerator Units	4.73%	0.55%	5.28%	0.82%	0.49%	1.31%
315.00 Accessory Electric Equipment	4.18%	0.52%	4.70%	0.92%	0.49%	1.41%
316.00 Miscellaneous Power Plant Equipment	5.49%	0.74%	6.23%	1.37%	0.47%	1.84%
Total Four Corners	4.58%	0.58%	5.16%	0.83%	0.49%	1.32%
Four Corners Units 1-3						
311.00 Structures and Improvements	6.56%	0.73%	7.29%			
312.00 Boiler Plant Equipment	5.81%	0.71%	6.52%			
314.00 Turbogenerator Units	5.90%	0.64%	6.54%			
315.00 Accessory Electric Equipment	5.43%	0.61%	6.04%			
316.00 Miscellaneous Power Plant Equipment	8.65%	1.02%	9.67%			
Total Four Corners Units 1-3	5.97%	0.71%	6.68%			
Four Corners Units 4-5						
311.00 Structures and Improvements	2.12%	0.35%	2.47%	2.36%	1.56%	3.92%
312.00 Boiler Plant Equipment	1.80%	0.32%	2.12%	2.32%	1.54%	3.86%
314.00 Turbogenerator Units	2.21%	0.36%	2.57%	2.68%	1.68%	4.36%
315.00 Accessory Electric Equipment	1.96%	0.33%	2.29%	2.34%	1.52%	3.86%
316.00 Miscellaneous Power Plant Equipment	2.21%	0.38%	2.59%	2.51%	1.65%	4.16%
Total Four Corners Units 4-5	1.89%	0.33%	2.22%	2.37%	1.56%	3.93%
Four Corners Common						
311.00 Structures and Improvements	2.79%	0.46%	3.25%	2.23%	0.48%	2.71%
312.00 Boiler Plant Equipment	2.71%	0.48%	3.19%	2.09%	0.49%	2.58%
314.00 Turbogenerator Units	2.20%	0.32%	2.52%	1.65%	0.28%	1.93%
315.00 Accessory Electric Equipment	2.95%	0.49%	3.44%	2.39%	0.53%	2.92%
316.00 Miscellaneous Power Plant Equipment	3.09%	0.54%	3.63%	2.50%	0.58%	3.08%
Total Four Corners Common	2.83%	0.49%	3.32%	2.24%	0.50%	2.74%
Navajo Units 1-3						
311.00 Structures and Improvements	2.63%	0.27%	2.90%	3.34%	0.24%	3.58%
312.00 Boiler Plant Equipment	2.80%	0.32%	3.12%	3.42%	0.28%	3.70%
314.00 Turbogenerator Units	2.06%	0.22%	2.28%	2.71%	0.20%	2.91%
315.00 Accessory Electric Equipment	2.19%	0.24%	2.43%	2.93%	0.21%	3.14%
316.00 Miscellaneous Power Plant Equipment	3.22%	0.36%	3.58%	3.75%	0.29%	4.04%
Total Navajo Units 1-3	2.69%	0.30%	2.99%	3.32%	0.27%	3.59%
Ocotillo Units 1-2						
311.00 Structures and Improvements	3.59%	1.02%	4.61%	4.91%	0.88%	5.79%
312.00 Boiler Plant Equipment	2.83%	0.85%	3.68%	3.41%	0.65%	4.06%
314.00 Turbogenerator Units	2.64%	0.79%	3.43%	4.74%	0.88%	5.62%
315.00 Accessory Electric Equipment	3.12%	0.91%	4.03%	4.55%	0.84%	5.39%
316.00 Miscellaneous Power Plant Equipment	5.26%	1.52%	6.78%	5.80%	1.10%	6.90%
Total Ocotillo Units 1-2	3.09%	0.91%	4.00%	4.29%	0.80%	5.09%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro Units 1-2						
311.00 Structures and Improvements	2.81%	0.80%	3.61%	5.51%	1.01%	6.52%
312.00 Boiler Plant Equipment	2.47%	0.71%	3.18%	4.40%	0.84%	5.24%
314.00 Turbogenerator Units	2.04%	0.59%	2.63%	3.30%	0.61%	3.91%
315.00 Accessory Electric Equipment	4.27%	1.23%	5.50%	5.65%	1.05%	6.70%
316.00 Miscellaneous Power Plant Equipment	3.95%	1.16%	5.11%	5.11%	0.96%	6.07%
Total Saguaro Units 1-2	2.67%	0.77%	3.44%	4.35%	0.82%	5.17%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	2.63%	0.01%	2.64%	1.33%	0.01%	1.34%
322.00 Reactor Plant Equipment	2.84%	0.05%	2.89%	1.50%	0.05%	1.55%
323.00 Turbogenerator Units	2.75%	0.01%	2.76%	1.44%	0.02%	1.46%
324.00 Accessory Electric Equipment	2.54%	0.01%	2.55%	1.19%	0.01%	1.20%
325.00 Miscellaneous Power Plant Equipment	2.88%	0.04%	2.92%	1.47%	0.04%	1.51%
Total Palo Verde	2.74%	0.03%	2.77%	1.41%	0.03%	1.44%
Palo Verde Unit 1						
321.00 Structures and Improvements	2.66%	0.01%	2.67%	1.13%		1.13%
322.00 Reactor Plant Equipment	3.16%	0.04%	3.20%	1.45%	0.04%	1.49%
323.00 Turbogenerator Units	3.01%	0.01%	3.02%	1.41%	0.02%	1.43%
324.00 Accessory Electric Equipment	2.64%	0.01%	2.65%	1.11%	0.01%	1.12%
325.00 Miscellaneous Power Plant Equipment	2.86%	0.03%	2.89%	1.29%	0.02%	1.31%
Total Palo Verde Unit 1	2.97%	0.03%	3.00%	1.34%	0.02%	1.36%
Palo Verde Unit 2						
321.00 Structures and Improvements	2.66%	0.01%	2.67%	1.20%	0.01%	1.21%
322.00 Reactor Plant Equipment	3.09%	0.08%	3.17%	1.52%	0.08%	1.60%
323.00 Turbogenerator Units	2.93%	0.02%	2.95%	1.41%	0.01%	1.42%
324.00 Accessory Electric Equipment	2.69%	0.01%	2.70%	1.25%	0.01%	1.26%
325.00 Miscellaneous Power Plant Equipment	3.05%	0.02%	3.07%	1.45%	0.02%	1.47%
Total Palo Verde Unit 2	2.94%	0.05%	2.99%	1.41%	0.04%	1.45%
Palo Verde Unit 3						
321.00 Structures and Improvements	2.34%		2.34%	1.22%		1.22%
322.00 Reactor Plant Equipment	2.38%	0.05%	2.43%	1.56%	0.05%	1.61%
323.00 Turbogenerator Units	2.42%	0.01%	2.43%	1.48%	0.02%	1.50%
324.00 Accessory Electric Equipment	2.34%	0.01%	2.35%	1.24%	0.01%	1.25%
325.00 Miscellaneous Power Plant Equipment	2.51%	0.02%	2.53%	1.36%	0.02%	1.38%
Total Palo Verde Unit 3	2.38%	0.03%	2.41%	1.44%	0.03%	1.47%
Palo Verde Water Reclamation						
321.00 Structures and Improvements	2.84%	0.02%	2.86%	1.69%	0.02%	1.71%
322.00 Reactor Plant Equipment	3.93%	0.03%	3.96%	2.01%	0.03%	2.04%
323.00 Turbogenerator Units	2.85%	0.02%	2.87%	1.45%	0.01%	1.46%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	2.83%	0.05%	2.88%	1.43%	0.05%	1.48%
Total Palo Verde Water Reclamation	2.84%	0.02%	2.86%	1.69%	0.02%	1.71%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Palo Verde Common						
321.00 Structures and Improvements	2.64%	0.02%	2.66%	1.30%	0.02%	1.32%
322.00 Reactor Plant Equipment	2.48%	0.08%	2.56%	1.22%	0.06%	1.28%
323.00 Turbogenerator Units	4.38%	0.06%	4.44%	2.15%	0.04%	2.19%
324.00 Accessory Electric Equipment	2.51%	0.01%	2.52%	1.21%	0.01%	1.22%
325.00 Miscellaneous Power Plant Equipment	2.99%	0.06%	3.05%	1.64%	0.06%	1.70%
Total Palo Verde Common	2.72%	0.04%	2.76%	1.38%	0.03%	1.41%
OTHER PRODUCTION (by Unit)						
Douglas CT						
341.00 Structures and Improvements	5.94%	0.29%	6.23%	5.13%	-0.26%	4.87%
342.00 Fuel Holders, Products and Accessories	1.82%	0.06%	1.88%	0.90%	-0.01%	0.89%
343.00 Prime Movers	0.73%	0.04%	0.77%	-0.25%	0.02%	-0.23%
344.00 Generators and Devices	0.70%	0.03%	0.73%	-0.28%	0.01%	-0.27%
345.00 Accessory Electric Equipment	0.98%	0.07%	1.05%	0.02%	0.02%	0.04%
346.00 Miscellaneous Power Plant Equipment	1.65%	0.08%	1.73%	0.70%	-0.03%	0.67%
Total Douglas CT	0.96%	0.05%	1.01%	-0.01%	0.01%	
Ocotillo CT Units 1-2						
341.00 Structures and Improvements	2.02%	0.10%	2.12%	4.19%	-0.20%	3.99%
342.00 Fuel Holders, Products and Accessories	1.93%	0.09%	2.02%	2.07%	-0.10%	1.97%
343.00 Prime Movers	1.26%	0.06%	1.32%	0.73%	-0.03%	0.70%
344.00 Generators and Devices	3.26%	0.13%	3.39%	3.44%	-0.61%	2.83%
345.00 Accessory Electric Equipment	1.68%	0.10%	1.78%	1.60%	-0.06%	1.54%
346.00 Miscellaneous Power Plant Equipment	1.77%	0.08%	1.85%	2.14%	-0.09%	2.05%
Total Octillo CT Units 1-2	2.22%	0.10%	2.32%	2.21%	-0.29%	1.92%
Redhawk CC Units 1-2						
341.00 Structures and Improvements	3.01%	0.42%	3.43%	3.13%	-0.12%	3.01%
342.00 Fuel Holders, Products and Accessories	3.46%	0.17%	3.63%	3.63%	-0.18%	3.45%
343.00 Prime Movers	2.98%	0.07%	3.05%	3.11%	-0.08%	3.03%
344.00 Generators and Devices	3.02%	0.12%	3.14%	3.33%	-0.83%	2.50%
345.00 Accessory Electric Equipment	2.99%	0.12%	3.11%	3.11%	-0.10%	3.01%
346.00 Miscellaneous Power Plant Equipment	3.27%	0.17%	3.44%	3.60%	-0.18%	3.42%
Total Redhawk CC Units 1-2	3.01%	0.12%	3.13%	3.24%	-0.50%	2.74%
Saguaro						
341.00 Structures and Improvements	3.82%	0.19%	4.01%	4.60%	-0.22%	4.38%
342.00 Fuel Holders, Products and Accessories	1.62%	0.07%	1.69%	1.27%	-0.03%	1.24%
343.00 Prime Movers	1.38%	0.07%	1.45%	0.63%	-0.03%	0.60%
344.00 Generators and Devices	3.10%	0.15%	3.25%	2.92%	-0.19%	2.73%
345.00 Accessory Electric Equipment	1.35%	0.08%	1.43%	0.63%	-0.02%	0.61%
346.00 Miscellaneous Power Plant Equipment	3.20%	0.16%	3.36%	2.57%	-0.12%	2.45%
Total Saguaro	2.71%	0.13%	2.84%	2.43%	-0.15%	2.28%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	3.82%	0.19%	4.01%	4.60%	-0.22%	4.38%
342.00 Fuel Holders, Products and Accessories	1.62%	0.07%	1.69%	1.27%	-0.03%	1.24%
343.00 Prime Movers	1.25%	0.06%	1.31%	0.45%	-0.02%	0.43%
344.00 Generators and Devices	4.08%	0.18%	4.26%	3.36%	-0.52%	2.84%
345.00 Accessory Electric Equipment	1.23%	0.07%	1.30%	0.46%	-0.01%	0.45%
346.00 Miscellaneous Power Plant Equipment	3.20%	0.16%	3.36%	2.57%	-0.12%	2.45%
Total Saguaro CT Units 1-2	2.33%	0.11%	2.44%	1.76%	-0.17%	1.59%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.94%	0.15%	3.09%	2.85%	-0.14%	2.71%
344.00 Generators and Devices	2.94%	0.15%	3.09%	2.85%	-0.14%	2.71%
345.00 Accessory Electric Equipment	2.94%	0.15%	3.09%	2.85%	-0.14%	2.71%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	2.94%	0.15%	3.09%	2.85%	-0.14%	2.71%
Solar Units						
341.00 Structures and Improvements	0.52%	0.02%	0.54%	-3.55%	0.20%	-3.35%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	5.59%	0.31%	5.90%	3.93%	-0.86%	3.07%
345.00 Accessory Electric Equipment	5.36%	0.27%	5.63%	7.41%	-0.37%	7.04%
346.00 Miscellaneous Power Plant Equipment						
Total Solar Units	5.46%	0.30%	5.76%	3.90%	-0.82%	3.08%
Sundance						
341.00 Structures and Improvements	2.21%	0.11%	2.32%	2.06%	-0.10%	1.96%
342.00 Fuel Holders, Products and Accessories	2.19%	0.11%	2.30%	2.05%	-0.10%	1.95%
343.00 Prime Movers	2.20%	0.11%	2.31%	2.04%	-0.11%	1.93%
344.00 Generators and Devices	3.02%	0.15%	3.17%	2.51%	-0.13%	2.38%
345.00 Accessory Electric Equipment	2.19%	0.11%	2.30%	2.05%	-0.10%	1.95%
346.00 Miscellaneous Power Plant Equipment	2.19%	0.11%	2.30%	2.49%	-0.12%	2.37%
Total Sun Dance	2.20%	0.11%	2.31%	2.05%	-0.11%	1.94%
West Phoenix						
341.00 Structures and Improvements	2.54%	0.15%	2.69%	3.04%	-0.14%	2.90%
342.00 Fuel Holders, Products and Accessories	3.53%	0.18%	3.71%	3.69%	-0.17%	3.52%
343.00 Prime Movers	2.97%	0.12%	3.09%	2.89%	-0.10%	2.79%
344.00 Generators and Devices	3.32%	0.15%	3.47%	3.38%	-0.37%	3.01%
345.00 Accessory Electric Equipment	3.31%	0.16%	3.47%	3.36%	-0.15%	3.21%
346.00 Miscellaneous Power Plant Equipment	3.08%	0.16%	3.24%	3.95%	-0.17%	3.78%
Total West Phoenix	3.17%	0.14%	3.31%	3.23%	-0.25%	2.98%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	4.01%	0.19%	4.20%	5.00%	-0.24%	4.76%
342.00 Fuel Holders, Products and Accessories	3.75%	0.19%	3.94%	4.02%	-0.18%	3.84%
343.00 Prime Movers						
344.00 Generators and Devices	3.83%	0.16%	3.99%	4.08%	-0.65%	3.43%
345.00 Accessory Electric Equipment	3.77%	0.18%	3.95%	4.01%	-0.15%	3.86%
346.00 Miscellaneous Power Plant Equipment	2.98%	0.16%	3.14%	4.17%	-0.18%	3.99%
Total West Phoenix CC Units 1-3	3.78%	0.17%	3.95%	4.08%	-0.50%	3.58%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	3.04%	0.15%	3.19%	3.05%	-0.15%	2.90%
342.00 Fuel Holders, Products and Accessories	2.98%	0.15%	3.13%	2.98%	-0.15%	2.83%
343.00 Prime Movers	2.98%	0.15%	3.13%	2.98%	-0.15%	2.83%
344.00 Generators and Devices	3.02%	0.16%	3.18%	3.07%	-0.30%	2.77%
345.00 Accessory Electric Equipment	3.25%	0.16%	3.41%	3.57%	-0.18%	3.39%
346.00 Miscellaneous Power Plant Equipment	3.19%	0.16%	3.35%	3.72%	-0.17%	3.55%
Total West Phoenix CC Unit 4	3.00%	0.15%	3.15%	3.02%	-0.18%	2.84%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2010) Investment	Net Salvage	Total	Proposed (at 12/31/2010) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
West Phoenix CC Unit 5						
341.00 Structures and Improvements	3.02%	0.16%	3.18%	2.92%	-0.15%	2.77%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	3.06%	0.10%	3.16%	3.01%	-0.08%	2.93%
344.00 Generators and Devices	3.03%	0.15%	3.18%	2.97%	-0.19%	2.78%
345.00 Accessory Electric Equipment	3.02%	0.15%	3.17%	2.91%	-0.15%	2.76%
346.00 Miscellaneous Power Plant Equipment	3.18%	0.16%	3.34%	3.40%	-0.17%	3.23%
Total West Phoenix CC Unit 5	3.04%	0.13%	3.17%	2.98%	-0.14%	2.84%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	1.36%	0.07%	1.43%	3.80%	-0.19%	3.61%
342.00 Fuel Holders, Products and Accessories	1.57%	0.08%	1.65%	0.61%	-0.03%	0.58%
343.00 Prime Movers	1.95%	0.08%	2.03%	1.00%	-0.03%	0.97%
344.00 Generators and Devices	2.48%	0.13%	2.61%	2.25%	-0.21%	2.04%
345.00 Accessory Electric Equipment	1.83%	0.10%	1.93%	0.95%	-0.04%	0.91%
346.00 Miscellaneous Power Plant Equipment	3.46%	0.17%	3.63%	3.25%	-0.16%	3.09%
Total West Phoenix CT Units 1-2	2.11%	0.10%	2.21%	1.55%	-0.09%	1.46%
West Phoenix Common						
341.00 Structures and Improvements	1.59%	0.13%	1.72%	2.76%	-0.12%	2.64%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total West Phoenix Common	1.59%	0.13%	1.72%	2.76%	-0.12%	2.64%
Yucca						
341.00 Structures and Improvements	3.31%	0.12%	3.43%	2.50%	-0.10%	2.40%
342.00 Fuel Holders, Products and Accessories	1.41%	0.03%	1.44%	1.00%	-0.05%	0.95%
343.00 Prime Movers	2.50%		2.50%	2.65%	-0.13%	2.52%
344.00 Generators and Devices	2.61%	0.12%	2.73%	1.28%	-0.24%	1.04%
345.00 Accessory Electric Equipment	2.41%	0.11%	2.52%	1.03%	-0.04%	0.99%
346.00 Miscellaneous Power Plant Equipment	2.37%	0.11%	2.48%	1.11%	-0.06%	1.05%
Total Yucca	2.46%	0.02%	2.48%	2.38%	-0.13%	2.25%
Yucca CT Units 1-4						
341.00 Structures and Improvements	3.58%	0.17%	3.75%	2.29%	-0.08%	2.21%
342.00 Fuel Holders, Products and Accessories	0.81%	0.04%	0.85%	0.11%		0.11%
343.00 Prime Movers	0.58%	0.03%	0.61%	-0.09%		-0.09%
344.00 Generators and Devices	2.61%	0.12%	2.73%	1.27%	-0.24%	1.03%
345.00 Accessory Electric Equipment	2.36%	0.13%	2.49%	0.75%	-0.03%	0.72%
346.00 Miscellaneous Power Plant Equipment	2.37%	0.11%	2.48%	1.11%	-0.06%	1.05%
Total Yucca CT Units 1-4	1.69%	0.08%	1.77%	0.64%	-0.09%	0.55%
Yucca CT Units 5-6						
341.00 Structures and Improvements	2.72%		2.72%	2.97%	-0.15%	2.82%
342.00 Fuel Holders, Products and Accessories	2.72%		2.72%	2.97%	-0.15%	2.82%
343.00 Prime Movers	2.72%		2.72%	2.97%	-0.15%	2.82%
344.00 Generators and Devices	2.72%		2.72%	2.97%	-0.15%	2.82%
345.00 Accessory Electric Equipment	2.72%		2.72%	2.97%	-0.15%	2.82%
346.00 Miscellaneous Power Plant Equipment	2.72%		2.72%			
Total Yucca CT Units 5-6	2.72%		2.72%	2.97%	-0.15%	2.82%

ARIZONA PUBLIC SERVICE COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION								
311.00 Structures and Improvements	$168,068,708	$5,299,006	$650,659	$5,949,665	$3,907,814	$468,971	$4,376,785	($1,572,880)
312.00 Boiler Plant Equipment	1,114,508,323	32,896,330	4,318,033	37,214,363	27,592,917	3,922,683	31,515,600	(5,698,763)
314.00 Turbogenerator Units	260,287,212	7,625,434	981,350	8,606,784	7,012,405	909,063	7,921,468	(685,316)
315.00 Accessory Electric Equipment	164,350,445	4,059,821	528,092	4,587,913	3,758,257	454,941	4,213,198	(374,715)
316.00 Miscellaneous Power Plant Equipment	81,726,740	3,110,985	473,618	3,584,603	2,460,131	337,989	2,798,120	(786,483)
Total Steam Production Plant	$1,788,941,428	$52,991,576	$6,951,752	$59,943,328	$44,731,524	$6,093,647	$50,825,171	($9,118,157)
NUCLEAR PRODUCTION								
321.00 Structures and Improvements	$698,846,801	$18,352,868	$82,295	$18,435,163	$9,265,673	$66,624	$9,332,297	($9,102,866)
322.00 Reactor Plant Equipment	1,130,933,859	32,152,405	598,662	32,751,067	16,955,122	593,091	17,548,213	(15,202,854)
323.00 Turbogenerator Units	354,174,138	9,754,391	44,384	9,798,775	5,113,500	63,385	5,176,885	(4,621,890)
324.00 Accessory Electric Equipment	275,016,677	6,987,700	27,502	7,015,202	3,260,068	27,502	3,287,570	(3,727,632)
325.00 Miscellaneous Power Plant Equipment	145,211,312	4,180,067	55,558	4,235,625	2,141,613	52,477	2,194,090	(2,041,535)
Total Nuclear Production Plant	$2,604,182,787	$71,427,431	$808,401	$72,235,832	$36,735,976	$803,079	$37,539,055	($34,696,777)
OTHER PRODUCTION								
341.00 Structures and Improvements	$67,262,184	$1,796,973	$154,270	$1,951,243	$1,943,435	($86,365)	$1,857,070	($94,173)
342.00 Fuel Holders, Products and Accessories	42,179,346	1,284,039	62,466	1,346,505	1,305,027	(59,713)	1,245,314	(101,191)
343.00 Prime Movers	664,641,919	17,360,793	579,944	17,940,737	17,097,476	(667,083)	16,430,393	(1,510,344)
344.00 Generators and Devices	588,169,993	18,909,096	830,642	19,739,738	19,503,087	(3,490,611)	16,012,476	(3,727,262)
345.00 Accessory Electric Equipment	86,274,192	2,405,635	112,836	2,518,471	2,361,735	(97,652)	2,264,083	(254,388)
346.00 Miscellaneous Power Plant Equipment	14,711,421	430,245	22,159	452,404	493,373	(22,998)	470,375	17,971
Total Other Production Plant	$1,463,239,055	$42,186,781	$1,762,317	$43,949,098	$42,704,133	($4,424,422)	$38,279,711	($5,669,387)
TRANSMISSION PLANT								
352.02 Structures and Improvements	$95,935	$2,350		$2,350	$2,561		$2,561	$211
353.00 Station Equipment	98,305,656	2,251,200		2,251,200	2,270,861	108,136	2,378,997	127,797
354.00 Towers and Fixtures	1,329,316	23,662		23,662	24,459		24,459	797
355.00 Poles and Fixtures	1,370,085	27,813	5,480	33,293	25,484	5,069	30,553	(2,740)
356.00 Overhead Conductors and Devices	1,947,677	33,500	(6,427)	27,073	34,084	6,427	40,511	13,438
Total Transmission Plant	$103,048,669	$2,338,525	($947)	$2,337,578	$2,357,449	$119,632	$2,477,081	$139,503
DISTRIBUTION PLANT								
361.00 Structures and Improvements	$60,888,680	$919,419	$36,533	$955,952	$955,952	$42,622	$998,574	$42,622
362.00 Station Equipment	406,799,985	8,786,880	(854,280)	7,932,600	8,908,920	(813,600)	8,095,320	162,720
364.01 Poles, Towers and Fixtures - Wood	310,263,864	7,011,963	(124,106)	6,887,857	7,105,042	(62,053)	7,042,989	155,132
364.02 Poles, Towers and Fixtures - Steel	167,311,767	4,601,074	267,699	4,868,773	4,266,450	435,011	4,701,461	(167,312)
365.00 Overhead Conductors and Devices	292,642,985	5,530,952	(556,022)	4,974,930	5,794,331	(234,114)	5,560,217	585,287
366.00 Underground Conduit	620,488,170	9,059,127	434,342	9,493,469	9,741,664	496,391	10,238,055	744,586
367.00 Underground Conductors and Devices	1,422,708,502	39,266,755	1,422,709	40,689,464	37,417,234	1,280,438	38,697,672	(1,991,792)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
368.00 Line Transformers	717,419,840	11,909,169	502,194	12,411,363	12,052,653	502,194	12,554,847	143,484
369.00 Services	323,341,677	7,113,517		7,113,517	7,113,517	323,342	7,436,859	323,342
370.01 Meters - Electronic	62,207,543	2,289,238		2,289,238	3,881,751	(18,662)	3,863,089	1,573,851
370.03 Meters - AMI	117,715,566	4,496,735		4,496,735	7,686,826		7,686,826	3,190,091
371.00 Installations on Customers' Premises	39,842,142	697,237	75,700	772,937	932,306	135,463	1,067,769	294,832
373.00 Street Lighting and Signal Systems	73,702,827	1,083,432	95,814	1,179,246	1,267,689	95,814	1,363,503	184,257
Total Distribution Plant	$4,615,333,548	$102,765,498	$1,300,583	$104,066,081	$107,124,335	$2,182,846	$109,307,181	$5,241,100
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$107,643,854	$2,206,699	$118,408	$2,325,107	$2,357,400	$139,937	$2,497,337	$172,230
391.CM Office Furn. and Equip. - Computer	89,098,127	9,079,099	8,910	9,088,009	10,763,054	17,820	10,780,874	1,692,865
397.00 Communication Equipment	152,910,098	7,217,357		7,217,357	8,180,690		8,180,690	963,333
Total Depreciable	$349,652,079	$18,503,155	$127,318	$18,630,473	$21,301,144	$157,757	$21,458,901	$2,828,428
Amortizable								
391.FE Office Furn. and Equip. - Furniture	$49,130,094	$2,456,505		$2,456,505	$2,455,941		$2,455,941	($564)
393.00 Stores Equipment	256,764	12,838		12,838	12,838		12,838	
394.00 Tools, Shop and Garage Equipment	28,424,012	1,421,201		1,421,201	1,406,986		1,406,986	(14,215)
395.00 Laboratory Equipment	1,385,366	69,268		69,268	58,318		58,318	(10,950)
398.00 Miscellaneous Equipment	5,909,111	246,213		246,213	246,213		246,213	
Total Amortizable	$85,105,347	$4,206,025		$4,206,025	$4,180,296		$4,180,296	($25,729)
Total General Plant	$434,757,426	$22,709,180	$127,318	$22,836,498	$25,481,440	$157,757	$25,639,197	$2,802,699
TOTAL UTILITY	$11,009,502,913	$294,418,991	$10,949,424	$305,368,415	$259,134,857	$4,932,539	$264,067,396	($41,301,019)
STEAM PRODUCTION (by Unit)								
Cholla								
311.00 Structures and Improvements	$72,335,187	$1,181,541	$127,512	$1,309,053	$2,072,612	$104,385	$2,176,997	$867,944
312.00 Boiler Plant Equipment	521,789,973	10,285,829	1,217,328	11,503,157	16,849,982	1,181,937	18,031,919	6,528,762
314.00 Turbogenerator Units	125,558,183	2,774,769	266,509	3,041,278	4,241,938	220,063	4,462,001	1,420,723
315.00 Accessory Electric Equipment	93,701,286	1,565,151	167,928	1,733,079	2,282,053	127,889	2,409,942	676,863
316.00 Miscellaneous Power Plant Equipment	27,985,746	640,239	75,733	715,972	869,191	55,760	924,951	208,979
Total Cholla	$841,370,375	$16,447,529	$1,855,010	$18,302,539	$26,315,776	$1,690,034	$28,005,810	$9,703,271

ARIZONA PUBLIC SERVICE COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Cholla Unit 1								
311.00 Structures and Improvements	$4,372,274	$100,125	$8,745	$108,870	$157,402	$7,433	$164,835	$55,965
312.00 Boiler Plant Equipment	73,213,804	2,643,018	270,891	2,913,909	3,089,623	190,356	3,279,979	366,070
314.00 Turbogenerator Units	25,640,590	369,224	33,333	402,557	1,176,903	61,537	1,238,440	835,883
315.00 Accessory Electric Equipment	8,816,493	220,412	21,160	241,572	321,802	16,751	338,553	96,981
316.00 Miscellaneous Power Plant Equipment	2,838,727	61,033	5,961	66,994	97,936	5,394	103,330	36,336
Total Cholla Unit 1	$114,881,888	$3,393,812	$340,090	$3,733,902	$4,843,666	$281,471	$5,125,137	$1,391,235
Cholla Unit 2								
311.00 Structures and Improvements	$6,168,012	$124,594	$11,719	$136,313	$173,321	$9,252	$182,573	$46,260
312.00 Boiler Plant Equipment	162,323,693	2,629,644	275,950	2,905,594	4,074,325	275,950	4,350,275	1,444,681
314.00 Turbogenerator Units	44,157,763	975,887	83,900	1,059,787	1,373,306	75,068	1,448,374	388,587
315.00 Accessory Electric Equipment	46,110,434	691,657	64,555	756,212	1,060,540	59,944	1,120,484	364,272
316.00 Miscellaneous Power Plant Equipment	8,714,396	179,517	18,300	197,817	283,218	17,429	300,647	102,830
Total Cholla Unit 2	$267,474,298	$4,601,299	$454,424	$5,055,723	$6,964,710	$437,643	$7,402,353	$2,346,630
Cholla Unit 3								
311.00 Structures and Improvements	$9,984,226	$153,757	$18,970	$172,727	$218,655	$9,984	$228,639	$55,912
312.00 Boiler Plant Equipment	228,064,943	3,808,685	501,743	4,310,428	7,754,208	570,162	8,324,370	4,013,942
314.00 Turbogenerator Units	54,849,058	1,409,621	148,092	1,557,713	1,667,411	82,274	1,749,685	191,972
315.00 Accessory Electric Equipment	31,001,286	480,520	62,003	542,523	669,628	37,202	706,830	164,307
316.00 Miscellaneous Power Plant Equipment	4,593,291	91,866	12,402	104,268	113,914	6,890	120,804	16,536
Total Cholla Unit 3	$328,492,804	$5,944,449	$743,210	$6,687,659	$10,423,816	$706,512	$11,130,328	$4,442,669
Cholla Common								
311.00 Structures and Improvements	$51,810,675	$803,065	$88,078	$891,143	$1,523,234	$77,716	$1,600,950	$709,807
312.00 Boiler Plant Equipment	58,187,533	1,204,482	168,744	1,373,226	1,931,826	145,469	2,077,295	704,069
314.00 Turbogenerator Units	910,772	20,037	1,184	21,221	24,318	1,184	25,502	4,281
315.00 Accessory Electric Equipment	7,773,073	172,562	20,210	192,772	230,083	13,992	244,075	51,303
316.00 Miscellaneous Power Plant Equipment	11,839,332	307,823	39,070	346,893	374,123	26,047	400,170	53,277
Total Cholla Common	$130,521,385	$2,507,969	$317,286	$2,825,255	$4,083,584	$264,408	$4,347,992	$1,522,737
Four Corners								
311.00 Structures and Improvements	$57,549,016	$3,059,759	$361,500	$3,421,259	$391,557	$209,285	$600,842	($2,820,417)
312.00 Boiler Plant Equipment	375,402,116	16,604,192	2,169,866	18,774,058	3,057,517	1,892,823	4,950,340	(13,823,718)
314.00 Turbogenerator Units	73,354,578	3,472,716	403,796	3,876,512	600,509	361,446	961,955	(2,914,557)
315.00 Accessory Electric Equipment	40,063,953	1,675,100	207,694	1,882,794	370,390	193,629	564,019	(1,318,775)
316.00 Miscellaneous Power Plant Equipment	25,722,887	1,411,061	189,065	1,600,126	352,051	120,272	472,323	(1,127,803)
Total Four Corners	$572,092,550	$26,222,828	$3,331,921	$29,554,749	$4,772,024	$2,777,455	$7,549,479	($22,005,270)

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Four Corners Units 1-3								
311.00 Structures and Improvements	$40,683,091	$2,668,811	$296,987	$2,965,798				($2,965,798)
312.00 Boiler Plant Equipment	242,101,914	14,066,121	1,718,924	15,785,045				(15,785,045)
314.00 Turbogenerator Units	50,183,693	2,960,838	321,176	3,282,014				(3,282,014)
315.00 Accessory Electric Equipment	24,333,485	1,321,308	148,434	1,469,742				(1,469,742)
316.00 Miscellaneous Power Plant Equipment	11,655,314	1,008,185	118,884	1,127,069				(1,127,069)
Total Four Corners Units 1-3	$368,957,497	$22,025,263	$2,604,405	$24,629,668				($24,629,668)
Four Corners Units 4-5								
311.00 *Structures and Improvements*	*$11,882,266*	*$251,904*	*$41,588*	*$293,492*	*$280,421*	*$185,363*	*$465,784*	*$172,292*
312.00 Boiler Plant Equipment	118,062,055	2,125,117	377,799	2,502,916	2,739,040	1,818,156	4,557,196	2,054,280
314.00 Turbogenerator Units	21,183,385	468,153	76,260	544,413	567,715	355,881	923,596	379,183
315.00 Accessory Electric Equipment	11,137,088	218,287	36,752	255,039	260,608	169,284	429,892	174,853
316.00 Miscellaneous Power Plant Equipment	3,614,952	79,890	13,737	93,627	90,735	59,647	150,382	56,755
Total Four Corners Units 4-5	$165,879,746	$3,143,351	$546,136	$3,689,487	$3,938,519	$2,588,331	$6,526,850	$2,837,363
Four Corners Common								
311.00 Structures and Improvements	$4,983,659	$139,044	$22,925	$161,969	$111,136	$23,922	$135,058	($26,911)
312.00 Boiler Plant Equipment	15,238,147	412,954	73,143	486,097	318,477	74,667	393,144	(92,953)
314.00 Turbogenerator Units	1,987,500	43,725	6,360	50,085	32,794	5,565	38,359	(11,726)
315.00 Accessory Electric Equipment	4,593,380	135,505	22,508	158,013	109,782	24,345	134,127	(23,886)
316.00 Miscellaneous Power Plant Equipment	10,452,621	322,986	56,444	379,430	261,316	60,625	321,941	(57,489)
Total Four Corners Common	$37,255,307	$1,054,214	$181,380	$1,235,594	$833,505	$189,124	$1,022,629	($212,965)
Navajo Units 1-3								
311.00 Structures and Improvements	$29,113,530	$765,686	$78,607	$844,293	$972,392	$69,872	$1,042,264	$197,971
312.00 Boiler Plant Equipment	166,003,214	4,648,090	531,210	5,179,300	5,677,310	464,809	6,142,119	962,819
314.00 Turbogenerator Units	24,699,305	508,806	54,338	563,144	669,351	49,399	718,750	155,606
315.00 Accessory Electric Equipment	21,491,344	470,660	51,579	522,239	629,696	45,132	674,828	152,589
316.00 Miscellaneous Power Plant Equipment	17,228,597	554,761	62,023	616,784	646,072	49,963	696,035	79,251
Total Navajo Units 1-3	$258,535,990	$6,948,003	$777,757	$7,725,760	$8,594,821	$679,175	$9,273,996	$1,548,236
Ocotillo Units 1-2								
311.00 Structures and Improvements	$4,759,658	$170,872	$48,549	$219,421	$233,699	$41,885	$275,584	$56,163
312.00 Boiler Plant Equipment	25,218,648	713,688	214,359	928,047	859,956	163,921	1,023,877	95,830
314.00 Turbogenerator Units	20,161,583	532,266	159,277	691,543	955,659	177,422	1,133,081	441,538
315.00 Accessory Electric Equipment	3,425,956	106,890	31,176	138,066	155,881	28,778	184,659	46,593
316.00 Miscellaneous Power Plant Equipment	6,010,574	316,156	91,361	407,517	348,613	66,116	414,729	7,212
Total Ocotillo Units 1-2	$59,576,419	$1,839,872	$544,722	$2,384,594	$2,553,808	$478,122	$3,031,930	$647,336

ARIZONA PUBLIC SERVICE COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Saguaro Units 1-2								
311.00 Structures and Improvements	$4,311,317	$121,148	$34,491	$155,639	$237,554	$43,544	$281,098	$125,459
312.00 Boiler Plant Equipment	26,094,372	644,531	185,270	829,801	1,148,152	219,193	1,367,345	537,544
314.00 Turbogenerator Units	16,513,563	336,877	97,430	434,307	544,948	100,733	645,681	211,374
315.00 Accessory Electric Equipment	5,667,906	242,020	69,715	311,735	320,237	59,513	379,750	68,015
316.00 Miscellaneous Power Plant Equipment	4,778,936	188,768	55,436	244,204	244,204	45,878	290,082	45,878
Total Saguaro Units 1-2	$57,366,094	$1,533,344	$442,342	$1,975,686	$2,495,095	$468,861	$2,963,956	$988,270
NUCLEAR PRODUCTION (by Unit)								
Palo Verde								
321.00 Structures and Improvements	$698,846,801	$18,352,868	$82,295	$18,435,163	$9,265,673	$66,624	$9,332,297	($9,102,866)
322.00 Reactor Plant Equipment	1,130,933,859	32,152,405	598,662	32,751,067	16,955,122	593,091	17,548,213	(15,202,854)
323.00 Turbogenerator Units	354,174,138	9,754,391	44,384	9,798,775	5,113,500	63,385	5,176,885	(4,621,890)
324.00 Accessory Electric Equipment	275,016,677	6,987,700	27,502	7,015,202	3,260,068	27,502	3,287,570	(3,727,632)
325.00 Miscellaneous Power Plant Equipment	145,211,312	4,180,067	55,558	4,235,625	2,141,613	52,477	2,194,090	(2,041,535)
Total Palo Verde	$2,604,182,787	$71,427,431	$808,401	$72,235,832	$36,735,976	$803,079	$37,539,055	($34,696,777)
Palo Verde Unit 1								
321.00 Structures and Improvements	$156,705,345	$4,168,362	$15,671	$4,184,033	$1,770,770		$1,770,770	($2,413,263)
322.00 Reactor Plant Equipment	454,207,200	14,352,948	181,683	14,534,631	6,586,004	181,683	6,767,687	(7,766,944)
323.00 Turbogenerator Units	125,268,196	3,770,573	12,527	3,783,100	1,766,282	25,054	1,791,336	(1,991,764)
324.00 Accessory Electric Equipment	114,860,792	3,032,325	11,486	3,043,811	1,274,955	11,486	1,286,441	(1,757,370)
325.00 Miscellaneous Power Plant Equipment	30,801,758	880,930	9,241	890,171	397,343	6,160	403,503	(486,668)
Total Palo Verde Unit 1	$881,843,291	$26,205,138	$230,608	$26,435,746	$11,795,354	$224,383	$12,019,737	($14,416,009)
Palo Verde Unit 2								
321.00 Structures and Improvements	$91,657,911	$2,438,100	$9,166	$2,447,266	$1,099,895	$9,166	$1,109,061	($1,338,205)
322.00 Reactor Plant Equipment	234,287,478	7,239,483	187,430	7,426,913	3,561,170	187,430	3,748,600	(3,678,313)
323.00 Turbogenerator Units	78,612,699	2,303,352	15,723	2,319,075	1,108,439	7,861	1,116,300	(1,202,775)
324.00 Accessory Electric Equipment	49,937,247	1,343,312	4,994	1,348,306	624,216	4,994	629,210	(719,096)
325.00 Miscellaneous Power Plant Equipment	27,087,580	826,171	5,418	831,589	392,770	5,418	398,188	(433,401)
Total Palo Verde Unit 2	$481,582,915	$14,150,418	$222,731	$14,373,149	$6,786,490	$214,869	$7,001,359	($7,371,790)
Palo Verde Unit 3								
321.00 Structures and Improvements	$163,192,491	$3,818,704		$3,818,704	$1,990,948		$1,990,948	($1,827,756)
322.00 Reactor Plant Equipment	414,451,923	9,863,956	207,226	10,071,182	6,465,450	207,226	6,672,676	(3,398,506)
323.00 Turbogenerator Units	147,910,539	3,579,435	14,791	3,594,226	2,189,076	29,582	2,218,658	(1,375,568)
324.00 Accessory Electric Equipment	90,837,828	2,125,605	9,084	2,134,689	1,126,389	9,084	1,135,473	(999,216)
325.00 Miscellaneous Power Plant Equipment	28,712,249	720,677	5,742	726,419	390,487	5,742	396,229	(330,190)
Total Palo Verde Unit 3	$845,105,030	$20,108,377	$236,843	$20,345,220	$12,162,350	$251,634	$12,413,984	($7,931,236)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Palo Verde Water Reclamation								
321.00 Structures and Improvements	$171,609,224	$4,873,702	$34,322	$4,908,024	$2,900,196	$34,322	$2,934,518	($1,973,506)
322.00 Reactor Plant Equipment	133,326	5,240	40	5,280	2,680	40	2,720	(2,560)
323.00 Turbogenerator Units	217,756	6,206	44	6,250	3,157	22	3,179	(3,071)
324.00 Accessory Electric Equipment								
325.00 Miscellaneous Power Plant Equipment	88,819	2,514	44	2,558	1,270	44	1,314	(1,244)
Total Palo Verde Water Reclamation	$172,049,125	$4,887,662	$34,450	$4,922,112	$2,907,303	$34,428	$2,941,731	($1,980,381)
Palo Verde Common								
321.00 Structures and Improvements	$115,681,830	$3,054,000	$23,136	$3,077,136	$1,503,864	$23,136	$1,527,000	($1,550,136)
322.00 Reactor Plant Equipment	27,853,932	690,778	22,283	713,061	339,818	16,712	356,530	(356,531)
323.00 Turbogenerator Units	2,164,948	94,825	1,299	96,124	46,546	866	47,412	(48,712)
324.00 Accessory Electric Equipment	19,380,810	486,458	1,938	488,396	234,508	1,938	236,446	(251,950)
325.00 Miscellaneous Power Plant Equipment	58,520,906	1,749,775	35,113	1,784,888	959,743	35,113	994,856	(790,032)
Total Palo Verde Common	$223,602,426	$6,075,836	$83,769	$6,159,605	$3,084,479	$77,765	$3,162,244	($2,997,361)
OTHER PRODUCTION (by Unit)								
Douglas CT								
341.00 Structures and Improvements	$49,075	$2,915	$142	$3,057	$2,518	($128)	$2,390	($667)
342.00 Fuel Holders, Products and Accessories	137,759	2,507	83	2,590	1,240	(14)	1,226	(1,364)
343.00 Prime Movers	1,101,449	8,041	441	8,482	(2,754)	220	(2,534)	(11,016)
344.00 Generators and Devices	551,765	3,862	166	4,028	(1,545)	55	(1,490)	(5,518)
345.00 Accessory Electric Equipment	353,277	3,462	247	3,709	71	71	142	(3,567)
346.00 Miscellaneous Power Plant Equipment	40,913	675	33	708	286	(12)	274	(434)
Total Douglas CT	$2,234,238	$21,462	$1,112	$22,574	($184)	$192	$8	($22,566)
Ocotillo CT Units 1-2								
341.00 Structures and Improvements	$721,568	$14,576	$722	$15,298	$30,234	($1,443)	$28,791	$13,493
342.00 Fuel Holders, Products and Accessories	791,584	15,278	712	15,990	16,386	(792)	15,594	(396)
343.00 Prime Movers	6,540,275	82,407	3,924	86,331	47,744	(1,962)	45,782	(40,549)
344.00 Generators and Devices	7,596,314	247,640	9,875	257,515	261,313	(46,338)	214,975	(42,540)
345.00 Accessory Electric Equipment	1,677,431	28,181	1,677	29,858	26,839	(1,006)	25,833	(4,025)
346.00 Miscellaneous Power Plant Equipment	637,727	11,288	510	11,798	13,647	(574)	13,073	1,275
Total Octillo CT Units 1-2	$17,964,899	$399,370	$17,420	$416,790	$396,163	($52,115)	$344,048	($72,742)

ARIZONA PUBLIC SERVICE COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Redhawk CC Units 1-2								
341.00 Structures and Improvements	$22,197,402	$668,142	$93,229	$761,371	$694,779	($26,637)	$668,142	($93,229)
342.00 Fuel Holders, Products and Accessories	2,637,978	91,274	4,485	95,759	95,759	(4,748)	91,011	(4,748)
343.00 Prime Movers	177,860,527	5,300,244	124,502	5,424,746	5,531,462	(142,288)	5,389,174	(35,572)
344.00 Generators and Devices	279,212,258	8,432,210	335,055	8,767,265	9,297,768	(2,317,462)	6,980,306	(1,786,959)
345.00 Accessory Electric Equipment	22,584,466	675,276	27,101	702,377	702,377	(22,584)	679,793	(22,584)
346.00 Miscellaneous Power Plant Equipment	4,005,866	130,992	6,810	137,802	144,211	(7,211)	137,000	(802)
Total Redhawk CC Units 1-2	$508,498,497	$15,298,138	$591,182	$15,889,320	$16,466,356	($2,520,930)	$13,945,426	($1,943,894)
Saguaro								
341.00 Structures and Improvements	$1,885,444	$72,024	$3,582	$75,606	$86,730	($4,148)	$82,582	$6,976
342.00 Fuel Holders, Products and Accessories	1,376,702	22,303	964	23,267	17,484	(413)	17,071	(6,196)
343.00 Prime Movers	8,624,812	118,642	5,751	124,393	54,194	(2,494)	51,700	(72,693)
344.00 Generators and Devices	32,512,372	1,007,027	50,115	1,057,142	949,491	(62,572)	886,919	(170,223)
345.00 Accessory Electric Equipment	1,701,779	23,027	1,289	24,316	10,757	(330)	10,427	(13,889)
346.00 Miscellaneous Power Plant Equipment	868,485	27,792	1,390	29,182	22,320	(1,042)	21,278	(7,904)
Total Saguaro	$46,969,594	$1,270,815	$63,091	$1,333,906	$1,140,976	($70,999)	$1,069,977	($263,929)
Saguaro CT Units 1-2								
341.00 Structures and Improvements	$1,885,444	$72,024	$3,582	$75,606	$86,730	($4,148)	$82,582	$6,976
342.00 Fuel Holders, Products and Accessories	1,376,702	22,303	964	23,267	17,484	(413)	17,071	(6,196)
343.00 Prime Movers	7,983,905	99,799	4,790	104,589	35,928	(1,597)	34,331	(70,258)
344.00 Generators and Devices	4,487,988	183,110	8,078	191,188	150,796	(23,338)	127,458	(63,730)
345.00 Accessory Electric Equipment	1,579,226	19,424	1,105	20,529	7,264	(158)	7,106	(13,423)
346.00 Miscellaneous Power Plant Equipment	868,485	27,792	1,390	29,182	22,320	(1,042)	21,278	(7,904)
Total Saguaro CT Units 1-2	$18,181,750	$424,452	$19,909	$444,361	$320,522	($30,696)	$289,826	($154,535)
Saguaro CT Unit 3								
341.00 Structures and Improvements								
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	640,907	18,843	961	19,804	18,266	(897)	17,369	(2,435)
344.00 Generators and Devices	28,024,384	823,917	42,037	865,954	798,695	(39,234)	759,461	(106,493)
345.00 Accessory Electric Equipment	122,553	3,603	184	3,787	3,493	(172)	3,321	(466)
346.00 Miscellaneous Power Plant Equipment								
Total Saguaro CT Unit 3	$28,787,844	$846,363	$43,182	$889,545	$820,454	($40,303)	$780,151	($109,394)

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Solar Units								
341.00 Structures and Improvements	$418,403	$2,176	$84	$2,260	($14,853)	$837	($14,016)	($16,276)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	15,963,981	892,387	49,488	941,875	627,384	(137,290)	490,094	(451,781)
345.00 Accessory Electric Equipment	728,283	39,036	1,966	41,002	53,966	(2,695)	51,271	10,269
346.00 Miscellaneous Power Plant Equipment								
Total Solar Units	$17,110,667	$933,599	$51,538	$985,137	$666,497	($139,148)	$527,349	($457,788)
Sundance								
341.00 Structures and Improvements	$12,653,247	$279,637	$13,919	$293,556	$260,657	($12,653)	$248,004	($45,552)
342.00 Fuel Holders, Products and Accessories	4,325,769	94,734	4,758	99,492	88,678	(4,326)	84,352	(15,140)
343.00 Prime Movers	229,732,211	5,054,109	252,705	5,306,814	4,686,537	(252,705)	4,433,832	(872,982)
344.00 Generators and Devices	301,285	9,099	452	9,551	7,562	(392)	7,170	(2,381)
345.00 Accessory Electric Equipment	26,408,712	578,351	29,050	607,401	541,379	(26,409)	514,970	(92,431)
346.00 Miscellaneous Power Plant Equipment	2,028,889	44,433	2,232	46,665	50,519	(2,435)	48,084	1,419
Total Sun Dance	$275,450,113	$6,060,363	$303,116	$6,363,479	$5,635,332	($298,920)	$5,336,412	($1,027,067)
West Phoenix								
341.00 Structures and Improvements	$27,606,161	$700,155	$40,562	$740,717	$840,081	($40,432)	$799,649	$58,932
342.00 Fuel Holders, Products and Accessories	28,090,344	990,209	50,137	1,040,346	1,037,207	(47,166)	990,041	(50,305)
343.00 Prime Movers	164,651,195	4,896,967	190,232	5,087,199	4,762,834	(165,600)	4,597,234	(489,965)
344.00 Generators and Devices	244,094,419	8,109,640	376,030	8,485,670	8,259,393	(907,610)	7,351,783	(1,133,887)
345.00 Accessory Electric Equipment	29,569,013	980,088	47,816	1,027,904	992,802	(43,228)	949,574	(78,330)
346.00 Miscellaneous Power Plant Equipment	6,447,142	198,892	10,433	209,325	254,815	(11,315)	243,500	34,175
Total West Phoenix	$500,458,274	$15,875,951	$715,210	$16,591,161	$16,147,132	($1,215,351)	$14,931,781	($1,659,380)
West Phoenix CC Units 1-3								
341.00 Structures and Improvements	$1,710,485	$68,590	$3,250	$71,840	$85,524	($4,105)	$81,419	$9,579
342.00 Fuel Holders, Products and Accessories	22,517,702	844,414	42,784	887,198	905,212	(40,532)	864,680	(22,518)
343.00 Prime Movers								
344.00 Generators and Devices	92,566,116	3,545,282	148,106	3,693,388	3,776,698	(601,680)	3,175,018	(518,370)
345.00 Accessory Electric Equipment	13,561,670	511,275	24,411	535,686	543,823	(20,343)	523,480	(12,206)
346.00 Miscellaneous Power Plant Equipment	4,722,353	140,726	7,556	148,282	196,922	(8,500)	188,422	40,140
Total West Phoenix CC Units 1-3	$135,078,326	$5,110,287	$226,107	$5,336,394	$5,508,179	($675,160)	$4,833,019	($503,375)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix CC Unit 4								
341.00 Structures and Improvements	$4,584,726	$139,376	$6,877	$146,253	$139,834	($6,877)	$132,957	($13,296)
342.00 Fuel Holders, Products and Accessories	4,135,109	123,226	6,203	129,429	123,226	(6,203)	117,023	(12,406)
343.00 Prime Movers	54,680,534	1,629,480	82,021	1,711,501	1,629,480	(82,021)	1,547,459	(164,042)
344.00 Generators and Devices	15,548,138	469,554	24,877	494,431	477,328	(46,644)	430,684	(63,747)
345.00 Accessory Electric Equipment	2,569,550	83,510	4,111	87,621	91,733	(4,625)	87,108	(513)
346.00 Miscellaneous Power Plant Equipment	315,741	10,072	505	10,577	11,746	(537)	11,209	632
Total West Phoenix CC Unit 4	$81,833,798	$2,455,218	$124,594	$2,579,812	$2,473,347	($146,907)	$2,326,440	($253,372)
West Phoenix CC Unit 5								
341.00 Structures and Improvements	$10,865,036	$328,124	$17,384	$345,508	$317,259	($16,298)	$300,961	($44,547)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	101,176,494	3,096,001	101,176	3,197,177	3,045,412	(80,941)	2,964,471	(232,706)
344.00 Generators and Devices	131,363,010	3,980,299	197,045	4,177,344	3,901,481	(249,590)	3,651,891	(525,453)
345.00 Accessory Electric Equipment	11,713,613	353,751	17,570	371,321	340,866	(17,570)	323,296	(48,025)
346.00 Miscellaneous Power Plant Equipment	235,560	7,491	377	7,868	8,009	(400)	7,609	(259)
Total West Phoenix CC Unit 5	$255,353,713	$7,765,666	$333,552	$8,099,218	$7,613,027	($364,799)	$7,248,228	($850,990)
West Phoenix CT Units 1-2								
341.00 Structures and Improvements	$880,435	$11,974	$616	$12,590	$33,457	($1,673)	$31,784	$19,194
342.00 Fuel Holders, Products and Accessories	1,437,533	22,569	1,150	23,719	8,769	(431)	8,338	(15,381)
343.00 Prime Movers	8,794,167	171,486	7,035	178,521	87,942	(2,638)	85,304	(93,217)
344.00 Generators and Devices	4,617,155	114,505	6,002	120,507	103,886	(9,696)	94,190	(26,317)
345.00 Accessory Electric Equipment	1,724,180	31,552	1,724	33,276	16,380	(690)	15,690	(17,586)
346.00 Miscellaneous Power Plant Equipment	1,173,488	40,603	1,995	42,598	38,138	(1,878)	36,260	(6,338)
Total West Phoenix CT Units 1-2	$18,626,958	$392,689	$18,522	$411,211	$288,572	($17,006)	$271,566	($139,645)
West Phoenix Common								
341.00 Structures and Improvements	$9,565,479	$152,091	$12,435	$164,526	$264,007	($11,479)	$252,528	$88,002
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices								
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total West Phoenix Common	$9,565,479	$152,091	$12,435	$164,526	$264,007	($11,479)	$252,528	$88,002

ARIZONA PUBLIC SERVICE COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/10 Investment	Current 2011 Annualized Accrual			Proposed 2011 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Yucca								
341.00 Structures and Improvements	$1,730,884	$57,348	$2,030	$59,378	$43,289	($1,761)	$41,528	($17,850)
342.00 Fuel Holders, Products and Accessories	4,819,210	67,734	1,327	69,061	48,273	(2,254)	46,019	(23,042)
343.00 Prime Movers	76,131,450	1,900,383	2,389	1,902,772	2,017,459	(102,254)	1,915,205	12,433
344.00 Generators and Devices	7,937,599	207,231	9,461	216,692	101,721	(19,002)	82,719	(133,973)
345.00 Accessory Electric Equipment	3,251,231	78,214	3,690	81,904	33,544	(1,471)	32,073	(49,831)
346.00 Miscellaneous Power Plant Equipment	682,399	16,173	751	16,924	7,575	(409)	7,166	(9,758)
Total Yucca	$94,552,773	$2,327,083	$19,648	$2,346,731	$2,251,861	($127,151)	$2,124,710	($222,021)
Yucca CT Units 1-4								
341.00 Structures and Improvements	$1,193,877	$42,741	$2,030	$44,771	$27,340	($955)	$26,385	($18,386)
342.00 Fuel Holders, Products and Accessories	3,316,669	26,865	1,327	28,192	3,648		3,648	(24,544)
343.00 Prime Movers	7,962,254	46,181	2,389	48,570	(7,166)		(7,166)	(55,736)
344.00 Generators and Devices	7,883,898	205,770	9,461	215,231	100,126	(18,921)	81,205	(134,026)
345.00 Accessory Electric Equipment	2,838,650	66,992	3,690	70,682	21,290	(852)	20,438	(50,244)
346.00 Miscellaneous Power Plant Equipment	682,399	16,173	751	16,924	7,575	(409)	7,166	(9,758)
Total Yucca CT Units 1-4	$23,877,747	$404,722	$19,648	$424,370	$152,813	($21,137)	$131,676	($292,694)
Yucca CT Units 5-6								
341.00 Structures and Improvements	$537,007	$14,607		$14,607	$15,949	($806)	$15,143	$536
342.00 Fuel Holders, Products and Accessories	1,502,541	40,869		40,869	44,625	(2,254)	42,371	1,502
343.00 Prime Movers	68,169,196	1,854,202		1,854,202	2,024,625	(102,254)	1,922,371	68,169
344.00 Generators and Devices	53,701	1,461		1,461	1,595	(81)	1,514	53
345.00 Accessory Electric Equipment	412,581	11,222		11,222	12,254	(619)	11,635	413
346.00 Miscellaneous Power Plant Equipment								
Total Yucca CT Units 5-6	$70,675,026	$1,922,361		$1,922,361	$2,099,048	($106,014)	$1,993,034	$70,673

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$168,068,708	$88,898,626	52.89%	$101,357,138	60.31%	$97,466,119	57.99%
312.00 Boiler Plant Equipment	1,114,508,323	598,114,849	53.67%	631,396,335	56.65%	606,430,932	54.41%
314.00 Turbogenerator Units	260,287,212	147,478,331	56.66%	149,050,761	57.26%	142,710,428	54.83%
315.00 Accessory Electric Equipment	164,350,445	108,884,358	66.25%	103,007,971	62.68%	97,962,586	59.61%
316.00 Miscellaneous Power Plant Equipment	81,726,740	42,315,482	51.78%	43,140,737	52.79%	41,121,581	50.32%
Total Steam Production Plant	$1,788,941,428	$985,691,646	55.10%	$1,027,952,942	57.46%	$985,691,646	55.10%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$698,846,801	$390,836,399	55.93%	$241,914,153	34.62%	$384,424,922	55.01%
322.00 Reactor Plant Equipment	1,130,933,859	556,209,183	49.18%	353,970,046	31.30%	561,119,881	49.62%
323.00 Turbogenerator Units	354,174,138	171,976,208	48.56%	115,517,890	32.62%	182,656,783	51.57%
324.00 Accessory Electric Equipment	275,016,677	169,883,421	61.77%	104,821,257	38.11%	166,763,875	60.64%
325.00 Miscellaneous Power Plant Equipment	145,211,312	77,544,578	53.40%	44,088,269	30.36%	71,484,329	49.23%
Total Nuclear Production Plant	$2,604,182,787	$1,366,449,789	52.47%	$860,311,616	33.04%	$1,366,449,789	52.47%
OTHER PRODUCTION							
341.00 Structures and Improvements	$67,262,184	$19,276,175	28.66%	$14,551,236	21.63%	$20,097,831	29.88%
342.00 Fuel Holders, Products and Accessories	42,179,346	17,522,636	41.54%	13,273,380	31.47%	16,081,785	38.13%
343.00 Prime Movers	664,641,919	221,422,821	33.31%	124,288,323	18.70%	201,363,609	30.30%
344.00 Generators and Devices	588,169,993	166,810,837	28.36%	183,668,979	31.23%	189,354,954	32.19%
345.00 Accessory Electric Equipment	86,274,192	31,558,684	36.58%	20,219,844	23.44%	29,690,808	34.41%
346.00 Miscellaneous Power Plant Equipment	14,711,421	4,637,245	31.52%	3,715,555	25.26%	4,639,410	31.54%
Total Other Production Plant	$1,463,239,055	$461,228,398	31.52%	$359,717,318	24.58%	$461,228,398	31.52%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$95,935	$52,736	54.97%	$64,115	66.83%	$52,904	55.15%
353.00 Station Equipment	98,305,656	22,173,057	22.56%	26,832,631	27.30%	22,141,048	22.52%
354.00 Towers and Fixtures	1,329,316	448,155	33.71%	510,240	38.38%	421,027	31.67%
355.00 Poles and Fixtures	1,370,085	225,637	16.47%	211,661	15.45%	174,653	12.75%
356.00 Overhead Conductors and Devices	1,947,677	306,587	15.74%	504,803	25.92%	416,540	21.39%
Total Transmission Plant	$103,048,669	$23,206,173	22.52%	$28,123,451	27.29%	$23,206,173	22.52%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$60,888,680	$13,925,108	22.87%	$11,153,574	18.32%	$14,425,802	23.69%
362.00 Station Equipment	406,799,985	77,004,485	18.93%	57,301,547	14.09%	74,112,634	18.22%
364.01 Poles, Towers and Fixtures - Wood	310,263,864	106,919,214	34.46%	83,765,803	27.00%	108,340,954	34.92%
364.02 Poles, Towers and Fixtures - Steel	167,311,767	18,785,628	11.23%	14,702,226	8.79%	19,015,554	11.37%
365.00 Overhead Conductors and Devices	292,642,985	56,679,654	19.37%	42,557,015	14.54%	55,042,361	18.81%
366.00 Underground Conduit	620,488,170	115,499,013	18.61%	105,266,915	16.97%	136,150,047	21.94%
367.00 Underground Conductors and Devices	1,422,708,502	461,218,302	32.42%	337,392,264	23.71%	436,376,163	30.67%
368.00 Line Transformers	717,419,840	204,170,212	28.46%	154,892,922	21.59%	200,335,296	27.92%
369.00 Services	323,341,677	117,434,522	36.32%	91,106,549	28.18%	117,835,322	36.44%
370.01 Meters - Electronic	62,207,543	19,661,616	31.61%	12,407,288	19.94%	16,047,329	25.80%
370.03 Meters - AMI	117,715,566	5,454,950	4.63%	6,965,881	5.92%	9,009,526	7.65%
371.00 Installations on Customers' Premises	39,842,142	4,515,230	11.33%	7,948,234	19.95%	10,280,082	25.80%
373.00 Street Lighting and Signal Systems	73,702,827	15,510,350	21.04%	15,314,314	20.78%	19,807,216	26.87%
Total Distribution Plant	$4,615,333,548	$1,216,778,286	26.36%	$940,774,532	20.38%	$1,216,778,286	26.36%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$107,643,854	$41,645,555	38.69%	$26,639,445	24.75%	$27,863,799	25.89%
391.CM Office Furn. and Equip. - Computer	89,098,127	26,326,394	29.55%	34,077,152	38.25%	35,643,344	40.00%
397.00 Communication Equipment	152,910,098	53,478,093	34.97%	62,059,040	40.59%	64,911,285	42.45%
Total Depreciable	$349,652,079	$121,450,043	34.73%	$122,775,638	35.11%	$128,418,428	36.73%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$49,130,094	$16,581,836	33.75%	$14,343,161	29.19%	$14,343,161	29.19%
393.00 Stores Equipment	256,764	53,028	20.65%	33,264	12.96%	33,264	12.96%
394.00 Tools, Shop and Garage Equipment	28,424,012	15,220,425	53.55%	11,518,585	40.52%	11,518,585	40.52%
395.00 Laboratory Equipment	1,385,366	835,033	60.28%	878,477	63.41%	878,477	63.41%
398.00 Miscellaneous Equipment	5,909,111	2,242,021	37.94%	1,190,470	20.15%	1,190,470	20.15%
Total Amortizable	$85,105,347	$34,932,343	41.05%	$27,963,957	32.86%	$27,963,957	32.86%
Total General Plant	$434,757,426	$156,382,385	35.97%	$150,739,595	34.67%	$156,382,385	35.97%
TOTAL UTILITY	$11,009,502,913	$4,209,736,678	38.24%	$3,367,619,454	30.59%	$4,209,736,678	38.24%
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$72,335,187	$32,658,749	45.15%	$27,740,590	38.35%	$25,961,589	35.89%
312.00 Boiler Plant Equipment	521,789,973	199,546,630	38.24%	165,902,051	31.79%	155,262,773	29.76%
314.00 Turbogenerator Units	125,558,183	49,336,701	39.29%	40,240,161	32.05%	37,659,564	29.99%
315.00 Accessory Electric Equipment	93,701,286	64,122,005	68.43%	49,240,217	52.55%	46,082,448	49.18%
316.00 Miscellaneous Power Plant Equipment	27,985,746	13,003,913	46.47%	9,520,688	34.02%	8,910,127	31.84%
Total Cholla	$841,370,375	$358,667,998	42.63%	$292,643,706	34.78%	$273,876,501	32.55%
Cholla Unit 1							
311.00 Structures and Improvements	$4,372,274	$2,485,697	56.85%	$1,891,795	43.27%	$1,770,475	40.49%
312.00 Boiler Plant Equipment	73,213,804	28,223,333	38.55%	22,707,383	31.02%	21,251,162	29.03%
314.00 Turbogenerator Units	25,640,590	6,606,429	25.77%	6,245,198	24.36%	5,844,694	22.79%
315.00 Accessory Electric Equipment	8,816,493	4,882,751	55.38%	3,728,135	42.29%	3,489,050	39.57%
316.00 Miscellaneous Power Plant Equipment	2,838,727	1,871,258	65.92%	1,309,008	46.11%	1,225,061	43.16%
Total Cholla Unit 1	$114,881,888	$44,069,468	38.36%	$35,881,519	31.23%	$33,580,442	29.23%
Cholla Unit 2							
311.00 Structures and Improvements	$6,168,012	$3,411,030	55.30%	$2,686,370	43.55%	$2,514,093	40.76%
312.00 Boiler Plant Equipment	162,323,693	106,524,199	65.62%	83,040,881	51.16%	77,715,480	47.88%
314.00 Turbogenerator Units	44,157,763	18,673,370	42.29%	16,165,636	36.61%	15,128,936	34.26%
315.00 Accessory Electric Equipment	46,110,434	33,572,567	72.81%	25,944,613	56.27%	24,280,788	52.66%
316.00 Miscellaneous Power Plant Equipment	8,714,396	3,655,960	41.95%	2,839,448	32.58%	2,657,354	30.49%
Total Cholla Unit 2	$267,474,298	$165,837,126	62.00%	$130,676,948	48.86%	$122,296,651	45.72%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Cholla Unit 3							
311.00 Structures and Improvements	$9,984,226	$7,051,816	70.63%	$5,394,931	54.03%	$5,048,955	50.57%
312.00 Boiler Plant Equipment	228,064,943	49,009,037	21.49%	46,827,913	20.53%	43,824,844	19.22%
314.00 Turbogenerator Units	54,849,058	23,540,403	42.92%	17,444,385	31.80%	16,325,679	29.76%
315.00 Accessory Electric Equipment	31,001,286	22,409,000	72.28%	16,990,227	54.80%	15,900,645	51.29%
316.00 Miscellaneous Power Plant Equipment	4,593,291	2,817,643	61.34%	2,115,521	46.06%	1,979,853	43.10%
Total Cholla Unit 3	$328,492,804	$104,827,899	31.91%	$88,772,977	27.02%	$83,079,977	25.29%
Cholla Common							
311.00 Structures and Improvements	$51,810,675	$19,710,205	38.04%	$17,767,493	34.29%	$16,628,066	32.09%
312.00 Boiler Plant Equipment	58,187,533	15,790,061	27.14%	13,325,873	22.90%	12,471,287	21.43%
314.00 Turbogenerator Units	910,772	516,499	56.71%	384,942	42.27%	360,255	39.55%
315.00 Accessory Electric Equipment	7,773,073	3,257,688	41.91%	2,577,242	33.16%	2,411,964	31.03%
316.00 Miscellaneous Power Plant Equipment	11,839,332	4,659,052	39.35%	3,256,711	27.51%	3,047,859	25.74%
Total Cholla Common	$130,521,385	$43,933,506	33.66%	$37,312,262	28.59%	$34,919,431	26.75%
Four Corners							
311.00 Structures and Improvements	$57,549,016	$31,835,205	55.32%	$51,262,088	89.08%	$50,583,658	87.90%
312.00 Boiler Plant Equipment	375,402,116	249,976,472	66.59%	332,878,015	88.67%	327,056,555	87.12%
314.00 Turbogenerator Units	73,354,578	46,674,854	63.63%	63,301,295	86.29%	62,460,065	85.15%
315.00 Accessory Electric Equipment	40,063,953	23,152,430	57.79%	34,187,081	85.33%	33,555,171	83.75%
316.00 Miscellaneous Power Plant Equipment	25,722,887	11,914,370	46.32%	18,479,812	71.84%	18,042,158	70.14%
Total Four Corners	$572,092,550	$363,553,331	63.55%	$500,108,290	87.42%	$491,697,606	85.95%
Four Corners Units 1-3							
311.00 Structures and Improvements	$40,683,091	$22,130,773	54.40%	$40,683,091	100.00%	$40,683,091	100.00%
312.00 Boiler Plant Equipment	242,101,914	166,321,891	68.70%	242,101,914	100.00%	242,101,914	100.00%
314.00 Turbogenerator Units	50,183,693	34,950,798	69.65%	50,183,693	100.00%	50,183,693	100.00%
315.00 Accessory Electric Equipment	24,333,485	14,311,157	58.81%	24,333,485	100.00%	24,333,485	100.00%
316.00 Miscellaneous Power Plant Equipment	11,655,314	5,718,804	49.07%	11,655,314	100.00%	11,655,314	100.00%
Total Four Corners Units 1-3	$368,957,497	$243,433,422	65.98%	$368,957,497	100.00%	$368,957,497	100.00%

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Four Corners Units 4-5							
311.00 Structures and Improvements	$11,882,266	$7,361,654	61.95%	$7,890,704	66.41%	$7,384,675	62.15%
312.00 Boiler Plant Equipment	118,062,055	75,799,402	64.20%	81,810,700	69.29%	76,564,190	64.85%
314.00 Turbogenerator Units	21,183,385	10,435,941	49.26%	11,584,172	54.69%	10,841,280	51.18%
315.00 Accessory Electric Equipment	11,137,088	7,001,791	62.87%	7,620,483	68.42%	7,131,782	64.04%
316.00 Miscellaneous Power Plant Equipment	3,614,952	2,053,080	56.79%	2,174,289	60.15%	2,034,852	56.29%
Total Four Corners Units 4-5	$165,879,746	$102,651,868	61.88%	$111,080,349	66.96%	$103,956,780	62.67%
Four Corners Common							
311.00 Structures and Improvements	$4,983,659	$2,342,778	47.01%	$2,688,292	53.94%	$2,515,892	50.48%
312.00 Boiler Plant Equipment	15,238,147	7,855,180	51.55%	8,965,400	58.84%	8,390,450	55.06%
314.00 Turbogenerator Units	1,987,500	1,288,114	64.81%	1,533,431	77.15%	1,435,092	72.21%
315.00 Accessory Electric Equipment	4,593,380	1,839,483	40.05%	2,233,113	48.62%	2,089,903	45.50%
316.00 Miscellaneous Power Plant Equipment	10,452,621	4,142,487	39.63%	4,650,209	44.49%	4,351,991	41.64%
Total Four Corners Common	$37,255,307	$17,468,041	46.89%	$20,070,444	53.87%	$18,783,329	50.42%
Navajo Units 1-3							
311.00 Structures and Improvements	$29,113,530	$17,980,695	61.76%	$16,421,048	56.40%	$15,367,968	52.79%
312.00 Boiler Plant Equipment	166,003,214	100,903,604	60.78%	91,281,962	54.99%	85,428,061	51.46%
314.00 Turbogenerator Units	24,699,305	18,790,977	76.08%	16,704,316	67.63%	15,633,070	63.29%
315.00 Accessory Electric Equipment	21,491,344	15,279,119	71.09%	13,685,439	63.68%	12,807,794	59.60%
316.00 Miscellaneous Power Plant Equipment	17,228,597	9,325,019	54.13%	8,484,627	49.25%	7,940,509	46.09%
Total Navajo Units 1-3	$258,535,990	$162,279,414	62.77%	$146,577,393	56.70%	$137,177,403	53.06%
Ocotillo Units 1-2							
311.00 Structures and Improvements	$4,759,658	$3,304,683	69.43%	$3,282,708	68.97%	$3,072,188	64.55%
312.00 Boiler Plant Equipment	25,218,648	23,841,573	94.54%	21,849,542	86.64%	20,448,334	81.08%
314.00 Turbogenerator Units	20,161,583	15,093,026	74.86%	14,294,685	70.90%	13,377,968	66.35%
315.00 Accessory Electric Equipment	3,425,956	2,585,027	75.45%	2,503,962	73.09%	2,343,383	68.40%
316.00 Miscellaneous Power Plant Equipment	6,010,574	3,863,288	64.27%	3,493,484	58.12%	3,269,448	54.39%
Total Ocotillo Units 1-2	$59,576,419	$48,687,597	81.72%	$45,424,381	76.25%	$42,511,321	71.36%

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Saguaro Units 1-2							
311.00 Structures and Improvements	$4,311,317	$3,119,294	72.35%	$2,650,705	61.48%	$2,480,715	57.54%
312.00 Boiler Plant Equipment	26,094,372	23,846,570	91.39%	19,484,765	74.67%	18,235,209	69.88%
314.00 Turbogenerator Units	16,513,563	17,582,774	106.47%	14,510,305	87.87%	13,579,761	82.23%
315.00 Accessory Electric Equipment	5,667,906	3,745,776	66.09%	3,391,272	59.83%	3,173,790	56.00%
316.00 Miscellaneous Power Plant Equipment	4,778,936	4,208,892	88.07%	3,162,126	66.17%	2,959,339	61.92%
Total Saguaro Units 1-2	$57,366,094	$52,503,306	91.52%	$43,199,172	75.30%	$40,428,815	70.48%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$698,846,801	$390,836,399	55.93%	$241,914,153	34.62%	$384,424,922	55.01%
322.00 Reactor Plant Equipment	1,130,933,859	556,209,183	49.18%	353,970,046	31.30%	561,119,881	49.62%
323.00 Turbogenerator Units	354,174,138	171,976,208	48.56%	115,517,890	32.62%	182,656,783	51.57%
324.00 Accessory Electric Equipment	275,016,677	169,883,421	61.77%	104,821,257	38.11%	166,763,875	60.64%
325.00 Miscellaneous Power Plant Equipment	145,211,312	77,544,578	53.40%	44,088,269	30.36%	71,484,329	49.23%
Total Palo Verde	$2,604,182,787	$1,366,449,789	52.47%	$860,311,616	33.04%	$1,366,449,789	52.47%
Palo Verde Unit 1							
321.00 Structures and Improvements	$156,705,345	$100,876,428	64.37%	$63,267,866	40.37%	$100,610,842	64.20%
322.00 Reactor Plant Equipment	454,207,200	241,944,101	53.27%	152,771,318	33.63%	242,942,460	53.49%
323.00 Turbogenerator Units	125,268,196	68,240,082	54.48%	43,041,449	34.36%	68,446,065	54.64%
324.00 Accessory Electric Equipment	114,860,792	74,151,478	64.56%	46,668,557	40.63%	74,214,023	64.61%
325.00 Miscellaneous Power Plant Equipment	30,801,758	18,990,462	61.65%	11,312,258	36.73%	17,989,161	58.40%
Total Palo Verde Unit 1	$881,843,291	$504,202,551	57.18%	$317,061,449	35.95%	$504,202,551	57.18%
Palo Verde Unit 2							
321.00 Structures and Improvements	$91,657,911	$56,731,380	61.89%	$36,063,237	39.35%	$55,579,960	60.64%
322.00 Reactor Plant Equipment	234,287,478	117,989,148	50.36%	73,783,989	31.49%	113,714,449	48.54%
323.00 Turbogenerator Units	78,612,699	34,734,451	44.18%	27,286,159	34.71%	42,052,898	53.49%
324.00 Accessory Electric Equipment	49,937,247	29,918,465	59.91%	19,123,865	38.30%	29,473,328	59.02%
325.00 Miscellaneous Power Plant Equipment	27,087,580	15,560,042	57.44%	9,157,168	33.81%	14,112,850	52.10%
Total Palo Verde Unit 2	$481,582,915	$254,933,485	52.94%	$165,414,419	34.35%	$254,933,485	52.94%

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Palo Verde Unit 3							
321.00 Structures and Improvements	$163,192,491	$101,112,724	61.96%	$59,252,916	36.31%	$94,572,123	57.95%
322.00 Reactor Plant Equipment	414,451,923	180,296,659	43.50%	118,151,189	28.51%	188,578,209	45.50%
323.00 Turbogenerator Units	147,910,539	68,313,093	46.19%	44,813,159	30.30%	71,525,182	48.36%
324.00 Accessory Electric Equipment	90,837,828	54,944,448	60.49%	32,458,800	35.73%	51,806,693	57.03%
325.00 Miscellaneous Power Plant Equipment	28,712,249	16,887,577	58.82%	9,443,346	32.89%	15,072,292	52.49%
Total Palo Verde Unit 3	$845,105,030	$421,554,500	49.88%	$264,119,411	31.25%	$421,554,500	49.88%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$171,609,224	$70,472,808	41.07%	$46,507,322	27.10%	$70,498,432	41.08%
322.00 Reactor Plant Equipment	133,326	50,006	37.51%	26,845	20.14%	40,694	30.52%
323.00 Turbogenerator Units	217,756	119,207	54.74%	71,456	32.81%	108,317	49.74%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	88,819	49,049	55.22%	28,780	32.40%	43,627	49.12%
Total Palo Verde Water Reclamation	$172,049,125	$70,691,070	41.09%	$46,634,404	27.11%	$70,691,070	41.09%
Palo Verde Common							
321.00 Structures and Improvements	$115,681,830	$61,643,060	53.29%	$36,822,812	31.83%	$63,163,565	54.60%
322.00 Reactor Plant Equipment	27,853,932	15,929,270	57.19%	9,236,704	33.16%	15,844,069	56.88%
323.00 Turbogenerator Units	2,164,948	569,376	26.30%	305,665	14.12%	524,320	24.22%
324.00 Accessory Electric Equipment	19,380,810	10,869,029	56.08%	6,570,036	33.90%	11,269,831	58.15%
325.00 Miscellaneous Power Plant Equipment	58,520,906	26,057,448	44.53%	14,146,717	24.17%	24,266,399	41.47%
Total Palo Verde Common	$223,602,426	$115,068,183	51.46%	$67,081,934	30.00%	$115,068,183	51.46%
OTHER PRODUCTION (by Unit)							
Douglas CT							
341.00 Structures and Improvements	$49,075	$17,696	36.06%	$18,844	38.40%	$24,163	49.24%
342.00 Fuel Holders, Products and Accessories	137,759	120,882	87.75%	93,051	67.55%	119,319	86.61%
343.00 Prime Movers	1,101,449	1,076,890	97.77%	834,801	75.79%	1,070,460	97.19%
344.00 Generators and Devices	551,765	535,119	96.98%	419,498	76.03%	537,919	97.49%
345.00 Accessory Electric Equipment	353,277	335,531	94.98%	260,799	73.82%	334,422	94.66%
346.00 Miscellaneous Power Plant Equipment	40,913	36,482	89.17%	28,321	69.22%	36,316	88.76%
Total Douglas CT	$2,234,238	$2,122,600	95.00%	$1,655,314	74.09%	$2,122,600	95.00%

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Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$721,568	$365,738	50.69%	$343,482	47.60%	$415,356	57.56%
342.00 Fuel Holders, Products and Accessories	791,584	624,258	78.86%	501,158	63.31%	606,027	76.56%
343.00 Prime Movers	6,540,275	6,067,636	92.77%	4,783,565	73.14%	5,784,541	88.44%
344.00 Generators and Devices	7,596,314	4,904,199	64.56%	4,298,851	56.59%	5,198,399	68.43%
345.00 Accessory Electric Equipment	1,677,431	1,386,807	82.67%	1,116,793	66.58%	1,350,485	80.51%
346.00 Miscellaneous Power Plant Equipment	637,727	489,648	76.78%	399,815	62.69%	483,477	75.81%
Total Octillo CT Units 1-2	$17,964,899	$13,838,285	77.03%	$11,443,664	63.70%	$13,838,285	77.03%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$22,197,402	$3,560,250	16.04%	$4,045,668	18.23%	$3,951,957	17.80%
342.00 Fuel Holders, Products and Accessories	2,637,978	116,802	4.43%	179,784	6.82%	175,620	6.66%
343.00 Prime Movers	177,860,527	45,932,112	25.82%	31,920,358	17.95%	31,180,973	17.53%
344.00 Generators and Devices	279,212,258	70,242,249	25.16%	88,204,328	31.59%	86,161,211	30.86%
345.00 Accessory Electric Equipment	22,584,466	5,595,952	24.78%	4,155,053	18.40%	4,058,808	17.97%
346.00 Miscellaneous Power Plant Equipment	4,005,866	372,713	9.30%	298,423	7.45%	291,510	7.28%
Total Redhawk CC Units 1-2	$508,498,497	$125,820,078	24.74%	$128,803,614	25.33%	$125,820,078	24.74%
Saguaro							
341.00 Structures and Improvements	$1,885,444	$981,183	52.04%	$815,125	43.23%	$1,016,029	53.89%
342.00 Fuel Holders, Products and Accessories	1,376,702	1,169,447	84.95%	921,069	66.90%	1,148,085	83.39%
343.00 Prime Movers	8,624,812	7,599,540	88.11%	5,968,880	69.21%	7,424,851	86.09%
344.00 Generators and Devices	32,512,372	10,086,665	31.02%	8,775,823	26.99%	10,275,001	31.60%
345.00 Accessory Electric Equipment	1,701,779	1,492,152	87.68%	1,178,170	69.23%	1,465,652	86.12%
346.00 Miscellaneous Power Plant Equipment	868,485	626,012	72.08%	501,721	57.77%	625,381	72.01%
Total Saguaro	$46,969,594	$21,954,998	46.74%	$18,160,789	38.66%	$21,954,998	46.74%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$1,885,444	$981,183	52.04%	$815,125	43.23%	$1,016,029	53.89%
342.00 Fuel Holders, Products and Accessories	1,376,702	1,169,447	84.95%	921,069	66.90%	1,148,085	83.39%
343.00 Prime Movers	7,983,905	7,434,419	93.12%	5,824,466	72.95%	7,260,024	90.93%
344.00 Generators and Devices	4,487,988	2,879,784	64.17%	2,461,151	54.84%	3,067,752	68.35%
345.00 Accessory Electric Equipment	1,579,226	1,460,559	92.49%	1,150,556	72.86%	1,434,134	90.81%
346.00 Miscellaneous Power Plant Equipment	868,485	626,012	72.08%	501,721	57.77%	625,381	72.01%
Total Saguaro CT Units 1-2	$18,181,750	$14,551,404	80.03%	$11,674,088	64.21%	$14,551,404	80.03%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	640,907	165,120	25.76%	144,414	22.53%	164,827	25.72%
344.00 Generators and Devices	28,024,384	7,206,881	25.72%	6,314,672	22.53%	7,207,249	25.72%
345.00 Accessory Electric Equipment	122,553	31,593	25.78%	27,615	22.53%	31,518	25.72%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$28,787,844	$7,403,594	25.72%	$6,486,701	22.53%	$7,403,594	25.72%
Solar Units							
341.00 Structures and Improvements	$418,403	$345,858	82.66%	$342,365	81.83%	$429,042	102.54%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	15,963,981	13,235,714	82.91%	10,452,157	65.47%	13,098,366	82.05%
345.00 Accessory Electric Equipment	728,283	196,423	26.97%	199,962	27.46%	250,587	34.41%
346.00 Miscellaneous Power Plant Equipment							
Total Solar Units	$17,110,667	$13,777,995	80.52%	$10,994,484	64.26%	$13,777,995	80.52%
Sundance							
341.00 Structures and Improvements	$12,653,247	$5,603,059	44.28%	$1,979,907	15.65%	$5,668,679	44.80%
342.00 Fuel Holders, Products and Accessories	4,325,769	1,948,218	45.04%	680,227	15.72%	1,947,560	45.02%
343.00 Prime Movers	229,732,211	104,718,058	45.58%	36,480,728	15.88%	104,448,094	45.47%
344.00 Generators and Devices	301,285	67,296	22.34%	35,790	11.88%	102,470	34.01%
345.00 Accessory Electric Equipment	26,408,712	11,833,373	44.81%	4,152,768	15.72%	11,889,803	45.02%
346.00 Miscellaneous Power Plant Equipment	2,028,889	583,235	28.75%	243,314	11.99%	696,634	34.34%
Total Sun Dance	$275,450,113	$124,753,240	45.29%	$43,572,734	15.82%	$124,753,240	45.29%
West Phoenix							
341.00 Structures and Improvements	$27,606,161	$8,028,233	29.08%	$6,810,562	24.67%	$8,241,502	29.85%
342.00 Fuel Holders, Products and Accessories	28,090,344	10,287,133	36.62%	9,248,768	32.93%	8,941,789	31.83%
343.00 Prime Movers	164,651,195	43,377,427	26.35%	35,863,165	21.78%	38,925,794	23.64%
344.00 Generators and Devices	244,094,419	63,154,504	25.87%	68,944,655	28.25%	69,012,168	28.27%
345.00 Accessory Electric Equipment	29,569,013	8,531,885	28.85%	8,079,177	27.32%	8,254,821	27.92%
346.00 Miscellaneous Power Plant Equipment	6,447,142	2,077,953	32.23%	2,027,036	31.44%	2,081,061	32.28%
Total West Phoenix	$500,458,274	$135,457,135	27.07%	$130,973,364	26.17%	$135,457,135	27.07%

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Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$1,710,485	$132,833	7.77%	$252,378	14.75%	$231,985	13.56%
342.00 Fuel Holders, Products and Accessories	22,517,702	7,906,615	35.11%	7,189,533	31.93%	6,608,587	29.35%
343.00 Prime Movers							
344.00 Generators and Devices	92,566,116	31,967,137	34.53%	36,532,482	39.47%	33,580,493	36.28%
345.00 Accessory Electric Equipment	13,561,670	4,298,346	31.69%	4,283,559	31.59%	3,937,428	29.03%
346.00 Miscellaneous Power Plant Equipment	4,722,353	1,314,748	27.84%	1,372,056	29.05%	1,261,187	26.71%
Total West Phoenix CC Units 1-3	$135,078,326	$45,619,679	33.77%	$49,630,008	36.74%	$45,619,679	33.77%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$4,584,726	$1,106,157	24.13%	$1,077,578	23.50%	$1,080,513	23.57%
342.00 Fuel Holders, Products and Accessories	4,135,109	1,084,373	26.22%	1,042,336	25.21%	1,045,174	25.28%
343.00 Prime Movers	54,680,534	14,295,034	26.14%	13,783,305	25.21%	13,820,838	25.28%
344.00 Generators and Devices	15,548,138	3,605,752	23.19%	4,130,977	26.57%	4,142,226	26.64%
345.00 Accessory Electric Equipment	2,569,550	310,875	12.10%	290,977	11.32%	291,770	11.35%
346.00 Miscellaneous Power Plant Equipment	315,741	1,866	0.59%	23,474	7.43%	23,538	7.45%
Total West Phoenix CC Unit 4	$81,833,798	$20,404,058	24.93%	$20,348,647	24.87%	$20,404,058	24.93%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$10,865,036	$2,253,755	20.74%	$2,144,466	19.74%	$2,335,341	21.49%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	101,176,494	21,250,703	21.00%	16,112,985	15.93%	17,547,170	17.34%
344.00 Generators and Devices	131,363,010	24,256,976	18.47%	25,516,806	19.42%	27,788,006	21.15%
345.00 Accessory Electric Equipment	11,713,613	2,446,192	20.88%	2,327,714	19.87%	2,534,899	21.64%
346.00 Miscellaneous Power Plant Equipment	235,560	19,526	8.29%	19,960	8.47%	21,737	9.23%
Total West Phoenix CC Unit 5	$255,353,713	$50,227,152	19.67%	$46,121,932	18.06%	$50,227,152	19.67%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$880,435	$480,418	54.57%	$425,221	48.30%	$538,595	61.17%
342.00 Fuel Holders, Products and Accessories	1,437,533	1,296,145	90.16%	1,016,899	70.74%	1,288,029	89.60%
343.00 Prime Movers	8,794,167	7,831,689	89.06%	5,966,874	67.85%	7,557,786	85.94%
344.00 Generators and Devices	4,617,155	3,324,639	72.01%	2,764,391	59.87%	3,501,444	75.84%
345.00 Accessory Electric Equipment	1,724,180	1,476,473	85.63%	1,176,927	68.26%	1,490,725	86.46%
346.00 Miscellaneous Power Plant Equipment	1,173,488	741,812	63.21%	611,546	52.11%	774,599	66.01%
Total West Phoenix CT Units 1-2	$18,626,958	$15,151,177	81.34%	$11,961,858	64.22%	$15,151,177	81.34%

ARIZONA PUBLIC SERVICE COMPANY
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Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
West Phoenix Common							
341.00 Structures and Improvements	$9,565,479	$4,055,069	42.39%	$2,910,919	30.43%	$4,055,069	42.39%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices							
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total West Phoenix Common	$9,565,479	$4,055,069	42.39%	$2,910,919	30.43%	$4,055,069	42.39%
Yucca							
341.00 Structures and Improvements	$1,730,884	$374,159	21.62%	$195,283	11.28%	$351,103	20.28%
342.00 Fuel Holders, Products and Accessories	4,819,210	3,255,895	67.56%	1,649,323	34.22%	3,143,385	65.23%
343.00 Prime Movers	76,131,450	12,651,159	16.62%	8,436,827	11.08%	12,528,897	16.46%
344.00 Generators and Devices	7,937,599	4,585,091	57.76%	2,537,877	31.97%	4,969,421	62.61%
345.00 Accessory Electric Equipment	3,251,231	2,186,561	67.25%	1,077,121	33.13%	2,086,231	64.17%
346.00 Miscellaneous Power Plant Equipment	682,399	451,201	66.12%	216,925	31.79%	425,030	62.28%
Total Yucca	$94,552,773	$23,504,066	24.86%	$14,113,356	14.93%	$23,504,066	24.86%
Yucca CT Units 1-4							
341.00 Structures and Improvements	$1,193,877	$336,710	28.20%	$160,084	13.41%	$313,660	26.27%
342.00 Fuel Holders, Products and Accessories	3,316,669	3,151,114	95.01%	1,550,836	46.76%	3,038,620	91.62%
343.00 Prime Movers	7,962,254	7,897,668	99.19%	3,968,568	49.84%	7,775,787	97.66%
344.00 Generators and Devices	7,883,898	4,581,346	58.11%	2,534,357	32.15%	4,965,676	62.99%
345.00 Accessory Electric Equipment	2,838,650	2,158,197	76.03%	1,050,078	36.99%	2,057,463	72.48%
346.00 Miscellaneous Power Plant Equipment	682,399	451,201	66.12%	216,925	31.79%	425,030	62.28%
Total Yucca CT Units 1-4	$23,877,747	$18,576,237	77.80%	$9,480,848	39.71%	$18,576,237	77.80%
Yucca CT Units 5-6							
341.00 Structures and Improvements	$537,007	$37,449	6.97%	$35,199	6.55%	$37,443	6.97%
342.00 Fuel Holders, Products and Accessories	1,502,541	104,781	6.97%	98,486	6.55%	104,765	6.97%
343.00 Prime Movers	68,169,196	4,753,490	6.97%	4,468,259	6.55%	4,753,110	6.97%
344.00 Generators and Devices	53,701	3,745	6.97%	3,520	6.55%	3,744	6.97%
345.00 Accessory Electric Equipment	412,581	28,365	6.87%	27,043	6.55%	28,767	6.97%
346.00 Miscellaneous Power Plant Equipment							
Total Yucca CT Units 5-6	$70,675,026	$4,927,830	6.97%	$4,632,507	6.55%	$4,927,830	6.97%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$168,068,708	$90,636,019	53.93%	$6,830,100	4.06%	$97,466,119	57.99%
312.00 Boiler Plant Equipment	1,114,508,323	556,790,163	49.96%	49,640,770	4.45%	606,430,932	54.41%
314.00 Turbogenerator Units	260,287,212	129,860,045	49.89%	12,850,383	4.94%	142,710,428	54.83%
315.00 Accessory Electric Equipment	164,350,445	90,544,133	55.09%	7,418,453	4.51%	97,962,586	59.61%
316.00 Miscellaneous Power Plant Equipment	81,726,740	37,582,478	45.99%	3,539,103	4.33%	41,121,581	50.32%
Total Steam Production Plant	$1,788,941,428	$905,412,837	50.61%	$80,278,809	4.49%	$985,691,646	55.10%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$698,846,801	$383,581,034	54.89%	$843,888	0.12%	$384,424,922	55.01%
322.00 Reactor Plant Equipment	1,130,933,859	566,004,611	50.05%	(4,884,730)	-0.43%	561,119,881	49.62%
323.00 Turbogenerator Units	354,174,138	182,997,393	51.67%	(340,611)	-0.10%	182,656,783	51.57%
324.00 Accessory Electric Equipment	275,016,677	166,169,883	60.42%	593,992	0.22%	166,763,875	60.64%
325.00 Miscellaneous Power Plant Equipment	145,211,312	72,567,826	49.97%	(1,083,497)	-0.75%	71,484,329	49.23%
Total Nuclear Production Plant	$2,604,182,787	$1,371,320,748	52.66%	($4,870,958)	-0.19%	$1,366,449,789	52.47%
OTHER PRODUCTION							
341.00 Structures and Improvements	$67,262,184	$21,421,911	31.85%	($1,324,080)	-1.97%	$20,097,831	29.88%
342.00 Fuel Holders, Products and Accessories	42,179,346	16,993,526	40.29%	(911,741)	-2.16%	16,081,785	38.13%
343.00 Prime Movers	664,641,919	217,437,077	32.71%	(16,073,468)	-2.42%	201,363,609	30.30%
344.00 Generators and Devices	588,169,993	138,974,256	23.63%	50,380,698	8.57%	189,354,954	32.19%
345.00 Accessory Electric Equipment	86,274,192	31,720,446	36.77%	(2,029,638)	-2.35%	29,690,808	34.41%
346.00 Miscellaneous Power Plant Equipment	14,711,421	4,908,526	33.37%	(269,115)	-1.83%	4,639,410	31.54%
Total Other Production Plant	$1,463,239,055	$431,455,742	29.49%	$29,772,656	2.03%	$461,228,398	31.52%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$95,935	$52,904	55.15%			$52,904	55.15%
353.00 Station Equipment	98,305,656	20,914,705	21.28%	1,226,343	1.25%	22,141,048	22.52%
354.00 Towers and Fixtures	1,329,316	421,027	31.67%			421,027	31.67%
355.00 Poles and Fixtures	1,370,085	145,544	10.62%	29,109	2.12%	174,653	12.75%
356.00 Overhead Conductors and Devices	1,947,677	333,317	17.11%	83,223	4.27%	416,540	21.39%
Total Transmission Plant	$103,048,669	$21,867,498	21.22%	$1,338,675	1.30%	$23,206,173	22.52%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$60,888,680	$13,552,575	22.26%	$873,227	1.43%	$14,425,802	23.69%
362.00 Station Equipment	406,799,985	84,799,301	20.85%	(10,686,667)	-2.63%	74,112,634	18.22%
364.01 Poles, Towers and Fixtures - Wood	310,263,864	91,375,643	29.45%	16,965,311	5.47%	108,340,954	34.92%
364.02 Poles, Towers and Fixtures - Steel	167,311,767	17,286,867	10.33%	1,728,687	1.03%	19,015,554	11.37%
365.00 Overhead Conductors and Devices	292,642,985	60,284,065	20.60%	(5,241,703)	-1.79%	55,042,361	18.81%
366.00 Underground Conduit	620,488,170	129,025,281	20.79%	7,124,765	1.15%	136,150,047	21.94%
367.00 Underground Conductors and Devices	1,422,708,502	399,128,076	28.05%	37,248,087	2.62%	436,376,163	30.67%
368.00 Line Transformers	717,419,840	185,848,537	25.91%	14,486,759	2.02%	200,335,296	27.92%
369.00 Services	323,341,677	111,932,430	34.62%	5,902,892	1.83%	117,835,322	36.44%
370.01 Meters - Electronic	62,207,543	15,853,516	25.48%	193,813	0.31%	16,047,329	25.80%
370.03 Meters - AMI	117,715,566	9,009,526	7.65%			9,009,526	7.65%
371.00 Installations on Customers' Premises	39,842,142	8,753,211	21.97%	1,526,871	3.83%	10,280,082	25.80%
373.00 Street Lighting and Signal Systems	73,702,827	16,865,318	22.88%	2,941,898	3.99%	19,807,216	26.87%
Total Distribution Plant	$4,615,333,548	$1,143,714,346	24.78%	$73,063,940	1.58%	$1,216,778,286	26.36%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$107,643,854	$27,025,896	25.11%	$837,903	0.78%	$27,863,799	25.89%
391.CM Office Furn. and Equip. - Computer	89,098,127	35,700,837	40.07%	(57,492)	-0.06%	35,643,344	40.00%
397.00 Communication Equipment	152,910,098	64,911,285	42.45%			64,911,285	42.45%
Total Depreciable	$349,652,079	$127,638,017	36.50%	$780,411	0.22%	$128,418,428	36.73%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$49,130,094	$14,343,161	29.19%			$14,343,161	29.19%
393.00 Stores Equipment	256,764	33,264	12.96%			33,264	12.96%
394.00 Tools, Shop and Garage Equipment	28,424,012	11,518,585	40.52%			11,518,585	40.52%
395.00 Laboratory Equipment	1,385,366	878,477	63.41%			878,477	63.41%
398.00 Miscellaneous Equipment	5,909,111	1,190,470	20.15%			1,190,470	20.15%
Total Amortizable	$85,105,347	$27,963,957	32.86%			$27,963,957	32.86%
Total General Plant	$434,757,426	$155,601,974	35.79%	$780,411	0.18%	$156,382,385	35.97%
TOTAL UTILITY	$11,009,502,913	$4,029,373,145	36.60%	$180,363,533	1.64%	$4,209,736,678	38.24%
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$72,335,187	$24,479,413	33.84%	$1,482,176	2.05%	$25,961,589	35.89%
312.00 Boiler Plant Equipment	521,789,973	150,404,763	28.82%	4,858,009	0.93%	155,262,773	29.76%
314.00 Turbogenerator Units	125,558,183	35,292,187	28.11%	2,367,377	1.89%	37,659,564	29.99%
315.00 Accessory Electric Equipment	93,701,286	43,751,882	46.69%	2,330,566	2.49%	46,082,448	49.18%
316.00 Miscellaneous Power Plant Equipment	27,985,746	8,545,568	30.54%	364,559	1.30%	8,910,127	31.84%
Total Cholla	$841,370,375	$262,473,814	31.20%	$11,402,688	1.36%	$273,876,501	32.55%
Cholla Unit 1							
311.00 Structures and Improvements	$4,372,274	$1,681,575	38.46%	$88,899	2.03%	$1,770,475	40.49%
312.00 Boiler Plant Equipment	73,213,804	20,333,102	27.77%	918,059	1.25%	21,251,162	29.03%
314.00 Turbogenerator Units	25,640,590	5,510,173	21.49%	334,522	1.30%	5,844,694	22.79%
315.00 Accessory Electric Equipment	8,816,493	3,316,587	37.62%	172,463	1.96%	3,489,050	39.57%
316.00 Miscellaneous Power Plant Equipment	2,838,727	1,162,297	40.94%	62,764	2.21%	1,225,061	43.16%
Total Cholla Unit 1	$114,881,888	$32,003,735	27.86%	$1,576,707	1.37%	$33,580,442	29.23%
Cholla Unit 2							
311.00 Structures and Improvements	$6,168,012	$2,385,288	38.67%	$128,806	2.09%	$2,514,093	40.76%
312.00 Boiler Plant Equipment	162,323,693	73,551,883	45.31%	4,163,597	2.56%	77,715,480	47.88%
314.00 Turbogenerator Units	44,157,763	14,144,366	32.03%	984,570	2.23%	15,128,936	34.26%
315.00 Accessory Electric Equipment	46,110,434	22,990,493	49.86%	1,290,295	2.80%	24,280,788	52.66%
316.00 Miscellaneous Power Plant Equipment	8,714,396	2,525,255	28.98%	132,099	1.52%	2,657,354	30.49%
Total Cholla Unit 2	$267,474,298	$115,597,285	43.22%	$6,699,366	2.50%	$122,296,651	45.72%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Cholla Unit 3							
311.00 Structures and Improvements	$9,984,226	$4,808,789	48.16%	$240,166	2.41%	$5,048,955	50.57%
312.00 Boiler Plant Equipment	228,064,943	44,142,614	19.36%	(317,770)	-0.14%	43,824,844	19.22%
314.00 Turbogenerator Units	54,849,058	15,303,829	27.90%	1,021,849	1.86%	16,325,679	29.76%
315.00 Accessory Electric Equipment	31,001,286	15,127,881	48.80%	772,765	2.49%	15,900,645	51.29%
316.00 Miscellaneous Power Plant Equipment	4,593,291	1,888,063	41.10%	91,790	2.00%	1,979,853	43.10%
Total Cholla Unit 3	$328,492,804	$81,271,177	24.74%	$1,808,800	0.55%	$83,079,977	25.29%
Cholla Common							
311.00 Structures and Improvements	$51,810,675	$15,603,761	30.12%	$1,024,305	1.98%	$16,628,066	32.09%
312.00 Boiler Plant Equipment	58,187,533	12,377,164	21.27%	94,123	0.16%	12,471,287	21.43%
314.00 Turbogenerator Units	910,772	333,819	36.65%	26,436	2.90%	360,255	39.55%
315.00 Accessory Electric Equipment	7,773,073	2,316,920	29.81%	95,044	1.22%	2,411,964	31.03%
316.00 Miscellaneous Power Plant Equipment	11,839,332	2,969,953	25.09%	77,906	0.66%	3,047,859	25.74%
Total Cholla Common	$130,521,385	$33,601,617	25.74%	$1,317,814	1.01%	$34,919,431	26.75%
Four Corners							
311.00 Structures and Improvements	$57,549,016	$47,168,132	81.96%	$3,415,526	5.93%	$50,583,658	87.90%
312.00 Boiler Plant Equipment	375,402,116	294,235,287	78.38%	32,821,268	8.74%	327,056,555	87.12%
314.00 Turbogenerator Units	73,354,578	57,411,102	78.27%	5,048,963	6.88%	62,460,065	85.15%
315.00 Accessory Electric Equipment	40,063,953	30,226,932	75.45%	3,328,238	8.31%	33,555,171	83.75%
316.00 Miscellaneous Power Plant Equipment	25,722,887	16,396,859	63.74%	1,645,299	6.40%	18,042,158	70.14%
Total Four Corners	$572,092,550	$445,438,313	77.86%	$46,259,293	8.09%	$491,697,606	85.95%
Four Corners Units 1-3							
311.00 Structures and Improvements	$40,683,091	$40,683,091	100.00%			$40,683,091	100.00%
312.00 Boiler Plant Equipment	242,101,914	242,101,914	100.00%			242,101,914	100.00%
314.00 Turbogenerator Units	50,183,693	50,183,693	100.00%			50,183,693	100.00%
315.00 Accessory Electric Equipment	24,333,485	24,333,485	100.00%			24,333,485	100.00%
316.00 Miscellaneous Power Plant Equipment	11,655,314	11,655,314	100.00%			11,655,314	100.00%
Total Four Corners Units 1-3	$368,957,497	$368,957,497	100.00%			$368,957,497	100.00%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Four Corners Units 4-5							
311.00 Structures and Improvements	$11,882,266	$4,444,578	37.41%	$2,940,097	24.74%	$7,384,675	62.15%
312.00 Boiler Plant Equipment	118,062,055	45,351,598	38.41%	31,212,592	26.44%	76,564,190	64.85%
314.00 Turbogenerator Units	21,183,385	6,104,744	28.82%	4,736,536	22.36%	10,841,280	51.18%
315.00 Accessory Electric Equipment	11,137,088	4,215,044	37.85%	2,916,738	26.19%	7,131,782	64.04%
316.00 Miscellaneous Power Plant Equipment	3,614,952	1,214,162	33.59%	820,691	22.70%	2,034,852	56.29%
Total Four Corners Units 4-5	$165,879,746	$61,330,126	36.97%	$42,626,654	25.70%	$103,956,780	62.67%
Four Corners Common							
311.00 Structures and Improvements	$4,983,659	$2,040,463	40.94%	$475,429	9.54%	$2,515,892	50.48%
312.00 Boiler Plant Equipment	15,238,147	6,781,775	44.51%	1,608,675	10.56%	8,390,450	55.06%
314.00 Turbogenerator Units	1,987,500	1,122,665	56.49%	312,427	15.72%	1,435,092	72.21%
315.00 Accessory Electric Equipment	4,593,380	1,678,403	36.54%	411,500	8.96%	2,089,903	45.50%
316.00 Miscellaneous Power Plant Equipment	10,452,621	3,527,384	33.75%	824,608	7.89%	4,351,991	41.64%
Total Four Corners Common	$37,255,307	$15,150,690	40.67%	$3,632,639	9.75%	$18,783,329	50.42%
Navajo Units 1-3							
311.00 Structures and Improvements	$29,113,530	$14,337,123	49.25%	$1,030,845	3.54%	$15,367,968	52.79%
312.00 Boiler Plant Equipment	166,003,214	79,671,764	47.99%	5,756,297	3.47%	85,428,061	51.46%
314.00 Turbogenerator Units	24,699,305	14,542,391	58.88%	1,090,679	4.42%	15,633,070	63.29%
315.00 Accessory Electric Equipment	21,491,344	11,936,434	55.54%	871,360	4.05%	12,807,794	59.60%
316.00 Miscellaneous Power Plant Equipment	17,228,597	7,410,835	43.01%	529,674	3.07%	7,940,509	46.09%
Total Navajo Units 1-3	$258,535,990	$127,898,547	49.47%	$9,278,855	3.59%	$137,177,403	53.06%
Ocotillo Units 1-2							
311.00 Structures and Improvements	$4,759,658	$2,566,375	53.92%	$505,813	10.63%	$3,072,188	64.55%
312.00 Boiler Plant Equipment	25,218,648	17,154,643	68.02%	3,293,691	13.06%	20,448,334	81.08%
314.00 Turbogenerator Units	20,161,583	11,206,819	55.59%	2,171,150	10.77%	13,377,968	66.35%
315.00 Accessory Electric Equipment	3,425,956	1,964,010	57.33%	379,373	11.07%	2,343,383	68.40%
316.00 Miscellaneous Power Plant Equipment	6,010,574	2,740,284	45.59%	529,164	8.80%	3,269,448	54.39%
Total Ocotillo Units 1-2	$59,576,419	$35,632,130	59.81%	$6,879,191	11.55%	$42,511,321	71.36%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Saguaro Units 1-2							
311.00 Structures and Improvements	$4,311,317	$2,084,975	48.36%	$395,740	9.18%	$2,480,715	57.54%
312.00 Boiler Plant Equipment	26,094,372	15,323,705	58.72%	2,911,504	11.16%	18,235,209	69.88%
314.00 Turbogenerator Units	16,513,563	11,407,546	69.08%	2,172,214	13.15%	13,579,761	82.23%
315.00 Accessory Electric Equipment	5,667,906	2,664,875	47.02%	508,915	8.98%	3,173,790	56.00%
316.00 Miscellaneous Power Plant Equipment	4,778,936	2,488,931	52.08%	470,408	9.84%	2,959,339	61.92%
Total Saguaro Units 1-2	$57,366,094	$33,970,033	59.22%	$6,458,781	11.26%	$40,428,815	70.48%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$698,846,801	$383,581,034	54.89%	$843,888	0.12%	$384,424,922	55.01%
322.00 Reactor Plant Equipment	1,130,933,859	566,004,611	50.05%	(4,884,730)	-0.43%	561,119,881	49.62%
323.00 Turbogenerator Units	354,174,138	182,997,393	51.67%	(340,611)	-0.10%	182,656,783	51.57%
324.00 Accessory Electric Equipment	275,016,677	166,169,883	60.42%	593,992	0.22%	166,763,875	60.64%
325.00 Miscellaneous Power Plant Equipment	145,211,312	72,567,826	49.97%	(1,083,497)	-0.75%	71,484,329	49.23%
Total Palo Verde	$2,604,182,787	$1,371,320,748	52.66%	($4,870,958)	-0.19%	$1,366,449,789	52.47%
Palo Verde Unit 1							
321.00 Structures and Improvements	$156,705,345	$100,210,002	63.95%	$400,840	0.26%	$100,610,842	64.20%
322.00 Reactor Plant Equipment	454,207,200	243,605,126	53.63%	(662,666)	-0.15%	242,942,460	53.49%
323.00 Turbogenerator Units	125,268,196	68,563,737	54.73%	(117,672)	-0.09%	68,446,065	54.64%
324.00 Accessory Electric Equipment	114,860,792	73,918,349	64.35%	295,673	0.26%	74,214,023	64.61%
325.00 Miscellaneous Power Plant Equipment	30,801,758	18,071,429	58.67%	(82,267)	-0.27%	17,989,161	58.40%
Total Palo Verde Unit 1	$881,843,291	$504,368,642	57.19%	($166,092)	-0.02%	$504,202,551	57.18%
Palo Verde Unit 2							
321.00 Structures and Improvements	$91,657,911	$55,303,443	60.34%	$276,517	0.30%	$55,579,960	60.64%
322.00 Reactor Plant Equipment	234,287,478	116,599,299	49.77%	(2,884,849)	-1.23%	113,714,449	48.54%
323.00 Turbogenerator Units	78,612,699	42,121,517	53.58%	(68,618)	-0.09%	42,052,898	53.49%
324.00 Accessory Electric Equipment	49,937,247	29,374,046	58.82%	99,282	0.20%	29,473,328	59.02%
325.00 Miscellaneous Power Plant Equipment	27,087,580	14,139,116	52.20%	(26,267)	-0.10%	14,112,850	52.10%
Total Palo Verde Unit 2	$481,582,915	$257,537,421	53.48%	($2,603,935)	-0.54%	$254,933,485	52.94%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Palo Verde Unit 3							
321.00 Structures and Improvements	$163,192,491	$94,101,615	57.66%	$470,508	0.29%	$94,572,123	57.95%
322.00 Reactor Plant Equipment	414,451,923	189,696,851	45.77%	(1,118,642)	-0.27%	188,578,209	45.50%
323.00 Turbogenerator Units	147,910,539	71,660,130	48.45%	(134,948)	-0.09%	71,525,182	48.36%
324.00 Accessory Electric Equipment	90,837,828	51,641,827	56.85%	164,867	0.18%	51,806,693	57.03%
325.00 Miscellaneous Power Plant Equipment	28,712,249	15,119,524	52.66%	(47,232)	-0.16%	15,072,292	52.49%
Total Palo Verde Unit 3	$845,105,030	$422,219,947	49.96%	($665,447)	-0.08%	$421,554,500	49.88%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$171,609,224	$70,713,132	41.21%	($214,700)	-0.13%	$70,498,432	41.08%
322.00 Reactor Plant Equipment	133,326	40,132	30.10%	562	0.42%	40,694	30.52%
323.00 Turbogenerator Units	217,756	108,220	49.70%	97	0.04%	108,317	49.74%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	88,819	44,663	50.29%	(1,036)	-1.17%	43,627	49.12%
Total Palo Verde Water Reclamation	$172,049,125	$70,906,147	41.21%	($215,077)	-0.13%	$70,691,070	41.09%
Palo Verde Common							
321.00 Structures and Improvements	$115,681,830	$63,252,842	54.68%	($89,278)	-0.08%	$63,163,565	54.60%
322.00 Reactor Plant Equipment	27,853,932	16,063,204	57.67%	(219,135)	-0.79%	15,844,069	56.88%
323.00 Turbogenerator Units	2,164,948	543,789	25.12%	(19,470)	-0.90%	524,320	24.22%
324.00 Accessory Electric Equipment	19,380,810	11,235,661	57.97%	34,169	0.18%	11,269,831	58.15%
325.00 Miscellaneous Power Plant Equipment	58,520,906	25,193,094	43.05%	(926,695)	-1.58%	24,266,399	41.47%
Total Palo Verde Common	$223,602,426	$116,288,591	52.01%	($1,220,408)	-0.55%	$115,068,183	51.46%
OTHER PRODUCTION (by Unit)							
Douglas CT							
341.00 Structures and Improvements	$49,075	$25,435	51.83%	($1,272)	-2.59%	$24,163	49.24%
342.00 Fuel Holders, Products and Accessories	137,759	126,131	91.56%	(6,812)	-4.94%	119,319	86.61%
343.00 Prime Movers	1,101,449	1,126,800	102.30%	(56,340)	-5.12%	1,070,460	97.19%
344.00 Generators and Devices	551,765	566,231	102.62%	(28,312)	-5.13%	537,919	97.49%
345.00 Accessory Electric Equipment	353,277	352,551	99.79%	(18,130)	-5.13%	334,422	94.66%
346.00 Miscellaneous Power Plant Equipment	40,913	38,228	93.44%	(1,911)	-4.67%	36,316	88.76%
Total Douglas CT	$2,234,238	$2,235,376	100.05%	($112,776)	-5.05%	$2,122,600	95.00%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$721,568	$438,132	60.72%	($22,775)	-3.16%	$415,356	57.56%
342.00 Fuel Holders, Products and Accessories	791,584	637,923	80.59%	(31,896)	-4.03%	606,027	76.56%
343.00 Prime Movers	6,540,275	6,092,814	93.16%	(308,273)	-4.71%	5,784,541	88.44%
344.00 Generators and Devices	7,596,314	5,144,430	67.72%	53,969	0.71%	5,198,399	68.43%
345.00 Accessory Electric Equipment	1,677,431	1,425,372	84.97%	(74,887)	-4.46%	1,350,485	80.51%
346.00 Miscellaneous Power Plant Equipment	637,727	509,749	79.93%	(26,272)	-4.12%	483,477	75.81%
Total Octillo CT Units 1-2	$17,964,899	$14,248,419	79.31%	($410,134)	-2.28%	$13,838,285	77.03%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$22,197,402	$4,378,540	19.73%	($426,583)	-1.92%	$3,951,957	17.80%
342.00 Fuel Holders, Products and Accessories	2,637,978	184,863	7.01%	(9,243)	-0.35%	175,620	6.66%
343.00 Prime Movers	177,860,527	36,294,403	20.41%	(5,113,430)	-2.87%	31,180,973	17.53%
344.00 Generators and Devices	279,212,258	41,223,600	14.76%	44,937,611	16.09%	86,161,211	30.86%
345.00 Accessory Electric Equipment	22,584,466	4,603,215	20.38%	(544,407)	-2.41%	4,058,808	17.97%
346.00 Miscellaneous Power Plant Equipment	4,005,866	306,853	7.66%	(15,343)	-0.38%	291,510	7.28%
Total Redhawk CC Units 1-2	$508,498,497	$86,991,473	17.11%	$38,828,605	7.64%	$125,820,078	24.74%
Saguaro							
341.00 Structures and Improvements	$1,885,444	$1,070,851	56.80%	($54,822)	-2.91%	$1,016,029	53.89%
342.00 Fuel Holders, Products and Accessories	1,376,702	1,212,223	88.05%	(64,138)	-4.66%	1,148,085	83.39%
343.00 Prime Movers	8,624,812	7,818,061	90.65%	(393,210)	-4.56%	7,424,851	86.09%
344.00 Generators and Devices	32,512,372	10,659,190	32.79%	(384,189)	-1.18%	10,275,001	31.60%
345.00 Accessory Electric Equipment	1,701,779	1,544,715	90.77%	(79,063)	-4.65%	1,465,652	86.12%
346.00 Miscellaneous Power Plant Equipment	868,485	658,741	75.85%	(33,361)	-3.84%	625,381	72.01%
Total Saguaro	$46,969,594	$22,963,781	48.89%	($1,008,783)	-2.15%	$21,954,998	46.74%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$1,885,444	$1,070,851	56.80%	($54,822)	-2.91%	$1,016,029	53.89%
342.00 Fuel Holders, Products and Accessories	1,376,702	1,212,223	88.05%	(64,138)	-4.66%	1,148,085	83.39%
343.00 Prime Movers	7,983,905	7,644,559	95.75%	(384,535)	-4.82%	7,260,024	90.93%
344.00 Generators and Devices	4,487,988	3,072,612	68.46%	(4,860)	-0.11%	3,067,752	68.35%
345.00 Accessory Electric Equipment	1,579,226	1,511,538	95.71%	(77,405)	-4.90%	1,434,134	90.81%
346.00 Miscellaneous Power Plant Equipment	868,485	658,741	75.85%	(33,361)	-3.84%	625,381	72.01%
Total Saguaro CT Units 1-2	$18,181,750	$15,170,525	83.44%	($619,120)	-3.41%	$14,551,404	80.03%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	640,907	173,502	27.07%	(8,675)	-1.35%	164,827	25.72%
344.00 Generators and Devices	28,024,384	7,586,578	27.07%	(379,329)	-1.35%	7,207,249	25.72%
345.00 Accessory Electric Equipment	122,553	33,177	27.07%	(1,659)	-1.35%	31,518	25.72%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$28,787,844	$7,793,257	27.07%	($389,663)	-1.35%	$7,403,594	25.72%
Solar Units							
341.00 Structures and Improvements	$418,403	$451,776	107.98%	($22,734)	-5.43%	$429,042	102.54%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	15,963,981	13,315,955	83.41%	(217,589)	-1.36%	13,098,366	82.05%
345.00 Accessory Electric Equipment	728,283	263,776	36.22%	(13,189)	-1.81%	250,587	34.41%
346.00 Miscellaneous Power Plant Equipment							
Total Solar Units	$17,110,667	$14,031,507	82.00%	($253,512)	-1.48%	$13,777,995	80.52%
Sundance							
341.00 Structures and Improvements	$12,653,247	$5,967,030	47.16%	($298,352)	-2.36%	$5,668,679	44.80%
342.00 Fuel Holders, Products and Accessories	4,325,769	2,050,063	47.39%	(102,503)	-2.37%	1,947,560	45.02%
343.00 Prime Movers	229,732,211	109,945,362	47.86%	(5,497,268)	-2.39%	104,448,094	45.47%
344.00 Generators and Devices	301,285	107,863	35.80%	(5,393)	-1.79%	102,470	34.01%
345.00 Accessory Electric Equipment	26,408,712	12,515,582	47.39%	(625,779)	-2.37%	11,889,803	45.02%
346.00 Miscellaneous Power Plant Equipment	2,028,889	733,299	36.14%	(36,665)	-1.81%	696,634	34.34%
Total Sun Dance	$275,450,113	$131,319,200	47.67%	($6,565,960)	-2.38%	$124,753,240	45.29%
West Phoenix							
341.00 Structures and Improvements	$27,606,161	$8,707,956	31.54%	($466,454)	-1.69%	$8,241,502	29.85%
342.00 Fuel Holders, Products and Accessories	28,090,344	9,470,027	33.71%	(528,238)	-1.88%	8,941,789	31.83%
343.00 Prime Movers	164,651,195	42,971,325	26.10%	(4,045,531)	-2.46%	38,925,794	23.64%
344.00 Generators and Devices	244,094,419	63,175,259	25.88%	5,836,908	2.39%	69,012,168	28.27%
345.00 Accessory Electric Equipment	29,569,013	8,812,067	29.80%	(557,246)	-1.88%	8,254,821	27.92%
346.00 Miscellaneous Power Plant Equipment	6,447,142	2,214,255	34.34%	(133,194)	-2.07%	2,081,061	32.28%
Total West Phoenix	$500,458,274	$135,350,890	27.05%	$106,245	0.02%	$135,457,135	27.07%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$1,710,485	$248,375	14.52%	($16,390)	-0.96%	$231,985	13.56%
342.00 Fuel Holders, Products and Accessories	22,517,702	7,014,024	31.15%	(405,438)	-1.80%	6,608,587	29.35%
343.00 Prime Movers							
344.00 Generators and Devices	92,566,116	27,950,267	30.19%	5,630,226	6.08%	33,580,493	36.28%
345.00 Accessory Electric Equipment	13,561,670	4,265,508	31.45%	(328,080)	-2.42%	3,937,428	29.03%
346.00 Miscellaneous Power Plant Equipment	4,722,353	1,349,606	28.58%	(88,418)	-1.87%	1,261,187	26.71%
Total West Phoenix CC Units 1-3	$135,078,326	$40,827,780	30.23%	$4,791,899	3.55%	$45,619,679	33.77%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$4,584,726	$1,137,382	24.81%	($56,869)	-1.24%	$1,080,513	23.57%
342.00 Fuel Holders, Products and Accessories	4,135,109	1,100,183	26.61%	(55,009)	-1.33%	1,045,174	25.28%
343.00 Prime Movers	54,680,534	14,548,250	26.61%	(727,413)	-1.33%	13,820,838	25.28%
344.00 Generators and Devices	15,548,138	3,788,787	24.37%	353,438	2.27%	4,142,226	26.64%
345.00 Accessory Electric Equipment	2,569,550	307,126	11.95%	(15,356)	-0.60%	291,770	11.35%
346.00 Miscellaneous Power Plant Equipment	315,741	25,696	8.14%	(2,158)	-0.68%	23,538	7.45%
Total West Phoenix CC Unit 4	$81,833,798	$20,907,424	25.55%	($503,366)	-0.62%	$20,404,058	24.93%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$10,865,036	$2,458,254	22.63%	($122,913)	-1.13%	$2,335,341	21.49%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	101,176,494	20,454,163	20.22%	(2,906,993)	-2.87%	17,547,170	17.34%
344.00 Generators and Devices	131,363,010	27,794,607	21.16%	(6,601)	-0.01%	27,788,006	21.15%
345.00 Accessory Electric Equipment	11,713,613	2,668,315	22.78%	(133,416)	-1.14%	2,534,899	21.64%
346.00 Miscellaneous Power Plant Equipment	235,560	22,881	9.71%	(1,144)	-0.49%	21,737	9.23%
Total West Phoenix CC Unit 5	$255,353,713	$53,398,219	20.91%	($3,171,067)	-1.24%	$50,227,152	19.67%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$880,435	$566,942	64.39%	($28,347)	-3.22%	$538,595	61.17%
342.00 Fuel Holders, Products and Accessories	1,437,533	1,355,820	94.32%	(67,791)	-4.72%	1,288,029	89.60%
343.00 Prime Movers	8,794,167	7,968,912	90.62%	(411,126)	-4.67%	7,557,786	85.94%
344.00 Generators and Devices	4,617,155	3,641,598	78.87%	(140,154)	-3.04%	3,501,444	75.84%
345.00 Accessory Electric Equipment	1,724,180	1,571,119	91.12%	(80,394)	-4.66%	1,490,725	86.46%
346.00 Miscellaneous Power Plant Equipment	1,173,488	816,073	69.54%	(41,474)	-3.53%	774,599	66.01%
Total West Phoenix CT Units 1-2	$18,626,958	$15,920,463	85.47%	($769,286)	-4.13%	$15,151,177	81.34%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
West Phoenix Common							
341.00 Structures and Improvements	$9,565,479	$4,297,004	44.92%	($241,935)	-2.53%	$4,055,069	42.39%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices							
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total West Phoenix Common	$9,565,479	$4,297,004	44.92%	($241,935)	-2.53%	$4,055,069	42.39%
Yucca							
341.00 Structures and Improvements	$1,730,884	$382,191	22.08%	($31,088)	-1.80%	$351,103	20.28%
342.00 Fuel Holders, Products and Accessories	4,819,210	3,312,297	68.73%	(168,911)	-3.50%	3,143,385	65.23%
343.00 Prime Movers	76,131,450	13,188,313	17.32%	(659,416)	-0.87%	12,528,897	16.46%
344.00 Generators and Devices	7,937,599	4,781,728	60.24%	187,693	2.36%	4,969,421	62.61%
345.00 Accessory Electric Equipment	3,251,231	2,203,167	67.76%	(116,936)	-3.60%	2,086,231	64.17%
346.00 Miscellaneous Power Plant Equipment	682,399	447,400	65.56%	(22,370)	-3.28%	425,030	62.28%
Total Yucca	$94,552,773	$24,315,095	25.72%	($811,029)	-0.86%	$23,504,066	24.86%
Yucca CT Units 1-4							
341.00 Structures and Improvements	$1,193,877	$342,777	28.71%	($29,117)	-2.44%	$313,660	26.27%
342.00 Fuel Holders, Products and Accessories	3,316,669	3,202,018	96.54%	(163,397)	-4.93%	3,038,620	91.62%
343.00 Prime Movers	7,962,254	8,185,039	102.80%	(409,252)	-5.14%	7,775,787	97.66%
344.00 Generators and Devices	7,883,898	4,777,787	60.60%	187,890	2.38%	4,965,676	62.99%
345.00 Accessory Electric Equipment	2,838,650	2,172,886	76.55%	(115,422)	-4.07%	2,057,463	72.48%
346.00 Miscellaneous Power Plant Equipment	682,399	447,400	65.56%	(22,370)	-3.28%	425,030	62.28%
Total Yucca CT Units 1-4	$23,877,747	$19,127,906	80.11%	($551,669)	-2.31%	$18,576,237	77.80%
Yucca CT Units 5-6							
341.00 Structures and Improvements	$537,007	$39,414	7.34%	($1,971)	-0.37%	$37,443	6.97%
342.00 Fuel Holders, Products and Accessories	1,502,541	110,279	7.34%	(5,514)	-0.37%	104,765	6.97%
343.00 Prime Movers	68,169,196	5,003,274	7.34%	(250,164)	-0.37%	4,753,110	6.97%
344.00 Generators and Devices	53,701	3,941	7.34%	(197)	-0.37%	3,744	6.97%
345.00 Accessory Electric Equipment	412,581	30,281	7.34%	(1,514)	-0.37%	28,767	6.97%
346.00 Miscellaneous Power Plant Equipment							
Total Yucca CT Units 5-6	$70,675,026	$5,187,189	7.34%	($259,359)	-0.37%	$4,927,830	6.97%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
311.00 Structures and Improvements	$178,569,299	$10,500,591	$168,068,708	-1.3%	-9.8%	($136,508)	($16,518,367)	($16,654,874)	-9.3%
312.00 Boiler Plant Equipment	1,206,247,872	91,739,549	1,114,508,323	-20.1%	-12.3%	(18,439,649)	(136,617,735)	(155,057,385)	-12.9%
314.00 Turbogenerator Units	297,937,926	37,650,714	260,287,212	-3.2%	-11.7%	(1,204,823)	(30,538,479)	(31,743,302)	-10.7%
315.00 Accessory Electric Equipment	169,852,137	5,501,692	164,350,445	-10.9%	-10.3%	(599,684)	(16,861,794)	(17,461,479)	-10.3%
316.00 Miscellaneous Power Plant Equipment	85,846,998	4,120,258	81,726,740	-16.5%	-12.0%	(679,843)	(9,798,157)	(10,477,999)	-12.2%
Total Steam Production Plant	$1,938,454,232	$149,512,804	$1,788,941,428	-14.1%	-11.8%	($21,060,507)	($210,334,532)	($231,395,039)	-11.9%
NUCLEAR PRODUCTION									
321.00 Structures and Improvements	$727,309,483	$28,462,682	$698,846,801	-4.3%	-0.5%	($1,223,895)	($3,337,529)	($4,561,424)	-0.6%
322.00 Reactor Plant Equipment	1,207,856,362	76,922,503	1,130,933,859	-17.7%	-1.3%	(13,615,283)	(15,144,579)	(28,759,862)	-2.4%
323.00 Turbogenerator Units	413,417,445	59,243,307	354,174,138	-2.5%	-0.4%	(1,481,083)	(1,566,990)	(3,048,072)	-0.7%
324.00 Accessory Electric Equipment	283,285,283	8,268,606	275,016,677	-2.7%	-0.5%	(223,252)	(1,260,223)	(1,483,475)	-0.5%
325.00 Miscellaneous Power Plant Equipment	184,562,340	39,351,028	145,211,312	-4.7%	-0.5%	(1,849,498)	(668,167)	(2,517,666)	-1.4%
Total Nuclear Production Plant	$2,816,430,913	$212,248,126	$2,604,182,787	-8.7%	-0.8%	($18,393,012)	($21,977,488)	($40,370,499)	-1.4%
OTHER PRODUCTION									
341.00 Structures and Improvements	$71,911,949	$4,649,765	$67,262,184	-2.8%	5.0%	($130,193)	$3,363,109	$3,232,916	4.5%
342.00 Fuel Holders, Products and Accessories	43,756,132	1,576,786	42,179,346	-2.1%	5.0%	(33,113)	2,108,967	2,075,855	4.7%
343.00 Prime Movers	730,501,247	65,859,328	664,641,919	-7.3%	5.0%	(4,807,731)	33,232,096	28,424,365	3.9%
344.00 Generators and Devices	737,042,178	148,872,185	588,169,993	72.2%	5.0%	107,485,718	29,408,500	136,894,217	18.6%
345.00 Accessory Electric Equipment	92,977,991	6,703,799	86,274,192	-5.8%	5.0%	(388,820)	4,313,710	3,924,889	4.2%
346.00 Miscellaneous Power Plant Equipment	15,434,369	722,948	14,711,421	-0.5%	5.0%	(3,615)	735,571	731,956	4.7%
Total Other Production Plant	$1,691,623,866	$228,384,811	$1,463,239,055	44.7%	5.0%	$102,122,246	$73,161,953	$175,284,198	10.4%
TRANSMISSION PLANT									
352.02 Structures and Improvements	$95,935		$95,935						
353.00 Station Equipment	101,228,038	2,922,382	98,305,656	5.5%	-5.0%	160,731	(4,915,283)	(4,754,552)	-4.7%
354.00 Towers and Fixtures	1,329,316		1,329,316						
355.00 Poles and Fixtures	1,370,085		1,370,085		-20.0%		(274,017)	(274,017)	-20.0%
356.00 Overhead Conductors and Devices	2,086,319	138,642	1,947,677		-20.0%		(389,535)	(389,535)	-18.7%
Total Transmission Plant	$106,109,693	$3,061,024	$103,048,669	5.3%	-5.4%	$160,731	($5,578,835)	($5,418,104)	-5.1%
DISTRIBUTION PLANT									
361.00 Structures and Improvements	$62,458,930	$1,570,250	$60,888,680	5.1%	-5.0%	$80,083	($3,044,434)	($2,964,351)	-4.7%
362.00 Station Equipment	462,114,890	55,314,905	406,799,985	5.5%	10.0%	3,042,320	40,679,999	43,722,318	9.5%
364.01 Poles, Towers and Fixtures - Wood	420,599,219	110,335,355	310,263,864	10.3%	-5.0%	11,364,542	(15,513,193)	(4,148,652)	-1.0%
364.02 Poles, Towers and Fixtures - Steel	179,979,685	12,667,918	167,311,767	-10.3%	-10.0%	(1,304,796)	(16,731,177)	(18,035,972)	-10.0%
365.00 Overhead Conductors and Devices	364,201,375	71,558,390	292,642,985	1.5%	5.0%	1,073,376	14,632,149	15,705,525	4.3%
366.00 Underground Conduit	649,562,771	29,074,601	620,488,170	-3.6%	-5.0%	(1,046,686)	(31,024,409)	(32,071,094)	-4.9%
367.00 Underground Conductors and Devices	1,630,368,211	207,659,709	1,422,708,502	4.2%	-5.0%	8,721,708	(71,135,425)	(62,413,717)	-3.8%
368.00 Line Transformers	793,271,807	75,851,967	717,419,840	2.3%	-5.0%	1,744,595	(35,870,992)	(34,126,397)	-4.3%
369.00 Services	368,140,186	44,798,509	323,341,677	-4.2%	-5.0%	(1,881,537)	(16,167,084)	(18,048,621)	-4.9%
370.01 Meters - Electronic	128,697,096	66,489,553	62,207,543	0.5%		332,448		332,448	0.3%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
370.03 Meters - AMI	118,648,206	932,640	117,715,566						
371.00 Installations on Customers' Premises	48,544,798	8,702,656	39,842,142	-12.3%	-15.0%	(1,070,427)	(5,976,321)	(7,046,748)	-14.5%
373.00 Street Lighting and Signal Systems	86,926,219	13,223,392	73,702,827	0.6%	-10.0%	79,340	(7,370,283)	(7,290,942)	-8.4%
Total Distribution Plant	$5,313,513,393	$698,179,845	$4,615,333,548	3.0%	-3.2%	$21,134,966	($147,521,170)	($126,386,204)	-2.4%
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$130,079,520	$22,435,666	$107,643,854	-8.2%	-5.0%	($1,839,725)	($5,382,193)	($7,221,917)	-5.6%
391.CM Office Furn. and Equip. - Computer	255,865,944	166,767,817	89,098,127	-0.2%		(333,536)		(333,536)	-0.1%
397.00 Communication Equipment	215,660,988	62,750,890	152,910,098	0.1%		62,751		62,751	
Total Depreciable	$601,606,452	$251,954,373	$349,652,079	-0.8%	-1.5%	($2,110,509)	($5,382,193)	($7,492,702)	-1.2%
Amortizable									
391.FE Office Furn. and Equip. - Furniture	$78,701,437	$29,571,343	$49,130,094						
393.00 Stores Equipment	1,621,234	1,364,470	256,764						
394.00 Tools, Shop and Garage Equipment	41,668,206	13,244,194	28,424,012						
395.00 Laboratory Equipment	2,420,247	1,034,881	1,385,366						
398.00 Miscellaneous Equipment	7,518,954	1,609,843	5,909,111						
Total Amortizable	$131,930,078	$46,824,731	$85,105,347						
Total General Plant	$733,536,530	$298,779,104	$434,757,426	-0.7%	-1.2%	($2,110,509)	($5,382,193)	($7,492,702)	-1.0%
TOTAL UTILITY	$12,599,668,627	$1,590,165,714	$11,009,502,913	5.1%	-2.9%	$81,853,915	($317,632,264)	($235,778,350)	-1.9%
STEAM PRODUCTION (by Unit)									
Cholla									
311.00 Structures and Improvements	$81,486,004	$9,150,817	$72,335,187	-1.3%	-5.2%	($118,961)	($3,786,879)	($3,905,840)	-4.8%
312.00 Boiler Plant Equipment	570,277,432	48,487,459	521,789,973	-20.1%	-6.0%	(9,745,979)	(31,234,973)	(40,980,952)	-7.2%
314.00 Turbogenerator Units	154,600,716	29,042,533	125,558,183	-3.2%	-5.7%	(929,361)	(7,104,491)	(8,033,852)	-5.2%
315.00 Accessory Electric Equipment	96,531,398	2,830,112	93,701,286	-10.9%	-5.5%	(308,482)	(5,134,111)	(5,442,594)	-5.6%
316.00 Miscellaneous Power Plant Equipment	29,964,877	1,979,131	27,985,746	-16.5%	-5.8%	(326,557)	(1,618,592)	(1,945,149)	-6.5%
Total Cholla	$932,860,427	$91,490,052	$841,370,375	-12.5%	-5.8%	($11,429,340)	($48,879,047)	($60,308,387)	-6.5%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Cholla Unit 1									
311.00 Structures and Improvements	$4,558,263	$185,989	$4,372,274	-1.3%	-5.0%	($2,418)	($218,614)	($221,032)	-4.8%
312.00 Boiler Plant Equipment	76,097,814	2,884,010	73,213,804	-20.1%	-5.7%	(579,686)	(4,173,187)	(4,752,873)	-6.2%
314.00 Turbogenerator Units	28,570,183	2,929,593	25,640,590	-3.2%	-5.4%	(93,747)	(1,384,592)	(1,478,339)	-5.2%
315.00 Accessory Electric Equipment	8,892,887	76,394	8,816,493	-10.9%	-5.2%	(8,327)	(458,458)	(466,785)	-5.2%
316.00 Miscellaneous Power Plant Equipment	2,848,079	9,352	2,838,727	-16.5%	-5.4%	(1,543)	(153,291)	(154,834)	-5.4%
Total Cholla Unit 1	$120,967,226	$6,085,338	$114,881,888	-11.3%	-5.6%	($685,721)	($6,388,141)	($7,073,862)	-5.8%
Cholla Unit 2									
311.00 Structures and Improvements	$6,214,286	$46,274	$6,168,012	-1.3%	-5.4%	($602)	($333,073)	($333,674)	-5.4%
312.00 Boiler Plant Equipment	169,689,538	7,365,845	162,323,693	-20.1%	-6.3%	(1,480,535)	(10,226,393)	(11,706,928)	-6.9%
314.00 Turbogenerator Units	53,219,332	9,061,569	44,157,763	-3.2%	-6.0%	(289,970)	(2,649,466)	(2,939,436)	-5.5%
315.00 Accessory Electric Equipment	47,069,909	959,475	46,110,434	-10.9%	-5.7%	(104,583)	(2,628,295)	(2,732,878)	-5.8%
316.00 Miscellaneous Power Plant Equipment	8,998,578	284,182	8,714,396	-16.5%	-5.9%	(46,890)	(514,149)	(561,039)	-6.2%
Total Cholla Unit 2	$285,191,643	$17,717,345	$267,474,298	-10.9%	-6.1%	($1,922,579)	($16,351,375)	($18,273,955)	-6.4%
Cholla Unit 3									
311.00 Structures and Improvements	$10,128,228	$144,002	$9,984,226	-1.3%	-4.9%	($1,872)	($489,227)	($491,099)	-4.8%
312.00 Boiler Plant Equipment	258,675,684	30,610,741	228,064,943	-20.1%	-5.8%	(6,152,759)	(13,227,767)	(19,380,526)	-7.5%
314.00 Turbogenerator Units	71,090,033	16,240,975	54,849,058	-3.2%	-5.5%	(519,711)	(3,016,698)	(3,536,409)	-5.0%
315.00 Accessory Electric Equipment	31,542,524	541,238	31,001,286	-10.9%	-5.2%	(58,995)	(1,612,067)	(1,671,062)	-5.3%
316.00 Miscellaneous Power Plant Equipment	4,815,515	222,224	4,593,291	-16.5%	-5.5%	(36,667)	(252,631)	(289,298)	-6.0%
Total Cholla Unit 3	$376,251,984	$47,759,180	$328,492,804	-14.2%	-5.7%	($6,770,004)	($18,598,390)	($25,368,394)	-6.7%
Cholla Common									
311.00 Structures and Improvements	$60,585,227	$8,774,552	$51,810,675	-1.3%	-5.3%	($114,069)	($2,745,966)	($2,860,035)	-4.7%
312.00 Boiler Plant Equipment	65,814,396	7,626,863	58,187,533	-20.1%	-6.2%	(1,532,999)	(3,607,627)	(5,140,627)	-7.8%
314.00 Turbogenerator Units	1,721,168	810,396	910,772	-3.2%	-5.9%	(25,933)	(53,736)	(79,668)	-4.6%
315.00 Accessory Electric Equipment	9,026,078	1,253,005	7,773,073	-10.9%	-5.6%	(136,578)	(435,292)	(571,870)	-6.3%
316.00 Miscellaneous Power Plant Equipment	13,302,705	1,463,373	11,839,332	-16.5%	-5.9%	(241,457)	(698,521)	(939,977)	-7.1%
Total Cholla Common	$150,449,574	$19,928,189	$130,521,385	-10.3%	-5.8%	($2,051,035)	($7,541,141)	($9,592,176)	-6.4%
Four Corners									
311.00 Structures and Improvements	$58,239,255	$690,239	$57,549,016	-1.3%	-15.6%	($8,973)	($8,958,635)	($8,967,608)	-15.4%
312.00 Boiler Plant Equipment	409,653,716	34,251,600	375,402,116	-20.1%	-22.1%	(6,884,572)	(82,800,603)	(89,685,175)	-21.9%
314.00 Turbogenerator Units	81,000,802	7,646,224	73,354,578	-3.2%	-19.9%	(244,679)	(14,609,614)	(14,854,293)	-18.3%
315.00 Accessory Electric Equipment	42,150,140	2,086,187	40,063,953	-10.9%	-21.1%	(227,394)	(8,442,317)	(8,669,711)	-20.6%
316.00 Miscellaneous Power Plant Equipment	26,689,243	966,356	25,722,887	-16.5%	-18.8%	(159,449)	(4,836,181)	(4,995,630)	-18.7%
Total Four Corners	$617,733,156	$45,640,606	$572,092,550	-16.5%	-20.9%	($7,525,067)	($119,647,350)	($127,172,417)	-20.6%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Four Corners Units 1-3									
311.00 Structures and Improvements	$41,169,552	$486,461	$40,683,091	-1.3%		($6,324)		($6,324)	
312.00 Boiler Plant Equipment	272,052,306	29,950,392	242,101,914	-20.1%		(6,020,029)		(6,020,029)	-2.2%
314.00 Turbogenerator Units	54,983,581	4,799,888	50,183,693	-3.2%		(153,596)		(153,596)	-0.3%
315.00 Accessory Electric Equipment	25,541,727	1,208,242	24,333,485	-10.9%		(131,698)		(131,698)	-0.5%
316.00 Miscellaneous Power Plant Equipment	12,423,967	768,653	11,655,314	-16.5%		(126,828)		(126,828)	-1.0%
Total Four Corners Units 1-3	$406,171,133	$37,213,636	$368,957,497	-17.3%		($6,438,475)		($6,438,475)	-1.6%
Four Corners Units 4-5									
311.00 Structures and Improvements	$11,904,152	$21,886	$11,882,266	-1.3%	-66.0%	($285)	($7,842,296)	($7,842,580)	-65.9%
312.00 Boiler Plant Equipment	121,163,055	3,101,000	118,062,055	-20.1%	-67.1%	(623,301)	(79,219,639)	(79,842,940)	-65.9%
314.00 Turbogenerator Units	22,904,472	1,721,087	21,183,385	-3.2%	-66.8%	(55,075)	(14,150,501)	(14,205,576)	-62.0%
315.00 Accessory Electric Equipment	11,536,586	399,498	11,137,088	-10.9%	-66.4%	(43,545)	(7,395,026)	(7,438,572)	-64.5%
316.00 Miscellaneous Power Plant Equipment	3,652,142	37,190	3,614,952	-16.5%	-66.7%	(6,136)	(2,411,173)	(2,417,309)	-66.2%
Total Four Corners Units 4-5	$171,160,407	$5,280,661	$165,879,746	-13.8%	-66.9%	($728,342)	($111,018,635)	($111,746,977)	-65.3%
Four Corners Common									
311.00 Structures and Improvements	$5,165,551	$181,892	$4,983,659	-1.3%	-22.4%	($2,365)	($1,116,340)	($1,118,704)	-21.7%
312.00 Boiler Plant Equipment	16,438,355	1,200,208	15,238,147	-20.1%	-23.5%	(241,242)	(3,580,965)	(3,822,206)	-23.3%
314.00 Turbogenerator Units	3,112,749	1,125,249	1,987,500	-3.2%	-23.1%	(36,008)	(459,113)	(495,120)	-15.9%
315.00 Accessory Electric Equipment	5,071,827	478,447	4,593,380	-10.9%	-22.8%	(52,151)	(1,047,291)	(1,099,441)	-21.7%
316.00 Miscellaneous Power Plant Equipment	10,613,134	160,513	10,452,621	-16.5%	-23.2%	(26,485)	(2,425,008)	(2,451,493)	-23.1%
Total Four Corners Common	$40,401,616	$3,146,309	$37,255,307	-11.4%	-23.2%	($358,250)	($8,628,715)	($8,986,965)	-22.2%
Navajo Units 1-3									
311.00 Structures and Improvements	$29,378,233	$264,703	$29,113,530	-1.3%	-7.1%	($3,441)	($2,067,061)	($2,070,502)	-7.0%
312.00 Boiler Plant Equipment	173,502,971	7,499,757	166,003,214	-20.1%	-7.7%	(1,507,451)	(12,782,247)	(14,289,699)	-8.2%
314.00 Turbogenerator Units	24,801,608	102,303	24,699,305	-3.2%	-7.5%	(3,274)	(1,852,448)	(1,855,722)	-7.5%
315.00 Accessory Electric Equipment	21,635,639	144,295	21,491,344	-10.9%	-7.3%	(15,728)	(1,568,868)	(1,584,596)	-7.3%
316.00 Miscellaneous Power Plant Equipment	17,789,874	561,277	17,228,597	-16.5%	-7.5%	(92,611)	(1,292,145)	(1,384,755)	-7.8%
Total Navajo Units 1-3	$267,108,325	$8,572,335	$258,535,990	-18.9%	-7.6%	($1,622,505)	($19,562,769)	($21,185,274)	-7.9%
Ocotillo Units 1-2									
311.00 Structures and Improvements	$5,072,871	$313,213	$4,759,658	-1.3%	-18.9%	($4,072)	($899,575)	($903,647)	-17.8%
312.00 Boiler Plant Equipment	25,522,211	303,563	25,218,648	-20.1%	-19.2%	(61,016)	(4,841,980)	(4,902,997)	-19.2%
314.00 Turbogenerator Units	20,642,999	481,416	20,161,583	-3.2%	-19.1%	(15,405)	(3,850,862)	(3,866,268)	-18.7%
315.00 Accessory Electric Equipment	3,673,044	247,088	3,425,956	-10.9%	-19.0%	(26,933)	(650,932)	(677,864)	-18.5%
316.00 Miscellaneous Power Plant Equipment	6,581,204	570,630	6,010,574	-16.5%	-19.1%	(94,154)	(1,148,020)	(1,242,174)	-18.9%
Total Ocotillo Units 1-2	$61,492,329	$1,915,910	$59,576,419	-10.5%	-19.1%	($201,580)	($11,391,369)	($11,592,949)	-18.9%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Saguaro Units 1-2									
311.00 Structures and Improvements	$4,392,936	$81,619	$4,311,317	-1.3%	-18.7%	($1,061)	($806,216)	($807,277)	-18.4%
312.00 Boiler Plant Equipment	27,291,542	1,197,170	26,094,372	-20.1%	-19.0%	(240,631)	(4,957,931)	(5,198,562)	-19.0%
314.00 Turbogenerator Units	16,891,801	378,238	16,513,563	-3.2%	-18.9%	(12,104)	(3,121,063)	(3,133,167)	-18.5%
315.00 Accessory Electric Equipment	5,861,916	194,010	5,667,906	-10.9%	-18.8%	(21,147)	(1,065,566)	(1,086,713)	-18.5%
316.00 Miscellaneous Power Plant Equipment	4,821,800	42,864	4,778,936	-16.5%	-18.9%	(7,073)	(903,219)	(910,291)	-18.9%
Total Saguaro Units 1-2	$59,259,995	$1,893,901	$57,366,094	-14.9%	-18.9%	($282,015)	($10,853,996)	($11,136,011)	-18.8%
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$727,309,483	$28,462,682	$698,846,801	-4.3%	-0.5%	($1,223,895)	($3,337,529)	($4,561,424)	-0.6%
322.00 Reactor Plant Equipment	1,207,856,362	76,922,503	1,130,933,859	-17.7%	-1.3%	(13,615,283)	(15,144,579)	(28,759,862)	-2.4%
323.00 Turbogenerator Units	413,417,445	59,243,307	354,174,138	-2.5%	-0.4%	(1,481,083)	(1,566,990)	(3,048,072)	-0.7%
324.00 Accessory Electric Equipment	283,285,283	8,268,606	275,016,677	-2.7%	-0.5%	(223,252)	(1,260,223)	(1,483,475)	-0.5%
325.00 Miscellaneous Power Plant Equipment	184,562,340	39,351,028	145,211,312	-4.7%	-0.5%	(1,849,498)	(668,167)	(2,517,666)	-1.4%
Total Palo Verde	$2,816,430,913	$212,248,126	$2,604,182,787	-8.7%	-0.8%	($18,393,012)	($21,977,488)	($40,370,499)	-1.4%
Palo Verde Unit 1									
321.00 Structures and Improvements	$158,549,759	$1,844,414	$156,705,345	-4.3%	-0.4%	($79,310)	($626,821)	($706,131)	-0.4%
322.00 Reactor Plant Equipment	476,577,165	22,369,965	454,207,200	-17.7%	-1.3%	(3,959,484)	(5,904,694)	(9,864,177)	-2.1%
323.00 Turbogenerator Units	144,152,207	18,884,011	125,268,196	-2.5%	-0.4%	(472,100)	(501,073)	(973,173)	-0.7%
324.00 Accessory Electric Equipment	116,985,487	2,124,695	114,860,792	-2.7%	-0.4%	(57,367)	(459,443)	(516,810)	-0.4%
325.00 Miscellaneous Power Plant Equipment	35,114,067	4,312,309	30,801,758	-4.7%	-0.4%	(202,679)	(123,207)	(325,886)	-0.9%
Total Palo Verde Unit 1	$931,378,685	$49,535,394	$881,843,291	-9.6%	-0.9%	($4,770,939)	($7,615,238)	($12,386,177)	-1.3%
Palo Verde Unit 2									
321.00 Structures and Improvements	$92,433,785	$775,874	$91,657,911	-4.3%	-0.5%	($33,363)	($458,290)	($491,652)	-0.5%
322.00 Reactor Plant Equipment	263,630,088	29,342,610	234,287,478	-17.7%	-1.3%	(5,193,642)	(3,045,737)	(8,239,379)	-3.1%
323.00 Turbogenerator Units	91,343,984	12,731,285	78,612,699	-2.5%	-0.4%	(318,282)	(314,451)	(632,733)	-0.7%
324.00 Accessory Electric Equipment	52,298,306	2,361,059	49,937,247	-2.7%	-0.5%	(63,749)	(249,686)	(313,435)	-0.6%
325.00 Miscellaneous Power Plant Equipment	29,386,233	2,298,653	27,087,580	-4.7%	-0.4%	(108,037)	(108,350)	(216,387)	-0.7%
Total Palo Verde Unit 2	$529,092,396	$47,509,481	$481,582,915	-12.0%	-0.9%	($5,717,072)	($4,176,514)	($9,893,586)	-1.9%
Palo Verde Unit 3									
321.00 Structures and Improvements	$164,694,826	$1,502,335	$163,192,491	-4.3%	-0.5%	($64,600)	($815,962)	($880,563)	-0.5%
322.00 Reactor Plant Equipment	437,104,524	22,652,601	414,451,923	-17.7%	-1.4%	(4,009,510)	(5,802,327)	(9,811,837)	-2.2%
323.00 Turbogenerator Units	174,370,914	26,460,375	147,910,539	-2.5%	-0.5%	(661,509)	(739,553)	(1,401,062)	-0.8%
324.00 Accessory Electric Equipment	93,473,730	2,635,902	90,837,828	-2.7%	-0.5%	(71,169)	(454,189)	(525,358)	-0.6%
325.00 Miscellaneous Power Plant Equipment	31,555,474	2,843,225	28,712,249	-4.7%	-0.5%	(133,632)	(143,561)	(277,193)	-0.9%
Total Palo Verde Unit 3	$901,199,468	$56,094,438	$845,105,030	-8.8%	-0.9%	($4,940,421)	($7,955,592)	($12,896,014)	-1.4%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$186,745,934	$15,136,710	$171,609,224	-4.3%	-0.5%	($650,879)	($858,046)	($1,508,925)	-0.8%
322.00 Reactor Plant Equipment	133,326		133,326	-17.7%	-1.4%		(1,867)	(1,867)	-1.4%
323.00 Turbogenerator Units	246,532	28,776	217,756	-2.5%	-0.5%	(719)	(1,089)	(1,808)	-0.7%
324.00 Accessory Electric Equipment									
325.00 Miscellaneous Power Plant Equipment	131,432	42,613	88,819	-4.7%	-0.5%	(2,003)	(444)	(2,447)	-1.9%
Total Palo Verde Water Reclamation	$187,257,224	$15,208,099	$172,049,125	-4.3%	-0.5%	($653,601)	($861,446)	($1,515,046)	-0.8%
Palo Verde Common									
321.00 Structures and Improvements	$124,885,179	$9,203,349	$115,681,830	-4.3%	-0.5%	($395,744)	($578,409)	($974,153)	-0.8%
322.00 Reactor Plant Equipment	30,411,259	2,557,327	27,853,932	-17.7%	-1.4%	(452,647)	(389,955)	(842,602)	-2.8%
323.00 Turbogenerator Units	3,303,808	1,138,860	2,164,948	-2.5%	-0.5%	(28,472)	(10,825)	(39,296)	-1.2%
324.00 Accessory Electric Equipment	20,527,760	1,146,950	19,380,810	-2.7%	-0.5%	(30,968)	(96,904)	(127,872)	-0.6%
325.00 Miscellaneous Power Plant Equipment	88,375,134	29,854,228	58,520,906	-4.7%	-0.5%	(1,403,149)	(292,605)	(1,695,753)	-1.9%
Total Palo Verde Common	$267,503,140	$43,900,714	$223,602,426	-5.3%	-0.6%	($2,310,979)	($1,368,698)	($3,679,676)	-1.4%
OTHER PRODUCTION (by Unit)									
Douglas CT									
341.00 Structures and Improvements	$49,075		$49,075	-2.8%	5.0%		$2,454	$2,454	5.0%
342.00 Fuel Holders, Products and Accessories	160,633	22,874	137,759	-2.1%	5.0%	(480)	6,888	6,408	4.0%
343.00 Prime Movers	1,101,449		1,101,449	-7.3%	5.0%		55,072	55,072	5.0%
344.00 Generators and Devices	551,765		551,765	72.2%	5.0%		27,588	27,588	5.0%
345.00 Accessory Electric Equipment	369,401	16,124	353,277	-5.8%	5.0%	(935)	17,664	16,729	4.5%
346.00 Miscellaneous Power Plant Equipment	40,913		40,913	-0.5%	5.0%		2,046	2,046	5.0%
Total Douglas CT	$2,273,236	$38,998	$2,234,238	-3.6%	5.0%	($1,416)	$111,712	$110,296	4.9%
Ocotillo CT Units 1-2									
341.00 Structures and Improvements	$744,373	$22,805	$721,568	-2.8%	5.0%	($639)	$36,078	$35,440	4.8%
342.00 Fuel Holders, Products and Accessories	791,584		791,584	-2.1%	5.0%		39,579	39,579	5.0%
343.00 Prime Movers	6,636,736	96,461	6,540,275	-7.3%	5.0%	(7,042)	327,014	319,972	4.8%
344.00 Generators and Devices	8,584,460	988,146	7,596,314	72.2%	5.0%	713,441	379,816	1,093,257	12.7%
345.00 Accessory Electric Equipment	1,771,355	93,924	1,677,431	-5.8%	5.0%	(5,448)	83,872	78,424	4.4%
346.00 Miscellaneous Power Plant Equipment	668,202	30,475	637,727	-0.5%	5.0%	(152)	31,886	31,734	4.7%
Total Octillo CT Units 1-2	$19,196,710	$1,231,811	$17,964,899	56.8%	5.0%	$700,161	$898,245	$1,598,406	8.3%
Redhawk CC Units 1-2									
341.00 Structures and Improvements	$26,241,141	$4,043,739	$22,197,402	-2.8%	5.0%	($113,225)	$1,109,870	$996,645	3.8%
342.00 Fuel Holders, Products and Accessories	2,637,978		2,637,978	-2.1%	5.0%		131,899	131,899	5.0%
343.00 Prime Movers	221,649,524	43,788,997	177,860,527	-7.3%	5.0%	(3,196,597)	8,893,026	5,696,430	2.6%
344.00 Generators and Devices	400,023,626	120,811,368	279,212,258	72.2%	5.0%	87,225,808	13,960,613	101,186,421	25.3%
345.00 Accessory Electric Equipment	26,990,534	4,406,068	22,584,466	-5.8%	5.0%	(255,552)	1,129,223	873,671	3.2%
346.00 Miscellaneous Power Plant Equipment	4,005,866		4,005,866	-0.5%	5.0%		200,293	200,293	5.0%
Total Redhawk CC Units 1-2	$681,548,669	$173,050,172	$508,498,497	48.3%	5.0%	$83,660,434	$25,424,925	$109,085,359	16.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Saguaro									
341.00 Structures and Improvements	$1,917,969	$32,525	$1,885,444	-2.8%	5.0%	($911)	$94,272	$93,362	4.9%
342.00 Fuel Holders, Products and Accessories	1,523,125	146,423	1,376,702	-2.1%	5.0%	(3,075)	68,835	65,760	4.3%
343.00 Prime Movers	8,666,061	41,249	8,624,812	-7.3%	5.0%	(3,011)	431,241	428,229	4.9%
344.00 Generators and Devices	32,947,021	434,649	32,512,372	72.2%	5.0%	313,817	1,625,619	1,939,435	5.9%
345.00 Accessory Electric Equipment	1,767,889	66,110	1,701,779	-5.8%	5.0%	(3,834)	85,089	81,255	4.6%
346.00 Miscellaneous Power Plant Equipment	880,120	11,635	868,485	-0.5%	5.0%	(58)	43,424	43,366	4.9%
Total Saguaro	$47,702,185	$732,591	$46,969,594	41.4%	5.0%	$302,927	$2,348,480	$2,651,407	5.6%
Saguaro CT Units 1-2									
341.00 Structures and Improvements	$1,917,969	$32,525	$1,885,444	-2.8%	5.0%	($911)	$94,272	$93,362	4.9%
342.00 Fuel Holders, Products and Accessories	1,523,125	146,423	1,376,702	-2.1%	5.0%	(3,075)	68,835	65,760	4.3%
343.00 Prime Movers	8,025,154	41,249	7,983,905	-7.3%	5.0%	(3,011)	399,195	396,184	4.9%
344.00 Generators and Devices	4,922,637	434,649	4,487,988	72.2%	5.0%	313,817	224,399	538,216	10.9%
345.00 Accessory Electric Equipment	1,645,336	66,110	1,579,226	-5.8%	5.0%	(3,834)	78,961	75,127	4.6%
346.00 Miscellaneous Power Plant Equipment	880,120	11,635	868,485	-0.5%	5.0%	(58)	43,424	43,366	4.9%
Total Saguaro CT Units 1-2	$18,914,341	$732,591	$18,181,750	41.4%	5.0%	$302,927	$909,088	$1,212,015	6.4%
Saguaro CT Unit 3									
341.00 Structures and Improvements									
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	640,907		640,907	-7.3%	5.0%		32,045	32,045	5.0%
344.00 Generators and Devices	28,024,384		28,024,384	72.2%	5.0%		1,401,219	1,401,219	5.0%
345.00 Accessory Electric Equipment	122,553		122,553	-5.8%	5.0%		6,128	6,128	5.0%
346.00 Miscellaneous Power Plant Equipment									
Total Saguaro CT Unit 3	$28,787,844		$28,787,844		5.0%		$1,439,392	$1,439,392	5.0%
Solar Units									
341.00 Structures and Improvements	$431,153	$12,750	$418,403	-2.8%	5.0%	($357)	$20,920	$20,563	4.8%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	17,736,803	1,772,822	15,963,981	72.2%	5.0%	1,279,977	798,199	2,078,177	11.7%
345.00 Accessory Electric Equipment	728,283		728,283	-5.8%	5.0%		36,414	36,414	5.0%
346.00 Miscellaneous Power Plant Equipment									
Total Solar Units	$18,896,239	$1,785,572	$17,110,667	71.7%	5.0%	$1,279,620	$855,533	$2,135,154	11.3%
Sundance									
341.00 Structures and Improvements	$12,671,247	$18,000	$12,653,247	-2.8%	5.0%	($504)	$632,662	$632,158	5.0%
342.00 Fuel Holders, Products and Accessories	4,325,769		4,325,769	-2.1%	5.0%		216,288	216,288	5.0%
343.00 Prime Movers	230,018,750	286,539	229,732,211	-7.3%	5.0%	(20,917)	11,486,611	11,465,693	5.0%
344.00 Generators and Devices	301,285		301,285	72.2%	5.0%		15,064	15,064	5.0%
345.00 Accessory Electric Equipment	26,442,312	33,600	26,408,712	-5.8%	5.0%	(1,949)	1,320,436	1,318,487	5.0%
346.00 Miscellaneous Power Plant Equipment	2,028,889		2,028,889	-0.5%	5.0%		101,444	101,444	5.0%
Total Sun Dance	$275,788,252	$338,139	$275,450,113	-6.9%	5.0%	($23,370)	$13,772,506	$13,749,136	5.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
West Phoenix									
341.00 Structures and Improvements	$28,030,775	$424,614	$27,606,161	-2.8%	5.0%	($11,889)	$1,380,308	$1,368,419	4.9%
342.00 Fuel Holders, Products and Accessories	29,454,913	1,364,569	28,090,344	-2.1%	5.0%	(28,656)	1,404,517	1,375,861	4.7%
343.00 Prime Movers	186,297,277	21,646,082	164,651,195	-7.3%	5.0%	(1,580,164)	8,232,560	6,652,396	3.6%
344.00 Generators and Devices	268,459,223	24,364,804	244,094,419	72.2%	5.0%	17,591,388	12,204,721	29,796,109	11.1%
345.00 Accessory Electric Equipment	31,615,986	2,046,973	29,569,013	-5.8%	5.0%	(118,724)	1,478,451	1,359,726	4.3%
346.00 Miscellaneous Power Plant Equipment	7,127,980	680,838	6,447,142	-0.5%	5.0%	(3,404)	322,357	318,953	4.5%
Total West Phoenix	$550,986,154	$50,527,880	$500,458,274	31.4%	5.0%	$15,848,551	$25,022,914	$40,871,464	7.4%
West Phoenix CC Units 1-3									
341.00 Structures and Improvements	$1,776,669	$66,184	$1,710,485	-2.8%	5.0%	($1,853)	$85,524	$83,671	4.7%
342.00 Fuel Holders, Products and Accessories	23,882,271	1,364,569	22,517,702	-2.1%	5.0%	(28,656)	1,125,885	1,097,229	4.6%
343.00 Prime Movers									
344.00 Generators and Devices	113,266,743	20,700,627	92,566,116	72.2%	5.0%	14,945,853	4,628,306	19,574,158	17.3%
345.00 Accessory Electric Equipment	15,554,341	1,992,671	13,561,670	-5.8%	5.0%	(115,575)	678,084	562,509	3.6%
346.00 Miscellaneous Power Plant Equipment	5,366,074	643,721	4,722,353	-0.5%	5.0%	(3,219)	236,118	232,899	4.3%
Total West Phoenix CC Units 1-3	$159,846,098	$24,767,772	$135,078,326	59.7%	5.0%	$14,796,550	$6,753,916	$21,550,466	13.5%
West Phoenix CC Unit 4									
341.00 Structures and Improvements	$4,584,726		$4,584,726	-2.8%	5.0%		$229,236	$229,236	5.0%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109	-2.1%	5.0%		206,755	206,755	5.0%
343.00 Prime Movers	54,739,557	59,023	54,680,534	-7.3%	5.0%	(4,309)	2,734,027	2,729,718	5.0%
344.00 Generators and Devices	16,699,190	1,151,052	15,548,138	72.2%	5.0%	831,060	777,407	1,608,466	9.6%
345.00 Accessory Electric Equipment	2,569,550		2,569,550	-5.8%	5.0%		128,478	128,478	5.0%
346.00 Miscellaneous Power Plant Equipment	334,270	18,529	315,741	-0.5%	5.0%	(93)	15,787	15,694	4.7%
Total West Phoenix CC Unit 4	$83,062,402	$1,228,604	$81,833,798	67.3%	5.0%	$826,658	$4,091,690	$4,918,348	5.9%
West Phoenix CC Unit 5									
341.00 Structures and Improvements	$10,865,036		$10,865,036	-2.8%	5.0%		$543,252	$543,252	5.0%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	122,437,292	21,260,798	101,176,494	-7.3%	5.0%	(1,552,038)	5,058,825	3,506,786	2.9%
344.00 Generators and Devices	133,742,977	2,379,967	131,363,010	72.2%	5.0%	1,718,336	6,568,151	8,286,487	6.2%
345.00 Accessory Electric Equipment	11,713,613		11,713,613	-5.8%	5.0%		585,681	585,681	5.0%
346.00 Miscellaneous Power Plant Equipment	235,560		235,560	-0.5%	5.0%		11,778	11,778	5.0%
Total West Phoenix CC Unit 5	$278,994,478	$23,640,765	$255,353,713	0.7%	5.0%	$166,298	$12,767,686	$12,933,984	4.6%
West Phoenix CT Units 1-2									
341.00 Structures and Improvements	$880,435		$880,435	-2.8%	5.0%		$44,022	$44,022	5.0%
342.00 Fuel Holders, Products and Accessories	1,437,533		1,437,533	-2.1%	5.0%		71,877	71,877	5.0%
343.00 Prime Movers	9,120,428	326,261	8,794,167	-7.3%	5.0%	(23,817)	439,708	415,891	4.6%
344.00 Generators and Devices	4,750,313	133,158	4,617,155	72.2%	5.0%	96,140	230,858	326,998	6.9%
345.00 Accessory Electric Equipment	1,778,482	54,302	1,724,180	-5.8%	5.0%	(3,150)	86,209	83,059	4.7%
346.00 Miscellaneous Power Plant Equipment	1,192,076	18,588	1,173,488	-0.5%	5.0%	(93)	58,674	58,581	4.9%
Total West Phoenix CT Units 1-2	$19,159,267	$532,309	$18,626,958	13.0%	5.0%	$69,081	$931,348	$1,000,428	5.2%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
West Phoenix Common									
341.00 Structures and Improvements	$9,923,909	$358,430	$9,565,479	-2.8%	5.0%	($10,036)	$478,274	$468,238	4.7%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices									
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment									
Total West Phoenix Common	$9,923,909	$358,430	$9,565,479	-2.8%	5.0%	($10,036)	$478,274	$468,238	4.7%
Yucca									
341.00 Structures and Improvements	$1,826,216	$95,332	$1,730,884	-2.8%	5.0%	($2,669)	$86,544	$83,875	4.6%
342.00 Fuel Holders, Products and Accessories	4,862,130	42,920	4,819,210	-2.1%	5.0%	(901)	240,961	240,059	4.9%
343.00 Prime Movers	76,131,450		76,131,450		5.0%		3,806,573	3,806,573	5.0%
344.00 Generators and Devices	8,437,995	500,396	7,937,599	72.2%	5.0%	361,286	396,880	758,166	9.0%
345.00 Accessory Electric Equipment	3,292,231	41,000	3,251,231	-5.8%	5.0%	(2,378)	162,562	160,184	4.9%
346.00 Miscellaneous Power Plant Equipment	682,399		682,399		5.0%		34,120	34,120	5.0%
Total Yucca	$95,232,421	$679,648	$94,552,773	52.3%	5.0%	$355,337	$4,727,639	$5,082,976	5.3%
Yucca CT Units 1-4									
341.00 Structures and Improvements	$1,289,209	$95,332	$1,193,877	-2.8%	5.0%	($2,669)	$59,694	$57,025	4.4%
342.00 Fuel Holders, Products and Accessories	3,359,589	42,920	3,316,669	-2.1%	5.0%	(901)	165,833	164,932	4.9%
343.00 Prime Movers	7,962,254		7,962,254	-7.3%	5.0%		398,113	398,113	5.0%
344.00 Generators and Devices	8,384,294	500,396	7,883,898	72.2%	5.0%	361,286	394,195	755,481	9.0%
345.00 Accessory Electric Equipment	2,879,650	41,000	2,838,650	-5.8%	5.0%	(2,378)	141,933	139,555	4.8%
346.00 Miscellaneous Power Plant Equipment	682,399		682,399	-0.5%	5.0%		34,120	34,120	5.0%
Total Yucca CT Units 1-4	$24,557,395	$679,648	$23,877,747	52.3%	5.0%	$355,337	$1,193,887	$1,549,225	6.3%
Yucca CT Units 5-6									
341.00 Structures and Improvements	$537,007		$537,007	-2.8%	5.0%		$26,850	$26,850	5.0%
342.00 Fuel Holders, Products and Accessories	1,502,541		1,502,541	-2.1%	5.0%		75,127	75,127	5.0%
343.00 Prime Movers	68,169,196		68,169,196	-7.3%	5.0%		3,408,460	3,408,460	5.0%
344.00 Generators and Devices	53,701		53,701	72.2%	5.0%		2,685	2,685	5.0%
345.00 Accessory Electric Equipment	412,581		412,581	-5.8%	5.0%		20,629	20,629	5.0%
346.00 Miscellaneous Power Plant Equipment									
Total Yucca CT Units 5-6	$70,675,026		$70,675,026		5.0%		$3,533,751	$3,533,751	5.0%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/10 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)									
Cholla									
311.00 Structures and Improvements	$72,335,187	$4,444,392	$67,890,795	-5.0%	-5.2%	($222,220)	($3,554,136)	($3,776,355)	-5.2%
312.00 Boiler Plant Equipment	521,789,973	30,408,224	491,381,749	-20.0%	-5.1%	(6,081,645)	(25,129,976)	(31,211,621)	-6.0%
314.00 Turbogenerator Units	125,558,183	7,127,529	118,430,654	-15.0%	-5.1%	(1,069,129)	(6,039,116)	(7,108,245)	-5.7%
315.00 Accessory Electric Equipment	93,701,286	5,619,797	88,081,489	-10.0%	-5.2%	(561,980)	(4,570,435)	(5,132,415)	-5.5%
316.00 Miscellaneous Power Plant Equipment	27,985,746	1,648,875	26,336,871	-15.0%	-5.2%	(247,331)	(1,378,726)	(1,626,057)	-5.8%
Total Cholla	$841,370,375	$49,248,817	$792,121,558	-16.6%	-5.1%	($8,182,305)	($40,672,389)	($48,854,693)	-5.8%
Cholla Unit 1									
311.00 Structures and Improvements	$4,372,274	$196,148	$4,176,126	-5.0%	-5.0%	($9,807)	($208,806)	($218,614)	-5.0%
312.00 Boiler Plant Equipment	73,213,804	3,210,974	70,002,830	-20.0%	-5.0%	(642,195)	(3,500,142)	(4,142,336)	-5.7%
314.00 Turbogenerator Units	25,640,590	1,119,176	24,521,414	-15.0%	-5.0%	(167,876)	(1,226,071)	(1,393,947)	-5.4%
315.00 Accessory Electric Equipment	8,816,493	394,231	8,422,262	-10.0%	-5.0%	(39,423)	(421,113)	(460,536)	-5.2%
316.00 Miscellaneous Power Plant Equipment	2,838,727	125,992	2,712,735	-15.0%	-5.0%	(18,899)	(135,637)	(154,536)	-5.4%
Total Cholla Unit 1	$114,881,888	$5,046,520	$109,835,368	-17.4%	-5.0%	($878,200)	($5,491,768)	($6,369,969)	-5.5%
Cholla Unit 2									
311.00 Structures and Improvements	$6,168,012	$357,565	$5,810,447	-5.0%	-5.4%	($17,878)	($313,764)	($331,642)	-5.4%
312.00 Boiler Plant Equipment	162,323,693	9,547,962	152,775,731	-20.0%	-5.4%	(1,909,592)	(8,249,889)	(10,159,482)	-6.3%
314.00 Turbogenerator Units	44,157,763	2,541,827	41,615,936	-15.0%	-5.4%	(381,274)	(2,247,261)	(2,628,535)	-6.0%
315.00 Accessory Electric Equipment	46,110,434	2,735,742	43,374,692	-10.0%	-5.4%	(273,574)	(2,342,233)	(2,615,808)	-5.7%
316.00 Miscellaneous Power Plant Equipment	8,714,396	498,472	8,215,924	-15.0%	-5.4%	(74,771)	(443,660)	(518,431)	-5.9%
Total Cholla Unit 2	$267,474,298	$15,681,567	$251,792,731	-16.9%	-5.4%	($2,657,090)	($13,596,807)	($16,253,897)	-6.1%
Cholla Unit 3									
311.00 Structures and Improvements	$9,984,226	$644,618	$9,339,608	-5.0%	-4.9%	($32,231)	($457,641)	($489,872)	-4.9%
312.00 Boiler Plant Equipment	228,064,943	14,059,017	214,005,926	-20.0%	-4.9%	(2,811,803)	(10,486,290)	(13,298,094)	-5.8%
314.00 Turbogenerator Units	54,849,058	3,408,856	51,440,202	-15.0%	-4.9%	(511,328)	(2,520,570)	(3,031,898)	-5.5%
315.00 Accessory Electric Equipment	31,001,286	2,003,329	28,997,957	-10.0%	-4.9%	(200,333)	(1,420,900)	(1,621,233)	-5.2%
316.00 Miscellaneous Power Plant Equipment	4,593,291	291,848	4,301,443	-15.0%	-4.9%	(43,777)	(210,771)	(254,548)	-5.5%
Total Cholla Unit 3	$328,492,804	$20,407,669	$308,085,135	-17.6%	-4.9%	($3,599,473)	($15,096,172)	($18,695,645)	-5.7%
Cholla Common									
311.00 Structures and Improvements	$51,810,675	$3,246,060	$48,564,615	-5.0%	-5.3%	($162,303)	($2,573,925)	($2,736,228)	-5.3%
312.00 Boiler Plant Equipment	58,187,533	3,590,271	54,597,262	-20.0%	-5.3%	(718,054)	(2,893,655)	(3,611,709)	-6.2%
314.00 Turbogenerator Units	910,772	57,671	853,101	-15.0%	-5.3%	(8,651)	(45,214)	(53,865)	-5.9%
315.00 Accessory Electric Equipment	7,773,073	486,495	7,286,578	-10.0%	-5.3%	(48,650)	(386,189)	(434,838)	-5.6%
316.00 Miscellaneous Power Plant Equipment	11,839,332	732,563	11,106,769	-15.0%	-5.3%	(109,884)	(588,659)	(698,543)	-5.9%
Total Cholla Common	$130,521,385	$8,113,060	$122,408,325	-12.9%	-5.3%	($1,047,542)	($6,487,641)	($7,535,183)	-5.8%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/10 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Four Corners									
311.00 Structures and Improvements	$57,549,016	$1,316,207	$56,232,809	-4.6%	-15.8%	($60,558)	($8,899,884)	($8,960,442)	-15.6%
312.00 Boiler Plant Equipment	375,402,116	10,195,716	365,206,400	-18.8%	-22.1%	(1,912,071)	(80,856,576)	(82,768,647)	-22.0%
314.00 Turbogenerator Units	73,354,578	1,783,918	71,570,660	-13.9%	-20.1%	(247,578)	(14,353,990)	(14,601,567)	-19.9%
315.00 Accessory Electric Equipment	40,063,953	1,194,264	38,869,689	-9.5%	-21.4%	(113,085)	(8,324,078)	(8,437,163)	-21.1%
316.00 Miscellaneous Power Plant Equipment	25,722,887	1,025,498	24,697,389	-14.6%	-19.0%	(149,372)	(4,686,051)	(4,835,424)	-18.8%
Total Four Corners	$572,092,550	$15,515,602	$556,576,948	-16.0%	-21.0%	($2,482,663)	($117,120,580)	($119,603,242)	-20.9%
Four Corners Units 1-3									
311.00 Structures and Improvements	$40,683,091	$105,056	$40,578,035						
312.00 Boiler Plant Equipment	242,101,914	635,363	241,466,551						
314.00 Turbogenerator Units	50,183,693	133,400	50,050,293						
315.00 Accessory Electric Equipment	24,333,485	63,417	24,270,068						
316.00 Miscellaneous Power Plant Equipment	11,655,314	29,684	11,625,630						
Total Four Corners Units 1-3	$368,957,497	$966,920	$367,990,577						
Four Corners Units 4-5									
311.00 Structures and Improvements	$11,882,266	$850,181	$11,032,085	-5.0%	-70.7%	($42,509)	($7,799,684)	($7,842,193)	-66.0%
312.00 Boiler Plant Equipment	118,062,055	8,453,329	109,608,726	-20.0%	-70.7%	(1,690,666)	(77,493,369)	(79,184,035)	-67.1%
314.00 Turbogenerator Units	21,183,385	1,498,647	19,684,738	-15.0%	-70.7%	(224,797)	(13,917,110)	(14,141,907)	-66.8%
315.00 Accessory Electric Equipment	11,137,088	797,284	10,339,804	-10.0%	-70.7%	(79,728)	(7,310,241)	(7,389,970)	-66.4%
316.00 Miscellaneous Power Plant Equipment	3,614,952	256,801	3,358,151	-15.0%	-70.7%	(38,520)	(2,374,213)	(2,412,733)	-66.7%
Total Four Corners Units 4-5	$165,879,746	$11,856,242	$154,023,504	-17.5%	-70.7%	($2,076,220)	($108,894,617)	($110,970,838)	-66.9%
Four Corners Common									
311.00 Structures and Improvements	$4,983,659	$360,969	$4,622,690	-5.0%	-23.8%	($18,048)	($1,100,200)	($1,118,249)	-22.4%
312.00 Boiler Plant Equipment	15,238,147	1,107,023	14,131,124	-20.0%	-23.8%	(221,405)	(3,363,207)	(3,584,612)	-23.5%
314.00 Turbogenerator Units	1,987,500	151,870	1,835,630	-15.0%	-23.8%	(22,781)	(436,880)	(459,660)	-23.1%
315.00 Accessory Electric Equipment	4,593,380	333,563	4,259,817	-10.0%	-23.8%	(33,356)	(1,013,836)	(1,047,193)	-22.8%
316.00 Miscellaneous Power Plant Equipment	10,452,621	739,014	9,713,607	-15.0%	-23.8%	(110,852)	(2,311,839)	(2,422,691)	-23.2%
Total Four Corners Common	$37,255,307	$2,692,440	$34,562,867	-15.1%	-23.8%	($406,442)	($8,225,962)	($8,632,404)	-23.2%
Navajo Units 1-3									
311.00 Structures and Improvements	$29,113,530	$1,152,915	$27,960,615	-5.0%	-7.2%	($57,646)	($2,013,164)	($2,070,810)	-7.1%
312.00 Boiler Plant Equipment	166,003,214	6,563,943	159,439,271	-20.0%	-7.2%	(1,312,789)	(11,479,628)	(12,792,416)	-7.7%
314.00 Turbogenerator Units	24,699,305	999,965	23,699,340	-15.0%	-7.2%	(149,995)	(1,706,352)	(1,856,347)	-7.5%
315.00 Accessory Electric Equipment	21,491,344	865,701	20,625,643	-10.0%	-7.2%	(86,570)	(1,485,046)	(1,571,616)	-7.3%
316.00 Miscellaneous Power Plant Equipment	17,228,597	674,320	16,554,277	-15.0%	-7.2%	(101,148)	(1,191,908)	(1,293,056)	-7.5%
Total Navajo Units 1-3	$258,535,990	$10,256,844	$248,279,146	-16.7%	-7.2%	($1,708,147)	($17,876,099)	($19,584,246)	-7.6%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/10 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Ocotillo Units 1-2									
311.00 Structures and Improvements	$4,759,658	$112,764	$4,646,894	-5.0%	-19.2%	($5,638)	($892,204)	($897,842)	-18.9%
312.00 Boiler Plant Equipment	25,218,648	619,855	24,598,793	-20.0%	-19.2%	(123,971)	(4,722,968)	(4,846,939)	-19.2%
314.00 Turbogenerator Units	20,161,583	490,682	19,670,901	-15.0%	-19.2%	(73,602)	(3,776,813)	(3,850,415)	-19.1%
315.00 Accessory Electric Equipment	3,425,956	83,505	3,342,451	-10.0%	-19.2%	(8,351)	(641,751)	(650,101)	-19.0%
316.00 Miscellaneous Power Plant Equipment	6,010,574	139,130	5,871,444	-15.0%	-19.2%	(20,869)	(1,127,317)	(1,148,187)	-19.1%
Total Ocotillo Units 1-2	$59,576,419	$1,445,935	$58,130,484	-16.1%	-19.2%	($232,431)	($11,161,053)	($11,393,484)	-19.1%
Saguaro Units 1-2									
311.00 Structures and Improvements	$4,311,317	$102,569	$4,208,748	-5.0%	-19.0%	($5,128)	($799,662)	($804,791)	-18.7%
312.00 Boiler Plant Equipment	26,094,372	632,826	25,461,546	-20.0%	-19.0%	(126,565)	(4,837,694)	(4,964,259)	-19.0%
314.00 Turbogenerator Units	16,513,563	406,572	16,106,991	-15.0%	-19.0%	(60,986)	(3,060,328)	(3,121,314)	-18.9%
315.00 Accessory Electric Equipment	5,667,906	134,335	5,533,571	-10.0%	-19.0%	(13,434)	(1,051,378)	(1,064,812)	-18.8%
316.00 Miscellaneous Power Plant Equipment	4,778,936	111,735	4,667,201	-15.0%	-19.0%	(16,760)	(886,768)	(903,528)	-18.9%
Total Saguaro Units 1-2	$57,366,094	$1,388,037	$55,978,057	-16.1%	-19.0%	($222,873)	($10,635,831)	($10,858,704)	-18.9%
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$698,846,801	$64,639,936	$634,206,865	-5.0%		($3,231,997)		($3,231,997)	-0.5%
322.00 Reactor Plant Equipment	1,130,933,859	102,004,842	1,028,929,017	-15.0%		(15,300,726)		(15,300,726)	-1.4%
323.00 Turbogenerator Units	354,174,138	32,132,580	322,041,558	-5.0%		(1,606,629)		(1,606,629)	-0.5%
324.00 Accessory Electric Equipment	275,016,677	25,062,524	249,954,153	-5.0%		(1,253,126)		(1,253,126)	-0.5%
325.00 Miscellaneous Power Plant Equipment	145,211,312	13,348,201	131,863,111	-5.0%		(667,410)		(667,410)	-0.5%
Total Palo Verde	$2,604,182,787	$237,188,084	$2,366,994,703	-9.3%		($22,059,888)		($22,059,888)	-0.8%
Palo Verde Unit 1									
321.00 Structures and Improvements	$156,705,345	$13,747,569	$142,957,776	-5.0%		($687,378)		($687,378)	-0.4%
322.00 Reactor Plant Equipment	454,207,200	39,422,061	414,785,139	-15.0%		(5,913,309)		(5,913,309)	-1.3%
323.00 Turbogenerator Units	125,268,196	10,895,310	114,372,886	-5.0%		(544,766)		(544,766)	-0.4%
324.00 Accessory Electric Equipment	114,860,792	10,080,165	104,780,627	-5.0%		(504,008)		(504,008)	-0.4%
325.00 Miscellaneous Power Plant Equipment	30,801,758	2,693,325	28,108,433	-5.0%		(134,666)		(134,666)	-0.4%
Total Palo Verde Unit 1	$881,843,291	$76,838,430	$805,004,861	-10.1%		($7,784,128)		($7,784,128)	-0.9%
Palo Verde Unit 2									
321.00 Structures and Improvements	$91,657,911	$8,278,376	$83,379,535	-5.0%		($413,919)		($413,919)	-0.5%
322.00 Reactor Plant Equipment	234,287,478	20,925,924	213,361,554	-15.0%		(3,138,889)		(3,138,889)	-1.3%
323.00 Turbogenerator Units	78,612,699	7,054,872	71,557,827	-5.0%		(352,744)		(352,744)	-0.4%
324.00 Accessory Electric Equipment	49,937,247	4,500,499	45,436,748	-5.0%		(225,025)		(225,025)	-0.5%
325.00 Miscellaneous Power Plant Equipment	27,087,580	2,422,656	24,664,924	-5.0%		(121,133)		(121,133)	-0.4%
Total Palo Verde Unit 2	$481,582,915	$43,182,328	$438,400,587	-9.8%		($4,251,709)		($4,251,709)	-0.9%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/10 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Palo Verde Unit 3									
321.00 Structures and Improvements	$163,192,491	$15,537,725	$147,654,766	-5.0%		($776,886)		($776,886)	-0.5%
322.00 Reactor Plant Equipment	414,451,923	39,000,560	375,451,363	-15.0%		(5,850,084)		(5,850,084)	-1.4%
323.00 Turbogenerator Units	147,910,539	13,963,005	133,947,534	-5.0%		(698,150)		(698,150)	-0.5%
324.00 Accessory Electric Equipment	90,837,828	8,641,800	82,196,028	-5.0%		(432,090)		(432,090)	-0.5%
325.00 Miscellaneous Power Plant Equipment	28,712,249	2,723,889	25,988,360	-5.0%		(136,194)		(136,194)	-0.5%
Total Palo Verde Unit 3	$845,105,030	$79,866,979	$765,238,051	-9.9%		($7,893,405)		($7,893,405)	-0.9%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$171,609,224	$16,126,075	$155,483,149	-5.0%		($806,304)		($806,304)	-0.5%
322.00 Reactor Plant Equipment	133,326	12,289	121,037	-15.0%		(1,843)		(1,843)	-1.4%
323.00 Turbogenerator Units	217,756	20,661	197,095	-5.0%		(1,033)		(1,033)	-0.5%
324.00 Accessory Electric Equipment									
325.00 Miscellaneous Power Plant Equipment	88,819	8,405	80,414	-5.0%		(420)		(420)	-0.5%
Total Palo Verde Water Reclamation	$172,049,125	$16,167,430	$155,881,695	-5.0%		($809,600)		($809,600)	-0.5%
Palo Verde Common									
321.00 Structures and Improvements	$115,681,830	$10,950,191	$104,731,639	-5.0%		($547,510)		($547,510)	-0.5%
322.00 Reactor Plant Equipment	27,853,932	2,644,008	25,209,924	-15.0%		(396,601)		(396,601)	-1.4%
323.00 Turbogenerator Units	2,164,948	198,732	1,966,216	-5.0%		(9,937)		(9,937)	-0.5%
324.00 Accessory Electric Equipment	19,380,810	1,840,061	17,540,749	-5.0%		(92,003)		(92,003)	-0.5%
325.00 Miscellaneous Power Plant Equipment	58,520,906	5,499,926	53,020,980	-5.0%		(274,996)		(274,996)	-0.5%
Total Palo Verde Common	$223,602,426	$21,132,917	$202,469,509	-6.3%		($1,321,047)		($1,321,047)	-0.6%

ARIZONA PUBLIC SERVICE COMPANY Statement G

Dismantlement Costs

Steam Production

Unit	Capacity (MW)	Cost per kW	2009 Cost	Plant	Distributed Cost	Inflation Rate	Year Spent	Trended Cost	Accrual Rate
A	B	C	D=B*C*1000	E	F	G	H	I	J=I/E
Cholla									
1	110	40.00	$4,400,000	$109,835,368	$3,720,058	2.00%	2028	$5,527,811	5.0%
2	245	40.00	9,800,000	251,792,731	8,285,584	2.00%	2033	13,593,379	5.4%
3	260	40.00	10,400,000	308,085,135	8,792,865	2.00%	2035	15,008,422	4.9%
C				122,408,325	3,801,493	2.00%	2035	6,488,717	5.3%
	615		$24,600,000	$792,121,558	$24,600,000			$40,618,329	5.1%
	Allocated to Common:		3,801,493						
	Allocated to Units:		$20,798,507						
Four Corners									
1-3	550		$50,993,709			2.00%	2012		
4-5	224		9,151,548	522,014,081	60,145,257	2.00%	2038	108,944,808	20.9%
C			4,534,879	34,562,867	4,534,879	2.00%	2038	8,214,306	23.8%
	774		$64,680,136	$556,576,948	$64,680,136			$117,159,114	21.0%
	Allocated to Common:								
	Allocated to Units:		$64,680,136						
Navajo									
1-3	315	40.00	$12,600,000	$248,279,146	$12,600,000	2.00%	2026	$17,995,903	7.2%
C									
	315		$12,600,000	$248,279,146	$12,600,000			$17,995,903	7.2%
	Allocated to Common:								
	Allocated to Units:		$12,600,000						
Ocotillo									
1-2	220	40.00	$8,800,000	$58,130,484	$8,800,000	2.00%	2020	$11,160,528	19.2%
C									
	220		$8,800,000	$58,130,484	$8,800,000			$11,160,528	19.2%
	Allocated to Common:								
	Allocated to Units:		$8,800,000						
Saguaro									
1-2	210	40.00	$8,400,000	$55,978,057	$8,400,000	2.00%	2020	$10,653,231	19.0%
C									
	210		$8,400,000	$55,978,057	$8,400,000			$10,653,231	19.0%
	Allocated to Common:								
	Allocated to Units:		$8,400,000						

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2010)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
311.00 Structures and Improvements									17.74	7.81	-9.3	-9.8
312.00 Boiler Plant Equipment									23.74	11.42	-12.9	-12.3
314.00 Turbogenerator Units									24.09	11.56	-10.7	-11.7
315.00 Accessory Electric Equipment									23.95	10.10	-10.3	-10.3
316.00 Miscellaneous Power Plant Equipment									20.72	10.74	-12.2	-12.0
Total Steam Production Plant									22.92	10.85	-11.9	-11.8
NUCLEAR PRODUCTION												
321.00 Structures and Improvements									51.83	33.93	-0.6	
322.00 Reactor Plant Equipment									48.64	33.28	-2.4	
323.00 Turbogenerator Units									49.58	33.38	-0.7	
324.00 Accessory Electric Equipment									53.64	33.27	-0.5	
325.00 Miscellaneous Power Plant Equipment									48.94	33.87	-1.4	
Total Nuclear Production Plant									50.11	33.50	-1.4	-0.8
OTHER PRODUCTION												
341.00 Structures and Improvements									29.91	22.98	4.5	
342.00 Fuel Holders, Products and Accessories									29.22	19.50	4.7	
343.00 Prime Movers									32.38	25.74	3.9	
344.00 Generators and Devices									28.82	22.37	18.6	
345.00 Accessory Electric Equipment									30.76	23.00	4.2	
346.00 Miscellaneous Power Plant Equipment									26.52	19.42	4.7	
Total Other Production Plant									30.49	23.76	10.4	5.0
TRANSMISSION PLANT												
352.02 Structures and Improvements	50.00	R4	50.38	19.18			50.00	R4	50.62	16.79		
353.00 Station Equipment	45.00	S0.5	45.98	33.50			45.00	S0.5	45.96	34.11	-4.7	-5.0
354.00 Towers and Fixtures	60.00	R3	60.18	39.78			60.00	R3	60.26	37.13		
355.00 Poles and Fixtures	50.00	R1.5	50.08	45.43	-20.00	-20.0	55.00	R1.5	55.15	48.05	-20.0	-20.0
356.00 Overhead Conductors and Devices	60.00	R3	59.90	50.16	18.7	20.0	60.00	R3	59.74	47.35	-18.7	-20.0
Total Transmission Plant									46.41	34.48	-5.1	-5.4

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2010)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
DISTRIBUTION PLANT												
361.00 Structures and Improvements	60.00	R3	59.87	47.22	-4.6	-5.0	60.00	R3	59.91	49.60	-4.7	-5.0
362.00 Station Equipment	43.00	L0.5	43.08	36.31	10.0	10.0	43.00	L0.5	43.06	36.12	9.5	10.0
364.01 Poles, Towers and Fixtures - Wood	40.00	L0	39.92	31.55	-0.5	-5.0	40.00	L0	39.92	30.83	-1.0	-5.0
364.02 Poles, Towers and Fixtures - Steel	35.00	L0.5	35.08	31.88	-5.7	-5.0	38.00	SC	38.18	35.13	-10.0	-10.0
365.00 Overhead Conductors and Devices	50.00	SC	49.97	43.42	10.2	10.0	48.00	L0	47.78	40.17	4.3	5.0
366.00 Underground Conduit	65.00	L1	64.94	56.80	-5.0	-5.0	60.00	L1	59.96	50.32	-4.9	-5.0
367.00 Underground Conductors and Devices	33.00	L1	32.94	26.28	-4.2	-5.0	35.00	L1	34.90	27.33	-3.8	-5.0
368.00 Line Transformers	55.00	L1	55.14	44.80	-4.3	-5.0	55.00	L1	55.12	44.08	-4.3	-5.0
369.00 Services	40.00	L1	40.47	31.15			40.00	L1	40.65	29.77	-4.9	-5.0
370.01 Meters - Electronic	26.00	R1.5					15.00	R0.5	14.87	11.94	0.3	
370.03 Meters - AMI	26.00	R1.5	26.00	25.47			15.00	R0.5	15.04	14.15		
371.00 Installations on Customers' Premises	55.00	SC	54.77	49.26	-10.6	-10.0	40.00	L0	40.15	33.33	-14.5	-15.0
373.00 Street Lighting and Signal Systems	65.00	L0	64.65	57.06	-9.1	-10.0	55.00	L0.5	54.60	44.94	-8.4	-10.0
Total Distribution Plant									40.07	32.39	-2.4	-3.2
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	45.00	L1	45.03	34.14	-5.3	-5.0	45.00	L1	44.91	34.13	-5.6	-5.0
391.CM Office Furn. and Equip. - Computer	8.00	L3	8.09	4.69	-0.1		8.00	L3	8.04	4.96	-0.1	
397.00 Communication Equipment	18.00	S1.5	18.04	11.17			18.00	S1.5	18.11	10.76		
Total Depreciable									15.95	10.38	-1.2	-1.5

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2010) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Amortizable												
391.FE Office Furn. and Equip. - Furniture	20.00	SQ	20.00	11.65			20.00	SQ	20.00	14.16		
393.00 Stores Equipment	20.00	SQ	20.00	2.73			20.00	SQ	20.00	17.41		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	12.39			20.00	SQ	20.00	11.90		
395.00 Laboratory Equipment	20.00	SQ	20.00	7.31			20.00	SQ	20.00	7.32		
398.00 Miscellaneous Equipment	24.00	SQ	24.00	19.34			24.00	SQ	24.00	19.16		
Total Amortizable									20.23	13.59		
Total General Plant									16.64	10.90	-1.0	-1.2
TOTAL UTILITY									34.24	24.32	-1.9	-2.9
STEAM PRODUCTION (by Unit)												
Cholla												
311.00 Structures and Improvements			46.39	25.69	-11.0				36.14	23.07	-4.8	-5.2
312.00 Boiler Plant Equipment			39.52	23.80	-11.5				31.90	22.07	-7.2	-6.0
314.00 Turbogenerator Units			36.92	25.19	-10.2				30.41	21.27	-5.2	-5.7
315.00 Accessory Electric Equipment			45.73	24.80	-11.0				43.68	21.89	-5.6	-5.5
316.00 Miscellaneous Power Plant Equipment			37.20	25.30	-11.9				33.22	22.38	-6.5	-5.8
Total Cholla									33.02	22.02	-6.5	-5.8
Cholla Unit 1												
311.00 Structures and Improvements	2028	200-SC	32.37	19.96	-9.1	-9.4	2028	200-SC	29.03	17.10	-4.8	-5.0
312.00 Boiler Plant Equipment	2028	200-SC	24.87	19.97	-10.2	-9.9	2028	200-SC	24.33	17.11	-6.2	-5.7
314.00 Turbogenerator Units	2028	200-SC	40.13	19.94	-9.7	-9.9	2028	200-SC	22.21	17.11	-5.2	-5.4
315.00 Accessory Electric Equipment	2028	200-SC	30.87	19.96	-9.6	-9.6	2028	200-SC	28.61	17.11	-5.2	-5.2
316.00 Miscellaneous Power Plant Equipment	2028	200-SC	33.42	19.96	-9.9	-9.9	2028	200-SC	30.40	17.10	-5.4	-5.4
Total Cholla Unit 1									24.36	17.11	-5.8	-5.6

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Cholla Unit 2												
311.00 Structures and Improvements	2033	200-SC	40.34	24.65	-9.3	-9.4	2033	200-SC	37.22	21.84	-5.4	-5.4
312.00 Boiler Plant Equipment	2033	200-SC	46.13	24.64	-10.4	-10.1	2033	200-SC	42.32	21.83	-6.9	-6.3
314.00 Turbogenerator Units	2033	200-SC	38.06	24.66	-9.1	-10.0	2033	200-SC	33.22	21.85	-5.5	-6.0
315.00 Accessory Electric Equipment	2033	200-SC	48.20	24.63	-9.7	-9.7	2033	200-SC	46.70	21.82	-5.8	-5.7
316.00 Miscellaneous Power Plant Equipment	2033	200-SC	39.88	24.65	-10.3	-10.0	2033	200-SC	31.65	21.85	-6.2	-5.9
Total Cholla Unit 2									40.57	21.83	-6.4	-6.1
Cholla Unit 3												
311.00 Structures and Improvements	2035	200-SC	50.03	26.49	-12.5	-12.5	2035	200-SC	48.83	23.70	-4.8	-4.9
312.00 Boiler Plant Equipment	2035	200-SC	47.58	26.50	-13.4	-13.2	2035	200-SC	29.93	23.74	-7.5	-5.8
314.00 Turbogenerator Units	2035	200-SC	35.50	26.53	-11.2	-13.2	2035	200-SC	33.81	23.73	-5.0	-5.5
315.00 Accessory Electric Equipment	2035	200-SC	49.74	26.49	-12.9	-12.9	2035	200-SC	49.50	23.69	-5.3	-5.2
316.00 Miscellaneous Power Plant Equipment	2035	200-SC	42.25	26.51	-13.4	-13.2	2035	200-SC	42.28	23.71	-6.0	-5.5
Total Cholla Unit 3									32.26	23.73	-6.7	-5.7
Cholla Common												
311.00 Structures and Improvements	2035	200-SC	48.54	26.49	-11.0	-11.1	2035	200-SC	34.99	23.73	-4.7	-5.3
312.00 Boiler Plant Equipment	2035	200-SC	40.70	26.51	-13.2	-11.8	2035	200-SC	30.71	23.73	-7.8	-6.2
314.00 Turbogenerator Units	2035	200-SC	39.11	26.52	-8.1	-11.8	2035	200-SC	38.99	23.72	-4.6	-5.9
315.00 Accessory Electric Equipment	2035	200-SC	38.82	26.52	-11.6	-11.5	2035	200-SC	34.82	23.73	-6.3	-5.6
316.00 Miscellaneous Power Plant Equipment	2035	200-SC	34.87	26.53	-12.4	-11.8	2035	200-SC	32.42	23.73	-7.1	-5.9
Total Cholla Common									32.73	23.73	-6.4	-5.8
Four Corners												
311.00 Structures and Improvements			19.89	10.73	-12.9				9.39	1.62	-15.4	-15.6
312.00 Boiler Plant Equipment			22.76	10.92	-13.9				15.98	3.30	-21.9	-22.1
314.00 Turbogenerator Units			21.14	10.46	-12.2				15.47	3.26	-18.3	-19.9
315.00 Accessory Electric Equipment			25.35	12.24	-13.7				10.83	2.55	-20.6	-21.1
316.00 Miscellaneous Power Plant Equipment			18.51	2.26	-14.7				13.30	4.65	-18.7	-18.8
Total Four Corners									14.30	3.04	-20.6	-20.9

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Four Corners Units 1-3												
311.00 Structures and Improvements	2016	200-SC	16.00	8.41	-11.1	-11.2	2012	200-SC	7.07			
312.00 Boiler Plant Equipment	2016	200-SC	18.33	8.41	-12.3	-11.4	2012	200-SC	11.77		-2.2	
314.00 Turbogenerator Units	2016	200-SC	18.04	8.41	-10.8	-11.4	2012	200-SC	12.07		-0.3	
315.00 Accessory Electric Equipment	2016	200-SC	19.82	8.41	-11.4	-11.3	2012	200-SC	7.28		-0.5	
316.00 Miscellaneous Power Plant Equipment	2016	200-SC	11.82	8.41	-11.8	-11.4	2012	200-SC	7.31		-1.0	
Total Four Corners Units 1-3									10.42		-1.6	
Four Corners Units 4-5												
311.00 Structures and Improvements	2031	200-SC	39.25	22.78	-16.7	-16.7	2038	200-SC	44.16	26.51	-65.9	-66.0
312.00 Boiler Plant Equipment	2031	200-SC	43.59	22.77	-17.3	-17.3	2038	200-SC	44.95	26.50	-65.9	-67.1
314.00 Turbogenerator Units	2031	200-SC	38.14	22.78	-16.6	-17.3	2038	200-SC	38.32	26.52	-62.0	-66.8
315.00 Accessory Electric Equipment	2031	200-SC	41.28	22.77	-16.9	-17.0	2038	200-SC	44.51	26.51	-64.5	-66.4
316.00 Miscellaneous Power Plant Equipment	2031	200-SC	38.12	22.78	-17.3	-17.3	2038	200-SC	41.35	26.51	-66.2	-66.7
Total Four Corners Units 4-5									43.81	26.50	-65.3	-66.9
Four Corners Common												
311.00 Structures and Improvements	2031	200-SC	42.23	22.77	-16.2	-16.7	2038	200-SC	47.11	26.50	-21.7	-22.4
312.00 Boiler Plant Equipment	2031	200-SC	44.03	22.77	-17.5	-17.3	2038	200-SC	50.51	26.49	-23.3	-23.5
314.00 Turbogenerator Units	2031	200-SC	61.58	22.73	-12.5	-17.3	2038	200-SC	66.67	26.43	-15.9	-23.1
315.00 Accessory Electric Equipment	2031	200-SC	38.90	22.78	-16.5	-17.0	2038	200-SC	43.49	26.51	-21.7	-22.8
316.00 Miscellaneous Power Plant Equipment	2031	200-SC	36.42	22.78	-17.4	-17.4	2038	200-SC	41.46	26.51	-23.1	-23.2
Total Four Corners Common									46.86	26.50	-22.2	-23.2
Navajo Units 1-3												
311.00 Structures and Improvements	2026	200-SC	33.77	18.05	-10.4	-10.4	2026	200-SC	32.06	15.19	-7.0	-7.1
312.00 Boiler Plant Equipment	2026	200-SC	32.09	18.06	-11.2	-10.9	2026	200-SC	31.18	15.19	-8.2	-7.7
314.00 Turbogenerator Units	2026	200-SC	40.76	18.05	-10.9	-10.9	2026	200-SC	40.93	15.18	-7.5	-7.5
315.00 Accessory Electric Equipment	2026	200-SC	38.85	18.05	-10.7	-10.7	2026	200-SC	37.34	15.18	-7.3	-7.3
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	28.67	18.06	-11.1	-10.9	2026	200-SC	28.11	15.19	-7.8	-7.5
Total Navajo Units 1-3									32.22	15.19	-7.9	-7.6

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Ocotillo Units 1-2												
311.00 Structures and Improvements	2020	200-SC	28.48	12.30	-28.4	-29.8	2020	200-SC	22.13	9.38	-17.8	-18.9
312.00 Boiler Plant Equipment	2020	200-SC	36.48	12.29	-30.0	-30.1	2020	200-SC	34.34	9.38	-19.2	-19.2
314.00 Turbogenerator Units	2020	200-SC	39.20	12.29	-29.9	-30.1	2020	200-SC	23.10	9.38	-18.7	-19.1
315.00 Accessory Electric Equipment	2020	200-SC	32.94	12.29	-29.1	29.9	2020	200-SC	24.21	9.38	-18.5	-19.0
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	19.18	12.30	-28.9	-30.1	2020	200-SC	18.29	9.38	-18.9	-19.1
Total Ocotillo Units 1-2									25.99	9.38	-18.9	-19.1
Saguaro Units 1-2												
311.00 Structures and Improvements	2020	200-SC	28.81	12.30	-28.7	-29.2	2020	200-SC	19.41	9.38	-18.4	-18.7
312.00 Boiler Plant Equipment	2020	200-SC	31.48	12.29	-29.1	-29.5	2020	200-SC	25.18	9.38	-19.0	-19.0
314.00 Turbogenerator Units	2020	200-SC	35.65	12.29	-28.9	-29.5	2020	200-SC	35.82	9.38	-18.5	-18.9
315.00 Accessory Electric Equipment	2020	200-SC	21.05	12.30	-29.0	-29.4	2020	200-SC	18.85	9.38	-18.5	-18.8
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	22.35	12.30	-29.3	-29.5	2020	200-SC	21.15	9.38	-18.9	-18.9
Total Saguaro Units 1-2									25.54	9.38	-18.8	-18.9
NUCLEAR PRODUCTION (by Unit)												
Palo Verde												
321.00 Structures and Improvements			53.62	36.57	-0.3				51.83	33.93	-0.6	-0.5
322.00 Reactor Plant Equipment			51.30	35.85	-1.8				48.64	33.28	-2.4	-1.3
323.00 Turbogenerator Units			52.13	36.08	-0.5				49.58	33.38	-0.7	-0.4
324.00 Accessory Electric Equipment			54.15	35.97	-0.3				53.64	33.27	-0.5	-0.5
325.00 Miscellaneous Power Plant Equipment			50.53	36.53	-1.2				48.94	33.87	-1.4	-0.5
Total Palo Verde									50.11	33.50	-1.4	-0.8
Palo Verde Unit 1												
321.00 Structures and Improvements	2024	200-SC	36.00	16.14	-0.3	-0.2	2044	200-SC	53.54	32.01	-0.4	-0.4
322.00 Reactor Plant Equipment	2024	200-SC	30.70	16.15	-1.4	-0.6	2044	200-SC	48.33	32.03	-2.1	-1.3
323.00 Turbogenerator Units	2024	200-SC	32.10	16.14	-0.5	-0.2	2044	200-SC	48.84	32.03	-0.7	-0.4
324.00 Accessory Electric Equipment	2024	200-SC	36.20	16.14	-0.3	-0.2	2044	200-SC	53.77	32.01	-0.4	-0.4
325.00 Miscellaneous Power Plant Equipment	2024	200-SC	33.60	16.14	-0.8	-0.2	2044	200-SC	50.74	32.02	-0.9	-0.4
Total Palo Verde Unit 1									50.01	32.02	-1.3	-0.9

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A	B	C	D	E	F	G	H	I	J	K	L	M
Palo Verde Unit 2												
321.00 Structures and Improvements	2025	200-SC	36.57	17.10	-0.2	-0.2	2045	200-SC	54.10	32.92	-0.5	-0.5
322.00 Reactor Plant Equipment	2025	200-SC	31.73	17.10	-2.7	-0.7	2045	200-SC	48.65	32.94	-3.1	-1.3
323.00 Turbogenerator Units	2025	200-SC	33.34	17.10	-0.6	-0.2	2045	200-SC	50.48	32.93	-0.7	-0.4
324.00 Accessory Electric Equipment	2025	200-SC	36.15	17.10	-0.3	-0.2	2045	200-SC	53.24	32.92	-0.6	-0.5
325.00 Miscellaneous Power Plant Equipment	2025	200-SC	32.11	17.10	-0.6	-0.2	2045	200-SC	49.81	32.94	-0.7	-0.4
Total Palo Verde Unit 2									50.43	32.93	-1.9	-0.9
Palo Verde Unit 3												
321.00 Structures and Improvements	2027	200-SC	37.18	19.00	-0.2	-0.2	2047	200-SC	54.39	34.74	-0.5	-0.5
322.00 Reactor Plant Equipment	2027	200-SC	36.61	19.00	-1.6	-0.7	2047	200-SC	48.75	34.77	-2.2	-1.4
323.00 Turbogenerator Units	2027	200-SC	36.19	19.00	-0.3	-0.2	2047	200-SC	49.91	34.76	-0.8	-0.5
324.00 Accessory Electric Equipment	2027	200-SC	37.11	19.00	-0.3	-0.2	2047	200-SC	53.96	34.74	-0.6	-0.5
325.00 Miscellaneous Power Plant Equipment	2027	200-SC	35.13	19.00	-0.6	-0.2	2047	200-SC	51.86	34.75	-0.9	-0.5
Total Palo Verde Unit 3									50.60	34.76	-1.4	-0.9
Palo Verde Water Reclamation												
321.00 Structures and Improvements	2027	200-SC	34.15	19.00	-0.5	-0.2	2047	200-SC	47.75	34.77	-0.8	-0.5
322.00 Reactor Plant Equipment	2027	200-SC	25.15	19.02	-0.7	-0.7	2047	200-SC	43.41	34.79	-1.4	-1.4
323.00 Turbogenerator Units	2027	200-SC	34.08	19.00	-0.6	-0.2	2047	200-SC	51.70	34.75	-0.7	-0.5
324.00 Accessory Electric Equipment												
325.00 Miscellaneous Power Plant Equipment	2027	200-SC	34.30	19.00	-1.7	-0.2	2047	200-SC	52.00	34.75	-1.9	-0.5
Total Palo Verde Water Reclamation									47.75	34.77	-0.8	-0.5
Palo Verde Common												
321.00 Structures and Improvements	2027	200-SC	34.28	19.00	-0.5	-0.2	2047	200-SC	51.01	34.75	-0.8	-0.5
322.00 Reactor Plant Equipment	2027	200-SC	36.09	19.00	-2.7	-0.7	2047	200-SC	52.35	34.75	-2.8	-1.4
323.00 Turbogenerator Units	2027	200-SC	22.36	19.02	-1.3	-2.0	2047	200-SC	40.77	34.80	-1.2	-0.5
324.00 Accessory Electric Equipment	2027	200-SC	35.75	19.00	-0.4	-2.0	2047	200-SC	52.49	34.75	-0.6	-0.5
325.00 Miscellaneous Power Plant Equipment	2027	200-SC	30.99	19.01	-1.8	-2.0	2047	200-SC	46.42	34.77	-1.9	-0.5
Total Palo Verde Common									49.88	34.76	-1.4	-0.6

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION (by Unit)												
Douglas CT												
341.00 Structures and Improvements	2020	200-SC	15.72	12.30	-5.0	-5.0	2020	200-SC	15.76	9.39	5.0	5.0
342.00 Fuel Holders, Products and Accessories	2020	200-SC	32.83	12.29	-4.3	-5.0	2020	200-SC	32.80	9.38	4.0	5.0
343.00 Prime Movers	2020	200-SC	46.12	12.29	-5.0	-5.0	2020	200-SC	46.39	9.38	5.0	5.0
344.00 Generators and Devices	2020	200-SC	46.70	12.29	-5.0	-5.0	2020	200-SC	46.97	9.38	5.0	5.0
345.00 Accessory Electric Equipment	2020	200-SC	42.17	12.29	-5.5	-5.0	2020	200-SC	42.30	9.38	4.5	5.0
346.00 Miscellaneous Power Plant Equipment	2020	200-SC	34.39	12.29	-5.0	-5.0	2020	200-SC	34.57	9.38	5.0	5.0
Total Douglas CT									42.69	9.38	4.9	5.0
Ocotillo CT Units 1-2												
341.00 Structures and Improvements	2020	200-SC	32.43	12.29	-5.0	-5.0	2020	200-SC	18.84	9.38	4.8	5.0
342.00 Fuel Holders, Products and Accessories	2020	200-SC	33.24	12.29	-5.0	-5.0	2020	200-SC	28.12	9.38	5.0	5.0
343.00 Prime Movers	2020	200-SC	40.66	12.29	-4.9	-5.0	2020	200-SC	40.85	9.38	4.8	5.0
344.00 Generators and Devices	2020	200-SC	24.36	12.30	-4.4	-5.0	2020	200-SC	21.32	9.38	12.7	5.0
345.00 Accessory Electric Equipment	2020	200-SC	35.70	12.29	-5.7	-5.0	2020	200-SC	31.55	9.38	4.4	5.0
346.00 Miscellaneous Power Plant Equipment	2020	200-SC	34.75	12.29	-4.8	-5.0	2020	200-SC	27.67	9.38	4.7	5.0
Total Octillo CT Units 1-2									27.26	9.38	8.3	5.0
Redhawk CC Units 1-2												
341.00 Structures and Improvements	2037	200-SC	32.73	28.40	-13.0	-5.0	2037	200-SC	32.09	25.61	3.8	5.0
342.00 Fuel Holders, Products and Accessories	2037	200-SC	28.88	28.41	-5.0	-5.0	2037	200-SC	27.60	25.62	5.0	5.0
343.00 Prime Movers	2037	200-SC	33.06	28.40	-2.8	-5.0	2037	200-SC	32.36	25.60	2.6	5.0
344.00 Generators and Devices	2037	200-SC	32.63	28.40	-4.2	-5.0	2037	200-SC	30.17	25.61	25.3	5.0
345.00 Accessory Electric Equipment	2037	200-SC	32.92	28.40	-4.2	-5.0	2037	200-SC	32.35	25.60	3.2	5.0
346.00 Miscellaneous Power Plant Equipment	2037	200-SC	30.34	28.41	-5.0	-5.0	2037	200-SC	27.80	25.62	5.0	5.0
Total Redhawk CC Units 1-2									31.04	25.61	16.0	5.0

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Saguaro												
341.00 Structures and Improvements			21.77	12.30	-5.0				17.25	9.39	4.9	
342.00 Fuel Holders, Products and Accessories			35.77	12.29	-4.5				31.95	9.38	4.3	
343.00 Prime Movers			39.66	13.71	-5.0				39.85	10.81	4.9	
344.00 Generators and Devices			30.90	25.10	-4.9				30.94	22.27	5.9	
345.00 Accessory Electric Equipment			39.91	13.67	-5.4				39.82	10.77	4.6	
346.00 Miscellaneous Power Plant Equipment			24.45	12.30	-4.9				23.96	9.38	4.9	
Total Saguaro									31.34	18.67	5.6	5.0
Saguaro CT Units 1-2												
341.00 Structures and Improvements	2020	200-SC	21.77	12.30	-5.0	-5.0	2020	200-SC	17.25	9.39	4.9	5.0
342.00 Fuel Holders, Products and Accessories	2020	200-SC	35.77	12.29	-4.5	-5.0	2020	200-SC	31.95	9.38	4.3	5.0
343.00 Prime Movers	2020	200-SC	40.25	12.29	-5.0	-5.0	2020	200-SC	40.46	9.38	4.9	5.0
344.00 Generators and Devices	2020	200-SC	20.79	12.30	-4.6	-5.0	2020	200-SC	20.81	9.38	10.9	5.0
345.00 Accessory Electric Equipment	2020	200-SC	40.51	12.29	-5.4	-5.0	2020	200-SC	40.41	9.38	4.6	5.0
346.00 Miscellaneous Power Plant Equipment	2020	200-SC	24.45	12.30	-4.9	-5.0	2020	200-SC	23.96	9.38	4.9	5.0
Total Saguaro CT Units 1-2									28.38	9.38	6.4	5.0
Saguaro CT Unit 3												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2037	200-SC	33.51	28.40	-5.0	-5.0	2037	200-SC	33.56	25.60	5.0	5.0
344.00 Generators and Devices	2037	200-SC	33.51	28.40	-5.0	-5.0	2037	200-SC	33.56	25.60	5.0	5.0
345.00 Accessory Electric Equipment	2037	200-SC	33.51	28.40	-5.0	-5.0	2037	200-SC	33.56	25.60	5.0	5.0
346.00 Miscellaneous Power Plant Equipment												
Total Saguaro CT Unit 3									33.56	25.60	5.0	5.0

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2010)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Solar Units												
341.00 Structures and Improvements	12.00	S3	14.32	3.20	-4.9	-5.0	12.00	S3	16.26	2.25	4.8	5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices	12.00	S3	12.12	5.48	-5.3	-5.0	12.00	S3	12.62	4.22	11.7	5.0
345.00 Accessory Electric Equipment	12.00	S3	12.06	5.18	-5.0	-5.0	12.00	S3	12.11	8.61	5.0	5.0
346.00 Miscellaneous Power Plant Equipment												
Total Solar Units									12.67	4.38	11.3	5.0
Sundance												
341.00 Structures and Improvements	2037	200-SC	30.70	28.41	-5.0	-5.0	2037	200-SC	30.66	25.61	5.0	5.0
342.00 Fuel Holders, Products and Accessories	2037	200-SC	30.73	28.41	-5.0	-5.0	2037	200-SC	30.69	25.61	5.0	5.0
343.00 Prime Movers	2037	200-SC	30.72	28.41	-5.0	-5.0	2037	200-SC	30.75	25.61	5.0	5.0
344.00 Generators and Devices	2037	200-SC	29.25	28.41	-5.0	-5.0	2037	200-SC	29.27	25.61	5.0	5.0
345.00 Accessory Electric Equipment	2037	200-SC	30.73	28.41	-5.0	-5.0	2037	200-SC	30.69	25.61	5.0	5.0
346.00 Miscellaneous Power Plant Equipment	2037	200-SC	30.73	28.41	-5.0	-5.0	2037	200-SC	29.31	25.61	5.0	5.0
Total Sun Dance									30.73	25.61	5.0	5.0
West Phoenix												
341.00 Structures and Improvements			33.13	25.94	-5.3				30.03	22.21	4.9	
342.00 Fuel Holders, Products and Accessories			27.72	20.61	-5.0				27.21	17.72	4.7	
343.00 Prime Movers			33.20	27.79	-3.7				32.93	25.02	3.6	
344.00 Generators and Devices			29.85	24.56	-4.7				29.47	21.91	11.1	
345.00 Accessory Electric Equipment			29.10	22.78	-4.9				29.17	20.65	4.3	
346.00 Miscellaneous Power Plant Equipment			29.54	17.41	-5.3				24.20	16.09	4.5	
Total West Phoenix									30.30	22.43	7.4	5.0

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2010)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
West Phoenix CC Units 1-3												
341.00 Structures and Improvements	2028	200-SC	24.76	19.97	-4.9	-5.0	2028	200-SC	20.32	17.11	4.7	5.0
342.00 Fuel Holders, Products and Accessories	2028	200-SC	26.40	19.97	-5.0	-5.0	2028	200-SC	25.88	17.11	4.6	5.0
343.00 Prime Movers												
344.00 Generators and Devices	2028	200-SC	25.85	19.97	-4.2	-5.0	2028	200-SC	25.48	17.11	17.3	5.0
345.00 Accessory Electric Equipment	2028	200-SC	26.26	19.97	-4.8	-5.0	2028	200-SC	26.01	17.11	3.6	5.0
346.00 Miscellaneous Power Plant Equipment	2028	200-SC	32.86	19.96	-5.4	-5.0	2028	200-SC	24.83	17.11	4.3	5.0
Total West Phoenix CC Units 1-3									25.49	17.11	13.5	5.0
West Phoenix CC Unit 4												
341.00 Structures and Improvements	2036	200-SC	32.84	27.47	-5.0	-5.0	2036	200-SC	32.78	24.67	5.0	5.0
342.00 Fuel Holders, Products and Accessories	2036	200-SC	33.52	27.47	-5.0	-5.0	2036	200-SC	33.58	24.67	5.0	5.0
343.00 Prime Movers	2036	200-SC	33.52	27.47	-5.0	-5.0	2036	200-SC	33.58	24.67	5.0	5.0
344.00 Generators and Devices	2036	200-SC	33.01	27.47	-5.2	-5.0	2036	200-SC	32.59	24.67	9.6	5.0
345.00 Accessory Electric Equipment	2036	200-SC	30.76	27.48	-5.0	-5.0	2036	200-SC	28.02	24.68	5.0	5.0
346.00 Miscellaneous Power Plant Equipment	2036	200-SC	31.27	27.47	-5.0	-5.0	2036	200-SC	26.86	24.68	4.7	5.0
Total West Phoenix CC Unit 4									33.11	24.67	5.9	5.0
West Phoenix CC Unit 5												
341.00 Structures and Improvements	2038	200-SC	33.49	29.32	-5.0	-5.0	2038	200-SC	33.50	26.54	5.0	5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2038	200-SC	33.06	29.32	-3.1	-5.0	2038	200-SC	32.59	26.54	2.9	5.0
344.00 Generators and Devices	2038	200-SC	33.48	29.32	-5.0	-5.0	2038	200-SC	32.94	26.54	6.2	5.0
345.00 Accessory Electric Equipment	2038	200-SC	33.52	29.32	-5.0	-5.0	2038	200-SC	33.56	26.54	5.0	5.0
346.00 Miscellaneous Power Plant Equipment	2038	200-SC	31.63	29.33	-5.0	-5.0	2038	200-SC	29.15	26.55	5.0	5.0
Total West Phoenix CC Unit 5									32.85	26.54	4.6	5.0

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2010) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
West Phoenix CT Units 1-2												
341.00 Structures and Improvements	2020	200-SC	39.03	12.29	-5.0	-5.0	2020	200-SC	19.08	9.38	5.0	5.0
342.00 Fuel Holders, Products and Accessories	2020	200-SC	36.53	12.29	-5.0	-5.0	2020	200-SC	36.73	9.38	5.0	5.0
343.00 Prime Movers	2020	200-SC	32.86	12.29	-4.8	-5.0	2020	200-SC	32.96	9.38	4.6	5.0
344.00 Generators and Devices	2020	200-SC	28.71	12.30	-5.0	-5.0	2020	200-SC	24.86	9.38	6.9	5.0
345.00 Accessory Electric Equipment	2020	200-SC	33.95	12.29	-5.4	-5.0	2020	200-SC	33.43	9.38	4.7	5.0
346.00 Miscellaneous Power Plant Equipment	2020	200-SC	23.33	12.30	-5.0	-5.0	2020	200-SC	20.80	9.38	4.9	5.0
Total West Phoenix CT Units 1-2									28.84	9.38	5.2	5.0
West Phoenix Common												
341.00 Structures and Improvements	2031	200-SC	42.59	22.77	-6.5	-5.0	2031	200-SC	29.46	19.96	4.7	5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices												
345.00 Accessory Electric Equipment												
346.00 Miscellaneous Power Plant Equipment												
Total West Phoenix Common									29.46	19.96	4.7	5.0
Yucca												
341.00 Structures and Improvements									35.51	31.16	4.6	
342.00 Fuel Holders, Products and Accessories									48.66	31.11	4.9	
343.00 Prime Movers									35.28	31.16	5.0	
344.00 Generators and Devices									44.96	31.13	9.0	
345.00 Accessory Electric Equipment									47.85	31.11	4.9	
346.00 Miscellaneous Power Plant Equipment									46.77	31.12	5.0	
Total Yucca									36.86	31.16	5.3	5.0

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2010)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Yucca CT Units 1-4												
341.00 Structures and Improvements	2020	200-SC	21.94	12.30	-4.9	-5.0	2043	200-SC	36.51	31.16	4.4	5.0
342.00 Fuel Holders, Products and Accessories	2020	200-SC	41.81	12.29	-4.9	-5.0	2043	200-SC	61.23	31.06	4.9	5.0
343.00 Prime Movers	2020	200-SC	45.24	12.29	-5.0	-5.0	2043	200-SC	65.30	31.04	5.0	5.0
344.00 Generators and Devices	2020	200-SC	26.33	12.30	-4.9	-5.0	2043	200-SC	45.07	31.13	9.0	5.0
345.00 Accessory Electric Equipment	2020	200-SC	27.75	12.30	-5.2	-5.0	2043	200-SC	51.04	31.10	4.8	5.0
346.00 Miscellaneous Power Plant Equipment	2020	200-SC	27.71	12.30	-5.0	-5.0	2043	200-SC	46.77	31.12	5.0	5.0
Total Yucca CT Units 1-4									52.60	31.10	6.3	5.0
Yucca CT Units 5-6												
341.00 Structures and Improvements							2043	200-SC	33.48	31.17	5.0	5.0
342.00 Fuel Holders, Products and Accessories							2043	200-SC	33.48	31.17	5.0	5.0
343.00 Prime Movers							2043	200-SC	33.48	31.17	5.0	5.0
344.00 Generators and Devices							2043	200-SC	33.48	31.17	5.0	5.0
345.00 Accessory Electric Equipment							2043	200-SC	33.48	31.17	5.0	5.0
346.00 Miscellaneous Power Plant Equipment												
Total Yucca CT Units 5-6									33.48	31.17	5.0	5.0

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the APS depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 362.00 – Station Equipment. Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the APS study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column C) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 2. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant
Account: 362.00 Station Equipment

Dispersion: 43 - L0.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2010 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2010	0.5	20,702,095	43.00	42.55	0.9895	1.0000	20,484,455	481,439
2009	1.5	28,443,020	43.00	41.69	0.9696	1.0000	27,578,821	661,473
2008	2.5	44,214,526	43.01	40.88	0.9505	1.0000	42,024,898	1,028,030
2007	3.5	20,078,730	43.01	40.10	0.9324	1.0000	18,721,265	466,892
2006	4.5	34,459,322	43.01	39.34	0.9148	1.0000	31,523,301	801,204
2005	5.5	36,386,765	42.98	38.62	0.8986	1.0000	32,696,212	846,677
2004	6.5	16,946,211	42.90	37.91	0.8838	1.0000	14,977,110	395,034
2003	7.5	16,711,457	43.03	37.23	0.8652	1.0000	14,459,118	388,339
2002	8.5	18,137,055	43.06	36.57	0.8495	1.0000	15,406,727	421,239
2001	9.5	19,817,265	43.15	35.94	0.8329	1.0000	16,506,076	459,293
2000	10.5	13,804,427	42.94	35.32	0.8225	1.0000	11,354,638	321,448
1999	11.5	19,147,511	43.18	34.73	0.8043	1.0000	15,399,716	443,425
1998	12.5	11,133,907	43.36	34.16	0.7877	1.0000	8,769,831	256,763
1997	13.5	6,976,698	43.07	33.60	0.7802	1.0000	5,443,360	161,992
1996	14.5	7,113,394	43.00	33.07	0.7691	1.0000	5,471,191	165,447
1995	15.5	3,867,810	42.62	32.55	0.7639	1.0000	2,954,494	90,755
1994	16.5	2,939,364	42.90	32.06	0.7473	1.0000	2,196,568	68,516
1993	17.5	4,518,641	43.19	31.58	0.7311	1.0000	3,303,740	104,611
1992	18.5	3,299,401	43.05	31.12	0.7229	1.0000	2,385,241	76,647
1991	19.5	3,878,592	42.07	30.67	0.7291	1.0000	2,827,785	92,187
1990	20.5	4,299,549	41.87	30.24	0.7224	1.0000	3,105,922	102,698
1989	21.5	4,429,694	44.07	29.83	0.6768	1.0000	2,998,146	100,508
1988	22.5	9,548,697	43.45	29.44	0.6775	1.0000	6,468,994	219,758
1987	23.5	5,504,471	44.78	29.05	0.6487	1.0000	3,570,722	122,921
1986	24.5	6,245,626	42.80	28.67	0.6697	1.0000	4,182,676	145,911
1985	25.5	6,804,962	43.77	28.29	0.6463	1.0000	4,398,253	155,482
1984	26.5	4,259,757	41.65	27.91	0.6702	1.0000	2,855,039	102,278
1983	27.5	3,369,708	42.83	27.55	0.6432	1.0000	2,167,349	78,680
1982	28.5	3,867,435	40.27	27.18	0.6750	1.0000	2,610,602	96,038
1981	29.5	2,197,584	43.62	26.82	0.6150	1.0000	1,351,428	50,381
1980	30.5	1,815,309	42.03	26.47	0.6298	1.0000	1,143,280	43,191
1979	31.5	3,672,304	44.11	26.12	0.5922	1.0000	2,174,792	83,259
1978	32.5	2,089,710	42.33	25.78	0.6089	1.0000	1,272,421	49,365
1977	33.5	1,373,571	44.02	25.44	0.5778	1.0000	793,591	31,200
1976	34.5	647,653	42.35	25.10	0.5927	1.0000	383,833	15,293
1975	35.5	804,184	46.43	24.77	0.5334	1.0000	428,947	17,319

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant
Account: 362.00 Station Equipment

Dispersion: 43 - L0.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2010 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1974	36.5	1,927,649	39.39	24.44	0.6204	1.0000	1,195,883	48,932
1973	37.5	1,243,097	45.51	24.12	0.5299	1.0000	658,746	27,316
1972	38.5	1,835,496	40.28	23.80	0.5908	1.0000	1,084,453	45,571
1971	39.5	657,693	43.97	23.48	0.5341	1.0000	351,243	14,958
1970	40.5	1,717,869	44.13	23.17	0.5251	1.0000	902,003	38,929
1969	41.5	760,378	44.81	22.86	0.5103	1.0000	387,996	16,970
1968	42.5	442,261	46.24	22.56	0.4879	1.0000	215,785	9,565
1967	43.5	318,764	45.70	22.26	0.4871	1.0000	155,258	6,975
1966	44.5	431,631	48.25	21.97	0.4553	1.0000	196,508	8,946
1965	45.5	182,048	42.75	21.67	0.5069	1.0000	92,285	4,258
1964	46.5	187,919	48.25	21.39	0.4432	1.0000	83,291	3,895
1963	47.5	328,083	43.43	21.10	0.4858	1.0000	159,383	7,553
1962	48.5	836,090	47.96	20.82	0.4341	1.0000	362,952	17,433
1961	49.5	105,433	42.85	20.54	0.4794	1.0000	50,546	2,461
1960	50.5	403,593	50.06	20.27	0.4049	1.0000	163,405	8,062
1959	51.5	116,498	43.69	20.00	0.4578	1.0000	53,330	2,667
1958	52.5	236,828	43.23	19.73	0.4564	1.0000	108,097	5,478
1957	53.5	144,058	43.23	19.47	0.4503	1.0000	64,869	3,332
1956	54.5	236,693	47.39	19.21	0.4053	1.0000	95,939	4,995
1955	55.5	263,209	48.36	18.95	0.3919	1.0000	103,155	5,443
1954	56.5	155,912	47.13	18.70	0.3967	1.0000	61,854	3,308
1953	57.5	97,574	44.91	18.45	0.4108	1.0000	40,079	2,172
1952	58.5	130,534	46.33	18.20	0.3929	1.0000	51,281	2,817
1951	59.5	29,426	44.63	17.96	0.4024	1.0000	11,841	659
1950	60.5	68,513	62.63	17.72	0.2829	1.0000	19,384	1,094
1949	61.5	74,709	58.77	17.48	0.2975	1.0000	22,223	1,271
1948	62.5	167,271	62.61	17.25	0.2755	1.0000	46,077	2,672
1946	64.5	3,742	66.24	16.79	0.2534	1.0000	948	56
1945	65.5	45,852	67.61	16.56	0.2450	1.0000	11,234	678
1943	67.5	124	64.02	16.12	0.2519	1.0000	31	2
1942	68.5	103,074	68.46	15.91	0.2324	1.0000	23,949	1,506
1941	69.5	921	68.39	15.69	0.2295	1.0000	211	13
1940	70.5	1,053	44.39	15.49	0.3488	1.0000	367	24
1939	71.5	4,690	71.45	15.28	0.2138	1.0000	1,003	66
1935	75.5	29,425	76.88	14.48	0.1884	1.0000	5,543	383
1929	81.5	5,471	81.22	13.38	0.1647	1.0000	901	67
Total	10.7	$406,799,985	43.06	36.12	0.8387	1.0000	$341,172,593	$9,446,217

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2010	Derived Additions	1971 Opening Balance	Experience to 12/31/2010 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2010	0.5	20,702,095		20,702,095	1.0000	0.5000
2009	1.5	28,515,638		28,443,020	0.9975	1.4962
2008	2.5	44,259,532		44,214,526	0.9990	2.4989
2007	3.5	20,260,272		20,078,730	0.9910	3.4833
2006	4.5	35,013,016		34,459,322	0.9842	4.4702
2005	5.5	37,234,267		36,386,765	0.9772	5.4129
2004	6.5	18,625,320		16,946,211	0.9098	6.3039
2003	7.5	17,460,275		16,711,457	0.9571	7.4001
2002	8.5	18,540,699		18,137,055	0.9782	8.3760
2001	9.5	20,246,280		19,817,265	0.9788	9.4103
2000	10.5	15,902,384		13,804,427	0.8681	10.1413
1999	11.5	19,989,956		19,147,511	0.9579	11.3010
1998	12.5	11,456,939		11,133,907	0.9718	12.3950
1997	13.5	7,606,332		6,976,698	0.9172	13.0012
1996	14.5	8,065,812		7,113,394	0.8819	13.8168
1995	15.5	5,462,633		3,867,810	0.7080	14.3157
1994	16.5	3,640,568		2,939,364	0.8074	15.4606
1993	17.5	5,461,100		4,518,641	0.8274	16.6038
1992	18.5	4,333,603		3,299,401	0.7614	17.2905
1991	19.5	5,404,322		3,878,592	0.7177	17.1375
1990	20.5	5,397,653		4,299,549	0.7966	17.7358
1989	21.5	4,852,251		4,429,694	0.9129	20.7330
1988	22.5	11,582,781		9,548,697	0.8244	20.8852
1987	23.5	6,089,217		5,504,471	0.9040	22.9735
1986	24.5	8,857,497		6,245,626	0.7051	21.7401
1985	25.5	8,450,138		6,804,962	0.8053	23.4293
1984	26.5	6,301,017		4,259,757	0.6760	22.0226
1983	27.5	4,296,972		3,369,708	0.7842	23.8970
1982	28.5	6,977,975		3,867,435	0.5542	22.0180
1981	29.5	3,178,217		2,197,584	0.6915	26.0312
1980	30.5	3,310,288		1,815,309	0.5484	25.0893
1979	31.5	5,432,311		3,672,304	0.6760	27.7985
1978	32.5	3,817,195		2,089,710	0.5474	26.6399
1977	33.5	2,345,255		1,373,571	0.5857	28.9335
1976	34.5	1,292,464		647,653	0.5011	27.8451
1975	35.5	1,131,156		804,184	0.7109	32.4983
1974	36.5	4,358,605		1,927,649	0.4423	26.0143

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 362.00 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2010	Derived Additions	1971 Opening Balance	Experience to 12/31/2010 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1973	37.5	2,168,175		1,243,097	0.5733	32.6685
1972	38.5	4,168,498		1,835,496	0.4403	27.9625
1971	39.5	1,198,504		657,693	0.5488	32.1640
1970	40.5		3,261,971	1,717,869	0.5266	32.8187
1969	41.5		1,506,880	760,378	0.5046	33.9778
1968	42.5		815,711	442,261	0.5422	35.8759
1967	43.5		662,909	318,764	0.4809	35.7943
1966	44.5		655,699	431,631	0.6583	38.7746
1965	45.5		527,904	182,048	0.3449	33.7074
1964	46.5		482,393	187,919	0.3896	39.6121
1963	47.5		896,787	328,083	0.3658	35.1953
1962	48.5		1,476,615	836,090	0.5662	40.1052
1961	49.5		453,274	105,433	0.2326	35.3652
1960	50.5		664,089	403,593	0.6077	42.9353
1959	51.5		527,014	116,498	0.2211	36.9058
1958	52.5		862,125	236,828	0.2747	36.7817
1957	53.5		727,325	144,058	0.1981	37.1069
1956	54.5		668,974	236,693	0.3538	41.5710
1955	55.5		861,024	263,209	0.3057	42.8371
1954	56.5		591,941	155,912	0.2634	41.8970
1953	57.5		387,431	97,574	0.2518	39.9524
1952	58.5		651,617	130,534	0.2003	41.6343
1951	59.5		240,909	29,426	0.1221	40.1844
1950	60.5		141,579	68,513	0.4839	58.4225
1949	61.5		288,531	74,709	0.2589	54.7982
1948	62.5		305,066	167,271	0.5483	58.8614
1947	63.5		38,715		0.0000	60.2396
1946	64.5		10,283	3,742	0.3639	62.9096
1945	65.5		80,545	45,852	0.5693	64.4672
1943	67.5		5,970	124	0.0208	61.2440
1942	68.5		143,577	103,074	0.7179	65.8544
1941	69.5		5,369	921	0.1716	65.9414
1940	70.5		723,683	1,053	0.0015	42.0967
1939	71.5		12,143	4,690	0.3862	69.2960
1938	72.5		1,270		0.0000	69.0000
1937	73.5		1,991		0.0000	56.0000
1935	75.5		35,712	29,425	0.8239	75.2359

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2010	Derived Additions	1971 Opening Balance	Experience to 12/31/2010 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1929	81.5		10,650	5,471	0.5137	80.1481
Total	10.7	$443,387,214	$18,727,676	$406,799,985	0.8803	

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	(197,326)	(315,403)			(512,729)
1972	(512,729)	4,293,454	267,313	20,268,903	23,782,315
1973	23,782,315	1,811,938	156,258	(1)	25,437,995
1974	25,437,995	3,836,944	200,589		29,074,349
1975	29,074,349	1,723,973	289,499		30,508,823
1976	30,508,823	1,457,810	328,724		31,637,910
1977	31,637,910	2,228,384	122,868		33,743,426
1978	33,743,426	3,599,800	221,922		37,121,304
1979	37,121,304	5,333,750	141,915		42,313,139
1980	42,313,139	3,217,662	195,943	18,957	45,353,814
1981	45,353,814	3,025,619	285,113	3,499	48,097,819
1982	48,097,819	6,814,111	553,733	(20,659)	54,337,538
1983	54,337,538	4,115,031	788,796	15,653	57,679,426
1984	57,679,426	5,352,720	540,334	172,655	62,664,467
1985	62,664,467	7,981,730	530,996	6,483	70,121,683
1986	70,121,683	6,729,114	488,282	(612,394)	75,750,122
1987	75,750,122	5,853,890	1,214,438	(48,594)	80,340,980
1988	80,340,980	10,646,542	2,585,562	1,425	88,403,386
1989	88,403,386	5,111,358	4,949,595	(22,258)	88,542,890
1990	88,542,890	5,281,728	1,077,929	57,545	92,804,234
1991	92,804,234	4,600,648	1,204,353	(81,832)	96,118,697
1992	96,118,697	5,551,769	704,500	(242)	100,965,724
1993	100,965,724	5,349,721	1,679,689	55,344	104,691,100
1994	104,691,100	4,265,607	663,584	5,105,806	113,398,930
1995	113,398,930	5,500,420	63,199	26,780	118,862,931
1996	118,862,931	9,201,675			128,064,606
1997	128,064,606	7,558,209		(1,237,571)	134,385,244
1998	134,385,244	11,400,750	870,741		144,915,254
1999	144,915,254	19,156,586	5,015,699		159,056,141
2000	159,056,141	14,750,178	729,953		173,076,366
2001	173,076,366	22,297,098	1,094,340		194,279,123
2002	194,279,123	19,710,942	1,585,452		212,404,613
2003	212,404,613	13,840,098	312,803		225,931,908
2004	225,931,908	20,644,519	3,956,064		242,620,363
2005	242,620,363	36,908,827	3,549,091	(931,135)	275,048,964
2006	275,048,964	37,921,966	5,074,017	(1,372,215)	306,524,699
2007	306,524,699	21,411,660	3,277,891	(35,705)	324,622,763
2008	324,622,763	58,498,010	4,869,485	(56,151)	378,195,137
2009	378,195,137	19,320,926	3,899,219	230,597	393,847,441
2010	393,847,441	14,249,796	1,825,016	527,764	406,799,985

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 362.00 Station Equipment

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	18,609,402	1,186,414			19,795,816
1972	19,795,816	4,189,415	267,313		23,717,918
1973	23,717,918	2,252,423	156,258		25,814,083
1974	25,814,083	4,307,788	194,414		29,927,457
1975	29,927,457	1,132,059	295,674		30,763,843
1976	30,763,843	1,291,776	328,724		31,726,895
1977	31,726,895	2,302,955	122,868		33,906,982
1978	33,906,982	3,825,953	221,922		37,511,013
1979	37,511,013	5,435,532	141,915		42,804,630
1980	42,804,630	3,173,386	195,943	18,957	45,801,029
1981	45,801,029	3,106,164	296,730	3,499	48,613,963
1982	48,613,963	6,867,579	581,445	(20,659)	54,879,437
1983	54,879,437	4,250,895	640,321	15,653	58,505,664
1984	58,505,664	6,104,416	526,751	172,655	64,255,985
1985	64,255,985	6,788,866	430,968	6,483	70,620,365
1986	70,620,365	8,464,109	412,710	(659,121)	78,012,643
1987	78,012,643	5,290,500	1,257,429	(48,593)	81,997,121
1988	81,997,121	10,580,905	2,149,202	1,620	90,430,444
1989	90,430,444	4,577,494	5,527,381	(22,258)	89,458,300
1990	89,458,300	5,231,070	1,207,750	57,545	93,539,164
1991	93,539,164	5,316,499	1,204,353		97,651,311
1992	97,651,311	4,546,303	688,591		101,509,023
1993	101,509,023	5,306,989	1,679,689	55,344	105,191,667
1994	105,191,667	3,429,665	663,584	5,105,806	113,063,554
1995	113,063,554	5,462,633	63,199	26,780	118,489,768
1996	118,489,768	9,303,383			127,793,152
1997	127,793,152	7,606,332	36,998	(1,237,571)	134,124,915
1998	134,124,915	11,456,939	870,741		144,711,114
1999	144,711,114	19,989,956	5,015,699		159,685,371
2000	159,685,371	15,902,384	729,953		174,857,802
2001	174,857,802	21,514,557	1,094,340		195,278,019
2002	195,278,019	18,540,699	1,585,452		212,233,266
2003	212,233,266	17,251,309	312,803		229,171,772
2004	229,171,772	18,692,168	3,975,898		243,888,043
2005	243,888,043	38,096,362	3,940,520	(931,135)	277,112,750
2006	277,112,750	35,096,624	4,625,757	(1,372,215)	306,211,402
2007	306,211,402	20,203,450	3,277,891	(35,705)	323,101,256
2008	323,101,256	44,372,505	4,869,485	(56,151)	362,548,125
2009	362,548,125	28,515,638	3,899,219	230,597	387,395,141
2010	387,395,141	20,702,095	1,825,016	527,764	406,799,985

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1929-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-1975	62.5	43.8	L1 *	7.83	39.1	S1	10.18	37.0	R2	11.46
1972-1976	57.3	41.9	L1	7.58	37.5	S0.5	10.05	36.5	R1.5	10.59
1973-1977	63.9	48.2	L1	6.72	42.4	S0.5	8.76	41.2	R1.5	9.11
1974-1978	62.0	47.8	L1	6.53	42.5	S0.5	8.59	42.2	S0.5	8.66
1975-1979	64.0	51.1	L1	5.88	46.0	S0.5	7.40	46.5	S0.5	7.34
1976-1980	69.1	58.0	L1	5.15	51.7	S0.5	6.37	75.2	O3 *	6.04
1977-1981	69.1	58.0	L1	5.45	56.6	L1	5.66	51.6	S0.5	6.09
1978-1982	59.5	51.0	L1	5.77	49.2	L1	6.22	44.6	R1.5	7.35
1979-1983	50.7	46.9	L1	5.40	44.0	S0.5	6.78	42.2	R1.5	7.54
1980-1984	46.8	44.5	L1	5.95	43.6	L1	6.34	41.1	S0.5	7.31
1981-1985	44.1	43.6	L1	5.89	42.7	L1.5	6.35	41.0	S0.5	7.03
1982-1986	43.4	44.1	L1 *	5.72	43.5	L1	6.03	42.1	S0	6.48
1983-1987	28.8	39.6	L1.5 *	4.12	38.1	S0.5	5.58	37.9	S0.5	5.72
1984-1988	20.8	36.1	L1	3.62	35.0	L1	4.37	34.5	S0	4.82
1985-1989	1.2	25.5	L0.5	3.91	25.6	L0.5	3.98	25.5	L0.5	3.56
1986-1990	1.8	25.6	L0.5	3.67	25.9	L0.5	3.77	25.6	L0.5	3.30
1987-1991	7.1	25.7	L0.5	3.29	25.9	L0.5	3.14	25.7	L0.5	3.27
1988-1992	10.1	27.8	L0	3.33	28.7	L0 *	2.86	28.0	L0	3.07
1989-1993	10.4	29.5	L0	2.80	30.8	L0 *	2.35	29.7	L0	2.51
1990-1994	42.6	48.8	L0	4.80	46.1	L0.5	5.98	97.7	O4 *	1.79
1991-1995	50.2	56.4	L0.5	4.71	50.4	S0	7.07	111.3	O3 *	1.95
1992-1996	56.0	66.9	L0.5	3.27	65.3	L0.5	3.51	131.1	SC *	2.45
1993-1997	65.1	82.0	L0.5	2.59	84.9	L0.5	2.42	145.9	SC *	2.24
1994-1998	76.9	81.2	L1 *	6.81	151.1	SC *	2.59	159.3	R1 *	1.14
1995-1999	51.7	49.0	L1	12.12	117.0	O3 *	1.86	117.0	O3 *	1.86
1996-2000	48.4	48.3	L0.5	11.15	111.6	O3 *	1.62	111.2	O3 *	1.54
1997-2001	34.2	45.9	L0.5	7.51	97.7	O4 *	3.27	52.8	L0 *	2.04
1998-2002	28.4	43.8	L0.5	7.38	94.3	O4 *	3.82	47.5	L0 *	2.10
1999-2003	30.7	48.0	L0.5	6.47	106.1	O4 *	5.89	49.5	SC *	2.61
2000-2004	31.9	54.8	L0.5	3.28	76.6	O3 *	2.90	52.5	R0.5	3.67
2001-2005	23.3	46.3	L0.5	3.90	79.7	O4 *	3.46	46.9	S-.5	3.08
2002-2006	17.3	41.1	L0.5	4.01	65.2	O4 *	2.25	42.3	L0	2.38
2003-2007	8.2	39.2	L0.5	1.53	40.5	L0.5 *	1.33	39.5	L0.5	1.32
2004-2008	3.7	35.9	L0.5	1.70	35.8	L1	1.64	35.5	L1	1.47
2005-2009	3.0	37.4	L0.5	1.96	37.1	L1	1.81	36.8	L1	1.62
2006-2010	2.1	40.9	L1	3.20	39.7	S0	1.82	39.4	S0	1.73

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1929-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2010	6.1	42.3	L0.5	1.26	43.1	L0.5	1.41	41.4	S-.5	1.74
1973-2010	6.1	42.3	L0.5	1.26	43.1	L0.5	1.43	41.4	S-.5	1.74
1975-2010	6.1	42.3	L0.5	1.26	43.1	L0.5	1.43	41.4	S-.5	1.74
1977-2010	6.1	42.3	L0.5	1.27	43.2	L0.5	1.46	41.4	S-.5	1.76
1979-2010	6.1	42.2	L0.5	1.27	43.1	L0.5	1.46	41.3	S-.5	1.75
1981-2010	6.1	42.0	L0.5	1.28	43.0	L0.5	1.44	41.2	S-.5	1.74
1983-2010	6.1	41.9	L0.5	1.31	43.0	L0.5	1.46	41.1	S-.5	1.75
1985-2010	6.1	41.9	L0.5	1.34	43.0	L0.5	1.48	41.1	S-.5	1.77
1987-2010	6.1	41.8	L0.5	1.33	42.9	L0.5	1.49	41.0	S-.5	1.77
1989-2010	6.3	42.5	L0.5	1.42	43.9	L0.5	1.70	41.6	S-.5	1.84
1991-2010	7.0	44.8	L0.5	1.53	45.2	L0.5	1.65	43.4	S-.5	1.81
1993-2010	6.9	44.6	L0.5	1.55	45.3	L0.5	1.77	43.2	S-.5	1.94
1995-2010	6.8	44.6	L0.5	1.59	45.3	L0.5	1.82	43.2	S-.5	1.97
1997-2010	6.2	43.0	L0.5	1.51	44.0	L0.5	1.77	41.9	S-.5	1.90
1999-2010	5.5	41.6	L0.5	1.47	42.7	L0.5	1.71	40.7	S-.5	1.86
2001-2010	5.2	42.8	L0.5	1.80	42.3	L1	1.49	41.3	S0	1.88
2003-2010	4.7	41.4	L0.5	1.72	40.8	L1	1.44	40.2	S0	1.80
2005-2010	2.3	39.9	L1	2.31	39.3	L1	1.72	38.9	S0	1.40
2007-2010	2.2	43.1	L1	4.63	41.1	S0.5	1.81	40.9	R1	1.88
2009-2010	0.5	50.8	L1	9.09	48.3	S0	6.96	46.7	R1	5.07

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1929-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

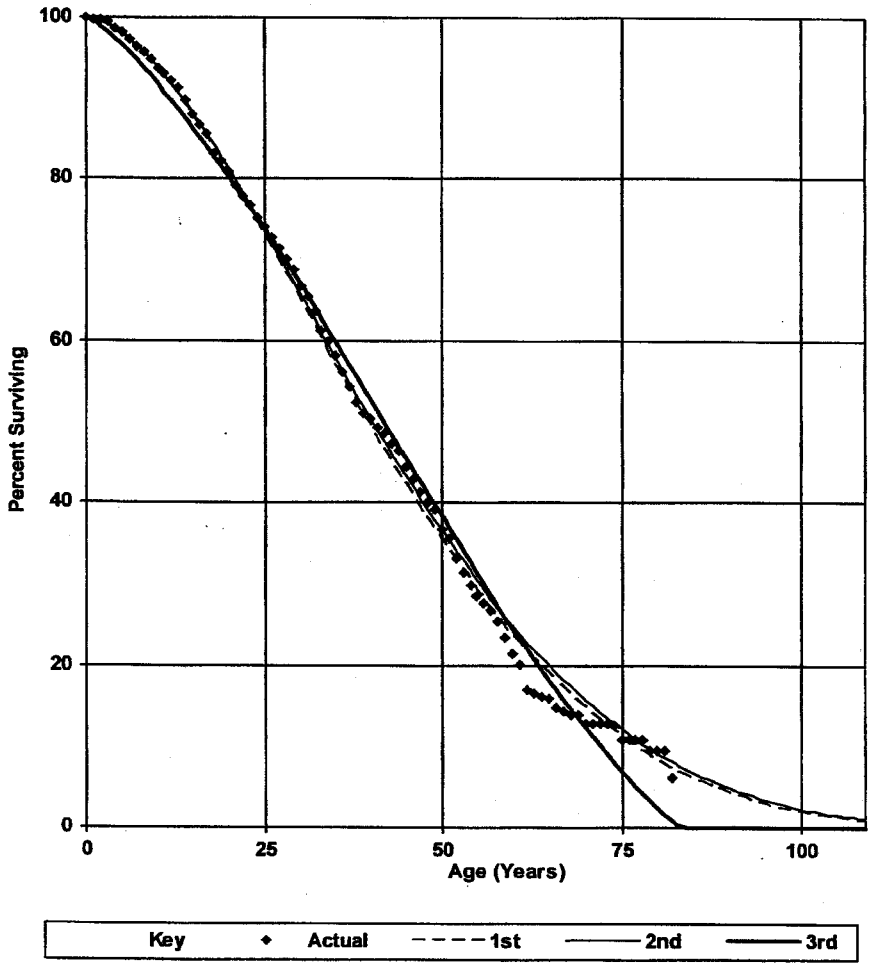
Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-1972	77.9	46.7	L1 *	10.72	39.6	S1	13.54	37.5	R2	14.46
1971-1974	71.3	47.9	L1	8.29	41.7	S0.5	10.42	39.1	R2	11.42
1971-1976	59.5	45.0	L1	6.35	39.2	S0.5	9.06	37.9	R1.5	9.81
1971-1978	57.7	47.8	L1	4.62	42.2	S0.5	6.86	41.2	R1.5	7.26
1971-1980	57.6	51.0	L1	3.66	46.0	S0.5	5.19	45.7	S0.5	5.25
1971-1982	51.0	49.6	L1	2.86	45.5	S0.5	4.18	43.5	S0.5	4.97
1971-1984	43.7	46.8	L1	2.72	44.0	L1.5	3.88	42.0	S0.5	4.90
1971-1986	41.8	47.4	L1	2.69	44.9	L1.5	3.69	43.7	S0.5	4.21
1971-1988	23.2	41.1	L1	2.86	38.8	S0	2.76	37.8	S0.5	3.58
1971-1990	6.7	33.8	L0.5	4.08	33.6	L1	3.89	32.5	S0	2.91
1971-1992	14.5	35.6	L0.5	2.63	35.2	L1	2.63	34.3	S-.5	3.05
1971-1994	16.5	36.8	L0.5	2.55	36.5	L0.5	2.61	35.9	L1	2.91
1971-1996	23.2	40.8	L0.5	3.11	40.7	L0.5	3.19	44.0	L0.5 *	2.93
1971-1998	32.2	43.8	L0.5	5.12	44.3	L0.5	4.87	70.7	O4 *	3.08
1971-2000	30.9	41.7	L0.5	6.52	60.7	O4 *	3.37	76.1	O4 *	1.92
1971-2002	25.6	43.4	L0.5	5.24	67.2	O4 *	1.69	66.0	O4 *	1.73
1971-2004	27.0	44.3	L0.5	5.67	69.5	O4 *	1.61	70.3	O4 *	1.57
1971-2006	19.8	42.1	L0.5	4.21	61.6	O4 *	0.94	45.5	L0	1.38
1971-2008	10.9	41.2	L0.5	1.68	42.3	L0.5	1.49	40.7	L0.5	2.03
1971-2010	6.1	42.3	L0.5	1.26	43.1	L0.5	1.41	41.4	S-.5	1.74

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1929-2010 Observation Band: 1971-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis

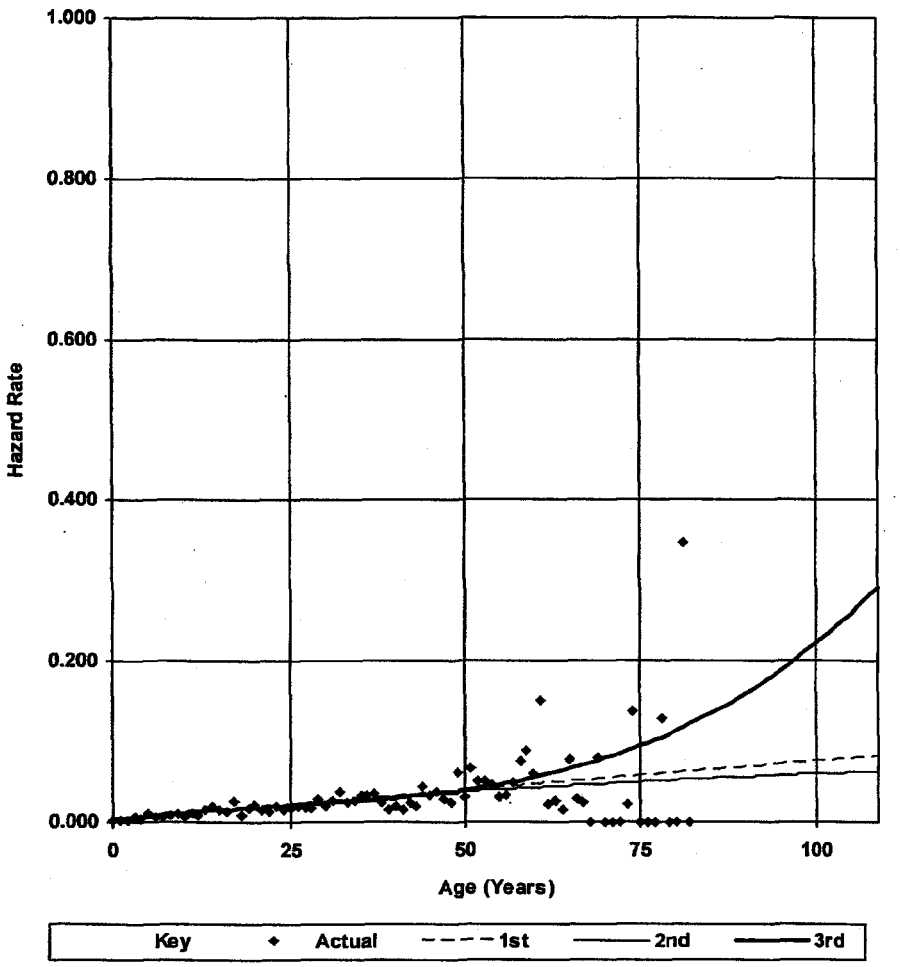
1st: 42.3-L0.5 2nd: 43.1-L0.5 3rd: 41.4-S-.5



ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1929-2010 Observation Band: 1971-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Function 1st: 42.3-L0.5 2nd: 43.1-L0.5 3rd: 41.4-S-.5



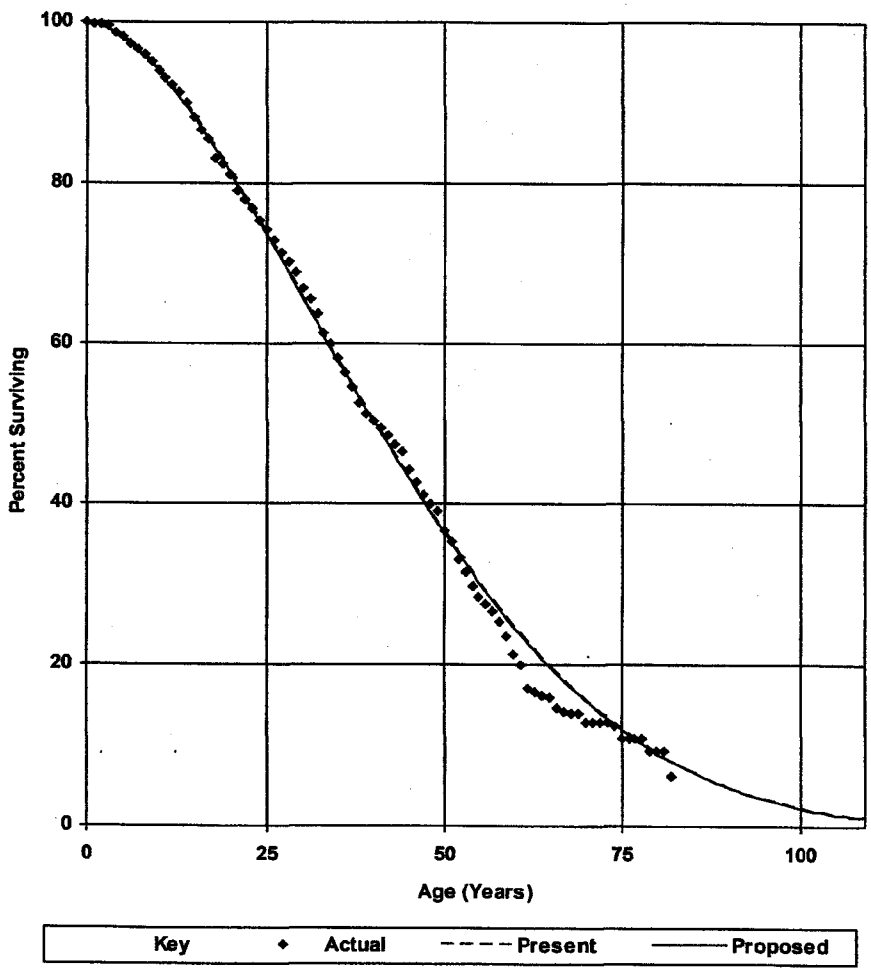
ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

T-Cut: None
Placement Band: 1929-2010
Observation Band: 1971-2010

Present and Proposed Projection Life Curves Present: 43.0-L0.5 Proposed: 43.0-L0.5



ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1980	195,943	23,940	12.2		44,600	22.8		(20,660)	-10.5	
1981	285,113	14,271	5.0		114,846	40.3		(100,575)	-35.3	
1982	553,733	101,079	18.3		158,044	28.5		(56,965)	-10.3	
1983	788,796	145,734	18.5		119,423	15.1		26,311	3.3	
1984	540,334	131,469	24.3	17.6	144,531	26.7	24.6	(13,062)	-2.4	-7.0
1985	530,996	146,551	27.6	20.0	106,927	20.1	23.9	39,624	7.5	-3.9
1986	488,282	16,662	3.4	18.7	60,520	12.4	20.3	(43,858)	-9.0	-1.7
1987	1,214,438	36,980	3.0	13.4	160,911	13.2	16.6	(123,931)	-10.2	-3.2
1988	2,585,562	2,309,201	89.3	49.3	246,124	9.5	13.4	2,063,077	79.8	35.9
1989	4,949,595	269,663	5.4	28.4	206,957	4.2	8.0	62,706	1.3	20.4
1990	1,077,929	445,162	41.3	29.8	131,454	12.2	7.8	313,708	29.1	22.0
1991	1,204,353	553,850	46.0	32.8	157,459	13.1	8.2	396,391	32.9	24.6
1992	704,500	239,226	34.0	36.3	215,787	30.6	9.1	23,439	3.3	27.2
1993	1,679,689	343,438	20.4	19.3	219,066	13.0	9.7	124,371	7.4	9.6
1994	663,584	124,296	18.7	32.0	98,392	14.8	15.4	25,904	3.9	16.6
1995	63,199	12,802	20.3	29.5	7,090	11.2	16.2	5,712	9.0	13.3
1996			0.0	23.1		0.0	17.4		0.0	5.8
1997			0.0	20.0		0.0	13.5		0.0	6.5
1998	870,741	282,808	32.5	26.3	16,340	1.9	7.6	266,468	30.6	18.7
1999	5,015,699	1,105,255	22.0	23.5	243,050	4.8	4.5	862,205	17.2	19.1
2000	729,953	200,673	27.5	24.0	54,063	7.4	4.7	146,610	20.1	19.3
2001	1,094,340	214,293	19.6	23.4	191,215	17.5	6.5	23,078	2.1	16.8
2002	1,585,452	184,970	11.7	21.4	1,317,557	83.1	19.6	(1,132,587)	-71.4	1.8
2003	312,803	990,085	316.5	30.8	676,647	216.3	28.4	313,438	100.2	2.4
2004	3,956,064	(273,543)	-6.9	17.1	157,777	4.0	31.2	(431,320)	-10.9	-14.1
2005	3,549,091	(27,246)	-0.8	10.4	222,288	6.3	24.4	(249,534)	-7.0	-14.1
2006	5,074,017	2,911,829	57.4	26.2	500,211	9.9	19.9	2,411,618	47.5	6.3
2007	3,277,891	119,477	3.6	23.0	588,630	18.0	13.3	(469,153)	-14.3	9.7
2008	4,869,485	107,233	2.2	13.7	863,196	17.7	11.3	(755,963)	-15.5	2.4
2009	3,899,219	605,278	15.5	18.0	1,107,953	28.4	15.9	(502,675)	-12.9	2.1
2010	1,825,016	112,006	6.1	20.4	379,706	20.8	18.2	(267,700)	-14.7	2.2
Total	53,585,817	11,447,443	21.4		8,510,763	15.9		2,936,679	5.5	

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1980	195,943	23,940	12.2		44,600	22.8		(20,660)	-10.5	
1981	296,730	14,271	4.8		114,846	38.7		(100,575)	-33.9	
1982	581,445	101,079	17.4		158,044	27.2		(56,965)	-9.8	
1983	640,321	145,734	22.8		119,423	18.7		26,311	4.1	
1984	526,751	131,469	25.0	18.6	144,531	27.4	25.9	(13,062)	-2.5	-7.4
1985	430,968	146,551	34.0	21.8	106,927	24.8	26.0	39,624	9.2	-4.2
1986	412,710	16,662	4.0	20.9	60,520	14.7	22.7	(43,858)	-10.6	-1.8
1987	1,257,429	36,980	2.9	14.6	160,911	12.8	18.1	(123,931)	-9.9	-3.5
1988	2,149,202	2,309,201	107.4	55.3	246,124	11.5	15.1	2,063,077	96.0	40.2
1989	5,527,381	269,663	4.9	28.4	206,957	3.7	8.0	62,706	1.1	20.4
1990	1,207,750	445,162	36.9	29.2	131,454	10.9	7.6	313,708	26.0	21.5
1991	1,204,353	553,850	46.0	31.9	157,459	13.1	8.0	396,391	32.9	23.9
1992	688,591	239,226	34.7	35.4	215,787	31.3	8.9	23,439	3.4	26.5
1993	1,679,689	343,438	20.4	18.0	219,066	13.0	9.0	124,371	7.4	8.9
1994	663,584	124,296	18.7	31.3	98,392	14.8	15.1	25,904	3.9	16.2
1995	63,199	12,802	20.3	29.6	7,090	11.2	16.2	5,712	9.0	13.4
1996			0.0	23.3		0.0	17.5		0.0	5.8
1997	36,998		0.0	19.7		0.0	13.3		0.0	6.4
1998	870,741	282,808	32.5	25.7	16,340	1.9	7.5	266,468	30.6	18.2
1999	5,015,699	1,105,255	22.0	23.4	243,050	4.8	4.5	862,205	17.2	18.9
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2001	1,094,340	214,293	19.6	23.3	191,215	17.5	6.5	23,078	2.1	16.8
2002	1,585,452	184,970	11.7	21.4	1,317,557	83.1	19.6	(1,132,587)	-71.4	1.8
2003	312,803	990,085	316.5	30.8	676,647	216.3	28.4	313,438	100.2	2.4
2004	3,975,898	(273,543)	-6.9	17.1	157,777	4.0	31.1	(431,320)	-10.8	-14.0
2005	3,940,520	(27,246)	-0.7	10.0	222,288	5.6	23.5	(249,534)	-6.3	-13.5
2006	4,625,757	2,911,829	62.9	26.2	500,211	10.8	19.9	2,411,618	52.1	6.3
2007	3,277,891	119,477	3.6	23.1	588,630	18.0	13.3	(469,153)	-14.3	9.8
2008	4,869,485	107,233	2.2	13.7	863,196	17.7	11.3	(755,963)	-15.5	2.4
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2010	1,825,016	112,006	6.1	20.8	379,706	20.8	18.6	(267,700)	-14.7	2.2
Total	53,585,817	11,447,443	21.4		8,510,763	15.9		2,936,679	5.5	

Peter M. Ewin

TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

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TESTIMONY OF PETE M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-_____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am the Director of Financial Planning and Forecasting for Arizona Public Service Company ("APS" or "Company"). In that capacity, among other responsibilities, I oversee the preparation of the Company's fuel and purchased power expense forecasts and the Company's Power Supply Adjustment ("PSA") filings with the Arizona Corporation Commission ("Commission").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received Bachelors and Masters degrees in Economics from Arizona State University in 1985 and 1988, respectively. I have analyzed and forecasted electric energy and demand growth since 1988, first as a Staff member of the Commission and, since 1990, as an employee for APS. I have specifically analyzed the dispatch of our generating units in combination with market purchases to serve native load demand since 1998, and assumed full responsibility for making the optimal dispatch and associated fuel cost projections in 2000. I was formerly President of the Arizona Economic Round Table, a group of Arizona-based economists that specialize in studying the Arizona economy, and I am still a member of that organization. I also serve on the Joint Legislative Budget Committee's Finance Advisory Committee. This advisory committee consists of a group of state economists who advise the Joint Legislative Budget Committee staff on the adequacy of the economic projections underlying their state revenue projections.

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

A. My testimony discusses the system average cost of fuel for generation and purchased power. In particular, I sponsor the Company's Base Fuel and Purchased Power pro forma, which sets forth the base rate level of fuel and purchased power expenses.[1] This requested base fuel rate reflects conditions expected to exist at the time the requested rates are likely to be in effect, which, in this proceeding, represents a decrease from the current authorized rate. My testimony explains the reasons for this decrease.

In addition, I sponsor the "Total Company" column for several pro forma adjustments to the 2010 Test Year ending December 31, 2010 ("Test Year" or "TY") set forth in SFR Schedule C-2, including:

- Base Fuel and Purchased Power;
- Remove Test Year PSA Revenue and Deferred Fuel Amortization; and
- Remove Test Year PSA Deferrals and Mark-to-Market Accruals.

The Base Fuel and Purchased Power pro forma has been prepared under two alternate resource plans reflecting the fact that the Company's proposed acquisition of Southern California Edison's ("SCE") share of Four Corners Units 4 and 5 has not yet been approved and completed. My testimony discusses the method used for each.

I will also discuss two modifications to the PSA Plan of Administration ("POA"). Specifically, I will explain why the removal of the 90/10 sharing provision and the inclusion of environmental chemical costs in the PSA are appropriate.

[1] Throughout the remainder of my testimony, the term "fuel expenses" may be used generically to refer to fuel and purchased power expenses.

Q. WERE YOU THE COMPANY'S WITNESS ON THESE SAME MATTERS IN THE PREVIOUS THREE APS RATE PROCEEDINGS?

A. Yes.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS's current base fuel recovery amount of 3.76¢ per kilowatt-hour ("kWh"), established in Decision No. 71448 (December 30, 2009), was premised on expected 2009 cost levels at the time of the settlement in that case. Since then, the system average fuel cost has continued to decrease primarily because of lower prices for natural gas and wholesale power purchases, as well as a lower reliance on higher-cost natural gas and purchased power relative to other generation sources. During the Test Year, APS's fuel costs had fallen to 3.35¢ per kWh and are expected to decline even further into 2012.

Given the decrease in fuel costs that has occurred since fuel rates were last set, the Company proposes that the base fuel recovery rate be set at 3.24¢/kWh, which rate reflects normalized levels of power plant performance, expected 2012 fuel and purchased power prices, and a credit for anticipated off-system sales margins. This rate will allow the Company to recover fuel costs incurred during the Test Year, adjusted to reflect the conditions the Company expects to experience during 2012 when the rates requested in this proceeding are expected to become effective. Attachment PME-1 shows these changes and their respective impact on the Company's overall fuel costs.

The method by which I calculated this new base fuel rate is consistent with the one used by the Company and accepted by the Commission in the Company's last two rate cases. If the Company's proposed acquisition of incremental ownership interests of Four Corners 4 and 5 is more certain at the time of the decision in this case, then I propose that the base fuel recovery be set at

3.13¢/kWh, which reflects the lower costs of generation which will result from that transaction.

APS is the only utility in Arizona that has a cost sharing element in its PSA. Although this is currently benefiting the Company, the provision is still unfair and unnecessary to protect APS customers from imprudent acts on the part of the Company.

Certain chemicals such as lime, ammonia, and sulfur are necessary to operate certain of the Company's power plants in order to comply with environmental emissions rules. Their use is directly proportional to unit output every bit as much as fuel itself and thus should also be recoverable through the PSA.

III. BASE FUEL AND PURCHASED POWER PRO FORMA

Q. ARE YOU PROPOSING TO ADJUST THE COMPANY'S AUTHORIZED BASE FUEL RATE?

A. Yes, I am proposing to decrease the base fuel rate from 3.76¢/kWh (authorized by the Commission in Decision No. 71448) to 3.24¢/kWh. This adjustment reduces the annual base rate revenue requirement by approximately $144 million (at Test Year sales levels). But for the 90/10 sharing arrangement in the PSA, which APS is proposing to remove in this proceeding, this would amount to no difference in the revenues actually collected from customers. With that sharing arrangement, the impact of the reduction in the base fuel rate amounts to a $21 million net decrease in revenues, or about 0.7%. It is important to update the Company's base fuel rate both so that the attendant impact on class rate design can be accounted for and to avoid the 90/10 sharing becoming, in essence, an automatic 10% penalty or reward. Attachment PME-1 shows the results of the proposed adjustments on Test Year revenues. However, as will be discussed later

in my testimony, the Company is proposing to remove the 90/10 sharing provision.

Q. WHAT FACTORS ARE BEHIND YOUR PROPOSED ADJUSTMENT?

A. The dramatic decline in natural gas prices and the associated decline in wholesale power prices since the last update to the base fuel rate is the largest single reason for the adjustment. By themselves, these changes in commodity prices account for $133 million of the $144 million reduction in base fuel expense. Additionally, the combination of lower retail sales and greater availability of baseload nuclear and coal generating units is leading to a lower reliance on natural gas-fired generation and wholesale power market purchases. Since natural gas and wholesale power are more costly on a variable fuel basis than nuclear and coal generation, a lower share of natural gas generation and wholesale purchases leads to a lower average cost. I have quantified the impact of this change at $60 million of the overall reduction described above.

There are several items that are offsetting these cost reductions. The most prominent are increased capacity costs and higher prices for nuclear fuel. The higher capacity costs are primarily related to having additional capacity under contract and amount to a $32 million increase. Higher uranium prices are the primary driver of higher nuclear fuel costs, which total just under $22 million of an increase.

Each of these factors represents changes in conditions since the last time the Company's base fuel rate was set (at 3.76¢/kWh). At that time, the Company relied on forward market expectations from November 2008 for the year 2009. The current estimates are based on March 2011 expectations for the year 2012. A summary of the quantification of these factors can be seen in Attachment PME-1.

Attachment PME-2 shows the average fuel cost for the Company's major resource types embedded in the current authorized and proposed base fuel rates.

Q. DO THESE PROPOSED ADJUSTMENTS REQUIRE NORMALIZATION OF CONDITIONS EXPERIENCED IN THE TEST YEAR?

A. Yes, the adjustments described above reflect both changes in prices and operations from the last time the Base Fuel Rate was set for the current Test Year, and known and measurable changes to Test Year conditions which are more representative of conditions that will be present when the Company's new rates are likely to take effect. Specifically, I am proposing to normalize actual Test Year fuel expenses and off-system sales margins for:

- Increased electricity sales due to customer growth;
- lower commodity market prices for natural gas and power;
- higher coal and nuclear prices due to standard contract escalators;
- normalized maintenance and unplanned outage times;
- the cancellation by Salt River Project ("SRP") of a capacity power contract with APS;
- additional renewable resources consistent with the Company's Renewable Energy Standard ("RES") requirements; and
- other miscellaneous items, such as broker fees, third-party wheeling expenses, and short-term and long-term capacity costs.

Of the total proposed adjustment, $113.7 million reflects costs that are already reflected in the Test Year and the remaining $29.8 million is for costs that are normalized to 2012 levels, the time when rates from this request are likely to take effect. For the Test Year ending December 31, 2010, the Company's actual

average base fuel and purchased power expense, excluding the impact of the period's non-cash fuel cost deferrals, was 3.35¢/kWh. Attachment PME-3, page 1 of 4, shows the components that make up this cost level.

Q. ARE YOU PROPOSING TO NORMALIZE FUEL EXPENSES FOR THE COMPANY'S PROPOSED ACQUISITION OF SCE'S OWNERSHIP SHARE OF FOUR CORNERS UNITS 4 AND 5?

A. I have prepared a proposed base fuel rate both with and without the planned transaction. While the company is planning for the acquisition of SCE's share of Four Corners 4 and 5 in the latter half of 2012, the resolution of the transaction is yet to be determined. Given this uncertainty, I have followed a two-step approach to determining the appropriate base fuel rate. In the first step, I have made all of the typical and necessary normalizing adjustments to test year fuel expenses and calculated the resulting average cost of fuel as if there is no change in ownership at Four Corners. This results in a base fuel rate of 3.24¢/kWh and the components of this cost level can be seen in attachment PME-3, page 2 of 4. The normalizing adjustments are described in more detail in my testimony below.

In the second step, the additional generation capacity from SCE's share of Four Corners 4 and 5 is added to the Company's available resources. This additional lower-cost generation displaces higher-cost natural gas generation and wholesale market power purchases and results in a lower proposed Base Fuel Rate of 3.13¢/kWh. This result can be seen in Attachment PME-3, page 3 of 4.

In the event that the proposed acquisition of Four Corners 4 and 5 is, for whatever reason, delayed or cancelled or otherwise uncertain at the time of a decision in this case, then the Base Fuel Rate of 3.24¢/kWh would be the appropriate rate to adopt in this proceeding. On the other hand, if the Four Corners transaction has received all necessary approvals, then it may be appropriate to adopt the Base Fuel Rate of 3.13¢/kWh. The following section of my testimony discusses the

development and implementation of the normalizing adjustments aside from those relating to the acquisition of Four Corners 4 and 5.

Q. PLEASE EXPLAIN HOW THE PRO FORMAS FOR FUEL EXPENSE AND OFF-SYSTEM MARGIN ARE DEVELOPED.

A. I developed the pro forma for fuel expense net of off-system sales margins using the approach used by the Company and accepted by the Commission for establishing the Company's base fuel rate in the last two rate cases. Under that approach, I simulated the impacts of the adjustments I mentioned above using the Company's production cost simulation tool RTSim. This computer model replicates the dispatch of the APS system and is the primary fuel expense and off-system sales forecasting tool APS uses to prepare its annual budgets, long-range fuel forecasts, and near-term operational plans. The vast majority of the input assumptions I have used in the proposed base fuel adjustment are the same as or consistent with the expected levels in the Company's operating plans prepared for internal use. Most importantly, the estimated fuel expense is based on the March 31, 2011 forward curve for natural gas and power prices and the corresponding valuation of the Company's hedges.

Q. HOW DOES THE PRODUCTION COST SIMULATION MODEL CALCULATE THE AVERAGE FUEL AND PURCHASED POWER COST?

A. The model simulates the dispatch of the APS generating units on a daily and hourly basis. It takes into account the APS system load shape, fuel prices (including wholesale market prices for power) and characteristics of APS-owned generating plants (such as heat rates, overhaul cycles, unplanned outage rates, start-up costs and ramp rates, among others), along with commitments for purchases and sales of power. The model also simulates necessary market purchases for those times when load exceeds generating capacity, and likewise

simulates market sales during those times when the system is not fully utilized but generating units are economic.

The projected hourly production of each of the units, along with wholesale market purchases and sales, is priced at the corresponding contract or market price projections included in the model. Fixed costs—those expenses that do not vary directly with the level of production—are then added to the model results. These expenses include firm gas transportation, fuel handling, third party wheeling costs, wholesale market capacity costs, and broker fees. The result is the total expected fuel expense and off-system sales revenue consistent with the assumptions used in the model.

Q. DO THESE RESULTS FLOW DIRECTLY INTO YOUR PROPOSED FUEL PRO FORMA?

A. No. The process I have used captures the impacts of the relevant factors on the Company's *average* base fuel cost. The change in the average cost from the Company's Test Year amounts applied to the adjusted Test Year retail sales amounts produces the appropriate adjustment for the Test Year pro forma. This calculation is shown on Attachment PME-4. Attachment PME-3 shows the major components of the proposed base fuel rate of 3.24¢/kWh, the realized Test Year fuel costs of 3.35¢/kWh, and the current authorized level of 3.76¢/kWh. This base fuel rate results in a pro forma to Test Year fuel and purchased power costs of $(29,810,000) (see SFR Schedule C-2, page 10, column 28). The alternate base fuel rate, which includes the acquisition of SCE's share of Four Corners 4 and 5, produces an additional reduction in normalized fuel costs of $31.1 million ((3.1298¢/kWh – 3.2415¢/kWh) x 27,833,756 MWh = -$31,090,305).

Q. CAN YOU DESCRIBE THE NORMALIZING ADJUSTMENTS RELATED TO FUEL PRICES?

A. Yes. Commodity prices for natural gas and wholesale market power have decreased from the levels included in the current base fuel rate and translate into a decrease in fuel expense of $133 million net of the value of the Company's hedge contracts. At the close of the market on March 31, 2011, delivered natural gas prices for calendar year 2012 averaged $5.21/MMBTU. These prices represent a 21% decrease from the delivered prices the Company is currently recovering in base rates.

In addition, because natural gas is the marginal fuel source for most wholesale power transactions, power prices have decreased in concert with gas prices. Prices for on-peak power delivered at Palo Verde for calendar year 2012 averaged under $44/MWh on March 31, 2011, a 25.7% decrease from the level currently being recovered in base rates. The weighted average of the on-peak and off-peak 2012 power prices the Company expects to pay is $28.73/MWh.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS FOR FUEL PRICES OTHER THAN NATURAL GAS AND POWER?

A. Yes. The Company's coal contracts have standard contract escalators which will lead to steady upward pressure on those fuel prices. The Test Year average cost (on a production basis) for the combined coal fleet was $17.45/MWh. Excluding a one-time credit for settlement of prior year contract issues, the average production cost was $18.45/MWh. (These one-time credits were credited to the PSA in 2010 and are being refunded to customers through the 2011 Historical Component.) In 2012, the average production cost is expected to be $19.51/MWh, equating to a 6% increase in delivered coal prices over two years. This increase reflects the escalation rates specific to each contract, but the dominant component having the greatest impact on the overall contract escalation is the price of petroleum products used in coal mining.

Nuclear fuel costs are also increasing into 2012. Production costs averaged $7.62/MWh in 2010, but are projected to increase to $8.97/MWh in 2012, an 18% increase. Most of these cost increases have already been realized as a result of the lengthy nuclear fuel cycle. Nuclear fuel is procured in several steps leading up to the time the nuclear fuel assemblies are installed during a refueling outage, beginning with the purchase of uranium, followed by conversion and enrichment processes and ending with the fabrication of the nuclear fuel into assemblies. These assemblies are then shipped to the plant prior to each unit's next refueling outage and installed during the outage. Typically only 1/2 to 1/3 of the existing fuel assemblies are replaced during any one outage. The lead time for the start of this procurement process is 15-18 months prior to the outage. This timing element means that between 85% and 90% of the cost for any particular year has already been set with a high degree of certainty six months prior to the start of that year. These costs are then recorded as fuel expense as the plant consumes the fuel while generating electricity through the course of the year. The cost increases expected to be recorded in 2012 principally reflect the much higher world-wide prices for uranium in recent years.

Q. ARE ANY RESOURCE CHANGES EXPECTED TO IMPACT FUEL COSTS?

A. Yes, the resources used to meet the Company's native load demand are dynamic, and the proposed fuel costs reflect several normalizing adjustments. First, the Company is continuing to acquire energy from renewable resources in line with its commitments to meet the requirements of the RES and the 2009 Settlement Agreement. In terms of contribution to total generated and purchased energy, renewables will have doubled by 2012 compared to the amount included in the current authorized base fuel rate of 3.76¢/kWh, from 2.0% of the total to 4.1% of

the total. These new resources are predominantly displacing natural gas generation and market power purchases.

Second, there are differences in the capacity available to the Company under long term contracts in 2012 compared to the Test Year and the amounts included in the current authorized base fuel rate. In 2010, the Company added a new 10-year 560 MW tolling contract with the Arlington combined cycle natural gas-fired power plant west of Phoenix. During 2010, this capacity was available for the months of June through September. In 2012 (and future years), the capacity is available for the months of May through October. Also in mid-2010, SRP terminated a long-term capacity and energy contract which resulted in the loss of almost 240 MW of capacity year-round. The net effect of these capacity changes, when put on an average cost basis and applied to 2010 Test Year normalized sales, is an increase of $32 million as can be seen in Attachment PME-1.

Finally, changes in planned and unplanned outage time for each of the Company's generating resources are being reflected in the normalized fuel cost. Planned outage time has been normalized in a manner consistent with the normalization of maintenance expense for these plants and consistent with the procedures used in previous rate cases. The planned outage time is adjusted to match the historical average planned outage time for each plant, with the exception of the nuclear plant. Because of the recent improvements at Palo Verde, including the installation of the Rapid Refueling Package at each unit, the projected 2012 refueling outage days were adopted as the normalized level. Also consistent with past practice, the projected unplanned outage time for 2012 was used as the normalized level for developing the fuel cost estimates. The projected effective forced outage factors ("EFOF") are consistent with the factors used by the Company in its internal financial and business planning. The EFOF levels

used in the normalized fuel cost calculation are displayed and compared to the EFOF levels used for the current authorized base fuel rate in Attachment PME-5.

IV. OTHER ADJUSTMENTS TO TEST YEAR FUEL REVENUE AND EXPENSE

Q. DURING THE TEST YEAR, THE COMPANY RECOVERED PRIOR PERIOD FUEL COSTS THROUGH THE PSA. HAVE YOU REMOVED THESE REVENUES?

A. Yes. Attachment PME-6 is a pro forma that removes revenues related to prior period fuel expense collected through the PSA from the Test Year. In addition, it removes the related prior period amortization of deferred fuel and the amortization of deferred SO_2 emission allowance sales margins. Together, these items have no impact on pre-tax operating income. This pro forma is included in SFR Schedule C-2 on page 10, column 29.

Q. WHAT OTHER CHANGES TO TEST YEAR FUEL EXPENSE ARE YOU PROPOSING?

A. In addition to the changes described above, I have included a pro forma that removes the PSA fuel deferrals and non-cash mark-to-market accounting entries from Test Year expense. These non-cash accounting adjustments have no bearing on the Company's anticipated fuel expenses in 2012 and beyond. The combined pre-tax impact of these adjustments is approximately $102 million as shown on Attachment PME-7 and in SFR Schedule C-2, page 10, column 30.

V. PSA PLAN OF ADMINISTRATION ("POA") MODIFICATIONS

Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS IN THE PSA POA IN THIS PROCEEDING?

A. Yes. The Company is proposing two modifications to the PSA POA. The first is to remove the 90/10 sharing provision which was approved in Decision No. 69663 (June 28, 2007) and the second is to include the cost associated with environmental chemical costs, primarily lime, in the PSA. Each modification is discussed below.

Q. STARTING WITH THE 90/10 SHARING PROVISION, PLEASE EXPLAIN WHY THE COMPANY IS REQUESTING ITS REMOVAL IN THIS CASE.

A. The Company is the only Arizona utility to have a 90/10 sharing provision. The 90/10 sharing provision was established by the Commission in 2005 as a method to encourage APS to prudently procure fuel. Since then, the Commission, through an audit of the Company's fuel procurement practices conducted by Liberty Consulting Group in 2006, evaluated APS's hedging and procurement practices and deemed them to be sound. This was recently confirmed in the 2010 Liberty benchmarking study. Further, the Commission, through the recent adoption of the new Integrated Resource Planning Rules ("IRP"), will effectively approve the Company's proposed resource mix. The combination of the good outcomes of the two Liberty studies and the Commission's review of the Company's resource mix, the only variables that exist are fuel and purchased power market prices – something entirely outside of APS's control – and power plant operations, which can be and have been effectively reviewed in prudence determinations.

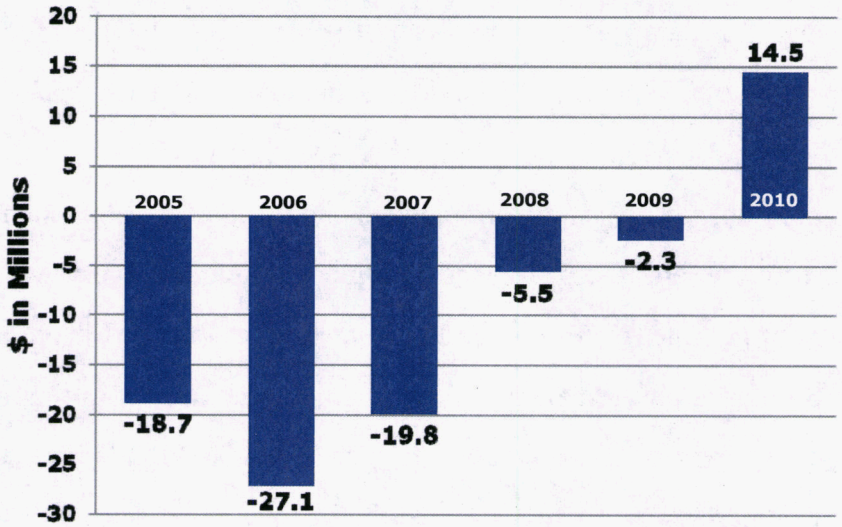
Another benefit from the removal of the 90/10 sharing provision is it will also facilitate resetting base fuel rates without controversy. Because gas generation and purchased power costs vary depending on market conditions, with the 90/10 sharing provision in place, if a lower base fuel rate were established in the case, and gas and power prices increased dramatically, the Company would be penalized for higher prices and would only be able to recover 90% of those costs. On the other hand, if a higher base fuel rate were set and then fuel and purchased power costs continued to decrease, APS would receive the benefit of this scenario and be able to keep 10% of the over-collection. Because market prices are so

variable and are not something APS can control, removing the 90/10 sharing provision in this case is reasonable and prudent.

Q. PLEASE EXPLAIN HOW THE 90/10 SHARING PROVISION WORKS.

A. Under the 90/10 sharing provision, the Company can only recover from customers 90% of most fuel expenses above the amounts recovered through the Base Fuel Rate. This mechanism also allows the Company to keep 10% of any fuel reductions below the Base Fuel Rate, which has worked to the Company's benefit with the lower than usual price of natural gas over the recent past. The chart below shows the annual and cumulative totals resulting from the provision. As is evidenced from the chart, since the provision has been in effect, it has been to the detriment of the Company by $59M. The chart also shows that the swings in benefit or penalty can be quite sizable, are driven primarily by market forces beyond the Company's influence, and will not be controlled any better by any changes in Company procurement practices.

CHART 1: PRE-TAX INCOME EFFECT OF 90/10 SHARING FEATURE IN PSA



Q. THE COMPANY IS ALSO REQUESTING TO INCLUDE CHEMICAL COSTS IN THE PSA. PLEASE EXPLAIN.

A. The Company is proposing to include in the PSA environmental chemical costs that directly correlate to the use of fuel. Chemicals, such as lime, ammonia, and sulfur are used to scrub the emissions from a coal plant and are dependent upon the amount of fuel burned. As production from the power plants varies, so too does the amount of chemicals used. The Company therefore proposes that annual changes in the chemical cost expense associated with power plant emission controls be included in the calculation of the PSA deferrals and rate recovery.

Q. PLEASE EXPLAIN HOW THE CHEMICAL COSTS WILL RUN THROUGH THE PSA.

A. The Company is proposing that chemical costs be treated in the PSA in a similar fashion to how SO_2 emission allowance sales margins are treated. The chemical costs incurred in the Test Year will be converted to an average cost per kWh based on the normalized Test Year sales, and that average cost will be established as the Base Cost for Allowable Chemicals. Upon approval in this proceeding, the Company will begin deferring any difference between the actual chemical costs incurred each month and the amount recovered in base rates through the Base Cost for Allowable Chemicals. These differences can be positive or negative, and the deferrals will apply to the Company's Operations and Maintenance ("O&M") Expenses. Prior to the beginning of each PSA Year, in accordance with the established procedures for setting new PSA rates, the Company will provide a forecast of anticipated chemical costs and chemical cost base rate recovery, and the difference in under- or over-recovery will be converted to an average rate per kWh and added to the Forward Component of the PSA. Similarly, any remaining under- or over-recovery from the previous year will be converted to an average rate per kWh and added to the PSA Historical Component.

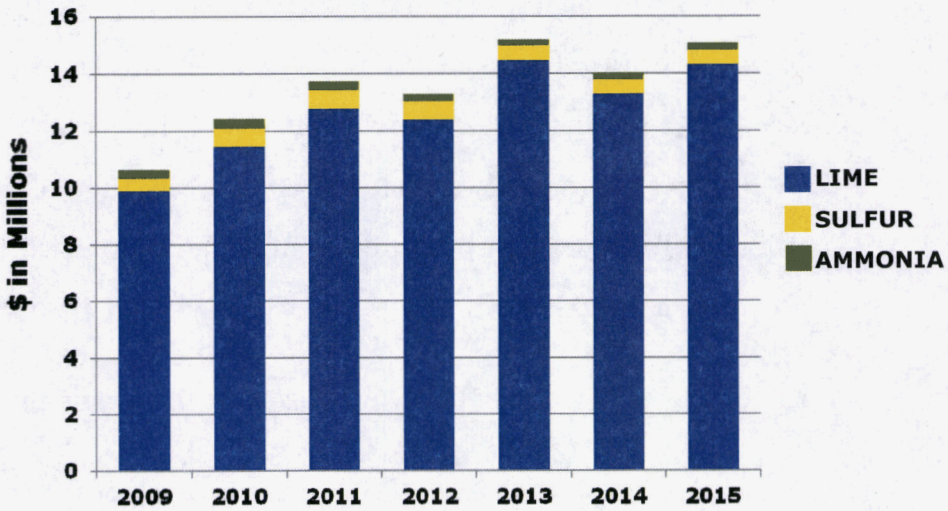
Q. WHAT IS THE PROPOSED BASE COST FOR ALLOWABLE CHEMICALS?

A. The Company incurred $12.4 million in power production-related chemical costs during the Test Year. Over 90% of this amount (almost $11.5 million) was for lime used at the Four Corners, Cholla and Navajo coal-fired generating stations. Another $600,000 was incurred for sulfur at the coal plants, and just over $300,000 was accounted for by ammonia nitrate, which is primarily used at the West Phoenix and Red Hawk combined cycle gas-fired plants. These amounts divided by the Test Year native load sales of 28,075 GWh yields an average Base Cost of Allowable Chemicals of 0.0442¢/kWh.

Q. DOES THE COMPANY HAVE A PROJECTION OF WHAT CHEMICAL COSTS WILL BE OVER THE NEXT FIVE YEARS?

A. Yes, the chart below shows that the Company expects these chemical costs to increase to as much as $15 million in the next several years, and that the amount of the chemical costs will vary considerably with the production levels of the Company's coal plants.

CHART 2: PRODUCTION-RELATED CHEMICAL COSTS



Q. IS THE COMPANY PROPOSING ANY ADDITIONAL MODIFICATIONS TO THE PSA IN THIS PROCEEDING?

A. Yes. The Company is proposing that the exemptions for customers on the E3, E4 and Solar 2 rate riders be discontinued. APS witness Charles Miessner discusses the reasons for these changes. Otherwise, the only changes would relate to updating the base rates for fuel and for the Test Year levels of SO_2 emission allowance sales margins. The new Base Net Margins on the Sale of Emission Allowances will be (0.0001)¢/kWh, as the sales of these allowances in the Test Year were *de minimus*. Attached as Attachment PME-8 is a redlined PSA POA showing the proposed changes from the current version and attached as PME-9 is a clean version of the PSA POA.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. The decline in market prices for natural gas and wholesale power has substantially reduced the Company's cost of fuel, and it is appropriate to reduce the Company's Base Fuel Rate to 3.2415¢/kWh. The determination of this rate is consistent with the approach accepted by the Commission in prior proceedings. It would also be appropriate to make a corresponding and offsetting adjustment to the PSA Forward Component simultaneously with the change in the Base Fuel Rate. With sufficient clarity around the successful completion of the Company's acquisition of the additional share of Four Corners Units 4 and 5 and the recovery of related fixed costs, it would be appropriate to establish the Company's Base Fuel Rate at 3.1298¢/kWh.

The Company is the only utility in Arizona with a sharing provision as part of its PSA mechanism, so the 90/10 sharing provision should be eliminated. Certain chemical costs at the power plants (lime, sulfur, ammonia) vary directly with the generation of electricity and are therefore volatile much like fuel costs.

Differences between actual chemical expenses and the amounts in the Test Year should be recovered or refunded through the PSA. Base rates in the PSA POA should be updated to adjusted Test Year levels, and the exemptions applied to certain rate riders in the PSA should be eliminated.

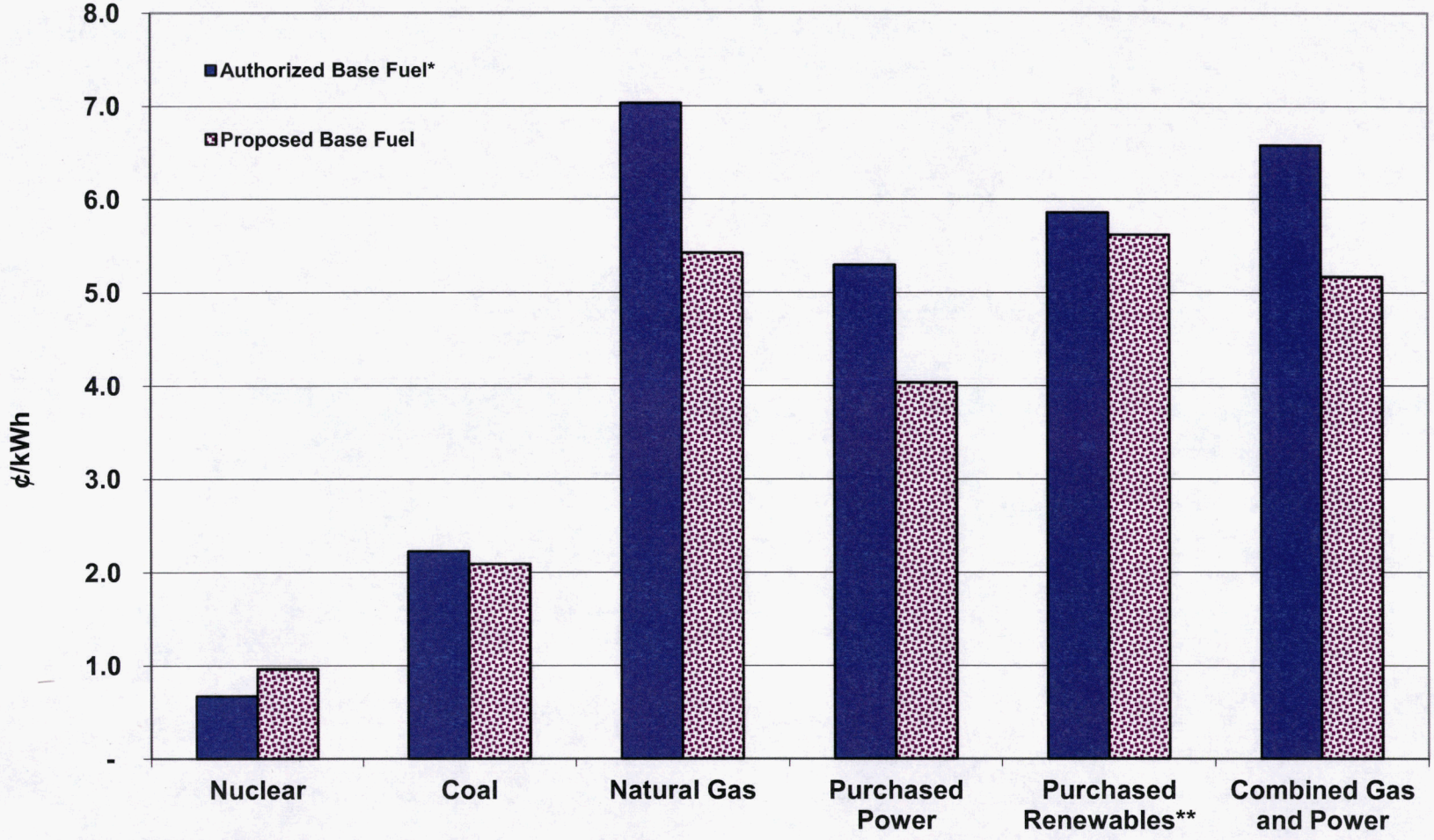
Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Summary of Base Fuel Cost Changes

	Current Authorized Level (2009 Conditions)	Proposed Proforma Level (2012 Conditions)	Proforma vs. Current Authorized
Base Fuel Cost (¢/kWh)	3.7571	3.2415	(0.5156)
Test Year Period Normalized Sales (GWh)	27,834	27,834	
Base Fuel Expense ($000,000)	1,045.7	902.2	**(143.5)**
Change in Future PSA Revenues ($000,000)			122.8
Net Change in Revenues From Customers ($000,000)			**(20.7)**
Reasons for Change ($000,000)			
Prices for Hedged Natural Gas, Purchased Power			(132.6)
Reduced Share of Natural Gas, Market Purchased Power			(59.8)
Coal Price			(14.5)
Gas Transportation			7.8
Nuclear Price			21.7
Capacity Costs			31.9
All Other Items			2.0
Total			**(143.5)**

Arizona Public Service Company
Average Fuel Cost by Type of Resource



* Authorized in Decision No. 71448
** Excludes above-market premium.

Components of APS Base Fuel Rate
Actuals TME 12/31/2010

	Fuel Expense ($000)	Production (GWH)	Native Load Sales (GWH)	Share of Production (%)	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [1]	69,197	9,079	8,388	29.9%	0.82	0.25
Coal [2]	195,673	11,210	10,357	36.9%	1.89	0.70
Natural Gas [3]	386,676	6,984	6,452	23.0%	5.99	1.38
Purchased Power [4]	221,949	2,409	2,225	7.9%	9.97	0.79
Renewable [5, 6]	37,421	706	653	2.3%	5.73	0.13
Fixed Gas Transport and Fuel Handling	63,081	-	-	0.0%		0.22
Total Native Load	973,997	30,388	28,075	100.0%		3.4692
Off System Margin Credit to Retail	(33,864)		28,075			(0.1206)
Net Retail Fuel Cost	940,133		28,075			**3.3486**

1 - Excludes fixed ISFSI expense
2 - Excludes coal reclamation costs.
3 - Includes fuel costs associated with long-term tolling arrangements.
4 - Includes native load hedge liquidation costs.
5 - Excludes costs for above market purchase premiums which are recovered through RES.
6 - Includes generation associated with company owned facilities.

Components of APS Base Fuel Rate
Proposed Rate Using 3/31/11 Market Prices
Excluding the Effects of Acquiring SCE Share of Four Corners Units 4 & 5

	Fuel Expense ($000)	Production (GWH)	Native Load Sales (GWH)	Share of Production %	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [1]	83,119	9,264	8,641	30%	0.96	0.2900
Coal [2]	246,710	12,648	11,798	41%	2.09	0.8609
Natural Gas [3]	286,846	5,667	5,287	18%	5.43	1.0009
Purchased Power [4, 5]	185,504	1,680	1,567	5%	11.84	0.6473
Renewable [6, 7]	66,610	1,463	1,365	5%	4.88	0.2324
Fixed Gas Transport and Fuel Handling	77,128	-	-	0%		0.2691
Total	945,916	30,721	28,658	100%		3.3006
Off System Margin Credit	(16,931)		28,658			(0.0591)
Net Retail Fuel Cost	928,986		28,658			**3.2415**

Native Load Sales	
Retail Sales	28,186
Sales for Resale	421
Pacificorp Supplemental Sales	51
Total Native Load Sales	28,658

1 - Excludes fixed ISFSI expense
2 - Excludes coal reclamation costs.
3 - Includes fuel costs associated with long-term tolling arrangements.
4 - Includes native load hedge liquidation costs.
5 - Includes fixed capacity contract costs.
6 - Excludes costs for above market purchase premiums which are recovered through RES.
7 - Includes generation associated with company owned facilities.

Components of APS Base Fuel Rate
Proposed Rate Using 3/31/11 Market Prices
Including the Effects of Acquiring SCE Share of Four Corners Units 4 & 5

	Fuel Expense ($000)	Production (GWH)	Native Load Sales (GWH)	Share of Production %	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [1]	83,119	9,264	8,641	30%	0.96	0.2900
Coal [2]	253,448	13,564	12,653	44%	2.00	0.8844
Natural Gas [3]	258,572	4,969	4,635	16%	5.58	0.9023
Purchased Power [4, 5]	178,544	1,462	1,363	5%	13.10	0.6230
Renewable [6, 7]	66,610	1,463	1,365	5%	4.88	0.2324
Fixed Gas Transport and Fuel Handling	77,128	-	-	0%		0.2691
Total	917,422	30,721	28,658	100%		3.2012
Off System Margin Credit	(20,459)		28,658			(0.0714)
Net Retail Fuel Cost	896,963		28,658			**3.1298**

Native Load Sales	
Retail Sales	28,186
Sales for Resale	421
Pacificorp Supplemental Sales	51
Total Native Load Sales	28,658

1 - Excludes fixed ISFSI expense
2 - Excludes coal reclamation costs.
3 - Includes fuel costs associated with long-term tolling arrangements.
4 - Includes native load hedge liquidation costs.
5 - Includes fixed capacity contract costs.
6 - Excludes costs for above market purchase premiums which are recovered through RES.
7 - Includes generation associated with company owned facilities.

Components of APS Base Fuel Rate
Current Authorized Rates From 2009 Rate Case Settlement

	Fuel Expense ($000)	Production (GWH)	Native Load Sales (GWH)	Share of Production %	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [1]	53,288	8,827	7,917	27%	0.67	0.18
Coal [2]	250,241	12,530	11,238	38%	2.23	0.85
Natural Gas [3]	479,802	7,607	6,823	23%	7.03	1.63
Purchased Power [4, 5]	233,210	3,092	2,773	9%	8.41	0.79
Renewable [6, 7]	35,221	670	601	2%	5.86	0.12
Fixed Gas Transport and Fuel Handling	69,212	-	-	0%		0.24
Total Native Load	1,120,974	32,726	29,353	100%		3.8189
Off System Margin Credit	(18,143)		29,353			(0.0618)
Net Retail Fuel Cost	1,102,831		29,353			**3.7571**

Native Load Sales	
Billed Retail Sales	29,343
Traditional Sales for Resale	343
Pacificorp Supplemental Sales	172
E-3 and E-4 Customers	(505)
Total Native Load Sales	29,353

1 - Excludes fixed ISFSI expense
2 - Excludes coal reclamation costs.
3 - Includes fuel costs associated with long-term tolling arrangements.
4 - Includes native load hedge liquidation costs.
5 - Includes fixed capacity contract costs.
6 - Excludes costs for above market purchase premiums which are recovered through RES.
7 - Includes generation associated with company owned facilities.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 28
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Base Fuel and Purchased Power**
Adjustment to Test Year Operations to include 2012 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption

Line No.	Description		Amount
	ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)		
1.	Normalized 2012 Fuel and Purchased Power Costs (¢/kWh)	3.2415	
2.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.3486	
3.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	(0.1071)	
	ADJUSTED TEST YEAR RETAIL SALES (MWh)		
4.	Test Year Retail Sales (MWh)	27,709,463	
5.	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh)		
6.	To Adjust to Normal Weather	116,749	
7.	To Annualize to December 31, 2010 Customer Level	7,544	
8.	Adjusted Test Year Retail Sales (MWh)	27,833,756	
9.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 3 x Line 8)		$ (29,810)
10.	**Operating Income (before income tax)**		**$ 29,810**
11.	Current Income Tax Rate - 39.51%		11,778
12.	**Operating Income After Tax**		**$ 18,032**

Arizona Public Service Company
Comparison of Generating Unit Effective Forced Outage Factors (EFOF)
Proposed Base Rate Level vs. Current Authorized Base Rate Level
(%)

	Current Authorized Level (2009 Conditions)	Proposed Level (2012 Conditions)
Nuclear	2.5	2.0
Four Corners	7.7	6.0
Cholla	5.3	4.1
Navajo	5.0	5.0
West Phoenix CC 1-3	7.0	6.3
West Phoenix CC 4	7.0	3.7
West Phoenix CC 5	10.0	6.8
Redhawk	7.5	6.6
Gila	3.7	2.7
Arlington	N/A	4.0
Steam Plants	6.5	6.0
Gas Turbines	6.5	2.3

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 29
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Test Year PSA Revenue and Deferred Fuel Amortization**
Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods

Line No.	Description	Total Company Amount
	Revenues	
1	Remove Test Year PSA Billed and Unbilled Revenue	$ 121,231
	Expenses	
2	Remove Test Year PSA Fuel Expense Deferral Amortization	127,728
3	Operating Revenues less Fuel and Purchased Power Costs	$ (6,497)
	Operations & Maintenance	
4.	Remove Test Year PSA SO2 Margin Deferral Amortization	$ (6,497)
5.	**Operating Income (before income tax)**	**$ -**
6.	Current Income Tax Rate - 39.51%	-
7.	**Operating Income After Tax**	**$ -**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 30
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals**
Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and non-cash mark-to-market accruals

Line No.	Description		Total Company
	Fuel and Purchased Power Costs		
1.	Current Period Retail PSA Fuel Expense Deferral	$ (99,349)	
2.	Deferred Mark to Market on Native Load Hedge	35,686	
3.	Total Test Year PSA Fuel Expense Deferral	(63,663)	
4.	Non-Cash Hedge-Related MTM Accruals	(38,127)	
5.	Pro Forma Adjustment to Fuel and Purchased Power Costs		(101,790)
6.	**Operating Income (before income tax)**		**101,790**
7.	Current Income Tax Rate - 39.51%		40,217
8.	**Operating Income After Tax**		**$ 61,573**

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on June 28, 2007 in Decision No. 69663 and amended by the Commission on ~~71448 in Decision No. 71448.~~December 30, 2009 in Decision No. 71448 and as further amended by the Commission on [insert date] in Decision No. xxxxx. The PSA provides for the recovery of fuel and purchased power costs, to the extent that actual fuel and purchased power costs deviate from the amount recovered through APS' Base Cost of Fuel and Purchased Power ($0.~~037571~~032415 per kWh) authorized in Decision No. ~~71448~~xxxxx, from ~~January 1, 2010.~~[insert date]. It also provides for refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base rate amount of ~~(($0.000242) per kWh)[1]~~. ($0.000001) per kWh[1]. Lastly, it provides for the refund or recovery of Allowable Chemical costs, to the extent that actual Allowable Chemical costs deviate from the base rate amount of $0.000442 per kWh[2].

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs ~~and~~, net margins on the sales of emission allowances, and environmental chemical costs ("PSA Costs") to set a rate that is then reconciled to actual costs experienced. ~~This PSA includes a 90/10 sharing mechanism under which APS absorbs 10 percent of the deviations between actual fuel and purchased power costs and the amount recovered through base rates. The demand component of long-term purchased power agreements (duration of three years or longer) acquired via a competitive procurement process, renewable energy costs not recovered through other mechanisms, and net margins from the sales of emission allowances are exempt from the 90/10 sharing.~~

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[1] *($0.000001) per kWh is the result of the following: (2010 net gains from sales of SO_2 allowances of $21,178)/(2010 test year native load sales of 28,075,248 MWh)/1000.*
[2] *$0.000442 per kWh is the result of the following: (2010 Allowable Chemical costs of $12,400,620)/(2010 test year sales of 28,075,248 MWh)/1000.*

~~[1] ($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 MWh)/1000.~~

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek a mid-year change in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission deem such an adjustment to be appropriate.
    b. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a ~~proposed~~ calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also

~~[1] ($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 MWh)/1000.~~

submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. ~~The over/under-recovery of costs is divided into two separate calculations to allow the application of the 90/10 sharing mechanism on those costs to which it applies.~~ The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e.; February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[3]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision, if necessary, is expected. In addition to the

[3] For example, the September 30, 2008 filing would include actual balances for February through August of 2008 and estimated balances for September 2008 through January 2009.

December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[4]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

[4] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.,* Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. However, the PSA rate may not change from the prior year's PSA rate by more than plus or minus $0.004 per kWh~~.~~ without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of ~~Solar- 2, E-3, E-4,~~ E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.[6]

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[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

[6] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the PSA.

c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Allowable Chemical Costs - Costs associated with reagent (lime), sulfur and ammonia used in the production of electricity.

Applicable Interest - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Cost of Allowable Chemicals - An amount generally expressed as a rate per kWh, which reflects the cost of Allowable Chemicals embedded in base rates as approved by the Commission in APS' most recent rate case. The Base Cost for Allowable Chemicals is set at $0.000442 per kWh effective on [insert date].

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost ~~and net margins from the sales of emission allowances~~ embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base ~~PSA Costs~~Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. ~~71448~~xxxxx set the base cost at $0.~~037571~~032415 per kWh effective on ~~January 1, 2010.~~[insert date].

Base Net Margins on the Sale of Emission Allowances~~–~~ - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in

the base rates as approved by the Commission in APS' most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ~~(($~~($0.~~000242~~000001) per kWh~~)~~ effective on ~~January 1, 2010.~~[insert date].

Base PSA Costs - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost, net margins from the sales of emission allowances, and allowable chemical costs embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base PSA Costs recovered in base revenue is the approved rate per kWh times the applicable sales volumes.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus the Net Margins on the Sales of Emission Allowances and Allowable Chemical Costs.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS' base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS' over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

PacifiCorp Supplemental Sales - The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990~~,~~ which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

PSA - The Power Supply Adjustment mechanism approved by the Commission in Decision No. 69663 and amended by the Commission in Decision No. ~~71448~~71448 and further amended by the commission in Decision No. xxxxx, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of PSA Costs that are eventually reconciled to actual costs experienced. This PSA allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36~~,~~ AG -1 RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. ~~71448~~xxxxx.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission

consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration

Schedule 1	Power Supply Adjustment (PSA) Rate Calculation ~~Effective February 1, 2010~~
Schedule 2	PSA Forward Component Rate Calculation ~~Effective February 1, 2010~~
Schedule 3	PSA Year Forward Component Tracking Account ~~(in effect February 1, 2010-January 31, 2011)~~
Schedule 4	PSA Historical Component Rate Calculation ~~Effective February 1, 2010~~
Schedule 5	Historical Component Tracking Account ~~(in effect February 1, 2010-January 31, 2011)~~
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account ~~(in effect XX 1, 20XX-XX 31, 20XX)~~

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in the Company's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    - a. ~~a.~~ Total power and fuel costs.
    - b. ~~b.~~ Margins on the sale of excess emission allowances.
    - c. ~~c.~~ Costs of allowable chemicals.
    - d. Customer sales in both MWh and thousands of dollars by customer class.
    - e. ~~d.~~ Number of customers by customer class.
    - f. ~~e.~~ A detailed listing of all items excluded from the PSA calculations.
    - g. ~~f.~~ A detailed listing of any adjustments to the adjustor reports.
    - h. ~~g.~~ Total off-system sales revenues.
    - i. ~~h.~~ System losses in MW and MWh.

j. ~~i.~~ Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per them, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. A summary of the net margins on the sale of emission allowances.
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, the net margins on the sale of emission allowances will also be refunded or recovered through the PSA. Lastly, allowable chemical costs will be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- xxx O&M (Allowable Chemical Costs)

Additionally, broker fees recorded in FERC account 557 are allowable up to the limit set in Decision No. ~~71448~~xxxxx.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 and AG-1 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on June 28, 2007 in Decision No. 69663 and amended by the Commission on December 30, 2009 in Decision No. 71448 and as further amended by the Commission on [insert date] in Decision No. xxxxx. The PSA provides for the recovery of fuel and purchased power costs, to the extent that actual fuel and purchased power costs deviate from the amount recovered through APS' Base Cost of Fuel and Purchased Power ($0.032415 per kWh) authorized in Decision No. xxxxx, from [insert date]. It also provides for refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base rate amount of ($0.000001) per kWh[1]. Lastly, it provides for the refund or recovery of Allowable Chemical costs, to the extent that actual Allowable Chemical costs deviate from the base rate amount of $0.000442 per kWh[2].

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs, net margins on the sales of emission allowances, and environmental chemical costs ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

[1] *($0.000001) per kWh is the result of the following: (2010 net gains from sales of SO_2 allowances of $21,178)/(2010 test year native load sales of 28,075,248 MWh)/1000.*
[2] *$0.000442 per kWh is the result of the following: (2010 Allowable Chemical costs of $12,400,620)/(2010 test year sales of 28,075,248 MWh)/1000.*

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek a mid-year change in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission deem such an adjustment to be appropriate.
    b. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced

by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e.; February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[3]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision, if necessary, is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[4]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical

[3] For example, the September 30, 2008 filing would include actual balances for February through August of 2008 and estimated balances for September 2008 through January 2009.
[4] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.,* Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. However, the PSA rate may not change from the prior year's PSA rate by more than plus or minus $0.004 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.[6]

c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

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[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

[6] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the PSA.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Allowable Chemical Costs - Costs associated with reagent (lime), sulfur and ammonia used in the production of electricity.

Applicable Interest - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Base Cost of Allowable Chemicals - An amount generally expressed as a rate per kWh, which reflects the cost of Allowable Chemicals embedded in base rates as approved by the Commission in APS' most recent rate case. The Base Cost for Allowable Chemicals is set at $0.000442 per kWh effective on [insert date].

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. xxxxx set the base cost at $0.032415 per kWh effective on [insert date].

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on [insert date].

Base PSA Costs - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost, net margins from the sales of emission allowances, and allowable chemical costs embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base PSA Costs recovered in base revenue is the approved rate per kWh times the applicable sales volumes.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus the Net Margins on the Sales of Emission Allowances and Allowable Chemical Costs.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The

Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS' base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS' over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

PacifiCorp Supplemental Sales - The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990 which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

PSA - The Power Supply Adjustment mechanism approved by the Commission in Decision No. 69663 and amended by the Commission in Decision No. 71448 and further amended by the commission in Decision No. xxxxx, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of PSA

Costs that are eventually reconciled to actual costs experienced. This PSA allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36 AG -1 RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No.xxxxx.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration

Schedule 1	Power Supply Adjustment (PSA) Rate Calculation
Schedule 2	PSA Forward Component Rate Calculation
Schedule 3	PSA Year Forward Component Tracking Account
Schedule 4	PSA Historical Component Rate Calculation
Schedule 5	Historical Component Tracking Account
Schedule 6	PSA Transition Component Rate Calculation

Schedule 7 PSA Transition Tracking Account

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in the Company's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Margins on the sale of excess emission allowances.
    c. Costs of allowable chemicals.
    d. Customer sales in both MWh and thousands of dollars by customer class.
    e. Number of customers by customer class.
    f. A detailed listing of all items excluded from the PSA calculations.
    g. A detailed listing of any adjustments to the adjustor reports.
    h. Total off-system sales revenues.
    i. System losses in MW and MWh.
    j. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.

2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per them, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. A summary of the net margins on the sale of emission allowances.
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, the net margins on the sale of emission allowances will also be refunded or recovered through the PSA. Lastly, allowable chemical costs will be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power

- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- xxx O&M (Allowable Chemical Costs)

Additionally, broker fees recorded in FERC account 557 are allowable up to the limit set in Decision No. xxxxx.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 and AG-1 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

Charles A. Miessner

TESTIMONY OF CHARLES A. MIESSNER

On Behalf of Arizona Public Service Company

Docket No. E01345A-11-_____

June 1, 2011

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TESTIMONY OF CHARLES A. MIESSNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-_____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Charles A. Miessner, 400 North Fifth Street, Phoenix, Arizona 85004.

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

A. I am Pricing Manager for Arizona Public Service Company ("APS" or "Company").

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. My qualifications are provided in Attachment CAM-1, Statement of Qualifications.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to: support the Company's proposed changes to retail rates; provide the proposals for new rates; describe how the proposed revenue is allocated to individual rate classes; demonstrate that the proposed rate changes achieve the proposed overall increase in revenue; support the proposed changes to existing rate schedules, adjustment schedules, plans of administration ("POA") and service schedules; support the proforma adjustments to test year revenue; propose a simplified presentment of charges on customers' bills; and support Standard Filing Requirements ("SFR") Schedules H-1, H-2, H-3, H-4, and H-5.

III. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my Direct Testimony, I provide an overview of the Company's retail pricing plans; I describe how the Company's overall requested revenue increase is allocated to the various rate classes and how the proposed rates achieve the

requested revenue; I discuss the proposed changes to residential rates including the redesign of the low income discounts, Rate Rider Schedules E-3 and E-4, which will continue to provide assistance to customers in need, while simplifying the discount structure; I present the Company's proposals for new pricing plans including peak time rebates for residential customers, a station use rate to accommodate small and medium size renewable "merchant" generators, an interruptible rider rate for extra large general service customers, and an option for extra-large customers to obtain alternative generation supplies; and I outline the proposed rate changes for general service customers including the elimination of monthly minimum charges for some of the rate schedules, and the redesign of Rate Schedule E-32 L, transferring the embedded demand costs in the first tier energy charge into the explicit demand charge.

I also present the proposed new provisions for outdoor lighting rates, which serve to recover certain maintenance costs and lower the Company's potential financial risk from larger lighting contracts; I support the proposed revisions for the water pumping Rate Schedules E-221 and E-221-8T; I discuss how partial requirements Rate Schedules E-56 and SC-S have been revised; I support the company's proposal to consolidate the charges for transmission services into Adjustment Schedule TCA-1; and I present the Company's proposal for a new service schedule to provide incentives for commercial and industrial growth.

In addition, I propose revisions to the POAs for Adjustment Schedule DSMAC and Rate Rider Schedules E-3 and E-4; and I support the proposed revisions to various service schedules.

I also present the Company's proposal to cancel Rate Schedules E-40, E-53, Solar-2, Solar-3, and Share the Lights contracts. Finally, I outline the proposal to simplify the customer's bills, but provide detailed information on an opt-in basis.

IV. DESCRIPTION OF RETAIL RATES

Q. PLEASE SUMMARIZE APS'S RETAIL RATE OFFERINGS.

A. APS currently serves over one million retail customers with a variety of rate schedules and optional rate riders. Rate schedules are tailored to residential customers, general service or business customers, and classified customers. Optional rider rates are available for special requirements or services, such as on-site renewable generation, green power, low income and medical equipment discounts, dynamic pricing, and other specialized or experimental programs. A complete list of the current and proposed rate schedules and riders is provided in the SFR Index to Rate Schedules.

Q. CAN CUSTOMERS CHOOSE A RATE PLAN?

A. Typically, yes. For example, all residential, all general service, and some classified customers can choose between a standard rate offering and an optional demand response time-of-use rate for their main rate plan. Customers can also optionally participate in a number of rate riders that add some of the additional services mentioned above to their main rate plan.

V. ALLOCATION OF REQUESTED INCREASE TO RATE CLASSES

Q. WHAT IS THE COMPANY REQUESTING FOR AN OVERALL INCREASE IN RETAIL BASE RATES?

A. As provided in SFR H-1, APS is requesting an overall increase in retail base rates of $95,493,000, which is a 3.33% increase over adjusted test year base revenues.

Q. HOW IS THIS OVERALL INCREASE ALLOCATED TO THE VARIOUS RATE CLASSES?

A. APS is requesting an average increase of 3.95% for residential rates, 2.64% for general service, 3.62% for water pumping, 2.94% for dusk-to-dawn area lighting,

and 3.62% for street lighting service. The requested increases for individual rate schedules within these classes also vary from the overall class average. The requested increase for each rate schedule is provided in SFR Schedule H-1.

Q. WHAT FACTORS WERE CONSIDERED IN DETERMINING THIS ALLOCATION?

A. APS considered both cost of service and gradualism or rate stability in deriving the proposed rate increases for each customer class. First and foremost, the cost of service and resultant rates of return and revenue deficiencies served as a general guide in allocating the overall increase to the various rate classes. In addition, the Company considered gradualism, where the intent is to moderate the impact on any single customer class, in making the final recommendation.

Q. HOW DID THE COST OF SERVICE FACTOR INTO THE ALLOCATION OF RATE INCREASES?

A. In the cost of service study sponsored by APS Witness Zac Fryer, APS computed the test year costs, or revenue requirements, to serve various classes of customers and compared them with the test year revenue received from these classes. The difference between revenue and revenue requirements measures the revenue deficiency for each class. Furthermore, a rate of return was derived for each class as discussed and provided by APS Witness Fryer.

In general, rate classes which were most deficient in recovering their cost of service, or which had the lowest rate of return, received a relatively higher increase. Conversely, rate classes that produced greater cost recovery and thus had higher returns received a relatively lower allocated increase. The requested base rate increases and rates of return by class are provided in Attachment CAM-2.

Q. PLEASE EXPLAIN HOW GRADUALISM FACTORED INTO THE PROPOSED RECOMMENDATION.

A. As mentioned, APS considered gradualism or rate stability in determining the

recommended rate increases by specific customer classes. The objective is to avoid major rate increases or shocks for particular classes where the current revenue is well below their cost of service. For example, a significantly higher rate increase could have been justified for the residential class based on the cost of service compared with the Company's request. As discussed above, the Company is recommending an increase of 3.95% for residential customers, which is above the system average increase, but well below cost of service, in order to gradually bring them more in line with cost of service over time. This type of tradeoff of objectives in rate design was succinctly discussed by Bonbright as early as 1961 in his seminal work "Principles of Public Utility Rates". The Company believes that such considerations and tradeoffs are still germane today.

VI. RESIDENTIAL RATES

Q. WHAT RATE PLANS ARE AVAILABLE TO RESIDENTIAL CUSTOMERS?

A. The Company offers a variety of rate plans and optional riders to residential customers including: a conservation rate; five time-of-use rates (also referred to as demand response rates);[1] five rate plans for low income customers; a peak event pricing rate rider;[2] three green power rate riders; two solar rate riders;[3] net billing and net metering rate riders for renewable generation; two rate riders for low income and medical equipment discounts; and optional rates for dusk-to-dawn outdoor lighting.

Q. PLEASE DESCRIBE THE CONSERVATION RATE PLAN.

A. The conservation Rate Schedule E-12 has four pricing blocks that increase with the level of kWh usage during the May through October summer billing months.

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[1] Residential time-of-use rates ET-1 and ECT-1R were frozen to new customers on January 1, 2010 per A.C.C. Decision No. 71448.

[2] Also referred to as critical peak pricing.

[3] APS currently offers Rate Rider Schedules Solar-2 and Solar-3 but is proposing to cancel these rates in this proceeding.

This inclining block pricing structure incents customers to use less each month, and also encourages the higher usage customers to switch to a time-of-use rate. The Company currently serves nearly 450,000 customers under this rate plan.[4]

Q. WHAT CHANGES IS APS PROPOSING FOR THIS RATE?

A. APS is proposing to increase this rate by 3.37%, which is below the average residential increase because its rate of return is above the residential average return. In addition, the basic service charge will be increased to better reflect the residential average cost of metering and billing services. No other changes are proposed to Rate Schedule E-12.

Q. WHICH DEMAND RESPONSE RATES ARE AVAILABLE TO RESIDENTIAL CUSTOMERS?

A. The residential demand response rates include five time-of-use rate plans and a peak event pricing rate rider. The Company's "one series" time-of-use rates were first introduced in 1982. Rate Schedule ET-1 has on-peak hours from 9 a.m. to 9 p.m. weekdays, and on-peak prices that are about three times the off-peak prices in the summer billing season. Schedule ECT-1R has the same peak hours and an on-peak demand charge in addition to on-peak and off-peak energy charges.

In 2006, the Company introduced the "two series" time-of-use rates, ET-2 and ECT-2, which have shorter on-peak hours (12 noon to 7 p.m.) and a higher ratio of peak to off-peak prices. The new rates were designed to provide a better opportunity and a higher incentive for customers to shift their usage to off-peak hours. Furthermore, the Company intends to cancel the one series rates in a future rate case—once more customers have naturally migrated to the two series rates. At this time, the one series rates are frozen and are not available to new

[4] Average monthly customers during the test year, excluding low income customers.

customers. However, current customers can continue to be served under the rates at their current location.

The fifth time-of-use rate, Rate Schedule ET-SP, is patterned after Rate Schedule ET-2, but adds an additional super peak season and time period to better focus the higher on-peak prices to the core summer on-peak hours. Rate Schedule ET-SP was introduced in January 2010 and currently has 108 participants.

Residential customers may also participate in a peak event pricing program, Rate Rider Schedule CPP-RES, which also was introduced in January 2010. This rider may be added to any of the residential rate plans, except Rate Schedule ET-SP. The program currently has 68 participants.

Q. WHAT CHANGES IS THE COMPANY PROPOSING FOR THE EXISTING RESIDENTIAL DEMAND RESPONSE RATES?

A. APS is proposing to increase Rate Schedules ECT-2, ECT-1R, ET-2, ET-1, and ET-SP by approximately 4.0%. The Company also proposes to modestly reduce the ratio of peak to off-peak prices in Rate Schedules ET-1 and ET-2 to better reflect the current cost differences in on-peak and off-peak periods. For example, currently for Rate Schedule ET-2, the on-peak price in the summer months is 4.0 times the off-peak price, while the proposed on-peak summer price is 3.0 times the off-peak price. Likewise for Rate Schedule ET-1, the on-peak summer price is being reduced from 3.0 times to 2.5 times the off-peak price.

This proposed pricing structure will still have a higher ratio of on-peak to off-peak prices compared with current generation power costs. For example, current projections of on-peak wholesale prices in the APS region are typically only about 1.6 times the off-peak prices for the third quarter 2011, which represents core summer months.[5] While the wholesale pricing structure has more on-peak

[5] Forward Prices for month-ahead purchases, Dow Jones Energy Index, April 29th strike.

hours than APS's time-of-use rates, the comparative price ratio for wholesale market prices is nevertheless still likely to be below APS's proposed time-of-use price ratios. Even so, APS proposes this price structure to maintain an aggressive price signal to incent customers to shift usage to the off-peak hours.

In addition, the basic service charge will be increased consistent with cost of service for unbundled revenue cycle services such as metering and billing. The proposed basic service charge also includes a portion of the customer's distribution transformer cost to provide better cost recovery and reflects the lower meter reading costs due to the continued roll out of Advanced Metering Infrastructure ("AMI") metering technology.

Q. HOW MUCH DOES THE COMPANY PROPOSE TO INCREASE THE BASIC SERVICE CHARGE FOR RESIDENTIAL RATES?

A. The current bundled basic service charge for residential customers varies by rate schedule from $0.285 to $0.556 per day, which on average is about $8.67 per month for rate E-12 and $16.91 per month for the other residential rates. APS proposes to increase the bundled basic service charge for rate E-12 to $0.390 per day and $0.579 for the other residential rates. This results in average monthly basic service charges of $11.86 and $17.61 respectively.

Q. WHY IS THE BASIC SERVICE CHARGE FOR E-12 BEING INCREASED MORE THAN THE OTHER RESIDENTIAL RATES?

A. To better reflect the changes in cost of service that the Company has been experiencing over time.

Q. PLEASE ELABORATE.

A. The basic service charge recovers the costs of meters, meter reading, billing, and other costs that are driven by customer accounts. Rate Schedule E-12 has historically had lower metering costs compared to the other time-of-use rates because at one time the E-12 customers were served with a meter that was less

expensive than those required for time-of-use rates. In addition, because Rate Schedule E-12 has been available for many years, the overall un-depreciated meter costs were typically lower than the time-of-use rates, simply because of the average age of the meters in service.

Today, all residential customers are either typically served through an AMI meter or through a conventional meter that is standard for both E-12 and the time-of-use rates. As a result, the overall meter costs for Rate Schedule E-12 have become more similar to those for time-of-use rates.

Q. HAS THE INCREASED USAGE OF AMI METERS IMPACTED ANY OF THE BASIC SERVICE CHARGE COSTS?

A. Yes. The increased use of AMI has significantly reduced the cost of meter reading over the last few years. As a result, the Company is proposing to reduce the daily unbundled charge for meter reading from $0.062 for residential customers and $0.068 for general service customers to $0.038 for all customers. That's an average savings of over 40% for this charge.

Q. PLEASE DESCRIBE THE RESIDENTIAL LOW INCOME RATES.

A. APS offers five rate schedules for qualified low income customers: Rate Schedules E-12 Low Income, ET-1 Low Income, ECT-1R Low Income, ET-2 Low Income, and ECT-1R Low Income. These rate plans are similar to the non-low income versions, except that they have lower prices because they were exempted from the last general rate increase, as provided in Decision No. 71448. Average monthly participation in the low income rates during the test year was 62,580 customers.

Q. DO LOW INCOME CUSTOMERS GET A DISCOUNT IN ADDITION TO THE LOWER RATE?

A. Yes. The Company currently offers a discount for qualifying low income customers under Rate Rider Schedules E-3 and E-4. Under both schedules, the

discount varies by monthly usage levels. For example, under the E-3 program the discount is 40% for customers using less than 400 kWh per month, while the discount is 26% for usage of 401-800 kWh, 14% for 801-1200 kWh and $13 for usage above 1200 kWh. The E-4 program has similar percent discount levels, but higher qualifying consumption blocks. In addition, the higher usage customers are capped at $26 per month compared to $13 for the E-3 program.

Q. WHAT OTHER DISCOUNTS OR EXEMPTIONS ARE AVAILABLE TO LOW INCOME CUSTOMERS?

A. Qualified low income customers are also exempt from paying Adjustment Schedules PSA-1 and DSMAC-1 for power supply and the demand side management costs respectively.

Q. WHAT IS THE TOTAL SAVINGS FOR LOW INCOME CUSTOMERS?

A. The low income base rates are currently about 13% lower than other residential rates, for a savings on their total bill of about 11%, prior to any other discounts or exemptions. Coupled with the low income discount and adjustor exemptions, participants can save from 13% to 46% per month or more on their total bill.

Q. WHAT IS APS PROPOSING FOR THE LOW INCOME RATES, DISCOUNTS, AND EXEMPTIONS?

A. APS is proposing to continue to offer the low income rates and discounts, but to consolidate and simplify the overall package of savings. The Company proposes to increase the low income base rates by 3.0% to 3.6% more than the equivalent non-low income rate. For example, as mentioned above, APS requests to increase Rate Schedule E-12 by 3.37%, and Rate Schedule E-12 Low Income by an additional 3.6%, or 7.01% total increase. This additional increase is designed to close a portion of the 13% gap in base rates compared with other residential customers.

Furthermore, APS proposes to re-design the low income and medical equipment discounts in Rate Rider Schedules E-3 and E-4 and eliminate the low income exemption for Adjustment Schedules PSA-1 and DSMAC-1.

Q. WHY IS APS PROPOSING HIGHER THAN AVERAGE INCREASES FOR LOW INCOME RATES?

A. While the program savings are beneficial to low income customers, they can create fairness issues with other residential customers, including those who are financially distressed, but not enough so to qualify for the rates, who must pay for these savings through higher monthly bills. It also can create a rate shock to customers when they move off the low income rates as their financial situation improves. Therefore, APS believes that this overall gap should be moderately reduced.

Q. WHY IS APS PROPOSING TO RE-DESIGN THE DISCOUNTS?

A. The current E-3 and E-4 discounts were originally implemented in 1988 and the discount rate blocks presented above were based on a residential rate schedule that has not been available for several years. In addition, the discounts are somewhat complicated to explain to customers. Therefore, APS proposes to revise and simplify the discount structure for both the E-3 and E-4 programs.

Q. HOW DOES THE COMPANY PROPOSE TO RE-DESIGN THE DISCOUNTS?

A. The Company is proposing a single percentage discount of 25%, with a monthly cap of $18 for participants in the E-3 Energy Support Program and a cap of $36 for the E-4 Medical Care Equipment Support Program. In addition, APS is proposing that the discount not apply to the amounts billed under Adjustment Schedule TCA-1, which recovers transmission costs that are not recovered in base rates. As discussed below, these are "pass-through" costs that are established in a process at the Federal Energy Regulatory Commission ("FERC"). Therefore, APS does not have any mechanism to recover discounts on these

amounts given at the retail level. The revised Rate Rider Schedules E-3 and E-4 are provided as Attachments CAM-3 and CAM-4 respectively.

Q. WILL THE NEW DISCOUNT STRUCTURE PROVIDE THE SAME LEVEL OF SAVINGS?

A. On average, yes. The new discount structures are designed to produce the same total level of discounts for the E-3 and E-4 programs compared with the current discounts. The specific savings for any particular customer will obviously vary due to the modified rate structure. For example, customers using less than 400 kWh under the E-3 program currently receive a 40% discount, while the proposed structure will provide a 25% discount, which is lower. However, because of the low usage, the difference in the billed amount is less dramatic – about $2.60 to $6.00 per month for customers on Rate Schedule E-12. Conversely, customers on the E-3 program using more than 800 kWh per month will receive a 25% discount capped at $18 under the proposed discounts, compared with 14%, capped at $13 under the current program.

Q. WHY IS APS PROPOSING TO ELIMINATE THE LOW INCOME EXEMPTIONS FOR THE PSA AND DSM ADJUSTOR RATES?

A. As mentioned, the Company is proposing to eliminate the low income exemptions for Adjustment Schedules PSA-1 and DSMAC-1. The former recovers the costs of fuel and purchased power that are not recovered in base rates. The latter recovers the costs of energy efficiency and demand response programs that are not funded through base rates. APS believes that these exemptions are piecemeal and inappropriate in that all customers should fund these costs.

Q. WILL THIS ELIMINATION LIKELY HARM LOW INCOME CUSTOMERS?

A. Not necessarily. For example, currently the PSA surcharge is a negative amount or a credit on the bill, while the DSM surcharge is positive. The combined

impact of the two surcharges is slightly negative, resulting in a bill savings. Therefore, because qualifying low income customers are exempt from these surcharges, they miss out on this net bill savings. Now, the PSA can be, and in the past has been, a positive charge in which case the combined exemptions would help low income customers. Nevertheless, APS believes that the exemptions should be discontinued because it is appropriate that low income customers pay these surcharges, and it is better to manage the low income policy through a single program (the discounts) rather than piecemeal though ad hoc exemptions from certain surcharges.

Q. IS THE COMPANY PROPOSING ANY NEW RATES FOR RESIDENTIAL CUSTOMERS?

A. Yes. APS is proposing an experimental peak time rebate demand response program for residential customers, Rate Rider Schedule PTR-RES. This voluntary rate option will be a rider that can be used in conjunction with Rate Schedules E-12 and ET-2. The rate will be available for two years from the approval date, but can be extended beyond that time if the program concept proves to be advantageous. Program participation can be capped by APS at its discretion. However, any such cap will not be less than 1,000 customers.

Q. PLEASE DESCRIBE THE EXPERIMENTAL PROGRAM.

A. Under the peak time rebate program, the Company can designate up to 18 critical days during the core summer months when the load is either difficult or expensive to serve. Participating customers are notified the prior day and can achieve bill savings by avoiding usage from 2 p.m. to 7 p.m. during the critical day. The bill savings are provided as a rebate for all kWh reduced during the critical hours. The peak event days can occur on weekdays from June through September, excluding July 4th and Labor Day.

Q. HOW WILL THE REBATE BE DETERMINED?

A. The customer will receive a rebate of $0.25 per kWh for all kWh reduced during the critical hours. The kWh reduction will be determined by comparing the actual metered usage during those hours with a baseline load which reflects the customer's typical or expected usage during those hours. The Company has designed a specific baseline estimation protocol, which uses the customer's actual load data for other similar hours during days when a critical event was not called.

Q. HOW DOES THIS PROGRAM DIFFER FROM THE CURRENT PEAK EVENT PRICING PROGRAM?

A. Many aspects are the same for both programs, including the number of peak event days and hours, the customer notification, and the pricing level for peak event hours. However, under the current peak event pricing program, customers receive a monthly discount for all kWh but are charged a higher price during the peak event hours. The distinction can be thought of as the difference between a carrot and a stick. Customers save money by avoiding usage during peak event hours, thereby reaping the monthly discount and avoiding high peak event prices to the extent possible. Conversely, under the proposed peak time rebate program customers receive a rebate for the kWh reduced during peak event hours – only a carrot.

Additionally, the new peak time rebate program requires an estimation of the customer's baseline usage during critical events, as discussed above. In contrast, the peak event pricing program does not need a baseline calculation; the customer is simply billed for any usage during critical hours based on the metered usage during those hours.

Q. WHAT DOES APS HOPE TO LEARN FROM THE EXPERIMENTAL RATE?

A. The proposed peak time rebate program will be part of APS's overall demand response pricing strategy, which seeks to reduce load during peak summer hours,

by providing price signals to customers that better reflect the cost to provide electricity in various months and hours of the day throughout the year. As such, the Company hopes to understand the potential customer load response during system peak hours, the typical savings that a customer can expect, the potential customer acceptance of the rate concept, and other operational issues, such as the accuracy of the estimated baseline usage and any related customer care issues. The Company will also compare the peak time rebate program with the peak event pricing program to determine which concept is most advantageous to continue to offer going forward. The proposed Rate Rider Schedule PTR-RES is provided as Attachment CAM-5.

VII. GENERAL SERVICE RATES

Q. PLEASE DESCRIBE APS'S GENERAL SERVICE RATES.

A. APS offers a number of rate offerings for general service customers including standard and time-of-use rates for extra-small, small, medium, large, and extra large business customers. Extra-small rates are for customers with monthly loads less than or equal to 20 kW; small – 21 to 100 kW; medium – 101 to 400 kW; large – 401 to 3,000 kW; and extra large – greater than 3,000 kW. The Company's general service rate schedules include: standard Rate Schedules E-32 XS (extra-small), E-32 S (small), E-32 M (medium), E-32 L (large), E-34 (extra large); time-of-use Rate Schedules E-32TOU XS, E-32TOU S, E-32TOU M, E-32TOU L, GS-Schools M, GS-Schools L, and E-35 (extra large); and Rate Schedule E-30 for extra small unmetered loads. APS also offers several rate riders for general service customers: Rate Rider Schedule E-53 for sports field and stadium lighting, Rate Rider Schedule E-54 for seasonal service and Rate Rider Schedule RSSP, a rural schools solar program.

Q. WHAT IS A GENERAL SERVICE CUSTOMER?

A. General service refers to non-residential customers that are served under a

common rate offering that is not specific to a customer type, load type, or special purpose or circumstance. The latter is referred to as a classified customer and a classified rate schedule. General service customers include government entities, hospitals, schools, retail stores, offices, manufacturers, restaurants, warehouses, and other business customers.

Q. WHAT IS THE COMPANY PROPOSING FOR EXISTING GENERAL SERVICE RATES?

A. APS proposes to increase the general service class by 2.64% percent, which is below the system average requested increase. More specifically, the Company proposes to: eliminate the monthly contract minimum charges for certain rates; modify Rate Schedule E-32 L; cancel Rate Rider Schedule E-53; modify Rate Rider Schedule E-54; and add two new provisions for Rate Schedule E-30. APS also proposes to increase the time-of-use rates for schools, GS-Schools M and GS-Schools L, to preserve the current pricing relationship and bill comparison to Rates E-32 M and E-32 L respectively.

Q. WHAT IS A MONTHLY CONTRACT MINIMUM CHARGE?

A. A monthly contract minimum charge is a calculated alternative billed amount which sets the floor for a monthly bill. If the usual monthly bill calculation results in an amount that is less than the alternative minimum calculation, then the customer is billed the minimum amount.

Q. PLEASE EXPLAIN.

A. General service rates typically include a daily basic service charge, which is applied to the number of days in the monthly billing period, a demand charge which is applied to the maximum kW usage in any 15-minute period in the month, and energy charges, which are applied to the total kWh usage in the month. These three charge types comprise the usual calculation for a monthly bill.

For small, medium, and large general service rates, the alternative minimum billed amount consists of the basic service charge plus a minimum demand charge applied to either the highest billing kW over the last 12 months or a minimum amount specified in a service agreement, whichever is greater. Again, if this minimum amount is greater than the usual bill calculation, the minimum will apply.

Q. WHY DOES APS HAVE A MINIMUM BILL FOR GENERAL SERVICE CUSTOMERS?

A. The purpose of an alternative minimum bill is to protect the Company's investment in wires capacity that is made on behalf of the customer – an investment that is typically not fungible to other customers. If a customer's load drops significantly in any month, a portion of this wires investment is unused and potentially unrecovered from the specific customer. This can result in costs that are shifted to other customers or otherwise unrecovered altogether. The minimum bill also recovers metering and billing costs that occur regardless of how much energy or demand the customer actually consumes.

Q. WHY IS APS PROPOSING TO ELIMINATE THE MINIMUM CHARGE FOR SEVERAL GENERAL SERVICE RATES?

A. APS is proposing to eliminate the minimum bill provisions in Rate Schedules E-32 S, E-32 M, E-32 TOU S, and E-32 TOU M, but retain them for the large and extra-large general service rates. The Company believes that this proposal will simplify the rates, make them more customer friendly, and cut down on bill inquiries and the concomitant operational costs without unduly creating a risk of shifting wires costs to other customers.

In addition, relatively few customers and load for the small and medium rates were actually billed under the minimum provision during the test year. Furthermore, because the customers on these rates are all less than 400 kW of

load, the Company does not believe that eliminating the minimum provision will actually or potentially create any material risk of cost shifting to other customers.

On the other hand, the Company is not recommending to eliminate the minimum bill provisions for the large and extra-large general service rates, because each customer in these classes have relatively large wires investments and, therefore, the risk of cost shifting to other customers is potentially material.

Q. HOW DOES THE COMPANY PROPOSE TO MODIFY RATE SCHEDULE E-32 L?

A. Currently, Rate Schedule E-32 L has a two-tiered energy (kWh) charge which collects some of the demand component in the first tier, along with a demand charge and a basic service charge. APS is proposing to remove the first tier energy charge, modify the remaining energy charge to reflect the average energy cost per kWh, and revise the demand charge to include the implicit demand that was embodied in the first tier energy charge. This proposed design modification is more consistent with the extra-large general service rate structure. Therefore, the Company believes that this modification will smooth the transition between large and extra-large general service when customers change their usage over time. The revised redlined Rate Schedule E-32 L is provided as Attachment CAM-6.

Q. WHY IS APS PROPOSING TO ELIMINATE RATE RIDER SCHEDULE E-53?

A. Because the Company believes that the Rate Rider Schedule E-53 is no longer necessary given the proposed elimination of the minimum bills for certain general service rates discussed above. E-53 essentially eliminates the alternative minimum bill calculation for sports field lighting loads – the alternative minimum kW charge and basic service charge – when the lights are not in use for a billing month. Therefore, if E-53 is cancelled, customers would be subject to the basic

service charge in a month that they don't use their lights, but not the alternative minimum demand charge. The Company believes that this is appropriate because the basic service charge recovers the cost of metering equipment, meter reading costs and billing costs, which occur even when the lights aren't used.

Q. WHAT IS RATE RIDER SCHEDULE E-54?

A. Rate Rider Schedule E-54 eliminates or reduces the alternative minimum bill for customers with seasonal loads, such as agricultural process customers where their usage occurs mainly in the spring and fall and is minimal in the summer.

Q. HOW IS THE COMPANY PROPOSING TO MODIFY THIS RATE?

A. APS is proposing to make Rate Rider Schedule E-54 only applicable to customers served under Rate Schedule E-32 L because the rider is no longer necessary for Rate Schedules E-32 S and E-32 M in light of the proposed elimination of the alternative minimum bill for these rates. APS is also modifying the rate design to make it more customer-friendly and easier to understand and administer.

Q. PLEASE DESCRIBE RATE SCHEDULE E-30 AND THE PROPOSED MODIFICATION.

A. Rate Schedule E-30 is applicable for general service customers with relatively constant demand and energy requirements that are difficult or impractical to meter. The customer is billed for monthly kWh that are determined according to a mathematical derivation of the usage for the specific equipment, rather than from an electrical meter. The Company is modifying this rate to require that the determination of the fixed monthly billed energy usage will be derived from the manufacturer's nameplate rating of the equipment, and that the customer's electrical service must be supplied at one site through one point of delivery as specified by an individual customer contract.

Q. IS APS PROPOSING ANY NEW RATES FOR GENERAL SERVICE CUSTOMERS?

A. Yes. APS is proposing Experimental Rate Rider Schedule AG-1, which provides alternative generation service for extra-large general service customers with average monthly demands of 10 MW or more and are served under Rate Schedules E-34 and E-35. The experimental program will be available for three years from the initial date and limited to 200 MW of generation procured under this offering.

The Company is also proposing Rate Rider Schedule IRR which provides interruptible service for extra-large general service customers. This rate concept was previously filed under a separate matter pending under Docket No. E-01345A-10-0250, but is being included in the instant proceeding with the concurrence of potentially interested parties.

Q. PLEASE DESCRIBE RATE RIDER SCHEDULE AG-1.

A. Under this service, the customer can obtain an alternative source of generation to serve their full power requirements. The power must be delivered to one or more of the Company's points of delivery for wholesale power, as designated in a power supply agreement, and must serve at least 90%, but no more than 110%, of the customer's average hourly load. The Company will purchase and manage this generation on behalf of the customer for a management fee of $0.00060 per kWh. The customer will be responsible for any collateral costs associated with the alternative generation.

The Company will also provide scheduling and, if necessary, load following services for the power. APS will continue to supply transmission, delivery and revenue cycle services to the customer under the provisions of the customer's current retail rate schedule, Rate Schedule E-34 or E-35. The customer will also be subject to all of the adjustments in the retail rate schedule, except for Adjustment Schedule PSA-1. Furthermore, the billed amounts under the retail

rate and applicable adjustments will be based on the total billed kWh, kW, or billed dollar amount, including the cost of the alternative generation.

Q. WHAT IS LOAD FOLLOWING SERVICE?

A. Load following service is the hourly matching of generation supply to the customer's load. The customer's alternative generation could be structured to supply this service – to ramp up and down hourly to match the load. On the other hand, the customer may purchase an amount of energy that is constant (flat) across many or all hours of the day, month, quarter, or year. In this case, APS would provide load following service to supply the extra energy needed when the alternative generation is less than the customer's load and to credit the surplus energy when generation exceeds load. The hourly sales will be transacted at an hourly market proxy price plus $4.00 to $10.00 per MWh depending on the amount of power that is required. The hourly credits will be based on the hourly market price less $4.00 to $10.00 per MWh.

Q. WHAT HAPPENS IF THE ALTERNATIVE GENERATOR DEFAULTS OR THE CUSTOMER WANTS TO RETURN TO THE STANDARD APS GENERATION SERVICES?

A. The customer must contract for service under this schedule for at least one year, but no more than three years. If the customer wishes to return to the standard APS generation service before the contract term, due to a default or other reason, they will be assessed a returning customer charge, which will be based on the costs to serve the returning customer versus the unbundled generation charge and related adjustments in their retail rate schedule, not to be less than zero. If the alternative generation supplier defaults, the customer will have 60 days to find an alternate supplier or be considered a "returning customer". Default provisions

will be specified in the power supply agreement. The proposed Rate Rider Schedule AG-1 is provided as Attachment CAM-7.

Q. PLEASE DESCRIBE RATE RIDER SCHEDULE IRR.

This rate offers interruptible service to extra-large general service customers that can interrupt at least 500 kW of load when requested by the Company. Under this service, the customer can choose between two curtailment options, two notification options, and a one-year or five-year agreement. The Customer receives capacity and energy payments for the interruptible load based on these options. The customer may also incur a penalty for failing to curtail when requested. The proposed Rate Rider Schedule IRR is provided as Attachment CAM-15.

VIII. CLASSIFIED RATES

Q. PLEASE DESCRIBE THE COMPANY'S CLASSIFIED RATES.

A. The classified rates apply to specific types of customers, or specific end uses or customer circumstances. This class includes: rates for street lighting, outdoor area lighting, and water pumping; time-of-use rates for schools and religious houses of worship; a station use rate for merchant generators; and a variety of rates for renewable and on-site generation.

Q. WHAT DOES APS PROPOSE FOR CLASSIFIED RATES?

A. APS proposes to:

- Modify outdoor lighting Rate Schedules E-47 and E-58;
- Increase the demand charge for water pumping Rate Schedule E-221 to better reflect cost of service;
- Increase the demand charge and change the time-of-use hours for Rate Schedule E-221 8T to be consistent with other time-of-use rates;
- Eliminate the time-of-week option for Rate Schedule E-221;
- Cancel Rate Schedule E-40 for agricultural wind machines;

- Modify the demand and energy charges in Rate Schedule E-20, time-of-use service for religious houses of worship, to better reflect cost of service;
- Revise Rate Rider Schedule E-56 for on-sight distributed generation to clarify how the supplemental and backup charges are determined;
- Revise Rate Rider Schedule SC-S for on-site solar distributed generation to clarify and simplify the language and make the rate applicable to other renewable generation;
- Offer a new rate for station-use power for customers with monthly demand below 3 MW;
- Cancel Rate Schedule Solar-2 for off-grid solar service;
- Cancel Rate Rider Schedule Solar-3; and
- Revise the green power rider rate schedules to remove a provision for the exemption from adjustor schedule RES.

Q. WHAT MODIFICATIONS ARE BEING PROPOSED FOR OUTDOOR LIGHTING SCHEDULES?

A. The Company proposes to increase the rates for dusk to dawn lighting, Rate Schedule E-47, by 2.94% and 3.62% on average for street lighting, which includes Rate Schedules E-58, E-59, E-67 and special lighting contract 12. APS proposes to modify Rate Schedules E-47 and E-58 by adding a trip charge for certain maintenance services. Specifically, APS proposes that when the Company is not the responsible party contracted for the regular maintenance of a lighting system owned by a city, town or other governmental entity, a $100 trip charge per light will be charged when the customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the customer or its designee on their lighting equipment. The trip charge will also apply when the customer requests disconnect or reconnect for non-maintenance purposes.

In addition, APS proposes that for any lighting system investment of $25,000 or more, the customer will be required to sign an agreement that limits the Company's financial liability and protects against potential stranded lighting equipment investment. The revised redlined Rate Schedules E-47 and E-58 are provided as Attachments CAM-8 and CAM-9 respectively.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO WATER PUMPING RATES.

A. APS is proposing to increase the water pumping rates, Rate Schedules E-221 and E-221 8T, by 3.62%. In addition, APS is seeking to modestly increase the demand charges for these rates to better reflect cost of service and to be more consistent with the general service rates. Furthermore, the Company is proposing to change the on-peak hours for schedule E221-8T to 11 a.m. to 9 p.m. weekdays to better reflect the Company's hourly on-peak retail load and be consistent with general service time-of-use rates. Currently, the customer can choose an on-peak period of 8 consecutive hours from 9 a.m. to 10 p.m. all days. As a result, the customer could choose an on-peak period of 9 a.m. to 5 p.m., which would incent them to shift load to the 5 p.m. to 7 p.m. time period, which is right in heart of the Company's highest peak load hours in summer months. The Company's proposal will seek to correct this counter-productive price signal.

Lastly, APS proposes to eliminate the time-of-week option for Rate Schedule E-221. The option has low participation, and the time-of-use periods and price signals do not appropriately reflect the Company's peak time periods and costs.

Q. WHY IS APS PROPOSING TO CANCEL CERTAIN CLASSIFIED RATES?

A. APS is proposing to cancel Rate Schedules E-40, Solar-2 and Solar-3, because they have low participation and are either no longer necessary or appropriate. Rate Schedule E-40 for agricultural wind machines has one customer with very

minimal electrical usage. This customer will be switched to Rate Schedule E-32 S, which is more appropriate and cost based. Solar-2 has no customers; Solar-3 has two. Both rates are no longer necessary given the Company's other solar and green power program options.

Q. WHAT CHANGES IS THE COMPANY PROPOSING FOR ON-SITE DISTRIBUTED GENERATION RATES?

A. APS is seeking to clarify Rate Rider Schedule E-56 for partial requirement customers with on-site generation to better define how the charges for supplemental and backup power are determined. Currently, the rate offers supplemental service, the amount of power (kW) and energy (kWh) that the customer typically uses from APS, and backup service, the additional power and energy that they use when their generator goes down. The rate also offers maintenance service, which replaces backup power and energy when the generator outage occurs during specified time periods and with proper notice to APS.

The supplemental power is currently capped at a contracted amount that is specified in an electric supply agreement. The Company proposes that this contracted supplemental power is reset each year, based on the customer's actual metered kW during the summer billing season—specifically, the maximum daily 15-minute metered kW averaged over the billing months May through October. This will ensure that the supplemental power is consistent with the customer's actual demand during the summer months when the Company's capacity requirements are most critical.

In addition, APS is proposing clarifying language to specify that the rates for backup power, which are specified for customers served under "parent" Rate

Schedules E-34 and E-32[6] in conjunction with the Rate Rider Schedule E-56, will be based on the customer's total metered load and determined by the provisions of the parent rate schedules. This clarification is consistent with current practice.

The Company is also proposing to revise Rate Rider Schedule SC-S (special contract solar) to expand the types of renewable generation that qualify for the rate. Currently, only solar generation technologies can participate in SC-S. The Company proposes to allow participation for solar, wind, geothermal, biomass, and biogas renewable generation technologies. Rate Schedule SC-S will also be renamed Rate Rider Schedule E-56 R.

Q. WHAT IS STATION USE POWER?

A. Merchant generators require power for "station use", such as startup power, power draws from inactive inverters, HVAC and lighting loads associated with the generator and supporting facilities and other related power requirements. Currently, the Company offers station use power under Rate Schedule E-36 (which will be re-designated as Rate Schedule E-36 XL) to serve merchant generators with a power supply capacity greater than 3 MW. This rate schedule was originally designed to provide starting power for large gas-fired generators. The proposed Rate Schedule E-36 M will serve merchant generators with a power supply capacity of less than 3 MW.

Q. WHAT IS THE DIFFERENCE BETWEEN A MERCHANT GENERATOR AND ON-SITE DISTRIBUTED GENERATION?

A. On-site distributed generation is a power facility, such as solar, wind or combined heat and power, which is located on a retail customer's site and is primarily intended to serve the customer's load at that site. These customers are served under a partial requirements rate rider, such as Rate Schedules E-56, EPR-6 net

[6] E-32 L, E-32 M, and E-32 S are all billed under the same backup power charge under Rate Schedule E-56.

metering, EPR-2 net billing, or the proposed E-56 R (formerly SC-S), so named because the customer is still connected to APS's electrical grid and their generator typically serves part, but not all, of their load. A partial requirements rate rider is needed to provide backup service in case the customer's generator fails.

In contrast, a merchant generator is a power supply facility that is not located at a retail customer's site and not intended to serve a retail load. Its sole purpose is to produce power to sell on the wholesale market or to APS under a purchased power agreement. Therefore, there is no load to back up and no excess power flow to the grid—the entire production is transported across the grid and sold under separate contractual arrangements. However, as mentioned, these generating plants do require power from APS for starting the units and other auxiliary requirements related to the generator site.

Q. PLEASE DESCRIBE THE PROPOSED RATE SCHEDULE FOR STATION USE POWER.

Rate Rider Schedule E-36 M shall provide station use power for generators with auxiliary power requirements below 3 MW. Customers with average monthly billing demands below 100 kW will be billed according to the energy charges in Rate Schedule E-32 XS. All other participating customers will be billed according to the demand and energy charges specified in E-32 L. The unbundled charges for revenue cycle services, such as metering and billing, will be higher than the E-32 amounts consistent with the higher costs to meter this service. Transmission services will be charged according to Adjustment Rate Schedule TCA-1. Participating customers will be also subject to the other adjustment rates as well, with the exception of Adjustment Schedule PSA-1 for power supply costs. Proposed Rate Rider Schedule E-36 M is provided as Attachment CAM-10.

Q. WHAT MODIFICATION IS APS PROPOSING FOR THE GREEN POWER RATES?

A. Currently the green power rates exempt the customer from paying the charges for the renewable energy standard, Adjustment Schedule REAC-1 (formerly RES), for any kWh purchased under the green power schedules GPS-1, GPS-2 and GPS-3. APS is seeking to eliminate this exemption.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE THIS EXEMPTION?

A. APS believes that the exemption may potentially allow some customers to avoid paying their fair share of the renewable energy standard costs and, consequentially, result in the renewable programs being underfunded and ultimately shift costs to other customers.

On the surface, this exemption appears to have merit. The defense for the exemption has been that customers should not pay a renewable energy standard adjustment fee on green power that is already priced at a premium rate, which reflects the above market cost of renewable power—it's akin to paying twice for the same green power (they argue). However, it is important to consider that the renewable energy standard funding is mandatory for all customers, while green power is a voluntary purchase driven by the customer's corporate policies, third-party environmental certifications, or personal preferences. Furthermore, the green power purchases do not qualify for or contribute to APS's kWh requirements under the renewable energy standard—they are above and beyond those requirements. As a result, as stated, if some customers are exempt from the RES funding, it could result in underfunded programs and ultimately shift costs for the RES to other customers.

Therefore, the Company believes that all customers should be required to pay their fair share of the mandatory RES requirements, regardless of any voluntary purchases of green power, which again do not count toward those requirements.

IX. ADJUSTMENTS TO RATES AND PLANS OF ADMINISTRATION

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE ADJUSTMENT RATE SCHEDULES AND PLANS OF ADMINISTRATION?

A. Yes. APS proposes to:

- Revise the rate schedule and plan of administration for Adjustment Schedule PSA-1, power supply costs, as set forth in the Direct Testimony of APS witness Pete Ewen;
- Modify Adjustment Schedule TCA-1, transmission costs, to reflect the consolidation of the transmission costs currently recovered in base rates;
- Revise the rate schedule and plan of administration for Adjustment Schedule DSMAC-1, demand side management;
- Revise Adjustment Schedule RES, renewable energy standard, rename it REAC-1, and reduce the charges to reflect the transfer of certain revenue requirements from the RES to base rates;
- Implement a new adjustor rate for certain plant investments, Adjustment Schedule ERA and the POA, as presented in the Direct Testimony of APS witness Leland Snook;
- Implement a new decoupling mechanism, Adjustment Schedule EIA and the POA, also presented in the Direct Testimony of APS witness Leland Snook;
- Cancel Adjustment Schedule EIS, environmental improvement costs, as it is no longer necessary given the proposed Adjustment Schedule ERA-1; and
- Revise the plans of administration for low income support programs, Rate

Rider Schedules E-3 and E-4, to reflect the proposal to eliminate the exemption from Adjustment Schedules PSA-1 and DSMAC-1.

Q. HOW IS THE COMPANY PROPOSING TO MODIFY ADJUSTMENT SCHEDULE TCA-1?

A. The Company proposes to remove the charge for unbundled transmission services from the individual rate plans and consolidate these charges in the transmission cost adjustor rate, Adjustment Schedule TCA-1.

Q. PLEASE EXPLAIN.

A. Currently, the Company recovers the revenue requirements for transmission services from two charges: (1) an unbundled transmission rate, which is part of base rates; and (2) a transmission cost adjustor rate, Adjustment Schedule TCA-1. The adjustor rate provides for recovery of transmission revenue requirements that are not recovered through base rates. The total transmission revenue requirement is established annually through a filing with FERC. The resulting charges in Schedule TCA-1 are subsequently approved annually by the Commission.

Since the total revenue requirement and rate design are established in the FERC formula rate process, in which the Commission Staff is an active participant, APS proposes that the charges in Adjustor Schedule TCA-1 be reset concurrent with the FERC process, and additional action by the Commission is not necessary.

Q. WHY IS APS PROPOSING THIS CHANGE?

A. APS believes that it makes sense to consolidate the transmission charges into one rate schedule, and remove them from base rates because the transmission revenue requirement in total is approved by FERC, while the base rates and other adjustors are the domain of the ACC. The Company's proposal will provide a clean delineation of these separate rate setting processes.

Q. WILL THIS PROPOSAL INCREASE THE TRANSMISSION COST FOR ANY RETAIL CUSTOMERS?

A. No. The unbundled transmission charge is being transferred to Adjustment Schedule TCA-1 at the current approved level. No further changes are being made to the charges in TCA-1, other than to reflect this transfer. The revised Adjustment Schedule TCA-1 is provided as Attachment CAM-11.

Q. WHAT IS APS PROPOSING FOR THE TCA-1 PLAN OF ADMINISTRATION?

A. APS proposes to cancel the current POA for TCA-1 as it would no longer be applicable or necessary in light of the requested recovery of transmission costs in Adjustment schedule TCA-1 and the related revisions to that schedule.

X. <u>SERVICE SCHEDULES</u>

Q. WHAT CHANGES DOES APS PROPOSE FOR ITS SERVICE SCHEDULES?

A. APS proposes to:

- Revise Service Schedule 1, terms and conditions for electrical service, to reflect various proposed changes in service and credit policies and to clarify certain provisions to reflect current Company policies; and
- Propose a new Service Schedule 9 to provide incentives for commercial and industrial development in the APS service territory.

Q. WHAT CHANGES IS APS PROPOSING FOR SERVICE SCHEDULE 1?

A. APS is not requesting any changes to the charges set forth in Service Schedule 1. However, the Company proposes to change or add certain provisions, some of which are cosmetic, and some substantive. The Company proposes: (1) to add a definitions section and a statement of charges, both of which are purely cosmetic and do not change any of the provisions, charges or their application. Furthermore, the majority of the definitions are derived from the Arizona Administrative Code; (2) to modify Section 2.2.4 concerning service establishment charges to clarify that this section refers to customer-requested

outages for maintenance and metering equipment installations; (3) to revise Section 4.2.4 to provide that the customer is responsible for any collection agency charges for recovering bad debt; (4) to add Section 4.3.2.3.5 to provide APS the ability to rebill customers for periods exceeding three months for residential customers and six months for general service customers, where actual customer usage can be determined without estimation, subject to the applicable statute of limitations; and (5) to delete Sections 7.2.5 and 7.2.6 and move the language to newly created Sections 7.1.2.1 and 7.1.2.2, where the Company believes they more appropriately belong. These current provisions suspend the Company's obligation to provide additional customer notification of a pending disconnection when the customer attempts to resolve a disconnection condition with a dishonored payment, to the appropriate section of Service Schedule 1.

The Company is also proposing Section 2.9, which specifies the conditions for releasing customer specific information to third parties. Under this proposal, customer specific information will not be released without prior written customer authorization, unless the information is requested by law enforcement or another public agency, is requested by the Commission or its staff, is reasonably required for legitimate account collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the customer. Furthermore, customer-specific information may be provided to suppliers of goods or services under contract with the Company, if such goods or services will assist the Company in providing efficient, effective, safe, or reliable service, and such contract includes a requirement that the information be kept confidential and is only used to fulfill the supplier's obligations to Company.

The revised Service Schedule 1 is provided as Attachment CAM-12.

Q. WHAT IS THE PROPOSED SERVICE SCHEDULE 9 FOR COMMERCIAL AND INDUSTRIAL DEVELOPMENT?

A. The proposed Service Schedule 9 is intended to support commercial and industrial development in the APS service territory. The Company proposes to provide a bill discount that declines over five years for qualifying new or expanding customers. Eligible customers include new customer sites and significant net expansions for existing sites served under extra-large general service rates E-34 and E-35, with a minimum new load of 500 kW for existing customers and 1,000 kW for new customers. The discount would be specific to each customer, as approved by the Commission. However, APS envisions that the discount would typically be structured over five years on a declining annual basis. The eligible customer would also be encouraged to participate in the Company's energy efficiency program, demand response program, or renewable energy program in order to provide even more bill savings and to help minimize any system peak impact from the new load. Total participation under this service would be limited to 100 MW of load or 50 new customers, whichever is less (on a MW basis). The proposed Service Schedule 9 is provided as Attachment CAM-13.

XI. PRESENTMENT OF CHARGES ON RETAIL BILLS

Q. PLEASE DESCRIBE THE CURRENT COMPONENTS OF APS'S RETAIL RATE SCHEDULES?

A. Each rate schedule specifies, among other things, all of the unbundled charges that are billed under the rate as well as the billing determinants that the charges apply to. Unbundled charges refer to prices for specific services, such as billing, metering, system benefits, distribution delivery, transmission, and generation capacity and energy. The billing determinants vary for each charge and rate schedule, but typically include such factors as the number of days in the monthly billing period, the total kWh usage, and for some rates, the maximum kW

demand in the billing period. Time-of-use rates have kWh and, in some cases, kW charges that vary for peak and off-peak time periods.

The rate schedules also include the bundled charges, which are the summation of all the individual unbundled charges for similar billing determinants. For example, the bundled daily charge would include the metering, charge, billing charge and any other charge that was billed according to the number of days in the billing period. The bundled kWh charge would be the summation of all the unbundled charges for specific services that are billed on the total kWh usage.

Q. HOW ARE THE RATES PRESENTED ON THE CUSTOMER'S BILL?

A. The customer's bill includes the amounts owed for each and every specific unbundled charge, rather than the bundled amounts for daily, kWh and kW charges.

Q. DOESN'T THIS MAKE THE BILLS FAIRLY COMPLICATED?

A. Yes, and long.

Q. DO MOST CUSTOMERS TYPICALLY LIKE TO SEE ALL OF THE UNBUNDLED CHARGES ON THEIR BILL?

A. No, I don't believe so. As a matter of fact, APS typically receives complaints from customers concerning the complexity of their bill and the amount of (what they believe to be) unnecessary information. This especially applies to residential and small business customers.

Q. WHY DOES APS INCLUDE ALL OF THIS DETAIL ON THE BILL?

A. APS is required to present the unbundled services and billing amounts on the customer's bill pursuant to A.A.C. R-14-2-1606 and R-14-2-210(B)(2)(k), which were promulgated as part of the direct access effort. The reasoning was that if a customer desired to procure direct access service from an alternative provider, unbundled components for direct access service would become bill credits.

Q. IS THE COMPANY PROPOSING TO CHANGE THE BILL PRESENTMENT IN THIS PROCEEDING?

A. Yes. The Company proposes to simplify the customer's bill by providing the bundled charges and related information. The detailed information on the unbundled charges and related information will be provided to customers on an opt-in basis. Such simplification of customers' bills was previously discussed in A.C.C. Decision No. 71448 (page 47, lines 14-18).

Q. WILL THE UNBUNDLED CHARGES STILL BE COMPUTED IN THE BILLING SYSTEM?

A. Yes. The unbundled amounts will be computed and available for all customers that desire this additional information. It just won't be automatically included on the customer's monthly bill. As a result, the unbundled bill format could be re-introduced in the future, if direct access service becomes viable in Arizona.

XII. PROFORMA ADJUSTMENTS TO TEST YEAR REVENUE

Q. WHAT ARE THE PROPOSED PROFORMA ADJUSTMENTS TO TEST YEAR REVENUE?

A. The retail revenue from base rates for the 2010 test year included in SFR H-1 has been adjusted for weather normalization, customer annualization, and low income discount programs. All of these factors are known and measurable and occur either within the test year or within a reasonable period thereafter. The revenue proforma adjustments are provided in Attachments CAM-16, CAM-17, and CAM-18.

Q. PLEASE DESCRIBE THE PROFORMA REVENUE ADJUSTMENT FOR WEATHER NORMALIZATION.

A. Test year revenue is adjusted for normal weather to ensure that the final approved level of revenue from the instant proceeding reflects retail energy consumption associated with average or typical temperature and humidity patterns. This adjustment is derived by estimating the impact of temperature and humidity on customers' monthly energy usage and then comparing the test year level of these

weather variables to long run (10 year) average levels. The resulting impact on energy usage is multiplied by the appropriate revenue per kWh to derive an overall revenue adjustment. The estimate of the impact of weather on kWh usage and the resulting revenue adjustment is performed specifically for each rate class. The results for each class are then combined to provide the overall revenue proforma adjustment.

As it turns out, the test year had relatively mild weather compared to long term trends, which means that had the test year weather been "normal" the kWh consumption and revenue would have been higher. As a result, test year revenue from base rates was adjusted upward by $10.3 million for the weather normalization proforma.

Q. WHAT IS THE CUSTOMER ANNUALIZATION REVENUE PROFORMA?

A. The customer annualization revenue proforma adjusts test year revenue to reflect customer growth or decline during the test year. This adjustment ensures that the final approved level of revenue generally reflects the customer level that occurred at the end of the test year, which typically is a better indication of expected level going forward compared with the average customer level that occurred throughout the test year.

The adjustment is derived by first evaluating the change in customer levels during the test year for each major rate class. This is accomplished by subtracting the customer level in December of the test year (2010) from December of the previous year (2009). The customer level for each month is then adjusted to reflect this annual change. The monthly adjustments are multiplied by the average kWh per customer and then the appropriate revenue per kWh to calculate the required revenue adjustment. This process is performed specifically for each

rate class, the results of which are then combined to derive an overall revenue adjustment.

The change in customer levels during the test year was mixed for the various rate classes—some increased and others declined. Overall, change in the level of customers was very modest compared to other recent years. In fact, the net change from all of the various rate classes was slightly negative. The resulting proforma adjustment to test year revenues was a reduction of $0.3 million.

Q. PLEASE EXPLAIN THE PROFORMA REVENUE ADJUSTMENT FOR LOW INCOME PROGRAMS.

A. APS is proposing to adjust test year revenues to reflect the growth in low income programs from the end of the test year to mid-year 2012, when new rates are projected to be implemented. As discussed above, the Company's low income program has two impacts on base rates: (1) a lower base rate compared with other residential customers, and (2) a bill discount program. The combined low income savings resulted in test year base revenues being lower by approximately $20 million dollars, the impact of which is already factored into the proposed rates.

However, the low income impact is projected to grow by over 13% per year resulting in an additional reduction in revenue of $4.2 million for the period January 2011 through June 2012. Therefore, the proposed adjustment to test year revenues for low income programs is a reduction of $4.2 million.

Q. HOW DID THE COMPANY CALCULATE THE ANNUAL GROWTH RATE AND RESULTING REVENUE LOSS?

A. The annual growth rate reflects the growth in participating low income customers over the test year. In January 2010, the Company had 58,885 customers participating in the low income rates and discount programs. By December 2010, this number increased to 66,738 – an annual growth rate of 13.3%. This growth rate is consistent with poverty data from the U.S. Census Bureau that reported an

annual increase in poverty of 14% in counties served by APS for 2009, which is the most recent full year for which such data is available.[7] The resulting growth in customer savings (revenue loss) was estimated for the calendar year 2011 and for the first six months of 2012, based on this annual growth rate.

Q. WHY IS THE COMPANY PROPOSING THIS ADJUSTMENT?

A. APS believes that this adjustment to test year revenues is reasonable and appropriate. The amounts are known and measureable and occur in direct proximity to the test year. Furthermore, the Company believes it is important to provide full cost recovery for these customer support programs, which are growing along with the rising poverty in Arizona.

XIII. STANDARD FILING REQUIREMENTS

Q. WHICH STANDARD FILING REQUIREMENTS AND TARIFFS ARE YOU SUPPORTING?

A. I am sponsoring the following Standard Filing Requirements ("SFRs") and tariffs:

- Schedule H-1, summary of base revenues by customer classification;
- Schedule H-2, analysis of base revenues by detailed class;
- Schedule H-3, comparison of present and proposed rates;
- Schedule H-4, typical bill analysis;
- Schedule H-5, billing activity by block for each major rate;
- Rate Schedules, except as noted; and
- Service Schedules.

Q. WOULD YOU PLEASE DESCRIBE THESE SFRS?

A. Certainly. Schedule H-1 provides the present and proposed test year revenue for major customer classifications. Schedule H-2 provides similar information for all of the Company's major rate classes. Schedule H-3 lists all of the current and

[7] U.S. Census Bureau, Poverty 2008 and 2009, American Community Survey Briefs, Sept. 2010.

proposed bundled charges for each rate Schedule. Schedule H-4 provides a bill comparison of the present and proposed rates by various monthly usage levels for each major rate. Schedule H-5 provides a frequency distribution of customer bills and usage for each major rate. I also sponsor an index of all rate schedules and service schedules, along with all of the schedules, with a few exceptions as noted above.

XIV. CONCLUSION

Q. PLEASE PROVIDE CONCLUDING REMARKS FOR YOUR DIRECT TESTIMONY?

A. APS requests the Commission to authorize:

1. The proposed increases to retail rates;
2. The proposed modifications to retail rate designs for residential, general service and classified rate schedules;
3. The requested redesign of the low income and medical equipment discount programs, Rate Rider Schedules E-3 and E-4;
4. The transfer of the unbundled transmission charge in retail rates to Adjustment Schedule TCA-1;
5. The proposed new Rate Schedules PTR-RES, residential peak time rebate program and E-36 M, station use power, IRR, interruptible service, and AG-1, alternative generation service;
6. The canceling of Rate Schedules E-40, E-53, Solar-2, Solar-3, and Share the Lights Rate Schedules E-114, E-116, E-145 and E-129;
7. The requested revisions to Service Schedule 1;
8. The proposed new Service Schedule 9, commercial and industrial development; and
9. The requested revisions to the POAs for Adjustment Schedule DSMAC-1, and Rate Rider Schedules E-3 and E-4.

Q. HAVE YOU PREPARED AN ANALYSIS OF THE IMPACTS ON TYPICAL BILLS FROM THE PROPOSED RATE CHANGES?

A. Yes. The impacts on typical bills are provided as Attachment CAM-14 using the format that APS has previously used. The customer usage information has been updated to reflect the 2010 test year data. Current rates are those in effect as of the date of this filing for 2011.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Charles Miessner
Statement of Qualifications

Charles Miessner has over 30 years experience in the electric utility industry in the areas of pricing, planning, and business development for both utilities and private energy companies. Prior to joining Arizona Public Service he served in management and leadership positions for Progress Energy, Tucson Electric Power, AES - New Energy, New West Energy and The Salt River Project. His accomplishments include: developing integrated resource planning methods and models and starting up demand-side programs at Progress Energy and Tucson Electric Power; participating in the start-up of AES- New Energy; directing strategic planning, pricing, origination, and government affairs for New West Energy; and developing and managing rate planning and implementation for Arizona Public Service. Charles has appeared before regulators and legislators on energy issues in Arizona, California, Nevada and New Mexico.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING DECEMBER 2010

		(A)	(B)	(C)	(D)	(E)
	Formula:			(B) - (A)	(C) / (A)	
	Reference:					
Line No.	Customer Classification	Present Rates [1 2] ($000)	Proposed Rates [2] ($000)	Amount ($000)	%	Rate of Return %
1	Residential	1,470,134	1,528,238	58,104	3.95%	6.08%
2	General Service	1,342,599	1,378,012	35,413	2.64%	11.86%
3	Irrigation/Water Pumping	26,669	27,635	966	3.62%	6.08%
4	Outdoor Lighting	20,999	21,760	761	3.62%	7.18%
5	Dusk to Dawn Lighting Service	8,457	8,706	249	2.94%	9.76%
6	Total Sales to Ultimate Retail Customers	2,868,858	2,964,351	95,493	3.33%	8.29%

NOTES:
1) Adjusted present revenue
2) Includes transmission amount transferred to Adjustment Schedule TCA-1

RATE RIDER SCHEDULE E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Rider Schedule E-4 Medical Support Care Program concurrently.

APPLICATION

This rate rider schedule is applicable to all Standard Offer and Direct Access electric service billed under a r~~R~~esidential r~~R~~ate s~~S~~chedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision Nos. 55931, 56680 and 69663. All provisions of the applicable retail~~Residential~~ r~~R~~ate s~~S~~chedule will apply except as modified herein.

RATES

The total bill as calculated according to the applicable retail rate schedule before taxes, regulatory assessment and franchise fees, excluding amounts billed under Adjustment Schedule TCA-1, will be discounted by 25% with a maximum discount of $18.

~~The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:~~

~~A.~~ ~~For Bills with Usage of:~~	~~The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:~~
~~0 – 400 kWh~~	~~40%~~
~~401 – 800 kWh~~	~~26%~~
~~801 – 1200 kWh~~	~~14%~~
~~1201 kWh and above~~	~~$13.00~~

~~B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.~~

~~C. Adjustment Schedule DSMAC-1 will not apply to customers served under this rate schedule.~~

RATE RIDER SCHEDULE E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Rider Schedule E-3 Energy Support Program concurrently.

APPLICATION

This rate rider schedule is applicable to all Standard Offer and Direct Access electric service billed under a r~~R~~esidential- r~~R~~ate s~~S~~chedule~~s~~, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision Nos. 59222 and 69663. All provisions of the applicable retail rate schedule~~Residential Rate Schedule~~ will apply except as modified herein.

RATES

~~The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:~~ The total bill as calculated according to the applicable retail rate schedule before taxes, regulatory assessment and franchise fees, excluding amounts billed under Adjustment Schedule TCA-1, will be discounted by 25% with a maximum discount of $36.

~~A.~~	~~For Bills with Usage of:~~	~~The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:~~
	~~0 – 800 kWh~~	~~40%~~
	~~801 – 1400 kWh~~	~~26%~~
	~~1401 – 2000 kWh~~	~~14%~~
	~~2001 kWh and above~~	~~$26.00~~

~~B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.~~

~~C. Adjustment Schedule DSMAC-1 will not apply to customers served under this rate schedule.~~

RATE RIDER SCHEDULE PTR-RES
RESIDENTIAL SERVICE
PEAK TIME REBATE EXPERIMENT PROGRAM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

The Rider Rate Schedule PTR-RES is available to residential retail Standard Offer customers served under Rate Schedule ET-2. This rate requires the customer to have an Advanced Metering Infastructure meter, or AMI, in place at time of service. All provisions of Rate Schedule ET-2 will apply in addition to the rates and provisions in Schedule PTR-RES. Schedule PTR-RES is a pilot program and is available for a period of two years from its effective date. Participation shall be limited to the first 2,000 customers. A customer may not simultaneously participate in Schedule PTR-RES and another demand response rate or program, including Rate Schedule ET-SP.

DESCRIPTION

Under this program, the Company incents customers to reduce their electrical usage during critical hours when load is difficult or expensive to serve. During these ciritcal times, the Company may declare an event (PTR Event) where the customer receives a rebate for the amount of energy that they reduced. Such rebates will be credited on their monthly electric bill.

RATES

The Credit Rate shall apply to the Energy Reduction (kWh) during a PTR Event, as determined by the Company.

Credit Rate	$0.250000	per kWh

DETERMINATION OF LOAD REDUCTION

A. The Energy Reduction reduction during a PTR Event will be determined using a customer baseline load (CBL) method, which estimates how much electricity a customer would have used had they not reduced their usage in response to a PTR event. The Energy Reduction is determined by subtracting the actual metered load from the CBL for all hours during a PTR event.

B. The CBL shall be the customer's usage (kWh) from 2 p.m. to 7 p.m., averaged over the three highest days of the preceding ten non-holiday, non-event, weekdays prior to the event. The highest days shall be determined by the highest total consumption from 2 p.m. to 7 p.m.

CONDITIONS

A. PTR Events: PTR Events may be invoked by the Company for the period 2 p.m. to 7 p.m., weekdays (Monday through Friday) during June through September. Holidays are excluded, which include Independence Day (July 4th) and Labor Day (first Monday in September). A PTR Event can be called based on severe weather, high load, high wholesale prices, or a major generation or transmission outage, as determined by the Company.

B. Number and Duration of PTR Events: The Company will invoke a minimum of 6 and a maximum of 18 PTR Events and 90 event hours, based on five hours per event, per calendar year.

C. PTR Event Notification/Communication: The Company shall notify customers of a PTR Event by 4:00 PM the prior day through a phone message, e-mail, or text message. Receipt of such notice is the responsibility of the participating customer.

RATE RIDER SCHEDULE PTR-RES
RESIDENTIAL SERVICE
PEAK TIME REBATE EXPERIMENT PROGRAM

D. PTR Event Cancellation: Once a PTR event alert has been initiated, there are no conditions that shall warrant the event to be cancelled.

NET METERING

A customer may participate in Schedule PTR-RES and a net metering rate schedule, subject to meter availability. However, any customer generation in excess of load during a PTR Event will be netted according to the customer's otherwise applicable rate schedule and will not be netted against usage during a subsequent PTR Event.

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658~~1.068~~	per day, or
For service through Instrument-Rated Meters:	$ 1.328~~1.627~~	per day, or
For service at Primary Voltage:	$ 3.477~~3.419~~	per day, or
For service at Transmission Voltage:	$ 26.855~~22.915~~	per day

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 16.899~~9.384~~	per kW for the first 100 kW, plus
	$ 12.313~~4.993~~	per kW for all additional kW, or
Primary Service:	$ 16.188~~8.703~~	per kW for the first 100 kW, plus
	$ 11.605~~4.315~~	per kW for all additional kW, or
Transmission Service:	$ 13.188~~6.788~~	per kW for the first 100 kW, plus
	$ _ 9.601~~2.396~~	per kW for all additional kW.

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.059350~~.10093~~ per kWh ~~for the first 200 kWh per kW, plus~~ ~~$0.05902 per kWh for all additional kWh~~	$0.042490~~.08430~~ per kWh ~~for the first 200 kWh per kW, plus~~ ~~$0.04239 per kWh for all additional kWh~~

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129~~0.601~~	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414~~0.345~~	per day, or
Instrument-Rated Meters:	$ 1.084~~0.904~~	per day, or
Primary:	$ 3.233~~2.696~~	per day, or
Transmission:	$ 26.611~~22.192~~	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038~~0.058~~	per day
Billing:	$ 0.077~~0.064~~	per day

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

System Benefits Charge: $ 0.00165~~0.00210~~ per kWh

~~Transmission Charge: $ 1.585 per kW~~

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

Secondary Service: $ 8.145 ~~7.799~~ per kW for the first 100 kW, plus

$ 3.559~~3.408~~ per kW for all additional kW, plus

$ 0.00011~~0.00011~~ per kWh, or

Primary Service: $ 7.434 ~~7.118~~ per kW for the first 100 kW, plus

$ 2.851~~2.730~~ per kW for all additional kW, plus

$ 0.00011~~0.00011~~ per kWh, or

Transmission Service: $ 4.434~~5.203~~ per kW for the first 100 kW, plus

$ 0.847~~0.811~~ per kW for all additional kW, plus

$ 0.00011~~0.00011~~ per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$8.754 per kW, plus $0.05759~~0.09872~~ per kWh ~~for the first 200 kWh per kW, plus~~ ~~$0.05681 per kWh for all additional kWh~~	$8.754 per kW, plus $0.04073~~0.08209~~ per kWh ~~for the first 200 kWh per kW, plus~~ ~~$0.04018 per kWh for all additional kWh~~

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

MINIMUM

The bill for service under this rate schedule shall ~~Standard Offer and Direct Access customers will~~ not be less than the applicable Bundled Standard Offer Service Basic Service ~~c~~Charge plus the applicable Bundled Standard Offer Service Demand Charge for each kW as determined herein. ~~plus $2.115 for each kW of either: (1) the highest kW established during the twelve (12) months ending with the current month; or (2) the minimum kW specified in an agreement for service, whichever is the greater.~~

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

~~For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.~~ For billing purposes, the kW used in this rate schedule shall be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

For the purpose of placement on this rate, the~~The~~ Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

The Monthly Maximum Demand shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1~~S~~ pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

~~4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. 69663.~~

~~5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.~~

~~6~~4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

ADJUSTMENTS (cont)

~~7~~5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

CONTRACT PERIOD

For customers with monthly maximum demands greater than 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

EXPERIMENTAL RATE RIDER SCHEDULE AG-1
ALTERNATIVE GENERATION
GENERAL SERVICE

AVAILABILITY

This experimental rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for all Standard Offer customers who have an aggregated Peak load of 10 MW or more each month throughout the year, as measured at the customer's meter(s). All provisions of customer's current applicable rate schedule(s) will apply in addition to this Schedule AG-1, except as noted herein. This experimental rate schedule shall be available for three years after approval by the Arizona Corporation Commission. Total program participation shall be limited to 200 MW of peak load, on a first come first served basis.

DEFINITION

Generation Service Provider: A third party from which the customer contracts to provide power for their load.

DESCRIPTION OF SERVICES

The Generation Service Provider shall provide the customer firm power sufficient to meet their full requirements (total load), as agreed to by the customer and the Company.

The customer shall obtain a Generation Service Provider and notify the Company. The Company will subsequently contract with the Generation Service Provider on behalf of the customer for the specified power and manage the contract for the customer.

The Company shall provide transmission delivery and network services to the customer in accordance with normal retail electric service.

The Customer will be responsible for paying the cost of the energy from the Generation Service Provider for the Generation Service specified in the contract.

Other than the unbundled generation component, all kWh and kW charges in Customer's current applicable parent rate schedule and any other applicable adjustment schedules will be applied to the Energy or Demand, as applicable. Eligibility for placement on a rate schedule will be determined by Customer's Demand, in accordance with the Customer's parent Rate Schedule.

DELIVERY OF POWER TO APS' SYSTEM

Power provided from the Generation Service Provider must be firm power (Western System Power Pool Schedule C or equivalent) and must be contracted in advance and delivered to the Company at APS network delivery points that are not limited by APS' capability to deliver contracted quantities. If the Generation Services do not cover hourly loads in any given hour, the Company will supply for each hour, and the customer will pay for, necessary generation at the hourly pricing proxy plus $4/MWh for up to 10% of the hourly deficit and an additional hourly charge of $6/MWh for hourly supply deficit over 10%. If the Generation Services supplies more power than needed in any given hour, the Company will credit the customer for the excess power for each hour at the hourly pricing proxy minus $4/MWh for up to 10% of the excess and an additional deduction of $6/MWh for the hourly excess over 10%.

DETERMINATION OF HOURLY PRICING PROXY

Hourly pricing proxy shall be the published Dow Jones Electricity Palo Verde Hourly Index for the power delivery date. Hourly prices are expressed in $ per MWh.

RESERVE CAPACITY CHARGE

Customer will pay company a monthly reserve capacity charge equal to 15% of customer's monthly peak load.

POWER SUPPLY ADJUSTER AND HEDGE COST TRUE-UP

When taking this service, the customer will be subject to a true up mechanism (either plus or minus) to account for the unpaid or overpaid Power Supply Adjuster balance and hedge cost associated with the Customers Standard Offer Service.

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company, and enter into another power contract within 60 days. Prior to execution of a new power contract, the Company shall proved generation service to the Customer, which will be charged at the hourly pricing proxy for generation service.

If the customer is unable to secure a new generation contract in that sixty day period, they will be deemed a returning customer, subject to conditions below.

RETURN TO COMPANY'S BUNDLED GENERATION SERVICE

If the Customer returns to the Company's bundled Generation Service, the Customer will be charged a Returning Customer Charge. The charge will be identified in the Electric Service Agreement between the Customer and the Company and will be in addition to the Standard Offer service charges. The Returning Customer Charge will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning customer(s). The costs associated with serving customers that are required to enter into Returning Customer Charge agreements will be kept separate from the retail power supply costs subject to recovery through the Power Supply Adjustment. The types of costs that will be used to develop the Returning Customer Charge are incremental Power Supply, Transmission, Ancillary Services and Metering. These costs will be amortized over an appropriate period to allow their timely recovery. In no event, however, will the Returning Customer Charge be in place less than one year, or last longer than 36 months and in no case shall be less than zero for any individual customer.

When taking this service, the Customer will be subject to a true up mechanism (either plus or minus) to account for the unpaid or overpaid Power Supply Adjuster balance and related hedge cost associated with the Customers Standard Offer Service.

RATES

Service under this rate schedule shall be billed according to Customer's current applicable parent rate schedule, except as follows:

1. The adjustment schedules PSA, ERA-1 and EIS will not apply to the Customer's bill while said Customer is on Rate Schedule AG-1.
2. In addition, the Customer agrees to pay a Management fee of $0.00060 per kWh.
3. Other than the unbundled Generation component, all kWh and kW charges in Customer's current applicable parent rate schedule and any other applicable adjustment schedules will be applied to the Energy or Demand, as applicable.

CONTRACT TERM AND REQUIREMENTS

The term of the Customer's contract with the Generation Service Provider shall be for not less than one year, and shall not exceed three years.

The Customer will enter a contract with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related APS' management of the generation resource.

CREDIT REQUIREMENTS

Customer must provide all collateral and margining requirements defined in the Generation Service contract to the Company. Failure to do so will be considered a default by the Customer and result in a return to bundled services under the terms stated in the return to Company's bundled service above. In addition, Company will be paid by the Customer for any losses associated with terminating the contract with the Generation Service Provider.

All Generation Service Providers must have at least an investment grade credit rating and demonstrate creditworthiness acceptable to Company.

ADJUSTMENTS

All adjustments of the Customers parent Rate Schedule will apply to the Customers bill, including the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

RATES

The customer's bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide outdoor lighting, plus any adjustments incorporated in this schedule:

I. FIXTURES (Includes Mounting Arm, if Applicable)

				RATES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
A. Acorn	9,500 HPS	100	41	$27.88~~$27.06~~	$7.09~~$9.22~~
	16,000	150	69	30.85~~30.04~~	8.89 ~~11.65~~
B. Architectural	9,500 HPS	100	41	15.77 ~~15.38~~	5.61~~7.34~~
	16,000	150	69	18.33~~17.96~~	7.45 ~~9.82~~
	30,000	250	99	21.67 ~~21.31~~	9.51 ~~12.60~~
	50,000	400	153	26.60 ~~26.29~~	13.63 ~~18.13~~
	14,000 MH	175	72	21.99 ~~21.51~~	8.98 ~~11.79~~
	21,000 MH	250	101	24.88 ~~24.42~~	11.02 ~~14.54~~
	36,000 MH	400	159	30.98 ~~30.54~~	15.08 ~~20.00~~
	8,000 LPS	55	30	23.04 ~~22.35~~	7.61 ~~9.82~~
	13,500 LPS	90	50	27.11 ~~26.36~~	9.12 ~~11.84~~
	22,500 LPS	135	72	30.90 ~~30.11~~	11.07 ~~14.45~~
	33,000 LPS	180	90	37.16 ~~36.22~~	13.03 ~~17.02~~
C. Cobra/Roadway	5,800 HPS	70	29	8.93 ~~8.73~~	3.94 ~~5.16~~
	9,500 HPS	100	41	10.49 ~~10.28~~	4.81 ~~6.32~~
	16,000	150	69	13.05 ~~12.87~~	6.66 ~~8.82~~
	30,000	250	99	15.67 ~~15.52~~	8.61~~11.46~~
	50,000	400	153	21.18 ~~21.06~~	12.25 ~~16.37~~
	14,000 MH	175	72	15.21 ~~14.97~~	7.72~~10.20~~
	21,000 MH	250	101	17.70 ~~17.49~~	9.57 ~~12.69~~
	36,000 MH	400	159	23.20 ~~23.03~~	13.22 ~~17.63~~
	8,000 FL	100	38	17.67 ~~17.20~~	3.81~~5.04~~

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

RATES (cont)

I. FIXTURES (Includes Mounting Arm, if Applicable) (cont)

					RATES	
		Lumen	Watts	kWh	Company Owned	Customer Owned
D. Decorative Transit		9,500 HPS	100	41	$38.27 ~~$37.09~~	$8.58 ~~$11.11~~
		16,000 HPS	150	69	37.94 ~~36.88~~	6.25 ~~6.31~~
		30,000 HPS	250	99	43.59 ~~42.46~~	12.20 ~~16.02~~
E. Flood		30,000 HPS	250	99	20.94 ~~20.61~~	9.67 ~~12.81~~
		50,000 HPS	400	153	25.84 ~~25.56~~	13.35 ~~17.77~~
		21,000 MH	250	101	22.37 ~~22.00~~	10.23 ~~13.53~~
		36,000 MH	400	159	27.13 ~~26.82~~	13.79~~18.35~~
F. Post Top	Colonial Gray	8,000 FL	100	38	19.06 ~~18.54~~	3.96 ~~5.23~~
		9,500 HPS	100	41	10.82 ~~10.60~~	5.07~~6.65~~
	Colonial Black	9,500 HPS	100	41	12.49 ~~12.21~~	5.25 ~~6.88~~
	Decorative Transit	9,500 HPS	100	41	33.49 ~~32.47~~	7.90 ~~10.24~~
G. FROZEN		~~4,000 INC~~	~~295~~	~~103~~	~~$9~~.70 ~~$9.78~~	$3.87 ~~$5.47~~
		~~7,000 MV~~	~~175~~	~~73~~	12.82 ~~12.67~~	5.42 ~~7.27~~
		~~20,000 MV~~	~~400~~	~~150~~	~~25~~.19 ~~24.92~~	10.48 ~~14.12~~
	Brackets over 8 ft. and up to 16 ft. in length				1.78~~1.72~~	--

FROZEN

NOTES:
1. Company Owned fixtures are those fixtures that the Company installs, owns, operates, and maintains.
2. Customer Owned fixtures are those fixtures where the customer installs and maintains the lighting fixtures, and the Company approves the installation, operates the fixtures, and replaces Company standard lamps only.
3. Listed kWhs reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on April 21, 1983.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on June 1, 1987 in accordance with A.R.S. §49-1104(A).

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

RATES (cont)

II. POLES

				RATES
			Height	Company Owned
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$12.61~~$12.17~~
			22 ft.	14.20~~13.70~~
			25 ft	15.36 ~~14.82~~
			30 ft	17.65 ~~17.03~~
			32 ft	18.54 ~~17.89~~
	Round Steel	2 Simplex Adapters	12 ft.	13.45~~12.98~~
			22 ft.	15.45~~14.91~~
			25 ft.	16.12~~15.55~~
			30 ft.	18.73~~18.07~~
			32 ft.	19.98~~19.28~~
	Square Steel	5"	13 ft.	14.46~~13.95~~
			15 ft.	12.93~~12.47~~
			23 ft.	15.33~~14.79~~
			25 ft.	16.85~~16.26~~
			28 ft.	18.71~~18.05~~
			32 ft.	18.61~~17.95~~
	Concrete		12 ft.	43.10~~41.58~~
	Fiberglass		12 ft.	36.50~~35.21~~
	Decorative Transit	4"	16 ft.	35.58~~34.33~~
	Decorative Transit	6"	30 ft.	68.70~~66.28~~
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	12.14~~11.71~~
			22 ft.	13.72~~13.24~~
			25 ft.	14.87~~14.35~~
			30 ft.	17.19~~16.58~~
			32 ft.	18.05~~17.41~~
	Round Steel	2 Simplex Adapters	12 ft.	12.97~~12.51~~
			22 ft.	14.48~~13.97~~
			25 ft.	15.63~~15.08~~
			30 ft.	18.25~~17.61~~
			32 ft.	19.50~~18.81~~
		3 Bolt Arm	32 ft.	22.41~~21.62~~
	Square Steel	5"	13 ft.	13.99~~13.50~~
			15 ft.	14.30~~13.80~~
			23 ft.	14.84~~14.32~~
			25 ft.	16.38~~15.80~~
			28 ft.	18.20~~17.56~~
			32 ft.	18.90~~18.23~~

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

RATES (cont)

II. POLES (cont)

			Height	RATES Company Owned
C. Direct Bury	Round Steel		19 ft.	$19.09~~18.42~~
			30 ft.	14.90 ~~14.38~~
			38 ft.	18.19 ~~17.55~~
		Self	40 ft.	22.41 ~~21.62~~
		Stepped	49 ft.	67.36 ~~64.99~~
	Square Steel	4"	34 ft.	16.45 ~~15.87~~
		5"	20 ft.	15.62 ~~15.07~~
			30 ft.	16.28 ~~15.71~~
			38 ft.	17.67 ~~17.05~~
	Decorative Transit		41 ft. 6	21.22~~20.47~~
	Decorative Transit		47 ft.	26.43~~25.50~~
	Steel Distribution Pole (for lighting		35 ft.	24.40~~23.54~~
D. Post Top	Decorative Transit Anchor Base		16 ft.	36.35~~35.07~~
	Gray Steel/Fiberglass		23 ft.	12.60~~12.16~~
	Black Steel		23 ft.	13.90~~13.41~~
E. FROZEN	~~Wood Poles~~		~~30 ft.~~	~~$9.28~~~~8.95~~
			~~35 ft.~~	~~9.28~~~~8.95~~
			~~40 ft.~~	~~13.19~~~~12.73~~

NOTES:
1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.
2. Monthly rates for all new Company owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary line if customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in Section IV.1 below.
3. When adding lighting fixtures to an existing Company owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified in Section IV.1 below.
4. Any and all distribution wire required to serve lighting facilities placed on a customer owned pole, whether new or existing, is subject to the additional monthly wire charges specified in Section IV.1 below.

III. ANCHOR BASE

	Height	RATES Company Owned
A. Flush	4 ft.	$10.27~~9.91~~
	6 ft.	12.25~~11.82~~
B. Pedestal	8 ft.	14.03~~13.54~~

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

		RATES
	Height	Company Owned
For 32' Round Steel Pole only	4 ft. 6"	9.73~~9.39~~

IV. RATES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	RATES
	Company Owned
1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire if customer provides earthwork and conduit.	$3.63~~3.50~~
2. Additional maintenance charge for HPS lamp and luminaire that is not accessible by bucket truck.	2.90~~2.80~~
3. Additional maintenance charge for MH lamp and luminaire that is not accessible by bucket truck.	6.26~~6.04~~

TRIP CHARGE

When Company is not the responsible party contracted for the regular maintenance of a dusk to dawn lighting system owned by a city, town or other governmental entity, a $100.00 trip charge per light will be charged when customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the customer or its designee(s) on their dusk to dawn equipment. The trip charge will also apply when customer request disconnect or reconnect for non-maintenance purposes.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES~~E~~AC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, ~~and~~ Arizona Corporation Commission No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

~~4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. 69663.~~

~~5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.~~

~~6~~4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

~~7~~5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 71448.

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

6. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

~~8~~7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. The 4,000 and 7,000 lumen lamps use an open glass diffuser. All units are controlled by a photoelectric switch.

2. The customer is not authorized to make connections to the lighting circuits or to make attachments.

~~SPECIAL PROVISIONS (cont)~~

3. Should a customer request relocation of a dusk-to-dawn lighting installation, the costs of such relocation shall be paid by the customer.

4. The Company cannot guarantee that all dusk to dawn facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

~~6.~~ 5. The customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

6. _____

~~7.~~ The customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment, multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

~~8.~~ _____

~~9.~~ 7. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

8. Lighting Equipment and services with an initial Company cost exceeding $25,000 shall require a financial liability agreement between the Company and the customer.

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the customer requests any non-standard dusk-to-dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the customer will own, operate and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Monthly bills rendered for non-standard facilities will be computed at the following rates, plus any adjustments incorporated in this schedule. KWh will be determined by the Company, based on the rated wattage of the lighting equipment and an estimated average hourly usage per month.

A.	Service Charge	$3.47~~3.35~~ per installed lamp per month
B.	Energy Charge	$0.06577~~0.06345~~ per kWh per month

If, at the Company's discretion, the customer chooses to have the Company maintain the entire non-standard facility, the Company may require the customer to enter into a separate maintenance agreement which may be subject to additional charges mutually agreed upon by the Company and the customer.

CONTRACT PERIOD

All Dusk-to-Dawn lighting installations will require a written agreement for service for a minimum of three (3) years, or longer at Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-58
CLASSIFIED SERVICE
STREET LIGHTING SERVICE

AVAILABILITY

This rate schedule is available in those portions of cities, towns and unincorporated communities in which Company does a general retail electric business and where Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

APPLICATION

This rate schedule is applicable to service for continuous lighting, from dusk to dawn, of public streets, alleys, thoroughfares, public parks and playgrounds ~~from dusk to dawn~~ by use of Company's facilities where such service for the entire area is contracted for from the Company by the city, town, other governmental agencies, or a responsible individual for unincorporated communities. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

RATES

The bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide street lighting, plus any adjustments incorporated in this schedule:

I. FIXTURES (Includes Mounting Arm, if Applicable)

				RATES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
A. Acorn	9,500 HPS	100	41	$ 27.88~~$ 27.06~~	$9.39~~$9.22~~
	16,000 HPS	150	69	30.85~~30.04~~	11.79~~11.65~~
B. Architectural	9,500 HPS	100	41	15.77~~15.38~~	7.44~~7.34~~
	16,000 HPS	150	69	18.33~~17.96~~	9.89~~9.82~~
	30,000 HPS	250	99	21.67~~21.31~~	12.64~~12.60~~
	50,000 HPS	400	153	26.60~~26.29~~	18.14~~18.13~~
	14,000 MH	175	72	21.99~~21.51~~	11.91~~11.79~~
	21,000 MH	250	101	24.88~~24.42~~	14.64~~14.54~~
	36,000 MH	400	159	30.98~~30.54~~	20.06~~20.00~~
	8,000 LPS	55	30	23.04~~22.35~~	10.05~~9.82~~
	13,500 LPS	90	50	27.11~~26.36~~	12.06~~11.84~~
	22,500 LPS	135	72	30.90~~30.11~~	14.67~~14.45~~
	33,000 LPS	180	90	37.16~~36.22~~	17.26~~17.02~~
C. Cobra/Roadway	5,800 HPS	70	29	8.93~~8.73~~	5.23~~5.16~~
	9,500 HPS	100	41	10.49~~10.28~~	6.38~~6.32~~
	16,000 HPS	150	69	13.05~~12.87~~	8.85~~8.82~~
	30,000 HPS	250	99	15.67~~15.52~~	11.46~~11.46~~
	50,000 HPS	400	153	21.18~~21.06~~	16.32~~16.37~~

RATE SCHEDULE E-58
CLASSIFIED SERVICE
STREET LIGHTING SERVICE

I. FIXTURES (Includes Mounting Arm, if Applicable) (cont):

		Lumen	Watts	kWh	RATES: Investment by Company	RATES: Investment By Others
C. Cobra/Roadway (cont.)		14,000 MH	175	72	$15.21~~$14.97~~	$10.26~~$10.20~~
		21,000 MH	250	101	17.70~~17.49~~	12.72~~12.69~~
		36,000 MH	400	159	23.20~~23.03~~	17.60~~17.63~~
		8,000 FL	100	38	17.67~~17.20~~	5.06~~5.04~~
D. Decorative Transit		9,500 HPS	100	41	38.27~~37.09~~	11.35~~11.11~~
		16,000	150	69	37.94~~36.88~~	12.57~~12.41~~
		30,000	250	99	43.59~~42.46~~	16.18~~16.02~~
E. Flood		30,000	250	99	20.94~~20.61~~	12.86~~12.81~~
		50,000	400	153	25.84~~25.56~~	17.77~~17.77~~
		21,000 MH	250	101	22.37~~22.00~~	13.59~~13.53~~
		36,000 MH	400	159	27.13~~26.82~~	18.35~~18.35~~
F. Post Top	Colonial Gray	8,000 FL	100	38	19.06~~18.54~~	5.26~~5.23~~
		9,500 HPS	100	41	10.82~~10.60~~	6.72~~6.65~~
	Colonial Black	9,500 HPS	100	41	12.49~~12.21~~	6.96~~6.88~~
	Decorative	9,500 HPS	100	41	33.49~~32.47~~	10.44~~10.24~~
G. FROZEN		~~4,000 INC~~	~~295~~	~~103~~	~~$9.70~~~~$9.78~~	$5.23~~$5.47~~
		~~7,000 MV~~	~~175~~	73	12.82~~12.67~~	7.23~~7.27~~
		~~11,000 MV~~	~~250~~	~~96~~	16.04~~15.87~~	9.62~~9.68~~
		20,000 MV	400	150	25.19~~24.92~~	14.00~~14.12~~

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.
2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.
3. Listed kWhs reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on November 1, 1986.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on November 1, 1986 in accordance with A.R.S. §49-1104(A).

RATE SCHEDULE E-58
CLASSIFIED SERVICE
STREET LIGHTING SERVICE

II. POLES

				RATES	
			Height	Investment by Company	Investment By Others
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$12.61~~$12.17~~	$1.74~~$1.68~~
			22 ft.	14.20~~13.70~~	1.95~~1.88~~
			25 ft.	15.36~~14.82~~	2.12~~2.05~~
			30 ft.	17.65~~17.03~~	2.43~~2.34~~
			32 ft.	18.54~~17.89~~	2.46~~2.37~~
		2 Simplex Adapters	12 ft.	13.45~~12.98~~	1.86~~1.79~~
			22 ft.	15.45~~14.91~~	2.14~~2.06~~
			25 ft.	16.12~~15.55~~	2.22~~2.14~~
			30 ft.	18.73~~18.07~~	2.58~~2.49~~
			32 ft.	19.98~~19.28~~	2.76~~2.66~~
	Square Steel	5"	13 ft.	14.46~~13.95~~	1.99~~1.92~~
			15 ft.	12.93~~12.47~~	1.78~~1.72~~
			23 ft.	15.33~~14.79~~	2.10~~2.03~~
			25 ft.	16.85~~16.26~~	2.31~~2.23~~
			28 ft.	18.71~~18.05~~	2.57~~2.48~~
			32 ft.	18.61~~17.95~~	2.56~~2.47~~
	Concrete		12 ft.	43.10~~41.58~~	5.94~~5.73~~
	Fiberglass		12 ft.	36.50~~35.21~~	5.03~~4.85~~
	Decorative Transit Pedestrian	4"	16 ft.	35.58~~34.33~~	4.90~~4.73~~
	Decorative Transit	6"	30 ft.	68.70~~66.28~~	9.46~~9.13~~
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	12.14~~11.71~~	1.67~~1.61~~
			22 ft.	13.72~~13.24~~	1.89~~1.82~~
			25 ft.	14.87~~14.35~~	2.05~~1.98~~
			30 ft.	17.19~~16.58~~	2.37~~2.29~~
			32 ft.	18.05~~17.41~~	2.49~~2.40~~
		2 Simplex Adapters	12 ft.	12.97~~12.51~~	1.78~~1.72~~
			22 ft.	14.48~~13.97~~	1.99~~1.92~~
			25 ft.	15.63~~15.08~~	2.15~~2.07~~
			30 ft.	18.25~~17.61~~	2.51~~2.42~~
			32 ft.	19.50~~18.81~~	2.68~~2.59~~
		3 Bolt Arm	32 ft.	22.41~~21.62~~	3.08~~2.97~~
	Square Steel	5"	13 ft.	13.99~~13.50~~	1.93~~1.86~~
			15 ft.	14.30~~13.80~~	1.96~~1.89~~
			23 ft.	14.84~~14.32~~	2.05~~1.98~~
			25 ft.	16.38~~15.80~~	2.27~~2.19~~
			28 ft.	18.20~~17.56~~	2.51~~2.42~~
			32 ft.	18.90~~18.23~~	2.59~~2.50~~

RATE SCHEDULE E-58
CLASSIFIED SERVICE
STREET LIGHTING SERVICE

II POLES (cont)

			Height	RATES Investment by Company	RATES Investment By Others
C. Direct Bury	Round Steel		19 ft.	$19.09~~$18.42~~	$2.63~~$2.54~~
			30 ft.	14.90~~14.38~~	2.76~~2.66~~
			38 ft.	18.19~~17.55~~	2.83~~2.73~~
		Self Support	40 ft.	22.41~~21.62~~	3.54~~3.42~~
		Stepped	49 ft.	67.36~~64.99~~	9.29~~8.96~~
	Square Steel	4"	34 ft.	16.45~~15.87~~	2.85~~2.75~~
		5"	20 ft.	15.62~~15.07~~	2.58~~2.49~~
			30 ft.	16.28~~15.71~~	2.68~~2.59~~
			38 ft.	17.67~~17.05~~	3.07~~2.96~~
	Decorative Transit		41 ft 6	21.22~~20.47~~	3.12~~3.01~~
	Decorative Transit		47 ft.	26.43~~25.50~~	3.89~~3.75~~
	Steel Distribution Pole (for lighting only)		35 ft.	24.40~~23.54~~	3.21~~3.10~~
D. Post Top	Decorative Transit Anchor Base		16 ft.	36.35~~35.07~~	5.00~~4.82~~
	Gray Steel/Fiberglass		23 ft.	12.60~~12.16~~	2.07~~2.00~~
	Black Steel		23 ft.	13.90~~13.41~~	2.29~~2.21~~
E. Existing distribution pole suitable for streetlight use				1.53~~1.48~~	--
F. FROZEN	~~Wood Poles~~		~~30 ft.~~	~~$9.28~~~~8.95~~	$1.61~~1.55~~
			~~35 ft.~~	~~9.28~~~~8.95~~	1.53~~1.48~~

FROZEN

NOTE: The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the customer provides earthwork and conduit (excluding the underground to overhead transition).

III. ANCHOR BASE

		Height	RATES Investment by Company	RATES Investment By Others
A. Flush		4 ft.	$10.27~~9.91~~	$1.41~~1.36~~
		6 ft.	12.25~~11.82~~	2.12~~2.05~~
B. Pedestal		8 ft.	14.03~~13.54~~	2.45~~2.36~~
	For 32' Round Steel Pole only	4 ft. 6"	9.73~~9.39~~	1.69~~1.63~~

IV. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	RATES Company Owned
Underground Circuit Charges:	
a. ~~Per foot of cable, installed under paving~~	$0.16~~0.15716~~
b. ~~Per foot of cable, not installed under paving~~	0.06~~0.05589~~

FROZEN

RATE SCHEDULE E-58
CLASSIFIED SERVICE
STREET LIGHTING SERVICE

TRIP CHARGE

When Company is not the responsible party contracted for the regular maintenance of a street lighting system owned by a city, town or other governmental entity, a $100.00 trip charge per light will be charged when Customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street light equipment. The trip charge will also apply when Customer request disconnect or reconnect for non-maintenance purposes.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule ~~RES~~ REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 Arizona Corporation Commission Decision No. 69663, ~~and~~ Arizona Corporation Commission No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

~~4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. 69663.~~

~~5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.~~

~~6~~4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

~~7~~5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

~~8~~7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.

2. The Company cannot guarantee that streetlighting facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the streetlighting facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps,

RATE SCHEDULE E-58
CLASSIFIED SERVICE
STREET LIGHTING SERVICE

photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

3. The customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

SPECIAL PROVISIONS (con~~t~~)

4. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

NON-STANDARD FACILITIES

Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

EXTENSION OF STREET LIGHTING SYSTEM

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the customer. When the extension is underground the customer will provide earthwork as specified in ~~Section 6.1.2 of~~ the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's ~~customer's~~ request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable~~for a~~ contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE RIDER SCHEDULE E-36 M
CLASSIFIED SERVICE
STATION USE SERVICE MEDIUM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for start-up and/or auxiliary load requirements for generation plants with a power supply capacity requirement of less than 3 MW. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. Special metering may be required such as bi-directional metering. This rate schedule may be used in conjunction with other applicable rate schedules; however, service under this schedule is not eligible for Direct Access.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

OPTIONS

A. Customer may net the kWh output of their generator provided to APS through a purchase power contract or other arrangement against the electricity provided by APS to the Customer for station use. Under this option, the charges in this Schedule will not apply.

B. Company supplies the station use power needs to the customer at the rates and provisions in this rate rider schedule.

RATES

Customers shall be placed on a small or medium pricing tier annually, based on the maximum metered monthly demand, averaged over the summer months May through October, or if such load data is not available, other relevant data determined by the Company. If such average demand is greater than 3 MW the customer will be placed on Rate Schedule E-36 XL.

Small:
Customers placed on the small pricing tier shall be billed according to the rates and provisions in Rate Schedule E-32 XS, except for the unbundled basic service and revenue cycle service charges which are specified below.

Medium:
Customers placed on the medium pricing tier shall be billed according to the rates and provisions in Rate Schedule E-32 L, except for the unbundled basic service and revenue cycle service charges which are specified below.

RATE RIDER SCHEDULE E-36 M
CLASSIFIED SERVICE
STATION USE SERVICE MEDIUM

Unbundled Basic Service Charge:		
For E-32 M and E-32 L		
Self-Contained Meters:	$ 1.344	per day, or
Instrument-Rated Meters:	$ 1.322	per day, or
Primary Voltage Meters:	$ 6.830	per day
Revenue Cycle Service Charges:		
E-32 XS		
Metering:		
Self-Contained Meters:	$ 0.403	per day, or
Instrument-Rated Meters:	$ 1.055	per day, or
Primary Voltage Meters:	$ 3.146	per day
Meter Reading:	$ 0.068	per day
Billing:	$ 0.075	per day
E-32 L		
Metering:		
Self-Contained Meters:	$ 0.345	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary Voltage Meters:	$ 2.696	per day, or
Transmission	$ 22.192	per day
Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day

INTERCONNECTION REQUIREMENTS

The customer must meet all interconnection requirements as determined by the Company. The customer is responsible for all costs associated with interconnection of the customer's generation facility to the Company's system.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

ADJUSTMENT SCHEDULE TCA-1
TRANSMISSION COST ADJUSTMENT

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail ~~electric~~ rate schedules.~~, with the exception of Solar 2.~~ All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

~~Standard Offer rate schedules covered by this charge include a transmission component of base rates that was originally established at $0.00476 per kilowatt-hour in accordance with A.C.C. Decision No. 67744. Decision No. 67744 also established the TCA. Decision No. 69663 modified the collection of transmission costs in retail rates to tie to the costs found in the FERC approved Open Access Transmission Tariff.~~
In accordance with A.C.C. Decision No. XXXXX, Adjustment Schedule TCA-1 shall recover the transmission costs in retail rates provided in the Company's Open Access Transmission Tariff, which are revised annually and filed with the Federal Energy Regulatory Commission. The annual revisions to Adjustment Schedule TCA-1 shall be filed with the A.C.C. by May 15th each year, and shall become effective June 1. The revised charges shall be effective on customer's bills beginning with June billing cycles and shall not be prorated.

RATE

The charge shall be applied as follows:

Customer Class	TCA Charge
Residential	~~$0.002144~~XXXX/kWh
General Service 20 kW or less	~~$0.001602~~XXXX/kWh
General Service over 20 kW, under 3,000 kW	~~$0.740~~XXXX/kW
General Service 3,000 kW and over	~~$0.259~~XXXX/kW

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

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

Definitions

a. Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

b. Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

c. Billing Month means the period between any two regular readings of the utility's Meters at approximately 30 day intervals. [A.A.C. R14-2-201-(5)]

d. Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

e. Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

f. Delinquent Bill means a bill in which current electric charges are considered past due. (15 *calendar* days after the statement date.)

g. Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(12)]

h. Distribution Lines means the utility lines operated at distribution voltage which are constructed along public roadways or other bona fide rights-of-way, including Easements on Customer's property. [A.A.C. R-14-2-201-(13)]

i. Easement means a property owner grants the right to use land they own ("Grantor') to another party. An easement gives Company the right to have Company lines on property not owned by the Company. This allows Company to construct, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity. The Grantor may continue to use the land along the easement within certain limitations.

j. Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer (landlord) and Company, which provides continuous service to the landlord between tenants without incurring a service establishment charge to the landlord.

k. Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(23)]

l. Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(25)]

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m. Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(26)]

n. Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(27)]

o. Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C . R14-2-201(31)]

p. Service establishment charge means the charge for establishing a new account.

q. Tariffs mean the documents filed with the Arizona Corportion Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products. [A.A.C. R14-2-201(42)]

Statement of Charges

Description	**Charge**	**Reference**
Residential Service Establishment Charge	$25.00	2.2
Non-Residential Service Establishment Charge	$35.00	2.2
Trip Charge	$16.00	2.2.1
After hours Charge	$75.00	2.2.2
Same Day Connect Charge	$75.00	2.2.3
Non-standard Connect Charge	$75.00 per crew per hour	2.2.4
Direct Access Request	$10.00	2.3
Dishonored Payment Fee	$15.00	4.4.1
Field Call Charge	$15.00	4.5.1
Overhead Reconnection Charge	$96.50	4.5.2
Underground Reconnection Charge	$115.00	4.5.2
Lock Ring Key Charge	$70.00	6.2.2
Joint Site meeting for removal of Company Equipment	$62.00 per site per first half hour. Additional charge per hour for site meeting over one half hour	6.2.3

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	will be $53.00 per hour.	
Meter Reread	$16.50	6.4.4 & 6.4.5
Meter test in shop	$30.00	6.5
Meter test at site	$50.00	6.5
Electronically Transmitted Payment Discount	-$0.48	4.3.3

1. General

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

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

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

2. Establishment of Service

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

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

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

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

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2.2.1 The C~~c~~ustomer will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the C~~c~~ustomer's site and is unable to complete the C~~c~~ustomer's requested services due to lack of access to the P~~p~~oint of D~~d~~elivery.

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

2.2.3 The C~~c~~ustomer will additionally be required to pay a same day connect charge of $75.00 if the C~~c~~ustomer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same business day the request is being made, and Company agrees to work the request on the same business day of the request. This will be charged regardless of the time the order may be worked by Company on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

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

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

2.2.5 Company may waive the S~~s~~ervice E~~e~~stablishment C~~c~~harge where:

2.2.5.1 No field trip is required because A~~a~~pplicant accepts responsibility for energy billed and not yet paid and the change is effective with the last M~~m~~eter read and M~~m~~eter read date billed.

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

2.2.5.3 Where multiple connects are performed during the same site visit, in the same A~~a~~pplicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two D~~d~~elivery P~~p~~oints.

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

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

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

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

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

2.4.4 The A~~a~~pplicant is known to be in violation of Company's T~~t~~ariff.

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

2.4.6 The A~~a~~pplicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the A~~a~~pplicant is requesting service.

2.4.8 Residential s~~S~~ervice is requested by an A~~a~~pplicant and a prior C~~e~~ustomer, who will be living at the subject address, ~~with the applicant~~ owes a delinquent bill from the same or a prior residential service address.

2.4.9 Service is requested by an ~~The~~ A~~a~~pplicant, and a prior Customer who will be an actual user of the service at the subject address ~~is acting as an agent for a prior customer who is deriving benefits of the service and who~~ owes a delinquent bill for the same class of service from the same or a prior service address.

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

2.5 Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new A~~a~~pplicant for service at a primary and/or secondary residence if the A~~a~~pplicant is able to meet any of the following requirements:

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

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

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

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

2.5.1.5 Where three or more additional residential services are requested, Company may require Ceustomer to establish or reestablish a security deposit.

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

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

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

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

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

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

2.6 Establishment or -Reestablishment of Security Deposit

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

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

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

2.7.1 Security deposits may be required for each service location.

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

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

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

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

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

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

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

2.7.6 Residential security deposits shall not exceed the higher amount of either one (1) time the Ceustomer's maximum monthly bill or two (2) times the Ceustomer's average monthly bill as estimated by Company for the services being provided by Company.

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

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

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

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

2.9 Customer--Specific Information - Customer-specific information shall not be released without specific prior written Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with Company if:

2.9.1 Such goods or services will assist Company in providing efficient, effective, safe, or reliable service; and

2.9.2 Such contract includes a requirement that the information be kept confidential and is only used to fulfill the supplier's obligations to Company.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that Ceustomer for the requested type of service. In addition, Company shall notify its Ceustomers of any changes in Company T~~t~~ariff~~s~~ affecting those Ceustomers.

3.2 Rate Selection – The Ceustomer's service characteristics and service requirements determine the selection of applicable rate schedule. If the Ceustomer is receiving bundled service, Company will

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use reasonable care in initially establishing service to the Ceustomer under the most advantageous rate schedule applicable to the Ceustomer. However, because of varying Ceustomer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the Ceustomer would have paid less for service had the Ceustomer been billed on an alternate applicable rate or provision of that rate.

3.3 Optional Rates – Certain optional rate schedules applicable to certain classes of service allow the Ceustomer the option to select the rate schedule to be effective initially or after service has been established. Billing under the alternate rate will become effective from the next regularly scheduled Mmeter reading, after the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve (12) -month period. Where the rate schedule or contract pursuant to which the Ceustomer is provided service specifies a term, the Ceustomer may not exercise its option to select an alternate rate schedule until expiration of that term.

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

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

4. Billing and Collection

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

4.1.1 Company normally Mmeters and bills each site separately; however, at Ceustomer's request, adjacent and contiguous sites (not separated by private or public property or right of way), and operated as one integral unit under the same name and as a part of the same business, willmay at Company's option be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The Ceustomer's service installation will normally be arranged to accept only one type of service at one Ppoint of Ddelivery to enable service measurement through one Mmeter. If the Ceustomer requires more than one type of service, or total service cannot be

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measured through one M~~m~~eter according to Company's regular practice, separate M~~m~~eters will be used and separate billing rendered for the service measured by each M~~m~~eter.

4.2 Collection Policy - The following collection policy shall apply to all C~~c~~ustomer accounts:

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

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

4.2.3 Unpaid charges incurred prior to the C~~c~~ustomer selecting Direct Access will not delay the C~~c~~ustomer's request for Direct Access. These charges remain the responsibility of the C~~c~~ustomer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.2.4 All unpaid delinquent final bills may be referred to a collection agency for collection.

4.2.4.1 If collection agency referral is warranted for collection of unpaid final bills, Customer will be responsible for associated collection agency fees incurred.

4.3 Responsibility for Payment of Bills

4.3.1 The C~~c~~ustomer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final M~~m~~eter reading for those services involving energy usage, or if non-metered services are involved until Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the C~~c~~ustomer, Company may correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Schedule 8 (Bill Estimation) shall be applied when Company cannot obtain a complete and valid M~~m~~eter read. Situations that result in an estimated M~~m~~eter read include inclement weather, lack

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of access to a C~~c~~ustomer's M~~m~~eter, energy diversion, labor unavailability and equipment malfunction.

4.3.2.1 Refunds or credits to C~~c~~ustomers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings shall be billed to the C~~c~~ustomer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of M~~m~~eter T~~t~~ampering or energy diversion.

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of M~~m~~eter T~~t~~ampering or energy diversions, corrected charges for underbillings shall go back to the date M~~m~~eter T~~t~~ampering or energy diversions began, as determined by Company.

4.3.2.3.4 Where lack of access to the M~~m~~eter (caused by the C~~c~~ustomer) has resulted in estimated bills, corrected charges for underbillings shall go back to the B~~b~~illing M~~m~~onth of the last Company obtained M~~m~~eter read date.

4.3.2.3.5 Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event shall such rebilling exceed the applicable statute of limitations.

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

4.3.3 Where Company is responsible for rendering the C~~c~~ustomer's bill, Company will provide a monthly incentive of $0.48 per C~~c~~ustomer to C~~c~~ustomers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

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4.4 Dishonored Payments - If Company is notified by the Ceustomer's financial institution that they will not honor a payment tendered by the Ceustomer for payment of any bill, Company may require the Ceustomer to make payment in cash, by money order, certified or cashier's check, or other means which guarantee the Ceustomer's payment to Company.

4.4.1 The Ceustomer will be charged a fee of $15.00 for each instance where the Ceustomer tenders payment of a bill with a payment that is not honored by the Ceustomer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the Ceustomer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the Ceustomer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the Ceustomer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Termination Process Charges

4.5.1 Company will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the Ceustomer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.2 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.3 To avoid termination of service, the Ceustomer will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated Ppoint of Ddelivery, as specified in Section 6.3 of this Schedule, at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F. Company may deliver service for special Aapplications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The Ceustomer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the Ceustomer's side of the Ppoint of

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Ddelivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the Ceustomer under hazardous conditions.

5.2.2 The Ceustomer shall exercise all reasonable care to prevent loss or damage to Company property installed on the Ceustomer's site for the purpose of supplying service to the Ceustomer.

5.2.3 The Ceustomer shall be responsible for payment for loss or damage to Company property on the Ceustomer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.
~~5.2.3~~

5.2.4 The Ceustomer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the Mmeter.

5.2.5 The Ceustomer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the Ceustomer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service, except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the Ceustomer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The Ceustomer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other Ceustomers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites

5.4.1 Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to Company's equipment located on Ceustomer's sites for the purpose of repair, maintenance, and service restoration work that Company may need to perform.

5.4.2 Company's authorized agents shall have satisfactory unassisted access to the Ceustomer's sites at all reasonable hours to install, inspect, read, repair or remove its Mmeters or to install, operate or maintain other Company property, to verify that Ceustomer is in compliance with its obligations, or to inspect and determine the connected electrical load.

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If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to work with the Ceustomer, Company in its opinion does not have satisfactory unassisted access to the Mmeter, then Company shall have sufficient cause for termination of service or denial of any rate options where, in Company's opinion, access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized Mmeter. If such specialized Mmeter is installed, the Ceustomer will be billed the difference between the otherwise applicable Mmeter for their rate and the specialized Mmeter plus the cost incurred to install the specialized Mmeter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this section.

5.5 Easements

5.5.1 All suitable Eeasements or rights-of-way required by Company for any portion of an extension to serve a Ceustomer, which is either on sites owned, leased or otherwise controlled by the Ceustomer or developer, or other property required for the extension, shall be furnished in Company's name by the Ceustomer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All Eeasements or rights-of-way granted to, or obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the Ceustomer or the Ceustomer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Eeasement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the Ceustomer or the Ceustomer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the Ceustomer's expense. Company will notify the Ceustomer in writing of the violations.

5.6 Load Characteristics – The Ceustomer shall exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Ddemand, shall not impair service to other Ceustomers or interfere with operation of telephone, television, or other communication facilities. Customer shall meet power factor requirements as specified on applicable rate schedules.

6. Metering and Metering Equipment

6.1 Customer Equipment - The Ceustomer shall install and maintain all wiring and equipment beyond the Ppoint of Ddelivery except for Company's Mmeters and special equipment. The Ceustomer's entire installation must conform to all applicable construction standards and safety codes and the Ceustomer must furnish an inspection or permit if required by law or by Company. In circumstances where a clearance is not required by law, Company may require Ceustomer to execute a Letter In-Lieu of Electrical Clearance.

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6.1.1 The C~~c~~ustomer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the P~~p~~oint of D~~d~~elivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.asp.

6.1.2 Where a C~~c~~ustomer requests, and Company approves, a special M~~m~~eter reading device or communications services or devices to accommodate the C~~c~~ustomer's needs, the cost for such additional equipment and usage fees shall be the responsibility of the C~~c~~ustomer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company M~~m~~eters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company M~~m~~eters pursuant to conditions of Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the C~~c~~ustomer, and/or its agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. If Company must temporarily replace the MSP's M~~m~~eter and/or associated metering equipment during emergency situations or to restore power to a C~~c~~ustomer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the C~~c~~ustomer's side of the P~~p~~oint of D~~d~~elivery except its M~~m~~eter.

6.3.1 For overhead service, the P~~p~~oint of D~~d~~elivery shall be where Company's service conductors terminate at the C~~c~~ustomer's weatherhead or bus rider.

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6.3.2 For underground service, the Ppoint of Ddelivery shall be where Company's service conductors terminate in the Ceustomer's or development's service equipment. The Ceustomer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors.

6.3.3 For special Aapplications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and Ceustomer shall mutually agree upon the designated Ppoint of Ddelivery.

6.3.4 For the mutual protection of the Ceustomer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the Ceustomer's service entrance conductors. Such employees carry Company issued identification which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the Ceustomer will be measured by commercially acceptable measuring devices by Company (or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule 10). Where energy and, if applicable, Ddemand is estimated by Company, estimation will be in accordance with Company's bill estimation procedures approved by the Arizona Corporation Commission. Where it is impractical to Mmeter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer Ceustomers, or where Company is the MRSP, the readings of the Mmeter will be conclusive as to the amount of electric power supplied to the Ceustomer unless there is evidence of Mmeter Ttampering or energy diversion, or unless a test reveals the Mmeter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of Mmeter Ttampering or energy diversion, the Ceustomer, person or entity demonstrated to have tampered with the Mmeter and/or benefited from the tampering or diversion will be billed for the estimated energy and, if applicable, Ddemand, for the period in which the energy diversion took place. Additionally, where there is evidence of Mmeter Ttampering, energy diversion, or by-passing the Mmeter, the Ceustomer, person or entity demonstrated to have tampered with the Mmeter and/or diverted energy will also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a Mmeter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.3.1 Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and Ddemand that would have registered had the Mmeter been operating properly.

6.4.4 Where Company is the MRSP, Company will, at the request of the Ceustomer or the ESP, reread the customer's Mmeter within ten (10) working days after such request by the

Ceustomer. The cost of such rereads is $16.50 and may be charged to the Ceustomer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the Mmeter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its Mmeters regularly in accordance with a Mmeter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained Mmeter upon Ceustomer or ESP request. If the Mmeter is found to be within the plus or minus three percent (3%) limit, Company may charge the Ceustomer or the ESP $30.00 for ~~the~~ Mmeter test if the Mmeter is removed from the site and tested in the meter shop, and $50.00 if the Mmeter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes - Company shall refuse service to all new construction of apartment complexes and condominiums which are Mmaster Mmetered. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments (developments consisting of apartments, condominiums or townhouse developments built with four or more floors, usually using elevators for accessing floors) – Company will allow Mmaster Mmetering for residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Ceustomer for any of the reasons stated below,

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provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A Ceustomer violation of any of the applicable rules of the Arizona Corporation Commission or Company Ttariffs.

7.1.2 ~~7.1.2~~ Failure of the Ceustomer to pay a Ddelinquent Bbill for services provided by Company.

7.1.2.1 Additional notice will not be provided when Customer makes payments to -avoid/stop non-payment disconnection with a dishonored payment. Prior to reconnection of service, repayment of those funds and all other delinquent amounts will be required in cash, money order, or certified funds.

7.1.2.2 Additonal notice will not be provided when Customer pays to reconnect service with a dishonored payment. Prior to reconnection of service, payment of those funds and all other delinquent amounts will be required in cash, money order or certified funds.

7.1.3 The Ceustomer's breach of a written contract for service.

7.1.4 Failure of the Ceustomer to comply with Company's deposit requirements.

7.1.5 Failure of the Ceustomer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior Ceustomer to pay a Ddelinquent Bbill for utility services where the prior Ceustomer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or Eeasements necessary to serve the Ceustomer.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any Ceustomer without advance notice under any of the following conditions:

7.2.1 Company observes, or has evidence of, a hazard to the health or safety of persons or property.

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7.2.2 Company has evidence of M~~m~~eter T~~t~~ampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the C~~c~~ustomer to comply with the curtailment procedures imposed by Company during a supply shortage.

~~7.2.5 Customer made payments to avoid/stop non-payment disconnection with a dishonored payment. Prior to reconnection of service, repayment of those funds and all other delinquent amounts will be required in cash, money order, or certified funds.~~

~~7.2.6 Customer paid to reconnect service with a dishonored payment. Prior to reconnection of service, payment of those funds and all other delinquent amounts will be required in cash, money order or certified funds.~~

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the C~~c~~ustomer, and Company shall be under no further obligation to serve the C~~c~~ustomer.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the C~~c~~ustomer and Company, but no assignments by the C~~c~~ustomer shall be effective until the C~~c~~ustomer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

This Schedule sets forth the conditions under which the company may offer incentives to potential new commercial or industrial customers or to adding new load. The purpose of this Schedule is to reduce average system costs by increasing sales beyond otherwise obtainable levels at prices that, though lower than standard rates, will recover all variable costs and contribute to fixed costs.

1. Availability

   1.1 To new loads increased existing loads that meet the eligibility criteria.
   1.2 Limited to the lesser of 100 MW of new and additional load or 50 new customers.

2. Eligibility Criteria

To determine if a customer is eligible for incentive the following criteria will be evaluated:

2.1 Consideration of Alternative Locations- Incentives are available only to customers who have not located or expanded in the Company's service area prior to the Commission's review of the application and who would not locate or expand in the Company's service area in the absence of the incentive. Customer must provide the Company with evidence of consideration of locations outside of the Company's service area. This evidence must consist of written documentation, including but not limited to detailed quantitative analyses of location factors for alternative sites performed by the customer and/or consultants. The Company will use this information to determine whether the customer would reasonably locate elsewhere in the absence of the incentive and, accordingly, meets this eligibility criterion.

2.2 Effects on Competitors- Incentives are available only when other customers in the same line of business and market are not adversely impacted by the discounted rates. The customer must provide a detailed description of goods and services the customer produces, the technology employed, and the market(s) the customer serves. Based on this information and knowledge of its customer base, the Company must reasonably verify that this criterion is satisfied.

2.3 Sizes of the Load- Eligible loads are new customers of 1,000 kW or current customers adding at least 500 kW. The customer's loads include power purchased from APS and power generated by the customer using congeneration or small power production methods.

2.4 Annual Load Factor- 55% or greater, unless the customer meets the off-peak, seasonal, or interruptible criteria.

2.5 Off-Peak Operation- If daily off-peak kWh (based on all remaining hours excluding 11:00 am.-9:00 pm Monday through Friday) is greater than 50% of total kWh, the load factor criterion may be waived.

2.6 Seasonality- Loads that do not operate in the summer months of June through September will be given special consideration in the evaluation of the suitable incentive.

2.7 Interruptibility- If the new load or added load is interruptible and the customer's peak load is at least 3,000 kW, the load factor criterion may be waived.

2.8 Permanency-The Company reserves the right to waive any eligibility criteria other than 2.1 or 2.1 to any potential load that will leave the Company's service territory by xxxxxxx

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

2.9 Economic Feasibility- The load must be economic, based on the Company's extension policy using standard rates.

2.10 External Economic Benefits- To be Eligible for the Plan, a potential load must bring a significant number of jobs and/or ancillary business into Arizona. In conjunction with this criterion, capital investment by the customer mat also be considered.

2.11 Significance of Electric Bill- The Company will give particular attention to customers whose electric bills exceed 5% of their operating expenses.

2.12 Other Considerations- The customer must furnish the Company with all requested information so that its eligibility can be evaluated and so that the Company can complete a Customer Characteristics Report. Any customer-provided information that the Company furnishes to the Commission Staff on a confidential basis, will be returned to the Company within 60 days of the Company's filings of the application.

2.13 Energy Efficiency- The customer will be assisted by APS and Commission Staff in considering and employing state of the art, cost effective energy conservation measures at its facility. These measures may include efficiency motors and motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.

2.14 Absence of Conflicts-of Interest - The Commission believes that in Lieu of requiring APS to submit information on the customer's officer and their relationship with APS and its affiliates to limit conflicts of interest, APS will be required to submit an affidavit on this subject. The affidavit should state that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has or had any interest, direct or indirect, with any entity which has provided substantial services, including real estate broker serives, to such customer in connection with its proposed Schedule 9 Agreement with APS. Further, the affidavit should state that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has or had any direct or indirect interest in any property owned in whole or part by the customer.

If the affidavit provided by APS is inaccurate, the Commission shall impute as revenue in APS' rate cases the difference between the discounted rate and the tariffed rate which would otherwise apply to the customer for the period during which the discount was effect.

3. Rate Provisions

3.1 The Qualifying Customer Remains on the Otherwise Applicable Rate Schedule- The customer satisfying the eligibility and customer criteria may receive a discount, which may vary over the term of the contract, from his otherwise applicable base bill (excluding taxes and adjustments), but in no case will the discounted energy charges be below the Company's marginal cost. For current customers adding load, the discount will apply only to the added load.
Example: A qualified customer may receive a discount of 20% from its base bill in years one and two, 15% in years three and four and no discount in year five.

3.2 Time Limitation- The rate benefits will be limited to a specific period of five years or less.

3.3 Minimum Bill- Customer will receive no discount from the minimum bill as computed under the otherwise applicable rate.

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

3.4 Applicable Percent Discount and Period of Application- The specific discount and the period over which the discount is applied shall be determined after full evaluation by the Company. The specific discount will not result in energy charges below the Company's marginal cost.

4. Contracts

A contract will be signed with each qualifying customer to guarantee adherence to the customer criteria, specifying the incentives, and specifying other pertinent terms where different from Company's Standard Terms and Conditions, Service Schedule 1. Unless otherwise acted upon by the Commission, each contract filed with the Commission shall be deemed approved 30 days after filing.

Each contract must be accompanied by a Customer Characteristic Report. The following information must be included in the Customer Characteristics Report:

4.1 General Information
- 4.1.1 Customer name
- 4.1.2 Customer contact—name and address
- 4.1.3 Dates of customer application and Company decision
- 4.1.4 New or existing customer
- 4.1.5 Proposed effective date of contract

4.2 Location Decision
- 4.2.1 Customer name
- 4.2.2 Description of other locations considered
- 4.2.3 Other locations of customer's operations
- 4.2.4 An affidavit from customer demonstrating that the customer would not locate or expand in Arizona absent the discounts
- 4.2.5 Within ninety (90) days of approval of any contract under this Schedule, the customer must supply written documentation and analyses substantiating the affidavit provided under 4.2.4
- 4.2.6 If the requirements of 4.2.5 are not met within ninety (90) days of approval of the contract, the contract shall be void.
- 4.2.7 Proportion of customer's production and distribution expenses accounted for by electricity, by natural gas and by other energy sources (specify)

4.3 Effects on Competitors
- 4.3.1 Nature of business—description and North American Industry Classification System (NAICS) code
- 4.3.2 Customer location
- 4.3.3 Number of other customers in same business
- 4.3.4 Market area served by customer
- 4.3.5 Description of effects on other customers

4.4 Load Characteristics
- 4.4.1 Size of load
- 4.4.2 Annual load factor
- 4.4.3 Off-peak operation
- 4.4.4 Description of daily load shape
- 4.4.5 Seasonality
- 4.4.6 Interruptibility
- 4.4.7 Permanency of load

SERVICE SCHEDULE 9
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4.5 Energy Service Mix
- 4.5.1 Use of natural gas and other energy sources
- 4.5.2 Description of energy efficiency measures—building design, processing and other
- 4.5.3 Feasibility of cogeneration

4.6 Rates
- 4.6.1 Applicable rate schedule
- 4.6.2 Years discount in effect
- 4.6.3 Percentage discount by year
- 4.6.4 Estimated annual revenues
- 4.6.5 Estimated annual incremental electricity production costs

4.7 Special Contract Provisions
- 4.7.1 List of special provisions
- 4.7.2 Reasons for special provisions

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Proposed Rates
Includes PSA and RES Impacts

Residential (Average - All Rates)	Current Annual Average Monthly Bill (1)	Proposed Annual Average Monthly Bill (1,2)	Current Summer Monthly Bill	Proposed Summer Monthly Bill	Current Winter Monthly Bill	Proposed Winter Monthly Bill
Average kWh per Month	1,100	1,100	1,337	1,337	863	863
Base Rates	$ 123.90	$ 128.80	$ 161.07	$ 167.11	$ 86.72	$ 90.48
PSA- Forward Component	(2.91)	(0.02)	(3.53)	(0.02)	(2.28)	(0.01)
PSA - Historical Component	(3.32)	(0.51)	(4.03)	(0.62)	(2.60)	(0.40)
TCA	2.36	2.36	2.87	2.87	1.85	1.85
EIS	0.18	-	0.21	-	0.14	-
RES	4.05	1.99	4.05	1.99	4.05	1.99
DSMAC	2.99	2.99	3.63	3.63	2.34	2.34
Total	$ 127.25	$ 135.61	$ 164.27	$ 174.96	$ 90.22	$ 96.25
Bill Impact		**$ 8.36**		$ 10.69		$ 6.03
Percent Bill Impact		**6.57%**				

Residential (Rate E-12)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (1,2)	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	691	691	780	780	602	602
Base Rates	$ 86.40	$ 89.31	$ 108.04	$ 110.94	$ 64.76	$ 67.67
PSA- Forward Component	(1.83)	(0.01)	(2.06)	(0.01)	(1.59)	(0.01)
PSA - Historical Component	(2.09)	(0.32)	(2.35)	(0.36)	(1.82)	(0.28)
TCA	1.48	1.48	1.67	1.67	1.29	1.29
EIS	0.11	-	0.12	-	0.10	-
RES	4.05	1.99	4.05	1.99	4.05	1.99
DSMAC	1.88	1.88	2.12	2.12	1.64	1.64
Total	$ 90.00	$ 94.33	$ 111.59	$ 116.35	$ 68.43	$ 72.30
Bill Impact		**$ 4.33**		$ 4.76		$ 3.87
Percent Bill Impact		**4.81%**				

Commercial (Rate E-32, 0-20 kW)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (1,2)	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,430	1,430	1,575	1,575.00	1,285	1,285
Base Rates	$ 202.30	$ 206.85	$ 232.85	239.53	$ 171.75	$ 174.16
PSA- Forward Component	(3.78)	(0.02)	(4.16)	(0.02)	(3.39)	(0.02)
PSA - Historical Component	(4.32)	(0.66)	(4.75)	(0.73)	(3.88)	(0.59)
TCA	2.29	2.29	2.52	2.52	2.06	2.06
EIS	0.23	-	0.25	-	0.21	-
RES	14.49	7.12	15.96	7.84	13.02	6.39
DSMAC	3.89	3.89	4.28	4.28	3.49	3.49
Total	$ 215.10	$ 219.47	$ 246.95	$ 253.42	$ 183.26	$ 185.49
Bill Impact		**$ 4.37**		$ 6.47		$ 2.23
Percent Bill Impact		**2.03%**				

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Proposed Rates
Includes PSA and RES Impacts

Commercial (Rate E-32, > 20 kW)	Current Annual Average Monthly Bill (1)	Proposed Annual Average Monthly Bill (1,2)	Current Summer Monthly Bill	Proposed Summer Monthly Bill	Current Winter Monthly Bill	Proposed Winter Monthly Bill
Average kWh per Month	62,238	62,238	68,381	68,381	56,094	56,094
Base Rates	$ 5,977.26	$ 6,142.98	$ 7,044.20	7,304.50	$ 4,910.31	$ 4,981.45
PSA- Forward Component	(164.43)	(0.88)	(180.66)	(0.96)	(148.20)	(0.79)
PSA - Historical Component	(187.71)	(28.69)	(206.24)	(31.52)	(169.18)	(25.86)
TCA	144.81	144.81	155.06	155.06	134.55	134.55
EIS	9.96	-	10.94	-	8.98	-
RES	150.53	73.92	150.53	73.92	150.53	73.92
DSMAC	189.52	189.52	202.94	202.94	176.09	176.09
Total	$ 6,119.94	$ 6,521.66	$ 7,176.77	$ 7,703.94	$ 5,063.08	$ 5,339.36
Bill Impact		**$ 401.72**		$ 527.17		$ 276.28
Percent Bill Impact		**6.56%**				

Industrial (Rate E34/35)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (1,2)	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	3,581,412	3,581,412	3,729,201	3,729,201	3,433,622	3,433,622
Base Rates	$ 249,125.86	$ 257,184.98	$ 259,882.57	$ 273,343.82	$ 238,369.15	$ 241,026.14
PSA- Forward Component	(9,462.09)	(50.14)	(9,852.55)	(52.21)	(9,071.63)	(48.07)
PSA - Historical Component	(10,801.54)	(1,651.03)	(11,247.27)	(1,719.16)	(10,355.80)	(1,582.90)
TCA	1,710.44	1,710.44	1,804.19	1,804.19	1,616.68	1,616.68
EIS	573.03	-	596.67	-	549.38	-
RES	451.60	221.77	451.60	221.77	451.60	221.77
DSMAC	6,395.98	6,395.98	6,746.57	6,746.57	6,045.38	6,045.38
Total	$ 237,993.28	$ 263,812.00	$ 248,381.78	$ 280,344.98	$ 227,604.76	$ 247,279.00
Bill Impact		**$ 25,818.72**		$ 31,963.20		$ 19,674.24
Percent Bill Impact		**10.85%**				

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels in effect as of March 1, 2011.
(2) Bill includes impact of proposed revised General Rate Case charges, and PSA and RES surchages reset with implemetation of new rates

RATE RIDER IRR
EXTRA LARGE GENERAL SERVICE
INTERRUPTIBLE RIDER

AVAILABILITY

This rate schedule is available in territory served by the Company and at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers located in Metro Phoenix and City of Yuma service areas where the Peak Solutions Program is available are not eligible for this rate until January 1, 2015.

APPLICATION

This rate schedule is applicable to retail Standard Offer customers served on Schedules E-34 and E-35. All provisions of the customer's applicable retail rate schedule shall continue to apply in addition to the provisions of Schedule IRR.

Customer cannot participate in Schedule IRR in conjunction with other demand response programs and rates such as Peak Event Pricing (CPP-GS), Peak Solutions, Power Partners, and other demand response programs and rates that may be offered from time to time.

Participation under this schedule is subject to: the availability of required metering and communication equipment compatible with the customer's applicable retail rate schedule and electrical service configuration; completion of the necessary enhancements to the Company's billing system; and availability of the necessary load data to establish the Baseline Load.

DEFINITIONS

Program Year – The calendar year in which the customer is subject to, and compensated for, an Event.

Event - A request by APS for customers to interrupt their load due to high loads, system emergencies, and high wholesale capacity or energy prices, as determined by the Company.

Firm Service Level -The level of demand (kW) to which the customer agrees to reduce their load for each hour of an Event, as specified in the Interruptible Contract.

Baseline Load – The hourly load (kW) during an Event that would have occurred without the interruption.

Actual Interrupted Demand – The average kW that the customer reduces during all event hours in the Program Year.

Required Interrupted Demand – The average kW that the customer is obligated to reduce during all event hours in the program year.

Shortfall Demand – The average kW that the customer fails to reduce to the Firm Service Level during all event hours in the Program Year.

Actual Interrupted Energy – The energy (kWh) that the customer reduces during all event hours in the Program Year.

RATE RIDER IRR
EXTRA LARGE GENERAL SERVICE
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LOAD INTERRUPTION

Events can be called by APS due to high loads, system emergencies, and high wholesale capacity or energy prices. When APS notifies the customer of an Event, the customer shall reduce their load to the Firm Service Level for each hour of the Event. The customer is responsible for reducing load and shall not use back-up generation to achieve the required load reduction.

CUSTOMER ENROLLMENT AND CONFIRMATION

Customer enrollment shall occur during the open enrollment period, which is October 1 through December 31 prior to the next Program Year. For the first year of the program, enrollment may occur up to April 1 of the Program Year, if necessary, due to timing of initial approval of the Schedule IRR by the Arizona Corporation Commission.

During enrollment, customer shall choose program options, set the Firm Service Level, demonstrate the ability to curtail load by at least 500 kW, and execute an Interruptible Contract.

Each year during the open enrollment period the customer may reset their Firm Service Level, change program options, or discontinue participation in the schedule.

Customer may reset the Firm Service Level by April 1 of the Program Year, if necessary, due to a significant change in their expected load or business situation.

INTERRUPTIBLE HOURS AND OPTIONS

Events shall occur June through September, all days of the week including Holidays, from 12 noon to 8 p.m.

Customer shall choose the maximum number of Events and hours per Event per Program Year from the following choices:

Option	Max Hours per Event	Max Number of Events	Max Interruptible Hours
1	4	20	80
2	8	10	80

APS shall not call more than one interruption event per day. APS shall call at least 2 events per year.

EVENT NOTIFICATION

APS shall notify customer of an Event by email, cell phone, land line, text message or pager. Customer shall choose either a 30-minute or 2-hour notice. Customer is responsible for receiving notification and shall acknowledge receipt of notification to APS within 15 minutes.

BILLING DETERMINANTS

Baseline Load shall be calculated using hourly metered load (kW) data for the highest three load days out of the previous ten non-Event days and metered load data for the hours just prior to the interruption, as calculated by APS. The highest three load days shall be determined from the average kW for the Event hours. The Baseline Load shall not be less than the actual metered load or the Firm Service Level for any Event hour.

RATE RIDER IRR
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BILLING DETERMINANTS (cont)

Required Interrupted Demand shall be derived by subtracting the Firm Service Level (kW) from the Baseline Load (kW) for each Event hour and then averaged over all event hours for the Program Year.

Actual Interrupted Demand shall be derived by subtracting the metered load (kW) from the Baseline Load (kW) for each Event hour and then averaged over all Event hours for the Program Year. Load reductions below the Firm Service Level shall not be included in this calculation.

Shortfall Demand shall be derived by subtracting the Actual Interrupted Demand from the Required Interrupted Demand. This amount shall not be less than zero.

Actual Interrupted Energy shall be equal to the Actual Interrupted Demand multiplied by the total event hours during the Program Year.

All billing determinants shall be rounded to the nearest whole unit.

CREDITS

The customer shall receive a capacity and energy credit for reducing hourly usage during all event hours. The capacity credit shall be derived by multiplying the Actual Interrupted Demand by the applicable capacity credit rate. The energy credit shall be derived by multiplying the Actual Interrupted Energy by the applicable energy credit rate.

The credits shall be issued once a year in November billing cycles through a direct payment or a bill credit, at APS's option.

The credit rates shall be revised from time to time, as approved by the Arizona Corporation Commission, but shall not change during the Program Year.

All customers participating in a five-year agreement will be subject to the revised credit rates for the Program Year, regardless of the number of years remaining on their contract.

1 Year Agreement Credit Rate:

	30 Minute Notice		2-Hour Notice	
Option	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$7.975	$0.09969	$7.178	$0.08972
2	$5.995	$0.07493	$5.395	$0.06745

5 Year Agreement Credit Rate:

	30 Minute Notice		2-Hour Notice	
Option	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$9.882	$0.12353	$8.894	$0.11117
2	$7.428	$0.09285	$6.685	$0.08356

RATE RIDER IRR
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PENALTIES

For any Event Year, if the Average Shortfall Demand is greater than 5% and less than or equal to 10% of the Required Interrupted Demand, the customer will receive 50% of their capacity credit. If the Average Shortfall Demand exceeds 10% of the Required Interrupted Demand, the customer will not receive a capacity credit. In either case, the customer will continue to receive 100% of their energy credit. The penalty shall not apply to the first Event of the customer's first Program Year on Schedule IRR.

If the customer terminates participation prior to the contract term in a five-year agreement, they shall pay the Company a penalty equal to the relevant Capacity Credit rate times the Required Interrupted Demand from the most recent Event Year (with a minimum of 500 kW) times the number of years remaining on the agreement. The total penalty shall be assessed at the time of termination.

In addition, if a customer terminates participation prior to the contract term in a one-year or a five-year agreement, they shall not be allowed to participate in the rate for the two subsequent years.

ESTIMATION OF MISSING DATA

If at least 50% of the hourly metered load data is available for an Event, any missing hourly kW values shall be estimated by the average of the available hourly data for that Event. If less than 50% is available, the missing hourly kW values will be estimated at the Firm Service Level.

METERING

Customer shall be served with interval metering equipment necessary to record and communicate hourly (or partial hour) load data. APS shall provide and install the metering and communication equipment at no additional cost to the customer and shall pay any ongoing cell phone or other communication costs, if applicable.

TERMS AND CONDITIONS

Service under this rate schedule is subject to APS's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a service agreement.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 11, column 33
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Annualize Customer Levels
Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2010.

Line No.	Description		Total Company Amount
	Revenues		
1.	Operating Revenue		$ (290)
2.	Adjustment to sales (MWh) for the difference between customer annualized sales and actual sales	7,544	
	Expenses		
2.	Fuel and Purchased Power Expenses:		
3.	Adjustment to Sales (MWh)	7,544	
4.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.3486	
5.	Proforma Adjustment to Fuel and Purchased Power Expenses		253
6.	Operating Revenues Less Fuel and Purchased Power Expenses		$ (543)
7.	**Operating Income (before income tax)**		**$ (543)**
8.	Current Income Tax Rate - 39.51%		(215)
9.	**Operating Income After Tax**		**$ (328)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 12, column 33
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Low Income Customer Discount**
Adjustment to Test Year operations to reflect the increase in low income customer discounts from the Teat Year through July 2012.

Line No.	Description	Total Company Amount
	Revenues	
1.	Revenues in Base Rates	$ (4,179)
2.	Surcharge Revenue	-
3.	Other Electric Revenue	-
4.	Total Electric Operating Revenues	$ (4,179)
5.	**Other Operating Expenses**	
6.	Electric fuel and purchased power	$ -
7.	Operations and maintenance excluding fuel expenses	-
8.	Depreciation and amortization	-
9,	Income taxes	-
10.	Other taxes	-
11.	Total Operating Expenses	$ -
12.	**Operating Income (before income tax)**	**$ (4,179)**
13.	Current Income Tax Rate - 39.51%	(1,651)
14.	**Operating Income After Tax**	**$ (2,528)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 11, column 32
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: Normalize Weather Conditions
Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2010.

Line No.	Description			Total Company Amount
	Revenues			
1.	Operating Revenue		$	10,330
2.	Adjustment to sales (MWh) for the difference between customer annualized sales and actual sales	116,749		
	Expenses			
2.	Fuel and Purchased Power Expenses:			
3.	Adjustment to Sales (MWh)	116,749		
4.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.3486		
5.	Proforma Adjustment to Fuel and Purchased Power Expenses			3,909
6.	Operating Revenues Less Fuel and Purchased Power Expenses		$	6,421
7.	**Operating Income (before income tax)**		**$**	**6,421**
8.	Current Income Tax Rate - 39.51%			2,537
9.	**Operating Income After Tax**		**$**	**3,884**