0000170848

Arizona Public Service Company

Rate Application

E-01345A-16-0036

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DIRECT TESTIMONY OF DANIEL T. FROETSCHER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF DANIEL T. FROETSCHER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

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

A. My name is Daniel T. Froetscher. My business address is 400 North 5th Street, Phoenix, Arizona 85004. I am Senior Vice President of Transmission, Distribution and Customer Service for Arizona Public Service Company (APS or Company).

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. 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 became Vice President of Energy Delivery in October 2008 and assumed my current role in February, 2014.

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

A. My testimony introduces APS, and the role the Company plays in Arizona's communities. I describe the core principles driving APS, and the context behind this rate Application. My testimony concludes with a high-level discussion of what APS seeks with this filing, and how the requested relief will help APS build a bridge to a future of clean, sustainable energy in Arizona.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My direct testimony begins by describing APS, Arizona's largest and longest-serving electric utility, an employer of choice, and the state's largest taxpayer. APS plays a

significant role in sustaining Arizona's vibrant communities. Doing so requires that the Company stays committed to its core mission — safely and efficiently delivering reliable electricity to meet the changing needs of our customers.

I next describe the large number of significant changes occurring within the electric industry, including:

- Changes to and expansion of federal environmental policies;
- A rapid increase in the amount of deployed renewable energy;
- Dramatic changes to how electric grids and generation portfolios must be operated;
- Historically low natural gas prices;
- New regional market opportunities; and
- Rapidly evolving interests and opportunities for customers related to distributed and load management technologies.

Despite pressures imposed by these myriad changes, APS remains optimistic and committed to its core principles of safe, reliable, and affordable electricity for our customers while focusing on a sustainable energy future.

I conclude by describing what APS requires to continue delivering the high level of service our customers have come to know and expect. To fulfill its core mission in the next phase of the electric industry, APS must create and sustain a flexible distribution grid that enables customer choice and distributed technologies. This includes everything from a robust communication infrastructure to fast-ramping natural gas turbines that can supplement intermittent supply provided by renewable resources, such as solar and wind. To make this possible, APS needs the Commission's support, including approval of new rates that permit healthy and stable financial strength, a reasonable return on investments made for the benefit of customers, and modernized regulatory policies and

rate structures that incentivize all forms of technology and produce equitable results for APS's entire customer base. APS's rate Application lays out a sustainable path for clean energy and distributed technologies. Approval of APS's rate Application is critical for the Company to accomplish its pursuit of clean energy, customer choice, innovation, and sustainability — all of which are essential to building a bridge to the future for Arizona and the region.

III. APS'S ROLE IN ARIZONA'S ECONOMY

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF APS.

A. APS is Arizona's largest and longest-serving electric utility, delivering electricity to Arizona's growing population since 1886. APS has approximately 6,300 employees and is an employer of choice in Arizona. Today, APS serves more than 1.2 million retail and wholesale customers in all or part of 11 of Arizona's 15 counties — a service territory of approximately 35,000 square miles. APS owns more than 35,000 miles of transmission and distribution lines and underground cable to deliver energy to our customers. We also co-own and operate the Palo Verde Nuclear Generating Station (Palo Verde), a primary source of electricity for the Southwest and the largest nuclear generation facility in the United States, as well as two coal-fired plants and six natural gas plants. Currently, APS generates approximately 11% of its electricity from more than 1,200 MW of renewable resources, a number we expect to grow to at least 15% by 2025. In total, 47% of the electricity we provide to our customers comes from carbon free resource.

Q. WHAT ECONOMIC IMPACT DOES APS HAVE ON ARIZONA?

A. APS plays a significant role in Arizona's economy. With an extensive network of power plants, transmission and distribution lines, customer offices and support facilities, APS is the largest property taxpayer in the State by a significant margin, contributing approximately $175 million of property tax in 2015. This amount almost doubles the in-

lieu-of tax payment of Salt River Project, Arizona's second largest taxpayer. Last year, the Company purchased from more than 6,000 Arizona suppliers and spent approximately $620 million on goods and services offered by Arizona businesses.

In addition, APS is among the largest construction companies in the state. To provide reliable electric service and plan for the future, APS must construct extensive electric infrastructure. In 2015, APS's capital expenditures were $1.1 billion, and in 2016 that number is projected to reach approximately $1.2 billion. APS's construction programs require goods, materials, and labor sourced from Arizona, which infuse millions of dollars into Arizona's economy.

And APS generates more jobs than most other Arizona corporations. APS employs almost 6,300 Arizonans, including nearly 1,200 veterans, and directly creates jobs for thousands of contractors and vendors, and indirectly creates tens of thousands of additional jobs throughout the State. Roughly 2,000 of APS's employees and contractors are members of local unions. We are also one of the few S&P 500 companies headquartered in Arizona.

Q. WHAT DOES APS VIEW AS ITS CORE RESPONSIBILITIES?

A. APS's overarching vision is "Creating a Sustainable Energy Future for Arizona." From the perspective of day-to-day operations, APS's Mission Statement focuses on our customers: "We safely and efficiently deliver reliable energy to meet the changing needs of our customers." This responsibility extends to current and future customers. Everything APS does is focused on fulfilling this responsibility, and our performance shows it. In 2015, APS performed in the top decile for reliability and top quartile for customer satisfaction. Securing positions in both of these elite groups took a significant amount of resources, both in terms of man power and capital. Yet, APS did so while

managing its costs. In fact, since its last rate case, APS has kept O&M increases to below inflation.

Q. HOW HAS APS ACHIEVED TOP DECILE RANKINGS IN RELIABILITY AND TOP QUARTILE RANKINGS FOR CUSTOMER SATISFACTION WHILE KEEPING O&M INCREASES BELOW INFLATION?

A. APS has aggressively managed costs since its last rate case through the hard work of its employees and the thoughtful application of a rigorous cost management framework. In connection with wrapping up APS's last rate case, APS undertook a Sustainable Cost Management Initiative. This initiative set a framework for driving cost-efficient and performance improvement decisions over the long term. It helped establish business targets and tiered metrics that began at the enterprise-level and cascaded throughout the Company. The Initiative established mechanisms for identifying and closing gaps between current metric performance and target performance through business planning processes. APS also instituted a Corporate Resource Operating Model to maintain clear responsibilities for services across business units, and eliminated both low-value and duplicated services. Finally, APS's cost management effort included a rigorous process for prioritizing capital investment decisions to effectively and efficiently balance the needs of prudent business area operations for system replacement and improvements against fiscal constraints.

The entire process has been driven by accountability and the efficient allocation of resources. APS takes seriously its responsibility to carefully manage its operations in a prudent, efficient, and effective manner. As a result of this corporate-wide effort after the last rate case, APS has kept O&M cost increases, measured on a per kWh basis, to below 1% per year, a rate that is below annual inflation.

Q. HOW DOES APS VIEW ITS CORE RESPONSIBILITIES IN LIGHT OF THE RAPIDLY CHANGING ELECTRIC INDUSTRY?

A. The significant changes occurring in the industry won't alter the fundamental components of APS's mission, although those changes will affect how APS fulfills its mission. It is not by accident that the terms "safety, efficiency and reliable" are found within the Company's Mission Statement. These elements of our Strategic Framework, also known as our "Core," emphasize our fundamental responsibilities. The safety of our personnel and the public is a priority, with APS ranking within the top decile in our industry in multiple safety-related measures in the past several years. Similarly, APS's reliability performance, as measured across peer groups within the industry by the Electric Energy Institute (EEI), has also been in the top quartile. As noted earlier, our Customer Satisfaction performance has ranked within the top quartile of peer utilities. And as discussed by APS witness John Lucas, the Company has taken great strides to protect the environment in its field and power plant operations. Finally, efficiency and cost management are integral to APS. As discussed above, the Company has managed its O&M expenses at less than the rate of inflation since its last rate case. By effectively managing its costs, APS is able to keep rate pressure low for the benefit of our customers.

The need to safely, efficiently, and reliably supply electricity to our customers will not change. But it is also not by accident that the phrases "Sustainable Energy Future" and "Changing needs of our customers" are embedded within our Vision and Mission statements. The electric utility industry has faced significant changes from a policy-making, regulatory, societal, technology and customer standpoint—and the impacts of these factors and APS's response to them is at the heart of the proposals outlined in this proceeding.

Q. WHAT CHANGES ARE OCCURING IN THE ELECTRIC UTILITY INDUSTRY?

A. The industry is seeing a large number of significant changes that impact several different areas and dimensions of APS's business. These include:

- Environmental policy changes, such as the Clean Power Plan (CPP);
- Low natural gas prices;
- Federal and state policies that subsidize renewable energy, and the resulting significant influx of intermittent renewable generation on the grid, both grid-scale solar at the regional transmission level and rooftop solar at the local distribution level;
- Emerging market opportunities, such as the increasingly broad-based western Energy Imbalance Market; and
- The possibilities of technological innovation that will change how and when customers use electricity.

Q. PLEASE DESCRIBE THE ENVIRONMENTAL POLICIES AND HOW THOSE ARE CHANGING THE ELECTRIC UTILITY INDUSTRY.

A. In Arizona, environmental regulations have resulted in APS shuttering three of its units at the Four Corners Power Plant and one unit at its Cholla Power Plant, while at the same time requiring the investment of over $400 million dollars to install selective catalytic reduction (SCR) technology at Four Corners.[1]

Regarding prospective policies impacting the electric utility industry, the CPP, is a primary example. As contemplated, the CPP will place increasingly strict mandates on utilities as it relates to emissions from traditional fossil fuels, most notably coal

[1] APS witness John Lucas discusses APS's need to install SCRs in greater detail.

generation. The CPP could potentially cause sweeping changes across the industry. Although the CPP's future is uncertain as a result of action taken by the United States Supreme Court, utilities must still prepare for what may come. If coal units are to remain in play over the next 10 to 20 years, significant investment in pollution controls will be necessary, and they will be expensive.

Q. ASIDE FROM ENVIRONMENTAL POLICIES, WHAT OTHER MACRO-LEVEL INDUSTRY SHIFTS ARE CHANGING HOW APS MUST DO BUSINESS?

A. In a phrase: low natural gas prices. The utility industry has seen historically low natural gas prices for several years, and the outlook is that prices will remain low for the foreseeable future. Low natural gas prices affect several aspects of APS's business, from avoided cost calculations to resource planning. As an example, I will describe the impact of low natural gas prices on APS's coal fleet.

Low natural gas prices are making coal less cost competitive. Coupled with the environmental regulations referenced above, the economics of coal units, and particularly of smaller coal units like APS's Cholla Power Plant, are becoming increasingly challenged. In terms of operational viability, low natural gas prices affect coal in both short and long-term ways. The short-term effect stems from fuel switching. When natural gas prices are lower than coal prices, it is less expensive to dispatch natural gas, leaving the coal plant idle or at a reduced output. The long-term effect is related to capacity replacement. With forecasts for continued low natural gas prices and increasing environmental costs for coal plants, the tendency is to replace aging coal fleets with natural gas generation. Consistent with these changing market dynamics, APS retired Cholla Unit 2 on October 1, 2015, and plans to no longer burn coal in Cholla Units 1 and 3 beyond 2025. Going forward, APS continues to consider the

economics of its coal fleet and the critical importance of fuel diversity as it evaluates the best overall resource strategy for the benefit of its customers.

Q. HOW HAVE FEDERAL AND STATE SUBSIDIES IMPACTED THE GROWTH OF RENEWABLE ENERGY?

A. On the grid-scale level, tax incentives have spurred investment in renewable energy. Federal legislation introduced several years ago, coupled with state mandates for certain levels of renewable generation, has changed the landscape of utility-scale electric generation. The Production Tax Credit (PTC) and Investment Tax Credit (ITC) have stimulated investment in renewable energy for years, and were recently extended to 2019 for the PTC and 2023 for the ITC. These tax subsidies have spurred investment in wind and photovoltaic technologies at the grid scale. In the 2010 Test Year used during APS's last rate case, its grid-scale generation portfolio totaled 190 MWs of wind generation and 5.6 MWs of grid-scale solar facilities. That same portfolio now includes 289 MWs of wind generation, 484 MWs of grid-scale solar generation, and 30 MWs of other, less prevalent renewable generation like geothermal.

These tax incentives, paired with rate-related subsidies, have also spurred the adoption of distributed renewable technologies. At the end of the 2010 Test Year, 58.3 MWs of distributed solar had been installed on APS's system. At the end of the 2015 Test Year, 560 MWs of distributed solar, measured on the basis of nameplate capacity, has been installed on residential and non-residential rooftops and premises over the past six years, reflecting 38,426 customers who have opted to generate some of their own electricity.

This rapid growth of renewable generation isn't limited to Arizona. Until recently, California's Renewable Portfolio Standard (RPS) has required jurisdictional utilities to obtain 33% of their energy from renewable sources by 2020. Recently, that requirement

was increased to 50% by the year 2030. Such policy-making will only further increase the interest and investment in distributed and grid-scale renewable generation in the southwest region. Given APS's interconnection with California, this increased investment will only exacerbate some of the operational challenges associated with integrating renewable energy.

Q. HOW HAVE CUSTOMERS BEEN IMPACTED BY THIS RAPID INCREASE IN THE AMOUNT OF RENEWABLE GENERATION?

A. Renewable generation plays a valuable part in a balanced resource portfolio. But the rapid investment in renewables has impacted customers. The most immediately tangible impact is increased rates. Although these regulatory and tax subsidies have stimulated the platform for investment in renewables, they haven't come without a price: renewable energy is an expensive form of generation, particularly because it does not supplant the costs that utilities must incur to meet their load-serving obligations. Additionally, the cost consequences of renewable generation are not limited solely to pure production costs at the utility level. The cost shift resulting from the 38,426 rooftop solar installations on APS's system has spurred a furious debate on the value of solar, and the best approach for addressing the higher rates that customers without rooftop solar pay as a result of volumetric rate design and net metering.

Q. PLEASE DESCRIBE THE OPERATIONAL CHALLENGES ASSOCIATED WITH THE RAPID INCREASE IN INTERMITTENT RENEWABLE GENERATION ON THE GRID.

A. Regarding operational challenges, the "price" associated with renewable generation extends beyond pure economics. Simply stated, renewable generation has significant challenges: it is not a 24 hour x seven days / week resource, nor can it be scheduled (one can't depend entirely upon the wind blowing or the sun shining around the clock), dispatched, or generally curtailed – especially at the distributed level. What's more, the

capacity value of solar generation is limited. Rooftop solar in particular, which is typically installed on fixed, south-facing arrays, offers a limited resource value to APS's portfolio. Operationally therefore, renewables are a resource that the hosting utility must accommodate, regardless of whether the resource is needed, is appropriately (geographically) located, fits the real-time needs of a dynamic system, or meaningfully contributes to long-term resource needs.

This presents some real operational challenges for the utility. At the distribution-level, residential rooftop solar installations have the capability of altering distribution voltage levels and stability. This is particularly true during low load timeframes within which residential rooftop solar may be over-producing and feeding the grid, power quality and voltage issues (high voltage) can emerge for **all** customers within a given area, not just the solar customer. The utility cannot arbitrarily curtail the production of distributed, customer-installed rooftop solar, and therefore is challenged with managing voltage and power quality through its own equipment and devices — system investments that otherwise may not be necessary.

Q. IN ADDITION TO GRID OPERATIONS, HOW HAS THIS RAPID INFLUX OF RENEWABLE ENERGY AFFECTED APS'S GENERATION AND RESOURCE PORTFOLIO MANAGEMENT?

A. As described by APS witness James Wilde, the significant increase of renewable generation, and solar in particular, is changing APS's load profile. Production from photovoltaic solar generation begins to decrease significantly as dusk approaches. Customer load, however, does not decrease in tandem. The result is that APS must "ramp up" flexible generation resources to continuing supplying customer needs without any gap. This phenomenon — a morning peak, followed by low load during the day, and then a sharp ramping of load on the system as the sun sets—is known as the duck curve. APS's experience during the peak hour of the Test Year—August 15, 2015, at 5 p.m. —

is telling. At that time, the aggregate demand of APS's customers was at its highest for the entire year. But the production of rooftop solar was a fraction of its nameplate capacity, and fell rapidly. To continue meeting customer needs without any interruption in service, APS quickly brought online additional resources to replace falling solar production.

Beyond the previously-described changes to grid operations, the prevalence of solar generation on the system is requiring utilities to ensure an adequate supply of flexible generation that can quickly inject significant amounts of supply onto the grid. The combustion turbines being built as part of the Ocotillo Modernization Project (OMP) provide the type of fast-ramping service need to manage the duck curve.

Q. ARE THERE OTHER WAYS THAT APS IS WORKING TO OPTIMIZE ITS GRID AND GENERATION OPERATIONS IN LIGHT OF THESE ONGOING, SIGNIFICANT CHANGES?

A. As the previously-described challenges become a larger part of energy operations, utilities are seeking regional solutions to maintain high levels of reliability at a reasonable cost. One example of this is APS's participation in the broad-based western Energy Imbalance Market (EIM). The EIM is designed to optimize generation dispatch across participants and add another layer of flexibility for participating utilities to manage their energy systems. APS witnesses Barbara Lockwood and James Wilde discuss the EIM in more detail, including the customer benefits that APS anticipates will occur as a result of APS's participation.

Q. YOU'VE DISCUSSED MANY OF THE POLICY, REGULATORY, AND OPERATIONAL ASPECTS OF THE CHANGES TO THE UTILITY INDUSTRY. WHAT CHANGES ARE CUSTOMERS MORE DIRECTLY EXPERIENCING?

A. Without question, improvements in technology efficiency and pricing have spurred an increasing desire on the part of the customer to explore these options. Customers want choices and a greater sense of independence and control regarding energy matters. Many also want to be socially responsible.

As we build a bridge to the future for Arizona and the region, APS's responsibility to provide safe and reliable electricity includes planning for the next generation of technology advancement and adapting to meet the customer's changing needs. APS customers' needs regarding electricity and the use of the grid are rapidly evolving with many installing various forms of distributed technologies that can change how those customers use and rely on the grid. Rooftop solar is only one example. Rooftop solar provides customers an opportunity to supply some of their own energy, and at times export surplus energy to the grid. The presence, however, of more than 38,426 rooftop "generators" dispersed across the electrical system changes how the grid may function.

Each rooftop solar installation has the potential to feed energy into the grid, reversing the flow of energy and potentially causing other ripple effects across the grid, such as stable power quality and voltage management. APS's current group of more than 38,426 rooftop solar customers is growing by approximately 1,300 new systems each month, with each altering both the grid and the nature of the service that APS supplies to rooftop and non-rooftop solar customers alike. APS supports customer adoption of cost-effective rooftop solar. Yet, the Company has a responsibility ensure the grid remains reliably available to serve both these customers when their rooftop system is not

producing, and all other customers regardless of how rooftop solar might change how the grid functions.

Beyond rooftop solar, technology developments like load controllers, smart thermostats and appliances, multi-stage HVAC units and pool pumps, electric vehicles and residential battery storage, and widely available energy efficiency measures afford customers greater control in how and when they use energy, and support and enable the rate re-design alternatives proposed by APS in this filing. Additionally, these are only the current state of distributed technology offerings. Further developments in the production, storage and management of energy by the customer is fully expected, placing greater demands and complexity on APS to ensure its system enables these technologies without sacrificing service reliability for all customers during all times of the day.

The rapidly evolving options for customers regarding distributed technologies pose a series of challenges (and opportunities) for the Company. APS's responsibility to its current and future customers must include transitioning the distribution grid to a flexible network that meets and facilitates customers' evolving needs and their adoption of technology. That means modernizing both the grid infrastructure and rate design.

Q. WHERE DO APS'S CORE RESPONSIBILITIES LAY IN LIGHT OF THESE IMMENSE INDUSTRY CHANGES?

A. Viewed from these perspectives, it can appear that almost every aspect of APS's business is changing. In addition, APS has experienced slow retail sales growth over the past five years since its last rate case. Slow growth coupled with outdated volumetric rate design has complicated the recovery of fixed costs needed to maintain and develop the grid and fulfill APS's responsibilities to its customers. Nevertheless, APS has a

sustained responsibility to continue supplying customers with reliable electric service at reasonable cost. The proposals set forth in this rate Application are designed to ensure that APS can continue fulfilling its core responsibilities even as the industry formation continues.

IV. APS'S VISION FOR ARIZONA'S ENERGY FUTURE

Q. PLEASE DESCRIBE APS'S VISION FOR THE FUTURE OF ENERGY IN ARIZONA.

A. APS's vision includes four aspects: clean energy, sustainability, innovation, and technological options for customers. APS has been a leader in promoting clean energy for years, and seeks to promote the thoughtful deployment of and investment in clean energy of all types. This involves encouraging innovation at all levels, not just how the grid is operated or generation evolves, but also innovative solutions for customers. APS envisions a flexible, dynamic distribution platform—a next-generation grid that enables technological solutions and options for customers and encourages distributed technologies and effective demand-side management. Woven through this need for clean energy, innovation, and customer options is the overall goal of sustainability.

Sustainability is more than a buzz word. It is a business strategy. APS's vision is a business strategy that seeks superior operating performance, efficiency, a healthy environment, a vibrant economy, and a strong community. The strategy is supported by modern rate designs and cost recovery that are fair to our customers and company. Ultimately, APS's vision promotes the long-term sustainability of electrical infrastructure upon which all rely for safe and reliable electric service.

Q. WHAT DOES APS SEE AS A SUSTAINABLE FUTURE FOR CLEAN ENERGY?

A. Part of APS's overall vision is ensuring that clean energy itself is sustainable. APS is pursuing a long-term business strategy that supports the adoption of cost-effective renewable energy by APS and its customers. Achieving this outcome will require updating physical facilities, refining operational practices, and modernizing regulatory policies.

Operationally, sustainable clean energy requires a flexible grid that can react to changing and other, unpredictable, conditions. This requires a robust communications backbone that provides a high degree of visibility into and control over grid devices, and allows for the effective and timely transmission of data — both to grid devices and to the customer premise.

Physically, sustainable clean energy requires infrastructure that readily integrates the unpredictable deployment and operating characteristics of distributed technologies. This includes a strong wires infrastructure and the use of distributed automation that can adapt to situations that did not occur under the traditional model, such as reverse power flow and dynamically changing voltage conditions. Sustainable clean energy also includes a reliable power supply that can, for instance, "ramp down" during the day when rooftop solar production is high and quickly "ramp up" as the sun sets and high customer demand continues.

From a regulatory perspective, sustainable clean energy requires a focus on cost-based pricing to encourage, rather than discourage, new technologies. For instance, all customers, with or without rooftop solar, rely on the grid for service. But APS's current volumetric rate design shifts costs to customers without rooftop solar with each new

rooftop system. The result is that these customers without rooftop solar will pay higher rates by absorbing a greater proportion of the fixed costs associated with planning, constructing, operating, and maintaining the underlying electrical grid and grid-scale generation resources.

This is an unsustainable rate design that must change for clean energy to benefit all customers long-term.

Q. WHAT HAS APS DONE TO ADVANCE ITS VISION OF SUSTAINABLE CLEAN ENERGY?

A. APS has pursued and is pursuing numerous projects designed to lay a foundation for the future of clean energy in Arizona. The recent renewal of Palo Verde's operating license ensures a significant supply of carbon-free energy for years into the future. Regarding grid-scale solar facilities, APS has a long history of robust investment and a current portfolio of nearly 500 MWs. The portfolio includes the Solana Generating Station, a parabolic trough solar facility with molten salt thermal energy storage, permitting APS to produce energy well past sunset. APS is currently engaged in several projects designed to promote sustainable clean energy. The following examples are described in more detail by APS witnesses Stacy Derstine, Scott Bordenkircher, and Jacob Tetlow, respectively:

- **Solar Partners Program**. Following Decision No. 74878, APS began deploying rooftop solar at strategic grid locations to offer solar to under-served customers and to study how rooftop solar and advanced inverters could be used to enhance grid management.

- **Solar Innovation Studies**. APS is studying how solar can be paired with various types of distributed technologies in a way that permits customers to efficiently manage their use of energy and demand.

- **Grid-Scale Solar Development**. In response to customer interest in expanding their green energy portfolio, APS is constructing utility-scale solar projects for two separate large customers.

- **Modernized Customer Information System**. APS is updating its outdated customer information system (CIS) platform to enable flexibility in responding to customer needs

- **Advanced Distribution Management System (ADMS)**. ADMS is an advanced operating platform that will permit greater visibility into and control over the distribution system. ADMS's communication infrastructure will not only improve system functionality, but also facilitate the integration of distributed technologies.

- **Microgrids.** APS is building two microgrid projects that involve creating small network systems that can be isolated from and run independently of the grid as needed for reliability or other operational purposes.

These are only a few examples of how APS is actively working towards a sustainable future for clean energy.

Q. WHAT OUTCOMES IS APS SEEKING TO MEET CUSTOMER NEEDS AND ACHIEVE ITS VISION?

A. Each component of this rate Application feeds into and is critical to achieve three overarching outcomes.

First, to continue supplying reliable power at reasonable prices, APS needs to be financially healthy and stable. This includes the approval of new rates that reflect APS's costs, and to reflect the investments APS has made on behalf of its customers since its last rate case. It also includes the orderly and prompt resolution of this rate case.

Second, to continue investing in the grid to make a sustainable future for clean energy a reality, APS requires a reasonable return on its invested capital. A reasonable return can send a positive message to investors that Arizona is a good state in which to invest capital, and encourage future investment.

Third, to achieve a sustainable path forward for all types of clean energy and developing technologies, the design of APS's rates must be modernized. The current structure of cross-subsidies does not promote the cost-effective development of distributed technologies, and raises serious questions about equity among customers.

Q. WHAT WITNESSES IS APS PRESENTING AS PART OF ITS DIRECT CASE?

A. APS filed direct testimony from the following witnesses:

Barbara D. Lockwood	Elements of rate case
John Lucas	Fossil generation operations and capital expenditures
John J. Cadogan, Jr.	Nuclear generation operations and capital expenditures
Jacob Tetlow	Distribution operations and capital expenditures
Stacy Derstine	Customer service and education; general and intangible plant
James C. Wilde	Resource Planning
Scott Bordenkircher	Renewables and Technology update

Peter M. Ewen	Base fuel cost and the Power Supply Adjustor and financial projections, weather normalization, and bond rating information
Dr. Bente Villadsen	Cost of equity and fair value rate of return
Leland R. Snook	Ocotillo deferral, EIS modification, LFCR/Decoupling proposals, Schedules A and G of the SFRs, COSS, "fair value" calculation, AG-1, and C-I rates
Dr. Ahmad Faruqui	Principles of Rate Design
Charles A. Miessner	Residential rate design and programs
Elizabeth Blankenship	Historical accounting information, rate base and income statement pro formas, Cholla 2 accounting, and adjustor transfers to base rates
Dr. Ronald E. White	Depreciation study

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. While APS and the electric utility industry face complex challenges, each represents an exciting opportunity. APS is committed to its mission of providing safe, reliable, and affordable electricity for its customers. To do so, the Company seeks to create a future environment that promotes the long-term health of clean energy, encourages new technologies, and offers customers many desirable options, but we aren't there yet.

The environment APS envisions requires both flexible infrastructure and sustainable regulatory policies. Since its last rate case, APS has made and continues to make significant investments in modernizing the grid. These investments are designed to provide the backbone for supporting those distributed technologies we know of, and those that have yet to be invented. At the same time, APS has been investing in the generation needed to continue supplying reliable power to its customers regardless of

how those customers' needs evolve. With this Application, we are asking the Commission to support APS's vision of a sustainable environment for clean energy, new technologies, and customer options. This support entails finding APS's investments to be prudent and ensuring that APS can maintain its financial strength and stability. We are also asking the Commission to modernize our rate structure to address inequities and reflect the importance of distributed technologies and customer options.

The plan reflected in this Application benefits APS customers, the state of Arizona and the region. We are committed to providing our customers with electricity that is safe, reliable, efficient and environmentally responsible. We believe the Commission shares these objectives and we urge the Commission to approve the requests made in this Application.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

DIRECT TESTIMONY OF BARBARA D. LOCKWOOD

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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Regulatory Requirements Elimination ..... Attachment BLD-2DR

DIRECT TESTIMONY OF BARBARA D. LOCKWOOD
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

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

A. My name is Barbara D. Lockwood. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Vice President of Regulation for Arizona Public Service Company (APS or Company). I have management responsibility for all matters before the Arizona Corporation Commission (Commission), as well as, the Federal Energy Regulatory Commission (FERC).

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My background and experience are set forth in Attachment BDL-1DR to this direct testimony.

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

A. I discuss the emerging challenges and opportunities that APS experienced in the five years since the Company last filed a general rate case, as well as the new challenges and opportunities APS and the Commission will face in the not-so-distant future. Next I provide an overview of the Company's rate request, including the request for rate modernization, and show how that request is essential if APS is to meet its long-term goal of providing a sustainable energy future for its customers and the state as a whole. I also discuss the need for relief from certain unnecessary and outdated regulatory requirements that needlessly consume the resources of both the Company and the Commission.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. I have appeared at numerous Commission Open Meetings and Workshops as well as testified in the Company's 2005 general rate case, Docket No. E-01345A-05-0816, APS's 2009 Settlement Rate Case, Docket No. E-01345A-08-0172, and in Docket No. E-20690A-09-0346 (Solar City adjudication of public service corporation status).

II. SUMMARY OF DIRECT TESTIMONY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. It has been five years since APS filed its last rate case using a 2010 Test Year. Since that Test Year, APS has made tremendous progress toward achieving the policy goals established by the Commission including implementation of energy efficiency programs that have resulted in 2,535,515 MWh of energy savings for our customers, or some 9.2%. APS has also experienced explosive growth with rooftop solar customers increasing from 5,542 at the end of 2010 to some 38,426 as of the end of 2015, the Test Year the Company has proposed in this case. Adoption of rooftop solar continues to accelerate, currently growing by more than 1,300 applications per month in 2016. Additional technologies, both behind the meter and grid related, are further evolving and will continue to change how APS customers use electric service and how that service is provided. Of course, the effects of technology are not limited to the distribution and use of electricity. Natural gas fracking has revolutionized the gas industry leading to persistent low gas prices that along with increasingly more stringent environmental requirements have placed heavy operational and economic burdens on coal plants, including those owned by APS.

APS has also invested some $3.1 billion in new plant through 2015 and will invest another $5.6 billion between 2016 and 2020. The former figure includes the acquisition of a larger share of Four Corners, completion of the Arizona Sun projects, the beginning

of the Solar Partners program and extensive grid modernization, including the final deployment of more than 1.25 million Advanced Metering Infrastructure (AMI) meters. The latter encompasses "big-ticket" investments, such as the Ocotillo Modernization Project (OMP), the selective catalytic reduction (SCR) equipment at Four Corners, the installation of a new customer information system (CIS), the preparation for entrance into the western Energy Imbalance Market (EIM), the implementation of "Project Illumination" which includes an Advanced Distribution Management System (ADMS), as well as hundreds if not thousands of other smaller projects that will enhance safety, efficiency and customer value.

Building on the foundation established in previous cases, the investments and proposals made in this case provide a clear and compelling vision of the future. Thus, in many respects, this case serves as a transition from the challenges of the present and immediate past to the opportunities of the future—it is a bridge to the future for APS and its customers.

APS has been able to forestall filing a rate case for five years despite the challenges discussed above because of actions taken by the Commission in approving two settlement agreements, first in 2009 and then in 2012.[1] These Commission decisions authorized targeted adjustment mechanisms like the Lost Fixed Cost Recovery (LFCR) adjustment mechanism and Environmental Improvement Surcharge (EIS). Other adjustment mechanisms such as the Power Supply Adjuster (PSA) and the Transmission Cost Adjuster (TCA) were strengthened. Finally, the Commission allowed the Company's investment in an additional share of Four Corners to be included in rates in at the end of 2014. The two settlements also put in place performance criteria that

[1] Decision Nos. 71448 (December 30, 2009) and 73183 (May 24, 2012).

successfully encouraged APS to improve quality of service, strengthen its balance sheet, and successfully cut costs by more than $207 million through 2014. And although the reporting requirements from the 2009 Settlement have expired, those savings continued into 2015. In leveraging the commitment made in the last case around cost management, APS also launched the Sustainable Cost Management Initiative that is described by APS witness Daniel Froetscher that continues to drive cost efficiency for the long term.

APS is requesting in this case a net increase of $ 165.9 million in base rates, or 5.74%. The average annual bill impact for a typical APS residential customer would be $11.09 per month, or 7.96%. Residential rates are proposed to increase more than the overall average increase due in part to the "grandfathering" of Net Energy Metering (NEM) customers and the resultant $27.3 million in cost shift to other residential customers. Other adjustments have been made across the rate classes, including residential, to make progress on existing cross-class subsidization.

Please note, I say the request is "net increase" because APS is seeking to "zero out" or significantly reduce several current rate adjuster mechanisms and surcharges by folding these costs, already borne by APS customers, into base rates.

APS is requesting a 10.5% return on equity as supported by APS witness Dr. Bente Villadsen resulting in an 8.13% weighted average cost of capital. APS is also requesting a 1% return on its Fair Value Increment – the same as was granted in the Company's prior two rate proceedings. The electric utility industry is a capital intensive business. The substantial investments APS has made and continues to make on behalf of its customers requires a fair rate of return and a reasonable opportunity to earn that return.

APS has begun installing SCRs at Four Corners. The first will be placed in service in late 2017 and the second in early 2018. APS's share of this investment is approximately $400 million, excluding allowance for funds used during construction (AFUDC), overheads and related equipment overhauls. APS is requesting a cost deferral order from the time of installation to incorporation of the SCR costs in rates, using the same procedure as authorized in the 2012 Settlement (Decision No. 73183), and a step increase in rates as implemented in Decision No. 74876 (December 23, 2014). APS estimates this will require an additional approximately 2% across-the-board increase in rates beginning in 2019, or approximately $3.00 per month for a typical APS residential customer.

APS does not seek rate recovery of the OMP in this proceeding. Rather, the Company asks for an accounting order similar to that granted in Decision No. 73130 (April 24, 2012) running from the date of commercial operation of the OMP in 2018 and 2019 to the effective date of rates in APS's next succeeding rate case.

Although APS continues to believe that full per-customer revenue decoupling is a superior and more comprehensive answer to fluctuations in sales and thus cost recovery, APS will instead propose changes to the LFCR to make it more effective. APS is also requesting a modest expansion of the EIS from the current cap of $5 million to an annual year over year cap of $10 million. Improvements to the PSA and TCA are likewise requested in this Application as is the continued deferral of increases in Arizona property taxes beyond the levels allowed in rates by the Commission in this proceeding.

A critical part of the Company's rate proposal is a thorough modernization of its residential and extra small commercial rate plans. These changes will reduce intra-class

subsidies, better reflect the cost of service, provide incentives for the deployment of new customer technologies and offer new rate and billing options. These new rate proposals will make substantial progress on the specific subsidization of rooftop solar customers who, based on the cost of service study sponsored by APS witness Leland Snook, are currently only paying approximately 38% of the cost to provide them service.

Making progress on the cross-subsidization issue is critical in this proceeding. The total cost shift from solar residential and commercial customers to non-solar residential and commercial customers combined already totals $42.7 million annually. It is especially notable that this subsidy already exceeds the total annual subsidy currently provided to low income customers. Assuming grandfathering, the 20 year rooftop solar subsidy continues to grow rapidly at the rate of $740,000 per day. By the time this case is resolved in mid-2017, the total 20 year subsidy will total over $1 billion. These numbers are exclusive to the net energy metering subsidy and are in addition to the over $800 million in cash incentives committed or already paid to residential and commercial customers over the last decade.

APS will also expand its limited income support from $35.6 million during the Test Year to approximately $48 million and provide an alternative metering option for residential customers that prefer not to have AMI meters.

APS does not propose to renew the alternative generation (AG-1) option for large commercial and industrial (C&I) customers. At the same time, APS seeks to offer new rate options for these types of customers, including a high load factor (HLF) rate, an aggregation rate and an economic development Rate Rider. Other general service rates will be largely left intact because the Company believes they are already properly structured and reflect the cost of service.

Finally, APS is asking the Commission to eliminate the regulatory requirements listed in Attachment BDL-2DR. These regulatory requirements have long since served their purpose and simply add to the regulatory burden of both the Commission and the Company.

III. EMERGING CHALLENGES AND OPPORTUNITIES

Q. IN YOUR SUMMARY, YOU NOTED THAT APS HAD NOT FILED A GENERAL RATE CASE IN FIVE YEARS AND THE CHALLENGES SUCH A STAYOUT HAD PRESENTED. COULD YOU PLEASE ELABORATE?

A. Certainly. Arizona's recovery from the great recession in the latter half of the last decade has been painfully slow, although APS is seeing clear signs of growth in both recent years and in the future. During this period, the Commission enacted both the Energy Efficiency Standard Rules (EE rules) and NEM. The EE rules and NEM have been very successful in encouraging customer adoption of both EE and rooftop solar and have had correspondingly dramatic impacts on APS and its customers. Since the 2010 Test Year used in APS's last general rate case and through 2015, the Company's EE programs have reduced energy sales by some 2,535,500 MWh. The impact in the 2015 Test Year alone was approximately 552,400 MWh. These savings are larger than for any Arizona utility, both in absolute terms and as a percent of retail sales. The growth of NEM customers has been even more dramatic going from 842 when the NEM rules were passed in 2008 to 38,426 residential and non-residential customers by the end of 2015. Again, this far outstrips the penetration of NEM customers experienced by other Arizona utilities. The LFCR mechanism has allowed APS to recoup a portion of the margins associated with lost sales attributable to EE and NEM, but the LFCR merely socializes that portion of the cost shift until the next rate case – it neither eliminates it nor fully captures the magnitude of that shift.

Although sales growth all but disappeared during this period, the pace of investment to serve APS's more than 1.2 million customers did not correspondingly abate. The Company invested $1.2 billion in its distribution system alone, including $79.6 million to complete the deployment of AMI meters first begun in 2006.[2] Another $1.2 billion was invested in acquiring new generation or upgrading/overhauling existing generation. Most notable among these investments was the acquisition from Southern California Edison (SCE) of its share of Four Corners and the installation of some 185 MW of new APS-owned grid-scale and rooftop solar generation. And in the transmission space, APS invested another $723 million during this same period. Although transmission rates are set by the Federal Energy Regulatory Commission (FERC), they do impact retail electric prices whether through the TCA or when rolled into base rates.

Q. WHAT ABOUT THE FUTURE INVESTMENTS TO WHICH YOU ALLUDED IN YOUR SUMMARY?

A. Other Company witnesses will discuss them in more detail in conjunction with APS's request for inclusion of some of these investments in post-Test Year plant. However, let me touch on five of these due to the absolute amount of the dollar investments and their importance to meeting the Company's service obligations to its customers and the public.

- **Selective Catalytic Reduction.** As the Commission is well aware, APS acquired SCE's share of Four Corners on December 30, 2013, as authorized by the Commission in Decision No. 73130. It was known at the time that Four Corners would be required by the United States Environmental Protection Agency (EPA) to install SCRs in the next few years. APS was able to negotiate with the EPA for a short delay in their installation from 2016-2017 to 2017-2018, which helped

[2] The figures cited in my testimony exclude capitalized overheads and financing costs, but rather represent hard construction dollars.

maintain the rate stay-out another year but resulted in a potential mistiming with this case. In Decision No. 73130, the Commission recognized the special role of Four Corners in maintaining fuel diversity, reliable base load generation, and serving as a mainstay to the economic viability of the Navajo Nation. The SCRs are essential to the continued operation of Four Corners, but simply asking the Company to absorb capital costs estimated at approximately $400 million, excluding upgrades to the condition of related pollution control equipment, and additional estimated SCR-related operating costs in excess of $12 million per year until its next succeeding rate case - guarantees that APS will not and cannot earn a reasonable return on the fair value of its property regardless of what other decisions the Commission makes in this rate proceeding.

- **Integrating Renewable Energy.** The tremendous growth of renewables on the APS system does not just affect revenues and rates; it requires nimble fast-start gas generation units to integrate that renewable production into the system and respond to the rapid escalation of demand in the late afternoon and early evening when solar output wanes. The OMP (approximately $500 million) provides precisely the type of generation needed using an existing generation site within the Phoenix load pocket and replaces less-efficient units constructed in the 1960s. In short, functionality and efficiency will increase and air emissions and water use will decrease - a "win-win" if there ever was one. And of course, this is in addition to the some $138 million in grid-scale and rooftop solar generation also added by APS post-Test Year.
- **Customer Information System.** The Company's existing CIS was state of the art – 20 years ago. Today, it is obsolete and is being replaced with a system that is more efficient and can better take advantage of AMI data to provide new services to APS customers. But such sophisticated equipment, both hardware and

software, is not cheap; APS will be investing in 2016 and early 2017 some $120 million to bring this new CIS online.

- **Advanced Distribution Monitoring System.** The Advanced Distribution Monitoring System (ADMS) is the cornerstone of Project Illuminate, which is described in more detail in APS witness Jacob Tetlow's testimony. ADMS will allow for remote monitoring, diagnosis and operation of field devices, thus combining multiple areas of analytics into a single operating platform. Efficiency, reliability, power quality, and safety will all be positively affected once ADMS is fully operational. The total cost of ADMS is estimated at $53.6 million dollars.
- **Energy Imbalance.** APS is joining an increasingly broad-based western Energy Imbalance Market (EIM). Energy imbalance is an inherent reality of the physics of electric generation, but it has become an ever increasing issue with the proliferation of intermittent resources such as solar and wind. Joining the EIM will allow sales in five and 15 minute increments, instead of the traditional one-hour blocks. While joining the EIM does not change APS's overall resource or reliability requirements, it does improve the efficiency of dispatch and allow many more opportunities for APS to either make purchases or sales for the economic benefit of its customers. APS will spend nearly $26 million in capital alone for the upgraded software needed for this sophisticated energy market. APS witness James Wilde addresses the Company's participation in the EIM in greater depth in his direct testimony and APS witness Jacob Tetlow addresses the post-Test Year plant associated with the EIM.

Q. WITH ALL THAT HAS HAPPENED SINCE THE 2010 TEST YEAR USED IN THE 2012 SETTLEMENT AND ALL THAT IS SCHEDULED TO OCCUR IN THE NEXT FEW YEARS, HOW WAS APS ABLE TO AVOID A GENERAL RATE CASE FOR FIVE YEARS?

A. APS was able to avoid a general rate case due in part to three important circumstances:

- **Strong Commission leadership**. Without the regulatory support provided in the 2009 and 2012 Settlements, APS would have needed rate relief long before now. Specifically, the approval of the LFCR and the EIS, along with the strengthening of the PSA and TCA combined with the cost-deferral order and subsequent Rate Rider for the Four Corners acquisition allowed APS to cope with the financial impacts of the EE rules and NEM while receiving cost recovery for significant production-related capital investments. Not only did these mechanisms postpone the need for a general rate case, they reduced the magnitude of this current request by a staggering $272 million, not including the PSA and the System Benefit Charge, which were technically approved prior to the past two Settlement Agreements. This represents precisely the sort of rate gradualism desired by both APS and its customers.
- **Disciplined cost management**. The 2009 Settlement required APS to demonstrate and report a minimum of $150 million in cost savings during the years 2010 through 2014, or some $30 million per year. In fact, the Company exceeded that $30 million figure in each of the five years, and including savings from the two prior years resuled in some $207 million total. And, although the reporting requirement from the 2009 Settlement was no longer in effect, this pace of ongoing cost savings continued into 2015. APS also launched the Sustainable Cost Management Initiative, described by APS witness Daniel Froetscher that continues to drive cost efficiency for the long term.
- **Arizona's improved regulatory environment**. The regulatory challenges of Arizona's generous NEM and ambitious EE rules are widely recognized. But our

state's regulatory improving landscape, as evidenced by the settlements referenced above as well as the implementation of various adjustment mechanisms, and the Company's close attention to cost management have not gone unnoticed by the financial community. APS's senior debt rating [note: the ratings referenced are those from S&P, Moody's ratings have improved from Baa2 to A2] has gone from teetering on the edge of "junk" (BBB-) to a rating of A-, the highest since the 1980s. Higher ratings have permitted the Company to issue less-expensive (i.e. lower interest rate) debt, reducing the Company's weighted cost of debt from 6.38% at the end of 2010 to 5.13% as of year-end 2015. As a result of higher debt ratings, through the end of 2015 and based on the ratings improvement I noted above, APS has generated total interest savings of about $160 million which will result in significant savings to customers in the current rate case and over the remaining term of the related indebtedness.

Suffice it to say, APS customers, APS and the Commission itself have all benefitted from the regulatory and financial stability allowed by the 2009 and 2012 Settlements, as well as by actions taken by APS and the Commission since its response to those landmark decisions. Now we have the opportunity to continue building on those successes as APS and its customers enter into new challenges and opportunities – challenges and opportunities that will again require both Commission leadership and redoubled efforts by the Company to fulfill the promise of a bright energy future for Arizona.

IV. OVERVIEW OF THE RATE APPLICATION

Q. WOULD YOU PROVIDE A MORE DETAILED OVERVIEW OF THE COMPANY'S APPLICATION?

A. APS is requesting in this case a net increase of $165.9 million in base rates, effective July 1, 2017. The term "net increase" is an important one because APS is seeking to "zero out" or significantly reduce several current rate adjuster mechanisms and surcharges by folding these costs, already borne by APS customers, into base rates. If one were to look only at Schedule A-1 of the Standard Filing Requirements (SFRs), they might get a misleading impression of how this Application will impact APS customers. But it has been APS's experience that customers are not interested in where the charges appear on their bill or what regulators and the Company choose to call them. Instead, customers are interested in how much more or less they will have to pay each month. APS's request would have an average annual bill impact for a typical APS residential customer of $11.09 per month, or 7.96%. General Service customers will see lower percentage increases in their bills. It is also important to note that APS is seeking a second or "step" increase in rates for 2019 to reflect the completion and integration into rates of the Company's investment in SCRs for Four Corners (discussed in more detail below).

Q. WHAT WILL BE THE PRIMARY DRIVERS OF THIS INCREASE?

A. Although there are always numerous issues in any APS rate proceeding, as can be seen by the number of so-called pro forma adjustments to the 2015 Test Year shown on Schedules B and C of the SFRs, there are a few that are major drivers of the increased ACC revenue requirement. These include:

1. The impact of sales lost to EE and NEM as reflected in the LFCR – $46 million;[3]
2. The impact of sales lost to EE and NEM not recovered through the LFCR – $113 million;
3. The impact of increases in net plant-in-service through the end of the 2015 Test Year – $110 million;
4. The impact of post-Test Year plant additions through June 30, 2017 – $98 million;
5. The impact of higher depreciation expense and property taxes on both this additional plant and the plant existing as of the last rate case – $81 million depreciation and $36 million property taxes; and
6. The need for APS to earn an adequate return on equity (ROE) – $29 million.

To be fair, there are offsets to these increases. For example, base fuel costs will decrease by $62 million, the new Palo Verde Unit 2 lease effective this year will reduce lease expense by nearly $17 million, and the closure of Cholla Unit 2 reduced O&M expense by another $17 million. And these are just examples of the kind of cost reductions that comprised the $207 million figure I previously referenced.

Q. DID APS ALSO PURPOSELY EXCLUDE SOME COSTS FROM THE TEST YEAR TO MODERATE THE RATE IMPACT ON CUSTOMERS?

A. Yes. In addition to the usual out-of-period, nonrecurring and miscellaneous adjustments, APS removed all Supplemental Employee Retirement Plan (SERP) expenses from the

[3] Although this increases the base rate increase, there is no net bill impact because customers were already paying this amount through the LFCR.

Test Year as well as stock–based compensation. Together, these adjustments reduced APS's cost of service by about $22 million. While the Company believes that the costs associated with SERP and stock-based compensation are appropriate for recovery, we have removed them from the Test Year specifically to moderate the impact to customers.

Q. YOU HAVE PREVIOUSLY DISCUSSED THE PLANT ADDITIONS SINCE THE LAST TEST YEAR AND THOSE IN THE NEAR FUTURE AS WELL AS THE IMPACT ON THE COMPANY AND ITS CUSTOMERS OF EE AND ROOFTOP SOLAR. WHAT ABOUT THE OTHER DRIVERS YOU LISTED ABOVE?

A. Depreciation is by far the largest of these. APS commissioned a depreciation study as called for by A.A.C. R14-2-102(C) in 2015. It was conducted by Foster & Associates, and in particular by Dr. Ronald White – perhaps this country's best known expert on public utility depreciation. The study showed that APS's jurisdictional property had a significant depreciation reserve imbalance that was more than offset by the additional investment in existing assets that needed to be depreciated over the now expected remaining life of these assets. The net result was that annual depreciation expense needed to be increased by more than $80 million, not including depreciation on the PTYP. APS witness Dr. Ronald White and APS witness Elizabeth Blankenship provide the details of the depreciation study itself and the resultant depreciation expense pro forma adjustment to Operating Income.

As can be seen above, property taxes were another major factor. This is why APS is asking to continue deferring future increases in Arizona property taxes rather than requesting some manner of property tax adjustment mechanism.

Q. WHAT RETURN ON EQUITY IS APS REQUESTING THE COMMISSION TO USE IN DETERMINING A FAIR VALUE RATE OF RETURN?

A. Based on the analysis provided by APS witness Dr. Bente Villadsen, APS believes that a reasonable return on equity for a company facing the risks that APS faces is 10.5%. This ROE along with an embedded cost of debt of 5.13% would result in a weighted average cost of capital of 8.13%. Using a 1.0% return on the "Fair Value Increment" of the Company's Fair Value Rate base (as explained by Mr. Snook, Ms. Blankenship and Dr. Villadsen, respectively) results in APS's recommended fair value rate of return of 5.84%.

Q. PLEASE DISCUSS THE IMPORTANCE OF AN APPROPRIATE RETURN ON EQUITY.

A. While I am no expert on the cost of capital, I do know that APS needs to earn a return on equity commensurate with its risk and comparable to similar enterprises. APS competes with companies all over the world for the most fungible of commodities – capital. No one has an obligation, legal or moral, to invest in APS. If the return is inadequate in their minds, they simply move on to other investments. For a Company needing to invest more than a billion dollars a year for the foreseeable future to enable and account for an increasingly complex modern electrical grid, being shut out of the equity market is simply not an option.

Q. YOU SPOKE EARLIER OF ZEROING OUT OR REDUCING SOME OF THE COMPANY'S ADJUSTMENT MECHANISMS AND INCLUDING THEM IN BASE RATES. PLEASE EXPLAIN.

A. Although APS witness Elizabeth Blankenship will address the accounting aspects, let me say that there is nothing particularly unusual about this. For example, the PSA has been rolled into the new Base Fuel Rate in all but one rate case since the reinstitution of the PSA more than 10 years ago. Similarly, Arizona Sun investments being recovered

through the RES previously have been included in base rates as that opportunity presented itself. Newer adjustment mechanisms such as the LFCR and the EIS were, by their nature and design, intended to be included in base rates, although this proceeding represents the first such opportunity to do so.

There are two adjustment mechanisms where this will mark a change in the Company's previous position. These are the TCA and the demand side management adjustment clause (DSMAC). APS is proposing to roll all the costs presently being recovered through the TCA ($128.6 million) into base transmission rates and approximately another $10 million of DSMAC costs (in addition to the $10 million that has been included in base rates since 2005). There are reasons, pro and con, for reflecting costs in discrete adjusters versus base rates. For example, some believe the adjusters make the charges more transparent. Others believe they simply complicate the bill and sometimes make customers believe they are paying twice for the same cost (e.g., there is both a base transmission charge and the TCA, both of which are described as paying for FERC-regulated transmission services). In this case, APS's major motivation is to protect these vital revenue streams from the ongoing attacks by some intervenors against rate-adjustment mechanisms.

Q. IS APS ASKING FOR CHANGES TO EXISTING RATE ADJUSTMENT MECHANISMS?

A. Yes, both minor and substantive. I will go through each of the changes beginning with the PSA.

APS is asking to include water and chemical costs in the PSA, as well as battery storage. These first two costs vary as directly with electric power supply as much as do fuel and purchased power and are becoming increasingly significant. The latter represents new

opportunities for APS to acquire the power needed to serve our customers. APS witness Peter Ewen provides the more detailed explanation of why this change is appropriate.

Another change is a fairly straightforward alteration to the EIS, doubling its effective cap from $5 million per year to $10 million, with the latter figure becoming a year-over-year cap rather than a cumulative cap. The mechanics of this are discussed by APS witness Leland Snook. This should allow recovery of the numerous minor, but cumulatively significant, environmental improvements between rate cases, but still require Commission approval of large investments such as the SCRs.

Next, APS is seeking to add a balancing account feature to the TCA, which is also explained by Mr. Snook. All other APS adjustment mechanisms have a balancing account feature to prevent unintended over or under recoveries of costs, and the omission of such a provision for the TCA strikes APS as more of an oversight than a valid distinction between the TCA and other rate adjusters.

Q. IS APS PROPOSING CHANGES IN THE LFCR?

A. Yes. Although full per customer revenue decoupling as described in Mr. Snook's direct testimony is preferable from both a Company and, I believe, a customer perspective, APS is instead proposing changes to the LFCR to make it more effective. These include:

- Inclusion of fixed costs attributable to generation not otherwise recovered through production-related demand charges;
- Inclusion of regulatory asset costs (the ultimate example of a fixed cost); and
- Elimination of transmission costs now included in base rates if the Commission accepts the Company's proposal to add a balancing account feature to the TCA.

Q. WHAT IS APS PROPOSING TO DO ABOUT THE SCR'S AT FOUR CORNERS?

A. The SCRs will be installed at Four Corners in late 2017 and early 2018. APS's share of this investment not including related repairs to existing pollution control equipment described by APS witness John Lucas is approximately $400 million. As in the case of the Four Corners acquisition from SCE, APS is requesting a cost deferral order from the time of installation to incorporation of the SCR costs in rates using the same procedure as authorized in the 2012 Settlement (Decision No. 73183), and the step increase implemented in Decision No. 74876 (December 23, 2014). APS estimates this will necessitate an additional approximate 2% across-the-board increase in rates beginning in 2019, or approximately $3.00 per month for a typical APS residential customer. Mr. Snook discusses the details of this deferral and step increase.

Q. WHY IS APS NOT SEEKING A SIMILAR DEFERRAL AND STEP INCREASE FOR THE OMP?

A. APS does not seek rate recovery of the OMP in this proceeding for several reasons. First, it is another year removed from the Test Year even as compared to the SCRs. Second, unlike Four Corners, the OMP has not been determined by the Commission to represent a prudent investment for APS customers. Trying to make that determination in this docket would likely cause a significant delay to an already complicated proceeding. Thus, the Company asks for an accounting order similar to that granted in Decision No. 73130 running from the date of commercial operation of the OMP in 2018 and 2019 to the effective date of rates in APS's next succeeding rate case. Mr. Snook will again be the APS witness discussing the mechanics of the deferral while APS witness James Wilde addresses the OMP itself.

Q. WHAT ARE THE CONSEQUENCES OF NOT ACHIEVING THE DEFERRALS FOR BOTH THE SCR'S AND OMP AND THE STEP INCREASE FOR THE SCR'S?

A. The financial impacts to the Company for these $900 million of investments are so large that the Company would be compelled to file another rate case as soon as possible. Please see APS witness Peter Ewen's testimony for more information about the financial impacts not receiving the deferral and step increase treatment.

Q. YOU HAVE MENTIONED SEVERAL TIMES THE IMPORTANCE OF RATE DESIGN IN THIS APPLICATION. WHY IS THIS THE CASE?

A. Rate design modernization and reform, especially for residential customers, is not just important, it is critical. Adding a third billing element, called demand, in addition to making the basic service charge itself more cost-based, will reduce intra-class subsidies, better reflect the cost of service, and provide incentives for the deployment of new customer technologies. As discussed in APS witness Charles Miessner's direct testimony, this will not be a one-size-fits-all approach. APS is proposing several new rate and billing options, including those tailored to both high and low use customers. APS will also change aspects of its time-of-use rates to better reflect cost of service and better integrate them into the three-part structure based on APS's more than three decades of experience with residential three-part rates.

Q. WHY MODERNIZE RATE DESIGN NOW?

A. From my perspective, for three simple reasons.

- APS has the technology to do it. Although demand has been measured for years by APS with pre-AMI technology, it is only with AMI that APS has the detailed information needed to more fully inform and educate residential customers about demand.

- Intra-class subsidies within the residential class are significant but still manageable if addressed now. The subsidies include, but are not limited to, the cost shift inherent in NEM, and can be managed, and customers presently enjoying this subsidy can be "grandfathered." The ability to insulate these customers from significant changes through grandfathering will not last long, perhaps not even until the Company's next rate case unless significant progress is made now.
- It's the right thing to do. Three-part rates better track cost of service and incent new behind-the-meter technologies for customers – essentially rendering utility rate design technology neutral.

Q. WHAT ARE THE CONSEQUENCES OF NOT MODERNIZING RATE DESIGN IN THIS PROCEEDING?

A. The costs to APS's residential and commercial non-solar customers combined is already $42.7 million annually and is growing rapidly. It is especially notable that this subsidy already exceeds the total annual subsidy currently provided to limited income customers. Making progress on the rooftop solar cross-subsidization issue is critical in this proceeding. In just the time it takes to process this case, that number will grow approximately $20.1 million assuming the current pace of installations continues. Although APS has not requested recovery of those incremental costs in this case, we reserve the right to revise our request to include those costs if installations continue at such a rapid pace. If no progress is made in this case and the issue is deferred until APS's next case (assuming that case is 3 years after this case), the total annual cost shift will have ballooned to $102.9 million per year. The following table summarizes the annual and nominal 20 year cost shift.

Cost Shift Summary

Cost shift for installations through 12/31/2015	$42.7 million/yr
Additional cost shift through 7/1/2017	$20.1 million/yr
Additional cost shift from 7/1/2017 to 7/1/2020	$40.1 million/yr
Nominal incremental value of 20 year cost shift	$740,000/day
Nominal total value of 20 year cost shift through 7/1/2017	$1 billion

All of these cost shift numbers are specifically related to net energy metering and are in addition to the over $800 million in cash incentives committed or already paid to rooftop solar customers.

Q. WILL APS BE IN A POSITION TO ASSIST CUSTOMERS WITH INFORMATION AND EDUCATION WHEN MAKING THESE RATE CHOICES?

A. Yes. AMI will facilitate this effort, but time may also be required, which is why APS supports a transition period before full implementation of all the residential rate options proposed in this case. APS witness Stacy Derstine discusses the Company's plans for customer education during and after this transition phase.

Q. WHAT ABOUT CHANGES TO NEM ITSELF?

A. Residential adoption of three-part rates will address much of the costs shift attributable to self-consumption of rooftop solar, which reduces energy usage by the customer but does little to reduce demand. But rate reform itself does nothing about the excessive pricing of "export" energy from rooftop solar, i.e., energy not used by the host customer but exported out to the grid. Mr. Snook, Mr. Miessner, and Mr. Wilde are APS's primary witnesses on this issue, but suffice it to say, the export rate should be treated

like every other APS purchase of power – recovered through the PSA and priced at the actual avoided generation cost. APS recognizes that the amount paid for excess energy exported to the grid by customers with distributed generation, and the structure of that payment, is currently being considered in the proceeding in Docket No. E-00000J-14-0023. That proceeding is expected to conclude later this year and the outcome of that proceeding could be relevant to the decision on the export rate in this case.

Q. SHOULD EXISTING ROOFTOP SOLAR CUSTOMERS BE "GRANDFATHERED?"

A. Yes. APS proposes that those residential rooftop solar customers who have installed their systems or have completed applications for interconnection on file with APS by July 1, 2017, would continue to be subject to the NEM provisions in effect as of that date. Similarly, they would be eligible to remain on their present rate schedules subject to whatever general changes in rates are approved by the ACC. APS witness Charles Miessner more fully describes the grandfathering provisions.

Q. HOW LONG WOULD GRANDFATHERED STATUS LAST?

A. For 20 years after interconnection of the individual customer's system, irrespective of changes in ownership of the host premise during that period.

Q. WHY CHOOSE A SPECIFIC DATE FOR GRANDFATHERING RATHER THAN SIMPLY SAY "END OF THE RATE CASE" OR "NEW RATE EFFECTIVE DATE?"

A. APS believes using a specific date in the future allows for easier planning by both the utility and the prospective rooftop solar customer. It also removes an incentive for intervenors to delay these rate proceedings after July 1, 2017.

Q. DOES APS PROPOSE CHANGES FOR LIMITED-INCOME CUSTOMERS?

A. As explained by Ms. Stacy Derstine, APS will expand its limited income support from $35.6 million during the Test Year to approximately $48 million. APS also instituted a program this year to improve the Company's outreach to customers eligible for limited-income assistance. Finally, as explained by Ms. Derstine, APS will convert its usage-driven percentage discount to a flat $34 per month for E-3 customers and $57 per month for E-4 customers, capped by 80% of the total bill. This will target increased funding to those low-use customers that might be impacted by other rate design changes.

Q. THE COMMISSION PREVIOUSLY DEFERRED THE ISSUE OF AMI "OPT-OUT" TO THIS RATE CASE. WHAT IS THE COMPANY'S PROPOSAL?

A. APS has been greatly informed by the alternative metering program for residential customers opposed to AMI meters proposed by Unisource Electric Service Company (UNSE) and endorsed by Staff in that proceeding. Although different from what APS had originally proposed, UNSE and Staff appear to have agreed on a formula for determining both an appropriate policy and reasonable cost-based fees for this service. APS witness Scott Bordenkircher discusses the program itself, while APS witness Charles Miessner addresses the Company's proposed charges.

Q. WHAT ABOUT RATES FOR C&I CUSTOMERS?

A. APS proposes to eliminate the alternative generation (AG-1) option for large C&I customers. Although Mr. Miessner discusses some of the ways the Commission could improve the AG-1 program, the fundamental problem is that it is not cost-based and thus must be subsidized by other customers to be attractive. This is a problem that simply cannot be overcome. Thus, APS asks to offer new rate options for these types of customers, including a high load factor (HLF) rate, an aggregation rate and an economic development Rate Rider. Other general service rates will be largely left intact because

the Company believes they are already properly structured and reflect cost of service. Mr. Miessner explains the Company's rate design proposals for C&I customers in much greater detail in his direct testimony.

Q. IS TIMING CRITICAL FOR THIS CASE?

A. Absolutely. Two-thirds of APS's revenues come in the third quarter of the year. Even a 30-day slip past July 1, 2017, can mean a loss of $16 million in revenues (net of continued deferrals from the Company's last rate proceeding and AG-1). APS has done everything it can to provide notice to parties of this filing and to expedite the process. APS strongly urges the Commission to adopt new rates in this proceeding by July 1, 2017.

V. ELIMINATION OF OBSOLETE, REDUNDANT AND UNNECESSARY COMPLIANCE FILINGS

Q. WHAT EXISTING COMPLIANCE FILING OBLIGATIONS IS APS PROPOSING THAT THE COMMISION WAIVE OR ELIMINATE?

A. APS is asking that the Commission waive or eliminate several antiquated, duplicative or simply unnecessary reporting requirements. The Company does not seek to avoid any substantive requirement of a prior Commission order or regulation but simply to eliminate unnecessary reporting requirements. Although these reporting requirements are either no longer necessary or are redundant, they remain in the Commission's compliance database, and therefore APS must comply with them and Commission Staff verify that compliance unless they are formally waived or otherwise removed by Order of the Commission. Please see Attachment BDL-2 for a more detailed description and justification on the requested waivers and eliminations discussed below.

Rule Waiver Requests

Due to the inactivity of the Retail Electric Competition Rules, APS requests a waiver from the reporting requirements of the following, until such a time as competition in the state of Arizona comes to fruition: A.A.C. R14-2-1613 (Retail Electric Competition Reporting Requirements) and A.A.C. R14-2-1617 (Retail Electric Competition Consumer Disclosure Labels). APS is also requesting a waiver from the reporting requirements contained in A.A.C. R14-2-2308 (Net Metering Filing and Reporting Requirements) because it is a redundant report: APS submits annual compliance reports required under the Renewable Energy Standard Rules that provide substantially similar information.

Elimination of Decision-Based Compliance Filing Requirements

APS makes numerous filings when needed, annually, or every three years that are either outdated or redundant; therefore the Company requests that the Commission formally remove the below listed compliance requirements. Compliance items classified as redundant should be eliminated because the information contained therein can be found in other reports or filings made by APS. Compliance items classified as outdated should be eliminated because the information contained therein no longer serves the intended purposes. APS will not burden this record by going over these requirements one-by-one in my testimony but rather will refer the Commission to my Attachment BDL-2DR, which lists each filing requirement, its origin and the reason for the Company's request that the requirement be eliminated by the Commission in this proceeding.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. This case marks an important step in transitioning APS and its customers to an exciting but challenging future. APS is modernizing and making more sustainable its electric system with improvements such as the SCRs, the OMP, ADMS, AMI, EIM and

the new CIS. But the bridge to the future requires more than equipment. APS also needs to modernize its pricing, and the Company's proposals are a significant step in the right direction while still providing meaningful rate choices for customers.

For APS, this case represents a critical milestone in our effort to shape the next-generation power grid for our customers. The Company takes pride in its leadership in solar energy, rate reform and energy efficiency, all having delivered benefits to our customers. We seek to continue innovating, to continue taking the industry forward, and to continue making our state a great place to live. To do all of that, we're proposing changes that benefit APS customers and the Company, and, if approved, they will serve as a bridge to the future for Arizona, its residents and the entire region.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BARBARA LOCKWOOD

Vice President, Regulation
Arizona Public Service Company

Barbara Lockwood is vice president of regulation for Arizona Public Service (APS). Based in Phoenix, APS is Arizona's largest electric company and serves nearly 1.2 million customers around the state.

Lockwood manages federal and state regulatory activities for APS. Prior to moving into regulatory, she served as general manager of energy innovation, where she managed technology and renewable energy programs, including the operation and maintenance of the utility's solar generation fleet.

Lockwood began her career at DuPont in chemical engineering and management roles. She then spent a number of years in environmental consulting providing property development, compliance, and business acquisition services to national and global companies in a variety of industries. Lockwood joined APS in 1999.

Her policy and regulatory experience includes testimony before the U.S. House of Representatives Select Committee on Energy Independence and Global Warming as well as a field hearing with Congresswoman Gabrielle Giffords on the Federal Investment Tax Credit and its effect on solar development in the Southwest.

Lockwood served on the Western Governors' Association Solar Task Force and the Arizona State Renewable Energy Task Force. She has also served on the Solar Technical Advisory Board for the National Renewable Energy Laboratory, the Research Advisory Committee for the Electric Power Research Institute and the Board of Directors for the GridWise Alliance.

She currently serves as vice chair of the Board of Trustees for the Arizona Science Center and is the past president of Keep Phoenix Beautiful.

Lockwood holds a Bachelor of Science in chemical engineering from Clemson University and a Master of Science in environmental engineering from Georgia Institute of Technology. She is a registered professional chemical engineer in Arizona.

Detailed Description of Compliance and Reporting Requirements to be Waived or Eliminated

RULE-BASED COMPLIANCE REQUIREMENTS

Rule	Topic	Frequency	Description	Justification
R14-2-1613(A)	Retail Competition	Annual	Report on competitive services and standard offer services provided by Electric Service Providers and Affected Utilities	Retail competition is not in force in Arizona, and many of the Commission's rules have been remanded to the Commission. The reason the report was required no longer exists, and the information provided in the report can be found in other annual reports provided such as the utility annual reports and the historical IRP annual filing.
R14-2-1617	Retail Competition	Annual	Provide a Consumer Disclosure Label containing price, fuel mix, and emissions data for the prior year	This rule was remanded to the Commission for approval by the Attorney General and is no longer in force. In addition, the reason for the report – to provide data on retail competition – no longer exists. The majority of the information in this report can be found in other reports filed by APS.
R14-2-2308	Net Metering	Annual	Provide the inverter or generator rating, monthly energy deliveries and if available the monthly peak demand for each net metering facility	Since the rule was enacted in 2009, there has been a proliferation of net metering facilities. As of December 31, 2015, APS had over 40,500 connections, both residential and non-residential. Annual compliance reports provided as part of the RES rules provide an overview of net metered facilities, and arizonagoessolar.org provides additional details regarding DG systems on the APS system.

DECISION-BASED COMPLIANCE REQUIREMENTS

Decision	Docket	Topic	Frequency	Description	Justification
Redundant Filings					
70531 Page 22, line 1 (09/30/08)	E-01345A-08-0106	RES	Annual	Report any damage payments received related to the Solana PPA contract	This is a redundant requirement. In Decision No. 72022, the Company is ordered to report any damages or other considerations as a result of RES PPA contract non-compliance.
72058 Page 10, line 25 (01/06/11)	E-01345A-10-0314	RES	Annual	Report any damage payments received related to the Perrin Ranch PPA contract	This is a redundant requirement. In Decision No. 72022, the Company is ordered to report any damages or other considerations received as a result of RES PPA contract non-compliance.
71275 Page 15, line 4 (9/17/09)	E-01345A-09-0263	RES	Annual	Report production from systems installed as a result of the 2009 school UFI program and do not report "phantom" production	These systems were all installed in 2010 in accordance with the program, where residential incentive funds were transferred to school projects. This is now a redundant requirement as APS is required to report only actual production (after the first year) for all projects.
71244 Page 8, line 13 (08/06/09)	E-01345A-09-0255	Rates	Annual	Report detailing transmission projects and O&M costs included in each Transmission Cost Adjustor reset and expected future TCA costs	This report was made redundant by reporting requirements contained in Decision Nos. 73262 and 73183.
71310 Page 4, line 1 (10/30/09)	E-01345A-05-0816 E-01345A-05-0826 E-01345A-05-0827	Palo Verde	Annual	Present an overview of the Palo Verde reports at the Summer Preparedness Open Meeting	APS's Summer Preparedness presentations provide an overview of all APS generating plants; therefore this requirement is redundant.

Detailed Description of Compliance and Reporting Requirements to be Waived or Eliminated

Decision	Docket	Topic	Frequency	Description	Justification
Outdated Filings					
68112 Page 7, line 3 (09/09/05)	E-01345A-03-0775 E-01345A-04-0657	Bill Estimation	Non-dated	Participate in benchmarking studies that compare APS estimation and other billing practices to other utilities	APS representatives participate in industry associations and working groups that share information on these issues and many others regularly. Benchmarking studies do not provide any additional information and are no longer necessary.
68112 Page 8, line 17 (09/09/05)	E-01345A-03-0775 E-01345A-04-0657	Bill Estimation	Every 3 years	Conduct an audit of estimation, meter reading, and billing practices	Three consecutive audits have shown that APS's practices are robust and function as intended, and the audits have found no significant issues needing review or additional discussion. These audits are no longer necessary.
68645 Page 9, line 3 (04/12/06)	E-01345A-05-0674	Rates	Annual	Provide load shape data for participants served under experimental rates ET-2 and ECT-2	ET-2 and ECT-2 rates are now permanent and addressed in general rate cases. Specific reporting is no longer necessary.
69569 Page 8, line 8 (05/21/07)	E-01345A-05-0711	Bill Estimation	Non-dated	Update allocation data for summer/winter on-peak usage, load factor, and usage per day when change is more than 5%	This allocation data has changed only once by more than 5% since the bill estimation procedures were developed and there is no reason to expect that they will change significantly in the future. This requirement is no longer necessary.
71310 Attachment (10/30/09)	E-01345A-05-0816 E-01345A-05-0826 E-01345A-05-0827	Palo Verde	Annual	Report capacity factor and associated information for Palo Verde units	The Nuclear Performance Reporting Standard requires two levels of reporting: annual reports and event triggered reports. As the annual report is based on capacity factor, and the capacity factor at Palo Verde has improved steadily since the standard was developed, only event reports are necessary today.
71448 Page 61, line 12 (12/30/09)	E-01345A-08-0172	Rate Case	As necessary	Notify Commission prior to replacing full-time employees with off-shored employees	This compliance requirement was put in place at a time when some Arizona utilities were reported to be considering off-shoring certain technical operations and was intended to be a preventive measure. This requirement is no longer necessary.
71448 Page 61, line 26 (12/30/09)	E-01345A-08-0172	Rate Case	Annual	Develop a Carbon Credit Tracking Mechanism	This requirement was set in a time when it appeared likely that a federal carbon pricing or cap-and-trade policy would be enacted. With the implementation of the Clean Power Plan, no additional policies are expected and this is no longer necessary.
71958 Page 6, line 26 (11/01/10)	E-01345A-10-0013	RES	Annual	Notify Commission if the Bagdad REC and Energy project has precluded any other commercial system from receiving incentives	This requirement is no longer necessary because the Commission has eliminated incentives for commercial distributed generation systems, therefore the project can no longer preclude the receipt of incentives.
72022 Page 29, line 1 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Summarize RES reports (Compliance Report and Implementation Plans) with 1-2 page summaries and a PowerPoint presentation	When this requirement was instituted, APS's RES filings were large and complicated. Today's plans request only a continuation of existing programs (no new programs) and are 6 to 7 pages in length overall. These plans contain executive summaries. Additional summaries are unnecessary.

Detailed Description of Compliance and Reporting Requirements to be Waived or Eliminated

Decision	Docket	Topic	Frequency	Description	Justification
72022 Page 28, line 22 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Disclose if affiliates, employees, or directors have financial or other interest in renewable energy projects	The status of the renewable energy markets have evolved since this requirement was instituted. Today, APS owns distributed generation, and new incentives are not available so there is no conflict of interest concern at this time.
72582 Page 14, line 22 (09/15/11)	E-01345A-10-0123	Technology Innovation	Annual	Report on the development of the EV market in APS territory	APS's application in this docket was intended to complement the DOE's EV Project, which has since run its course. The EV market advances today mainly through private endeavor, and this report is no longer necessary.
73089 (04/05/12) Page 62, line 1	E-01345A-11-0232	DSM/EE	Annual	Present an overview of the DSM Annual Progress Report at an Open Meeting	Since this requirement was instituted, the Commission has declined to change the EE rules and the Company now uses Staff's cost-benefit methodology. This presentation is no longer necessary.
73089 (04/05/12) Page 60, line 15	E-01345A-11-0232	DSM/EE	Annual	Report the measures installed by customers subsequent to the receipt of study or design assistance incentives	The requirement was intended to ensure that study/design expenses were justified by the customer actually installing recommended measures. Reports continue to support the conclusion that study expenses lead to customer projects. Reporting is no longer necessary.
73089 (04/05/12) Page 61, line 6	E-01345A-11-0232	DSM/EE	Annual	Report spending associated with non-energy efficiency measures in the Appliance Recycling program	The appliance recycling program has been terminated.
73089 (04/05/12) Page 61, line 11	E-01345A-11-0232	DSM/EE	Annual	Provide information on how savings from the Bid for Efficiency pilot measure are verified	The Bid for Efficiency pilot program was never implemented therefore this requirement is not necessary.

DIRECT TESTIMONY OF JOHN R. LUCAS

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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Fossil Generation Post-Test Year Plant Additions ..... Attachment JRL-1DR

DIRECT TESTIMONY OF JOHN R. LUCAS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is John R. Lucas. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am the General Manager of Generation Engineering and Projects supporting Fossil Generation at Arizona Public Service Company (APS or Company).

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have more than 30 years of experience in the power generation and energy delivery business for APS including experience in leading and managing teams for planning, designing, constructing, operating and maintaining electric utility systems. I have provided the overall strategy and execution of business objectives, including leadership, budget, technical direction, change management and strategic guidance for the teams. In addition to my current role, my background includes extensive experience in Power Operations and Maintenance of the Transmission and Distribution system, understanding of the Western Electricity Coordinating Council (WECC) interconnected system, and the Operating Criteria and Standards of both WECC and the North American Electric Reliability Corporation's (NERC).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. I have testified before the line siting committee in Docket No. L-00000D-08-0330-00138 and have given presentations at the Commission regarding summer preparedness and activities surrounding the bi-annual transmission planning process.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides a general overview of APS's Fossil Generation business unit, and provides a high-level picture of what is required to safely and reliably generate electricity at the Company's fossil-fueled power plants. Specifically:

- I outline Fossil Generation's intense focus on safety, reliability, the environment, and cost management.
- I will discuss changes to the fossil plants since the 2011 rate case filing.
- I will also identify the specific projects completed in the 2015 Test Year and planned through June 30, 2017, and discuss Fossil Generation's contribution to the Company's post-Test Year Plant Adjustment.

III. INTRODUCTION TO FOSSIL GENERATION

Q. TO WHAT DOES "FOSSIL GENERATION" OR "FOSSIL" REFER?

Fossil Generation is an APS business unit that operates a fleet of two coal-fired, six natural gas-fired, and one oil-fired generating station, which collectively provide more than 5,500 megawatts of reliable electric generating capacity. APS also owns 14% of the Navajo Generating Station, operated by the Salt River Project (SRP). In total, 4,851 megawatts of the capacity generated by our Fossil fleet serve APS. At present, Fossil Generation has a workforce of approximately 800 employees. Our 2015 operations required capital expenditures of $224 million, operations and maintenance (O&M) expenditures of $202 million and decommissioning expenditures of $33 million.

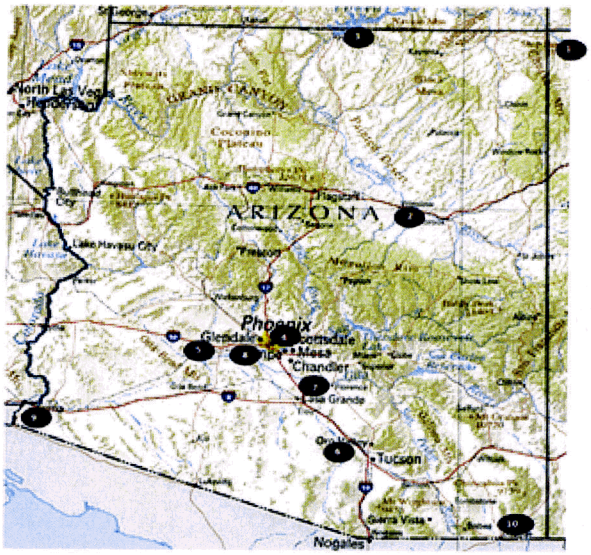
Q. PLEASE BRIEFLY DESCRIBE APS'S FOSSIL GENERATION FLEET.

A. APS's customer demand for electrical power varies during the course of a day and is greatly impacted by the weather and day of the week for our business and industrial customers. When matching generation resources with variable customer demand,

Fossil's generating assets complement Palo Verde's nuclear generation and the variable generation supplied during the daytime by solar plants and roof-top generation.

The Fossil fleet provides flexibility to the APS generation portfolio. The Gas & Oil fleet provides flexible peaking resources and the Coal fleet, while not as flexible, may reduce output at night or over the weekend to align with periods of low demand.

The Fossil fleet also provides volt-ampere reactive (VAR) support to the transmission and distribution network, essential to ensuring efficient movement of electricity within the grid. As the map and corresponding table demonstrate, nine of the 10 power plants within the APS Fossil Generation fleet are scattered throughout Arizona. The exception is Four Corners, the first plant listed below, which is located on the Navajo Nation near Farmington, New Mexico.



Summary Table of Generating Capabilities

	PLANT	FUEL TYPE	UNITS	OWNED CAPACITY
1	Four Corners	Coal	2	970
2	Cholla	Coal	2	387
3	Navajo	Coal	3	315
	Sub-total Coal fleet			**1,672**
4	Ocotillo	Natural Gas	4	330
5	Redhawk	Natural Gas	2	984
6	Saguaro	Natural Gas	2	189
7	Sundance	Natural Gas	10	420
8	West Phoenix	Natural Gas	7	997
9	Yucca	Natural Gas/Oil	6	243
10	Douglas	Oil	1	16
	Sub-total Gas & Oil fleet			**3,179**
	Total Fossil Fleet			**4,851**

Since the last rate case filing in 2011, the following changes have been made to the Fossil generating assets:

- **June 30, 2013** — APS retired Saguaro steam Units 1 and 2, removing 210 megawatts of 1955 vintage natural gas generating capacity.

- **December 30, 2013** — APS retired Four Corners Units 1, 2 and 3 (560 megawatts of coal generating capacity) and purchased Southern California Edison's 48% share of Four Corners Units 4 and 5 (739 megawatts), increasing APS's share in Four Corners by 179 megawatts.
- **October 1, 2015** — APS retired Cholla Unit 2, removing 260 megawatts of coal generating capacity.

Between 2013 and 2015, APS retired 1,030 megawatts of fossil fueled generating capacity, including 820 megawatts of coal and 210 megawatts of old natural gas steam units. Overall, APS's net ownership in fossil fueled generating capacity has decreased by 291 megawatts since the last rate case.

A. *Focus on Safety*

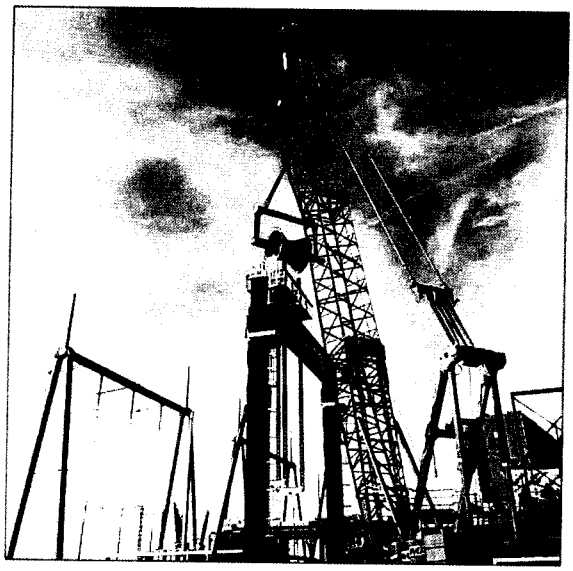
Q. WHAT IS FOSSIL GENERATION DOING TO INSTILL A STRONG SAFETY CULTURE?

A. Safety is a core value at APS. The APS value statement is "We work safely; it's the most important thing we do every day. Every employee has the absolute right and responsibility to prioritize safety – of self, co-workers and the public – above all else." We reinforce this in Fossil by having safety in our mission statement and Safety Effectiveness as one of our five Focus Areas.

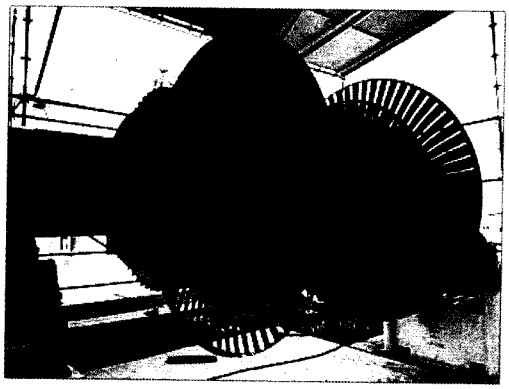
Running a power plant is inherently hazardous, and the men and women who work at our plants generating power for customers throughout the Southwest face significant safety risks each and every day. Think of how a steam unit generates electricity: a fuel is burned in a huge boiler to create enough heat to turn water into steam. That steam is highly pressurized and carried through thick metal pipes to the turbine. The turbine rapidly spins a generator, which changes mechanical spinning energy into electrical

energy. Maintenance repairs increase the exposure to potential safety hazards. During planned outages for equipment overhauls, employees and contractors may be working on one unit that is idled for repairs, but the other unit(s) at the plant will be operating and generating electricity. Often, large cranes and other equipment are utilized to perform heavy lifts of machinery that can weigh several hundred tons. Months and years of planning, attention to details and clear communication are critical to ensuring a safe, well executed outage.

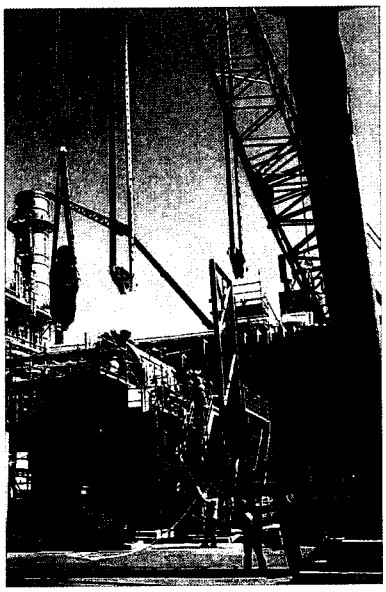
Commencing October 2014 through April 2015, Redhawk Power Plant executed sequential planned outages to overhaul the two combined cycle units including the replacement of the Steam Turbine Generators on each of the units. Photos from this outage illustrate the types of additional heavy equipment used at plants to move generating equipment during overhauls.

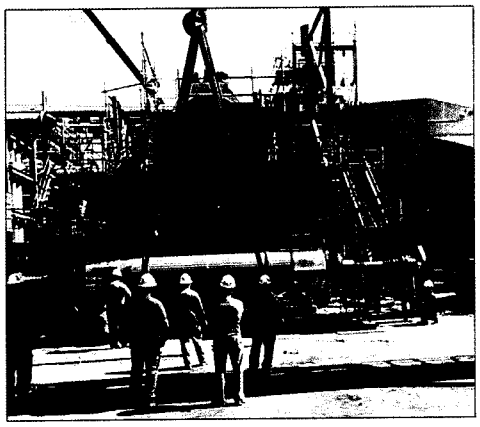


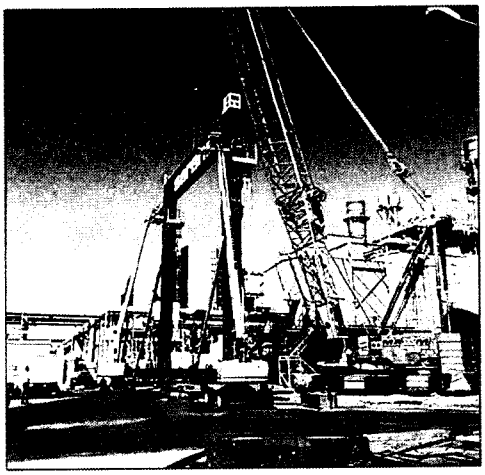
A crane was used to remove the Steam Turbine Upper-half Casing and Rotor from the enclosure to the ground in order to perform repairs on the Rotor blades.



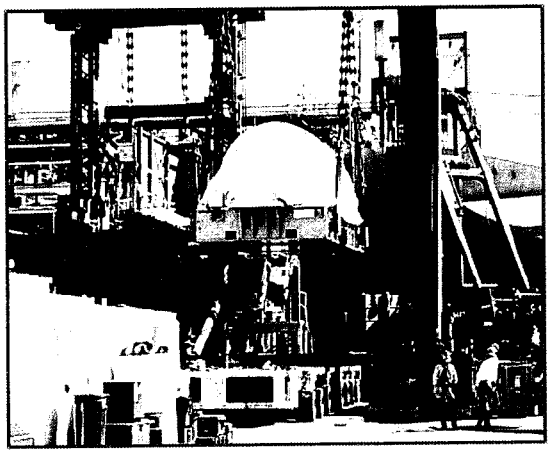
The old Steam Turbine Generator Rotor was removed from Generator Stator and lowered safely to the ground for scrap disposal.





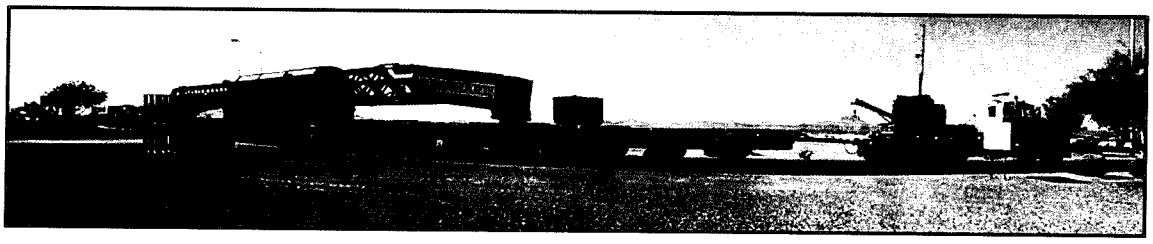


A Sarens Gantry lifting device was erected specifically for the project because of space limitations at the plant restricted the use of a crane capable of lifting the 275 Ton new Steam Turbine Generator. The lifting device was used to remove the old Steam Turbine Generator Stator.



As demonstrated on the photo to the right, the Sarens Gantry was also used to lift and slide the new Steam Turbine Generator into position in order to connect the new generator to the repaired Steam Turbine.

To further illustrate the size of the equipment, a 295 foot articulated flatbed was used to transport the replacement Steam Turbine Generator from Houston to Redhawk Power Plant. The flatbed had 16 independently driven axels and three 600 HP Prime mover trucks. Ten support personnel were needed to operate the transport truck to ensure safe delivery of the new 275 Ton Steam Turbine Generator.



The Redhawk overhaul was replete with potential safety hazards. Indeed, all power plant workers face potential hazards every day when working amongst hazardous materials, high temperature and pressure piping, and rotating equipment.

APS is focused on safety at every turn and every work day in the Fossil organization begins with a safety message and every job begins with a pre-job briefing to acknowledge, discuss and plan for potential risks before work commences. It is reassuring to all of us that APS has made safety its first priority and insists that our employees and contractors do the same. That is the message behind the Company's 'United in Safety' campaign. Safety is our #1 priority and every person at a Fossil facility is responsible for the safety of themselves, co-workers and the public.

B. *Focus on the Environment and Regulatory Compliance*

Q. IS FOSSIL GENERATION FOCUSED ON PROTECTING THE ENVIRONMENT?

A. Yes. In January 2016, the Arizona Department of Environmental Quality (ADEQ) recognized APS's West Phoenix Power Plant for going beyond the state's environmental

regulations. The plant joined APS's Ocotillo Power Plant as a Platinum member of the ADEQ's Voluntary Environmental Stewardship Program. They are the only power plants in the program, and are two of just10 facilities that have received the program's highest honor.

Q. PLEASE DESCRIBE THE ENVIRONMENTAL CHALLENGES FACING FOSSIL GENERATION.

A. APS, like other fossil-fueled electric generators, faces several environment-related regulatory pressures from federal, state, local, and Indian County regulators. The regulating entities include the Environmental Protection Agency (EPA), Maricopa County Air Quality Department, Pinal County Air Quality Control District and Arizona Department of Environmental Quality (ADEQ), and the Navajo Nation Environmental Protection Agency. The EPA is the primary federal regulating agency, and each district and agency may enact its own set of environmental rules and regulations as long as they are at least as stringent as their federal counterparts.

APS has been focused on actions needed to comply with the standards for the Clean Air Act:

- Mercury and Air Toxics Standards for Utilities (MATS)
- Regional Haze Regulations (RHR)
- Reasonably Available Control Technology (RACT)
- New Source Performance Standards (NSPS) and New Source Review (NSR)

APS also complies with standards for the Clean Water Act:

- National Pollutant Discharge Elimination System (NPDES)
- Section 316(b) Rules for Cooling Water Intake Structures
- Effluent Limit Guidelines

Other Environmental regulatory standards APS meets include:

- Resource Conservation and Recovery Act (RCRA) impacting Coal Combustion Residuals (CCR)

As outlined in the table below, Regional Haze compliance has and will continue to be the biggest driver of environmental expenditures over the next few years.

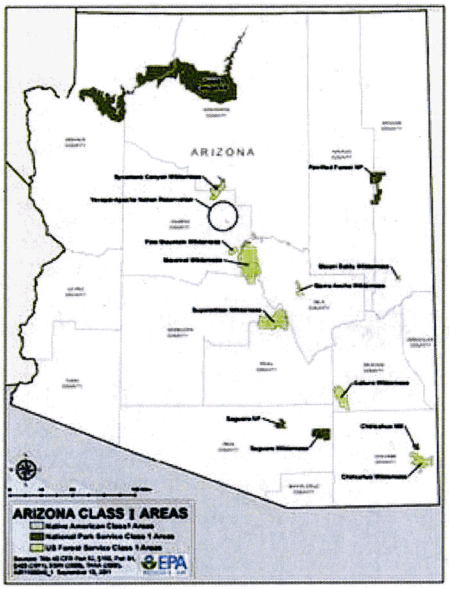
	Regional Haze / BART	Mercury and Other Hazardous Air Pollutants	Coal Combustion Residuals	Four Corners Consent Decree
EPA Ruling	Announced in 1999, with site-specific requirements announced more recently	MATS compliance by April 2015, with potential for one-year extension	Announced on December 19,2014 (Subtitle D)	New limit of 95% SO2 removal as measured by a 30-operating-day rolling average must be met by 2018
Technology	Selective Catalytic Reduction (SCR)	Activated Carbon Injection (ACI) + Fabric Filter (Baghouse)	Lined Ash Impoundment facilities	Absorber Modules of the Flue Gas Desulfurization (FGD)
Four Corners Power Plant Units 4&5	• Approximately $400M for SCRs in 2015-2018 • Cost includes construction of a Urea to Ammonia plant necessary to supply a steady stream of ammonia to the SCR's catalyst	• Meets removal standard • Required to install Continuous Emissions Monitoring Systems (CEMS) to monitor performance and ensure continued regulatory compliance	• Closure of existing non-lined impoundments & build new lined ash containment facilities • Over $10M spent 2015-2017 in preparation for CCR regulations	• Restore SO2 removal capabilities of existing absorber modules that are part of the Flue Gas Desulfurization (FGD) • Approximately $40M for upgrades to existing absorber modules in 2015 - 2018
Cholla Power Plant Units 1 & 3	• September 11, 2014, APS announced a proposal to close Unit 2 by April 2016 and stop burning coal on Units 1 & 3 • Unit 2 retired October 1, 2015 • Cost for an SCR on Unit 3 is approximately $100M. • Unit 1 currently not BART eligible	• Activated Carbon Injection technology and Continuous Emissions Monitoring • Approximately $9M in 2014-2016 • Additional chemical costs for operation	• Closure of non-compliant facilities and build sufficient capacity to support operations until the cessation of burning coal in mid-2020s	n/a
Navajo Generating Station Units 1-3	• Up to ~$200M for SCRs and Fabric Filters	Installed pre-combustion injection of calcium bromide method to enhance mercury oxidation	• Approximately $2 million to install monitoring wells	n/a

Note: All amounts shown as APS ownership
- Cholla Unit 4 is owned by PacifiCorp
- Navajo Generating Station is operated by Salt River Project (SRP)

Q. WHAT IS REGIONAL HAZE COMPLIANCE AND THE IMPACT TO FOUR CORNERS?

A. Regional Haze Regulations were authorized under Section 169A of the Clean Air Act. This rule requires the use of Best Available Retrofit Technology (BART) to eliminate current and prevent future man-made visibility impairments in geographic locations classified as Class I areas, and to achieve 'natural background conditions' by 2064. The term Class I Area describes certain national parks and wilderness areas that were designated by Congress in 1977 as having special goals to improve levels of visibility in

these areas, and to prevent any further impairment of visibility due to human causes. *See* Arizona Class 1 areas on map below. Oxides of Nitrogen (NOx), Sulfur (SO_2) and particulate matter are considered the contributing factors in regional haze.



In alignment with the EPA's Federal Implementation Plan [77 FR 165, August 24, 2012] and the Consent Decree issued June 24, 2015 for Four Corners Power Plant Units 4 and 5, APS must install Selective Catalytic Reduction (SCR) technology to reduce the NOx emissions to a level of 0.08 lb./mmbtu and replace sections of the Flue Gas Desulfurization (FGD) systems to meet 95% SO_2 emissions removal from the flue gas created from coal combustion.

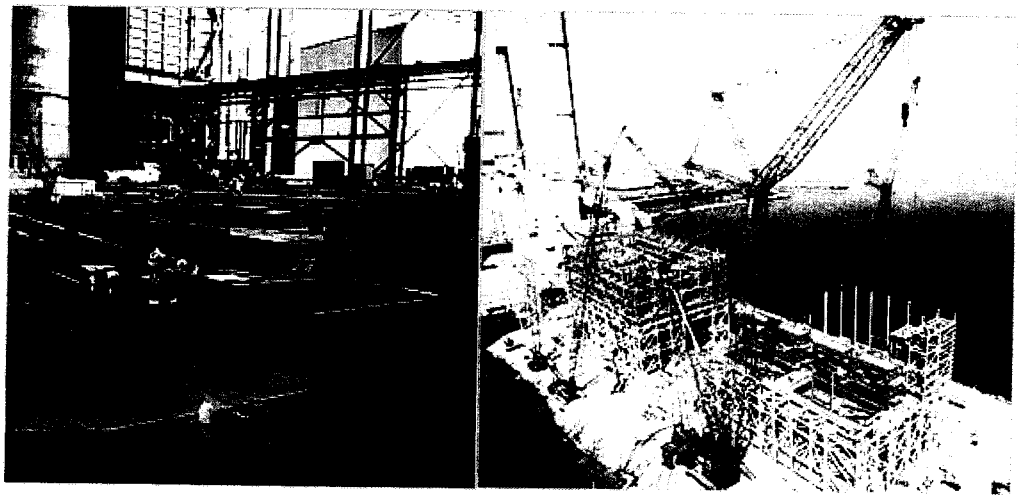
Q. PLEASE EXPLAIN MORE ABOUT THE SCR PROJECT.

A. Since the 1970s, automobiles and trucks have had catalytic converters as part of the exhaust system. In most cars, the catalytic converter is a cylindrical shape device located after the engine and before the muffler. The device uses a catalyst to change the chemical composition of exhaust gas resulting from the combustion of gasoline into a less-harmful matter.

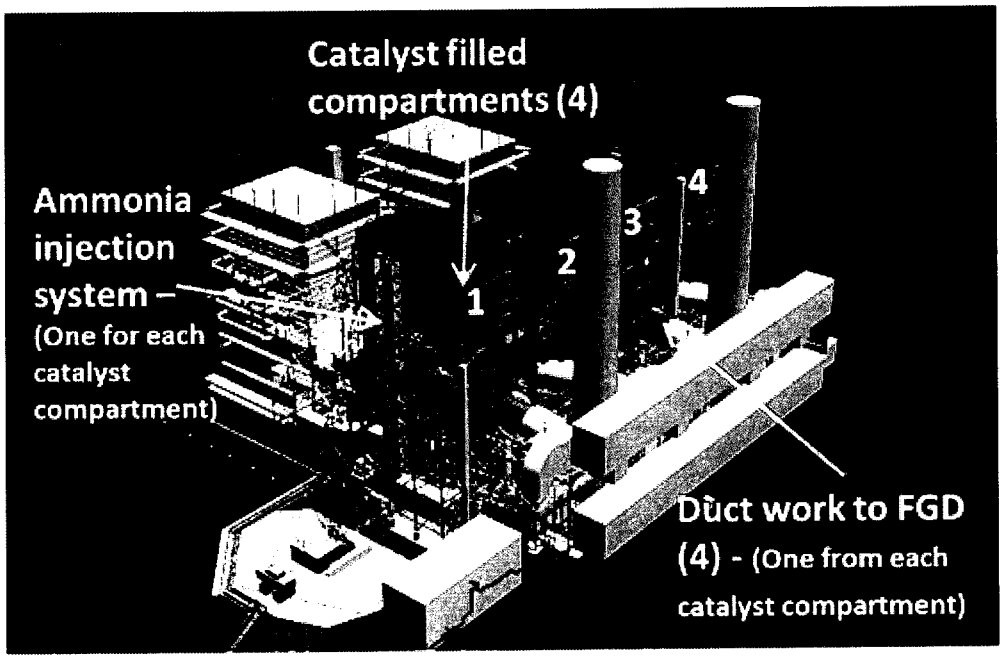
At Four Corners, the SCRs will take the post-coal combustion gas that contains nitrogen oxides from the units' boilers, inject ammonia (NH_3) and then flow through a catalyst filled compartment where the mixture will react with its nitrogen oxides (NOx) to create nitrogen (N_2) and water (H_2O). The flue gas will continue through the duct work to fabric filters (also known as baghouses) and onto the FGD systems for SO_2 removal before exiting the stacks with significantly lower emissions.

APS started the SCR project in early 2014 using a competitive-bid process to evaluate qualitative and quantitative metrics before completing an Engineering, Procurement and Construction (EPC) contract with a firm experienced in SCR projects. The open-book process was used to examine the cost estimates and the cost-estimate basis before completing the contract. APS's share of the SCR project is projected to be approximately $400 million and $35 million to upgrade the condition of the FGD.

In 2016, infrastructure and the pilings/footings necessary to support the new equipment are under construction (below left).



A crane, like the one above (right), capable of lifting 825 Tons is being installed to be able to lift and set modularized components of the SCR into place, illustrated below.



The SCR must be operational at Four Corners for one of the units by March 31, 2018 and by July 31, 2018 for the remaining unit.

Q. DOES FOSSIL GENERATION PLAN FOR FUTURE ENVIRONMENTAL REGULATIONS? IF SO, HOW?

A. Absolutely. When we foresee that a new regulation may impact some portion of our fleet, Fossil develops working teams that include members from each area of the company whose perspective is needed to develop an integrated approach to cost-effectively address the issue.

Our engineering department examines the options available to meet the potential rule early in the rulemaking process so that these alternatives and their costs and schedules are available as we prepare comments to the proposed rule and for business planning purposes.

Our environmental department obtains the necessary environmental permits, drafts or amends policies and develops training as needed to provide guidance on the new rule(s) and outline the steps required to become and remain compliant. From a budgeting perspective, the Environmental Department keeps Fossil's leaders continuously informed of regulatory developments, so that they may account for environmental concerns in the budgeting and operational planning process.

When a pending regulation is sufficiently close to finalization, the working team assesses the likely timing for and cost of compliance, and when appropriate, includes those costs in the Company's long-range forecast to be considered in corporate financial projections. When it is cost effective to do so, Fossil completes required environmental upgrades in advance of the rule.

Q. WHAT IMPACTS DOES APS ANTICIPATE ON ITS FOSSIL PLANTS AS A RESULT OF THE CLEAN POWER PLAN AND HOW IS APS PLANNING TO ADDRESS THESE IMPACTS?

A. Unlike the BART rulings, discussed above, that are power plant specific, the Clean Power Plan is based upon total emissions within a state's boundary. Representatives from APS are working with ADEQ and other Arizona utilities and electric generators to develop recommendations for the Arizona Compliance Plan. APS witness James Wilde will provide testimony on the Clean Power Plan.

Q. WHAT WAS THE COST OF ENVIRONMENTAL COMPLIANCE DURING THE 2015 TEST YEAR?

A. Project expenditures in 2015 that ensure compliance with Environmental regulations totaled $41 million. These projects include:

- $23 million for Selective Catalytic Reduction implementation at Four Corners;

- $4 million for the installation of equipment at Cholla to meet Mercury and Air Toxics Standards requirements by April 2016;
- $4 million on catalyst replacements across the fleet; and
- $3.6 million to complete projects to maintain reliability of the Continuous Emissions Monitoring System (CEMS) at all of the plants and ensure compliance with Environmental Protection Agency 40 CFR 75 - Part 75 Emissions Monitoring Policy.

Q. PLEASE IDENTIFY THE ENVIRONMENTALLY-DRIVEN CAPITAL PROJECTS THAT FOSSIL GENERATION WILL COMPLETE BY JUNE 30, 2017.

A. A listing of all of the capital projects that Fossil Generation will place in service for customers by June 30, 2017 is attached to my testimony at JRL-1DR. The costs of the environmental projects are estimated to be $37.2 million. See all of the projects that are labeled FG_Environmental in the category column. Two of the main environmental projects being completed in the post-Test Year Plant period include:

- Installation of activated carbon injection system to reduce mercury emissions on Cholla Units 1 and 3. The scope of these projects is estimated to cost $6.7 million.
- Overhaul of Four Corners Units 4 and 5 absorber modules to meet 95% SO2 removal and reduce moisture carry-over to the steam stack. The scope of these projects is estimated to cost more than $20 million.

Q. ARE THERE EXTERNAL DRIVERS OTHER THAN THE PREVIOUSLY DISCUSSED REGULATIONS THAT HAVE IMPACTED FOSSIL?

A. Yes. Another external force impacting Fossil's operating costs is the cost of water, specifically at Redhawk Power Plant that is located near Arlington and next to the Palo Verde Nuclear Generating Station (PVNGS). Redhawk's cooling water is supplied by

the PVNGS Water Reclamation Facility. The facility uses effluent from cities and towns in the region as its source of water. Water Reclamation uses various processes to transform the effluent into water of sufficient quality to use for Redhawk's cooling towers. In 2010, PVNGS successfully negotiated a new contract with the Sub-Regional Operating Group (SROG) to have a secure supply of effluent through 2050. Since the original contract with the SROG cities was negotiated in 1973 the market value of the effluent had grown substantially but the two parties agreed to a more rapid escalator through 2025 versus a sudden jump in cost that would have had a significant increase in cost of generation. Beginning in 2026, a tiered water rate structure will be implemented. The implementation of this rate will increase the treated water cost for Redhawk by approximately 15% in 2026 and approximately 3% each year thereafter. Please see APS Witness Peter Ewen's testimony for a discussion of why APS is proposing to include the costs of water in its Power Supply Adjustor mechanism.

C. *Focus on Reliability*

Q. WHAT IS THE LARGEST IMPROVEMENT IN RELIABILITY FROM THE LAST RATE CASE?

A. The projects to replace of the Steam Turbine Generators on Redhawk Combined Cycle Units 1 and 2, discussed earlier, have resulted in the largest reliability improvements. Both Unit 1 and 2 Steam Turbine Generators had experienced design abnormalities demonstrated by extreme levels of vibration and noise. Abnormalities had caused multiple major issues, generator failures and forced outages. The risk for future component failures was high and the severity of a fault could have resulted in a steam turbine generator extended forced outage in excess of one year due to lead times. Upon Unit return-to-service, the projects delivered reductions in vibration and noise levels. While the replacements were complete only a little over a year ago, the average Equivalent Availability Factors since return-to-service are Unit 1 95.2% (February 2015

to March 2016) and Unit 2 95.9% (May 2015 to March 2016) versus the pre-project 5 year average of 82.8% and 81.1%, respectively. Equivalent Availability Factor is an industry standard reliability measurement defined as the fraction of a given operating period in which a generating unit is available without any outages or equipment de-ratings.

Q. HAS FOSSIL HAD ANY CHALLENGES WITH RELIABILITY, AND IF SO, HOW IS APS WORKING TO MITIGATE THOSE CHALLENGES?

A. In 2015, Fossil had to repair one of the combustion turbines on the West Phoenix Combined Cycle Unit 5. A catastrophic failure in November 2014, due to a design issue from the original equipment manufacturer, resulted in an eight month forced outage to replace the rotor, turbine components and a portion of the tubes in the heat recovery steam generator of this unit. These repair costs were covered under an insurance claim.

Q. HOW IS APS ADDRESSING THE CHALLENGES OF ITS AGING FOSSIL FLEET?

A. Fossil is taking both a programmatic approach and a strategic capital investment plan to address the reliability challenges of an aging fleet. Programmatically Fossil is focused on improving its Asset Management program. We are using the International Standards Organization's ISO55000 series [International Standard for Asset Management] and Electric Power Research Institute (EPRI) guidelines as the foundation for the Fossil initiative. The goal is to focus our activities to preventive maintenance versus corrective maintenance. It is more cost effective and requires less equipment down time to repair something just before is fails rather than after it fails and results in a forced outage. This is the same approach that car owners use. Scheduled car maintenance means parts are replaced just as they are ready to fail and prior to suffering a breakdown when driving.

Fossil uses the planned outage cycles to execute major O&M work and capital investments needed to keep the Fossil units running in a manner that is safe, environmentally compliant and reliable. Examples of some reliability programs/projects executed and/or planned are:

- **Redhawk Steam Turbine Generator Replacement** — In 2015, Fossil completed the previously mentioned $50 million project to address steam turbine generator abnormalities on both Redhawk combined cycle units. In 2016, Redhawk Power Plant is projected to provide 20% of Fossil's generation.
- **Douglas reliability** — In late 2014, APS invested $5 million for a turbine overhaul and original control system replacement for the 1972 vintage 16-megawatt generator located in Douglas, Arizona.
- **Yucca reliability** — In 2015, APS completed the $2 million generator rotor rewind of Yucca CT3. The 55-megawatt combustion turbine is used for Yuma load pocket support during periods of peak demand.

Q. WHAT COST IS REQUIRED TO ENSURE RELIABLE PERFORMANCE OF THE FOSSIL GENERATION FLEET?

A. The inspections and other activities described above required significant capital and O&M dollars. APS's share of the fleet's total reliability-related spend in the 2015 Test Year exceeded $230 million. These expenditures include the following:

- $115 million in reliability based capital projects
  –$57 million for reliability projects on coal plant assets
  –$58 million on the natural gas plant assets of which $17 million funded capital projects executed during the major overhaul on Redhawk's combined cycle units
- $118 million in reliability maintenance expenditures which includes $17.5 million in planned outage (overhaul) costs. The largest of which was the Hot

Gas Path inspection that occurred during the Redhawk major overhauls that cost $9.2 million.

Q. PLEASE IDENTIFY THE RELIABILITY-RELATED CAPITAL PROJECTS THAT FOSSIL GENERATION WILL COMPLETE BY JUNE 30, 2017.

A. A listing of all of the capital projects that Fossil Generation will place in service for customers by June 30, 2017 is attached to my testimony as Attachment JRL-1DR. The cost of reliability-related projects is estimated to be over $88 million. See all of the projects that are labeled FG_Reliability in the category column.

D. *Focus on Cost Management*

Q. IS FOSSIL GENERATION FOCUSED ON COST MANAGEMENT?

A. Yes. In accordance with the stay out that was part of the last APS Rate Case Settlement, Decision No. 73183, Docket No. E-01345A-11-0224, Fossil has been dedicated to keeping year-over-year O&M expenditures as flat as possible.

As previously mentioned, Fossil maintains a planned outage maintenance cycle according to EPRI and original equipment manufactures' recommendations; failure to comply with these recommendations could result in loss of equipment warranties and/or impairment of generating units' reliability. The need to maintain the planned outage cycle, implement changes to meet safety and environmental regulations, and absorb the annual cost-of-living increases associated with the International Brotherhood of Electrical Workers (IBEW) contract has put additional cost reduction pressures on Fossil and other APS business units. To offset some of these incremental costs, Fossil has:

- Prioritized planned outage and O&M project expenditures based upon industry best practices including Original Equipment Manufacturer's recommendations and EPRI industry guidelines;

- Implemented improvements in the work management process;
- Executed forced outage repairs on straight-time rather than over-time, when economically justified;
- Combined plant operations for Ocotillo, Sundance, Saguaro and Douglas; and
- Decommissioned older, less-efficient generating units.

Also of benefit to maintaining the year-over-year cost control measures was the lack of a major planned outage for turbine/boiler overhauls on the large coal units.

In 2016, Fossil entered a three-year period of major overhauls on the large coal units with planned outages for Cholla Unit 3 and Four Corners Unit 5 executed earlier this year. Investment in Four Corners Units 4 and 5 is imperative to improving the level of performance on these 770 megawatt units. To reliably operate to 2038, the current asset end of life, Fossil has a three year investment strategy to improve the health of Four Corners Units 4 and 5. Due to the decision to exit coal generation at Cholla by no later than the mid-2020s, the recently completed Unit 3 overhaul was reduced in scope to only those projects needed to maintain the unit's safe, environmentally compliant and reliable operations through that time.

IV. TOTAL FOSSIL GENERATION OPERATIONS AND CAPITAL REQUIREMENTS

A. *Total Capital Expenditures at the Fossil Plants.*

Q. WHAT WERE FOSSIL GENERATION'S NET PLANT ADDITIONS DURING THE TEST YEAR?

A. As illustrated in Standard Filing Requirement (SFR) E-5, Fossil Generation added approximately $116 million in plant during the 2015 Test Year, bringing the business unit's total plant balance to approximately $4.19 billion.

Q. WHAT LEVEL OF PLANT ADDITIONS DOES FOSSIL GENERATION EXPECT THROUGH JUNE 30, 2017?

A. Attached to this testimony as Attachment JRL-1DR is a detailed breakdown of the capital projects that will be in service as of June 30, 2017. As that exhibit shows, Fossil Generation expects to add a total of $161 million by that date. APS witness Elizabeth A. Blankenship describes additional details of the adjustment, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes and interest expense.

V. CONCLUSION

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

A. Fossil's mission is to deliver superior operational performance while instilling a strong safety culture and protecting our environment. Like other fossil-fueled generators in the industry, APS's fossil fleet faces significant challenges. I firmly believe that we will navigate those challenges and continue to deliver cost-effective, reliable power to APS's customers and others throughout the southwest.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

FOSSIL POST-TEST YEAR PLANT ADDITIONS

Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
1	Four Corners - Common	Main Air Compressor Replacements	The purpose of the project is to increase Unit reliability and reduce annual O&M cost. This project will replace the existing 40 year old Allis Chalmers air compressors and ancillary equipment. The Allis Chalmers compressors have exceeded useful life and are unreliable. The coolers are heavily corroded and impellers are damaged from scaling and have a failure rate of every three years.	FG_Reliability	3/31/2016	$ 11,755,489	$ 2,481,951	$ 14,237,439
2	Navajo - Navajo Units 1-3	Navajo Reliability Project Budget	The scope of this program to support APS's share of Navajo Generating Station's capital projects	FG_Navajo	6/30/2017	$ 4,269,898	$ 9,118,274	$ 13,388,171
3	Four Corners - Unit 5	High Energy Valve Rebuild	The purpose of the project is to proactively avoid Main Steam Valve and Control Valve weld joint failures in order to eliminate potential safety risk and maintain long-term unit reliability. Steam piping, Main Steam Valve and Control Valve bodies have been in service over 40 years and are approaching the end of serviceable life	FG_Reliability	4/1/2016	$ 4,021,912	$ 2,449,078	$ 6,470,990
4	Saguaro - Combustion Turbine 2	Hot Gas Path/Major Inspection	The purpose of this project is to rebuild the 501AA and ancillary mechanical and electrical equipment to help ensure future 90% reliability going forward to 2025.	FG_Reliability	5/1/2016	$ 2,627,086	$ 2,554,983	$ 5,182,069
5	West Phoenix - Combined Cycle 2	Major Inspection	The purpose of this project is to maintain Unit Reliability by conducting a major overhaul of the combustion turbine according to OEM recommended accumulated starts.	FG_Reliability	4/5/2016	$ 1,560,764	$ 3,488,650	$ 5,049,414
6	Four Corners - Unit 4	Phase 1 Water Piping Replacement	The purpose of this project is to ensure reliability of safety-critical systems (Potable, Service, and Firewater systems) through replacement of degraded water piping and to maintain compliance with OSHA standard 1910.151 and ANSI Z358.1. Reduce the probability of system outages caused by main breaks in degraded piping systems. For Potable water alone, there were 6 failures in 2012, 11 in 2013 and 9 in the first 3 months of 2014. Service water and fire water are experiencing similar failure rates.	FG_Safety	1/30/2016	$ 4,060,638	$ 390,965	$ 4,451,604
7	Saguaro - Combustion Turbine 2	Inlet Cooler and Silencer Replacement	The purpose is to increase reliability and availability by restoring power output provided by the evaporative cooling of inlet air, decreasing wear on the turbine blades, and reducing the possibility of foreign object damage to the turbines, which would result in costly emergency repairs and significant unplanned downtime.	FG_Reliability	5/1/2016	$ 2,547,943	$ 1,509,198	$ 4,057,142
8	Four Corners - Unit 4	Absorber Module Overhaul 4C	The purpose of this project is to comply with the 2015 Consent Decree requiring 95% SO2 removal with no bypass.	FG_Environmental	12/1/2016	$ 398	$ 4,039,470	$ 4,039,868
9	Four Corners - Unit 5	Absorber Module Overhaul 5SC	The purpose of this project is to comply with the 2015 Consent Decree requiring 95% SO2 removal with no bypass.	FG_Environmental	8/13/2016	$ -	$ 4,002,605	$ 4,002,605
10	Four Corners - Unit 4	Absorber Module Overhaul 4NC	The purpose of this project is to comply with the 2015 Consent Decree requiring 95% SO2 removal with no bypass.	FG_Environmental	8/13/2016	$ -	$ 3,996,744	$ 3,996,744
11	Four Corners - Unit 5	Absorber Module Overhaul 5NC	The purpose of this project is to comply with the 2015 Consent Decree requiring 95% SO2 removal with no bypass.	FG_Environmental	4/30/2017	$ -	$ 3,994,221	$ 3,994,221
12	Four Corners - Unit 4	Absorber Module Overhaul 4N	The purpose of this project is to comply with the 2015 Consent Decree requiring 95% SO2 removal with no bypass.	FG_Environmental	5/1/2016	$ -	$ 3,968,775	$ 3,968,775
13	Four Corners - Common	Common Building Replacement	The purpose of this project is the construction of a new building on plant site to replace the previous Common Facilities Building that was demolished in 2015 after being declared a safety risk to personnel.	FG_Safety	10/27/2016	$ 1,048,693	$ 2,896,020	$ 3,944,713
14	Saguaro - Combustion Turbine 2	Control System Replacement	The purpose of this project is to improve the unit reliability with a 90% dependable start going forward and to extend life of asset to 2025.	FG_Reliability	5/1/2016	$ 1,963,841	$ 1,826,472	$ 3,790,313
15	Cholla - Unit 3	Activated Carbon Injection	The purpose of this project is to meet the EPA regulatory requirement 40 CFR 63, Subpart UUUUU (commonly called Mercury and Air Toxics Standards or MATS) by the defined regulatory compliance date of April 16th, 2016.	FG_Environmental	3/15/2016	$ 3,325,694	$ 281,637	$ 3,607,331

FOSSIL POST-TEST YEAR PLANT ADDITIONS

Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
16	Sundance - Combustion Turbine 3 & 4	GSU Replacement	The purpose of this project is to restore unit reliability by replacing the GSU Transformer	FG_Reliability	4/15/2016	$ 1,425,637	$ 2,067,045	$ 3,492,682
17	Four Corners - Unit 5	Scrubber Outlet Duct Liner Replacement	The purpose of this project is to ensure continued integrity of the scrubber outlet duct and maintain Unit Reliability. The existing liner has experienced extensive corrosion. There is also damage to the carbon steel duct plate in several locations, as a result of moisture leaking through the liner. Corrosion of the carbon steel duct and stiffeners can compromise the structural integrity of the duct. In addition to potential structural damage, corrosion of the C22 liner and carbon steel plate has the potentional to allow flue gas to leak directly to the atmosphere, presenting an environmental concern.	FG_Environmental	4/1/2016	$ 877,315	$ 2,571,201	$ 3,448,516
18	Four Corners - Unit 5	CIP-Physical/Cyber Asset-System Upgrade	The purpose of the project is to comply with federal requirements in meeting physical and cyber security measures. Compliance Effective Date is estimated to be April 1, 2016. Failure to comply with the regulatory requirements by the effective date will place the unit in a non-compliance status which will result in fines. Fines can range from one million dollars per day per violation.	FG_Regulatory	1/29/2016	$ 2,787,715	$ 528,566	$ 3,316,282
19	Cholla - Unit 1	Activated Carbon Injection	The purpose of this project is to meet the EPA regulatory requirement 40 CFR 63, Subpart UUUUU (commonly called Mercury and Air Toxics Standards or MATS) by the defined regulatory compliance date of April 16th, 2016.	FG_Environmental	3/15/2016	$ 2,955,404	$ 186,250	$ 3,141,654
20	West Phoenix - Combined Cycle 2	Generator Breaker Replacement	The purpose of this project is to maintain unit reliability. The existing GCBs have caused lost MWHs, are obsolete, unreliable, and replacements parts are becoming more difficult to find.	FG_Reliability	4/5/2016	$ 1,385,053	$ 1,636,115	$ 3,021,168
21	Saguaro - Combustion Turbine 1	Control System Replacement	The purpose of this project is to improve the unit reliability with a 90% dependable start going forward and to extend life of asset to 2025.	FG_Reliability	3/17/2017	$ 24,153	$ 2,738,190	$ 2,762,343
22	Four Corners - Unit 5	Horizontal Reheat Bank Partial Replacement	The purpose of this project is to restore Unit Reliability. High ash loading and velocity have resulted in severe erosion of the Horizontal Reheater and economizer stringer tubing, resulting in tube failures and forced outages. This project will replace Horizontal Reheater elements and economizer stringer tubes that are subjected to the worst erosion.	FG_Reliability	4/1/2016	$ 837,871	$ 1,923,428	$ 2,761,299
23	Four Corners - Unit 5	Upper Economizer Replacement	The purpose of this project is to restore Unit reliability. High ash loading and velocity has resulted in severe erosion in the Economizer. These elements are repaired by weld build-up and tube shielding until they are sufficiently worn out to warrant replacement.	FG_Reliability	4/1/2016	$ 1,439,870	$ 1,274,810	$ 2,714,680
24	West Phoenix - Combined Cycle 1	Generator Breaker Replacement	The purpose of this project is to maintain unit reliability. The existing GCBs have caused lost MWHs, are obsolete, unreliable, and replacements parts are becoming more difficult to find.	FG_Reliability	4/1/2016	$ 978,229	$ 1,687,011	$ 2,665,240
25	Four Corners - Unit 5	Air Preheater Hot and Intermediate Basket Replacements	The purpose of this project is to ensure continued Unit reliability. Since installation of the Low NOx Burners in 1990, higher fly ash production has accelerated deterioration of the existing baskets.	FG_Reliability	4/1/2016	$ 1,343,374	$ 922,829	$ 2,266,203
26	Four Corners - Common	Coal Handling System Dust Elimination	The purpose of this project is to mitigate coal spilage and dusting which is a cause of potential Air Permit/Title V compliance issues, as well as OSHA's National Emphasis Program (NEP) on Combustible dust. The OSHA NEP references several NFPA standards, as well as OSHA's general duty clause [29 U.S.C. § 654, 5(a) as the basis for issuing citations]. The General Duty Clause states that employers must provide a safe place for employees to work. Excessive combustible dust creates unsafe working areas due to dust/spillage buildup.	FG_Safety	4/1/2016	$ 1,241,236	$ 1,015,377	$ 2,256,613

FOSSIL POST-TEST YEAR PLANT ADDITIONS

Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
27	Four Corners - Common	Heat Trace Phase 1	The purpose of this project is to maintain unit reliability through heat trace system replacements and improvements.	FG_Regulatory	10/27/2016	$ 252,736	$ 1,792,504	$ 2,045,240
28	Sundance - Common	Spare Generator Step Up Transformer	The purpose of this project is to improve unit reliability by providing a spare GSU transformer to reduce forced outage time incurred in the event of a GSU failure.	FG_Reliability	5/3/2016	$ 964,378	$ 821,837	$ 1,786,215
29	Four Corners - Unit 5	Coal Pipe Hanger Replacements	The purpose of this project is to maintain safety. Some of the existing pipe supports are overstressed due to the heavier ceramic lined pipe fittings. The overstressed supports allow excessive deflection that leads to joint leaks. The unit would have to be curtailed if a joint fails to avoid igniting combustible coal dust.	FG_Reliability	4/1/2016	$ 557,973	$ 1,055,985	$ 1,613,958
30	Ocotillo - Combustion Turbine 1	Row 3 Diaphragm Replacement	The purpose of this project is to restore unit reliability by replacing the 3rd row diaphragm, eliminating vibrations of the turbine system and returning the unit to service.	FG_Reliability	4/15/2016	$ 390,903	$ 1,141,289	$ 1,532,192
31	Ocotillo - Combustion Turbine 2	Main Lube Oil and Rotor Air Cooler Replacement	The purpose of this project is to maintain unit reliability during the hottest days of the year when this unit is most needed. The Main Lube Oil and Rotor Air Coolers are past their useful life and do not cool the oil to the required temperature. This creates a unit reliability concern.	FG_Reliability	4/19/2016	$ 346,742	$ 1,130,344	$ 1,477,086
32	Four Corners - Unit 5	Natural Gas Igniter System Replacement	The purpose of this project is to ensure continued safe and reliable Unit Start-up. The Unit currently experiences ignition system reliability problems that interrupt the lighting off procedure during start-up. These lighting off interruptions not only waste ignition fuel, but make it difficult to predict unit availability on start-up. The existing igniters are prone to fly ash/coal dust plugging which is a characteristic of positive pressure boilers.	FG_Safety	4/1/2016	$ 1,035,794	$ 427,292	$ 1,463,086
33	Four Corners - Unit 4	Natural Gas Igniter System Replacement	The purpose of this project is to ensure continued safe and reliable Unit Start-up. The Unit currently experiences ignition system reliability problems that interrupt the lighting off procedure during start-up. These lighting off interruptions not only waste ignition fuel, but make it difficult to predict unit availability on start-up. The existing igniters are prone to fly ash/coal dust plugging which is a characteristic of positive pressure boilers.	FG_Reliability	4/8/2016	$ (30,923)	$ 1,437,438	$ 1,406,516
34	Ocotillo - Combustion Turbine 1	Main Lube Oil and Rotor Air Cooler Replacement	The purpose of this project is to maintain unit reliability during the hottest days of the year when this unit is most needed. The Main Lube Oil and Rotor Air Coolers are past useful life and do not cool the oil to the required temperature. This creates a unit reliability concern.	FG_Reliability	4/19/2016	$ 781,413	$ 571,706	$ 1,353,120
35	Four Corners - Unit 5	Waterwall Center Panel Replacement	The purpose of this project is to maintain unit reliability while reducing the risk of forced outages due to wall tube leaks. For the past two years, the boiler has experienced an increased number of boiler tube leaks in the second and third pass transition zone waterwalls due to circumferential cracking.	FG_Reliability	4/1/2016	$ 39,845	$ 1,306,300	$ 1,346,145
36	West Phoenix - Combined Cycle 5	Combustion Turbine 5A Long Term Maintenance Parts - Siemens contract	The purpose of this project is to maintain Unit reliability by establishing a capital cash flow for the gas turbine long term maintenance program (LMTP) with the OEM. This 2016 project will be established to track the monthly payments for capital parts associated with unit overhauls.	FG_Regulatory	2/12/2016	$ -	$ 1,329,732	$ 1,329,732
37	West Phoenix - Combined Cycle 2	Auxiliary Cooling Water System Replacement	The purpose of this project is to maintain unit reliability by replacing the Auxiliary cooling water system.	FG_Environmental	3/19/2017	$ 105,527	$ 1,194,354	$ 1,299,880
38	Four Corners - Unit 5	4kV Switchgear Protective Relay Replacement	The purpose of this project is to ensure continued reliability of the Unit and avoid Unit trips or partial loss of generation through the replacement of the existing electromechanical relays which have reached the end of useful life and are unreliable during a fault. Testing of relays have noted wear and deterioration, and found many unrepairable and needing to be replaced. In addition replacement relays for the older style relays are no longer available in inventory.	FG_Reliability	4/1/2016	$ 331,585	$ 797,765	$ 1,129,350

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Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
39	West Phoenix - Combined Cycle 5	Combustion Turbine 5B Long Term Maintenance Parts - Siemens contract	The purpose of this project is to maintain Unit reliability by establishing a capital cash flow for the gas turbine long term maintenance program (LMTP) with the OEM. This 2016 project will be established to track the monthly payments for capital parts associated with unit overhauls.	FG_Regulatory	2/12/2016	$ -	$ 1,125,737	$ 1,125,737
40	West Phoenix - Combined Cycle 1	Auxiliary Cooling Water System Replacement	The purpose of this project is to maintain unit reliability by replacing the Auxiliary cooling water system.	FG_Environmental	3/11/2017	$ 22,706	$ 1,099,162	$ 1,121,868
41	Four Corners - Unit 4	Process Liquor Tank Replacement	The purpose of this project is to avoid a NPDES violation due to a tank failure. An independent inspection was conducted for the existing outdoor Unit 4 and 5 Process Liquor Tanks. Both tanks were found to be in very poor condition with significant corrosion due to pitting on the tank sidewalls and bottom as well as seepage where the coating has failed. Severe deterioration of the interior lining has contributed to a decrease in the tank metal thickness that is no longer in compliance to API 653 tank standards. The existing Unit 4 tank has provided a 31 year useful service life and will fail if not addressed.	FG_Reliability	11/15/2016	$ 59,227	$ 991,339	$ 1,050,566
42	West Phoenix - Common	Air Compressor Replacement	The purpose of this project is to maintain unit reliability by installing a reliable compressed air source to supplement the existing plant air system.	FG_Reliability	3/4/2016	$ 755,025	$ 241,178	$ 996,203
43	West Phoenix - Combined Cycle 5	Air Compressor Replacement	The purpose of this project is to provide reliable compressed air to the plant by replacing both of the existing CC5 air compressors which have reached the end of usable life.	FG_Reliability	12/15/2016	$ -	$ 899,906	$ 899,906
44	West Phoenix - Combined Cycle 5	Zero Liquid Discharge Fan Impeller and Housing Replacement	The purpose of this project is to restore unit reliability by replacing Zero Liquid Discharge components. The Zero Liquid Discharge fan components are at the end of useful life.	FG_Reliability	4/30/2016	$ 412,503	$ 460,177	$ 872,680
45	Four Corners - Unit 5	Baghouse Flyash Removal Controls	The purpose of this project is to maintain environmental compliance. The Baghouse Flyash Transport System controls the removal of ash from the hoppers of the particulate control device. A failure of this system will result in an extended 16-day forced outage for repair and return to service. Current controllers are approaching the end of life. All spare parts have been used.	FG_Reliability	4/1/2016	$ 530,312	$ 275,949	$ 806,261
46	Four Corners - Common	Overhead Cable Tray Replacement	The purpose of this project is to maintain plant reliability by replacing sections of damaged cable tray and to mitigate the risk of additional tray failures.	FG_Reliability	10/21/2016	$ 249,867	$ 451,298	$ 701,165
47	Four Corners - Unit 5	2015 Fabric Filter Bag Replacement	The purpose of this project is to ensure continued environmental compliance, while maintaining unit operational performance, in the capture and disposal management of fly ash. The fabric filter bags are approaching the end of their serviceable life and require replacement to ensure continued high efficiency particulate dust capture and removal and compliance with the PM standard defined in the Plant's Title V Permit.	FG_Environmental	11/20/2016	$ -	$ 688,461	$ 688,461
48	Redhawk - Combined Cycle 1	Protective Relay Replacement	The purpose of this project is to maintain unit reliability by replacing faulty transformer differential relays with similar digital relays.	FG_Reliability	11/18/2016	$ 38,664	$ 601,349	$ 640,013
49	Four Corners - Common	HVAC Equipment Replacement	The purpose of this project is to provide a reliable HVAC for plant controls equipment and personnel.	FG_Reliability	5/28/2016	$ 173,705	$ 442,675	$ 616,380
50	Four Corners - Unit 4	Baghouse Flyash Removal Controls	The purpose of this project is to maintain environmental compliance. The Baghouse Flyash Transport System controls the removal of ash from the hoppers of the particulate control device. A failure of this system will result in an extended 16-day forced outage for repair and return to service. Current controllers are approaching the end of life. All spare parts have been used.	FG_Reliability	4/15/2016	$ 423,158	$ 179,647	$ 602,805

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Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
51	Four Corners - Unit 5	Expansion Joint Replacement Secondary Air Duct	The purpose of this project is to maintain unit reliability. The expansion joint on the air side outlet of the Secondary Air Preheater which has reached the end of life and needs replacing. The joint has had numerous repairs and is no longer maintainable due to the corrosion and thin metal.	FG_Reliability	3/30/2016	$ 19,414	$ 564,269	$ 583,683
52	West Phoenix - Combined Cycle 5	5A CO Catalyst	The purpose of this project is to ensure continued compliance with the Title V air permit requirements. Catalyst must be replaced every 5 to 7 years in order to ensure proper performance.	FG_Environmental	2/22/2016	$ 508,083	$ 64,830	$ 572,913
53	West Phoenix - Combined Cycle 5	5B CO Catalyst	The purpose of this project is to ensure continued compliance with the Title V air permit requirements. Catalyst must be replaced every 5 to 7 years in order to ensure proper performance.	FG_Environmental	2/22/2016	$ 508,148	$ 64,246	$ 572,394
54	Four Corners - Unit 5	5S Primary Air Fan Replacement	The purpose of this project is to maintain Unit reliability. The probability of existing Primary Air fan impeller/rotor failures is increasing based on regular inspections and maintenance. Recent Unit 4(north) Primary Air fan wheel failure is indicative of ongoing mechanical degradation due to fatigue (normal operation). Recent Unit 5(south) Primary Air fan wheel inspection indicated additional cracking and required replacement.	FG_Reliability	4/8/2016	$ 233,455	$ 323,456	$ 556,911
55	Redhawk - Combined Cycle 2	Protective Relay Replacement	The purpose of this project is to maintain unit reliability by replacing faulty transformer differential relays with similar digital relays.	FG_Reliability	4/3/2017	$ 40,339	$ 481,712	$ 522,051
56	Yucca - Combustion Turbine 2	Cardox System Replacement	The purpose of this project is to increase availability of the unit's fire suppression system. The existing CO2 fire protection system is unreliable as existing controls and equipment are obsolete and unreliable. The cardox tank insulation is failing causing fire retardant compressor to cycle frequently which increases compressor maintenance	FG_Safety	1/12/2017	$ 791	$ 470,549	$ 471,339
57	Yucca - Combustion Turbine 1	Cardox System Replacement	The purpose of this project is to increase availability of the unit's fire suppression system. The existing CO2 fire protection system is unreliable as existing controls and equipment are obsolete and unreliable. The cardox tank insulation is failing causing fire retardant compressor to cycle frequently which increases compressor maintenance	FG_Safety	1/12/2017	$ 791	$ 470,549	$ 471,339
58	Four Corners - Common	Coal Handling Controls Replacement	The purpose of this project is maintain unit reliability by replacing the existing Coal Handling Control System. The existing Control System has a history of problems and is considered unreliable due to a lack of immediate troubleshooting support for the system and system parts. This system controls coal flow to both Units 4 & 5, which can run at full load only 4 hours without re-supply. The inability to deliver coal will eventually affect the operation of the Unit and require the Unit to be taken off line.	FG_Reliability	12/16/2016	$ -	$ 466,718	$ 466,718
59	West Phoenix - Combined Cycle 5	Circulating Water Inlet Valve Replacement	The purpose of this project is to allow for safe maintenance of the circulating water system. The current valve is leaking water through the gearbox.	FG_Reliability	3/6/2017	$ 1,390	$ 455,983	$ 457,374
60	Four Corners - Unit 5	Exit Gas Expansion Joint Replacement	The purpose of this project is to reduce the risk of fugitive dust violations.	FG_Reliability	3/30/2016	$ 33,475	$ 420,276	$ 453,750
61	West Phoenix - Combined Cycle 2	Generator Protective Relay Replacement	The purpose of this project is to increase unit reliability by decreasing consequential damage to the generator and/or turbine, and increasing protection accuracy. The existing relays are less accurate, near end of life and obsolete.	FG_Reliability	4/5/2016	$ 209,535	$ 242,573	$ 452,108
62	West Phoenix - Combined Cycle 1	Generator Protective Relay Replacement	The purpose of this project is to increase unit reliability by decreasing consequential damage to the generator and/or turbine, and increasing protection accuracy. The existing relays are less accurate, near end of life and obsolete.	FG_Reliability	4/1/2016	$ 218,551	$ 215,907	$ 434,457
63	Four Corners - Unit 4	Bottom Ash Roof and Monorail Replacement	The purpose of this project is to ensure the structural integrity of the existing Bottom Ash pit steel roof and monorail systems and enable safe access to seal trough platforms and important equipment in and around the Bottom Ash pit area.	FG_Reliability	6/16/2016	$ 47,366	$ 383,619	$ 430,985

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Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
64	Four Corners - Unit 4	River Station Weir Fish Passage	The purpose of this required one time payment to the New Mexico Fish and Game will be used to modify the fish weir passage at the River Station.	FG_Regulatory	3/31/2016	$ -	$ 407,381	$ 407,381
65	Four Corners - Unit 5	Bottom Ash Roof and Monorail Replacemen	The purpose of this project is to enable safe access to seal trough platforms and important equipment in and around the Bottom Ash pit area and ensure the structural integrity of the existing Bottom Ash pit steel roof and monorail systems.	FG_Reliability	5/13/2016	$ 47,807	$ 356,170	$ 403,977
66	Cholla - Unit 1	Fabric Filter Bag Replacement 2016	The purpose of this project is to ensure that the plant complies with Title V permit requirements. The existing Ryton PPS polymer coated fabric filter bags are approaching the end of their useful life and require replacement. These bags were installed in early 2011 and have a 5-year life expectancy.	FG_Environmental	12/1/2016	$ -	$ 380,465	$ 380,465
67	Four Corners - Unit 5	Generator Protective Relay Replacement	The purpose of this project is to maintain unit reliability by completing the second phase replacement of the existing electromechanically relays and provide a second multifunction relay as redundancy to prevent loss of the generator protection functions.	FG_Reliability	4/1/2016	$ 183,748	$ 156,833	$ 340,581
68	Four Corners - Unit 5	5S FD Fan Motor Replacement	The purpose of this project is to ensure continued unit reliability and avoid extended outage in the event of an FD fan motor failure. The existing FD Fan motors are aging and are increasingly prone to failures.	FG_Reliability	4/1/2016	$ 225,959	$ 107,585	$ 333,543
69	West Phoenix - Common	Reverse Osmosis Membrane Replacement	The purpose of this project is to maintain Unit reliability by maintaining water quality required for plant operations and equipment protection.	FG_Environmental	11/15/2016	$ -	$ 328,339	$ 328,339
70	Four Corners - Unit 5	Generator SSO Relay Replacement	The purpose of this project is to maintain plant safety requirements. The purpose of the SSO relays is to protect the generator from shaft torsional stress caused by subsynchronous resonance conditions. Failure could result in catastrophic machine damage and plant personnel injury. The SSO manufacturer no longer exists and there is no product support for technical assistance or spare parts.	FG_Reliability	4/1/2016	$ 48,570	$ 276,734	$ 325,304
71	Yucca - Common	Precipitator Replacement	The purpose is ensure continued compliance with the Plants Title 5 Air Permit, while maintaining unit availability. The lube oil mist eliminator is approaching the end of its serviceable life and requires replacement. Furthermore, replacement is required to mitigate the increasing risk of opacity excursions and violation to the Plant's Title 5 Air Permit. Relocation of the Precipitator shall improve employee access and mitigate risk of NOV associated with oil leaks via improved containment.	FG_Environmental	1/27/2017	$ -	$ 309,172	$ 309,172
72	Four Corners - Unit 4	4S Forced Draft Fan Motor Replacement	The purpose of this project is to ensure continued unit reliability and avoid an extended outage in the event of an Forced Draft (FD) fan motor failure. The existing FD Fan motors are aging and are increasingly prone to failures.	FG_Reliability	4/15/2016	$ 225,957	$ 80,906	$ 306,863
73	West Phoenix - Combined Cycle 1	Generator Synchronization Relay Replacement	The purpose is to improve the unit reliablity. The DCS has limited response time and operational parameters compared to a synchronizer.	FG_Reliability	4/1/2016	$ 129,471	$ 174,741	$ 304,212
74	Four Corners - Unit 4	Lagging and Insulation Replacement Top of Windbox - 2016	The purpose of this project is to maintain a safe plant work environment by eliminating potential hazards. These replacements are intended to reduce the hazards that exist when lagging and insulation are loose or deteriorating and therefore not maintaining surface temperature requirements, creating potential unsafe conditions for plant personnel and equipment.	FG_Reliability	11/18/2016	$ -	$ 294,710	$ 294,710
75	Sundance	Reverse Osmosis Membrane Replacement	The purpose of this project is to maintain Unit reliability by maintaining water quality required for plant operations and equipment protection.	FG_Environmental	11/16/2016	$ -	$ 285,210	$ 285,210
76	West Phoenix - Combined Cycle 2	Generator Synchronization Relay Replacement	The purpose is to improve the unit reliablity. The DCS has limited response time and operational parameters compared to a synchronizer.	FG_Reliability	4/5/2016	$ 145,400	$ 135,494	$ 280,894

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Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
77	Four Corners - Unit 5	Forced Draft Fan Motor Replacement	The purpose of this project is to ensure continued unit reliability and avoid extended outage in the event of a Forced Draft (FD) Fan motor failure. The existing FD Fan motors are aging and are increasingly prone to failures.	FG_Reliability	11/21/2016	$ 82,341	$ 192,423	$ 274,764
78	Four Corners - Unit 4	Baghouse Lagging and Insulation Replacement, 2016	The purpose of this project is to maintain a safe plant work environment by eliminating potential hazards. These replacements are intended to reduce the hazards that exist when lagging and insulation are loose, thus creating potential unsafe conditions for plant personnel and equipment.	FG_Environmental	11/26/2016	$ -	$ 265,123	$ 265,123
79	Four Corners - Unit 5	Baghouse Lagging and Insulation Replacement, 2016	The purpose of this project is to maintain a safe plant work environment by eliminating potential hazards. These replacements are intended to reduce the hazards that exist when lagging and insulation are loose creating potential unsafe conditions for plant personnel and equipment.	FG_Environmental	11/26/2016	$ -	$ 265,121	$ 265,121
80	West Phoenix - Combined Cycle 5	Steam Turbine Flash Tank Replacement	The purpose of this project is to maintain Unit reliablity by preventing a forced outage from tank wall rupture. The steam turbine flash tank and attemperator are damaged and require replacement. The flash tank and attemperator system is necessary for bypass routing of steam during startup, shutdown, and intermittent trips.	FG_Reliability	2/22/2016	$ 46,925	$ 216,704	$ 263,629
81	Redhawk - Common	Zero Liquid Discharge Permanent Polymer & Antifoam Skids	The purpose of this project is to maintain ZLD reliability and reduce environmental risks associated with skid leaks/failures by replacing the temporary Zero Liquid Discharge Polymer & Antifoam skids with permanent skids.	FG_Reliability	4/15/2016	$ 151,609	$ 100,974	$ 252,583
82	Douglas - Combustion Turbine	SCT-PPT Regulator Retrofit	The purpose of this project is to maintain unit reliability. APS serves the City of Douglas, AZ over two transmission lines. If one of the two lines is lost, reliability is greatly compromised. To compensate for this deficiency, the Douglas GT must be reliably remotely started to carry a sizable portion of the local load. The GE original 40+ year old voltage regulator on the Douglas/Fairview Combustion Turbine is only marginally functional. It was declared obsolete and unsupported by GE many years ago. It must be replaced to insure availability & reliability of the Douglas GT.	FG_Reliability	4/29/2016	$ -	$ 238,351	$ 238,351
83	Four Corners - Unit 4	Bottom Ash Flush Water Header Replacement	The purpose of this project is to maintain unit reliability by restoring required material integrity of the bottom ash flush water system . The existing bottom ash flush water header, made of carbon steel, has corroded below code minimum wall thickness in multiple areas. Recent Nondestructive Examination, has observed a thin wall throughout the length of the header. Multiple repairs have been previously performed due to holes in the header system.	FG_Reliability	4/15/2016	$ 47,350	$ 185,511	$ 232,861
84	Four Corners - Unit 5	Bottom Ash Flush Water Header Replacement	The purpose of this project is to maintain unit reliability by restoring required material integrity of the bottom ash flush water system . The existing bottom ash flush water header, made of carbon steel, has corroded below code minimum wall thickness in multiple areas. Recent Nondestructive Examination, has observed a thin wall throughout the length of the header. Multiple repairs have been previously performed due to holes in the header system.	FG_Reliability	3/30/2016	$ 41,391	$ 190,554	$ 231,945

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Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
85	Four Corners - Unit 4	Baghouse Vent Header Replacement	The purpose of this project is to replace the deteriorated baghouse compartment ventilation headers to maintain environmental compliance. The compartment ventilation header has thinned over time. This has caused the header to collapse when ventilation poppets are latched closed as well as cause the flue gas to leak through the ventilation poppets and into the atmosphere. Vent poppets will not seat properly giving an indication of a bad bag compartment or high differential pressure derates.	FG_Environmental	4/15/2016	$ -	$ 218,147	$ 218,147
86	Four Corners - Common	Motor Replacements	The purpose of this project is to maintain plant reliability	FG_Reliability	12/30/2016	$ -	$ 212,595	$ 212,595
87	Four Corners - Common	Four Corners Capital Tools 2016	The purpose of this project is to maintain plant reliability. These new tools and equipment will be used for maintenance, inspection and repair of plant equipment. Adding to the inventory of plant tools and diagnostic equipment increases maintenance efficiency and reduces equipment failures by improving and expanding the plant's monitoring and problem detection capabilities. The tools will be purchased, as required, by the plant throughout 2016.	FG_Reliability	12/30/2016	$ -	$ 204,433	$ 204,433
88	Four Corners - Common	Pump Replacements	The purpose of this project is to maintain plant reliability. Capital budget will be used for purchase and installation of new capital pumps as failures or immediate need occurs throughout the 2016 calendar year.	FG_Reliability	12/30/2016	$ -	$ 201,116	$ 201,116
89	Four Corners - Unit 4	HP and LP Generator Foundation Replacement	The purpose of this project is to determine the potential cause(s) of the Unit 4 and Unit 5 HP and LP Generator foundation settlement in order to improve unit reliability. Recommendations will then be offered on what steps are necessary to address the settling in order to maintain Unit operation and prevent damage to the turbine generator and other equipment located on the foundation. The Unit 4 and Unit 5 HP and LP Generator foundations have been settling at varying rates for the past few decades.	FG_Reliability	8/5/2016	$ -	$ 192,465	$ 192,465
90	Sundance - Units 1 & 2	Air Compressor Dryer Replacement	The purpose of this project is to maintain unit reliability. The plant operates with no air dryers in service due to concerns that there will be backpressure build up before the undersized air dryers and loss of plant air.	FG_Reliability	11/1/2016	$ -	$ 182,725	$ 182,725
91	Cholla - Common	Radio Systems Replacement	The purpose of this project is to maintain plant safety. The radio communication equipment is vital to the plant's daily activities. It allows plant staff to coordinate execution of field work orders with the unit control rooms such that accidental starts are avoided and emergency calls can be made.	FG_Regulatory	11/14/2016	$ 1,055	$ 181,356	$ 182,411
92	Four Corners - Unit 5	Baghouse Expansion Joint Replacement	The purpose of this project is to maintain compliance with fugitive dust regulations. The expansion joints that have reached end of life due to high velocity and temperature flue gas. The flyash causes erosion and abrasion to the expansion joints.	FG_Reliability	3/30/2016	$ 87,442	$ 94,091	$ 181,533
93	Four Corners - Unit 5	Expansion Joint Replacement SO2 Scrubber	The purpose of this project is to maintain compliance with fugitive dust regulations. The original expansion joints have reached the end of life. The expansion joints are cracked and leaking into the atmosphere. Several repairs have been made on these expansion joints, and now require a full replacement.	FG_Reliability	3/30/2016	$ 60,164	$ 102,306	$ 162,470
94	Four Corners - Unit 5	Baghouse Battery & Charger Replacement	The purpose of this project is to increase unit reliability by replacing the Baghouse 125VDC battery system as the batteries have reached the end of design life (>20 years old). Aging batteries often do not fully charge and may not support the critical Baghouse DC loads when needed. Also, the battery charging equipment is 35 years old and undersized due to the recent addition of a UPS system.	FG_Reliability	4/8/2016	$ 33,472	$ 127,309	$ 160,782

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Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
95	Redhawk - Common	Reverse Osmosis Membrane Replacement	The purpose of this project is to maintain Unit reliability by maintaining water quality required for plant operations and equipment protection.	FG_Environmental	4/1/2016	$ -	$ 155,274	$ 155,274
96	Four Corners - Unit 5	Baghouse Vent Header Replacement	The purpose of this project is to replace the deteriorated baghouse compartment ventilation headers to maintain unit reliability. The compartment ventilation header has thinned over time. This has caused the header to collapse when ventilation poppets are latched closed as well as cause the flue gas to leak through the ventilation poppets and into the atmosphere. Vent poppets will not seat properly giving an indication of a bad bag compartment or high differential pressure derates.	FG_Environmental	3/30/2016	$ 22,573	$ 130,692	$ 153,265
97	Four Corners - Unit 4	Baghouse Battery & Charger Replacement	The purpose of this project is to increase unit reliability by replacing the Baghouse 125VDC battery system as the batteries have reached the end of design life (>20 years old). Aging batteries often do not fully charge and may not support the critical Baghouse DC loads when needed. Also, the battery charging equipment is 35 years old and undersized due to the recent addition of a UPS system.	FG_Reliability	4/8/2016	$ 37,116	$ 109,659	$ 146,775
98	Four Corners - Unit 5	Lagging and Insulation Replacement Top of Windbox	The purpose of this project is to maintain compliance with fugitive dust regulations.	FG_Environmental	3/30/2016	$ 5,918	$ 129,730	$ 135,647
99	Redhawk - Combined Cycle 2	ST-2 Battery Replacement	The purpose of this project is to maintain unit reliability. These batteries are vintage 2001 and are approaching the end of their useful life. While system voltages are stable, all systems are showing voltage separation which is being monitored. The desert climate and age are causing cells to crack on top of the battery around posts.	FG_Reliability	2/18/2016	$ 4,377	$ 115,834	$ 120,210
100	Redhawk - Combined Cycle 1	ST-1 Battery Replacement	The purpose of this project is to maintain unit reliability. These batteries are vintage 2001 and are approaching the end of useful life. While system voltages are stable, all systems are showing voltage separation which is being monitored. The desert climate and age are causing cells to crack on top of the battery around posts.	FG_Reliability	2/17/2016	$ 4,377	$ 114,940	$ 119,317
101	Four Corners - Unit 5	SO2 Battery & Charger Replacement	The purpose of this project is to increase unit reliability by replacing the SO2 125VDC battery system as the batteries have reached the end of design life (>20 years old). Aging batteries often do not fully charge and may not support the critical Scrubber DC loads when needed. Also, the battery charging equipment is 35 years old and in need of replacement.	FG_Reliability	4/8/2016	$ 29,842	$ 83,643	$ 113,485
102	Four Corners - Unit 4	SO2 Battery & Charger Replacement	The purpose of this project is to increase unit reliability by replacing the SO2 125VDC battery system as the batteries have reached the end of design life (>20 years old). Aging batteries often do not fully charge and may not support the critical Scrubber DC loads when needed. Also, the battery charging equipment is 35 years old and in need of replacement.	FG_Reliability	4/8/2016	$ 30,783	$ 79,251	$ 110,034
103	Yucca - Common	Process Control Network Stability	The purpose of this project is to maintain unit reliability of core network functions for continued operational capability. This project will increase process control network availability for future growth over the next 3-5 years, and bring the facility up to approved APS network standards. This project will minimize risks to power generation and grid stability.	FG_Reliability	7/19/2016	$ 530	$ 102,806	$ 103,337
104	West Phoenix - Common	West Phoenix Capital Tools 2016	The purpose of this project is to purchase tools needed by the plant to support continued unit operability and reliability.	FG_Reliability	12/19/2016	$ -	$ 99,758	$ 99,758
105	Yucca - Combustion Turbine 5	Reverse Osmosis Membrane Replacement	The purpose of this project is to maintain Unit reliability by maintaining water quality required for plant operations and equipment protection.	FG_Environmental	11/15/2016	$ 253	$ 88,388	$ 88,640
106	Yucca - Combustion Turbine 6	Reverse Osmosis Membrane Replacement	The purpose of this project is to maintain Unit reliability by maintaining water quality required for plant operations and equipment protection.	FG_Environmental	11/15/2016	$ -	$ 88,370	$ 88,370

FOSSIL POST-TEST YEAR PLANT ADDITIONS

Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
107	Four Corners - Unit 5	Air Receiver Tanks Replacement	The purpose of this project is to maintain unit reliability. The air receiver tanks that were externally inspected and ultrasonically (UT) examined to determine remaining wall thickness for all vessel walls need to be replaced. The remaining shell wall thickness was below minimum per the UT examination and report.	FG_Reliability	6/30/2016	$ 5,192	$ 73,008	$ 78,200
108	Four Corners - Common	Emergency Response Equipment Replacement	The purpose of this project is to implement on-site safety response measures. Breathable Oxygen Cascade System – This is to provide a resource for refilling SCBA bottles used for Emergency Response Team functions requiring an SCBA (Firefighting, Hazmat, IDHL Environments). Lifepack 15 - This device would be staged on the ambulance for Emergency Medical Response by the ERT in AED mode to obtain vital signs, and apply defibrillation as necessary. In a cardiac emergency, the ACLS RN on-site, or off-site ACLS response can use the device for immediate cardiac monitoring and ACLS mode as needed for life saving measures.	FG_Regulatory	11/24/2016	$ -	$ 64,384	$ 64,384
109	Saguaro - Combustion Turbine 2	Charger Replacement	The purpose is to maintain unit reliability by replacing the battery charger which is approaching the end of its useful life. Quarterly testing of the battery system indicates that there are ground fault alarm on one of the chargers.	FG_Reliability	4/30/2016	$ 43,529	$ 19,997	$ 63,525
110	West Phoenix - Combined Cycle 4	Circulating Water Pump Suction Screen Replacement	The purpose of this project is to maintain unit reliability by preventing any foreign materials from the cooling towers into the suction of the pumps. Foreign debris could cause a mechical failure of the cooling tower and force an unplanned outage.	FG_Reliability	4/30/2016	$ -	$ 55,042	$ 55,042
111	Four Corners - Common	Plant Elevators Modernization	The purpose of this project is to maintain a safe and reliable elevator system. Upgrade are necessary to meet state and local safety codes and regulations. Currently the Plant has several elevators that are out of services with various components that are in disrepair.	FG_Regulatory	5/18/2016	$ -	$ 44,472	$ 44,472
112	Saguaro - Gas Turbine 3	Reverse Osmosis Membrane Replacement	The purpose of this project is to maintain Unit reliability by maintaining water quality required for plant operations and equipment protection.	FG_Environmental	11/15/2016	$ -	$ 43,649	$ 43,649
113	Sundance	Sundance Capital Tools 2016	The purpose of this project is to provide tools and equipment that will be used for maintenance, inspection and repair of plant equipment. These tools will be purchased throughout 2016 and will be added to the plant tools inventory, increase maintenance efficiency and reduce equipment failures.	FG_Reliability	8/10/2016	$ -	$ 31,038	$ 31,038
114	Ocotillo - Common	Ocotillo Capital Tools 2016	The purpose of this project is to provide tools and equipment that will be used for maintenance, inspection and repair of plant equipment. These tools will be purchased throughout 2016 and will be added to the plant tools inventory, increase maintenance efficiency and reduce equipment failures.	FG_Reliability	10/20/2016	$ -	$ 28,354	$ 28,354
115	Redhawk - Common	Redhawk Capital Tools 2016	The purpose of this project is to provide tools and equipment that will be used for maintenance, inspection and repair of plant equipment. These tools will be purchased throughout 2016 and will be added to the plant tools inventory, increase maintenance efficiency and reduce equipment failures.	FG_Reliability	8/10/2016	$ -	$ 23,057	$ 23,057
116	Yucca - Common	Microsoft License Agreement	The purpose of this project is to maintain plant effectiveness with Plant computers that run on Microsoft operating software. The software is needed to maintain the operations and maintenance programs and historical records. Without this information the plant cannot operate without going back to the old manual systems.	FG_Reliability	10/3/2016	$ -	$ 12,860	$ 12,860

FOSSIL POST-TEST YEAR PLANT ADDITIONS

Line No.	Plant/Unit	Project Name	Purpose	Category	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
117	Yucca - Common	Yucca Capital Tools 2016	The purpose of this project is to provide tools and equipment that will be used for maintenance, inspection and repair of plant equipment. These tools will be purchased throughout 2016 and will be added to the plant tools inventory, increase maintenance efficiency and reduce equipment failures.	FG_Reliability	11/23/2016	$ -	$ 8,198	$ 8,198
118	Yucca - Common	Yucca Major Inspection Overhaul	The purpose of this project is to maintain unit reliability. Per the OEM, a Major Inspection overhaul is required based on the number of accumulated starts.	FG_Reliability	1/12/2017	$ -	$ 686	$ 686
119		Trailing Costs for Projects In-Service in 2015	This is a combination of multiple projects that went into service in 2015 but have trailing clean-up costs that extend into 2016.			$ -	$ 145,431	$ 145,431
120		**Total Fossil**				**$ 63,483,838**	**$ 97,151,543**	**$ 160,635,381**

DIRECT TESTIMONY OF JOHN J. CADOGAN, JR.

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF JOHN J. CADOGAN, JR.
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Cadogan, Jr. My business address is Palo Verde Nuclear Generating Station, 5801 S. Wintersburg Road, Tonopah, Arizona 85354-7529.

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

A. I am employed by Arizona Public Service Company (APS or Company) as the Vice President of Nuclear Engineering at the Palo Verde Nuclear Generating Station (Palo Verde or Station). My biography is found at Attachment JJC-1DR.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of APS.

Q. WHAT IS APS'S OWNERSHIP SHARE OF PALO VERDE?

A. APS owns a 29.1% share of each Palo Verde unit and the common facilities. APS receives an allocation of approximately 1,165 megawatts (MW) from the three units when they are each operating at full power.

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

The purpose of my testimony is to describe Palo Verde and support APS's request to include Palo Verde capital expenditures into its rate base and Palo Verde operations and maintenance (O&M) expenses in its cost of service. The capital expenditures at Palo Verde that I support are those that have been placed in service since APS's last rate case through June 30, 2017.

The O&M expenses I support are those incurred during the twelve months ending December 31, 2015, the Test Year for this proceeding. Unless otherwise noted, my testimony describes these capital and O&M expenditures from the total Station perspective. APS's share of these total Station costs is 29.1%.

II. OVERVIEW OF PALO VERDE NUCLEAR GENERATING STATION

Q. PLEASE DESCRIBE PALO VERDE.

A. Palo Verde is a nuclear electric generating station located on a 4,286-acre site approximately 50 miles west of Phoenix, Arizona. The facility consists of three separate, standardized generating units and a variety of common support facilities with a total design electrical rating of 4,003 MW (average yearly conditions). Palo Verde is the largest nuclear power plant in the United States.

The Unit 1 operating license was approved by the Nuclear Regulatory Commission (NRC) in 1984, and the unit entered service in 1986. In 2006, the Unit 1 design electrical rating was increased by 68 MW (from 1,265 MW to 1,333 MW) as a result of the 2005 steam generator and low-pressure-turbine replacements.

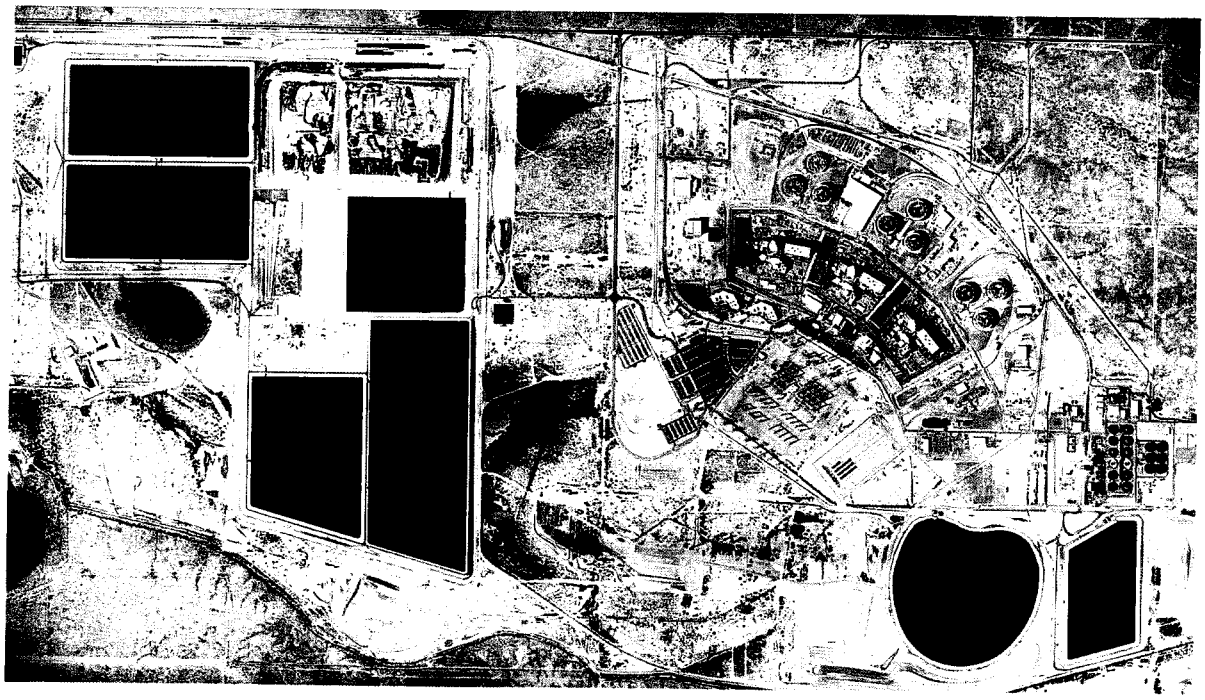
The Unit 2 operating license was approved by the NRC in 1985, and the unit entered service in 1986. In 2004, the design electrical rating of Unit 2 was increased by 71 MW (from 1,265 MW to 1,336 MW) as a result of the 2003 steam generator and low-pressure-turbine replacements.

The Unit 3 operating license was approved by the NRC in 1987, and the unit entered service in 1988. In 2008, the design electrical rating of Unit 3 was increased by 65 MW (from 1,269 MW to 1,334 MW) as a result of the 2007 steam generator and low-pressure-turbine replacements.

On December 11, 2008, APS submitted an application to the NRC to extend the licenses of each unit for an additional 20 years. The NRC approved the license renewal application on April 21, 2011. The new expiration dates for the NRC operating licenses for the three Palo Verde Units are June 1, 2045 (Unit 1), April 24, 2046 (Unit 2), and November 25, 2047 (Unit 3).

Palo Verde is interconnected to the bulk electric system through a switchyard that operates at 525 kilovolts. The interconnected switchyard is co-owned by APS and is operated by the Salt River Project Agricultural Improvement and Power District (SRP). Photograph JJC-1 is an overhead photo of Palo Verde.

Photograph JJC-1 - Palo Verde Nuclear Generating Station



Q. HOW IS PALO VERDE OWNED AND OPERATED?

A. Palo Verde is owned by seven southwestern utilities (Owners) and is operated by APS. The Palo Verde co-owners are APS, SRP, Southern California Edison Company, El Paso Electric Company, Public Service Company of New Mexico,

Southern California Public Power Authority, and Los Angeles Department of Water and Power.

Q. PLEASE EXPLAIN APS'S ROLE IN OPERATING PALO VERDE.

A. Pursuant to the contract between and among the Owners, which is referred to as the Arizona Nuclear Power Project Participation Agreement, APS is the NRC operating license holder and operating agent of Palo Verde. In this regard, APS manages the employees and contractors working at Palo Verde, and makes decisions with regard to its safe and reliable operation, such as scheduling maintenance and refueling outages, shutting down a unit for a refueling outage or a short-notice outage when an issue arises, and restarting a unit after an outage.

APS confers with and receives approval from the Owners on many things, including all major capital projects. The involvement of the Owners in Palo Verde operations is facilitated by several committees, including the Administrative Committee, which is comprised of Owner senior executives, and the Engineering and Operating (E&O) Committee.

Q. WHAT ARE UNIQUE ASPECTS OF NUCLEAR POWER PLANTS IN COMPARISON TO TRADITIONAL FOSSIL-FUELED BASE LOAD PLANTS?

A. Nuclear power plants are ideal base load generating plants because their operations are predictable and reliable and they have the lowest incremental operating costs and highest capacity compared with other traditional base load plants. However, nuclear power plants in the U.S. are regulated by the NRC. As a condition of its NRC license, each plant is required to develop and maintain strict plant operating standards, plant designs, Technical Specifications and detailed procedures that must be complied with to meet the license requirements. If an anomalous situation occurs, Technical

Specifications require that certain actions must be performed and conditions met within specific timeframes to continue to operate the plant. In some cases, when these prescribed actions cannot be met within predetermined timeframes, the Technical Specifications require that the plant be taken out of service. NRC regulations, radiological conditions, and prescriptive operating procedures require the plant's operators to follow a specific process for shutdown, outages, and restart.

Additionally, due to radiological conditions in some areas of nuclear power plants, actions not required at fossil-fueled plants are taken to minimize personnel exposure. These actions, such as using protective clothing, and installing and working around lead shielding, increase the amount of time, and therefore cost, required to perform work.

Each U.S. nuclear plant contains multiple systems and operational features that create redundancy — or multiple barriers — to ensure safe operations. Regulations and maintenance practices in nuclear plants are in place to repair, replace, and ensure the safety margin of the primary and secondary systems. This means that a plant may be down-powered or removed from service to repair a system that does not directly impact the operations or output of the plant but is done to ensure the safe operation of the back-up systems.

Nuclear plants have specific operations and maintenance procedures (and corresponding training for personnel) to control plant operations. These procedures cover not only normal plant operation, but a multitude of other conditions such as abnormal operations and emergencies. As a result, plant operators have limited discretion in how the plant is to be operated. By contrast, fossil-fueled plants do not have strict technical specifications that require the plant to be taken out of service under similar circumstances.

Q. WHAT ARE THE ADVANTAGES AND CHALLENGES OF THE PALO VERDE PLANT CONFIGURATION?

A. Palo Verde is the largest nuclear power station in the U.S. and consistently produces the most power of any power production facility in the country. Furthermore, it is the first and only power plant in the country — of any fuel source — to produce more than 31 million MWh in one year. Indeed, in 2015, Palo Verde achieved its 24th consecutive year as the nation's largest power producer of all fuel sources and, for the 10th time, exceeded its own record for power generation — producing 32.4 million MWh. The previous record was 32.3 million MWh in 2014.

The Palo Verde units are three identical, independent, stand-alone pressurized water reactor units. The units are a Combustion Engineering (CE) System 80 design, which were designed to maximize reliability and performance. As identical units, there are economies of scale with engineering modifications to the units, training of operators and mechanics, outage planning, and other activities that are replicated on each unit.

However, some of the economies of scale associated with operating Palo Verde also present challenges. The three Palo Verde units and the Water Reclamation Facility, which is discussed below, occupy a large footprint relative to other nuclear plants, with the units each being approximately one quarter (1/4) mile apart. Palo Verde's large footprint also gives it a unique challenge relative to the country's three other three-unit nuclear power plants (which cover 840, 700, and 510 acres). The sheer size of Palo Verde requires larger physical security systems and a greater number of security personnel to meet operational and regulatory requirements. There is also minimal sharing of systems between the three units. All of these factors require additional staff. As an example, each unit has its own separate control room — versus a shared control room as is found in many two-unit plants — thus requiring three sets of operators.

The CE System 80 plant, by design, has approximately 20% more components (pumps, motors, valves, etc.) than other comparably sized pressurized water reactors, such as the South Texas Project and Waterford (Louisiana) nuclear stations. The CE System 80 plant was designed for greater reliability, however, more people are required to maintain and operate the additional equipment. Because the units are identical, an issue at one unit can be transportable to the other units. A degraded or non-conforming condition in any one unit must immediately be analyzed in the other two units to determine if the degraded or non-confirming issue exists there. Therefore, a design or maintenance issue in any unit could require actions — including shutdown — to be taken in all three units.

Q. PLEASE DESCRIBE THE PALO VERDE WATER RECLAMATION FACILITY AND ITS OPERATION.

A. One aspect of Palo Verde that distinguishes it from any other nuclear power plant in the world is that it is not located on or near a large body of water. Therefore, it must obtain water from other sources and must discharge any waste water to a system that will not adversely impact surface or underground water supplies. This unique aspect of Palo Verde is a necessary cost of doing business that is not incurred at any other nuclear power plant in the world.

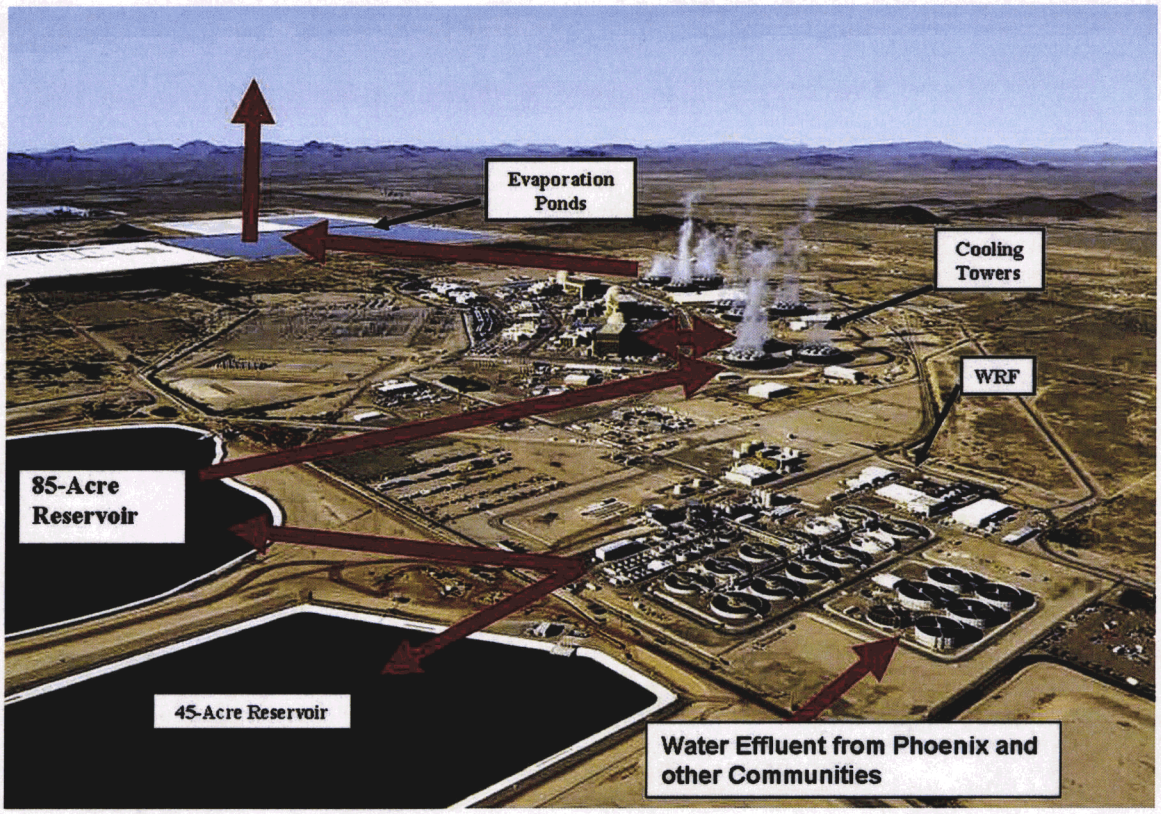
Palo Verde purchases its cooling water from two waste water treatment plants (WWTP) located in the greater-Phoenix area: (1) the 91st Avenue WWTP, operated by the City of Phoenix on behalf of the Sub Regional Operating Group (SROG) cities of Glendale, Mesa, Phoenix, Scottsdale, and Tempe; and (2) the City of Tolleson WWTP.

Effluent from the 91st Avenue and Tolleson WWTPs is conveyed 36 miles to Palo Verde. Once received at Palo Verde, the effluent is treated at the Palo Verde Water Reclamation Facility to remove ammonia and minerals that would otherwise damage or

cause scaling on vital plant cooling components. After being treated, the water is stored in either one of Palo Verde's on-site 45-acre or 85-acre reservoirs. When cooling water is needed, it is pumped to the cooling towers where it is cycled more than 20 times before a small amount (less than 5%) is blown down and discharged to one of the three evaporation ponds. The remaining 95% of the cooling water is evaporated to the atmosphere.

The Water Reclamation Facility operations described above require a separate physical water treatment plant with a staff of approximately 100 people, along with chemicals, materials, and supplies. Additionally, as a zero-liquid discharge plant, Palo Verde must also operate and maintain three very large evaporation ponds — covering 250, 220, and 180 surface acres, respectively, for a total of 650 acres — until all the cooling tower blowdown water evaporates. In all other nuclear plants, the cooling water would simply be discharged into the river, lake, or ocean from which it was withdrawn. The unique requirements associated with the use of wastewater for cooling increases Palo Verde's operating costs by more than $1.40 per MWh. Photograph JJC-2 shows the Palo Verde path of cooling water.

Photograph JJC-2 – Palo Verde Effluent Water Flow Path



Q. PLEASE DESCRIBE PALO VERDE'S RECENT OPERATING PERFORMANCE.

A. 2015 was a very successful year for Palo Verde. Its accomplishments in 2015 include:

- **Nuclear safety:** Lowest-ever number of days in yellow risk management action level (RMAL).
- **Radiological safety:** Lowest-ever Collective Radiation Exposure of 58 roentgen equivalent man (rem - the unit of measure for ionizing radiation), and lowest-ever personnel contamination events of 27.
- **Safety culture:** Completed biannual safety culture survey; results reflect continual improvements, showing people and leadership are making a difference.
- **Knowledge and training:** Continual improvements and efforts in formal training programs, knowledge transfer and knowledge sharing.

- **Net generation:** Highest-ever net generation in Palo Verde history of 32.4 million MWh.
- **Site capacity factor:** 94.0% with summer capacity factor of 100.1%.
- **Outage performance:** Safely completed two scheduled refueling outages with spring 3R18 outage duration of 29 days (scheduled 30-day outage) and fall 2R19 outage duration of 36 days, which is a testament to Palo Verde teamwork based on the amount of discovery and emergent work that was safely completed that added only six additional days to 2R19.
- **Post-Fukushima modifications:** Completed the installation in all three units of post-Fukushima Flexible and Diverse Mitigation Strategies (FLEX) equipment and modifications. Not only will the FLEX equipment meet an NRC regulatory obligation, but Palo Verde management is working with the NRC to allow Palo Verde operators to use FLEX equipment during routine power operations and during outages to reduce RMAL.

Q. DOES PALO VERDE FACE ANY CHALLENGES WITH EMPLOYEE ATTRITION?

A. Yes, Palo Verde continues to manage the wave of retirements that are affecting the commercial nuclear power industry. Since 2007, Palo Verde has replaced approximately 1,400 employees, a substantial majority of whom have reached retirement eligibility over the past eight years. Palo Verde is typically staffed with approximately 2,200 full time employees, so it has had to replace nearly two thirds (2/3) of its work force in the past eight years.

To address this turnover, Palo Verde has a comprehensive hiring strategy and talent-acquisition process. For those skilled positions that are challenging to fill, Palo Verde has a robust knowledge transfer and retention process. Certain positions require several

years to train and qualify a worker, so to facilitate the knowledge transfer that has taken place and inevitably will continue to take place, Palo Verde will hire early enough in advance of projected and anticipated retirements so that it maintains its complement of fully qualified workers. The hiring and talent-acquisition process does, however, impact budgets due to the sometimes lengthy training and qualification pipeline necessary to ensure that Palo Verde is staffed with fully qualified workers in all disciplines.

Q. WHAT IS PALO VERDE DOING TO DEVELOP AND ACQUIRE NEW TALENT?

A. Palo Verde continues to work with local high schools, community colleges, and universities to develop talent. For example, Palo Verde management has been instrumental in creating the Western Maricopa Education Center (West-MEC) Southwest Campus, an energy-centric campus and program in Buckeye. West-MEC is an Arizona public school district dedicated to providing innovative career and technical education programs that will prepare students for economic independence. Palo Verde also continues to foster its long-term relationship with Estrella Mountain Community College, and routinely recruits and hires engineers from Arizona's three public universities for its engineering legacy program.

III. PALO VERDE FINANCIAL AND COST MANAGEMENT

Q. WHAT IS THE PALO VERDE APPROACH TO EFFICIENT CAPITAL AND O&M COST MANAGEMENT?

A. Palo Verde's mission is to "**SAFELY** and efficiently *generate* electricity for the *long term*."

Cost analysis is taken very seriously to ensure that the Station continues to operate safely and efficiently, while associated expenditures (capital projects, O&M expenses,

and nuclear fuel utilization) are managed appropriately. Palo Verde uses a variety of measures to ensure that costs are managed appropriately. These include benchmarking peer nuclear facilities, developing our leaders' business acumen, and using strategic methods such as Top 10 and Long Range Planning programs to prioritize capital projects.

Cost effectiveness efforts also focus on budget development and control. Budget assumptions, such as staffing, timing, and duration of outages, are established by the Business Operations Department after working with other groups at Palo Verde. This allows each of the business groups at Palo Verde to identify necessary work and begin the process of assembling their budgets. Thereafter, managers and executives review the proposed budget and scope in a series of meetings. The resulting draft budget is then submitted to the Owners. Once the budget is unanimously approved by the Owners, Palo Verde leaders and the Business Operations Department actively track projects, and O&M and nuclear fuel spend rates. Monthly Executive Cost Reports are provided to the Owners for further information and oversight.

Q. HOW IS THE PALO VERDE BUDGET ORGANIZED?

A. The Palo Verde budget is broken down into nine budget categories, which are used for management and oversight of capital projects in the budget. The categories include Plant Modifications, Plant Equipment and Replacements, Buildings, General Plant, Information Technology, Water Reclamation Facility, Overheads, Emergent Work Fund and Fukushima/Major Strategic Projects. A summary table of Palo Verde's nine budget categories can be found in Attachment JJC-2DR.

A. *Capital Planning and Management*

Q. DESCRIBE PALO VERDE'S CAPITAL PLANNING AND MANAGEMENT PROCESS.

A. Palo Verde employs a robust and prescriptive process for identification, review, and approval of all capital expenditures. This process includes detailed procedures to assure proper management of capital improvement projects by having a defined, sequential process to identify, evaluate, approve, prioritize, schedule and monitor capital expenditures.

Every capital project has a project manager and a project sponsor. The project sponsor provides support to resolve project issues, barriers, and problems above the authority of the project manager, who manages day-to-day aspects of project implementation. The project sponsor also reviews the project's risk register periodically with the project manager to ensure risks are current and appropriate contingency plans have been developed, and presents required information according to established processes to required committees and subcommittees.

Capital projects are initially managed by a variety of committees, including the Plant Health Committee (PHC), Long Range Plan (LRP) Committee and Facilities Committee, depending on the type (and budget category) of a project. The PHC is a senior management committee that provides oversight and support for processes and programs that contribute to the overall health and performance of plant equipment. The PHC determines the priority and schedule for implementing improvements to plant equipment including all equipment related modifications.

The LRP Committee plans, develops, and maintains a 40-year integrated Long Range Plan, taking into account general, component, and strategic Long Range Plans, to ensure

that Palo Verde achieves its mission to safely and efficiently generate electricity for the long term. The LRP process covers the full duration of the originally licensed Station life (*i.e.*, 2025, 2026, and 2027) as well as the extended Station life through the period of extended operation (*i.e.*, 2045, 2046, and 2047).

These committees are governed by the Management Review Committee, which ultimately approves budgeting decisions, as well as changes to the executed budgets when requested amounts differ or exceed the annual funding approved for a budget category.

After a project has been approved by Palo Verde executive management, the project must then be approved by the Palo Verde Owners. This approval is the responsibility of the Palo Verde E&O Committee, which reviews and approves, or ratifies, modifies and otherwise acts upon projects at regularly scheduled E&O Committee meetings or phone calls. Procedures of the E&O Committee require Palo Verde management to maintain internal written guidelines providing instruction to Palo Verde personnel regarding capital versus O&M categorization as defined by Units of Property or the Retirement Units Catalog; project cost estimation; and project authorization preparation and approval process. Palo Verde management must also report monthly to the E&O Committee on capital improvement budget status.

1. Palo Verde Capital Additions to Rate Base

Q. WHAT LEVEL OF PLANT ADDITIONS DOES PALO VERDE EXPECT THROUGH JUNE 30, 2017?

A. Attachment JJC-3DR includes a list of all Palo Verde capital projects that will be in service as of June 30, 2017. As that exhibit shows, Palo Verde expects to add a total of $123.9 million of APS Plant by that date. These additions contribute $48.1 million to

the Company's post-Test Year Plant adjustment, as detailed on SFR Schedule B-2, page 1, column 3.

APS Witness Elizabeth Blankenship describes additional details of the adjustment, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes, and interest expense.

Q. WHAT ARE SOME OF THE MORE SIGNIFICANT PLANT ADDITIONS THAT CONTRIBUTE TO THE COMPANY'S POST-TEST YEAR PLANT ADJUSTMENT?

A. Of the approximately $124 million in total Company capital expenditures for the period January 1, 2016 through June 30, 2017, that APS is proposing to be included in the Company's Post-Test Year Plant pro forma adjustment, the five largest projects will ensure continued safe and efficient generation from Palo Verde for the long term. They are: (1) a multi-year project to improve the numerous administrative procedures governing the full spectrum of work performed at Palo Verde; (2) the addition of a seventh clarifier train to the Water Reclamation Facility to allow for extended outages to repair and refurbish the six original clarifier trains; (3) the repair of concrete in the Unit 1 ultimate heat sink, which is also referred to as a spray pond; (4) the replacement of the Unit 3 main generator excitation system, which will replace originally installed equipment that has become obsolete; and (5) the first in a series of projects to refurbish Water Reclamation Facility clarifiers.

a) Procedure Upgrade

Q. WHAT IS THE PROCEDURE UPGRADE PROJECT?

A. As I mentioned earlier in my testimony, as a condition of its NRC license, each U.S. nuclear plant is required to develop and maintain strict plant operating standards, including detailed procedures that must be complied with to meet the license

requirements. The procedures cover not only normal plant operations, but a multitude of other conditions such as abnormal operations and emergencies.

In the mid-2000s, Palo Verde was under increased NRC scrutiny due to a number of performance-related issues. The Palo Verde management team performed a number of evaluations into the performance-related issues and discovered that among the fundamental problems were systemic weaknesses in the quality of programs, procedures and processes governing the performance of work. The procedure upgrade project is a multi-year initiative to correct those weaknesses. Beginning in late 2008, this project has replaced and reformed 2,382 procedures, totaling 109,262 pages. This project has improved performance in a number of ways, including the facilitation of the knowledge transfer and retention process that I mentioned earlier in my testimony. The results have been reflected in reduction in human performance errors, and overall improved Station performance.

Q. WHAT IS THE COST OF THE PROCEDURE UPGRADE PROJECT?

A. The cost of the procedure upgrade project is approximately $20.4 million.

b) Seventh Clarifier Train

Q. WHAT IS THE SEVENTH CLARIFIER TRAIN?

A. A clarifier train is an essential system at the Water Reclamation Facility, and is comprised of a system of components and processes that treat effluent water from the SROG 91st Avenue and the City of Tolleson WWTPs prior to the water's use as cooling tower makeup water. Palo Verde was designed and constructed with six clarifier trains.

Each clarifier train has the capacity to process 10,000 gallons per minute (gpm), for a total of 60,000 gpm. When originally constructed, this overall capacity level met design basis safety margins by providing considerable margin for cooling water production, as

the total requirements of the three units in the peak-usage summer months was 50,000 gpm. However, the completion of power uprate projects since Palo Verde commissioning has increased the need for cooling water to 60,000 gpm in the peak months.

The existing six clarifier trains have exceeded their 20-year life expectancy and require extensive refurbishment. Refurbishment of the clarifiers requires taking each of the clarifier trains offline for a duration of four to eight months. During this refurbishment period, the remaining five clarifier trains will not be able to keep up with the current demand for cooling water within the required design basis safety margin, therefore a seventh train was constructed.

Q. WHAT IS THE TOTAL COST OF THE SEVENTH CLARIFIER TRAIN?

A. The cost of the seventh clarifier train is approximately $10.4 million.

c) Unit 1 Spray Pond Repair

Q. DESCRIBE THE UNIT 1 SPRAY POND REPAIR.

A. All U.S. commercial nuclear power plants are required by NRC regulations and their operating licenses to have a system to which the combined heat load of structures, system and components that are important to safety can be transferred under normal operating and accident conditions. This system is referred to as the ultimate heat sink. Palo Verde is not located on or near a large body of water, so it uses engineered ultimate heat sinks – spray ponds.

The spray ponds – including the Unit 1 spray pond – are constructed of steel reinforced concrete. Water has leeched through the concrete and, over time, eventually reached the steel reinforcement bars, which have started to rust. The rust causes the steel to expand, thus cracking the concrete. The cracking in the Unit 1 spray pond cannot be arrested by

any other means, and these spray ponds serve a regulatory-required safety function, so the cracking will be repaired.

Q. WHAT IS THE COST OF THE UNIT 1 SPRAY POND REPAIR PROJECT?

A. The cost of the Unit 1 spray pond repair is approximately $8.1 million.

d) Unit 3 Main Generator Excitation System Replacement

Q. WHAT IS THE UNIT 3 MAIN GENERATOR EXCITATION SYSTEM REPLACEMENT PROJECT?

A. The purpose of the Main Generator Excitation System is to control Main Generator electrical output values. Palo Verde's original Main Generator excitation and voltage regulation system for each of the three units is a General Electric (GE) product. The excitation system is the shortest-lived component of the electrical generators, with life expectancy ranging from 15 to 30 years. Of the 30 GE systems of this design, only four in the U.S. have not been upgraded, and three of those four are at Palo Verde (one per unit). GE has informed its customers that it will no longer support this system with spare parts. Palo Verde has an adequate supply of spare parts for the short term, but long-term sustainability will be challenged. Therefore, the generator excitation systems in each of the three units will be replaced; this project is the Unit 3 replacement.

Q. WHAT IS THE COST OF THE MAIN GENERATOR EXCITATION SYSTEM REPLACEMENT PROJECT?

A. The cost of the Unit 3 generator excitation system replacement is approximately $6.5 million.

e) Water Reclamation Facility Clarifier Train Refurbishment

Q. WHAT IS THE WATER RECLAMATION FACILITY CLARIFIER TRAIN REFURBISHMENT PROJECT?

A. As I previously mentioned, the existing six clarifier trains have exceeded their 20-year life expectancy and require extensive refurbishment. Evaluations of the condition of each of the six clarifier trains have been completed; train five is the most degraded therefore the highest priority for refurbishment. This project includes a substantial overhaul and replacement of major systems and components, with installation of equipment that is similar to that installed in the seventh clarifier train, but at a lower cost than demolishing this train and reconstructing it.

Q. WHAT IS THE COST OF THE WATER RECLAMATION FACILITY CLARIFIER TRAIN REFURBISHMENT PROJECT?

A. The cost of the Water Reclamation Facility clarifier train refurbishment project is approximately $4.6 million.

B. *Operations and Maintenance Expenses*

Q. WHAT IS THE PALO VERDE APPROACH TO EFFICIENT O&M MANAGEMENT AND WHAT PROGRAM OR PROCESS IS IN PLACE TO ADDRESS OVERSIGHT AND MANAGEMENT OF O&M EXPENDITURES?

A. Palo Verde management has been and will continue to take a strategic view of costs and invest in the Station to maintain it in excellent material condition, and invest in the knowledge and performance of the people who run it for the long term.

The process for oversight and management of the O&M budget is similar to the process I described regarding oversight and management of the capital budget. The O&M budget is assembled each year by Palo Verde management and submitted to the Owners for review and approval. Budget assumptions are established by the Business Operations Department after working with department leadership at Palo Verde.

Assumptions include such significant aspects as Palo Verde staffing and duration of planned outages. This allows departments to identify necessary work and to begin the process of assembling their budgets. A series of challenge meetings are held involving Palo Verde leaders and executives to review the proposed budget amounts and scope, all working towards budget submittal to the Owners. Once the budget is approved, status is managed and overseen by Palo Verde leaders and the Business Operations Department and as part of the budget update that is provided to the Owners at each E&O Committee meeting, as well as at quarterly meetings of the Palo Verde Administrative Committee, which is chaired by the APS Executive Vice President / Chief Nuclear Officer.

Q. WHAT AMOUNT OF TOTAL PALO VERDE NON-FUEL O&M EXPENSE WAS INCURRED DURING THE TEST YEAR?

A. The amount of non-fuel, unadjusted total O&M for the Test Year was $635.7 million. The APS share of this was approximately 29.1 percent.

Q. HOW DOES THIS AMOUNT COMPARE TO THE FIVE-YEAR AVERAGE?

A. Operations and maintenance costs during the Test Year compare favorably to the five-year average from 2010-2014 as demonstrated in Attachment JJC-4DR. Rigorous cost controls and management oversight have allowed for an overall five-year decrease in the O&M costs. This trend in operating costs is due to Palo Verde's continued emphasis on the balance between long-term sustainability of Station performance and cost efficiencies. At the same time, due to capital improvements to improve reliability and reduce outage duration (discussed below), as well as work process improvements from projects such as the procedure upgrade (discussed above), Palo Verde capacity factor has improved, which has directly improved our operating cost.

Q. WHAT DO YOU CONCLUDE ABOUT PALO VERDE O&M?

A. Palo Verde costs are carefully scrutinized and are reasonable and prudent. Palo Verde is a valuable asset to APS and produces large quantities of safe, clean, reliable, and efficient power for its customers. Palo Verde O&M costs have consistently been in the U.S. nuclear industry second quartile, which is particularly noteworthy given $1.40+ per MWh additional costs associated with operation of the Water Reclamation Facility.

C. *Refueling Outages*

Q. HOW HAS PALO VERDE PLANT REFUELING OUTAGE PERFORMANCE IMPROVED SINCE THE TEST YEAR IN DOCKET NO. E-01345A-11-0224?

A. Palo Verde performance, as reflected by capacity factor, has continued to improve since July 2012. In 2009 and 2010, Palo Verde conducted longer refueling outages to replace large containment components, including replacement of steam generators. To improve nuclear safety, the reactor vessel heads also were replaced, and rapid refueling packages were installed on all three units to improve industrial safety and streamline outage critical path schedule performance.

Since the completion of these planned longer refueling outages, outage performance has significantly improved and been more in line with industry performance. Accordingly, Palo Verde site-wide capacity factor has continued to improve: in 2013, it was 91.1%, in 2014, it was 93.7% in 2014; and in 2015, it was 94.0%.

IV. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes, Palo Verde takes a deliberate approach to efficient cost management to ensure the safe and reliable operation of the Station while providing energy at reasonable cost. We take our responsibility to the public at large, ratepayers and stakeholders very

seriously and have put procedures and processes in place that help us meet that responsibility. Capital and O&M costs were necessary and prudently incurred to maintain a safe, reliable, and efficient nuclear generating facility for the long term.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

JOHN J. CADOGAN, JR.,
VICE PRESIDENT, NUCLEAR ENGINEERING

As Vice President of Nuclear Engineering, Mr. Cadogan provides strategic and operational direction and control over all Palo Verde Nuclear Generating Station engineering functions. This includes day-to-day maintenance and operations support, which primarily is provided through Plant Engineering functions like systems, components, and programs engineering, and also focuses on equipment monitoring, reliability and thermal efficiency to maximize generation output.

One of the more strategic elements of his role as Vice President of Nuclear Engineering is related to large engineering projects. At Palo Verde, this includes oversight of Modification Engineering and project management personnel. The focus of his involvement with these large projects includes long-range planning strategy development to assure safe, efficient, and reliable long-term generation and regulatory compliance for the Palo Verde units. Typical engineering projects include: large electrical equipment obsolescence upgrades; age-degraded systems, structures, and component redesigns; and regulatory-required complex analyses/modifications.

Mr. Cadogan also oversees several more analytically-based elements of Palo Verde's Engineering organization including Design and Nuclear Fuels Engineering. These elements include the following diverse engineering-discipline functions: mechanical, electrical, instrument and control, civil/structural, reactor engineering, and nuclear analysis. These disciplines all are required to support operational, maintenance, and regulatory requirements that usually fall beyond the technical complexity or task duration that can be efficiently performed by Plant Engineering.

Mr. Cadogan has held and continues to hold industry leadership roles with the Institute of Nuclear Power Operations (INPO) and the Electric Power Research Institute (EPRI) in the area of equipment reliability strategy development and implementation. Mr. Cadogan also has extensive experience in equipment failure and degradation causal analysis and use of predictive equipment monitoring technologies.

Prior to joining APS in September 2009, Mr. Cadogan spent 30 years in the nuclear energy industry, holding numerous positions in power plant operations support, design, and construction. Mr. Cadogan served as director of Engineering at the Duane Arnold Energy Center in Iowa. Prior to moving to that role in 2007, Mr. Cadogan was on loan to INPO for two years where he served as a lead evaluator in the equipment reliability area. Mr. Cadogan also served in several leadership roles at the Turkey Point Nuclear Power Plant.

Mr. Cadogan has overseen design groups performing such functions at several operating nuclear stations — with early aspects of his career as a registered professional mechanical engineer in the design and construction of new nuclear plants. Beyond these direct technical leadership expertise areas, Mr. Cadogan is experienced in shaping engineering effectiveness initiatives like technical conscience, human-error reduction, and nuclear safety culture promotion, which are vital underpinning elements of the nuclear engineering organization.

Mr. Cadogan is a registered Professional Mechanical Engineer with a Master in Engineering Management degree from the University of South Florida and a Bachelor of Science degree in Marine (Power) Engineering from the Massachusetts Maritime Academy. In addition, Mr. Cadogan attended the INPO Senior Nuclear Plant Manager course and completed the Management Senior Reactor Operator Certification at Turkey Point Nuclear Plant.

Category	Title	Description
1	Plant Modifications	Changes to the plant design, including simulator and process computers, but excluding all Water Reclamation Facility items and non-power block buildings
2	Plant Equipment and Replacements	Tools and Equipment. Used predominantly to perform routine and repetitive maintenance, construction, and training activities. This excludes items incidental with the purchase of other systems, equipment, and consumable materials Replacements. Replacement of Retirement Units "in kind" or intended to be "in kind," excluding items that are included in General Plant, Computers, or the Water Reclamation Facility
3	Buildings	Initial construction and qualified remodel of all buildings structures and facilities, including roof replacements and initial furnishings
4	General Plant	Predominantly communications-related equipment, rolling stock (vehicles), land purchases, and road and parking lot installation
5	Information Technology	Non-process computer hardware and software, computer license agreements, and miscellaneous computer equipment in support of Plant activities including Nuclear Fuel Management
6	Water Reclamation Facility	All water reclamation facility modifications, replacements, and process computers not covered in other categories
7	Overheads	Overheads in support of Capital Improvements and Distributables in support of Plant Modifications and Plant Replacements
8	Emergent Work Fund	Funding for any emergent capital projects not individually identified or budgeted or for unexpected costs identified during previously planned capital project development or implementation
9	Fukushima/Major Strategic Projects	NRC-mandated large strategic capital projects requiring special attention

Nuclear Post-Test Year Plant Additions

Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
1	090064	PVCMMN	Nuclear Admin & Tech Manual Repl	PVNGS procedure deficiencies have contributed to ineffective program administration and human performance issues. In response to numerous Corrective Action Program investigations, this project was implemented to re-structure and re-write the site's nuclear administrative and technical manuals to improve program administration and human performance issues.	9/30/2016	$ 18,683,188	$ 1,739,732	$ 20,422,921
2	120046	PVWRF	WRF 7th Clarifier Train	The scope of this project is to add a 7th train of clarifiers to increase production safety margins for the WRF.	3/31/2016	$ 9,896,936	$ 481,104	$ 10,378,040
3	110050	PV1	SP Concrete Replacement U1	The scope of this project is replacement of degraded concrete components of the spray pond structures. The spray ponds are approximately 30 years old with cracks in the concrete and is in need of repair to ensure long-term safe operation.	2/1/2017	$ 6,297,452	$ 1,793,887	$ 8,091,339
4	100010	PV3	Dig Upgrd Generrex U3	The scope of this project is to design and install digital components for the Main Generator Excitation and Voltage Regulation System (GENERREX) to replace obsolete analog components.	2/1/2017	$ 3,002,155	$ 3,452,016	$ 6,454,171
5	160070	PVWRF	Clarifiers Life Extension - 2016	The scope of this project is to inspect, and replace degraded or outdated clarifier components, and concrete to extend the Clarifier's useful life for an additional 30 years.	5/31/2017	$ 128,154	$ 4,511,649	$ 4,639,803
6	110033	PVWRF	Sewage Treatment Plant Repl	The scope of this project is to design and build a replacement sewage treatment plant as parts of the current plant is over 30 years old.	3/31/2016	$ 3,823,031	$ 345,760	$ 4,168,791
7	120135	PVCMMN	Mitigating Strategies (FLEX) and BDBM	This project will develop a beyond design basis manual in response to the letter the NRC issued (50.59(f) issued March 12, 2012) requiring PVNGS to develop a Diverse and Flexible Coping Strategy (FLEX) in response to the Fukushima Daiichi event, see attached.	11/2/2016	$ 4,038,883	$ 400,452	$ 4,439,335
8	140009	PV1	CEA Repl U1	The purpose of this project is to replace the current CEAs in Unit 1 with the new Ag-In-Cd design CEAs during 1R19, spring 2016. The Unit 1 CEA's five cycle life will expire in 2016 therefore replacement is required.	5/6/2016	$ 2,467,034	$ 439,715	$ 2,906,749
9	160062	PV3	CT Life Extension 2016 U3	The scope of this project is replacement of structural components and fill in the cooling towers to improve their operational efficiency, structural integrity, and extend their lives.	12/31/2016	$ -	$ 2,497,761	$ 2,497,761
10	160061	PV1	CT Life Extension 2016 U1	The scope of this project is replacement of structural components and fill in the cooling towers to improve their operational efficiency, structural integrity, and extend their lives.	5/8/2016	$ 121,219	$ 2,307,078	$ 2,428,297
11	150038	PV3	Main Transformer Repl U3	Purchase of new Main Transformer for installation in accordance with the Transformer LRP. The reliability strategy is to use extensive planned outage maintenance and testing along with time-based replacement to reduce the likelihood of in-service failures.	10/30/2016	$ 570,368	$ 1,632,318	$ 2,202,686
12	130108	PVCMMN	Ingress/Egress Parking Lot Modifications	The purpose of this project is to modify walk areas and parking spaces in the Ingress/Egress Parking Lot to address ADA code compliance and safety issues.	11/30/2016	$ 1,524,953	$ 703,918	$ 2,228,871
13	160118	PV2	CT Life Extension 2017 U2	The scope of this project is replacement of structural components and fill in the cooling towers to improve their operational efficiency, structural integrity, and extend their lives.	5/1/2017	$ -	$ 2,147,178	$ 2,147,178

Nuclear Post-Test Year Plant Additions

Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
14	150107	PVCMMN	Drainage Reconfiguration - Phase 1	Over the 35-year life of the Site, the rainfall catchment areas in the southern area of the Site have filled with sediment. In addition, expansion of the Evaporation Ponds has reduced the area available to handle storm-water run-off. The scope of this project is to reconfigure the ground surface area south of the units to improve drainage and water flow away from the built-out areas of the Site by restoring the catchment areas to their original capacity.	11/30/2016	$ 1,006,355	$ 1,107,883	$ 2,114,238
15	110079	PVCMMN	PRA Model - Fire	The scope of this project is to build a Probability Risk Assessment model for potential fire events to comply with a recent NRC requirement to upgrade the Site's capability to assess the risk of a fire incident that causes safety equipment to be unavailable.	3/31/2016	$ 2,325,169	$ 123,022	$ 2,448,191
16	100187	PV3	SP Filtration System Repl U3	Replace the existing Spray Pond Filtration equipment with new up-to-date technology equipment, including auto backwash for the filters. Existing equipment will be removed from service, disassembled, and removed from the Units.	6/30/2017	$ 1,126,163	$ 976,244	$ 2,102,408
17	150162	PV1	Safety Injection Gate Valve Repl	The purpose of this project is to replace the Unit 1 Shutdown Cooling Isolation valve which is the pressure boundary between the RCA and shutdown cooling. Replacement is recommended as the existing valve is degraded to a condition in which maintenance/refurbishment will not maintain operational performance and successful passing of surveillance testing.	5/8/2016	$ 819,441	$ 1,005,315	$ 1,824,755

Nuclear Post-Test Year Plant Additions

Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
18	150137	PV1	RCP Motor Repl 1R19	The scope of this project is replacement of Reactor Coolant Pump motors during outages per the long range plan.	5/3/2016	$ 1,195,446	$ 590,923	$ 1,786,369
19	150138	PV3	RCP Motor Repl 3R19	The scope of this project is replacement of Reactor Coolant Pump motors during outages per the long range plan.	11/1/2016	$ 597,208	$ 1,138,263	$ 1,735,471
20	090186	PV1	Inverter Modification U1	Replacement of four Elgar inverters and installation of two "swing" or back-up inverters per unit.	5/1/2016	$ 1,361,785	$ 483,673	$ 1,845,457
21	160059	PV2	RCP Motor Repl 2R20	The scope of this project is replacement of Reactor Coolant Pump motors during outages per the long range plan.	5/7/2017	$ -	$ 1,685,760	$ 1,685,760
22	160015	PVWRF	WRSS Pipeline - 2016	The scope of this project is continuous rebuilding of the WRSS pipeline that runs from the Phoenix sewage treatment facility to WRF extending the useful life of the pipe.	10/31/2016	$ 64	$ 1,495,266	$ 1,495,330
23	130168	PV3	Security Access Control FP - U3	The scope of this project is replacement of major sections of the site's existing Fire Protection System, in conjunction with #000068 - Security Access Control System Replacement. The NRC has mandated certain requirements for nuclear plants' security and fire protection systems. Palo Verde was not in compliance with those requirements so the systems must be replaced.	11/30/2016	$ 320,405	$ 886,105	$ 1,206,510
24	120083	PVCMMN	HVAC Replacement - Bldg A, B, & EIC	The purpose of this project is to replace the HVAC units that are reaching the end of their useful life.	2/28/2017	$ -	$ 1,194,194	$ 1,194,194
25	150139	PVWRF	WRF Domestic Water Well "A"	The scope of this project is to drill a new water well for domestic water.	8/31/2016	$ 603,560	$ 520,680	$ 1,124,239
26	160017	PVCMMN	Microsoft License Fees 2016	Microsoft licenses its suite of software programs on a three-year basis. The scope of this project is to re-license Microsoft software products for the three years from mid-2016 to mid-2019.	6/30/2016	$ -	$ 1,116,187	$ 1,116,187
27	160060	PVCMMN	Internal Protected Area Delay Barriers	PVNGS is continually upgrading its ability to deal with security threats based on industry experience and evaluations of threats faced by the nuclear industry. The scope of this project is to install additional delay barriers inside the Protected Area to increase the security margin for high value equipment.	8/31/2016	$ 490,419	$ 541,511	$ 1,031,930
28	170040	PV2	CW Pipeline Repl U2	The scope of this project is replacement of degraded piping in the circulating water system per the long range plan.	6/30/2017	$ -	$ 876,201	$ 876,201
29	140022	PVWRF	WRF Centrifuge Repl - 2016	The scope of this project is replacement of the degraded, or outdated central centrifuge equipment components.	12/31/2016	$ 127,912	$ 742,708	$ 870,620
30	160068	PV1	CW Pipeline Repl U1	The scope of this project is replacement of degraded piping in the circulating water system per the long range plan.	5/1/2016	$ 781	$ 838,334	$ 839,115

Nuclear Post-Test Year Plant Additions

Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
31	100247	PVCMMN	PM Eqpmnt Configure Doc - Non Crits	To improve the efficiency of plant equipment while simultaneously reducing the costs of equipment maintenance, this project is documenting the configuration of all plant noncritical equipment by recording four data elements for each piece: 1) Basis Justification 2) Duty Cycle 3) Critical Requirements and 4) Environmental Conditions of Operation. Then sophisticated algorithms will be run to optimize maintenance.	12/21/2016	$ 767,837	$ 151,030	$ 918,867
32	140096	PV1	Loss of Phase on Startup Xfmr U1	This project is to meet the USNRC requirements to detect and automatically separate the plant Safety Related electrical busses from the open phase condition in order to provide assurance that plant safety functions will be maintained.	12/31/2016	$ 43,907	$ 748,051	$ 791,958
33	150034	PV2	Inverter Modification U2	Replacement of four Elgar inverters and installation of two "swing" or back-up inverters per unit.	5/1/2017	$ -	$ 732,760	$ 732,760
34	160138	PVCMMN	Facilities Upgrades Non PA - 2016	Upgrades/Replacements to facilities outside the Protected Area (PA) with the purpose of making the site safer and more efficient.	12/31/2016	$ -	$ 714,296	$ 714,296
35	100053	PVCMMN	Bldg A - 3rd Floor East End Remodel	The scope of this project is the remodeling of the third floor area of Building A with the purpose of increasing employee efficiency.	3/31/2016	$ 593,943	$ 102,655	$ 696,597
36	130114	PV3	RCP Control Cable MSO U3	The scope of this project is to replace the control cables for critical reactor coolant pump operations to a three hour rated cable to ensure the operators will have plenty of time to trip the RCPs in the event of a multiple spurious fire. The cable replacement will minimize the need to perform local actions at the 13.8KV switchgear located in the 100ft Turbine Building and prevent the RCP motors from experiencing bearing and seal failure upon a loss of cooling.	11/15/2016	$ 457,438	$ 257,120	$ 714,558
37	090188	PV3	Inverter Modification U3	Replacement of four Elgar inverters and installation of two "swing" or back-up inverters per unit.	11/1/2016	$ 44,745	$ 632,004	$ 676,749
38	160115	PVCMMN	Vehicle Replacement - 2016	The scope of this project is for the replacement of vans and site vehicles that have reached the end of their useful life, increasing equipment availability and reducing repair costs.	6/30/2016	$ 37,420	$ 639,200	$ 676,621
39	160137	PVCMMN	Facility Upgrades PA - 2016	Upgrades/Replacements to facilities in the Protected Area (PA) with the purpose of making the site safer and more efficient.	12/31/2016	$ -	$ 672,737	$ 672,737
40	130170	PV1	SP Chemical Addition Upgrd U1	The purpose of this project is to improve the usability and safety of the spray pond injection system. The chemical skid, pipes and tanks will be replaced with alloy materials which will ensure system reliability and leak prevention.	6/30/2017	$ 36,325	$ 615,568	$ 651,893
41	150105	PVCMMN	CAP 1-Issue Tracking Sys - Phase 2	This is the second in a series of 3 projects to streamline and enhance the SWMS System's Corrective Action Program modules to address significant issues involving difficulties to: 1) linearly link original reports to follow-up actions, 2) separate major issues from minor items, and 3) automatically develop trending and closure reports. The project scope in Phase 2 is to upgrade SWMS to include the ability to track the Corrective Action Program issues to process Corrective Maintenance, Warehouse Deficiency Notice, and Plant Change Request work mechanisms in more streamlined fashion than the current process.	2/28/2017	$ 65,489	$ 542,534	$ 608,023

Nuclear Post-Test Year Plant Additions

Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
42	150120	PV3	HypoTrench (Blowdown M/U) U3	The scope of this project is to replace / refurbish concrete structures, piping, and associated components that are showing major signs of degradation due to water and chemicals extending its useful life an additional 30 years.	9/30/2016	$ 191,520	$ 367,367	$ 558,888
43	110096	PV1	Spray Pond Margin Recovery U1B	The scope of this project is to increase Spray Pond margin and provide greater system maneuverability by installing new motor operated bypass valve and resize flow orifice FO-215/216.	5/8/2016	$ 188,698	$ 288,042	$ 476,740
44	170095	PV2	Steam Generator Dispersant App U2	The scope of this project is to install a chemical feed skid that will inject dispersant into the secondary feedwater system which will allow iron that would otherwise deposit in the Steam Generator, to remain in solution and be removed via the blowdown system. The dispersant will effectively reduce the iron accumulation in the Steam Generators at an economical cost compared to having to perform more frequent chemical cleanings.	5/15/2017	$ 68,611	$ 407,754	$ 476,365
45	150167	PVCMMN	MNSA Capital Spare	The MNSA is an instrument that will serve as a spare Bottom Mounted Instrumentation (BMI) nozzle. Obtaining a MNSA will minimize outage schedule impacts if BMI leakage (due to nozzle weld cracking) is found.	12/30/2016	$ 37,462	$ 436,209	$ 473,671
46	150117	PVWRF	Process Piping Replacement	The scope of this project is to replace and reroute the degraded process water piping throughout WRF extending the useful life of the piping an additional 30 years.	12/31/2016	$ 54,610	$ 389,339	$ 443,949
47	080052	PV3	Personnel Air Lock (PAL) Mod U3	This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 3. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release.	12/31/2016	$ 85,399	$ 363,441	$ 448,839
48	130019	PVCMMN	Oracle Hardware Replacement 2015	Computer hardware has a defined useful life - typically 3-5 years - due to reliability and obsolescence issues. The scope of this project is ongoing replacement of key computer server hardware to ensure continued reliable operation of the Site's computer network.	6/15/2016	$ 317,486	$ 59,376	$ 376,862
49	160139	PV1	Station Battery Repl U1 2016	The purpose of this project is to maintain the batteries according to the long range plan. These batteries are critical for safe shutdown of the reactor in the event of a station blackout.	4/30/2016	$ 14,760	$ 339,523	$ 354,283
50	160113	PVCMMN	Concrete & Paving - 2016	The scope of this project is for the replacement/installation of concrete and paving, improving site safety and protecting company assets.	12/31/2016	$ -	$ 324,679	$ 324,679
51	150018	PVWRF	GF Filter Media - 2017	The scope of this project is replacement of the filter media, strainers, and troughs in the gravity filter system that have surpassed it's useful life.	5/30/2017	$ -	$ 318,591	$ 318,591
52	110206	PV1	Small Normal Chiller Replacement U1	Project scope is the replacement of all small Normal Chillers with a "Chiller Farm". Current Chillers are obsolete and no longer supported by the vendor.	5/6/2016	$ 128,112	$ 199,614	$ 327,726
53	110167	PV1	Main FP Turbine OH Lifting system "A"	The existing 8 ½ ton under slung hoists currently used above the Main Feed Water Pump Turbines in each unit does not allow the hoists to be centered safely over the components during required lifts necessary during maintenance work. Scope is to replace existing 8 ½ ton Main Feed Water Pump Turbine hoists with safer modern radio controlled hoists capable of reaching all components associated with the MFWPT line work. Each hoist will be replaced by a combination of a jib crane and a monorail hoist.	5/15/2016	$ 224,049	$ 91,254	$ 315,302

Nuclear Post-Test Year Plant Additions

Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
54	120129	PVCMMN	Auto Shop Fuel Tanks & Pump Repl	The purpose of this project is to bring the auto shop fuel tanks up to code and replace fuel pumps.	3/15/2016	$ 285,077	$ 18,914	$ 303,990
55	160019	PVCMMN	Cathodic Protection 2016	Ongoing replacement of failed anodes and support devices employed in the Cathodic Protection System.	12/31/2016	$ -	$ 290,588	$ 290,588
56	150062	PV1	RCP Control Cable MSO U1	The scope of this project is to replace the control cables for critical reactor coolant pump operations to a three hour rated cable to ensure the operators will have plenty of time to trip the RCPs in the event of a multiple spurious fire. The cable replacement will minimize the need to perform local actions at the 13.8KV switchgear located in the 100ft Turbine Building and prevent the RCP motors from experiencing bearing and seal failure upon a loss of cooling.	5/8/2016	$ 194,036	$ 90,261	$ 284,297
57	170091	PV2	Main Generator HVB U2	This project is to replace the Main Generator High Voltage Bushings which are at the end of their useful life. Replacement of the bushings according to the Long Range Plan reflects safety first and replaces original plant equipment which could be a personnel safety or generation risk.	5/5/2017	$ -	$ 277,174	$ 277,174
58	140076	PVWRF	WRF Lab Refurbishment	This project refurbishes the WRF lab with new fittings, fixtures, and updated equipment to extend the useful life an additional 30 years.	12/31/2016	$ 42,923	$ 225,927	$ 268,849
59	150085	PV3	Spray Pond Margin Recovery U3B	The scope of this project is to increase Spray Pond margin and provide greater system maneuverability by installing new motor operated bypass valve and resize flow orifice FO-215/216.	11/6/2016	$ 13,033	$ 239,291	$ 252,324
60	160038	PV3	Valve Replacements U3 2016	Replacement of valves per the Long Range Plan with the purpose of protecting plant equipment and increasing equipment availability.	11/15/2016	$ -	$ 252,176	$ 252,176
61	160135	PV1	Valve Replacements U1 2016	Replacement of valves per the Long Range Plan with the purpose of protecting plant equipment and increasing equipment availability.	5/15/2016	$ 30,555	$ 218,969	$ 249,524
62	150086	PV2	Spray Pond Margin Recovery U2A	The scope of this project is to increase Spray Pond margin and provide greater system maneuverability by installing new motor operated bypass valve and resize flow orifice FO-215/216.	5/7/2017	$ -	$ 245,315	$ 245,315
63	110172	PV1	Duct Banks & Cabling Repl U1	The scope of this project is the replacement of the Duct Banks and cabling from the Emergency Diesel Generator (EDG) buildings to the Diesel Fuel Oil Transfer Pump (DFOTP) vaults.	7/30/2016	$ 103,550	$ 151,912	$ 255,462
64	140024	PVWRF	GF Filter Media - 2016	The scope of this project is replacement of the filter media, strainers, and troughs in the gravity filter system that have surpassed it's useful life.	6/30/2016	$ 152,557	$ 81,594	$ 234,151
65	160165	PVCMMN	BMI Nozzle Inspection Tooling	The scope of this project is for the purchase of a BMI Nozzle Inspection Tool to enhance the ability to inspect BMI nozzles during outages.	6/30/2017	$ -	$ 223,689	$ 223,689
66	160173	PV1	Spent Fuel Pool Vortex Breaker U1	The purpose of this project is to install a vortex breaker into the Spent Fuel Pool (SFP) to eliminate the potential of low water levels in the SFP below the submergence requirement.	5/30/2017	$ -	$ 220,514	$ 220,514

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
67	150109	PVCMMN	Supply Chain Reports/Dashboard S/W	Information required to monitor performance in the Supply Chain Group, including metrics concerning efficiency of material ordering and supply, are produced manually by pulling data from disparate systems. The scope of this project is to build a data warehouse from these various systems to automate the production of Supply Chain performance reporting and related metrics.	12/31/2016	$ 73,927	$ 147,644	$ 221,572
68	160151	PV3	Main Generator HVB U3	This project is to replace the Main Generator High Voltage Bushings which are at the end of their useful life. Replacement of the bushings according to the Long Range Plan reflects safety first and replaces original plant equipment which could be a personnel safety or generation risk.	11/8/2016	$ -	$ 207,179	$ 207,179
69	140144	PV1	Roof Penetration Seals - U1	Recent inspections of the roofs of the Fuel, Auxiliary, and Control Buildings of the three units found that roof penetration seals were not of sufficient depth to handle the rooftop water from an extreme rainfall event. The scope of this project is to upgrade the affected roof penetration seals to provide sufficient depth to handle an extreme rainfall event.	12/31/2016	$ 128,134	$ 78,386	$ 206,520
70	160142	PV1	Secondary Vessel Reline U1 2016	The scope of this project is to reline regen vessels according to the LRP during the refueling outage work window.	5/1/2016	$ 6,252	$ 196,022	$ 202,274
71	130064	PV3	Stator Leak Monitoring System HP U3	Replacement of existing Stator Leak Monitoring System (SLMS) with the modern SLMS - High Performance panels.	11/6/2016	$ 93,365	$ 119,608	$ 212,973
72	160026	PV3	Station Battery Repl U3 2016	The purpose of this project is to maintain the batteries according to the long range plan. These batteries are critical for safe shutdown of the reactor in the event of a station blackout.	11/15/2016	$ -	$ 194,231	$ 194,231
73	160150	PV3	Permanent Power for Turbine Bldg U3	The purpose of this project is to permanently install cables needed to support temporary power during outages. The permanent installation of the cables will eliminate the current practice of installing and removing the cables for each outage. This will minimize resource requirements and make outages more efficient.	12/31/2016	$ -	$ 193,833	$ 193,833
74	140148	PV3	Roof Penetration Seals - U3	Recent inspections of the roofs of the Fuel, Auxiliary, and Control Buildings of the three units found that roof penetration seals were not of sufficient depth to handle the rooftop water from an extreme rainfall event. The scope of this project is to upgrade the affected roof penetration seals to provide sufficient depth to handle an extreme rainfall event.	12/15/2016	$ 82,049	$ 107,217	$ 189,266
75	150164	PV2	Permanent Power for Turbine Bldg U2	The purpose of this project is to permanently install cables needed to support temporary power during outages. The permanent installation of the cables will eliminate the current practice of installing and removing the cables for each outage. This will minimize resource requirements and make outages more efficient.	3/30/2017	$ -	$ 182,008	$ 182,008
76	110123	PVCMMN	Building A Cafeteria	The purpose of this project is to upgrade the facilities in the Building A Cafeteria to allow for better quality and service. The scope is to replace the old equipment and improve the work flow.	7/31/2016	$ -	$ 159,936	$ 159,936
77	170082	PV2	Valve Replacements U2 2017	Replacement of valves per the Long Range Plan with the purpose of protecting plant equipment and increasing equipment availability.	5/1/2017	$ -	$ 159,296	$ 159,296

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
78	120028	PVCMMN	Simulator: Update RELAP Model	The current software that models the Pressurizer function is a complicated set of custom coding and algorithms that lack graphics capability and are capable of being supported by only a few individuals who were involved in its creation. The scope of this project to replace this software with modern, modular software that provides improved modeling capability as well graphics capability, and will supported by a widely-used software vendor to the nuclear industry.	10/31/2016	$ -	$ 158,151	$ 158,151
79	150131	PV1	Turbine Building Lighting U1	This project is to replace the lighting in the Turbine Building for all three units.	4/9/2016	$ 98,690	$ 60,101	$ 158,791
80	140147	PV2	Roof Penetration Seals - U2	Recent inspections of the roofs of the Fuel, Auxiliary, and Control Buildings of the three units found that roof penetration seals were not of sufficient depth to handle the rooftop water from an extreme rainfall event. The scope of this project is to upgrade the affected roof penetration seals to provide sufficient depth to handle an extreme rainfall event.	12/15/2016	$ 50,306	$ 106,481	$ 156,787
81	160053	PV3	Main FP Turbine OH Lifting system "A"	The existing 8 ½ ton under slung hoists currently used above the Main Feed Water Pump Turbines in each unit does not allow the hoists to be centered safely over the components during required lifts necessary during maintenance work. Scope is to replace existing 8 ½ ton Main Feed Water Pump Turbine hoists with safer modern radio controlled hoists capable of reaching all components associated with the MFWPT line work. Each hoist will be replaced by a combination of a jib crane and a monorail hoist.	11/15/2016	$ 22,581	$ 126,182	$ 148,763
82	150193	PV1	Auxiliary Feedwater Cross-Tie	Modification permits using the fire protection system to supply water to the steam generators in the event of a failure of all three (3) Auxiliary Feedwater pumps. The change addresses probabilistic risk associated with postulated fire events and is needed to support NRC approval of the Risk-Informed Technical Specifications.	12/31/2016	$ -	$ 144,483	$ 144,483
83	170028	PV2	Main FP Turbine OH Lifting system "A"	The existing 8 ½ ton under slung hoists currently used above the Main Feed Water Pump Turbines in each unit does not allow the hoists to be centered safely over the components during required lifts necessary during maintenance work. Scope is to replace existing 8 ½ ton Main Feed Water Pump Turbine hoists with safer modern radio controlled hoists capable of reaching all components associated with the MFWPT line work. Each hoist will be replaced by a combination of a jib crane and a monorail hoist.	3/30/2017	$ -	$ 143,765	$ 143,765
84	140079	PV1	Main FP Turbine OH Lifting system "B"	The existing 8 ½ ton under slung hoists currently used above the Main Feed Water Pump Turbines in each unit does not allow the hoists to be centered safely over the components during required lifts necessary during maintenance work. Scope is to replace existing 8 ½ ton Main Feed Water Pump Turbine hoists with safer modern radio controlled hoists capable of reaching all components associated with the MFWPT line work. Each hoist will be replaced by a combination of a jib crane and a monorail hoist.	2/1/2017	$ -	$ 143,328	$ 143,328
85	160143	PV3	Secondary Vessel Reline U3 2016	The scope of this project is to reline regen vessels according to the LRP during the refueling outage work window.	11/1/2016	$ -	$ 142,436	$ 142,436
86	170089	PV2	Secondary Vessel Reline U2 2017	The scope of this project is to reline regen vessels according to the LRP during the refueling outage work window.	5/1/2017	$ -	$ 141,773	$ 141,773

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
87	160034	PV3	Pump Replacements U3 2016	The scope of this project is to replace pumps according to the long range plan to maintain the reliability of the pumps.	11/15/2016	$ -	$ 141,465	$ 141,465
88	160122	PV3	FAC Mod U3 2016	Replacement of pipe damaged by Flow Accelerated Corrosion (FAC) according to routine inspections.	11/15/2016	$ -	$ 137,904	$ 137,904
89	130167	PV2	Security Access Control FP - U2	The scope of this project is replacement of major sections of the site's existing Fire Protection System, in conjunction with #000068 - Security Access Control System Replacement. The NRC has mandated certain requirements for nuclear plants' security and fire protection systems. Palo Verde was not in compliance with those requirements so the systems must be replaced.	12/31/2016	$ 97,362	$ 36,351	$ 133,713
90	160040	PVCMMN	Mobility - Tagging Clearance	At present, the process in SWMS for individuals to sign on to clearance items is cumbersome and time-consuming, and restricted to computers. The scope of this project is to upgrade specific components of the SWMS software to enhance functionality of the clearance module to enable individuals to access this module from hand-held devices to sign on to clearance items.	12/31/2016	$ -	$ 129,872	$ 129,872
91	160084	PV1	MET Tower Cyber Security Upgrade	The scope of this project is to install cyber security firewalls and physical security protections to protect the meteorological tower from the from the PV Process Local Area Network, in response to the Cyber Security Rule 10CFR73.54.	12/31/2016	$ -	$ 129,872	$ 129,872
92	160178	PVCMMN	Autonomy Software	The current version of this software that provides search capability for records in the Site's Work Management system is reaching end-of-life and will lose vendor support in 2016. Replacement with the latest version of the software is required to maintain ongoing vendor support for this software and ensure reliable operations.	11/30/2016	$ -	$ 129,488	$ 129,488
93	160174	PVCMMN	Network Switch/Router Upgrades	Computer hardware and related communication equipment have a defined useful life - due to reliability and obsolescence issues. The scope of this project is ongoing replacement of key computer hardware / communications components to ensure continued reliable operation of the Site's computer network.	12/31/2016	$ 84,736	$ 43,650	$ 128,386
94	160152	PVCMMN	Start-Up Xfmr X03 HVB Repl	The purpose of this project is to replace the Start-Up Transformer High Voltage Bushings (HVBs) which are the end of their useful life. Replacement will allow the site to maintain the reliability of its large power production equipment.	5/26/2016	$ 4,185	$ 121,982	$ 126,167
95	170102	PVCMMN	Start-Up Xfmr X01 HVB Repl	The purpose of this project is to replace the Start-Up Transformer High Voltage Bushings (HVBs) which are the end of their useful life. Replacement will allow the site to maintain the reliability of its large power production equipment.	2/25/2017	$ -	$ 124,386	$ 124,386
96	160069	PVWRF	Cathodic Protection - 2016	Ongoing replacement of failed anodes and support devices employed in the Cathodic Protection System.	3/31/2016	$ -	$ 122,302	$ 122,302
97	140045	PV1	Stator Leak Monitoring System HP U1	Replacement of existing Stator Leak Monitoring System (SLMS) with the modern SLMS - High Performance panels.	5/8/2016	$ 59,024	$ 59,385	$ 118,409
98	140089	PV3	HVAC Replacement - 2016 U3 OSB	This project is to replace the HVAC unit on the Unit 3 outage support building	2/26/2016	$ 110,480	$ 1,357	$ 111,837

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
99	150055	PVCMMN	SEATS System S/W Upgrade	The Software Error Tracking System (SEATS) is used site-wide to track and monitor software errors. The system is cumbersome to use and based on outdated software technology. The scope of this system is to replace the software with the latest modular software that will be easier to use and easier to maintain.	9/30/2016	$ -	$ 106,193	$ 106,193
100	160104	PV1	EDG AVR U1 "B" Train Repl	Replace the existing emergency EDG voltage regulator 90VR in Generator Control Panel and the two existing Motor Operated Potentiometers (MOP's)	4/15/2016	$ -	$ 103,021	$ 103,021
101	150102	PV3	EDG AVR U3 "A" Train Repl	Replace the existing emergency EDG voltage regulator 90VR in Generator Control Panel and the two existing Motor Operated Potentiometers (MOP's)	3/30/2017	$ (344)	$ 102,884	$ 102,540
102	170012	PVCMMN	Fire Prot. Upgrades - 2017	The original fire detection system installed at PVNGS shared a computer control system with the Site's perimeter security control system. This dual function control system was determined to be unacceptable from a security standpoint. The scope of this project is to install a separate, stand-alone fire protection systems, including detectors and panels.	5/1/2017	$ -	$ 101,950	$ 101,950
103	120126	PV3	Air Washer Repl - HF System U3	This project will replace the air washers and related piping in the Fuel Building. The existing air washers are at or beyond their useful life and leakage is creating the potential for tritium to leak into the groundwater.	12/30/2016	$ 7,378	$ 92,852	$ 100,230
104	110204	PV1	Air Washer Repl - HF System U1	This project will replace the air washers and related piping in the Fuel Building. The existing air washers are at or beyond their useful life and leakage is creating the potential for tritium to leak into the groundwater.	12/30/2016	$ -	$ 98,703	$ 98,703
105	130162	PV2	Digital Asset Protection System - U2	In response to the Cyber Security Rule 10CFR73.54, which requires strengthening of the Site's cyber security capabilities, this project provides 24/7 real time monitoring capabilities of the Plant Process Control Systems to identify potential cyber security threats.	12/31/2016	$ 8,228	$ 90,041	$ 98,268
106	130163	PV3	Digital Asset Protection System - U3	In response to the Cyber Security Rule 10CFR73.54, which requires strengthening of the Site's cyber security capabilities, this project provides 24/7 real time monitoring capabilities of the Plant Process Control Systems to identify potential cyber security threats.	12/31/2016	$ 3,642	$ 94,331	$ 97,974
107	160133	PV3	Turbine Valves U3 2016	The scope of this project is to replace turbine valves according to the long range plan to maintain the reliability of the valves.	11/15/2016	$ -	$ 97,115	$ 97,115
108	160002	PV1	FAC Mod U1 2016	Replacement of pipe damaged by Flow Accelerated Corrosion (FAC) according to routine inspections.	5/15/2016	$ 3,833	$ 93,043	$ 96,876
109	160114	PVCMMN	Fire Prot. TSC Command Center	The scope of this project is to install pro-inert gas in a critical part of the TSC to protect vital plant equipment.	4/30/2016	$ 52,915	$ 42,271	$ 95,186
110	170093	PV3	Turbine Building Lighting U3	This project is to replace the lighting in the Turbine Building for all three units.	10/8/2016	$ 34,788	$ 59,980	$ 94,767
111	150165	PVCMMN	Mobile Food Trailer	Purchase a mobile food trailer that can be used inside the PA during outages, reducing rental charges and traffic in and out of the Protected Area.	3/1/2016	$ -	$ 94,807	$ 94,807

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
112	160159	PVCMMN	Security Camera Replacement 2016	This project is to replace the security cameras onsite.	12/31/2016	$ -	$ 94,482	$ 94,482
113	160056	PV2	Turbine Valves U2 2017	The scope of this project is to replace turbine valves according to the long range plan to maintain the reliability of the valves.	5/1/2017	$ -	$ 90,799	$ 90,799
114	160132	PV1	Turbine Valves U1 2016	The scope of this project is to replace turbine valves according to the long range plan to maintain the reliability of the valves.	5/15/2016	$ 1,058	$ 89,618	$ 90,676
115	150110	PV2	Transfer Canal Gate Seal U2	This project is to install a redundant gate seal between the spent fuel pool and refueling canal to ensure addequate inventory is maintained in the spent fuel pool.	1/31/2016	$ 86,952	$ 1,795	$ 88,746
116	170064	PVCMMN	Security Camera Replacement 2017	This project is to replace the security cameras onsite.	4/30/2017	$ -	$ 88,936	$ 88,936
117	150068	PVCMMN	EP Plus S/W Replacement	PVNGS has multiple Engineering software programs to monitor, test, and record equipment reliability. The current software used for these programs is obsolete and is being replaced by the vendor, which will eventually end support for the current system. The scope of this project is to upgrade to the latest version of this software to improve its functionality and to maintain vendor support.	3/4/2016	$ 51,950	$ 29,764	$ 81,714
118	150108	PVCMMN	Kofax Capture Screening Software	This project is to replace the outdated scanning and processing system with the modern and reliable KOFAX Capture suite.	2/28/2016	$ 68,874	$ 12,483	$ 81,357
119	160050	PVWRF	Site Culvert Rehabilitation 2016	This project rebuilds/replaces worn out drainage culverts on the PV site extending the useful life of the culverts.	12/31/2016	$ -	$ 81,170	$ 81,170
120	160183	PVCMMN	Site Tools - RP/Chemistry	This project allows the site to purchase and replace old tools and equipment that are unreliable and obsolete with improved and safer models of tools.	12/31/2016	$ -	$ 81,170	$ 81,170
121	150047	PVWRF	Clarifier Flow Meters	Purchase and installation of metering equipment at the 1st clarifiers in the Water Reclamation Facility to improve oversight of operations.	11/30/2016	$ -	$ 80,929	$ 80,929
122	130161	PV1	Digital Asset Protection System - U1	In response to the Cyber Security Rule 10CFR73.54, which requires strengthening of the Site's cyber security capabilities, this project provides 24/7 real time monitoring capabilities of the Plant Process Control Systems to identify potential cyber security threats.	12/31/2016	$ 37,562	$ 42,150	$ 79,712
123	160036	PV3	Motor Replacements U3 2016	Replacement of Motors per Long Range Plan preventing unplanned outages.	11/15/2016	$ 2,908	$ 75,978	$ 78,886
124	180109	PV3	GSU 3B Bushing Repl U3	The purpose of this project is to replace the Main Transformer High Voltage Bushing (HVB) which are the end of their useful life. Replacement will allow the site to maintain the reliability of its large power production equipment.	11/6/2016	$ -	$ 77,692	$ 77,692
125	170037	PV2	Pump Replacements U2 2017	The scope of this project is to replace pumps according to the long range plan to maintain the reliability of the pumps.	5/1/2017	$ -	$ 76,462	$ 76,462

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
126	170103	PV2	GSU 2C Bushing Repl U2	The purpose of this project is to replace the Main Transformer High Voltage Bushing (HVB) which are the end of their useful life. Replacement will allow the site to maintain the reliability of its large power production equipment.	5/7/2017	$ -	$ 74,869	$ 74,869
127	150112	PVCMMN	Network Bandwidth Upgrade	This project will upgrade the PV business network bandwidth by ten-fold.	2/10/2016	$ 351,381	$ 4,316	$ 355,697
128	160054	PV1	Motor Replacements U1 2016	Replacement of Motors per Long Range Plan preventing unplanned outages.	5/15/2016	$ 514	$ 69,464	$ 69,978
129	160085	PVCMMN	Fire Prot. North Annex	The scope of this project is to install pro-inert gas in a critical part of the North Annex to protect vital plant equipment.	6/30/2016	$ 35,239	$ 33,572	$ 68,811
130	160035	PV1	Pump Replacements U1 2016	The scope of this project is to replace pumps according to the long range plan to maintain the reliability of the pumps.	5/15/2016	$ 14,698	$ 52,603	$ 67,301
131	160130	PVCMMN	Digital Signage 2016	At present, considerable effort is extended to print and install posters and signs at multiple locations around the Site to inform personnel about the latest initiatives and activities. The scope of this project is to install of digital signage around the Site to facilitate efficient and effective information transfer to all site personnel.	12/31/2016	$ -	$ 66,235	$ 66,235
132	160181	PVCMMN	Site Tools - Engineering	This project allows the site to purchase and replace old tools and equipment that are unreliable and obsolete with improved and safer models of tools.	12/31/2016	$ -	$ 64,936	$ 64,936
133	170032	PV2	Motor Replacements U2 2017	Replacement of Motors per Long Range Plan preventing unplanned outages.	5/1/2017	$ -	$ 63,719	$ 63,719
134	160134	PV1	RCP Seal Replacements U1 2016	The scope of this project is replacement of the reactor coolant pump seals according to the LRP during outages.	5/15/2016	$ 44,282	$ 12,572	$ 56,854
135	160175	PVCMMN	Tririga Data/Maps for Facilities	At present, the Site does not have a digital Master Facilities Plan that is kept current for changes made to buildings and work areas inside buildings. This makes planning remodeling and reconstruction projects difficult as the current situation for a proposed remodeling project must be verified by walk downs and inspections as well as making it difficult to plan multiple overlapping projects simultaneously. The scope of this project is purchase and install a real-time Facilities Data/Mapping program for development of a Master Facilities Plan that can be updated on-line as changes are made to buildings and work areas, to facilitate the facility management function and streamline project planning.	10/31/2016	$ -	$ 56,483	$ 56,483
136	160058	PV3	RCP Seal Replacements U3 2016	The scope of this project is replacement of the reactor coolant pump seals according to the LRP during outages.	11/15/2016	$ -	$ 55,356	$ 55,356
137	160182	PVCMMN	Site Tools - Maintenance	This project allows the site to purchase and replace old tools and equipment that are unreliable and obsolete with improved and safer models of tools.	12/31/2016	$ 14,085	$ 40,817	$ 54,902
138	170092	PV2	Turbine Building Lighting U2	This project is to replace the lighting in the Turbine Building for all three units.	4/9/2017	$ 35,586	$ 18,805	$ 54,391

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
139	110187	PVCMMN	Scintillation Hand & Foot Monitor	This project is to replace the scintillation hand and foot monitor.	5/30/2017	$ -	$ 53,842	$ 53,842
140	160153	PV1	Main Xfmr Arrester Repl U1	The purpose of this project is to replace transformer surge arresters during the planned outages identified on the Long Range Plan. The existing porcelain arresters will be replaced with zinc oxide arresters with a silicone rubber shed. This replacement reflects safety first and replaces degraded plant equipment which could be personnel safety or generation risk.	5/8/2016	$ 6,184	$ 45,042	$ 51,226
141	170080	PV2	RCP Seal Replacements U2 2017	The scope of this project is replacement of the reactor coolant pump seals according to the LRP during outages.	5/1/2017	$ -	$ 50,019	$ 50,019
142	160111	PVCMMN	SCR Automated Process S/W	At present, Work Management SCR's (Scope Change Requests) are processed manually, taking considerable time to process and rendering real-time tracking difficult. The scope of this project is to replace the manual SCR process with an electronic process to improve overall efficiency and effectiveness of the process.	12/31/2016	$ -	$ 48,702	$ 48,702
143	160160	PVCMMN	HVAC Smaller than 25 Ton - 2016	The scope of this project is to replace HVAC units smaller than 25 tons that are beyond their useful life and repairs are frequent.	12/31/2016	$ -	$ 48,702	$ 48,702
144	160107	PV1	Bulk Acid Storage Tank 2016	This project is to remove and replace Bulk Acid Storage Tanks which are degraded beyond repair. The new replacement tanks will be fabricated and coated off site by vendors specializing in chemical tank fabrication and coating.	7/31/2016	$ -	$ 47,981	$ 47,981
145	160108	PVCMMN	Category B Software Infrastructure	The Category B environment includes software used for analysis of safety systems and safety equipment from the Engineering Group. Currently the software is difficult to maintain and update. The project scope is to replace existing Category B Engineering environment with hardware to enable each software element to have its own environment, to reduce support and improve sustainability of this system.	8/1/2016	$ -	$ 42,030	$ 42,030
146	160110	PVCMMN	DMX Reports and Dashboard	The DMX module (Data Management Module) in SWMS and related Access databases store data and produce reports concerning controlled records processed by the Support Services Department. The legacy system, which is over 15 years old, is both convoluted and outdated, and is not compliant with current standards for production systems. The scope of this project is to create a new data store and reporting system using PV-standard reporting tool that will replace the current system, to improve reliability and reduce support efforts in the future.	7/30/2016	$ 3,750	$ 34,742	$ 38,492
147	150089	PVWRF	DS/DW Building Life Ext 2016	The scope of this project is to remodel the WRF Domestic Water Service Building to update degraded areas, and to extend its useful life an additional 30 years.	12/31/2016	$ 34,375	$ 2,533	$ 36,908
148	160154	PV3	Main Xfmr Arrester Repl U3	The purpose of this project is to replace transformer surge arresters during the planned outages identified on the Long Range Plan. The existing porcelain arresters will be replaced with zinc oxide arresters with a silicone rubber shed. This replacement reflects safety first and replaces degraded plant equipment which could be personnel safety or generation risk.	11/6/2016	$ -	$ 37,227	$ 37,227
149	160191	PVCMMN	Plant Cooling Water Motor Rewind	This project is to rewind the plant cooling water motor.	2/28/2016	$ -	$ 36,527	$ 36,527

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Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
150	160145	PVCMMN	Start-Up Xfmr Surge Arrestors X03	The purpose of this project is to replace transformer surge arresters during the planned outages identified on the Long Range Plan. The existing porcelain arresters will be replaced with zinc oxide arresters with a silicone rubber shed. This replacement reflects safety first and replaces degraded plant equipment which could be personnel safety or generation risk.	5/26/2016	$ -	$ 36,246	$ 36,246
151	130157	PVWRF	WRF 1st Stage Thickener Life Ext 2016	The scope of this project is to replace the degraded components and make necessary concrete repairs to extend the useful life of the WRF First Stage Thickener system for the next 30 years.	12/31/2016	$ 32,851	$ 2,421	$ 35,272
152	160176	PVCMMN	NAN Phone Reliability improvements	NAN phones are special telephone used to make required notifications to offsite organizations during an emergency response. These phones are currently using an outdated cabling network that is experiencing reliability issues. The scope is to update the technology used for this connection to improve reliability.	7/31/2016	$ -	$ 35,186	$ 35,186
153	160136	PVCMMN	Site Tools & Equipment 2016	This project allows the site to purchase and replace old tools and equipment that are unreliable and obsolete with improved and safer models of tools.	12/31/2016	$ -	$ 32,468	$ 32,468
154	160161	PVCMMN	Elevator Repl TSC	The purpose is to replace this elevator that is reaching the end of its useful life.	12/31/2016	$ -	$ 32,468	$ 32,468
155	160162	PVCMMN	Elevator Repl Bldg "E"	The purpose is to replace this elevator that is reaching the end of its useful life.	12/31/2016	$ -	$ 32,468	$ 32,468
156	160163	PV1	Elevator Repl OSB U1	The purpose is to replace this elevator that is reaching the end of its useful life.	12/31/2016	$ -	$ 32,468	$ 32,468
157	160164	PV2	Elevator Repl OSB U2	The purpose is to replace this elevator that is reaching the end of its useful life.	12/31/2016	$ -	$ 32,468	$ 32,468
158	160180	PV3	Elevator Repl OSB U3	The purpose is to replace this elevator that is reaching the end of its useful life.	12/31/2016	$ -	$ 32,468	$ 32,468
159	160149	PV1	Permanent Power for Turbine Bldg U1	The purpose of this project is to permanently install cables needed to support temporary power during outages. The permanent installation of the cables will eliminate the current practice of installing and removing the cables for each outage. This will minimize resource requirements and make outages more efficient.	12/31/2016	$ -	$ 25,000	$ 25,000
160	170067	PV2	FAC Mod U2 2017	Replacement of pipe damaged by Flow Accelerated Corrosion (FAC) according to routine inspections.	5/1/2017	$ -	$ 23,894	$ 23,894
161	160157	PV3	Fire Prot. U3 OSB Fire Detection Repl	The scope of this project is to replace the Fire Actuation Control Panel at the OSB and add a new detector zone, complying with NFPA code.	3/15/2016	$ 3,875	$ 15,873	$ 19,748
162	160037	PV2	Motor Replacements U2 2016	The scope of this project is to replace emergent motors in need of immediate replacement.	12/31/2016	$ -	$ 16,883	$ 16,883

Nuclear Post-Test Year Plant Additions

Line No.	Work Order/Funding Project	Operating Unit	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
163	160039	PVWRF	Hypochlorite Tank Repl 2016	This project replaces one of WRF's hypochlorite storage tanks as the current tank has reached the end of it's useful life.	12/31/2016	$ -	$ 16,234	$ 16,234
164	140074	PVCMMN	Elevator A and B Control System Repl	The scope of this project is to increase elevator reliability by replacing the control systems in both elevators at each building.	3/15/2016	$ -	$ 15,801	$ 15,801
165	160155	PVWRF	Lab Auto Titrator	The scope for this project is to replace the existing Auto-Titrator Analyzer.	3/31/2016	$ 11,027	$ 2,984	$ 14,011
166	090088	PV1	Personnel Air Lock (PAL) Mod U1	This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 1. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release.	5/15/2016	$ 11,388	$ 350	$ 11,738
167	160158	PVCMMN	Fire Prot. Vehicle Maint Facility	The scope of this project is to replace the Fire Actuation Control Panel at the OSB and add a new detector zone, complying with NFPA code.	7/15/2016	$ -	$ 11,196	$ 11,196
168	160177	PVCMMN	Integrity Server	Computer hardware has a defined useful life - typically 3-5 years - due to reliability and obsolescence issues. The scope of this project is ongoing replacement of key computer server hardware to ensure continued reliable operation of the Site's computer network.	2/1/2016	$ 10,478	$ 319	$ 10,797
169	160063	PV2	Pump Replacements U2 2016	The scope of this project is to replace emergent pumps in need of immediate replacement.	12/31/2016	$ -	$ 10,065	$ 10,065
170	120125	PV2	Air Washer Repl - HF System U2	This project will replace the air washers and related piping in the Fuel Building. The existing air washers are at or beyond their useful life and leakage is creating the potential for tritium to leak into the groundwater.	12/30/2016	$ 8,485	$ 625	$ 9,111
171			**Total Nuclear**			**$66,596,657**	**$ 57,363,976**	**$123,960,633**

Palo Verde Nuclear Generation Station
O&M and Operating Cost
2010 - 2015

	2010	2011	2012	2013	2014	2015
O&M Cost ($M)	$ 658.6	$ 648.2	$ 638.9	$ 628.3	$ 644.6	$ 635.7
Operating Cost (O&M Cost / MWh)	$ 21.11	$ 20.72	$ 20.01	$ 19.99	$ 19.94	$ 19.54
MWh	31,199,935	31,277,883	31,933,916	31,431,082	32,323,543	32,525,592

APS Share of PVNGS

	2010	2011	2012	2013	2014	2015
O&M Cost ($M)	$ 191.7	$ 188.6	$ 185.9	$ 182.8	$ 187.6	$ 185.0
Operating Cost (O&M Cost / MWh)	$ 21.11	$ 20.72	$ 20.01	$ 19.99	$ 19.94	$ 19.55
MWh	9,079,181	9,101,864	9,292,770	9,146,445	9,406,151	9,461,778

DIRECT TESTIMONY OF JACOB TETLOW

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF JACOB TETLOW
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jacob Tetlow. I am General Manager of the Transmission and Distribution (T&D) Operations and Maintenance Department at Arizona Public Service Company (APS or Company), and my business address is 2122 West Cheryl Drive, Phoenix, Arizona, 85021.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Mechanical Engineering from Arizona State University, and worked as an engineer and supervisor prior to joining APS in 2001. During my years at APS, I have held various front-line and leadership positions including Production Manager at the Company's Cholla Power Plant, Director of Gas and Oil Generation, Director of Coal Generation, and Director of Distribution Operations and Maintenance. I was named to my current position in March of 2014.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am responsible for the safe and reliable operation of the Company's transmission and distribution system throughout APS's 35,000 square-mile service territory, which includes the provision of service to our customers through efficient and cost-effective system maintenance. I am also responsible for the Company's forestry programs, service restoration, and emergency event preparedness.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony describes the key functions of the T&D Operations and Maintenance Department and how these functions contribute to the safe and reliable service provided to APS customers. I discuss representative programs, initiatives and expenditures the Company pursued during the 2015 Test Year. Specifically, I describe:

- APS's performance in several key operational areas, with a particular focus on the Company's ongoing commitment to operate and maintain the T&D system in a cost-effective and sustainable manner;
- The impact of the unusually strong 2015 summer storm season on the Company's Test Year expenditures; and
- Planned capital expenditures within the T&D organization that are included in the Company's 18-month post-Test Year plant pro forma.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My direct testimony discusses the Company's responsibility to provide safe and reliable service to our more than 1.2 million customers in all or part of 11 of the state's 15 counties. To provide this service, APS uses T&D infrastructure that includes:

- More than 29,000 miles of distribution lines;
- Over 6,000 miles of transmission lines;
- 430 substations;
- 300,000 transformers; and
- More than 550,000 power poles and structures.

Because APS is headquartered in the Phoenix metropolitan area, the Company is often thought of as a largely urban utility, when in fact APS has one of the lowest customer densities for electric utilities in the United States. The Company serves urban and rural

customers in a large service territory that includes a variety of elevations, climates, and terrains. Serving customers in such a diverse territory is challenging and requires a focused operations and maintenance strategy.

I discuss the three key operational directives that are the T&D Department's primary responsibilities: safety, reliability, and cost management. APS's overall mission statement—*We safely and efficiently deliver reliable energy to meet the changing needs of our customers*—reflects and reinforces each of these directives. APS must continually monitor its performance in these areas to maintain—and improve upon—the high level of service our customers have come to expect.

As transmission-related costs are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) and are not included in the Test Year in this case, my testimony focuses on the APS distribution system and cost recovery for distribution-related expenditures, including post-Test Year plant additions.

III. SAFETY

Q. PLEASE DESCRIBE THE IMPORTANCE OF SAFETY AT APS.

A. The first and highest priority for all APS employees is to work safely. Safety is especially important for many T&D employees who routinely work with lines and facilities that are either energized or may become energized at a moment's notice. APS has a rigorous safety program and documented safety manual in place and continually looks to improve the effectiveness of its safety culture. The Accident Prevention Manual (APM) is updated regulary by a joint management and union committee demonstrating the commitment to safety exists at all levels of the company.

APS also recognizes its responsibility to our customers and to the general public to create a safe environment when providing electric service. This responsibility translates into a variety of concrete actions, from safely maintaining the substations located in urban areas to patrolling both our transmission and distribution lines annually to detect and repair unsafe conditions. If the Company receives a call from a customer with a safety-related concern regarding our service facilities, we dispatch employees immediately to assess the situation and take any action needed to create a safe environment, including repairing, replacing or de-energizing facilities if needed.

APS's Public Safety Consultants give more than 175 safety presentations each year to communities, schools, and businesses, providing safety information and promoting recognition of electrical safety hazards. APS's safety programs emphasize both personal employee safety and the safety of our customers.

Q. WHAT ARE SOME OF THESE SAFETY PROGRAMS?

A. Investment in safety—both employee and public safety—is a top priority. Employees participate in regular training programs through the year. These programs include those that increase skill sets, improve crew safety, efficiency and planning or familiarize field personnel with new equipment and procedures. A safety program that is especially important to the T&D organization is our state-of-the-art defensive driving program. The T&D Department logs more than 12 million miles on the road throughout our service territory each year. APS's driving program ensures that T&D employees regularly practice defensive driving techniques, and has been effective in promoting safe driving habits.

In addition, in early 2015 the T&D Department reviewed and revised its Fatigue Management Program, which focuses on managing the number of hours our employees work. This program limits employees to 15 hours of work and then requires eight hours

of rest time to ensure they are focused on the task at hand and to minimize the risk of mental or physical fatigue upon return to work. We employ this program even during the worst of our summer storms, to ensure the overall safety of our employees and the safety of our customers.

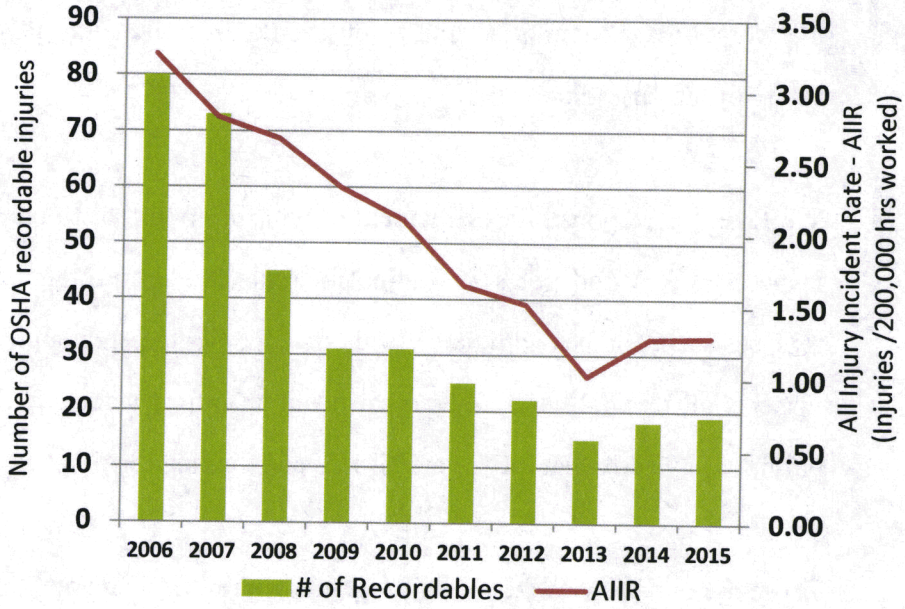
We take our responsibilities interacting with the public seriously. For example, APS inspects aged wood poles at routine intervals for termite damage and wood rot, and replaces suspect poles with new wood or steel poles depending on access. APS annually inspects all of its 29,000 miles of distribution infrastructure, looking for potential key public safety and reliability related issues and making repairs.

These are but a few of the safety programs within the Company today. The scope of the safety-related programs and initiatives in place are founded in providing employees the right training, tools, and overall environment to keep themselves, their team members, and the public safe at all times.

Q. HAVE THESE PROGRAMS BEEN SUCCESSFUL?

A. Yes. Figure 1 below shows the effectiveness of the Company's safety programs over the last ten years, which demonstrates that our commitment to continuous improvement, safety education and performance programs do make a significant impact on the safety and well-being of our employees.

Figure 1.
T&D Department Historical Safety Record



We have achieved this safety record by actively emphasizing safety accountability at all levels of the organization. The strong and continued emphasis on identifying and eliminating safety risks caused by human performance, efforts towards eliminating unwanted events, and strong management and employee commitment to safety have produced measureable results that we continually reinforce through our everyday work practices. We want our employees to go home in the same condition they came to work, returning safely to family and friends.

IV. RELIABILITY

Q. YOU MENTIONED THAT RELIABILITY IS A CORE RESPONSIBILITY OF YOUR DEPARTMENT. HOW DO YOU FURNISH RELIABLE SERVICE TO YOUR CUSTOMERS?

A. Maintaining and improving APS's transmission and distribution system reliability is a core responsibility of the T&D Operations and Maintenance Department and is the second key operational area we focus upon. In an age of rapid technology advances,

both business and residential customers depend on reliable electric service as an essential component of their everyday lives. APS has a strong reliability record, which is the result of our comprehensive maintenance and asset management programs.

For example, APS has a reliability program focused solely on underground direct buried cable. The company began installing direct buried cable in the 1950's and 1960's, a common utility practice at the time. The practice of cable installation by direct bury was discontinued in 1986, and since then, all underground cable has been installed in conduit. The useful life of the direct buried cable is approximately 30 years and much of the direct buried cable is now beyond the end of its design life, resulting in an increase in cable failures. APS has taken a proactive approach to this issue by implementing a cable replacement program that will replace this aging infrastructure. It is more cost effective to proactively replace the cable as opposed to reactively replacing the cable following a fault. In 2015, we invested over $20 million to continue this program; an investment that will result in fewer cable failures and increased reliability to our customers.

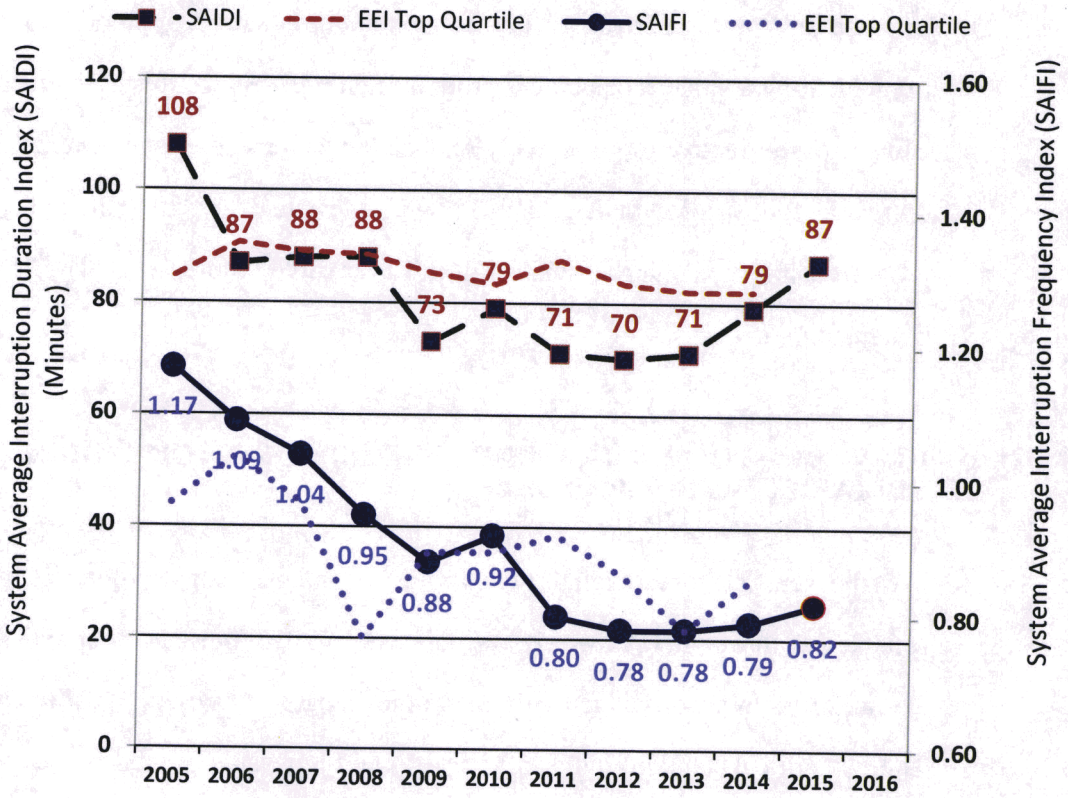
Q. HOW DO YOU DETERMINE THE SUCCESS OF YOUR CUSTOMER RELIABILITY PROGRAMS?

A. We measure customer reliability through standard industry metrics and customer satisfaction through JD Power & Associates. In 2015, our customer satisfaction ranked 2nd out of 54 Investor Owned Utilities in the category of Power, Quality and Reliability. The two critical standard industry metrics used to measure reliability are:

- System Average Interruption Frequency Index (SAIFI) which is a measure of the average number of interruptions a customer experiences in a year; and
- System Average Interruption Duration Index (SAIDI) which measures the number of interrupted minutes a customer experiences in a year.

APS has achieved excellent performance in both areas over the past decade, including reducing the frequency of customer outages by 30% and duration of customer outages by 19%. This accomplishment is the result of our reliability programs, our dedicated employees, system improvement projects and investments in technology. Figure 2 below charts our performance in these industry metrics over the past ten years as compared to the industry benchmark of our peer utilities in the Edison Electric Institute. These statistics include all weather related events demonstrating that APS has consistently performed at top quartile or better as compared to our industry peers.

Figure 2.
APS Actual SAIFI & SAIDI (All Weather)



A. *Vegetation Management*

Q. HOW DOES A VEGETATION MANAGEMENT PROGRAM IMPROVE CUSTOMER RELIABILITY?

A. Vegetation interference with power lines is one of the most common causes of service interruptions throughout the industry. Our vegetation management program is geared toward the minimization of customer power interruptions caused by trees and other vegetation in the vicinity of our power lines. APS spends approximately $18 million annually to properly manage 35,000 miles of power lines throughout our service territory.

APS employs professional tree care experts to perform line clearance and spray herbicides using methods based on scientific research and best practices that minimize the impact of necessary clearances on sensitive wildlife, plants, and cultural resources.

Within our overall vegetation management program, APS has instituted an aggressive fire mitigation program. In 2015, the Company hired a full-time fire mitigation specialist, who serves as a liaison between APS and the governmental Fire Incident Command, keeping lines of communication open between the APS Distribution Operations Center and the Fire Incident Command. During non-fire season, this employee focuses solely on programs, work practices, and technology to further reduce risk and impacts of wildfire.

Also, as part of the Company's fire mitigation program, APS has installed Expulsion Limiting Fuses (ELF) in targeted forested areas. ELFs reduce the amount of burning material ejected from a fuse when it fails, greatly limiting fire risk.

B. *Storm Restoration*

Q. DO ARIZONA'S STORM SEASONS IMPACT YOUR ABILITY TO PROVIDE RELIABLE SERVICE TO YOUR CUSTOMERS?

A. Without a doubt, Arizona's summer monsoons have a significant impact on our transmission and distribution system. Although T&D employees understand the effects of these storms and are well prepared for the rigors of storm restoration, it is inevitable that monsoons will cause customer outages over the course of a summer season. It is our goal to minimize the extent and duration of storm outages and restore service to our customers as quickly as possible.

We work hard to restore customers' service during an outage and to keep them informed in the meantime on the expected outage duration. Many of these customers can see us out on the streets restoring service in the middle of the night or while a storm still rages. It is a source of pride and gratitude that at the end of each storm, we receive many notes from customers praising our employees on their hard work and courteous service. APS's employees do work with incredible tenacity and vigor during storms, and I am proud of our employees and their dedication to providing the best possible service to our customers under difficult and dangerous circumstances.

Q. WAS THE 2015 SUMMER STORM SEASON TYPICAL?

A. Not at all. The 2015 storm season proved to be one of the most challenging seasons in many years. In fact:

- Rainfall was significantly higher than normal as May 2015 was the second wettest May in Arizona history;
- Temperatures were higher than normal as August 2015 was the second hottest August in Arizona history; and

- The number of days with customer outages resulting from storm activity increased by 20% as compared to the previous five years.

One measure we use to assess storm impacts over a season is the number of damaged poles due to these storms. In the summer of 2015, we had 568 poles damaged as a result of storm activity. This is more than twice the number of poles damaged during the same summer storm period in 2014 or 2013. Each of these unusual conditions, in conjunction with monsoon storms, caused considerable damage to our system and negatively impacted our reliability during the 2015 summer storm season.

In order to combat the weather, the Company has continued to expand our Stopper Pole program. A stopper pole is a heavy duty steel pole installed at strategic locations along lengthy stretches of utility poles in areas with increased exposure to summer monsoon storms. Stopper poles are designed to stop or limit the number of downed and damaged poles and lines during a storm. Although APS has been using stopper poles for some time, in 2013 the T&D Department initiated a formal program to identify areas where proactive installation of the poles would prevent significant outages. In 2015, APS installed 103 stopper poles at a cost of approximately $1.9 million. APS estimates that since 2012, stopper pole installations have reduced the frequency and duration of outages by 80% in the areas targeted for stopper pole installations.

V. COST MANAGEMENT

Q. PLEASE DESCRIBE THE ROLE OF COST MANAGEMENT IN YOUR DEPARTMENT.

A. An effective cost management strategy plays a significant role in the business of providing electric service and is the third key operational focus of the T&D Department. It is the Company's objective to provide affordable electric service to our customers—

even while the cost of equipment and material necessary to build and maintain facilities continues to escalate.

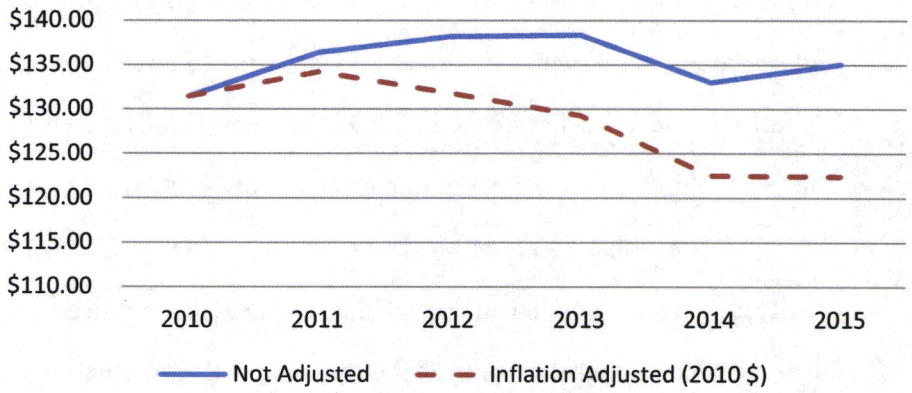
Earlier sections of my testimony discuss our efforts to provide safe and reliable service. This safe and reliable service requires investments in existing facilities that maintain, upgrade, and expand the system across our service territory. Even with regular maintenance, equipment will inevitably reach the end of its useful life or become obsolete. Storms and third-party intrusion events—such as vehicle accidents and wildfires—can also damage and destroy equipment.

Customer growth also requires investment in new or upgraded facilities. For all of these situations, the T&D Department must manage the Company's existing assets and deploy new facilities using a disciplined, cost-conscious approach to keep customer rates as low as possible. The need to invest in the system for both short and long term reliability, while at the same time driving down costs, is our most difficult and complex challenge.

Continuous improvement doesn't stop with safety and reliability—it's also reflected in Figure 3 below, which shows that over the past five years we have continued to drive down the transmission and distribution O&M cost per customer. After adjusting for inflation, the expenses associated with the delivery of the energy across the Transmission and Distribution system is 7% lower as compared to five years ago. All of these cost reductions were accomplished while serving 1.1% more customers annually over the same period of time.

Figure 3.

T&D Department
O&M Expense per Customer



Q. WHAT ARE SOME OF THE PROGRAMS OR EFFORTS IN YOUR DEPARTMENT AIMED AT MANAGING COST?

A. At APS, we have several predictive maintenance programs which utilize advanced technologies to determine the health of our systems. For example, we have infrared cameras that we use to scan power lines and associated equipment looking for hot spots before they cause an outage. It's always more efficient to proactively maintain facilities than reactively repair or rebuild them following a forced outage.

One recent initiative to improve the efficiency of our maintenance crews is our new work management system, also known as Maximo. Maximo is the IBM application we use to initiate, plan, schedule, execute and close out repair orders for our field employees. This was a $17 million project to consolidate three different versions of Maximo into the latest version, which includes significant functional enhancements such as a new scheduling tool and performance reports. In addition, this has allowed APS to identify best in class work practices and standardize these practices across multiple business units.

Q. DOES YOUR DEPARTMENT FACE ANY SPECIFIC CHALLENGES IN THIS AREA?

A. A specific challenge that impacts our ability to effectively manage costs is our workforce attrition rate. This challenge is not unique to APS. Utilities throughout the industry are facing large workforce turnover as the "Baby Boomer" generation continues to retire. In the T&D Department, 21% of our employees are eligible to retire today. In five years, this number increases to approximately 37%. In fact, 2015 was a record year for retirements—4% of our employees retired from APS—and the level of retirements is predicted to be even higher in 2016. In 2015, T&D experienced a total of 8% workforce attrition. In response to this challenge, we will continue to recruit and train new employees to manage our existing system, while at the same time, seek employees with the skill sets to work with emerging technologies and evolving customer expectations.

APS must invest in and commit to developing a diverse and engaged workforce to be successful in the future and effectively manage costs for the long term benefit of our customers.

VI. NEW TECHNOLOGICAL AND OPERATIONAL INITIATIVES

Q. YOU MENTIONED THAT APS IS INSTALLING NEW, STATE-OF-THE-ART TECHNOLOGIES. WHAT NEW INITIATIVES ARE BEING PURSUED IN YOUR DEPARTMENT?

A. In the T&D Department, we have embarked upon several new and exciting infrastructure replacement and upgrade projects that incorporate the latest available technologies and will strengthen APS's ability to reliably serve our customers. These initiatives build upon the Company's long-standing history of research and adoption of innovative technologies that have provided benefits to both APS and our customers. Electric utility industry technology has advanced significantly in the last few years as evidenced by the influx of distributed resources being deployed by our customers in the

Company's service territory. Much of the advanced technology that APS is deploying is in fact related to managing distributed resources and their impact on our system to enable our customers to continue adopting these technologies, while we continue to provide reliable service. Below, I describe a few of the initiatives currently underway in this area.

A. *Project Illuminate*

Q. WHAT IS PROJECT ILLUMINATE?

A. Project Illuminate is a major initiative within the T&D Department that will enhance system reliability by allowing distribution system operators to remotely monitor and control the system and its associated devices, and will provide greater situational awareness of the system in real time. The cornerstone of the project is the installation of an Advanced Distribution Management System (ADMS) that will allow for automation of distribution field devices and significantly enhanced visibility into our system—visibility that inspired the name of the project.

Q. WHAT IS ADMS?

A. ADMS is an advanced operating platform that will be installed at the Company's Distribution Operations Center. The new ADMS system will combine a base distribution operating platform, outage management system, advanced engineering applications and distribution equipment control system in one integrated operating platform. These systems, working together, will allow APS to perform advanced engineering and analytics on the system, and provide our system operators with industry-leading functionality.

ADMS will replace the Company's current Distribution Operation Management System (DOMS). DOMS was a state-of-the-art system-management software and provided

APS with a unified view of its distribution system, increasing our ability to provide our customers with reliable service through increased outage management and restoration.

APS has outgrown the DOMS system due to technological advancements and the need for an overall approach to integrating distributed resources into the APS system. ADMS is next-generation technology, and will allow the Company to effectively manage the challenges of both current and future distributed energy sources.

Q. WHAT ARE THE BENEFITS OF ADMS?

A. There are many benefits to both APS and our customers. Specifically, ADMS will:

- Increase the efficiency of the distribution system;
- Improve safety;
- Increase the life of distribution facilities through reduced losses;
- Improve communications between the field and the operating center; and
- Allow APS to fine tune power quality and better manage voltage across the system, especially critical given the adoption rates of rooftop solar.

This project will also increase the reliability performance of the system through real-time outage communication, leading to reduced restoration times and increased system stability. APS witness Daniel Froetscher discusses the need for APS to create an enabling grid for distributed technologies, and ADMS is a core example of this effort.

In addition to creating a flexible environment to integrate new distributed technologies, ADMS brings more immediate benefits to customers in the form of improved reliability. The enhanced communication infrastructure and the ability to remotely manage power quality will strengthen system reliability.

When fully implemented, ADMS will allow the Company to offer its customers enhanced proactive communications, such as opt-in notification applications for smart phones and other energy management options to keep our customers informed and enable them to actively manage energy costs.

B. *Distribution Upgrades*

Q. PLEASE DESCRIBE SOME OF THE UPGRADED AND NEW TECHNOLOGY APS HAS INSTALLED ON ITS DISTRIBUTION SYSTEM.

A. In the past few years, APS has installed several new technological upgrades on its distribution system that will help the Company maintain and improve the reliability of the system. In 2015, APS realized an estimated 6.4% reduction in the duration of outages our customers experienced (measured by the SAIDI metric) that were attributable to the installation of new advanced technologies on the distribution grid. These include:

Supervisory Controlled Switches (SCS). These switches are installed directly on the distribution grid. They have the capability to provide real-time information to our operations control center, and can be controlled remotely. SCS reduce outage time by remotely re-routing power around equipment that has failed. APS has installed approximately 145 SCS to date at a cost of $6.4 million through the end of 2015.

Communicating Fault Indicators (CFI). CFIs provide remote indications of an electrical line failure, where it is, and what type of failure has occurred. CFIs have significantly reduced outage minutes by allowing APS operators to locate equipment failures from the operations control center instead of physically finding the failure point in the field, reducing trouble-shooting time and allowing field personnel to be dispatched to the trouble location. At the end of the Test Year, the Company had installed approximately 1,270 CFIs at a cost of $1.1 million.

Network Protector Replacement/Supervisory Control And Data Acquisition (SCADA). Network locations are major interconnections, such as hospitals and high rise buildings on the grid, where large customers or buildings need additional lines to serve them. These locations have very complex line connections that in the past required visual inspection to determine their status. These connections are being replaced with fully automated components using SCADA capability to provide real-time operating status details and the ability to remotely monitor and switch lines. These configurations not only increase system reliability, but also improve public safety. APS has upgraded 27 sites with these automated components at a cost of $6.2 million through the end of the Test Year.

APS will continue to implement these technologies after the end of the Test Year in this case; therefore, capital expenditures for each of these projects are included in the Company's post-Test Year pro forma. These post-Test Year expenditures are detailed in Attachment SBB-1DR to the testimony of APS witness Scott Bordenkircher.

VII. POST-TEST YEAR EXPENDITURES

Q. ARE ANY OF THE PROPOSED POST-TEST YEAR CAPITAL PROJECTS RELATED TO DISTRIBUTION FACILITIES OR PROGRAMS?

A. Yes. As can be seen in Attachments JT-1DR and JT-2DR, APS is proposing that approximately $470 million in Total Company capital expenditures for the period January 1, 2016 through June 30, 2017 be included in the Company's post-Test Year plant pro forma adjustment for distribution, information technology, and facilities projects. These projects contribute $75.5 million to the Company's proposed Total Company rate base, as shown in SFR B-2, page 2, column 4. Additional details of these post-Test Year adjustment expenditures, such as accumulated depreciation, accumulated

deferred income taxes, depreciation expense, property taxes, and interest expense are described by APS witness Elizabeth Blankenship.

Of the $470 million in capital expenditures, $46.5 million is directly related to installation of ADMS system components as discussed earlier in my testimony. During the post-Test Year period, APS will install SCADA devices, communications facilities, and Distribution Management System and Outage Management System software applications associated with ADMS.

A. *Distribution Capital Expenditures*

Q. PLEASE DESCRIBE THE PROPOSED POST-TEST YEAR CAPITAL EXPENDITURES RELATED TO THE DISTRIBUTION SYSTEM.

A. The proposed distribution system capital expenditures for projects that will be in service at June 30, 2017 total approximately $270 million, and are detailed in Attachment JT-1DR.

The majority of these expenditures, some $164.7 million, will be necessary to meet expected growth in the Company's service territory. APS must be in a position to serve new customers safely, reliably, and efficiently. New customers require new distribution feeders, substations, capacitors, regulators, meters, and other equipment necessary to ensure the Company fulfills its obligation to serve and supports the energy needs of these customers.

An additional $38.1 million will be spent during the post-Test Year period to continue the cable replacement program which supports the provision of reliable service to our customers. This program was discussed earlier in my testimony.

B. *Information Technology and Facilities Capital Expenditures*

Q. PLEASE DESCRIBE THE PROPOSED POST-TEST YEAR CAPITAL EXPENDITURES RELATED TO INFORMATION TECHNOLOGY AND FACILITIES.

A. The proposed information technology and facilities capital expenditures for projects that will be in service at June 30, 2017 total $200 million, and are detailed in Attachment JT-2DR.

Other than the installation of components for the ADMS system, the largest expenditure in this category during the post-Test Year period will be approximately $25.7 million related to the implementation of Energy Imbalance Market (EIM) protocols and software. The EIM is a sub-hourly real-time energy market that will expand the Company's ability to efficiently dispatch its generating resources, and will provide additional tools to manage the impact of rooftop solar intermittency on the APS system. The benefits of the EIM to APS and its customers are discussed in the testimony of APS witness James Wilde.

VIII. CONCLUSION

Q. MR. TETLOW, DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS has a responsibility to our customers to operate the Company's transmission and distribution systems to the highest level of safety, reliability, and efficiency. Safe and reliable service requires investment in facilities, programs, and employees that maintain, upgrade, and expand the system across our service territory.

Approval of the Company's requested increase in this rate case will allow us to continue to provide the high level of service and reliability our customers enjoy today.

DISTRIBUTION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
1	Service and Line Extensions – Residential	Cost to provide new service and upgraded service to residential customers and thereby adding new revenue	6/30/2017	$ 3,159,009	$ 50,472,228	$ 53,631,237
2	Transformers	Pre-capitalized cost of distribution transformer purchases that are used for additions and replacements in the distribution system	6/30/2017	$ -	$ 30,962,592	$ 30,962,592
3	Unplanned UG Cable Replacement	Replace all of the remaining direct buried primary distribution cable at the lowest cost with the highest reliability impact. In addition, replacement of cable already installed in conduit may be included.	6/30/2017	$ 5,561,440	$ 21,332,742	$ 26,894,183
4	Service and Line Extensions – Non-Residential	Cost to provide new service and upgraded service to commercial and industrial customers and thereby adding new revenue	6/30/2017	$ 1,981,073	$ 21,332,105	$ 23,313,178
5	Unplanned/Emergency	Replacement of distribution capital equipment resulting from unforeseen system conditions that resulted in unplanned outages	6/30/2017	$ 1,728,075	$ 16,914,107	$ 18,642,181
6	Service Replacements	Replace direct-bury service/secondary distribution cable with cable in conduit	6/30/2017	$ 184,842	$ 11,010,805	$ 11,195,646
7	Advanced Distribution Management System ("ADMS") RTUs Dual-Port	Project is required to dual-port existing Remote Terminal Units ("RTUs") to communicate with both Energy Management System ("EMS") and new Advanced Distribution Management System ("ADMS")	12/31/2016	$ 2,860,211	$ 7,976,106	$ 10,836,316
8	Wood Pole Replacement	Replacement of poles found to not have 10 years of remaining life	6/30/2017	$ 1,292,114	$ 9,404,733	$ 10,696,847
9	Anthem New Substation	Feeder is at max load and the only way to fix the issue is to build another substation. Deadman Wash is incapable of a third transformer on the substation foot print - plan is to build a new substation and pull 3 feeders to relieve load	6/1/2017	$ -	$ 7,541,905	$ 7,541,905
10	Commerce Substation	Develop and build a new 69/12kV dedicated substation. Install 4 new underground 69kV lines to the new substation. Reconfigure the existing overhead 69kV to support the new underground lines and routes. Install a new fiber from Yorkshire substation.	1/30/2016	$ 4,733,537	$ 1,720,445	$ 6,453,982
11	Overhead Planned Replacement	Replacement of end-of-life, degraded or damaged equipment (noted during annual public safety line patrols and annual climbing inspections)	6/30/2017	$ 707,284	$ 4,914,792	$ 5,622,076
12	Substation Aged Equipment Replacement	Replace aging substation equipment which is at end-of-service life, problematic or in an advanced degradated state due to loading and/or operation	6/30/2017	$ 1,136,159	$ 4,181,548	$ 5,317,708
13	Harquahala Substation Rebuild	Rebuild Harquahala substation to accommodate new City of Scottsdale wells	12/30/2016	$ 3,306	$ 5,200,724	$ 5,204,031
14	Aged Conductor Replacement/ Mitigation	Install modern protection devices to protect legacy small wire from damage/burning down during fault conditions. In some situations, reconductor small wire and backbone sections	6/30/2017	$ 164,262	$ 4,741,023	$ 4,905,285

DISTRIBUTION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
15	Storm – Lines	The purpose of this program is to replace transmission lines damaged resulting from storm and unplanned events	6/30/2017	$ 127,940	$ 2,891,870	$ 3,019,810
16	Good Samaritan / Honor Health Hospital Expansion	Pull two new feeders from Evans Churchill. The work will also involve a new conduit and trench from 7th Street and Roosevelt, heading east to 10th Street and Culver using an existing conduit system on a bridge crossing the I-10. A new automatic transfer switch system will be installed on site.	12/31/2016	$ 639,812	$ 2,177,819	$ 2,817,631
17	Pebblecreek Sub-Install 2nd 41 MVA	This work allows load to be transferred to avoid overloading Pebblecreek feeders #5, #10 and #12 and transformer #3; and allows loading to be reduced on Litchfield feeder #1 and transformer #3. Provides operational and maintenance flexibility.	6/1/2017	$ -	$ 2,735,597	$ 2,735,597
18	Overhead Feeder from Sandvig to New Load Center	There is not enough capacity to serve upcoming loads in Flagstaff (Estimated 3-5MW coming to the area). Upgrades to an existing substation to accommodate.	11/1/2016	$ 594	$ 2,691,878	$ 2,692,471
19	Sedona Feeder #14 – Replace Poles Oak Creek Canyon	Replace many poles on Sedona feeder #14 due to deteriorating condition and many poles utilizing the old stub pole configuration to extend the life	6/1/2017	$ 189,461	$ 2,421,698	$ 2,611,158
20	Calderwood Substation – Add 2nd Transformer	This project was identified due to forecasted overloads on the existing configuration. The substation is designed for a two transformer build-out, but currently only has one transformer.	6/1/2016	$ 104,094	$ 2,339,870	$ 2,443,964
21	Gateway – Add Feeder Exit	Add a new feeder and feeder extension from Gateway. The work is being divided into multiple phases, including a 3 mile duct bank/feeder extension from North Valley Parkway and then west on Sonoran Desert Parkway to the Taylor Morrison site.	6/1/2016	$ -	$ 2,388,028	$ 2,388,028
22	Rebuild Saddle Creek Ranch Line	Rebuild 16 miles of line without neutral to serve the proposed Saddle Creek Ranch development	6/1/2016	$ 1,478,906	$ 904,358	$ 2,383,264
23	Tuthill 2nd Transformer	Avoids a potential overload on the single Tuthill transformer that would result in an inability to serve existing or new load at Verrado master planned community and provides Operational and maintenance flexibility during planned and unplanned outages.	6/1/2017	$ 1,837	$ 2,291,193	$ 2,293,030
24	Streetlights and Dusk to Dawn	Cost to add and improve APS owned streetlight system and customer requested dusk to dawn lights	6/30/2017	$ 846,988	$ 1,300,763	$ 2,147,751
25	Elden Substation – Add Fourth Feeder Exit	Re-route Elden feeder #2 to increase its rating and allow it to be expressed to the area south of Snowbowl. A new feeder, Elden feeder #13, will be installed to provide capacity for new loads west and south of Elden substation.	11/1/2016	$ 83,020	$ 1,970,262	$ 2,053,282
26	Waddell New Feeder	At Waddell Substation, install a 12kV feeder breaker in bay #21. New feeder relieves overloads on Waddell feeders #12 and #17 and Dysart feeder #21.	6/1/2017	$ -	$ 2,030,710	$ 2,030,710
27	Woody Mountain Sub Transformer Upgrade	Increase reliability and allow for additional load growth in the western area of Flagstaff which is a prime location for commercial/industrial growth	4/1/2016	$ 616,492	$ 1,335,345	$ 1,951,837

DISTRIBUTION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
28	Underground Cabinet Replacement	Replacement of underground switching cabinets	6/30/2017	$ 129,198	$ 1,587,146	$ 1,716,344
29	Underground Transformer Replacement	Replacement of transformers that are no longer able to be repaired	6/30/2017	$ 175,153	$ 1,507,813	$ 1,682,965
30	Ebay Expansion Project	Current load on existing feeder and other feeders in the area do not allow for the additional load to be added to the existing feeders.	2/26/2016	$ 592,075	$ 1,000,441	$ 1,592,516
31	Tuthill Feeder Extension	Install 2.5 miles of cable in existing and new duct bank to extend Tuthill feeder #2 from Verrado Way and McDowell Road to Sunrise Road and Indian School Road	12/30/2016	$ -	$ 1,504,933	$ 1,504,933
32	Delano – Add New Feeder Breaker	Add new feeder at Delano substation to off load feeders DE05 and DE10	6/1/2016	$ 296	$ 1,500,163	$ 1,500,459
33	Switzer Canyon Substation Transformer Upgrade	At Switzer Canyon Substation, upgrade each of the 2 existing 15.9MVA and 17.9MVA transformers to 2-20MVA transformers before winter 2016	11/1/2016	$ -	$ 1,378,174	$ 1,378,174
34	Capitalized Tools	Individual tools, equipment, or components with a replacement unit cost of $5,000 or greater	6/30/2017	$ 276,579	$ 798,307	$ 1,074,886
35	Hedgepeth Hills Substation – Install 6th 12kV Feeder	In Hedgepeth Hills Substation, install the 6th 12kV feeder breaker in bay 10	6/1/2016	$ 124,959	$ 906,448	$ 1,031,407
36	Gila Bend Sub	Rebuild 1.3 miles of system backbone for feeder tie between GB22 and GB10. Small wire runs along the main corridor in Gila Bend upgrade to provide for load transfer capability between the two radial feeders.	6/1/2017	$ 30,128	$ 940,940	$ 971,068
37	Litchfield Sub Feeder Tie	Avoids a feeder overload and provides Operational flexibility for planned and unplanned outages and for feeder reconfiguration as needed by system conditions.	6/1/2017	$ -	$ 904,324	$ 904,324
38	Distribution System Improvement	Distribution system improvements are requirements from Planning, Operations, or Maintenance to upgrade facilities to handle increased or future load, improve reliability, or improve switching capabilities. System improvements may be in conjunction with new revenue projects, governmental road improvements, cable replacements, etc.	6/30/2017	$ 64,882	$ 794,272	$ 859,155
39	Soldiers Trail Feeder Upgrade and Rebuild to Pulliam Airport	Upgrade the existing 3-phase line crossing I-17 south of new Soldier's Trail substation	12/30/2016	$ 2,919	$ 856,097	$ 859,015
40	Willis – Add 2nd 12kV Feeder	At Willis Substation, install 1-12kV feeder breaker in bay #1, 7,200 feet of cable, and a new 3-way switching cabinet	6/1/2016	$ 7,703	$ 792,859	$ 800,563
41	Clearwater Hills Upgrade	Upgrade areas within the Clearwater Hill subdivision located off Tatum Blvd and Clearwater Parkway by installing new conduit encased cable and rebuild approximately 8,500 feet of direct-buried cable	12/31/2016	$ 10,232	$ 772,390	$ 782,622

DISTRIBUTION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
42	Wildflower Feeder Bay	At Wildflower Substation, install a feeder breaker in bay #12. This work allows load to be transferred from Wildflower feeders #4 and #5 to avoid forecasted overloads and, if necessary, from Pebblecreek feeder #12 to relieve heavy loading on this feeder.	6/1/2017	$ -	$ 776,359	$ 776,359
43	Valley Farms Sub	When the outage of Coolidge – Valley Farms 115kV line occurs, the transmission source which is Coolidge 115kV substation is disconnected. The Valley Farms 69kV load looks to the next transmission source which is Oracle Junction 115kV substation. By changing the transmission source to a greater distance this causes low voltage in the Valley Farms 69kV substation.	6/1/2016	$ -	$ 614,431	$ 614,431
44	Javelina Substation – Install 8th Feeder Breaker	At Javelina Substation, install the eighth 12kV feeder breaker	6/1/2016	$ 18,716	$ 565,363	$ 584,079
45	Sun Dog Capacitor Bank	The loss of Sundog Tap – Sundog 69kV line causes a voltage deviation greater than 5%. Install a 7.2 MVAR 69kV capacitor bank at Sundog 69kV substation.	12/31/2016	$ 215,599	$ 358,318	$ 573,918
46	Forestry/Landscaping	Provides improvements to substation facilities typically requested by municipalities. Improvements can be in the form of fencing, sidewalk, drive way or landscaping.	6/30/2017	$ -	$ 544,923	$ 544,923
47	Sedona Bypass	Trench and install 2,600 feet cable to bypass the overloaded lines for Sedona feeder SE06.	6/1/2016	$ -	$ 510,987	$ 510,987
48	STORM - Substations	Replacement of damaged equipment due to storms.	6/30/2017	$ -	$ 508,777	$ 508,777
49	Dysart-Hwy 85 Rebuild	During underground conversion, a feeder was loaded to 171% of its 84 amp rating and potentially higher causing the conductor to anneal. The conductor has the potential to fail across the railroad tracks or along Highway 85.	6/1/2016	$ 10,482	$ 441,517	$ 451,999
50	Lincoln Street North Switching Cabinet	Four major customers' lines are tied together via 2-Y splices without ability to isolate separately, covering 6 city blocks. Install equipment for faster fault location, isolation and service restoration to seven key customers.	3/31/2016	$ -	$ 451,513	$ 451,513
51	Mummy Mountain 69 Line Breakers	Add 69kV line breakers at Mummy Mountain Substation to eliminate paired element scheme. These schemes are outdated, not cost efficient, and not operator friendly.	5/1/2017	$ -	$ 396,541	$ 396,541
52	Non AMI Meters-Meter Ops	Purchase of non automated meters which are needed throughout APS' service territory.	6/30/2017	$ -	$ 395,160	$ 395,160
53	Palm Valley Feeder Rebuild	Relieves forecasted overloads on Palm Valley feeder #13 and Litchfield feeder #12 due to growth in area residential communities and provides Operational flexibility for planned and unplanned outages.	6/1/2016	$ 36,211	$ 295,761	$ 331,972
54	Vicksburg New Feeder Breaker & Feeder Exits	Install substation Viper recloser, 3-795+N line, and gang operated switch to accommodate the addition of six new well pumps and mitigate a feeder overload recloser bypass limited at 400 Amps.	6/1/2016	$ 1,298	$ 300,125	$ 301,423

DISTRIBUTION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
55	Thayer Substation	Install 3.6MVAR substation cap banks at Thayer to provide voltage support to the transmission system due to increase load for Royal Paper's second plant. Install a 12kV breaker for the bypass to the primary meter to allow for the additional load demand.	6/1/2016	$ 895	$ 290,332	$ 291,227
56	Acoma Feeder Upgrade	Obligation in serving customer Scottsdale Quarter Block - increased rating capacity on three feeders for 6.2 MW total gained capacity.	6/1/2016	$ -	$ 250,093	$ 250,093
57	Camelback #10 Parallelling	Two new customer loads on Scottsdale Rd. north of Thomas Rd. totaling 1.5MW that will overload the Papago Butte 03 transformer by 2% in 2016	6/1/2016	$ -	$ 243,763	$ 243,763
58	Valley Farms Capacitor Bank	The loss of the Coolidge – Valley Farms 115kV line causes voltage deviations greater than 5% on the Valley Farms 69kV bus. Install a 14.4 MVAR 69kV capacitor bank at Valley Farms 69kV substation.	6/1/2016	$ -	$ 218,834	$ 218,834
59	Four Corners General Services	Install new 12kV line from Hogback substation and 12/4kV transformer	3/30/2017	$ -	$ 128,945	$ 128,945
60	Univision-Hayes Gulch	The objective of this project is to provide the Univisión broadcast site with a reliable three phase point of connection	6/30/2016	$ -	$ 116,077	$ 116,077
61	Paradise Feeder #2 Relocation	Mitigate overloading on feeder Paradise 02 and greatly increase operability between three feeders. Allow switching of 2.1 MW off feeder.	6/1/2016	$ -	$ 106,946	$ 106,946
62	Cave Creek Substation – Extend Overhead 69kV Lines	Build 9.2 miles of 69kV line from Cave Creek substation to Gavilan Peak substation	6/1/2016	$ 72,920	$ 29,219	$ 102,139
63	Paradise Getaway Reconductoring	Identified due to a 5% overload on Paradise 10 feeder in 2014. It involves reconductoring the getaway cable at Paradise substation located at the south west corner of HWY 51 and E. Greenway Rd.	6/1/2016	$ 66	$ 99,682	$ 99,748
64	Deer Valley #17 Parallel	Remove bottleneck on DV17 Feeder that was overloading during the 2014 summer.	6/1/2016	$ -	$ 76,955	$ 76,955
65	ADMS RTU C300 Replacement Project	Replacement of 13 C300 legacy units	12/31/2016	$ -	$ 12,272	$ 12,272
66	Prescott City Sub	Retain a portion of property in 2016 to relocate and rebuild the Prescott City substation due to the sale of the Prescott Service Yard and a design deficiency of the current substation configuration by 2020.	12/31/2016	$ -	$ 11,563	$ 11,563
67	Forfeited Refundable Advances	Represents refunds forfeited due to the fact that the customer did not complete the required meter sets or build outs over a 5-year period from the date the execution agreement was signed	12/31/2016	$ -	$ (11,698,773)	$ (11,698,773)

DISTRIBUTION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
68	Trailing Costs for Projects In-Service in 2015	This is a combination of multiple projects that went into service in 2015 but have trailing clean-up costs that extend into 2016. The major projects in distribution include: Javelina Substation, Mt. Floyd Substation, Jomax 9&10 Lines, AZ State Retiremnt Bldg, and Chase Center.		$ -	$ 4,646,214	$ 4,646,214
69	**Total Distribution**			**$ 29,370,766**	**$ 241,121,447**	**$ 270,492,214**

IT AND FACILITIES POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
1	Advanced Distribution Management System ("ADMS")	Install distribution SCADA devices, Distribution Management System and Outage Management System applications	1/25/2017	$ 21,141,589	$ 12,353,934	$ 33,495,523
2	Energy Imbalance Market ("EIM")	Implementation plan for joining the CAISO EIM	10/1/2016	$ 6,687,299	$ 18,983,997	$ 25,671,297
3	Prescott Service Center	New Service Center in Prescott, AZ	1/31/2017	$ 1,240,206	$ 13,939,696	$ 15,179,902
4	HW/SW License Maintenance Renewal Program	Includes renewals of existing licenses that qualify for capitalization per accounting guidelines. This does not include license expansions or new licenses.	6/30/2017	$ -	$ 12,312,776	$ 12,312,776
5	New Market Operation Solutions	Replace TranZ application for Power Trading and Settlement	3/1/2016	$ 10,145,656	$ 1,339,326	$ 11,484,982
6	Well Health	Current conditions of some substation grounding wells could pose an environmental risk by allowing pollutants into the aquifer.	6/30/2017	$ 4,847,922	$ 4,591,062	$ 9,438,984
7	Pay Practices	Better define pay practice rules and implement consistent adherence to them	5/31/2016	$ 4,549,049	$ 4,231,514	$ 8,780,563
8	Facilities Run Maintain-Building	Replace assets at the end-of-life in a planned cycle. Subset of Facilities run and maintain program for components identified in building category (i.e., roofing, plumbing, electrical, interior finishes, flooring)	6/30/2017	$ 3,122,205	$ 4,726,690	$ 7,848,896
9	Corporate Headquarters Elevator Modernization	Replacement of outdated controls. This project will utilize advanced current technology and more energy-efficient equipment to improve customer satisfaction, reduce malfunctions of elevators, reduce down time, increase efficiency, improve ride quality, improve performance and decrease wait times.	1/15/2017	$ 4,862,560	$ 2,611,098	$ 7,473,657
10	Unified Communications Program	Lifecycle upgrades to the core unified communications systems	6/30/2017	$ -	$ 6,099,747	$ 6,099,747
11	502/505 Optimize Space and Emergency Operations Center ("EOC")	Build new parking area; remodel 502 level 3; establish dedicated EOC and remodel DOC area	8/1/2016	$ 3,538,774	$ 1,968,154	$ 5,506,928
12	Compute Program	Replace end-of-life equipment	6/30/2017	$ -	$ 5,176,643	$ 5,176,643
13	Local Area Network Program	Replace end-of-life equipment	6/30/2017	$ 58,273	$ 4,856,255	$ 4,914,528
14	CHQ Level 2	Renovation of 2nd Floor at CHQ to accommodate the relocation of training functions currently located at the APS Learning Center	10/30/2016	$ 289,650	$ 4,390,477	$ 4,680,126

IT AND FACILITIES POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
15	Maximo Meter Asset Project	Replace the current Meter Information System	3/31/2017	$ 481,415	$ 2,562,947	$ 3,044,362
16	Enterprise Drawing Control System	Upgrade the drawing repository software and implement as an enterprise wide solution	5/31/2017	$ 805,998	$ 2,112,161	$ 2,918,159
17	Physical Security System Program	Replacement of end-of-life equipment	6/30/2017	$ 34,439	$ 2,701,748	$ 2,736,186
18	Facilities Run Maintain-Exterior	Replace assets at the end-of-life in a planned cycle. Subset of Facilities run and maintain program for components identified in exterior category (i.e., paving, fencing)	6/30/2017	$ 892,620	$ 1,643,693	$ 2,536,313
19	ADMS, DOC, and ECC Training	Build out of ECC/DOC operations training space at the DVN1 Building	8/30/2016	$ 200,421	$ 2,039,741	$ 2,240,162
20	West Phoenix Warehouse Replacement Project	Replacement of existing warehouses which are in very poor condition with a single conslidated warehouse to support long-term SCM operations at WPPP	3/31/2016	$ 22,996	$ 2,148,560	$ 2,171,555
21	Ocotillo SCM Warehouse	Provide conditioned warehouse to support the Ocotillo Modernization project for the next 12-18 months. Upon completion of the Ocotillo Modernization, the warehouse will be turned over to support regional SCM operations for Ocotillo, Saguaro, Sundance and West Phoenix Power Plants.	8/31/2016	$ -	$ 2,035,146	$ 2,035,146
22	Enterprise Database/Apps Program	Retire or upgrade enterprise wide standard software and Oracle/SQL databases to vendor supported versions	6/30/2017	$ 442,067	$ 1,478,303	$ 1,920,370
23	Wide Area Network Program	Replacement of end-of-life equipment	6/30/2017	$ 342,436	$ 1,442,144	$ 1,784,580
24	Distribution Network	Upgrades in support of the Smart Grid/Distribution applications, related field component deployments and ADMS integration	6/24/2016	$ 304,881	$ 1,242,697	$ 1,547,579
25	Distribution PI Historian	Distribution data analytic PI visualizing tool for distribution operations data	2/1/2017	$ 895,481	$ 625,146	$ 1,520,627
26	FeederAll Replacement	Replace the current outdated system to vendor supported system	10/31/2016	$ -	$ 1,289,915	$ 1,289,915
27	Storage Program	Replacement of Disaster Recovery and production filers	6/30/2017	$ -	$ 1,286,458	$ 1,286,458
28	Monitoring Systems Program	Enterprise monitoring standardization and simplification	6/30/2017	$ 654,030	$ 584,407	$ 1,238,437

IT AND FACILITIES POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
29	2020 Vision - Materials Logistics Information System	Modernize the current MLIS system	1/1/2016	$ 1,124,472	$ 613	$ 1,125,085
30	Secure System Configuration and Asset Management	Security configuration of network devices	7/11/2016	$ 478,133	$ 636,773	$ 1,114,906
31	ECC Visualization	Deliver visualization commitments made to FERC as a result of the September 8th outage and Incorporate Human Factors Engineering to reduce the possibility of human performance errors	4/7/2016	$ 605,837	$ 431,742	$ 1,037,578
32	Records Management and Retention	Develop a holistic program for records management and retention for APS	12/1/2016	$ 432,482	$ 499,430	$ 931,913
33	Consumer App	Increase customer satisfaction and improve customer interaction with company and the data we can provide them	8/31/2016	$ 153,127	$ 695,770	$ 848,897
34	Phone Allocation	Annual Phone Allocation	6/30/2017	$ (3,422)	$ 843,252	$ 839,831
35	Power Saguaro GT1-3 HMI Upgrade	Replace legacy Operator Console (Human Machine Interface) hardware and software	11/18/2016	$ 50,611	$ 778,607	$ 829,218
36	Non Production Wells	Well identification, well risk assessment, and potential well abandonment of substation grounding wells	6/30/2017	$ -	$ 811,700	$ 811,700
37	Transportation Shop Equipment	Replace aging/outdated /worn out /out of compliance garage tools, equipment and environmental tanks & plumbing	6/30/2017	$ 373,539	$ 320,310	$ 693,848
38	Yucca HMI Upgrade Project 2016-2017	Replace legacy Operator Console (Human Machine Interface) hardware and software.	4/30/2017	$ 3,606	$ 663,630	$ 667,235
39	Corporate Modifications	Facilities program to support business modifications for departments that do not carry a Capital budget.	6/30/2017	$ -	$ 660,108	$ 660,108
40	Facilities Run Maintain-HVAC	Facilities program to support replacement of HVAC equipment and systems in order to maintain a reliable facility portfolio.	6/30/2017	$ 57,729	$ 553,796	$ 611,525
41	Microsoft Office Upgrade	Upgrades to the core Client applications	6/30/2017	$ -	$ 459,098	$ 459,098
42	Digital Signage	Install digital signage screens at various locations to promote employee engagement and communications	9/30/2016	$ 315,909	$ 129,173	$ 445,081

IT AND FACILITIES POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
43	CHQ Campus Security	Mitigate security incidences that are on the rise at CHQ and throughout the industry	11/30/2016	$ 242,446	$ 195,491	$ 437,937
44	Mobile Workforce	Improve mobile access to APS information any time from any device.	3/15/2017	$ -	$ 432,368	$ 432,368
45	Modernization of Control House-Substations	Execute on the required upgrades to system-wide substations for Critical Infrastructure Protection (CIP) compliance	1/29/2016	$ 85,176	$ 294,931	$ 380,107
46	Enterprise Project Management System (EPMS)	Standardize project management tracking and reporting processes	6/30/2016	$ 60,514	$ 118,616	$ 179,130
47	Field Area Network Program	Upgrade remote communications for field SCADA devices	6/30/2017	$ -	$ 139,882	$ 139,882
48	Hyperion Upgrade	Upgrade Budget, Forecast and Long-Range Planning System	4/18/2016	$ 124,948	$ 4,968	$ 129,916
49	Enterprise Monitor	Existing CISCO equipment has exceeded End of Life (EOL) parameters and requires replacement to maintain system integrity and to reduce risk of loss of service	5/31/2016	$ -	$ 89,052	$ 89,052
50	SigmaFlow	This project will help to prepare APS for audits through efficient use of workflows, data collection, and document certification. SigmaFlow will allow for increased efficiency in the areas of tracking, reporting, and document retention. It will also allow for automation of workflows and proper certification of compliance documents.	3/31/2016	$ 51,357	$ 21,647	$ 73,004
51	Real Time Gas Display	The purpose of this project is to modify the electronic data transfers "schedules" interface so that APS will continue to be able to receive data from Kinder Morgan. The existing Real Time Gas Display will have to be modified to conform to the new DART system.	12/31/2016	$ -	$ 64,715	$ 64,715
52	Security Systems - Site Awareness	Proactive approach to cyber security	7/11/2016	$ -	$ 8,986	$ 8,986
53	Trailing Costs for Projects In-Service in 2015	This is a combination of multiple projects that went into service in 2015 but have trailing clean-up costs that extend into 2016. The major projects in include: DVC Remodel and Local Area Network		$ 548,827	$	$ 548,827
54	**Total IT and Facilities**			**$ 69,716,433**	**$ 130,177,917**	**$ 199,894,351**

DIRECT TESTIMONY OF STACY L. DERSTINE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF STACY L. DERSTINE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Stacy L. Derstine. I am Vice President of Customer Service and Chief Customer Officer for Arizona Public Service Company (APS or Company). My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I earned a Bachelor of Science Degree in Business Management from the University of Phoenix. I began my employment with APS in 1989 and have served in numerous leadership capacities in the Regulatory and Customer Service business units during my tenure with the Company, including most recently as the General Manager of Regulatory Affairs and Compliance. I became Vice President of Customer Service in 2014.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am responsible for all facets of customer service at APS. This includes the Call Center, Revenue Operations, Marketing, and customer programs involving energy efficiency and renewable energy.

II. SUMMARY

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR DIRECT TESTIMONY.

A. My direct testimony describes the mission and main functions of APS's Customer Service organization. I will discuss key initiatives during the Test Year and 18 month post-Test Year period, including the Company's deployment of a new customer information and billing system (New CIS), technology upgrades and enhancements that

make it more convenient and efficient for our customers to do business with APS, and changes to the limited income program. Also, I will discuss the Company's current and future plans to inform and educate customers about three-part rates, and our plans regarding how we would transition customers to three-part rates.

III. INTRODUCTION TO THE CUSTOMER SERVICE ORGANIZATION

Q. PLEASE BRIEFLY DESCRIBE THE MISSION OF APS'S CUSTOMER SERVICE BUSINESS UNIT AND ITS ROLE IN THE COMPANY.

A. Our mission is simple: we strive to make it easier for our customers to do business with APS. Customer Service provides customers with convenient and efficient ways to do business with us and manage, to the extent they choose to, their electricity usage. Customer Service is primarily responsible for direct interactions with customers, such as handling customer inquiries and transactions, marketing, customer programs, and preparing billing statements. Every day our customers interact with us on a wide range of topics using several different channels, including in-person, via telephone, computer, or smart phone. For example, each year:

- APS receives approximately six million telephone calls;
- aps.com is accessed more than eleven million times and processes approximately seven million transactions; and
- Customer Service processes over thirteen million customer payments.

The mission of Customer Service strives to provide an exceptionally strong value to our customers by offering a superior and engaging customer experience while providing convenience, helpful tools and our energy expertise.

Q. HAS APS NEEDED TO CHANGE THE WAY IT COMMUNICATES AND DOES BUSINESS WITH ITS CUSTOMERS BASED ON CHANGES IN TECHNOLOGY?

A. How we do business and communicate with customers is evolving. Customers' communication preferences have changed dramatically since our last rate case and APS is working to put the tools in place that will allow customers to do business with us when and how they want. Customers are increasingly using mobile technologies to obtain account information, conduct self-service transactions and pay bills. Most households have an internet connection and a computer and about three-fourths of the population has a smart phone. Gone are the days when most business was transacted by customers coming into a brick and mortar facility during business hours. Today many customers want to connect service, disconnect service, pay their bill, receive information about their usage, or report a problem such as an outage, without ever having to talk to a customer service associate. They want to use their phones, tablets or laptops to do business with us at all hours of the day and night.

Q. HOW IS APS ADAPTING TO THESE CHANGES?

A. To ensure we meet customer expectations, APS is transforming how we do business with our customers. Our investment in systems to help automate customer transactions and enable self-service are examples of how APS is providing customers with fast and convenient ways of conducting business with the Company.

One enhancement in progress is an upgrade to the automated phone system to increase the functionality of this very important communication method. APS's Interactive Voice Response system (IVR) is an automated telephone system that allows customers to report outages, make a payment, set-up a payment plan and retrieve account information. There are several upgrades being made to the IVR. The upgrades will greatly improve the functionality and menu navigation abilities of the system as well as

enable customers to (i) automatically obtain current account billing information, such as their bill amount, last payment received and current due date, and (ii) automatically access their account numbers.[1] These changes will not only improve the customer's experience when calling APS, but should also reduce costs over time by reducing the number of calls that are transferred to a customer service associate.

Q. HAS APS MADE ANY OTHER CHANGES OR ENHANCEMENTS IN HOW IT INTERACTS WITH ITS CUSTOMERS SINCE ITS LAST RATE CASE?

A. Yes. APS has enhanced its systems to allow customers to request and receive notifications and alerts via text, phone or email. Customers can log onto aps.com and elect to receive notifications regarding outages, kW and kWh usage amounts, and bill amounts via text, phone or email. The notifications are customizable and customers can elect which alerts they want to receive, as well as how and when they want to receive them. For example, a customer can elect to receive a text alert[2] when the power is out at their home or their monthly bill or monthly usage hits a certain threshold. Examples of notification thresholds set by a customer on aps.com are shown below in **Figure 1** and **Figure 2**.

[1] Our data suggests that we handle a large number of calls from customers inquiring if a payment has been received or simply requesting their account number.

[2] More than 60% of the customers who have elected to receive notifications choose to receive them via text.

FIGURE 1

outage

- outage notification

Notify me of a power outage in my area.

- Notify me when there is a power outage in my area
- Notify me of the estimated time of restoration of power
- Notify me if there are updates to the estimated time of restoration
- Notify me when power has been restored in my area

Text or email me at:

[redacted]@gmail.COM [redacted]

Currently being notified at:

✓(602) [redacted](unsubscribe)

FIGURE 2

usage

- usage alert - demand (kW) threshold

Notify me when my demand (kW) usage meets the threshold I select.

3.0 Demand (Update)

Text or email me at:

(602) [redacted] subscribe

Currently being notified at:

✓ [redacted] (unsubscribe)

- usage alert - energy (kWh) threshold

Notify me when my energy usage (kWh) meets the threshold I select.

300 Usage (Update)

Text or email me at:

(602) [redacted] subscribe

Currently being notified at:

✓ [redacted] (unsubscribe)

- usage alert - on-peak energy (kWh) threshold

Notify me when my on-peak kWh meets the threshold I select.

250 Usage (Update)

Text or email me at:

(602) [redacted] subscribe

Currently being notified at:

✓ [redacted] (unsubscribe)

APS has also recently launched an outage map on aps.com that can be viewed on any mobile device. This enables customers to report outages, view outage activity and see updates on outage restoration efforts on their mobile device. APS is also launching a free mobile phone app.

Q. PLEASE DESCRIBE APS'S MOBILE PHONE APP PROJECT.

A. APS recently developed its first mobile app providing customers the ability to do business with APS from their mobile telephone and receive information at their fingertips. The free app will be available in mid-2016. It allows customers to pay their bills from a mobile phone, view prior usage data, make a payment arrangement, report outages, and view the outage map and restoration efforts. This is an important tool as it provides our customers with an easy and convenient way to engage with APS. Some of the available screens and function of the APS app are shown in Attachment SLD-1DR.

Q. WHAT IS APS DOING FOR CUSTOMERS WHO DO NOT HAVE ACCESS TO TECHNOLOGY?

A. Technology does not take the place of all personal interactions with the customer. Some customers prefer to do business over the phone or in person and some questions simply cannot be handled in an automated manner. For these reasons, APS also continues to maintain a call center, staffed by trained team members who can assist customers that prefer to do business in this manner or those that do not have access to technology.

Q. WHAT OTHER THINGS IS APS DOING TO IMPROVE CUSTOMER SERVICE TO ITS CUSTOMERS?

A. Customers increasingly look for convenient and easy tools for contacting and doing business with APS. To help customers in navigating its website, APS is adding more on-line website support for users making it easier for customers to interact with APS and

find the information they need on the website. The site will have searchable articles that are based on customers' most commonly asked questions when contacting APS. This is one example of how APS offers customers options beyond calling the customer care center, resulting in more convenience for customers, faster service, and decreased costs of doing business over time, which benefits all APS customers.

For similar reasons, APS is working on the deployment of informational videos. The videos are short, customized videos that can be sent to customers via email periodically or after a triggering event. For example, one potential use of video is to send new customers a welcome video that explains their bill and payment options. The videos could also be used to educate customers regarding energy efficiency, renewable energy, and three-part rates.

IV. CUSTOMER COMMUNICATION AND EDUCATION REGARDING DEMAND RATES AND NEW SERVICE PLANS

Q. HOW DOES APS CURRENTLY INFORM CUSTOMERS ABOUT DEMAND RATES?

A. As discussed in the testimony of APS witness Charles A. Miessner, APS currently has 120,000 customers on a demand rate. APS is focused on providing customers with information about how their peak usage affects their bills under demand rates and strategies to manage both demand and energy costs. When a customer requests service with APS, service plans are discussed and if the demand plan is the best for the customer, the customer service associate provides information to the customer as to what they need to know for this plan. APS customer service associates also discuss service plans when a customer calls to inquire about their bill. If the customer is on a demand rate or if the demand rate is better suited for the customer, we have that conversation at that time.

APS's efforts focus on educating customers that they can save on their bills by shifting usage to off-peak times, staggering the use of major appliances during peak times, and save money by reducing their overall usage with conservation and energy efficiency strategies. A sample of APS's peak usage brochure, "Saving Money is Easy," is designed to educate customers about demand, and is attached as Attachment SLD-2DR. Also, attached as Attachment SLD-3DR, is a copy of a sample advertisement APS recently ran in the newspaper.

APS is using multiple channels to get information to customers about demand rates. The "Saving Money is Easy" brochure, and other printed materials about demand and demand rates are available on aps.com and the azenergyfuture.com websites. Printed materials are also available in APS offices and field personnel carry copies of the Attachment SLD-2DR in their trucks, so they can share this information with customers who happen to ask them. APS also provides specific rate information, as well as its Commission approved tariff sheets, on aps.com.

Q. IS APS DOING ANY OUTREACH IN THE COMMUNITY REGARDING ITS CURRENT AND PROPOSED DEMAND RATES?

A. Yes. APS is performing community outreach to discuss demand rates and peak usage. APS has had numerous meetings with stakeholders and community leaders to discuss its rate case as well as the proposed demand rates, including meetings with representatives from AARP, Arizona Community Action Association, the Residential Utility Consumer Office, Sun City Home Owners Association, Sun City Recreation Centers, PORA (Sun City West), Southwest Energy Efficiency Project, and Chicanos Por La Causa to name a few. In addition, APS has pulled together a Community Outreach team to present at town halls, rotary clubs, homeowner associations, chambers of commerce and other

organizations throughout our community. This outreach effort began prior to filing our rate case and will continue before any customer transitions to a new rate.

Q. WHAT ARE THE MAIN POINTS CUSTOMERS NEED TO KNOW ABOUT DEMAND RATES?

A. Most customers are not interested in knowing the technical definition of a kilowatt or kilowatt hour. They simply want APS to help them understand what they need to know in order to manage their demand and energy, which helps them manage how much their bill costs. The message to our customers to help them save money on a demand rate is simple: "Shift, Stagger and Save." In addition to the 120,000 customers already on a demand rate with TOU features, APS has over 450,000 customers on a TOU rate. Most of these customers already understand that it makes sense to "shift" when they do their laundry, run their dishwasher, or run their pool pump, to off-peak times. Most customers also already understand that they can reduce or save energy by turning off the lights and adjusting the thermostat before leaving. What's new for customers with a demand rate is learning to "stagger" those high energy use activities that a customer cannot shift to off-peak times or chooses to not shift to off-peak times. For example, a customer could stagger using the oven to make dinner with when they do laundry or run the dishwasher. This concept is illustrated in **Figure 3** below.

FIGURE 3

Q. WHAT TOOLS ARE AVAILABLE FOR CUSTOMERS TO VIEW THEIR DEMAND?

A. APS customers can access their demand and energy usage information on aps.com (as shown in **Figure 4**) and on the APS mobile app (as shown in **Figure 5**). As illustrated in the visuals below, customers can view their demand and usage by hour and by week. As discussed above, customers can also receive personalized alerts, regarding their demand, via texts, email, and phone.

FIGURE 4

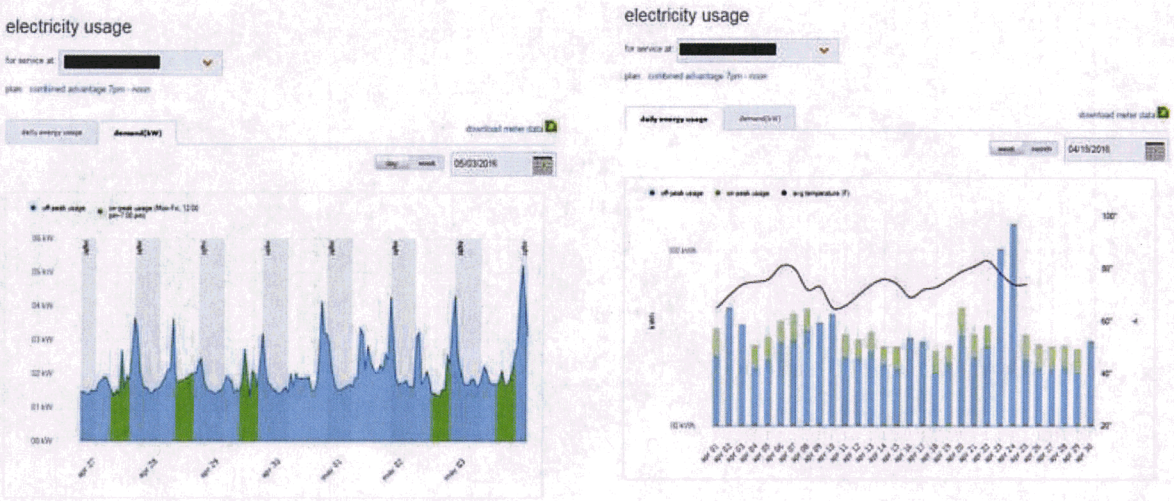
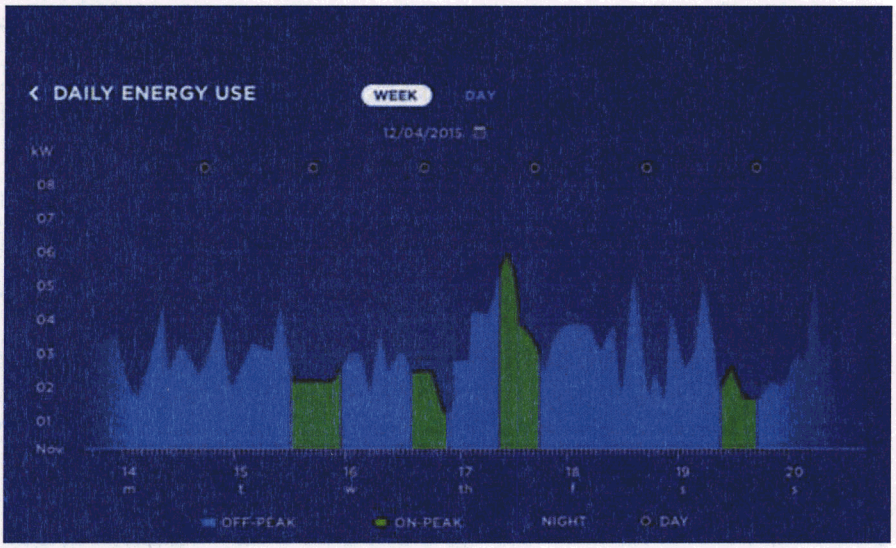
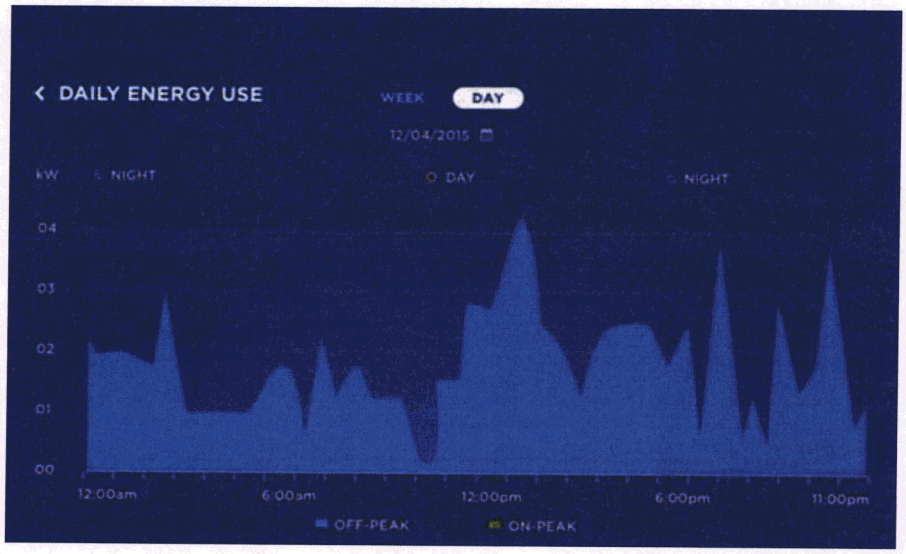


FIGURE 5





Q. HOW WILL APS EXPLAIN THE NEW SERVICE PLANS TO CUSTOMERS?

A. APS will be implementing an education plan regarding changes to the service plans and will work with customers to refine its messaging. This plan will include bill inserts, website content, emails, and direct mail. It is our objective to make the transition to new plans as seamless for our customers as possible. APS will develop communications that are simple and easy to understand and which not only describe the specifics of the new plans, but also allow customers to be aware of behavioral actions they can take and programs they can participate in to help manage their demand and energy usage. APS will also offer an online rate calculator to customers so they can explore the new plans.

Importantly, APS will help customers identify which of the new rate plans is best for them based upon their past usage profile. APS will complete a plan comparison using each customer's historical usage profile, and move each customer to the new rate plan that is best suited for them. It is significant to note that although APS will move each customer to the best plan, the customer can select a different option if they so choose.

APS has an array of programs designed to assist customers in managing their demand and energy usage and ultimately manage their costs. As we communicate with customers about the new plans, we will leverage the opportunity to provide information regarding available programs and products. We will do this by creating packages and options that fit customer preferences. As an example, some customers want products and services that allow them to set energy and service preferences and forget about it. For these customers, APS will offer options such as the budget billing, autopay, smart thermostat, and paperless billing. Other customers might prefer options that allow them to be an "active energy manager." For those customers, APS would offer options such as, energy analyzer,[3] energy audit,[4] alert/notification, and other energy management offerings. In an effort to provide a wide range of packages to fit customer choices, APS will work with customers to refine the available options. As part of all customer communications, APS will encourage them to visit aps.com for more information and options.

Q. DO CUSTOMERS HAVE TO SELECT ONE OF THESE OPTIONAL PACKAGES?

A. No. The packages or any component within the packages, are completely voluntary. APS offers them to provide customers with a simple and easy way to locate and access the programs, products and services that might appeal to a particular customer or customer group.

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[3] *See* APS Energy Analyzer at https://aps.energysavvy.com/.

[4] *See* APS Residential Home Energy Checkup at https://www.aps.com/en/residential/savemoneyandenergy/homecheckup/Pages/home.aspx and APS Commercial Energy Audits at https://www.aps.com/en/business/savemoney/tradeallies/Pages/energy-audits-and-studies.aspx.

Q. HOW WILL APS USE APS.COM IN THE EDUCATION PLAN?

A. In all communications to customers, APS will encourage them to visit aps.com for more information and options. The communications will drive customers to a section on the website that provides a one-stop shop to access information and select programs and products that are helpful to customers in learning about the new rates, and how to manage their energy costs. A mock-up of the main page is attached as Attachment SLD-4DR for illustrative purposes. From this page, customers will be able to access:

- an interactive tool designed to confirm the best plan, and offer programs and products that align with customer preferences;
- a summary of the new rate plans and a link to the tariffs;
- a rate calculator;
- hints and tips for managing demand;
- an in-depth explanation about demand and how it is calculated; and
- information about vendors and products and services that customers might engage with to help manage energy and demand.

Q. DO YOU BELIEVE YOUR CUSTOMERS HAVE THE TOOLS TO MANAGE THEIR BILLS AND USAGE IF PLACED ON DEMAND RATES TODAY?

Yes. The tools and information exist now for customers who want to manage and/or reduce their peak demand. Customers can monitor their usage and demand via aps.com or the APS app and use behavioral strategies to manage their bill such as "Shift, Stagger and Save." In addition, customers can use various technologies to manage their demand, ranging from easy to use, low cost items such as smart thermostats and timers on water heaters, to more complex and expensive tools such as load controllers, and battery storage, with or without rooftop solar. Importantly, and as discussed in Mr. Miessner's testimony, a study of existing customers on APS's demand rate demonstrated that customers can manage and reduce their demand.

V. APS'S PLAN TO MIGRATE ITS CUSTOMERS TO THE NEW RATE PLANS

Q. HOW DOES APS PLAN TO TRANSITION ITS CUSTOMERS TO THE NEW RATE STRUCTURES IT IS PROPOSING?

A. APS plans on transitioning its customers to the new rate plans proposed in this case in phases. APS will move customers to the new plans based upon their billing cycle. No existing residential customers will be migrated during the three peak summer months of June, July and August; months that can be avoided with a mid-2017 rate case decision. Prior to moving any customers to new service plans, APS will analyze the customer's prior year's usage and determine which of the new rate plans is the best for the customer. APS will move all residential customers to the plan that is best for them, provided they are eligible for that plan. However, once the new rate plans first go into effect, a customer may choose any of the new plans. Customers do not have to wait to be migrated and can elect any plan that they are eligible for – not just the rate APS believes would be the best option for them. APS anticipates that all residential customers will be migrated to the new plans within 9-12 months of the date a decision is entered in this case.

Prior to migrating any customer, APS will send the customer a customized letter. The letter will explain that APS has done an analysis of their account and will be automatically moving them to the plan that is best for them based upon their usage history. The communication will also contain behavioral tips for saving money on the new plans, focusing on Shift, Stagger and Save, as described above and in Attachment SLD-5DR. Customers will also be encouraged to visit aps.com for more information about the new plans and options.

Customers will be moved in groups according to billing cycle. APS will use the following process.

- APS will identify groups of customers sharing the same billing cycle and send an initial letter through U.S. mail and via email (aps.com registered customers) containing the information discussed above, explaining the migration process, and the plan that will best meet their needs based upon their past usage history. APS will also advise the customer of the effective date of the rate plan change, and provide referral information to the APS Customer Care Center and aps.com, where additional information about the new rate plans can be obtained. Additionally, behavioral tips focusing on Shift, Stagger and Save as described above, will also be provided. A sample of the initial letter is attached as Attachment SLD-5DR; and
- After sending the initial letter and in conjunction with the time they are moved to the new plan, that group of customers will be sent an additional notice reminding them their plan has changed. The reminder notice will be sent via bill insert and email (for aps.com registered customers).

VI. APS'S DEPLOYMENT OF A NEW CUSTOMER INFORMATION SYSTEM (CIS)

Q. WHAT IS THE CUSTOMER INFORMATION SYSTEM AND WHAT PURPOSE DOES IT SERVE?

A. The CIS is the foundational computer platform that integrates with more than 60 other systems to support customer communications and transactions. It is integral to the establishment of service, routing of service personnel to the field, preparing and sending bills, receiving payments, and a host of other functions. It is the heart of the systems and programs that allow our customers to interact with us and for us to respond to their requests and meet their needs.

Q. WHAT SYSTEM DOES APS CURRENTLY USE TO PROVIDE THE SERVICES DESCRIBED ABOVE?

A. APS currently uses a highly customized mainframe-based CIS that was implemented in the mid-1990s. It is an aging system that was built during a time when many of the technologies that are common place today did not exist and systems were generally less integrated.

Q. DOES APS HAVE PLANS TO REPLACE ITS CURRENT CIS?

A. Yes.

Q. WHY IS APS REPLACING ITS CURRENT CIS?

A. APS's current CIS uses a computer programing language, COBOL, that is largely obsolete. This makes it increasingly difficult to find programmers to work on the system, as many U.S. universities no longer teach this programming language. It also increases the risk of system failure due to integration issues between this old CIS system and emerging new systems and technologies. CIS requires customization every time an upgrade or change is needed to one of the 60 or more systems that interconnect with it, which is costly, time consuming, and introduces risk given the age of the CIS system. APS needs a CIS system that can meet the changing technology needs of its customers and the business. Devices and programs—rooftop solar, battery storage, electric vehicles, and text/e-mail notifications—and rate design that were once considered cutting edge are now commonplace and customers expect that APS will respond to their choices. Adapting and providing for customer and industry changes requires a CIS platform that can meet customer needs.

Q. PLEASE DISCUSS APS'S PLANS TO REPLACE ITS CURRENT CIS.

A. APS is deploying a new system to replace its mainframe CIS. The Company is in the process of implementing Oracle's Customer Care & Billing (CC&B) software package — a state-of-the-art, industry-leading browser-based customer system (hereafter New CIS). The New CIS will provide APS with the flexibility and scalability to meet customer and technology demands well into the future. APS plans to begin using its New CIS in March 2017.

Q. HOW DID APS IDENTIFY THE ORACLE CC&B SYSTEM?

A. APS looked at two prominent modern CIS systems that were designed to handle the size and complexity of the Company's business. APS currently uses Oracle's Financial and Enterprise Resource Planning systems for all of its back office work, e.g., finance, payroll and accounting, and by selecting the Oracle CC&B system, both systems will be on a single technology platform, which makes integration, maintenance and future upgrades easier. APS selected Oracle's system to reduce the complexity of CIS system integration, thus improving the fit and functionality of the New CIS option with APS's existing and new systems (for example, *see* Jacob Tetlow's testimony at p. 15 for information regarding the new ADMS). The Oracle CC&B system is also used by more than 50 utilities in North America, including TEP, and more than 200 utilities worldwide.

Q. ARE THERE ANY BENEFITS TO CUSTOMERS FROM THE NEW CIS SYSTEM?

A. Yes.

Q. PLEASE EXPLAIN ANY BENEFITS.

A. The New CIS will allow for a customized customer experience. This includes customized communications, customized website visits and overall enablement giving the customer a more relevant and better experience.

Upgrading to a New CIS that includes many standard features allows APS to more readily take advantage of future upgrades and software improvements issued by Oracle. New CIS will improve operational efficiencies and allow APS to implement more advanced billing structures that promote energy technologies customers want. Implementing Oracle CC&B will allow APS to benefit from the lessons learned and guidance of a platform already in place at more than 200 utilities worldwide; thus, leveraging Oracle to help APS implement industry best practices and alignment with industry trends. It is anticipated that using CC&B will minimize APS specific programming or customizations.

Once APS has completed implementation and stabilization of the New CIS, APS expects to see timing and cost reductions for routine rate and billing changes. With this new system we will be able to implement different rate designs without an extensive amount of customized work from programmers like the current system requires. Also, the New CIS will integrate with our online applications (i.e., aps.com and the new APS app) and allow for changes across the entire platform, whereas today they are separate systems. Although it is difficult to quantify the exact dollar amount of savings from these upgrades, it is clearly an efficiency that will benefit our customers.

Q. HOW MUCH DOES THE NEW CIS COST?

A. The New CIS system is expected to have a total cost of approximately $120 million (*see* Attachment SLD-6DR).

Q. WILL CUSTOMERS SEE A CHANGE AFTER IMPLEMENTATION OF NEW CIS?

A. Customers will experience minimal required changes. Customers will not notice any changes to their bills or any services from our customer care center. Each customer will, however, receive a new account number and APS will make some minor changes to its current customer programs. The flexibility presented by New CIS, however, should manifest itself in a better future experience for our aps.com and mobile app users. In addition, APS is evaluating the need for a comprehensive bill redesign.

VII. ENERGY SUPPORT PROGRAMS (RATE RIDERS E-3 AND E-4) FOR LIMITED-INCOME CUSTOMERS

Q. WHAT IS THE ENERGY SUPPORT PROGRAM (ESP) ALSO KNOWN AS RATE RIDER E-3?

A. The ESP provides eligible limited-income customers with a discount on their monthly electric bills.

Q. WHAT IS THE MEDICAL CARE EQUIPMENT SUPPORT PROGRAM (MCESP) ALSO KNOWN AS RATE RIDER E-4?

A. The MCESP provides eligible limited-income customers who require life sustaining medical equipment with a discount on their monthly electric bills.

Q. WHO IS ELIGIBLE FOR THESE LIMITED-INCOME PROGRAMS?

A. Customers with gross monthly household incomes that are at or below 150% of federal poverty guidelines qualify for the ESP or MCESP.[5] The current program eligibility is tiered based on gross income and number of individuals in the household. For example, a family of four would need to have a gross monthly income of $3,031 or less to qualify for the program and receive a discount.

Q. WHAT IS THE AVERAGE AMOUNT OF THE DISCOUNT PER MONTH FOR ELIGIBLE CUSTOMERS ON THESE TWO PROGRAMS?

A. Currently, the amount of the discount can vary from month-to-month. The average discount for current customers on the ESP (Rate Rider E-3) is $34.00 per month; the average discount for current customers on the MCESP (Rate Rider E-4) is $57.00 per month.

Q. WHAT IS THE TOTAL AMOUNT SPENT ON THESE LIMITED-INCOME DISCOUNTS DURING THE TEST YEAR?

A. In the Test Year, APS provided more than $35.6 million in assistance to limited-income customers through the ESP and MCESP programs.

Q. IS APS RECOMMENDING ANY CHANGES TO THE ESP?

A. Yes. As described in Mr. Miessner's testimony APS is asking to change from a tiered discount rate to a flat monthly discount amount for eligible customers. A flat discount provides customers with more stability and predictability. It also is more transparent and informs customers of how much more their bills will be when their situations improve and they transition off the discount program.

---

[5] *See* Decision No. 71448 (Dec. 30, 2009).

Q. MR. MIESSNER DESCRIBED A MORE SIMPLE WAY TO APPLY THE LOW-INCOME DISCOUNT. WILL YOU PLEASE DISCUSS THE PROGRAM IMPLEMENTATION CHANGES THAT APS IS UNDERTAKING?

A. Yes. APS is currently working on implementing several changes to how eligible customers enroll in these programs. Specifically, APS is establishing a procedure to enroll eligible customers who have pre-qualified because they are already receiving government assistance through a program that has similar income requirements. In addition, APS is contracting with a third-party vendor to verify the income of customers applying to enroll in the programs. The goal of these changes is to ensure that customers who receive the discount meet the eligibility requirements and can be promptly enrolled.

Q. WHY IS APS UNDERTAKING THESE CHANGES TO ITS INCOME VERIFICATION PROCESS?

A. The ESP program provides much needed assistance to our most vulnerable customers. To ensure that APS is reserving the assistance money for those customers that meet the guidelines, validating eligibility is important. With verification processes in place, APS will be able to undertake more efforts to market the program and expand enrollment to eligible customers.

Q. HOW IS APS STREAMLINING THE ENROLLMENT PROCESS FOR INDIVIDUALS ON ASSISTANCE?

A. APS will accept applicable public assistance award letters as proof of individual's eligibility for ESP. They will not have to provide separate proof of income. APS will work with community agencies to ensure they understand the process and can assist customers with the process.

Q. PLEASE DESCRIBE WHY ALL OF THESE CHANGES ARE BENEFICIAL.

A. Arizona is 10th in the nation for poverty-stricken population. APS is committed to helping our community, state, and customers — specifically its limited-income customers. The changes that we have underway ensure that the funding for limited income programs gets to the qualified population, provides an easier way for customers already receiving assistance to enroll, and makes the discount consistent from month-to-month and clear for customers to understand.

VIII. BRIEF DISCUSSION OF POST TEST YEAR PLANT EXPENDITURES

Q. PLEASE IDENTIFY ANY CAPITAL PROJECTS THAT WILL BE COMPLETED IN THE CUSTOMER SERVICE BUSINESS UNIT AFTER THE TEST YEAR, BUT BEFORE JUNE 30, 2017.

A. A list of the capital projects that Customer Service will place in service for customers by June 30, 2017 is attached to my testimony as SLD-6DR. The total costs for these projects are estimated to be $120.5 million. The two projects to be completed by Customer Service in the post-Test Year plant window include:

- Implementation of New CIS. This project is anticipated to be in-service in March of 2017, and is estimated to cost approximately $120 million; and
- Implementation of IVR modernization and enhancements. This project is anticipated to be in-service in July of 2016, and is estimated to cost approximately $507,000.

New CIS is discussed on pages 15-18, and IVR is discussed on page 3 of this testimony. APS witness Elizabeth Blankenship describes the additional details of the adjustment related to both capital projects, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes, and interest expense.

Q. PLEASE IDENTIFY ANY OTHER INITIATIVES THAT CUSTOMER SERVICE IS PUTTING INTO SERVICE AFTER THE TEST YEAR.

A. In 2016, APS is executing a contract with a third party vendor to process the enrollment and certification of customers requesting to be put on the ESP and receive the limited income discount. APS is seeking recovery of these funds, which are critical to managing the ESP. A pro forma adjustment showing the funds anticipated to be spent annually beginning in 2016 is attached to the Direct Testimony of Charles A. Miessner as Attachment CAM-4DR.

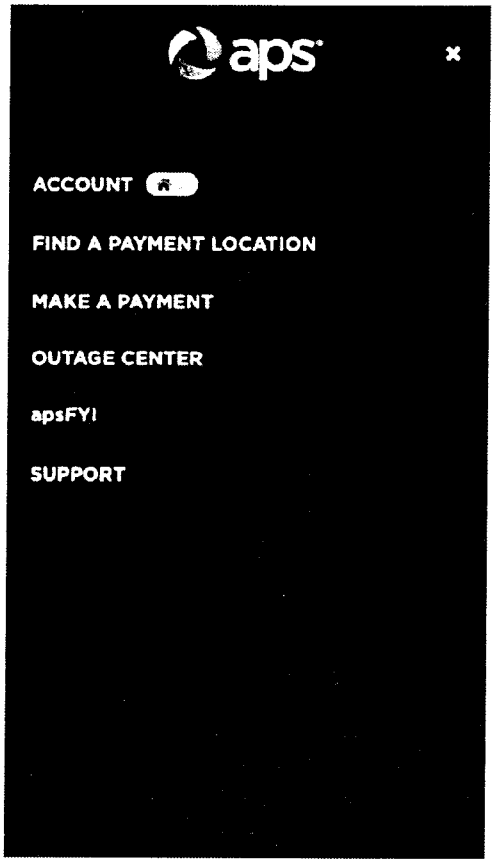
Proiect #	Project Name	Total Projected APS Costs ($000)
1	Customer Information System	$ 119,978
2	Interactive Voice Response Modernization	$ 507

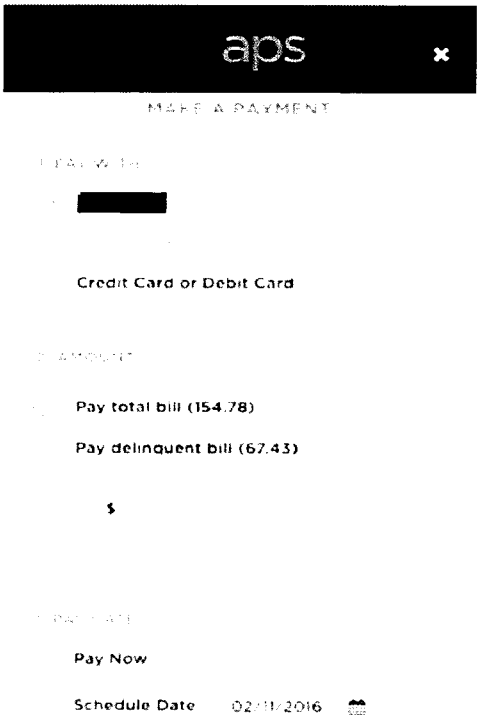
IX. CONCLUSION

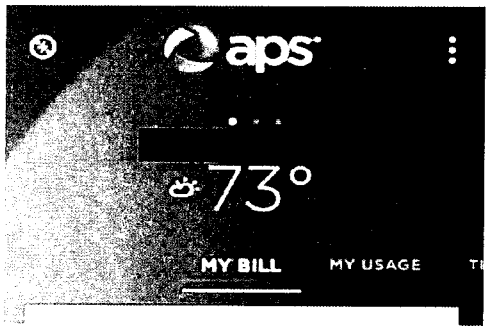
Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APS Mobile App Illustrations



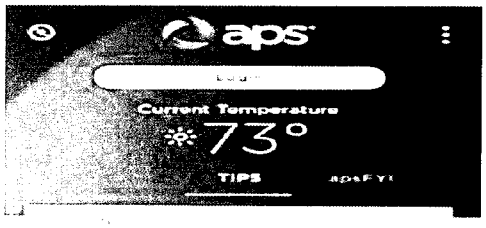


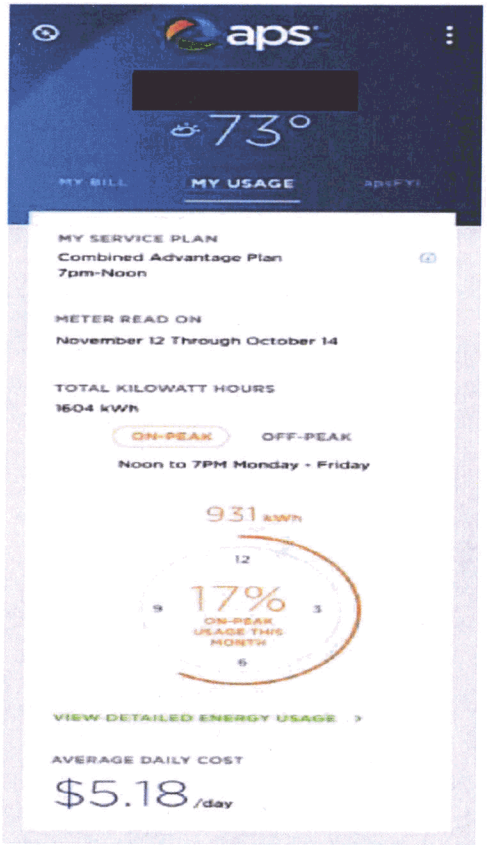


$133.00 paid on November 20, 2015

$219.64

February 26, 2016

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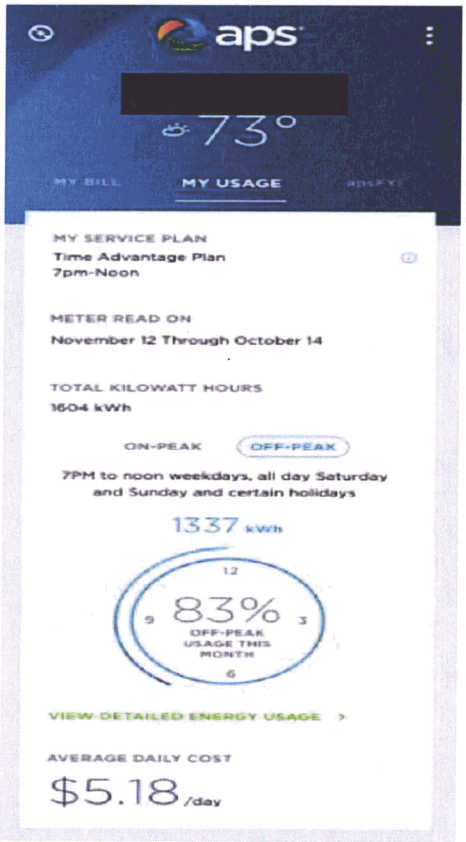
MY BILL
MY USAGE
MY SERVICE PLAN
Combined Advantage Plan
7pm-Noon
METER READ ON
November 12 Through October 14
TOTAL KILOWATT HOURS
1604 kWh
ON-PEAK
OFF-PEAK
Noon to 7PM Monday - Friday
931 kWh
12
9
17%
3
ON-PEAK USAGE THIS MONTH
6
VIEW DETAILED ENERGY USAGE
AVERAGE DAILY COST
$5.18 /day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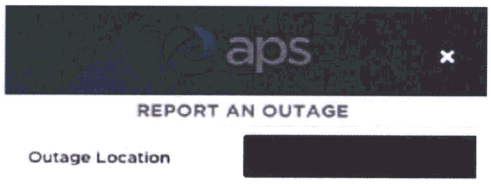
MY BILL
MY USAGE
MY SERVICE PLAN
Time Advantage Plan
7pm-Noon
METER READ ON
November 12 Through October 14
TOTAL KILOWATT HOURS
1604 kWh
ON-PEAK
OFF-PEAK
7PM to noon weekdays, all day Saturday and Sunday and certain holidays
1337 kWh
12
9
83%
3
OFF-PEAK USAGE THIS MONTH
6
VIEW DETAILED ENERGY USAGE
AVERAGE DAILY COST
$5.18 /day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Outage Location
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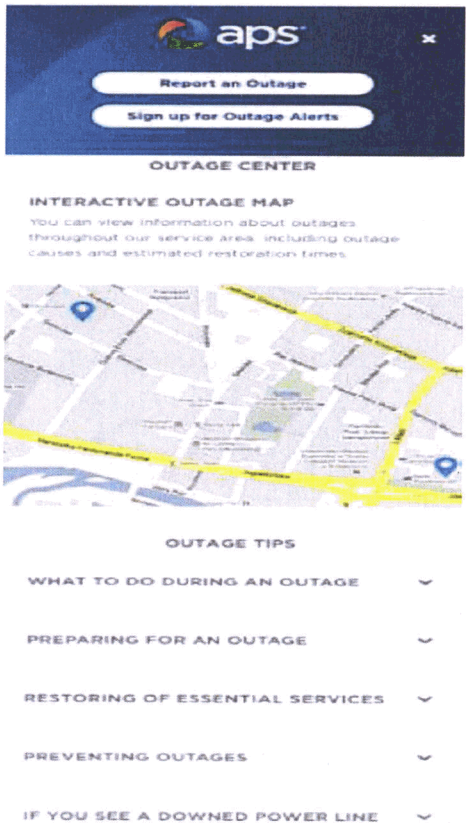
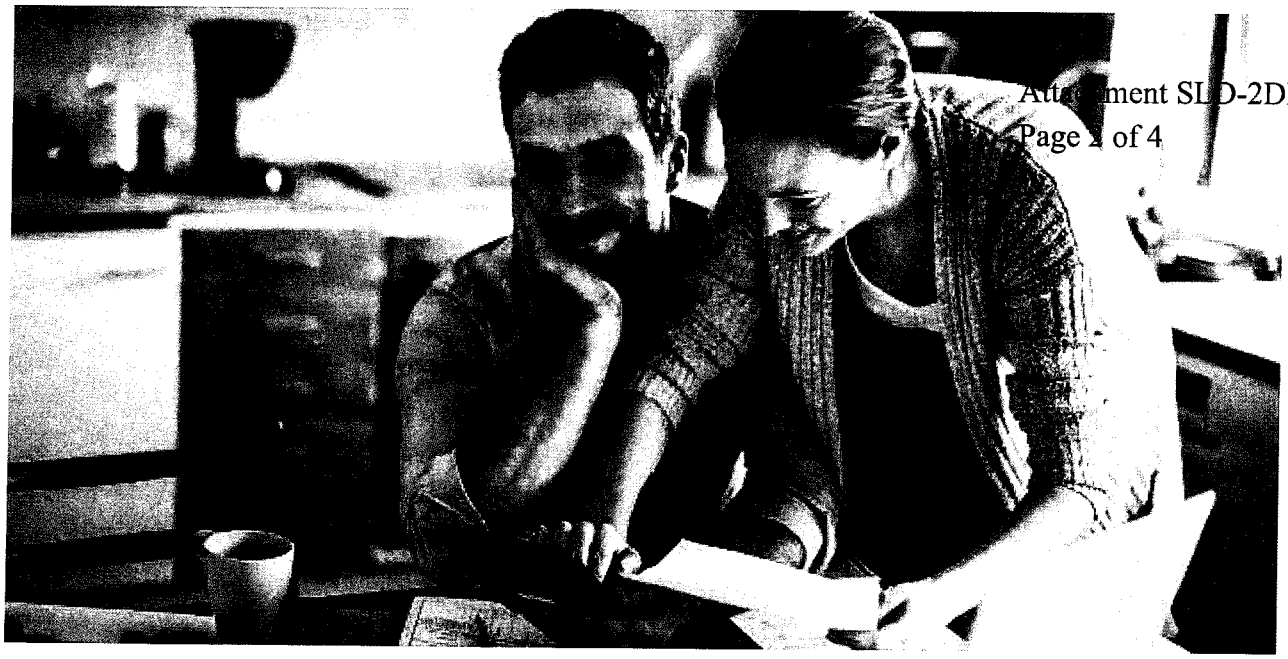
Submit
Cancel


aps
Report an Outage
Sign up for Outage Alerts
OUTAGE CENTER
INTERACTIVE OUTAGE MAP
You can view information about outages throughout our service area, including outage causes and estimated restoration times.
OUTAGE TIPS
WHAT TO DO DURING AN OUTAGE
PREPARING FOR AN OUTAGE
RESTORING OF ESSENTIAL SERVICES
PREVENTING OUTAGES
IF YOU SEE A DOWNED POWER LINE

Saving money is easy.

Lower your peak usage.
Lower your bill.

aps



How does peak usage impact your bill?

Simply put, peak usage is the **one hour of the month** when your energy use **during on-peak hours** is at its highest. On-peak hours—which vary based on rate plan—are weekday late afternoons through evenings when most Arizonans are coming home from school or work and the demand for energy is high. It's important to know that peak usage is **averaged over an entire hour** so you don't have to worry about any one moment in time. Because there's a direct tie between your peak usage and your bill amount, you can save money by making small changes to your energy use.

Comparing two customers

Let's look at an example of two families—with identical appliances and rate plans—who have different peak usage numbers based on how many major appliances they're using at the same time, during on-peak hours.

The Lara family, who puts a priority on comfort and convenience, comes home from work and...

- Sets their AC at 75°
- Cooks dinner
- Turns on the TV
- Starts a few loads of laundry

The Smith family, who is more concerned with saving money, comes home from work and...

- Sets their AC at 79°
- Cooks dinner
- Turns on the TV

THE LARA HOME		
Air Conditioner	**On**	**3.8 kW**
Oven	**On**	**1.3 kW**
Washer	**On**	**0.4 kW**
Dryer	**On**	**1.9 kW**
Television	**On**	**0.1 kW**
PEAK USAGE		**7.5 kW**

THE SMITH HOME		
Air Conditioner	**On**	**2.5 kW**
Oven	**On**	**1.3 kW**
Washer	Off	0.0 kW
Dryer	Off	0.0 kW
Television	**On**	**0.1 kW**
PEAK USAGE		**3.9 kW**

Examples are based on 1,800 sq. ft. homes during a typical summer evening. Kilowatt (kW) numbers are based on typical use during an hour.

Who will save more money?

It's no surprise that the Smith family's peak usage is almost half that of the Lara family's given that the Smiths are not running all their major appliances at once. So while the Lara family will pay their typical bill amount, **the Smith family will save on their bill.** Why? Because the lower your peak usage, the greater your savings.

3 ways to save

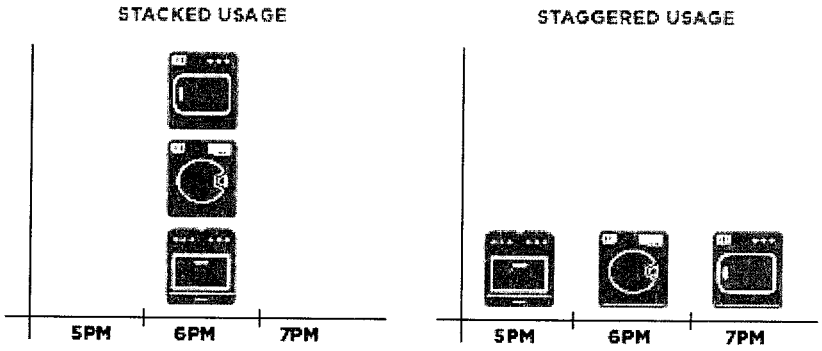
By making small changes to when and how you use energy, you can lower your peak usage and save money.

1. Shift...

the use of appliances to off-peak hours when energy is more affordable. For example, set your dishwasher to run on a delay cycle and put your pool pump on a timer.

2. Stagger...

the use of major appliances (air conditioner, electric water heater, dryer, oven) during on-peak hours. For example, do your laundry later in the evening or on weekends.



3. Save...

on your overall usage by taking advantage of some basic energy-efficiency programs, tips and tools. For example, get a rebate when you tune up your AC, set your thermostat a few degrees higher in the summer and lower in the winter and take our quick and easy online Energy Analyzer survey to get an energy-saving report customized for your home.

What does that term mean?

- **ON-PEAK**
  The time of day when energy use is higher and electricity is more expensive
- **OFF-PEAK**
  The time of day when energy use is lower and electricity is less expensive
- **TIME-OF-USE RATE**
  A rate plan with on-peak and off-peak hours
- **DEMAND RATE**
  A 3-part rate plan which includes basic, total usage and peak usage charges
- **TOTAL USAGE**
  The total amount of energy used during a billing cycle (kWh)
- **PEAK USAGE**
  The highest one hour of on-peak energy use during a billing cycle (also referred to as "demand" or "kW")

Did you know?

Compared to other rate plans, demand rates give you three ways to save money:

- Shift
- Stagger
- Save

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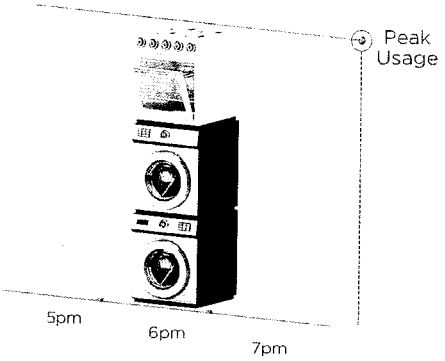
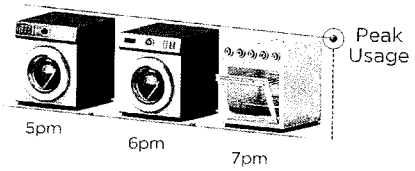
Demand rates can be explained in two words: When and How.

Demand rates are tied to the use of major appliances. When and how we use them matters. During on-peak hours, avoid using multiple major appliances at one time. Simply stagger use during those hours and save. It's that easy. In fact, 117,000 APS residential customers currently use demand rates and save.



Avoid using multiple appliances at one time during on-peak hours.



Stagger appliance use during on-peak hours and save.

To learn more about the advantages of demand rates, visit aps.com/demandrates

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aps | search

account services | save money & energy | solar programs | help & support

residential > account services > your plan, your options

your plan, your options

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your lifestyle

Let us help you find the best plan for you. To get started, click on the button below that best describes your lifestyle. You will be asked a series of questions that will not only lead you to the best rate plan for you, but also suggest programs and tips to help you save money.

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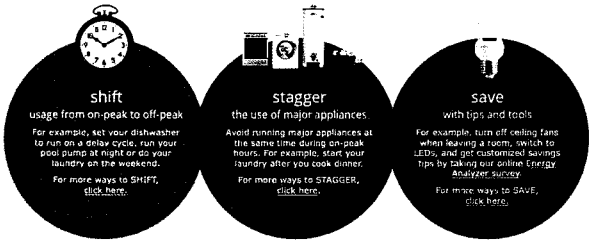
3 ways to save



> tariff sheet > compare and apply > summary of rate plans

program options

Your rate plan options. Here are ways you can better manage your bill.

ac tune up
Replacing your hvac unit isn't the only way to save on cooling costs. Let a qualified trade ally perform an advanced diagnostic tune-up and you could save up to 20%.

> APS qualified suppliers

smart thermostats
Find rebates for programmable thermostats. Set yours to automatically raise or lower your temperature settings, helping manage your bill.

LED programs
We offer instant discounts on LEDs and CFLs. Save up to $80 over the life of each bulb.

> find retailers

other APS programs
We offer a wide variety of energy saving programs for your convenience and energy needs.

> other programs

how demand rates work

Demand rate plans have three components:

- Service Charge: service charge for your connection to the grid
- Total Usage: off-peak and on-peak energy used
- Peak Usage: highest one hour of energy used during on-peak hours

Simply put, peak usage is the one hour of the month when your energy use during on-peak hours is at its highest. On-peak hours, which vary by rate plan, are weekday afternoons through early evenings.

Demand rates are tied to the use of major appliances during on-peak hours. The more you stagger the use of major appliances during those hours, the more you save.

> learn more

rate plan comparison calculator

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calculator

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giving programs
recent stories
volunteers
educational resources
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our company
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site map | service areas

see what's next for Arizona's energy future

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your plan, your options

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your lifestyle

Let us help you find the best plan for you. To get started, click on the button below that best describes your lifestyle. You will be asked a series of questions that will not only lead you to the best rate plan for you, but also suggest programs and tips to help you save money.

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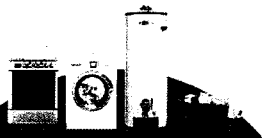
3 ways to save

shift

usage from on-peak to off-peak

For example, set your dishwasher to run on a delay cycle, run your pool pump at night or do your laundry on the weekend.

For more ways to SHIFT, click here.



stagger

the use of major appliances

Avoid running major appliances at the same time during on-peak hours. For example, start your laundry after you cook dinner.

For more ways to STAGGER, click here.

save

with tips and tools

For example, turn off ceiling fans when leaving a room, switch to LEDs, and get customized savings tips by taking our online Energy Analyzer survey.

For more ways to SAVE, click here.

> tariff sheet > compare and apply > summary of rate plans

program options

program options

Your rate plan options. Here are ways you can better manage your bill.

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Replacing your hvac unit isn't the only way to save on cooling costs. Let a qualified trade ally perform an advanced diagnostic tune-up and you could save up to 20%.

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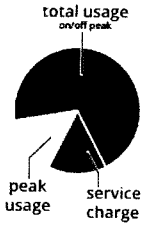

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> learn more

rate plan comparison calculator

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calculator

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For Illustrative Purposes

aps

Your rate plan will be changing as of [DATE TO COME]. Here's what you need to know.

We are introducing new residential rate plans that give you the opportunity to save by simply managing when and how you use energy.

To help you maximize savings and minimize effort, we'll **automatically** switch you to the rate plan that works best for you based on your current usage. Therefore, **no action is required on your part**. However, if you prefer to compare plans, please visit aps.com/findmyplan or call 800-###-####.

Your new rate plan is: [INSERT RATE PLAN NAME HERE].
Your first bill reflecting your new rate will be: [INSERT MONTH/YEAR HERE]

Why the change?

Weekdays from 3pm-8pm, when most Arizonans are coming home, is when the demand for energy is high, causing the price of electricity to increase. This time of day is known as on-peak. To help manage the overall demand of energy AND help you save money, our new rate plans encourage the use of electricity during off-peak hours when the price of electricity is lower.

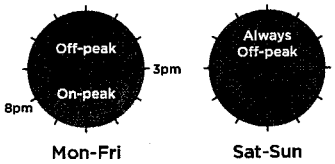
Understanding when and how you use energy matters.

Off-Peak Monday-Friday, 8pm-3pm and all day Saturday and Sunday, when energy use is lower and electricity is less expensive.

On-Peak Monday-Friday, 3pm-8pm, when energy use is higher and electricity is more expensive.

Peak Usage Your highest one hour of on-peak energy use during a billing cycle (also referred to as "demand"). You can save money by making small changes to your peak usage.

ON AND OFF-PEAK HOURS



PEAK USAGE

Energy used during on-peak hours

3 ways to save during on-peak hours (3pm-8pm on weekdays)

We will automatically switch you to the rate plan that works best for you based on your usage. For further details on this plan or to compare plans and to get options to fit your lifestyle, go to aps.com/findmyplan or call 800-###-####.

CUSTOMER SERVICE POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
1	Customer Information System Replacement	The CIS Replacement project will move the current CIS system to a modern/stable platform that conforms to technology standards and application languages, consolidates 5 billing engines into one, reduces the cost to support current CIS system, eliminates the need for manual data fixes, and meets current business objectives in a single system.	3/5/2017	$ 31,569,108	$ 88,408,402	$ 119,977,511
2	IVR Modernization	The IVR Modernization project will modernize the interactive voice response system to increase self-service transactions and deflect calls through the increased use of the automated phone system.	7/31/2016	$ -	$ 507,157	$ 507,157
3	**Total Customer Service**			**$ 31,569,108**	**$ 88,915,560**	**$ 120,484,668**

DIRECT TESTIMONY OF JAMES C. WILDE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF JAMES C. WILDE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is James C. Wilde. I am the Director of Resource Planning for Arizona Public Service Company (APS and Company). My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I received a Bachelor of Science degree in Corporate Finance from Grand Canyon University and a Master of Business Administration from Grand Canyon University. I joined APS in 2003. Prior to being named Director of Resource Planning, I was the Director of Enterprise Risk Management.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I oversee APS's Integrated Resource Planning efforts through which APS plans and develops resources to meet the future electricity needs of all its customers.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I discuss the changing nature of customer demand patterns and a general shift from the need for electric resources that provide energy year around, to those resources that are highly dispatchable for meeting customer's peak summer-time demands. Through this discussion, I demonstrate the need for flexible peaking resources in the APS portfolio and the benefits of participating in the Energy Imbalance Market (EIM), as well as a need to re-align APS's Demand Side Management (DSM) programs with an emphasis on shifting energy savings toward meeting late afternoon and evening peak demand. Through the discussion of changing demand patterns, I will also demonstrate the need to update customer price signals through demand based rates and updated time-of-use (TOU) rates. I will then discuss APS's Coal Strategy and demonstrate the customer benefits of retiring Cholla Unit 2 and the Company's decision to no longer burn coal at

the remaining units at Cholla by the mid-2020's. Through the discussion on APS's Coal Strategy, I will demonstrate that, should the Clean Power Plan (CPP) come to fruition, APS is well positioned to comply, given its current understanding of the potential requirements.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR DIRECT TESTIMONY

A. As described in the Company's 2014 Integrated Resource Plan, low natural gas prices, combined with the cost of environmental regulations and increases in solar generation are having significant impacts on APS's overall resource picture, as well as the region's. Specifically, increasing penetration of solar on APS's system and throughout the region has dramatically changed not only the resource requirements, but the nature of power consumption on APS's system and pricing patterns in wholesale energy markets. The growth of solar generation causes APS to need more flexibly dispatched peaking resources to integrate the increased levels of renewable energy into the electric grid. As APS shapes its resource portfolio to provide a platform for integrating increased levels of renewable energy, resource integration will also be aided by greater participation in regional energy markets, specifically through participation in the EIM. Increased penetration of variable resources has shined a light on the opportunities and benefits of increased market transactions with a broader set of trading partners. With a broader set of trading partners comes diversity of demand patterns and diversity of resources. Combining the diversity benefits of the participating EIM balancing authorities is expected to provide cost savings for customers.

My testimony also demonstrates the need to re-align the programs in APS's DSM portfolio. Given continued low natural gas prices, increasing penetration of renewable energy resources and corresponding low wholesale market power prices, some of the

DSM measures currently being offered to APS customers are either no longer cost-effective or are simply no longer needed. A re-alignment of these programs to focus more on reducing summer-time peak demand and less on reducing energy usage during mid-day non-summer periods is needed, especially given the abundant and low cost energy supplies available during non-summer mid-day hours when solar energy produces the majority of its output.

Consistent with customer demand patterns and wholesale market pricing changes, APS will also need to respond by re-aligning its generation fleet with dispatch flexibility being the central theme. Flexible peaking generation such as the Ocotillo Modernization Project (OMP) and customer-sited microgrid resources provide the flexible dispatch characteristics our system needs today, and will increasingly need in the future. These types of resources are necessary and in the public interest because they provide a platform to integrate increasing levels of renewable energy resources.

Sending proper price signals to incentivize customer demand patterns that better align with system costs is perhaps at the core of the solutions needed. APS's customer demand patterns have changed significantly as a result of rooftop solar penetration, but customer price signals have not. As a result, customers are being incentivized to save energy at times of the day when energy supplies are abundant and lower cost, rather than during peak demand and high cost hours. Aligning price signals that are reflective of current market supply and demand factors will help customers ultimately save money by helping to reduce the amount of new generation that would otherwise be needed on the system.

While continued low natural gas prices provide clear savings for this portion of APS's current and future fleet, they also have created opportunities for customer savings in the

coal fleet. In its 2014 IRP, APS discussed how low natural gas prices have changed the fleet outlook and how APS expected to be utilizing more natural gas resources in the future. As this specifically relates to the Cholla Power Plant, APS retired Cholla Unit 2 in October of 2015 and announced it would no longer burn coal in the remaining Cholla units by no later than the mid-2020's. While APS retains the option to convert the remaining Cholla units to natural gas operation, the 2014 IRP contemplated a retirement of the two remaining units by 2025. The 2014 IRP demonstrated savings for this retirement case of approximately $100 million[1] in net present value (NPV). Today, the updated estimate of NPV customer savings of the retirement case is approximately $400 million.

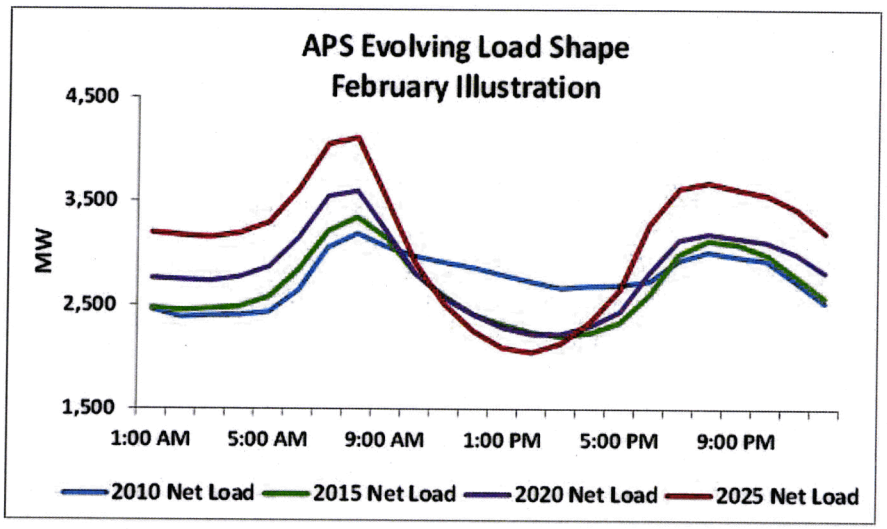
III. THE CHANGING LANDSCAPE: SOLAR PENETRATION, CUSTOMER DEMAND AND THE ENERGY MARKETS

Q. PLEASE DESCRIBE HOW INCREASED SOLAR PENETRATION HAS CHANGED THE NATURE OF CUSTOMER DEMAND?

A. As demonstrated in **Figure 1,** net customer load shapes are changing, especially in non-summer months as solar penetration continues to increase. Non-summer net demand drops in the middle of the day when solar is producing, creating a steep ramp down into the mid-day hours and back up into the peak evening hours when solar shuts off and other resources need to be started to meet peak demand. In California, they call this non-summer load shape the "duck curve" because it has a tail, a belly in the middle, and a head at the end of the day when net customer demand is high.

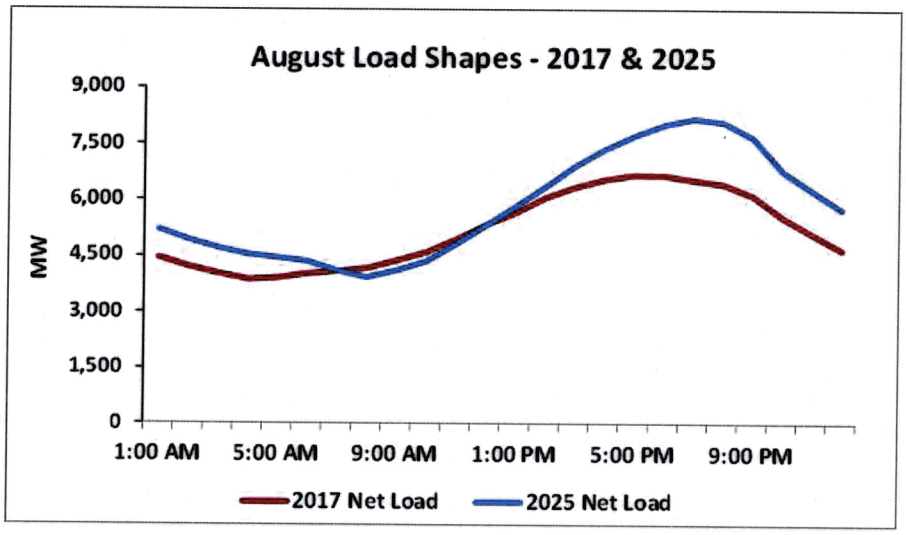
[1] *See* Docket No. E-00000V-13-0070, APS's 2014 IRP at page 61.

Figure 1.



Summer-time net load after the effects of renewable energy is also changing APS's peak from around 5 p.m. to around 6 p.m., and peak is expected to shift to 7 p.m. or later by the mid-2020's as **Figure 2** illustrates.

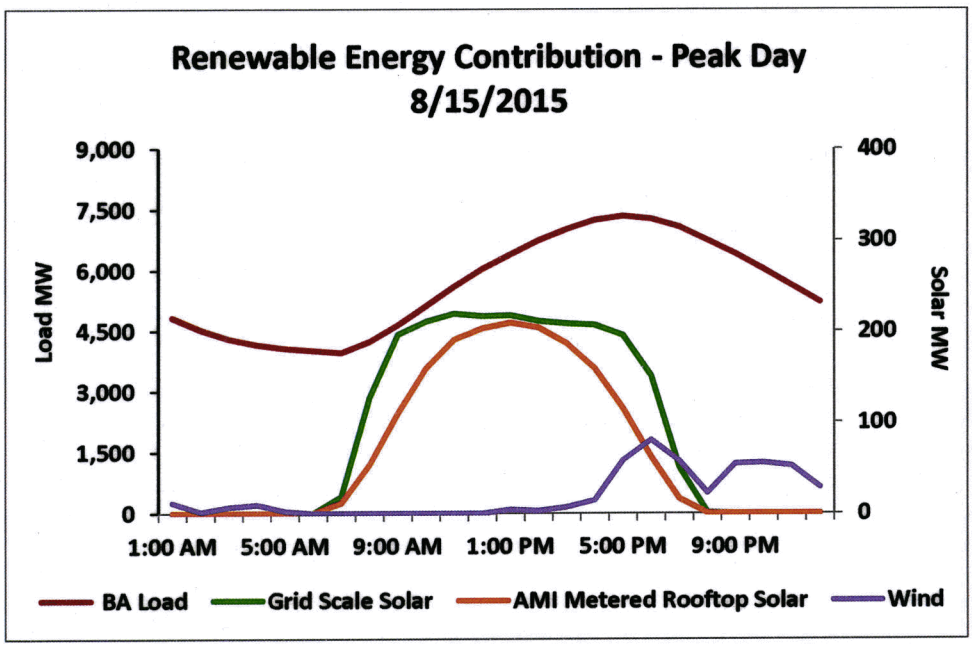
Figure 2.



The shift in the timing of net peak load is due to increases in solar penetration on the system. For example, while the sun is highest in the sky around noon to 1 p.m., rooftop solar produces most of its output as its position is fixed and primarily southward facing.

However, as the sun begins to set toward the end of the day, solar output drops dramatically as shown in **Figure 3** – just at the time when our customers are using the most energy. As can be seen from the chart below, rooftop solar's output profile does not align with how customers actually use energy. Conversely, single-axis-tracking (SAT) grid-scale solar, like AZ Sun plants, produce more total energy and provide more power later in the day, making it better suited for meeting the high customer load seen on a typical summer afternoon.

Figure 3.



Q. HOW DOES INCREASED SOLAR GENERATION AND CHANGING DEMAND IMPACT APS'S RESOURCE FLEET?

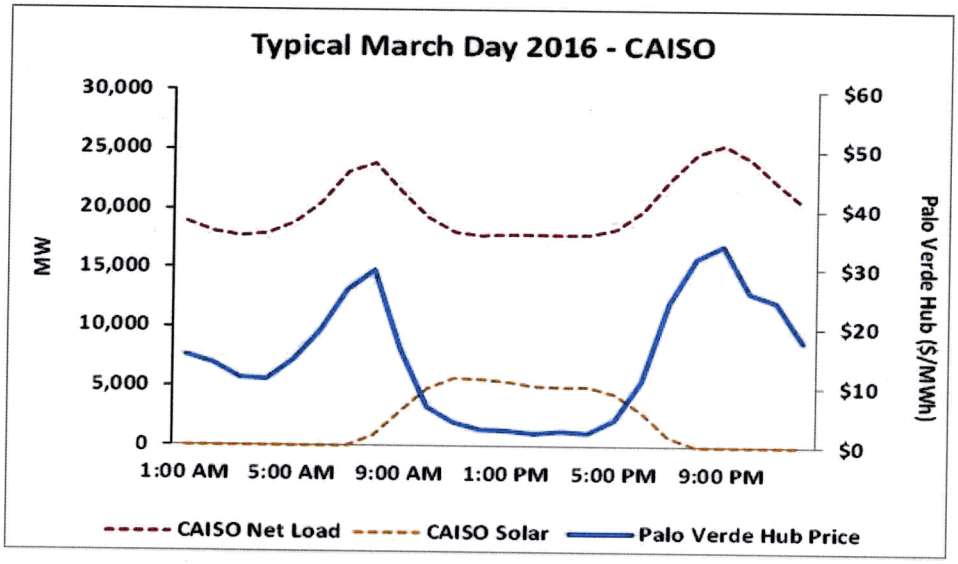
A. Steep reductions in demand followed by steep increases can present operational challenges to the overall resource portfolio. During low demand periods in the middle of a non-summer day, APS must turn down generating units or shut them off entirely to make room for solar production. Due to operational limitations, once larger units are

shut off, they typically cannot be restarted for up to eight hours or even longer in the case of a coal unit, making them unavailable for the evening peak. Because of these operational limitations, more flexible generating units are often utilized. Flexible resources such as combustion turbines, reciprocating engines, energy storage and demand response are well suited to respond to these challenges. As rooftop solar penetration increases, APS's resource fleet will increasingly need more dispatch flexibility and these types of resources can provide a platform for integrating more solar onto the grid.

Q. HOW HAVE WHOLESALE POWER MARKETS CHANGED AS A RESULT OF INCREASES IN SOLAR GENERATION?

A. Along with regional increases in solar penetration, wholesale power prices at the Palo Verde hub have also changed, primarily in non-summer months when there is an abundance of solar generation on the system and relatively low customer demand. As demonstrated in **Figure 4**, power prices are lower in the middle of the day when solar is producing its maximum output.

Figure 4.



This trend toward lower priced energy during mid-day hours is likely to continue and even grow as California approaches its new, higher renewable portfolio standard of 50% renewables by 2030, bringing more solar to the region. Lower wholesale power prices can present customer savings opportunities for utilities like APS who are able to make economic purchases during these hours. However, in order to be able to make these purchases, APS must make room on its system. In order to make room, APS must either back down other generation or shut it off entirely. As discussed above, flexible resources like combustion turbines can be shut off and started back up hours later. Larger units like combined cycle or coal units are not, however, designed to be this flexible and have limited capability to respond to the growing need for flexibility.

Q. WHAT DO ALL OF THESE CHANGES MEAN FOR APS'S FUTURE RESOURCE PORTFOLIO?

A. While lower wholesale power market pricing is good for customers today, APS must also plan for the future by making changes in APS's resource portfolio to be able to make room for even more solar on our system. As discussed in the 2014 IRP, low market prices, combined with the high cost of environmental regulations and increasing penetration of rooftop solar will necessitate more flexibly dispatched resources and fewer traditional base load resources.

Q. HOW IS APS PLANNING TO ADAPT TO THESE CHANGES?

A. APS is executing a number of integrated strategies to adapt to the changes in its load shape and the markets. First, APS will be implementing its OMP and microgrid projects to increase the amount of fast ramping flexible resources it has in its portfolio. Second, APS is executing its strategy to manage coal generation and attendant environmental regulations. APS retired the smaller, less efficient Four Corners Units 1-3 and Cholla Unit 2. APS has also committed that it will no longer burn coal in Cholla Units 1 and 3

after the mid-2020's and will continue to monitor and evaluate the economics of the on-going operations of Cholla Units 1 and 3.

IV. THE NEED FOR ADDITIONAL RESOURCES AND EFFECTS OF THE CHANGING LOAD SHAPE

Q. GOING FORWARD, WILL ADDITIONAL RESOURCES BE NEEDED TO MEET APS CUSTOMERS' ELECTRICITY NEEDS?

A. Yes. As demonstrated in **Figures 5** and **6,** and as discussed in its 2014 IRP and 2017 Preliminary IRP, APS has significant resource needs into the future. In total, APS expects to need over 3,500 MW of additional resources by 2022 to cover power contract expirations and anticipated future load growth. **Figure 5** shows APS's cumulative resource needs through 2032, and **Figure 6** shows the new resource contributions needed to meet the cumulative resource needs – including anticipated customer resources such as rooftop solar and DSM.

Figure 5.

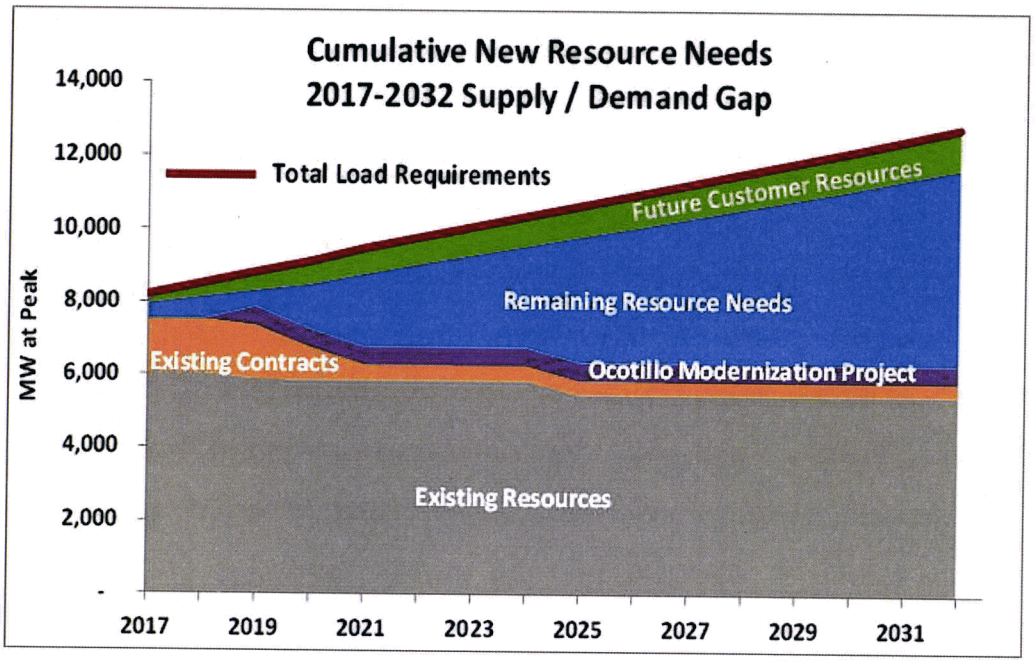
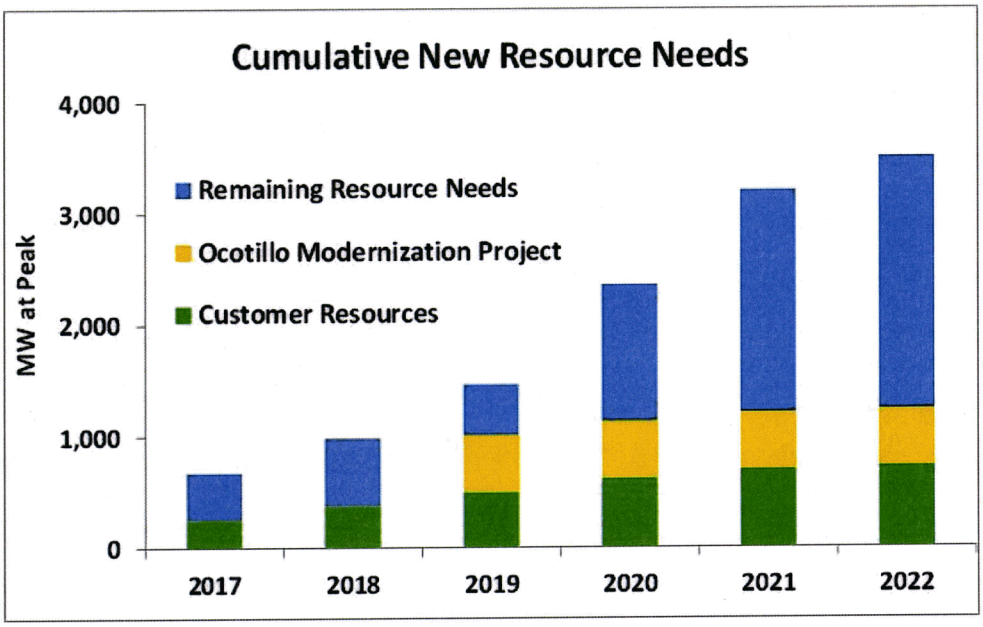


Figure 6.



Q. HOW DOES APS PLAN TO MEET ITS CUSTOMERS' NEED FOR INCREASED PEAK CAPACITY?

A. As discussed in its 2014 IRP and 2017 Preliminary IRP, APS has a multifaceted plan to meet its future load growth needs. One of the first steps is the implementation of APS's OMP, which replaces approximately 220 MW of natural gas powered steam turbines installed in the 1960s with 510 MW of state-of-the-art, fast ramping combustion turbines. APS has also issued an all-source request for proposal (RFP) seeking 400 – 600 MW of flexible, peaking capacity to be in commercial operation starting in 2020. The remainder of APS's near term needs will be primarily met with resources such as market purchases, microgrid resources, demand side management programs and renewable energy.

Q. WHAT ROLE DO YOU ANTICIPATE THAT BATTERY STORAGE WILL HAVE IN HELPING TO MEET APS'S RESOURCE NEEDS?

A. Battery storage is anticipated to play a role in APS's future resource fleet, providing that costs come down as expected and the technology is sufficiently mature. APS is currently anticipating that by the early to mid-2020's, battery storage will begin to be cost effective relative to other technologies and will look toward the recently issued all-source RFP for current price information. However, APS is not waiting until the 2020's to investigate the potential to add this important resource. As discussed in Mr. Bordenkircher's testimony, APS is planning to gain experience with battery storage as part of its Solar Partner Program as well as its Solar Innovation Study. While the backbone of the future flexible resource fleet is projected to be quick-starting natural gas generation, battery storage levels in APS's resource portfolio are planned to increase as costs become more competitive with other resource options.

Q. HOW WOULD DEMAND SIDE MANAGEMENT HELP ADDRESS APS'S CHANGING RESOURCE NEEDS AND CUSTOMER LOAD SHAPES?

A. The current Energy Efficiency Standard was written at a time when renewable resources were not as abundant in the region as they are today. As I explained earlier in my testimony, increasing levels of renewable resources have changed APS's net load shape and have impacted wholesale power market prices. Because of these changes, resource needs have changed. APS now has access to plentiful supplies of resources during non-summer months, especially during mid-day hours when solar production is at its highest. Due to the availability of low-cost, abundant energy supplies during non-summer months, APS will need to re-evaluate the DSM programs needed for the future. Many of the current programs provide energy savings during these non-summer mid-day hours. Since APS's resource needs have shifted toward evening hours when the sun is setting and solar is producing little if any energy, APS now needs programs that create

targeted energy and demand savings in the late afternoon and evening hours. In addition, as APS experiences growth on its system, there may be opportunities for implementing DSM programs on targeted distribution feeders to help defer equipment upgrades. Because of these changes, APS is in the process of re-evaluating its portfolio of DSM programs to make them more focused on reducing peak demand, rather than simply reducing energy across all hours of the year. Such refocused programs will not only align better with actual resource needs, but will also provide additional education and resource opportunities for customers if they choose to manage their demand in response to APS's new proposed three-part rates. APS is providing more detail regarding proposed changes to DSM programs in its 2017 DSM Implementation Plan.

Q. WOULD DEMAND RATES AND CHANGES TO THE TOU PERIODS ASSIST APS IN RESPONDING TO THE CHANGING LOAD SHAPES?

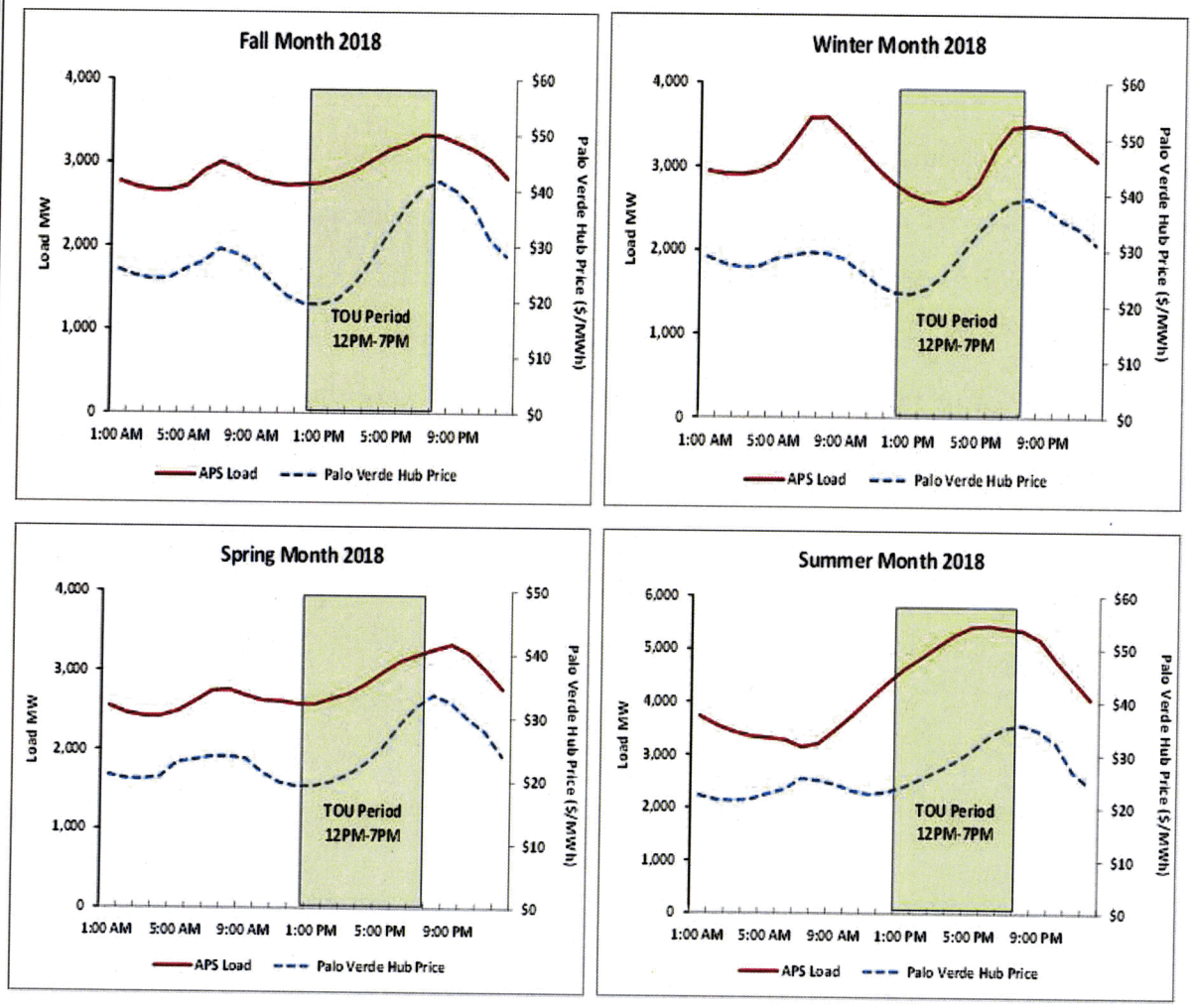
A. Yes. The changes to customer load shapes and wholesale power markets have made it clear that an update to APS's rates is needed. As discussed in Mr. Miessner's testimony, demand rates coupled with time-of-use energy charges can help decrease peak system demand.

Q. APS HAS PROPOSED CHANGING THE TOU PERIODS USED IN ITS RATES. WHY IS THAT NECESSARY?

A. APS has both 9 a.m. – 9 p.m. and 12 p.m. – 7 p.m. TOU periods, although the 9 a.m. – 9 p.m. period is currently frozen. APS's TOU periods were developed at a time when there were negligible amounts of solar resources on the APS system, or in the region. Where DSM programs and TOU rates were developed in part to help flatten the load profile, rooftop solar works against this and actually makes the customer load profile worse. The result is that APS's 12 p.m. to 7 p.m. TOU period, for example, sends customers a price signal to conserve power during times when there is either low

demand, or low wholesale prices, or both. As **Figure 7** depicts, wholesale power prices are following a similar pattern to APS's load shape. During times of low demand, wholesale power prices are low, and conversely, at times of higher demand, wholesale power prices are higher.

Figure 7.



As the charts above demonstrate, the current TOU period of 12 p.m. to 7 p.m. no longer provides an appropriate price signal given the changes to load and wholesale power prices. Put simply, the current TOU on and off-peak periods send the wrong price signal at the wrong time. They incent customers to conserve energy mid-day and early

afternoon when customer demand and wholesale prices are low and energy is abundant on the regional system, and fail to encourage energy and demand reductions in the evening hours when wholesale prices are high and system demand is peaking.

Q. IF THE CURRENT 12 P.M. TO 7 P.M. PERIOD IS NO LONGER APPROPRIATE, WHAT PERIOD IS APPROPRIATE?

A. During summer and especially non-summer months, higher customer demand and wholesale market pricing have shifted later into the evening hours. In non-summer months particularly, the peak is generally expected to occur between 7 p.m. and 9 p.m. as the prior charts illustrate. In the summer months, APS's peak has generally occurred between 4 p.m. and 6 p.m., although very high loads continue into the evening hours due to homes and other infrastructure retaining heat. APS's summer peak is expected to shift further toward early evening hours as more solar is added to the APS system. Because of these later peak load conditions, a TOU period of 3 p.m. to 8 p.m. would be more appropriate. Using fall and summer months as examples, **Figures 8 and 9** demonstrate how a later TOU period would better align with the later peak load conditions and wholesale market pricing.

Figure 8.

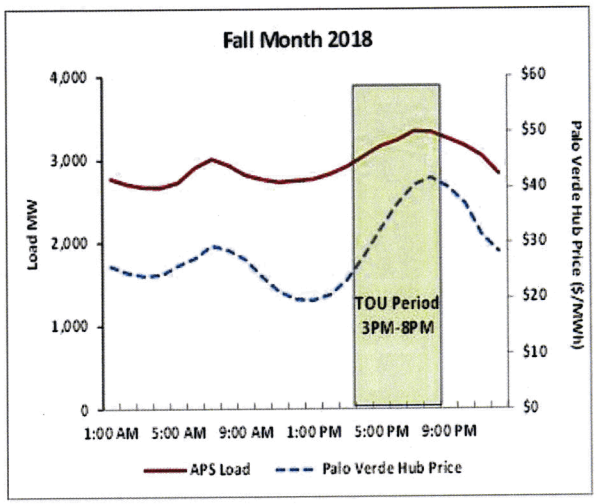
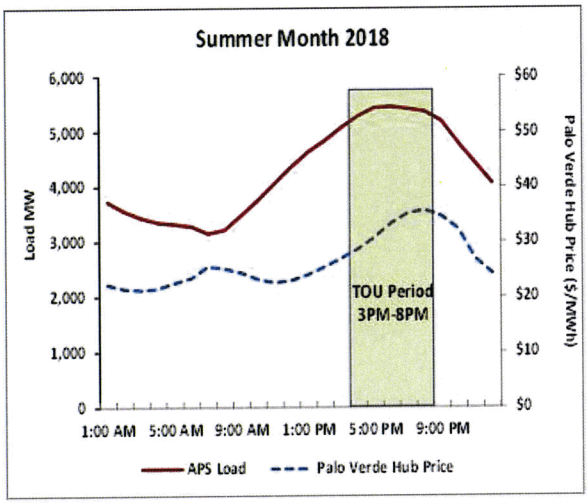


Figure 9.



Q. HAVE UTILITY AVOIDED COSTS BEEN IMPACTED BY THE CHANGING LOAD SHAPES YOU HAVE DESCRIBED?

A. Yes. The changing system load shape attributed to the increasing penetration of rooftop solar impacts avoided costs in a similar fashion. Increasing rooftop solar reduces system net energy consumption and associated avoided costs during solar production hours. Specifically, a large percentage of energy from rooftop solar is exported to the grid during times when there is low overall system demand. As a result, the avoided costs can be even lower for the exported energy portion of rooftop solar production.

Q. DOES THE EPR-6S RATE RIDER MR. MIESSNER REFERENCES IN HIS DIRECT TESTIMONY TAKE INTO ACCOUNT THE EXPORT ENERGY SHAPE ASSOCIATED WITH ROOFTOP SOLAR?

A. No. The EPR-6S Rate Rider reflects an avoided cost based upon a traditional, firm block energy purchase over all hours of the year. Rooftop solar customers export energy to the grid primarily in non-summer months. During the high energy usage periods of summer months, very little rooftop solar energy is exported during peak demand hours when wholesale market prices and associated avoided costs are higher. Accounting for this pattern of energy exports significantly lowers the avoided costs associated with rooftop solar.

Q. HAVE YOU ESTIMATED WHAT THE AVOIDED COST DIFFERENCE IS BETWEEN THE PROPOSED EPR-6S PURCHASE RATES FOR EXPORT GENERATION AND WHAT A SHAPED ROOFTOP SOLAR EXPORT ONLY ENERGY RATE MIGHT BE?

A. Yes. The proposed EPR-6S rate is higher than the avoided costs of a shaped, rooftop solar export only rate. For example, the weighted annual average energy cost on the EPR-6S would decrease from 2.90 ¢/kWh to 1.78 ¢/kWh if the rate reflected only the value of rooftop solar exports.

Q. WHAT IS THE RELATIONSHIP BETWEEN THIS AND THE VALUE OF SOLAR DOCKET, HAPPENING IN DOCKET NO. E-00000J-14-0023?

A. The value of solar docket has evaluated methodologies that include export only energy values associated with rooftop solar. That docket is expected to conclude later this year and the outcome of that proceeding could be relevant to the decision on the export rate in this case.

Q. GIVEN THE LARGE AMOUNT OF RESOURCES NEEDED IN THE FUTURE, WOULD DEMAND RATES HELP ADDRESS THESE NEEDS?

Yes. Since APS must build or procure sufficient resources to meet summer-time peak demand, a rate structure that coincides with that peak demand would be appropriate. Without demand rates, customers do not have as much of an incentive to reduce demand at the time of peak. As a result, APS will need to build or procure more resources than otherwise would be necessary. With demand rates, customers would receive a price signal that would further incentivize them to reduce consumption at the time of peak. By aligning customer price signals with peak demand, APS could defer building or procuring resources in the future since customers would be incentivized to reduce demand.

V. <u>ENERGY IMBALANCE MARKET</u>

Q. EXPLAIN WHAT THE EIM IS?

A. The EIM is a sub-hourly real-time energy market that optimizes the dispatch of generators within and between balancing authority areas every 15 and 5 minutes. This market supplements the existing day ahead and hourly energy trading practices that are used to lower customer costs by achieving a more efficient dispatch of generating units to meet APS customer load. The dispatch of generation under the EIM is expected to be

more efficient due to this market having more resources and load to optimize against, and more frequent transaction opportunities.

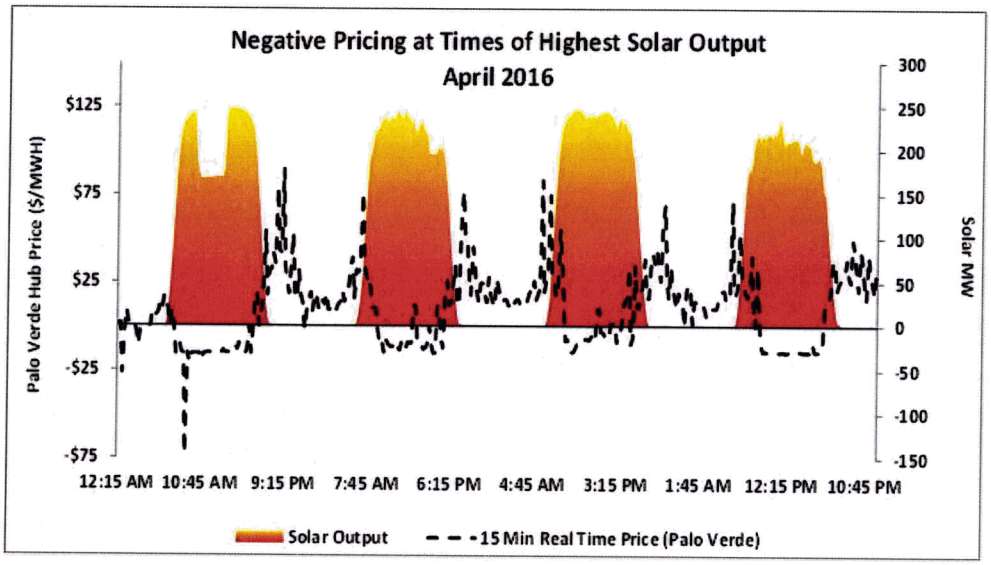
EIM participation is voluntary and is different from joining the California Independent System Operator. Utilities that participate in the EIM do not relinquish control of their generating or transmission assets, and maintain all of their reliability and compliance responsibilities.

The EIM market will not replace existing wholesale energy markets and APS will continue to transact through existing market mechanisms while participating in the EIM. The EIM is designed to complement each utility's existing energy trading practices, not replace them.

Q. EXPLAIN HOW APS'S PLANNED PARTICIPATION IN THE EIM FITS WITH THE CHANGING MARKETS YOU HAVE DESCRIBED?

A. As you can see from **Figure 10**, there is a direct relationship in the timing of solar generation output to low and negative wholesale market pricing during non-summer months. By participating in the EIM, APS will have more opportunities to take advantage of these beneficial pricing opportunities on behalf of customers. The EIM provides APS the ability to transact power in 5 minute increments. Transacting in 5 minute increments provides utilities not only opportunities to purchase power at low prices, but also opportunities to sell power at higher prices.

Figure 10.



This relationship indicates that as more solar energy comes onto the regional grid, the value its production represents is low, and may become even lower over time as California progresses toward its Renewable Portfolio Standard of 50% by 2030.

Participating in regional energy markets is helpful in optimizing generation dispatch decisions. With increasing levels of rooftop solar adding more complexity to forecasting net customer demand, it is perhaps more important than ever that APS fully participate in this market to help integrate renewable energy supplies. Participating in the EIM provides an additional tool to fine tune its dispatch decisions and save customers money.

Q. IS EIM A SUBSTITUTE FOR DEVELOPING NEW RESOURCES IN THE RESOURCE PLAN?

A. No. Participating in the EIM does not alter each utility's resource planning/procurement accountabilities. Each EIM participant is required to have sufficient resources to meet their own peak load needs and to satisfy their own operational requirements – for

example, having sufficient resources to meet their own planning reserves and flexible ramping capabilities to meet their own "duck curve" challenges.

The EIM is not a substitute for flexible capacity in the resource plan. Rather, the EIM is a sub-hourly real-time energy market in which sales and purchase opportunities vary with each increment of time. The EIM is essentially an optimization tool used once the resource plan's assets are already in place. Utilities must still provide for their own resource adequacy by procuring or constructing sufficient resources to meet their customer's needs.

Q. HOW WILL CUSTOMERS BENEFIT FROM APS'S PARTICIPATION IN THE EIM?

A. APS's participation in the EIM is expected to result in savings to customers by reducing production costs due to improved access to a diverse set of resources and load across the broader geographic footprint. The anticipated annual benefit to APS customers is expected to be in the range of $7 to $18.1 million per year.[2]

EIM provides increased flexibility to handle intra-hour variations in load and variable resource output. This increased flexibility is important as more renewable energy is added to the grid. The EIM will deploy software that identifies profitable trading opportunities between balancing authorities on both a 15 and 5 minute basis. This new software system optimizes resource selection and transmission utilization while recognizing constraints; something that cannot be done using existing business practices.

[2] *See* Docket No. E-00000V-13-0070, APS's Energy Imbalance Market informational filing (April 17, 2015)

Taking advantage of the diversity of loads and resources across the EIM footprint allows EIM participants to individually carry a reduced amount of reserves intended for intra-hour fluctuations in load and renewable resource output. Because the EIM optimizes generation across the entire participant footprint every 15 and 5 minutes, production cost savings are realized for participating utilities and their customers. Specifically, participation by APS in the EIM would yield two principal benefits:

1.) Sub-hourly dispatch benefits. APS will realize the efficiency of optimized combined 15 and 5 minute dispatch and real-time unit commitment across APS and the current EIM footprint. As an EIM participant, APS would have the opportunity to sell power above cost or purchase power if it's cheaper than APS's cost, on a 5 minute basis. This represents an increase in capabilities compared to bilateral transactions that are typically done on an hourly basis.

2.) Reduced flexibility reserves. In this context, the term "flexibility reserves" refers to the on-line generating capacity that is needed to respond to minute-by-minute variations in customer demand and/or renewable resource production. By reflecting the diversity of load and renewable resource variability across the APS system as well as the footprint of current EIM participants, APS will be able to carry less flexibility reserves needed to manage these variations than if operating alone. Currently, APS maintains flexibility reserves to manage load and renewable generation fluctuations within the hour. However, due to the diversity across the broader EIM footprint, the variability of the entire system may be less than the sum of the individual utilities' variability. This expected reduction in reserves benefits all EIM participants, providing for customer cost savings.

VI. OCOTILLO MODERNIZATION PROJECT

Q. WHAT IS THE OMP?

A. The OMP retires 220 MW of aging steam generating units located at APS's Ocotillo Power Plant in Tempe and replaces them with 510 MW of state-of-the art combustion turbine technology, for a net site increase of 290 MW.

Q. WHY IS APS UNDERTAKING THE OMP?

A. As noted in Commission Decision No. 75068, the OMP offers "a unique opportunity to add capacity at a strategic location within the Phoenix Load pocket." In addition, the OMP adds peak capacity that will be needed to meet future resource needs and the new combustion turbines will provide operational flexibility in APS's portfolio to help manage an evolving load shape while integrating increasing levels of renewable energy. The combustion turbines selected for this project are capable of multiple starts and stops each day and have fast ramping capabilities, so they start providing power to the grid within six minutes and can be at full capacity in less than ten minutes. Thus, the OMP provides a key resource to help address the changing load shape and increasing renewable energy on APS's system. Finally, the site's attributes and existing infrastructure which includes, among other things, existing water supplies, existing natural gas pipelines and transmission infrastructure provide for a favorable economic opportunity for APS's customers. The unique location of the OMP in the Phoenix load pocket also affords dynamic voltage support for the grid.

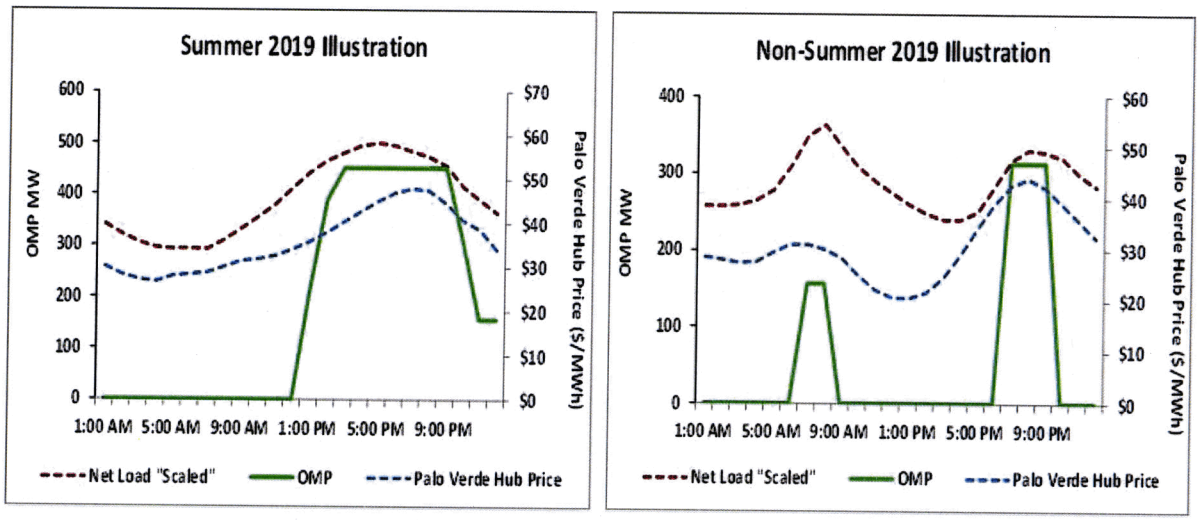
Q. ARE THERE OTHER BENEFITS TO THE OMP?

A. Yes. The new combustion turbines will be more efficient than the existing generating units. They have lower NOx and CO emissions on a per kWh basis. In addition, they utilize hybrid cooling technology that will result in less water use on a per kWh basis.

Q. HOW DOES THE OMP HELP ADDRESS THE CHANGES IN CUSTOMER LOAD SHAPES AND WHOLESALE ENERGY MARKETS YOU HAVE DESCRIBED ABOVE?

A. Flexibly dispatched generation, such as the combustion turbines APS will be installing as part of the OMP, will increasingly be needed in the APS portfolio to provide a platform to integrate renewable energy and respond to the changing load shapes. As wholesale power markets continue to evolve, flexible generation provides APS the capability to adjust generation output as needed to take advantage of economic wholesale market opportunities, thereby saving customers money. As **Figure 11** below illustrates from 2019 model forecast data, OMP's operational characteristics are well suited to meet summer-time peak conditions, while integrating renewable energy variability and taking advantage of wholesale market pricing opportunities.

Figure 11.



Q. ARE THERE OTHER REASONS THAT APS DECIDED TO PURSUE THE OMP?

A. Yes. In addition to meeting the resource needs identified above, the OMP site provides transmission support for the Phoenix load pocket by balancing the flow of electricity in the Phoenix area. Also, the existing steam unit technology has become obsolete and it

has become increasingly difficult to find replacement parts and people with the skills to do regular maintenance and repairs on the outdated machines.

Q. DID APS CONDUCT A COMPETITIVE RFP FOR THE OMP?

A. Yes.

Q. WHAT WERE THE RESULTS OF THAT COMPETITIVE RFP?

A. The results indicated that the OMP was the low cost option for customers. Navigant consulting performed the role of Independent Monitor and their letter validated "the fairness and transparency of the solicitation and evaluation processes conducted by APS." Navigant also stated that "APS performed its Proposal evaluation and subsequent selection process in a logical, unbiased, and comprehensive manner consistent with other power supply offer evaluation processes we have performed or observed."[3]

VII. MANAGED COAL STRATEGY INCLUDING RETIREMENT OF CHOLLA 2 AND CLEAN POWER PLAN

Q. PLEASE DESCRIBE THE COMPANY'S RATIONALE FOR CLOSING CHOLLA UNIT 2?

A. As discussed in APS's 2014 IRP as Amended, the closure of Cholla Unit 2 provided significant economic and environmental benefits for APS's customers. Cholla Unit 2 required significant and expensive upgrades to comply with the federal Mercury and Air Toxics Standards (MATS) and the Regional Haze Rule. Cholla 2 did not have fabric filters to manage mercury emissions, nor did it have selective catalytic reduction (SCR) – this is similar to Four Corners Units 1-3, which were retired at the end of 2013. Since Cholla 2 does not have either of these pieces of equipment, it would have been very

[3] *See* Docket No. E-00000V-13-0070, APS's Notice of Filing Independent Monitor's Certification Letter (September 1, 2015).

costly to comply with the increased environmental regulations and as a result, Cholla 2 was retired on October 1, 2015. Unlike Four Corners Units 4 and 5, Cholla has much smaller units and as a result, there are no economies of scale. So, when costly environmental upgrades were required to be added, there simply wasn't enough energy produced from the smaller units at Cholla to absorb the high cost of the additional emissions equipment that would be required. Put simply, it was not cost-effective to do the environmental upgrades necessary to continue the operation of Cholla Unit 2.

Q. WHAT ARE APS'S PLANS FOR CHOLLA UNITS 1 AND 3?

A. APS is continually assessing the best path for the remaining Cholla units based upon economics and the changing environmental regulatory landscape. In communication with PacifiCorp and the Environmental Protection Agency, APS has decided that it will no longer burn coal in Cholla Units 1 and 3 after the mid-2020s but has not yet determined whether the units will be retired or converted to natural gas.

The Managed Coal Strategy in APS's 2014 IRP demonstrated the cost-effectiveness of APS's plans for Cholla as well as the remainder of our coal fleet. In particular, APS examined a scenario where Cholla 2 would be retired by April of 2016 and Cholla Units 1 and 3 would be retired by no later than 2025, after the existing coal contract expires.[4] The scenario assumed that Cholla coal generation would be replaced largely by natural gas generation. This scenario produced approximately $100 million of customer savings over continuing to operate the units past 2025.

[4] Peabody Coalsales LLC (a Peabody Energy Corp. subsidiary), is the sole provider of coal to the Cholla Power Plant. While the Peabody bankruptcy has not yet affected delivery, on May 4, 2016, APS filed a motion with the U.S. Bankruptcy Court for the Eastern District of Missouri to seek a determination that APS has the right to terminate its coal supply agreement for the Cholla Power Plant. The motion has not yet been ruled on. Should the agreement be terminated, APS will evaluate its options to purchase coal from available resources.

Q. HAS THE COMMISSION APPROVED THE RETIREMENT OF CHOLLA UNIT 2?

A. Yes. In the 2014 IRP process, APS requested that the Commission approve, pursuant to A.A.C. Rule 14-2-704(E), APS's proposed plan to retire Cholla Unit 2. In Decision No. 75068, the Commission Ordered "that the proposed retirement of Arizona Public Service Company's Cholla Unit 2 is approved as provided in A.A.C. Rule 14-2-704(E)." The Commission made no determination of a specific treatment or recommendation for rate base or ratemaking purposes.

Q. IS CHOLLA THE ONLY PLANT INVOLVED IN THE MANAGED COAL STRATEGY YOU DESCRIBED? WHAT ABOUT FOUR CORNERS AND NAVAJO?

A. No. APS's plan for Four Corners continues to be executed. Due to the large size of these units, the economics of continuing to invest in this plant was overwhelmingly favorable for APS's customers as demonstrated during the last rate case. At this point, APS and the other owners have begun work to install the required SCR upgrades by 2018, and the on-going lease and fuel agreements have been signed by the continuing owners. APS witness John Lucas provides additional information about the Four Corners SCR project in his testimony.

APS's other interest in coal generation is at the Navajo Generating Station in Page, AZ. APS's share of this plant is 315 MW, or 14% of the plant's output. There are currently three large generating units at the Navajo site, but due to the departure of Los Angeles Department of Water and Power and NV Energy by the end of 2019 coupled with an agreement with the EPA regarding future emission controls, it's likely that one of the units will close by 2020. The current lease and coal supply agreements expire at that time, so the continuing ownership amounts and agreements are currently being evaluated. As a result of the upcoming decision as to whether to continue in the plant

beyond 2019, APS will be performing analysis and considering what is best overall for customers. At this time, APS has made no decision regarding its future participation at Navajo.

Q. PLEASE EXPLAIN HOW THE CLEAN POWER PLAN AFFECTS THE MANAGED COAL STRATEGY THAT WAS DESCRIBED AND THE OVERALL RESOURCE PLAN?

A. The Managed Coal Strategy is driven by three primary factors: competing low natural gas prices, the high cost of compliance with environmental regulations at coal plants, and increasing levels of rooftop solar. Existing environmental regulations deal primarily with reducing nitrogen oxides and mercury, while the CPP deals with reducing carbon dioxide (CO2). The regulations impacting the coal fleet associated with reducing nitrogen oxides and mercury are not part of the CPP, but rather part of the Clean Air Act Regional Haze Rule and associated Best Available Retrofit Technology assessment, as well as the MATS respectively.

With respect to APS's existing power plants, the CPP imposes state specific goals to achieve reductions in CO2 emission rates from existing generators, based on 2012 emissions. The rule provides guidance to states in developing plans to meet the interim goals from 2022-2029 and the final goals from 2030 and beyond. Under the rule, States would have been required to submit their plans to EPA by September of 2016, unless granted an extension. Even though the CPP has been stayed, the Arizona Department of Environmental Quality and the Arizona utilities are working together to develop a plan for future submittal to EPA, in the event the CPP comes to fruition. In addition to the state plan, the EPA is taking comments on proposed rules and a proposed federal compliance plan that would apply to generating units on tribal lands. For APS, this would affect the Four Corners and Navajo generating plants.

There are a number of variables that remain uncertain with both state level compliance as well as compliance on tribal lands. These include, for example, whether Arizona will propose compliance based on an emissions rate or mass (tons of emissions) basis, and how the CPP will affect unit operations on tribal lands. Depending on how these variables are ultimately resolved, some generating units in the region may be required to curtail operations or purchase emission allowance credits, while others may be able to operate on a business as usual basis. In the event the CPP comes to fruition, APS will continue to be an advocate for CPP compliance options that allow the Company's generators the maximum operational flexibility. Depending on the outcome of these variables, a change in APS's generation portfolio or additional costs to operate affected units may result. Due to APS's Managed Coal Strategy, and the significant investments the Company has made in renewable energy and DSM programs, APS is well positioned to comply with a potential Arizona compliance plan. Analysis is on-going, and significant work remains before the Company can be certain of the final outcome.

In regard to APS facilities on tribal lands, there are many uncertainties about the potential impact of the CPP. If the Navajo Nation becomes subject to EPA's generic federal compliance plan as currently proposed, APS may be unable to comply with these standards without purchasing some level of compliance credits or curtailing operations at some level. However, there are a number of uncertainties associated with this evaluation including but not limited to: the existence and liquidity of compliance credit markets, existing contractual obligations with current and former owners of Four Corners and the Navajo Plant, and the type of federal plan applied to the Navajo Nation. While APS has filed comments with the EPA seeking an alternative to the imposition of a federal compliance plan and related carbon emission performance standards, if the EPA determines that this regulation is required and a sufficient carbon market results

from the ultimate compliance plan, APS may need to purchase some level of compliance credits.

VIII. TECHNOLOGY PROJECTS

Q. WHAT OTHER PROJECTS ARE BEING DEVELOPED BY APS THAT FIT WITH THE CHANGING RESOURCE NEEDS YOU HAVE DESCRIBED?

A. Consistent with APS's need for flexible resources, the Company is working with customers who either currently have on-site back-up generation resources, or desire to have back-up sources of energy. These are called micro-grid projects. As discussed in the testimony of Mr. Bordenkircher, APS is currently developing two microgrid projects with customers. The microgrid projects are comprised of small reciprocating engines that can start up and be at full power in approximately 20 seconds, making them well suited to respond to the flexibility needs of the broader APS system. Not only are these projects designed to maintain power supplies to the specific customer in the event of an outage, APS can also call upon this generation for its broader system needs and for meeting peak summer-time customer demand. Because these types of generating resources are highly flexible in their operation, starting quickly and able to ramp up and down quickly, they are well suited to help address the integration of renewable energy resources such as solar generation as well as local area distribution system constraints that may arise. Because APS can dispatch this generation to meet the broader needs of the system, these microgrid resources benefit all APS customers by not only helping to integrate renewable energy resources, but by deferring the amount of new resources otherwise needed in the future to meet peak summer-time demand.

IX. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. As described in the 2014 IRP and 2017 Preliminary IRP, low natural gas prices, combined with the high cost of compliance with environmental regulations and increases in solar generation are having significant impacts on APS's overall resource picture, as well as the region's. Specifically, increasing penetration of rooftop solar on APS's system and throughout the region has dramatically impacted not only the resource plan, but is impacting the nature of power consumption and wholesale energy markets. As a result of these changes, APS will need a resource portfolio that is more flexible than today's portfolio. Adding flexibility to the portfolio involves many factors including: developing fast-starting resources that ramp up and down quickly; continuing to execute on the Managed Coal Strategy; and addressing the demand side of the equation through realigned DSM programs, demand rates and updated TOU rates. These changes working together will all serve to provide a sustainable energy future for customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

DIRECT TESTIMONY OF SCOTT B. BORDENKIRCHER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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Renewables, Microgrid and Technology Innovations Post-Test Year Plant Additions ..... Attachment SBB-1DR

DIRECT TESTIMONY OF SCOTT B. BORDENKIRCHER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Scott B. Bordenkircher. I am the Director of Transmission and Distribution Technology Innovation and Integration at Arizona Public Service Company (APS or Company). My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I earned a Bachelor of Science in Business and Information Systems from the University of Phoenix. I began employment with APS in 2005 and have served in numerous management and leadership capacities during my tenure with the Company, including Director of Information Security and Compliance and Director of IT Applications. I was made Director of Technology Innovation and Integration in June, 2014.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am responsible for the research, development, assessment, selection, and implementation of new technologies for APS's electric grid both at the Distribution and Transmission levels. This includes Advanced Metering Infrastructure (AMI), energy storage, advanced grid technologies such as supervisory controlled switches, automated voltage regulation, and fault indication, as well as new customer programs like microgrids, utility-owned residential solar, and home energy automation. I am also responsible for enterprise data analytics.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My direct testimony describes key technology investments APS has made, and is making, in the electric grid to enhance reliability and performance, increase efficiency, enable alternative energy and distributed energy resources, and empower customer choice. My testimony discusses key customer programs including the Solar Partner Program and the Solar Innovation Study, APS's grid modernization efforts, APS's successes in distribution automation, AMI, and the newly launched microgrid program. Additionally, I will identify projects planned through June 30, 2017, and discuss Technology Innovation and Integration's contribution to the Company's post-Test Year plant adjustment.

III. TECHNOLOGIES AND APS PROGRAMS

A. *Advanced Grid Technologies*

Q. WHAT ARE ADVANCED GRID TECHNOLOGIES AND WHY ARE THEY PREFERABLE TO THE TRADITIONAL GRID?

A. Although utilities across the nation have different definitions of the advanced grid, the reality is straightforward: advanced grid technologies, including intelligent automated devices, are incorporated into the existing electrical grid in order to increase system visibility, reliability, and control. These devices permit APS to receive near real-time operational data and more accurate information about its facilities, infrastructure and customer power quality. This information is made available to the distribution operations center, which, through two-way communication and control, can remotely command field devices. These capabilities enhance efficiency, increase reliability, and reduce cost. Aside from the operational benefits to APS, these technologies also allow customers to access more information about their individual usage, thereby helping them to more efficiently use electricity. A modern, flexible grid facilitates customer choice

and enables the addition of distributed energy resources such as rooftop solar and energy storage. Given the increasing importance of these resources, and the need for APS to support its customers' choices about these resources, APS views the adoption of advanced grid technologies as a positive inevitability.

Q. WHY ARE ADVANCED GRID TECHNOLOGIES NEEDED TO SUPPORT DISTRIBUTED ENERGY RESOURCES?

A. The traditional grid was designed to support the one-way flow of power; from centralized generation facilities to the end-use customer. The introduction of distributed energy resources in the grid represents a fundamental change in the design basis of the system. Adding generation into the middle of individual distribution feeders can cause two-way power flow. As customers adopt more and more distributed energy resources, the need to transition to an advanced grid becomes increasingly necessary. For example, unchecked PV penetration on distribution feeders can cause power flow and load patterns to emerge that actually push local voltage beyond allowable ANSI standards. Advanced grid technologies, like advanced inverters, can be an important tool to allow APS to regulate the output of these resources and proactively prevent such voltage overload problems from occurring. In addition, an advanced grid implements two-way, secure, digital communication that allows APS to communicate with each device on the network, and operate devices from a central location. By doing so, advanced grid technologies can help ensure power quality is maintained even with the intermittent nature of rooftop solar and other emerging technologies. Maintaining power quality to protect APS customers' appliances and equipment from surges caused by the increasing level of installed rooftop solar is one of APS's core responsibilities.

Q. WHAT HAS APS DONE TO INTEGRATE ADVANCED GRID TECHNOLOGIES AND WHAT DOES IT PLAN TO DO IN THE NEAR TERM?

A. APS developed a Transmission and Distribution Operations Vision Plan (Ops Vision Plan) in 2013 to address APS's advanced grid technology needs on a 5-year rolling basis. The Ops Vision Plan is updated annually to adjust for changing power grid conditions and customer demands, such as the changing speed of intermittent resource adoption, new technology additions, and shifting customer loads. Through the Ops Vision Plan, APS is building a modernized and flexible grid by investing more than $120 million in grid technologies through 2020. APS's post-Test Year plant cost is $32.6 million for the following technologies: Integrated Volt/VAR Control, Supervisory Controlled Switches, Network Protectors, Network Backbone, Supervisory Cap Bank Controllers, Distribution Substation Health Monitoring and Communicating Fault Indicators. Additional details on some specific technologies are discussed below.

Q. WHAT ADVANCED GRID TECHNOLOGIES HAS APS INCORPORATED AND HOW DO THEY BENEFIT CUSTOMERS?

A. APS's advanced grid technologies include:

Fire Mitigation Technologies

Fire Mitigation Technologies include Downed Conductor Detectors (DCD), a combination of sensors and automation technology that provides real time alerts to the distribution operators when a power line has fallen to the ground. This technology helps to prevent fires by allowing APS operators to know immediately when a wire is down on any of the circuits where these devices are installed and therefore greatly decreases response time. APS currently has 48 DCDs installed.

Supervisory Capacitor Bank Controls

A capacitor is an electrical device that is used to correct voltage or power factor issues that occur with normal grid operations. This improves the overall efficiency of the utility system and ensures power quality for customer end-use equipment. Capacitors are installed in groups (called "cap banks",) and are used to maintain proper voltage levels along the length of a feeder; from substation to end-of-line. APS is in the process of upgrading its capacitor bank communication control systems to allow for two-way communications between these devices and the operations control center. This has allowed distribution system operators to monitor the status of the cap banks and mitigate abnormal voltage levels remotely. The ability to dynamically control cap banks is especially critical when integrating higher penetration levels of distributed energy. By the end of 2016, APS will have upgraded over 300 cap banks.

Integrated Volt-VAR Control (IVVC)

IVVC is an automated system of capacitors and voltage regulators that are able to autonomously control voltage levels along a distribution feeder. This includes functionality for flattening (or leveling out) the voltage across a long distance feeder, thereby enabling a reduction in energy production. This system also provides necessary support for rooftop solar by mitigating the negative voltage effects of intermittent power production along a feeder. On feeders where IVVC is installed, customers benefit by having a higher level of power quality, which is necessary for the proper functioning of consumer appliances, and the increased ability to support customer-sited energy resources. APS has been installing IVVC systems since 2012; there are currently 6 installed, and the Company anticipates having a total of 28 by the end of June 2017.

Distribution Substation Health Monitoring

Customers, and the grid, benefit from investments made in technologies that can reduce the frequency and duration of unplanned outages and prolong the useful life of equipment. Adding real-time monitoring and analysis devices to APS's substations allows APS to better predict equipment failures and make necessary adjustments, thus prolonging the life of the equipment. This also reduces, or even eliminates, customer outage minutes, and enables a more efficient and cost-effective use of grid assets. Implementing this technology involved the deployment of dissolved gas analysis monitors on APS transformers, connected to APS's Transformer Oil Analysis and Notification (TOAN) system which analyzes the data and provides early warning of potential failure. Software updates were made to TOAN from 2013 to 2014 to process the additional data from the monitor deployments, and APS deployed 41 monitors across 25 substations from 2014 to the end of 2015. APS expects to deploy an additional 15 monitors from January of 2016 through June of 2017.

Network Backbone

All of the aforementioned technologies are only as good as the communications system used to relay the information from the field to APS's operations control center. Launched in 2013, the Network Backbone program implements long distance, high bandwidth, secure data communications between APS's operations centers and field installations. This collection of fiber-optic, microwave, and other wireless communication mediums serves as the highway for information and control signals to flow. Continuing investment in this network serves to extend its reach to additional substations throughout APS's service territory. The use of APS's private network backbone better ensures cybersecurity and provides additional reliability and bandwidth necessary to

carry the company's critical data. Without this program, many of the customer benefits realized by other grid modernization efforts would not be possible.

B. *Advanced Metering Infrastructure*

Q. WHAT IS AMI, WHAT ARE ITS ADVANTAGES, AND HOW DOES IT BENEFIT CUSTOMERS?

A. AMI stands for Advanced Metering Infrastructure. This safe, encrypted, FCC-compliant metering technology allows APS to conduct the following functions remotely, which used to be performed manually: meter reading, programming meters with new rates and programs, and performing service connects and disconnects. AMI has resulted in a significant increase in efficiencies, and reductions in O&M costs and vehicle emissions. It has also reduced the number of safety-related incidents because there are fewer personnel in the field. For customers, AMI has increased the opportunity to gain more knowledge of their energy use. AMI meters also provide power quality data which is used to ensure that electricity is delivered to customers at the correct voltage. This grants APS operators a greater level of system visibility than what they've had previously. This augmented system visibility and situational awareness, and the ability to leverage the AMI network for other uses, makes it a foundational platform for many future advanced grid programs.

Q. DOES APS INTEND TO CHANGE ITS AMI SYSTEM?

A. No, APS does not currently have any plans to make bulk changes to its AMI system. However, during the first half of 2016, the Company replaced approximately 140,000 of its initially deployed AMI meters, and the Company may replace additional AMI meters as it finds necessary. These first generation meters utilized 2G cellular technology to transfer the meter data; a technology currently being phased out by cellular companies in

favor of 4G and LTE networks. The cellular radios built into these early meters utilized AT&T's wireless network and AT&T identified December 31, 2016 as the last day it would support 2G technology. Due to AT&T's announcement, APS had to replace those specific AMI meters with new meters that could be supported by current cellular networks. APS surveyed the AMI vendor marketspace and after a competitive selection process, chose Landis+Gyr as the replacement meter. These meters will allow APS and its customers to continue to recognize the benefits of AMI.

Q. DOES APS HAVE AN OPTION FOR THE FEW CUSTOMERS WHO CHOOSE TO NOT TO HAVE AN AMI METER?

A. Despite all the advantages that AMI meters provide for the customer and the utility, APS understands some customers desire not to have AMI meters and will be proposing an AMI Opt-Out Option in Schedule 1 discussed further in the direct testimony of Charles A. Miessner. In the past, when a customer has opted to have a non-standard APS meter instead of a standard APS meter (an AMI meter), the non-standard meter could have been either an analog or a digital meter. As the Company moves towards more wide-spread demand rates, it will require its non-standard meter to be digital. Additionally, customers with rooftop solar and non-residential customers will not be able to opt out of an AMI meter.

Q. ARE THERE CERTAIN CUSTOMERS WHO CANNOT OPT-OUT OF HAVING AN AMI METER?

A. Yes, rooftop solar customers and non-residential customers cannot opt-out. APS does not allow customers who have rooftop solar to opt out of having an AMI meter because it is critical to APS's grid reliability and load forecasting accuracy that APS have current production data from all rooftop solar systems. It would not be practical or timely to collect this data manually and significant lags in this information could cause issues with distribution system configuration and capacity planning that could result in outages or

equipment overloads. Non-residential customers may not opt-out of having a standard meter because they are larger customers with more complex billing structures, including demand rates based on 15 minute intervals for certain commercial customers, that require the sophistication of an AMI meter.

Q. DECISION NO. 75047 (APRIL 30, 2015) ORDERED APS TO PROVIDE INFORMATION TO ASSIST THE COMMISSION IN EVALUATING ISSUES RELATED TO CUSTOMERS WHO CHOOSE TO NOT HAVE AN AMI METER. IS THERE ANY INFORMATION RELATING TO THAT ORDER YOU WOULD LIKE TO DISCUSS?

A. Yes, I will address the following topics: the total number of APS customers who have elected to be served with non-standard (non-AMI) meters in the Test Year; a breakdown by region of the number of APS customers who have elected to be served with non-standard meters in the Test Year; the average per-customer, per-Test Year costs of providing service with a non-standard meter as compared to the average per-customer, test-year costs of providing service with an AMI meter; the Test Year costs and expenses attributable to allowing customers to receive service through a non-standard meter; and a comparative analysis of the costs and benefits of AMI meters as opposed to the costs and benefits of non-standard meters. The other information requested in the decision is provided in the direct testimony of Mr. Miessner.

- At the end of the Test Year, APS had a total of 16,568 customers who elected to be served with non-AMI meters.

- The breakdown of customers in 2015 who had non-standard meters is listed below:

Region of Arizona		**# of Meters**
Northwestern	Prescott, Cottonwood, Sedona, Dewey, Flagstaff	10,352
Metro Phoenix		3,610
Northeastern	Payson, Show Low, Snowflake	1,856
Southeastern	Casa Grande, Bisbee, Douglas, Globe, Miami	518
Southwestern	Yuma, Parker, San Luis	232
Grand Total		**16,568**

- A residential customer that chose to opt-out created additional meter reading related costs to APS during the Test Year of $232.15; this is comprised of $66.79 for the initial set-up plus an additional $13.78 per month. A commercial customer's additional cost in 2015 was $499.95; this is comprised of $334.59 for the initial set-up plus an additional $13.78 per month.

- The total cost and expenses attributable to meter reading for non-AMI meters in the Test Year was $3,071,131. This cost includes expenses such as: the additional transportation costs and wear and tear on vehicles; additional employees or additional employee time allocation to manually read meters and input the information into the billing system; and additional supplies, equipment and technology.

- Throughout the deployment of the Company's AMI meters, APS has provided the Commission with information regarding the costs, benefits, and deployment status of automated meters. Pursuant to Decision No. 68112, the Company provided semi-annual reports detailing APS's move toward advanced infrastructure, and the cost of AMI has been examined by the Commission in each of the Company's last three rate cases. AMI meters continue to provide operational efficiencies, as discussed above,

and are an integral part of enabling technological advances in distributed resources and grid stability.

C. *Advanced Data Analytics*

Q. WHAT IS ADVANCED DATA ANALYTICS AND VISUALIZATION?

A. Advanced data analytics and visualization (ADA) is the transformation of raw data into usable and actionable business information that is then presented to a user in such a manner as to allow for timely, accurate decision making. ADA grants the ability to analyze data already available to the utility; to see congestion on the distribution system and take steps to alleviate the constraints on those lines, preventing outages experienced by our customers. For example, ADA can be used when customers purchase Electric Vehicles (EV) – if a load analysis is not performed on the transformer to ensure it is right-sized to accommodate the additional EV load, the customer may overload the transformer beyond its design rating and experience an unplanned outage. ADA allows APS to predict what could go wrong before it does and limits the risk of not being able to accommodate customer choices and technology opportunities. By more closely monitoring current assets, APS can optimize those assets to elongate lifespan and increase efficiency. As APS modernizes its power grid, data analytics will also provide customers with additional beneficial insight into their energy usage and demand which will give them opportunities to save on their bills

Q. WHERE/HOW IS ADVANCED DATA ANALYTICS BEING IMPLEMENTED AT APS?

A. APS is implementing advanced data analytics programs that can more accurately predict rooftop solar production, monitor and trend power quality, provide outage intelligence, and perform predictive and preventative asset health analysis. APS is following a use

case based approach, where each use case is solving an existing business challenge. Currently ADA is being implemented across Transmission, Distribution, Customer Service, and Marketing & Trading business units, with plans to expand to Generation, Resource Planning, and Finance business units over the next 1-3 years. Common platform and architecture principles are being leveraged in development of these applications across the enterprise, thus making the entire process more effective and efficient. APS has taken steps to ensure customer information and data remains private by utilizing best-in-class, defense-in-depth security architectures. APS's post-Test Year plant cost for ADA applications and toolsets is $6.5 million.

D. *Battery Storage*

Q. DOES APS CURRENTLY HAVE ANY PROGRAMS THAT INCORPORATE BATTERIES?

A. APS has two programs that incorporate batteries. The Solar Partner Program (SPP) incorporates two grid-scale battery storage systems. These are larger MWH-scale batteries that will be interconnected to the distribution grid at strategic locations (one in a substation and one at approximately the mid-point of a distribution feeder). The Solar Innovation Study (SIS) includes smaller kWH-scale battery storage systems at the residential level. SIS will install 25 battery systems interconnected behind-the-meter to provide customer-side services. Both of these programs involve deploying batteries in a controlled and monitored manner to assess how the potential benefits of batteries can be fully enjoyed by all customers in the most cost-effective way. Both are discussed in detail below.

Q. WHAT ARE THE POTENTIAL BENEFITS TO APS CUSTOMERS OF INTEGRATING BATTERY STORAGE ON THE GRID?

A. Grid-scale (12kV or higher) battery storage can offer a number of benefits to the grid, including: providing generation capacity, ancillary services (such as voltage support, frequency regulation and spinning reserves), and facilitating the deferment of certain distribution equipment purchases and upgrades if placed in key areas. The precise impact of grid-scale batteries is not yet fully known, and much of the research APS is undertaking in this area revolves around proving out their capabilities as well as the most effective manner in which to operate them. Due to their limited size, it is not clear if residential-level batteries can provide the same type or degree of benefits that grid-scale batteries might offer. APS is optimistic that SPP and SIS will help provide the necessary field experience and data to support and demonstrate the benefits and challenges of battery storage at the grid-scale and residential levels. More study beyond these two limited programs may be warranted in the future.

E. *Solar Partner Program*

Q. WHAT IS THE SOLAR PARTNER PROGRAM?

A. The Solar Partner Program (SPP) was designed to forge an innovative path for future solar deployment. The program enables APS to partner with customers and the state's local solar installers to create a brighter, cleaner energy future for Arizona. Consistent with Decision No. 74878, APS has installed approximately 10 MW of rooftop solar on approximately 1,600 homes at targeted locations. Each rooftop solar installation includes an advanced inverter and secure, two-way communications which allow APS to monitor and control power production and the advanced inverter functions of the rooftop solar site. APS is the first utility in the nation to deploy and control UL Listed advanced inverter technology remotely from a centralized control system. The rooftop solar

systems are on APS's side of the meter and all power produced by the systems flows directly to the grid for use by all APS customers. Participating customers do not pay anything for the systems themselves, APS retains ownership. In exchange for making their roofs available for this program, APS compensates each participant with a bill credit of $30 per month. In addition to the rooftop solar systems, APS has also installed two, 2 MWh batteries on two strategically selected distribution feeders as discussed earlier in my Testimony.

Q. DID APS CREATE AN ADVISORY COMMITTEE FOR THE SOLAR PARTNER PROGRAM?

A. Yes, APS created the Solar Partner Program Advisory Council comprised of representatives from the Commission and Commission Staff, the Electric Power Research Institute, the Residential Utility Consumer Office, National Renewable Energy Laboratory, the Smart Electric Power Alliance, other Arizona electric utility system operators and engineers, the Arizona rooftop solar industry, inverter manufacturers, and university power systems engineering departments to discuss and advise on the parameters of SPP. The advisory council meets twice per year to review the direction of the program and to provide feedback on the program design, research methodologies and results.

Q. WHY WAS THE SOLAR PARTNER PROGRAM CREATED?

A. SPP was created to assist both APS and the U.S. electric industry in understanding how the increasing penetration of various customer-sited technologies affects the grid, meet customer (all customers) demand for solar options, and contribute to APS's Renewable Energy Standard Tariff requirements. The program will help APS in identifying the best possible combination of secure and reliable communications technologies and infrastructure that will allow real-time monitoring and control of rooftop solar systems.

The program will also evaluate the effectiveness of advanced inverters and grid-scale batteries on stabilizing power quality and managing voltage and will provide a greater understanding of feeder capacity benefits. Lastly, the data collected will be used to evaluate if changes to the interconnection standards are necessary, as well as provide qualitative data on the interplay between other automated grid devices.

Q. WHY IS SPP GOOD FOR APS CUSTOMERS?

A. SPP is exploring how to optimize the grid and increase reliability for the long-term benefit of all customers. SPP provides a no-risk rooftop solar option to APS customers that might not otherwise qualify with third-party leasing companies. In addition, SPP does not just benefit the individual home on which the rooftop solar system is installed, but instead, because of being connected on the grid side of the meter, the energy produced by that system is delivered for use by all customers. The goal of the program will be to validate the assertion that advanced inverters can mitigate the adverse effects of increased photovoltaic (PV) through enhanced power regulating capabilities, and in what circumstances. APS anticipates that the program will prove that the operational challenges of distributed solar can, in many cases, be effectively managed by configuring advanced inverters and issuing real-time commands. While there has been similar research based on generic engineering models in the past, general theoretical conclusions still need broader field verification. For the research to have the greatest benefit to APS customers, it must be conducted on APS's grid. The collection and analysis of data will help anticipate and identify the tools that are the most effective at mitigating the negative impacts of increased PV penetration on the distribution grid. This program will also allow APS to validate and further develop complex planning models which will improve near- and long-term forecasting.

Q. HOW MANY SPP ROOFTOP SOLAR SYSTEMS HAVE BEEN INSTALLED AND ARE CURRENTLY (OR ANTICIPATED TO BE) IN SERVICE? HOW MUCH HAS APS SPENT ON SPP?

A. In 2015, 3 MW of SPP rooftop solar systems were installed; the remaining 7 MW of SPP rooftop solar systems will be installed by June of 2016. APS's post-Test Year plant cost for the installation of 10 MW of residential rooftop solar is $30.1 million. APS's average price per Watt for solar installation was $2.77. When all of the components of the SPP program are combined, including solar installations, secure communications, the advanced inverter control system, and the battery energy storage systems, APS's total capital investment in this important research program is approximately $40 million.

F. *Solar Innovation Study*

Q. WHAT IS THE SOLAR INNOVATION STUDY?

A. The Solar Innovation Study (SIS) is a 75-customer home energy management and rate research and development field program to examine the integration of customer-sided advanced technologies with demand-based rates. The study is comprised of 75 single family homes (both standard efficiency homes and high efficiency Energy Star homes), where APS owned and operated technologies are installed. 50 homes are equipped with a combination of rooftop solar, advanced inverters, home energy management systems, and load controllers; 15 other homes have rooftop solar, advanced inverters, home energy management systems, load controllers, and battery energy storage; and the last tranche of 10 homes have rooftop solar, advanced inverters, home energy management systems, and battery energy storage. In addition, 22 of the homes (spread among all of the groups) will have advanced, variable-speed air conditioners installed on them.

Q. WHAT IS THE PURPOSE OF THE SIS STUDY?

A. The purpose of SIS is to study customers' integration of demand-based rates with various demand and energy saving products along with distributed energy resource technologies. Various rate designs will also be tested via rate modeling in order to reaffirm which models result in bills most aligned with the utility's cost to serve. APS anticipates highlighting the participants' successes utilizing rooftop solar, distributed energy resources, home energy management solutions, the grid, and demand rates in a way that reduces costs to APS and maximizes opportunities for customers.

Q. CAN YOU EXPLAIN WHY THE SIS STUDY IS VALUABLE TO ALL CUSTOMERS?

A. The SIS benefits all customers because it explores additional opportunities for how home energy management systems, integrated with other customer products and devices, can enable customers to better control their demand and energy consumption. The lessons learned from this study could identify strategies that support the sustainable growth of renewable resources and the continued adoption of distributed energy resources that can meet both the needs of the customer and the utility.

G. *Red Rock Solar*

Q. WHAT SOLAR POST-TEST YEAR PLANT IS APS PROPOSING TO INCLUDE?

A. APS is proposing to include a 40 megawatt solar plant called Red Rock Solar.

Q. WHAT IS RED ROCK SOLAR?

A. Red Rock Solar is a 40 MW, single-axis tracking, grid-scale solar facility that APS is developing on 400 acres of APS-owned land in Red Rock, Arizona. APS will own,

operate, and maintain the plant. The facility is intended to provide renewable energy to Arizona State University (ASU) and PayPal, who have agreed to pay a special rate for the energy output. Over the 20-year term of the agreement, ASU and PayPal will be purchasing Renewable Energy Credits (RECs) and equivalent energy to what Red Rock Solar is producing. APS's post-Test Year plant cost for Red Rock Solar is $94.7 million. Additional information on the rate treatment is discussed in the direct testimony of Leland Snook.

Q. PLEASE EXPLAIN WHY RED ROCK SOLAR IS BENEFICIAL TO ALL CUSTOMERS?

A. Projects like Red Rock Solar are an important method of encouraging economic development, load retention and the deployment of new renewable resources. With this type of solar project, APS has the opportunity to provide more renewable energy to the grid, without creating additional costs for other APS customers. It also sets a tone that Arizona is open to businesses looking to relocate and utilize renewable energy in a cost-effective manner.

H. *Microgrids*

Q. WHAT IS A MICROGRID?

A. A microgrid can be defined simply as an electrical circuit that can either be disconnected from the centralized grid and operated autonomously (stand-alone or islanded), or be operated connected in parallel with the electric grid. Microgrids can range from simple onsite backup generation to complex, multiple interconnected loads and distributed generation resources. Microgrids frequently combine quick-acting, dispatchable generation and distributed energy resources, such as battery storage or renewables.

Q. IS APS CURRENTLY WORKING ON ANY MICROGRID PROJECTS?

A. Yes, APS will have two microgrids in service by the third quarter of 2016. The first project is a partnership with Marine Corps Air Station Yuma (MCASY) on the development of 25 MW of capacity in Yuma, Arizona. APS's post-Test Year plant cost for the microgrid project is $21.6 million. APS is seeking recovery of the full cost of this project based on a customer benefits analysis which showed that APS's need for peaking capacity and frequency response reserves, which would otherwise have to be obtained through other mechanisms, could both be provided by a single project at a cost savings compared to other sources in the market. The microgrid will function as a backup generator for the base whenever there's an outage affecting all or part of the site, and it can also be used as a supplemental power source for the rest of the community. Advanced, clean-burning EPA Tier-4 diesel generator sets (gensets) were selected as the generation type for the micro-grid due to rapid (less than 20 seconds to full power output) response time and their low emissions. Whereas natural gas might take minutes, clean-burning diesel gensets take seconds to start up and provide power to the grid with comparable emissions. Another benefit these units provide is that they can be programmed to switch on automatically to ensure reliable power and frequency support in the event of a grid-frequency disturbance which helps to counteract larger system blackouts.

For the second project, APS has partnered with Aligned Data Center (ADC) in Phoenix to develop a 62.5 MW diesel genset-based microgrid project with a new 69 kV enhanced capability substation. The costs for this project are being shared between APS and ADC. ADC is covering the portion of the cost that is proportionate to their direct benefit and APS is seeking recovery of the portion that benefits all grid-tied customers. The first phase of this project will be constructed in 2016 and consists of 12.5 MW of generation. APS's post-Test Year cost for the ADC microgrid is $5.6 million, for its portion of the

project. This represents a cost for new capacity that is lower than what is available in the market. Four different power lines sourced from three different distribution substations will bring electricity to the on-site substation; ensuring that if one line fails, the other lines will provide redundancy to ensure that electricity keeps flowing to the high-reliability data center. This project will not only increase reliability and power quality for customers at reduced cost, but it will also serve a larger effort to draw businesses to the State of Arizona.

Q. YOU MENTION INCREASED RELABILITY FOR CUSTOMERS, COULD YOU EXPAND ON WHY MICROGRIDS ARE BENEFICIAL FOR APS'S SYSTEM AND ITS CUSTOMERS?

A. Microgrids are helpful to all customers because they increase the reliability of the distribution grid; especially in the local area. A microgrid can provide additional energy support on demand when a localized grid outage prevents power from continuing down the line. In addition, due to their fast-acting nature, microgrids can provide ancillary services, like frequency response, when APS's system needs them due to grid disturbances or major outages. Also by having generation resources located closer to certain customers, APS can respond and ensure uninterrupted service when events like storms cause wide-scale infrastructure damage.

For example, the Aligned Data Center microgrid will be valuable to all customers because it will deliver additional localized power and be able to island from the central grid during periods of high congestion. APS will have additional optionality in managing the grid and delivering greater reliability to our customers due to the ability to call upon the generators to supply power when it is needed. This provides the dual benefit of creating the ability to serve a localized area of the grid if needed along with the ability to act as a system capacity resource for the benefit of all APS customers. The project is also beneficial due to its cost-sharing structure. When APS is able to share in

the costs of new generation with a site host, everybody wins; the larger APS customer community wins because this structure helps APS realize new peaking capacity via very cost-effective means which helps keep rates low, the State of Arizona benefits from a program with the ability to attract new economic development, and the host wins by being able to install on-site backup generation more cost-effectively than on a stand-alone basis.

IV. PLANT ADDITIONS

Q. WHAT LEVEL OF PLANT ADDITIONS DO YOU EXPECT THROUGH JUNE 30, 2017?

A. Attached to this testimony as SBB-1DR is a breakdown of the capital projects discussed in this testimony that will be in service as of June 30, 2017. As that exhibit shows, Renewables, Microgrid and Technology Innovation expects to add a total of $239 million of plant by that date. These additions contribute $101 million to the Company's post-Test Year Plant adjustment, as detailed on SFR B-2, page 2, column 6. APS Witness Elizabeth Blankenship describes additional details of the adjustment, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes and interest expense.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

Yes. Technology advancements and innovation will continue to play an important role in enhancing the safety, reliability and efficiency of APS's systems. Key technology investments must be pursued to prepare the electric grid for the future. These improvements will empower customer choice and further enable the adoption of alternative energy and distributed energy resources.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

RENEWABLES, MICROGRID AND TECHNOLOGY INNOVATION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
1	Red Rock Solar	Build a 40MW Solar Facility on APS-owned land at Saguaro	12/15/2016	$ 234,700	$ 94,474,480	$ 94,709,180
2	Solar Partner Program	Install 10MW of residential rooftop solar systems (~1500) on selected feeders	6/30/2016	$ 9,482,345	$ 20,607,794	$ 30,090,139
3	MCAS Yuma Microgrid	Design, procure, and construct a 25 MW Microgrid project at the Marine Corps Air Station Yuma	8/31/2016	$ 9,333,839	$ 12,292,675	$ 21,626,513
4	AMI 2.0 and P1D Meter Replacements	APS' remaining P1D meters are nearing end-of-life and must be replaced due to changes in the 2G AT&T network	6/1/2016	$ 11,757,571	$ 9,450,297	$ 21,207,869
5	Automated Meter Infrastructure (AMI) Meters	Pre-capitalized cost of AMI meters purchases that are used for additions and replacements	6/30/2017	$ -	$ 12,563,878	$ 12,563,878
6	Integrated Voltage Variance Controls	The APS distribution system is required to maintain acceptable voltage at points along the feeders under all loading conditions. Integrated Volt/Var Control ("IVVC") adds capabilities to remotely control capacitor banks and voltage regulators	12/31/2016	$ 4,160,729	$ 5,017,513	$ 9,178,241
7	Supervisory Controlled Switches	This project will increase restoration capability will have the ability to speed recognition and response time. It has the potential to reduce a complete feeder outage to a smaller segment of the feeder; the remainder of feeder then can be picked up through the SCSs. This improves SAIFI, SAIDI, and CAIDI, and reduces Troublemen patrol and switching time.	12/31/2016	$ 3,030,686	$ 5,525,211	$ 8,555,897
8	Network Protectors	Data acquisition will improve distribution operation center vault readings, typically performed by crews. Monitoring equipment health will enable APS to modify maintenance plans, and position for a proactive approach to equipment replacement. The network protector project aligns with the grid modernization strategy as outlined in the 2025 Operations Vision.	6/30/2017	$ 1,676,548	$ 5,757,192	$ 7,433,740
9	Advanced Data Analytics	Development of analytic applications such as solar forecasting and visualization, revenue protection, voltage exceptions and visualization, etc.	10/1/2016	$ 1,660,574	$ 4,792,821	$ 6,453,395
10	Solar Power Partners – Communication Devices	Install the required communications, monitoring, and control equipment to support Resource Management's 10MW residential rooftop solar program	6/30/2016	$ 3,316,775	$ 2,327,995	$ 5,644,770
11	Aligned Energy Microgrid	To provide back-up power to data center. Also, APS will own and operate microgrid and share the use of the generators to support the grid with peak shaving and frequency response resources	6/1/2016	$ (1,498,011)	$ 7,138,104	$ 5,640,093
12	Network Backbone	The existing communication networks are not sustainable in their existing form to support APS future grid modernization efforts	12/31/2016	$ 736,170	$ 4,341,983	$ 5,078,153
13	Solar Power Partners – Energy Storage	Procure and install two battery storage systems at a location where the effect on mitigating high solar penetration can be tested. This will occur under the 10 MW Solar Power Partner program	8/31/2016	$ 13,178	$ 4,317,903	$ 4,331,082
14	Solar Innovation Study	Perform field research with 75 existing single family solar homes by integrating technology packages (energy storage, load management devices, smart inverters, smart thermostats, etc.) to modify load shapes to better align with grid requirements	6/30/2016	$ 1,111,707	$ 2,094,976	$ 3,206,683

RENEWABLES, MICROGRID AND TECHNOLOGY INNOVATION POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	Estimated In-Service Date	Project Cost To-Date	Projected Costs to Close	Total Projected Costs
15	Supervisory Cap Bank Controllers	This project will have the ability to speed recognition and response time. It has the potential to reduce a complete feeder outage to a smaller segment of the feeder; the remainder of feeder then can be picked up through the SCSs. This improves SAIFI, SAIDI, and CAIDI, and reduces Troublemen patrol and switching time.	12/31/2016	$ -	$ 1,052,137	$ 1,052,137
16	Inverter Replacement Program	Solar Operations Capital Inverter Replacement Program to be performed at various solar legacy sites throughout Arizona	6/30/2017	$ 5,982	$ 843,135	$ 849,117
17	Distribution Substation Health Monitoring	The equipment will monitor for certain gases that indicate potential transformer failure. This will reduce maintenance costs and the number of catastrophic failures	6/30/2016	$ 81,902	$ 629,447	$ 711,349
18	Communicating Fault Indicators	This increased visibility will give APS the capability to expedite direction of line patrol. This will allow field personnel to more quickly locate the faulted cable. It is anticipated that improvements in SAIFI, SAIDI, CAIDI will be seen as well as a reduction in patrol time. Of the 225 devices installed on 32 feeders, CAIDI has been reduced by 31-min since in-service in 2013.	6/30/2017	$ 24,995	$ 643,451	$ 668,446
19	Trailing Costs for Projects In-Service in 2015	This is a combination of multiple projects that went into service in 2015 but have trailing clean-up costs that extend into 2016. The major projects in distribution include: City of Phx and Luke Air Force Base AZ Sun projects; spare parts moved from the project into inventory.			$ (492,109)	$ (492,109)
20	**Total Renewables, Microgrid & Technology Innovation**			**$ 45,129,689**	**$ 193,378,885**	**$ 238,508,574**

DIRECT TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

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 Forecasts for Arizona Public Service Company (APS or Company). In that capacity, among other responsibilities, I oversee the preparation of the Company's financial forecasts, including the details of 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 the 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.

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

A. My testimony discusses three main areas: APS's financial projections, the system average cost of fuel for generation and purchased power, and modifications to the PSA. In particular, I discuss the several benefits resulting from the regulatory framework

established for APS by the 2012 Settlement Agreement (Settlement or Settlement Agreement)[1], as well as explain why, because of the Settlement's financial design, APS is seeking a rate increase now. I sponsor the forecasted portions of Standard Filing Requirement (SFR) Schedules A, D, and F that are included in the Company's rate Application.

Additionally, 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.[2] 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 2015 Test Year ending December 31, 2015 (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

I also discuss a few modifications to the PSA Plan of Administration (POA). Specifically, I explain why the inclusion of environmental chemical costs and generation-related water costs in the PSA are appropriate, and also explain how the POA should be adjusted to enable the Company to potentially take advantage of energy storage opportunities, if cost effective and necessary for reliability purposes.

[1] Approved in Decision No. 73183 (May 24, 2012).

[2] Throughout the remainder of my testimony, the term "fuel expenses" may be used generically to refer to fuel and purchased power expenses.

Q. HAVE YOU EVER TESTIFIED BEFORE THE COMMISSION IN PREVIOUS APS RATE PROCEEDINGS?

A. Yes. I have presented testimony on the Company's fuel and purchased power expense and the PSA POA, among other topics, in APS's previous four rate cases before the Commission.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The 2012 Settlement Agreement led directly to a perceived improvement in APS's financial condition and, indeed, APS's actual financial performance improved as well. Much of this improvement stems from the perception of a more constructive regulatory regime which provides a better opportunity for APS to earn its authorized return on equity (ROE) and the expectation that APS will be able to maintain the improvement in its financial condition. For the last four years, the Company has been able to earn close to its authorized ROE for the first time in more than 15 years. (Notably, during this period the Company has not earned more than its authorized ROE.)

As a consequence, the Company's bond ratings have improved substantially, with material benefits in lowering the Company's borrowing costs. Those cost savings are being passed back to customers in the current rate request. With the improved financial performance, APS was able to extend the rate case moratorium period by an additional year.

But the Settlement Agreement was not expected to extend financial support forever, and APS's financial metrics are now reflecting the limits of the mechanisms created to facilitate the desired rate gradualism. In the absence of base rate relief and/or other regulatory support, APS again faces Total Company ROE projections of 9.0% in 2017, 8.4% in 2018, and 7.7% in 2019. Returns like these are far below not only the 10.5%

authorized ROE APS is requesting in this case, but also the 10.46% average ROE actually earned in 2015 by other investor-owned utilities (IOU) throughout the country. Without new rate relief that sustains APS's actual earned ROE at a reasonable level, APS will face challenges in raising the capital needed to invest in its system so it can provide safe and reliable electric service to APS customers and fulfill Arizona's efficiency, renewable energy, and other policy objectives. This is particularly relevant as the Company enters a period of elevated investment needs in the next couple of years.

My testimony also addresses the projected accounting data required by the Commission's SFRs to support the Company's rate case filing. Specifically, I sponsor the projected information presented on the following SFR Schedules:

- A-2 through A-5 – Summary Schedules
- D-1 through D-3 – Cost of Capital
- F-1 thru F-4 – Projected Financial Information

APS witness Elizabeth Blankenship sponsors the historical and actual Test Year information required by those Schedules. APS witness Leland Snook jurisdictionalizes the Total Company data to isolate those items that fall within the Commission's regulatory jurisdiction.

APS's current base fuel recovery amount of 3.21¢ per kilowatt-hour (kWh), established in Decision No. 73183 (May 24, 2012), was premised on expected 2012 cost levels at the time of the settlement in that case. Since then, the system average fuel cost has fallen modestly because natural gas prices are substantially lower than when rates were set previously. The delivered spot price of natural gas is expected to be $2.64/mmBtu in 2017 when new rates go into effect; in 2011, the Company's base fuel rate incorporated an expectation of natural gas prices of $4.39/mmBtu in 2012. Additionally, costs for

purchased capacity are lower due to the expiration of a long-term capacity contract, which is expected to be replaced by a summer-only and smaller capacity purchase. In contrast, and as a mitigant to these downward trends, a higher share of generation supply is sourced from higher-cost renewable energy providers, and with the passage of time, fuel prices in long term coal supply contracts increase in concert with the standard inflation escalators incorporated in those contracts.

Given the modest 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 2.9882¢/kWh[3], which rate reflects normalized levels of power plant performance, expected 2017 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 2017 when the rates requested in this proceeding are expected to become effective. Attachment PME-1DR 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 four rate cases.

Chemicals such as lime, ammonia, activated carbon and sulfur are necessary to comply with environmental emissions rules relating to the operation of certain of the Company's power plants. Their use is directly proportional to unit output every bit as much as fuel itself and therefore the Company is proposing that annual fluctuations in these expenses be recovered through the PSA. The same is true for water and water-related chemicals and purification processes used directly in the generation of electricity, particularly at the Palo Verde Nuclear Generating Station (PVNGS), and thus fluctuations in costs

[3] I may refer to this rate rounded to 2.99¢/kWh in the testimony that follows.

related to water consumption for generating electricity should also be recoverable through the PSA. My testimony proposes that the Base Chemical Cost be set at 0.0500¢/kWh and the Base Water Cost be set at 0.0606¢/kWh.

Finally, the Company may have cost-effective opportunities between rate cases to procure energy storage products from third-party providers. These storage products would likely substitute for capacity purchases from other resources, thereby displacing costs which would be recovered through the PSA. Including storage costs in the PSA will put these costs on the same footing as more conventional capacity purchase costs. My testimony proposes that the PSA POA be modified to allow such costs, if incurred, to be recovered in the PSA.

III. THE POSITIVE MOMENTUM GENERATED BY THE SETTLEMENT AGREEMENT

Q. YOU INDICATED THAT THE SETTLEMENT AGREEMENT TOOK ANOTHER STEP IN THE RIGHT DIRECTION FOR ARIZONA ENERGY POLICY. PLEASE EXPLAIN.

A. The Settlement Agreement was the fulfillment of a more modernized regulatory framework which was initially designed and implemented in the 2009 Settlement. This enabled APS to continue a higher level of operating performance and to make investments in projects driven by energy policy, while easing the resulting rate impacts on customers gradually over time. It achieved this result by way of regulatory measures that tackled the root of the Company's historically subpar financial performance and poor earned ROE: rates that have not kept pace with the Company's capital expenditures, due in large part to regulatory lag.

Since the adoption of the Settlement Agreement in mid-2012, APS's financial performance has materially improved. In each of the last four years, APS has been able

to earn within 50 basis points of, but not more than, the 10% ROE authorized in the Settlement Agreement and raise its credit metrics to a sufficiently strong level such that all three primary credit rating agencies have upgraded the Company's bond ratings to A- or above. These favorable financial results have been achieved at the same time that the Company continued to press forward on several key energy policy priorities for the State, including:

- The continued implementation of energy efficiency (EE) programs for retail customers to meet the State's EE Standard, one of the most aggressive standards in the country;

- The development and installation of additional large-scale renewable resources, both Company-owned and those owned by third parties, to meet the objectives articulated in the 2009 Settlement;

- The continued implementation of an extremely generous net metering program to encourage the adoption of distributed generation (DG), primarily rooftop photovoltaic (PV) solar panels;

- The implementation and management of an experimental buy-through rate for extra-large commercial and industrial customers;

- The expansion of the bill assistance support program for low income residential customers;

- A method for automatically reducing rates upon completion of the nuclear decommissioning trust funding requirements associated with Unit 2 at PVNGS;

- A mechanism to allow for the orderly acquisition of Southern California Edison's ownership interest in Units 4 and 5 at the Four Corners Generating Plant (Four Corners) and the concurrent retirement of Units 1-3 without prompting a brand new full-scale rate case application, and;

- The adoption of a revised, more economically-efficient line extension policy.

Most notably, these financial and policy results were achieved with only modest rate increases imposed on APS's retail customers in between rate cases. Average retail prices (in cents/kWh) increased by less than 1.5% in each of the last two years, an example of rate gradualism in operation. Indeed, since the end of 2009, just prior to the adoption of the 2009 Settlement, retail prices have increased on average by less than 2% per year. From this evidence, one can clearly see that the modifications to the regulatory framework implemented in the last two rate case settlements have generated meaningfully positive results for the Company, its customers and forward-looking energy policy in the State.

Q. WHAT PROMPTED THE CREDIT RATING AGENCIES TO RAISE THEIR RATINGS ON APS'S DEBT SECURITIES?

A. The improvement in the regulatory framework exhibited in the last two settlement agreements provided the right signal to the agencies that the Company's financial position would be more sound in the future, and the realization of improved financial results provided the credibility that the agreements reflected meaningful change in the regulatory outlook in Arizona. Following its upgrade of APS's bond rating in 2015, Moody's Investors Services (Moody's) made the following observations:

> The upgrade of Pinnacle and APS' ratings is driven by a strong financial profile that we expect to continue under a constructive and credit supportive Arizona regulatory environment... The Arizona Corporation Commission (ACC) has made significant progress in developing a credit supportive framework for the state's investor-owned

> regulated utilities. Actions taken by the ACC have included: 1) shortening the time taken to finalize rate case orders; 2) providing a strong suite of rate recovery mechanisms; and 3) tackling the difficult cost-shift issue associated with distributed generation. These actions are credit positive for APS and have enabled APS to earn close to its allowed return on equity and generate strong financial metrics...[4]

Fitch Ratings (Fitch) had a similar reaction, stating in its decision to upgrade APS in 2015:

> General Rate Case (GRC) orders have been more balanced for APS in the past several years and more timely adjudication of rate filings is a constructive development that has enabled the utility to improve its earned returns. Regulators also have adopted several regulatory mechanisms to facilitate cost recovery outside of and in between GRCs.[5]

There is a consistent theme running through these comments which Standard and Poor's Rating Services (S&P) summarized in an industry-wide report in this way:

> One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions where a utility operates... Steady application of transparent, comprehensible policies and practices lowers risk.[6]

S&P further highlighted specific policies which were important considerations when determining a regulated utility's credit rating, namely:

> We consider a regulatory approach that allows utilities the opportunity to consistently earn a reasonable return as a positive credit factor... We examine "regulatory lag" along with the record of earned returns to assess timeliness... In addition to the regulator's efficiency in completing rate cases, we consider the obsolescence of the costs on which rates are based, the timing of interim rates, and other practices... that affect a utility's ability to earn its authorized return.[7]

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[4] *See* Moody's Investors Service, Rating Action: Moody's upgrades Pinnacle West Capital and Arizona Public Service; outlooks are stable, June 2, 2015.

[5] *See* Arizona Public Service Co., A Subsidiary of Pinnacle West Capital Corp., Full Rating Report, June 29, 2015.

[6] *See* Standard & Poor's Ratings Services, RatingsDirect, Assessing U.S. Investor-Owned Utility Regulatory Environments, May 18, 2015, p. 2.

[7] *Id.* p. 3.

The factors emphasized here by the rating agencies have been evident in the changed regulatory framework adopted in the Company's last two rate cases, and those changes have directly led to a much-improved bond rating and lower financing costs for APS.

Q. DO CUSTOMERS RECEIVE ANY BENEFIT FROM HIGHER BOND RATINGS?

A. Absolutely. Higher credit ratings reflect the rating agencies' estimation of lower risk of full or partial default on the Company's debt and an overall assessment of lower financial stress on the Company. These assessments are used by creditors who provide funds to the Company – primarily in support of the Company's capital investment program – to gauge how high the interest rate on the loaned funds needs to be to fully compensate them for the risk of not recouping their investment. Lower risk leads to lower interest rates when the Company borrows money. These savings are returned to customers in each successive rate case.

As an example, in the 2010 Test Year for the Company's prior rate case, the cost of long-term debt averaged 6.38%. Five years later, the Company's average cost of long-term debt has moved down to 5.13% due to the inclusion of new long-term debt issuances and the refinancing of existing debt over the last five years at lower interest rates than the average of the debt existing at December 2010. On $3.729 billion of long-term debt, this change in interest rates equates to a Total Company savings of almost $50 million annually. Some of this savings has been generated from lower market interest rates in general and some from the ability to command a lower interest rate as the Company's debt ratings have improved.

IV. APS'S FINANCIAL CONDITION

Q. GIVEN THE SUBSTANTIAL BENEFITS OF THE SETTLEMENT AGREEMENT, WHY DO YOU NEED A RATE INCREASE NOW?

A. Simply put, because the regulatory mechanisms put in place in the Settlement Agreement were not designed to sustain APS forever. The post-Test Year Plant provision included in rates most of the capital projects that APS had placed in service as of March 30, 2012. However, it did not include $2.1 billion worth of plant investment, excluding the acquired portion of Four Corners, which is now serving customers. Nor did it include the additional $1.1 billion of new plant that will be in service by the anticipated July 1, 2017 rate effective date. In addition, the Lost Fixed Cost Recovery (LFCR) mechanism instituted with the Settlement Agreement is wholly insufficient in mitigating the revenue erosion resulting from the continued growth in EE and DG among APS's customers. The LFCR charge provides for only 30-40% recovery of the costs unrecovered due to EE and DG, which means the Company is facing a shortfall of approximately $113 million in revenue just from the amount of EE and DG added since the end of the last Test Year in 2010. *See* Mr. Snook's testimony for more information on the LFCR.

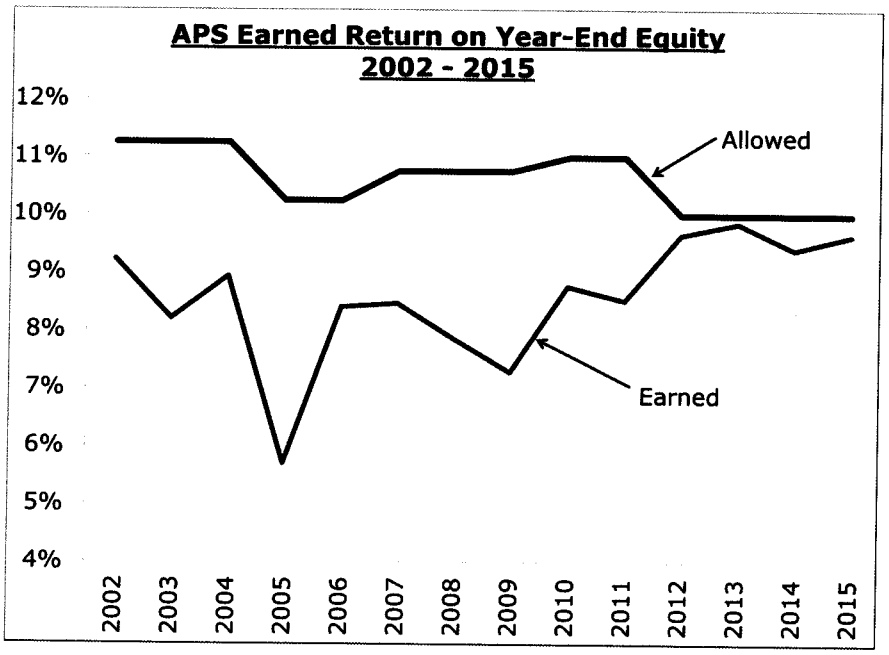
In fact, notwithstanding stringent cost management since 2010, the Company's actual earned ROE begins to sag in upcoming years and resembles the ROEs typical of pre-Settlement days. On a Total Company basis, APS expects to actually earn in 2016 an ROE of 9.1% on year-end equity, a number that falls to 8.4% by 2018. These returns fall off in the later years because of the material capital investments required in 2017 and beyond. Without rate relief, the returns in the latter years are at levels similar to or below what APS was experiencing before the last two rate case settlements.

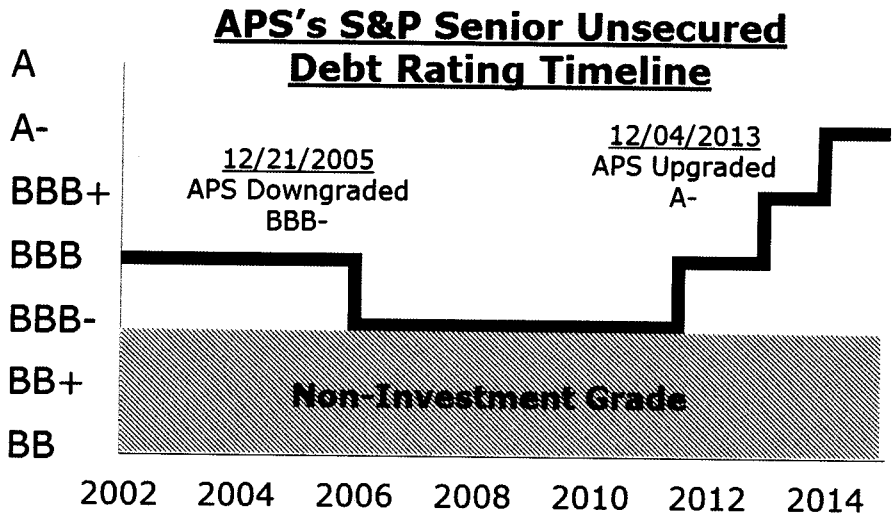
Q. SINCE THE COMPANY'S EARNED ROE IN THE TEST YEAR WAS SO CLOSE TO ITS ALLOWED ROE, SHOULDN'T THE COMPANY WAIT AT LEAST AN ADDITIONAL YEAR BEFORE FILING ITS CASE?

A. No. Even though the financial performance was reasonably strong in the Test Year, the trend in coming years, as I just described, deteriorates as the Company continues to invest in the business but is faced with low to no sales growth due to the high levels of future EE and DG adopted by customers. The earned ROE in 2016 and 2017 is expected to fall from the levels achieved in the Test Year by 50-60 basis points in the absence of new rates as proposed by the Company in this case. A delay in filing would lead to a sustained two-year period, at least, where the Company did not have a reasonable chance to earn its authorized return. Such an outcome would indeed catch the attention of the rating agencies and, depending on other factors surrounding the Company's financial condition, could prompt a re-evaluation of the current ratings. The Company expects to be raising over $1.7 billion through the issuance of long-term debt in the next four years to fund its elevated capital investment needs, so any reduction in the Company's credit rating would have a material financial impact on the Company's cost of capital, and by extension, its customers.

Furthermore, the Company's experience in the 2000s suggests that once a utility falls into an under-performing hole, it takes many years to climb out. APS entered the decade of the 2000s earning its allowed ROE or very close to it, but through a combination of a rate moratorium, significant fuel price increases, high capital expenditures driven by rapid growth and the resultant regulatory lag, the Company quickly found itself routinely earning ROEs approximately 200 basis points lower than those allowed in its rate cases. The degradation in financial performance resulted in a quick decline in the Company's credit ratings to BBB-, the lowest rating still considered investment grade, and rising financing costs for the Company and its customers. This weak financial condition was not restored to adequate financial health until the beginning of this decade

following the adoption of the two rate case settlements I have described previously. See the two charts below for a graphic depiction of APS's ratings history and APS's ROE during that same time.





Two rather important conclusions to be drawn from this episode are:

1. The improved regulatory framework adopted through the last two settlements has worked as intended by supporting a return to a constructive environment

2. Half-measures in the regulatory policy arena can have significant negative consequences from which it can take a long time to recover.

Q. WILL A ONE-TIME RATE INCREASE BE SUFFICIENT TO SUSTAIN THE COMPANY'S FINANCIAL CONDITION UNTIL THE NEXT RATE CASE?

A. No. As described by Mr. Snook, the Company is also seeking an accounting order to defer the costs upon completion of the Four Corners selective catalytic reduction (SCR) equipment and the Ocotillo Modernization Project (OMP) until those costs can be included in base rates. These projects combined represent almost $1 billion of capital investment and even with the improved pace of adjudicating recent APS rate cases, any regulatory lag on this level of investment has a significantly negative effect. For each year that these projects are in service but not included in rates, the Company will experience erosion of its earned ROE of between 80 and 120 basis points – per project. Because the in-service dates for these projects are so close to each other, the combined effect of both projects if not included in rates in 2019 would be materially negative. However, to avoid pancaked rate cases, the Company believes an accounting order allowing the deferral of all of the operating and carrying costs until the costs for these projects can be reviewed and accepted in a normal rate case would be adequate to support a more stable financial pattern for the Company. Furthermore, as Mr. Snook describes in his testimony, the Company is seeking approval to hold the current rate case open for the express purpose of including, following the appropriate Commission review of project costs, the SCR installations in base rates in early 2019. This step would

continue the process of rate gradualism for customers and maintain financial stability for the Company (which ultimately benefits customers, as well).

Q. CAN THE COMPANY ACHIEVE ITS FINANCIAL NEEDS THROUGH FURTHER COST CUTTING?

A. No. APS simply cannot cut enough costs to earn even close to its authorized rate of return without significantly sacrificing reliability and service quality. Since 2010, the Company's previous Test Year, the Company has held the line on cost growth to a remarkable degree. Over the last five years, the Company's Operations and Maintenance (O&M) Expenses have increased at an average annual rate of only 0.4% per year, a rate much lower than the 1.8% rate of general inflation over that same period. But despite these significant cost-management efforts, APS will still have an annual ACC-jurisdictional revenue requirement deficiency of $87 million in 2017, and $155 million in 2018.

To address this deficiency on the expense side rather than the revenue side would mean eliminating projects that are vital to APS's basic service obligations, projects such as those described by APS witnesses John Cadogan, John Lucas, and Jacob Tetlow. APS certainly would not want to risk sacrificing reliability in order to improve its financial condition, and is confident that that its customers or the Commission would want it to do so either.

V. KEY FORECASTED FINANCIAL RESULTS AND CONCLUSION

Q. PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING.

A. With respect to the Company's SFR schedules, my testimony covers the forecasted accounting statements and financial results. The Total Company data is the same type of information that is disclosed directly or indirectly in both the APS and the consolidated Pinnacle West audited financial statements, each of which are included in filings made with the SEC for historical years. The forecasted information periodically is supplied to investors and filed with the SEC.

Additionally, all of the accounting projections provided in my testimony follows 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 FERC Uniform System of Accounts, which this Commission has adopted. *See* AAC R14-2-212(G).

The Direct Testimony of APS witness Elizabeth Blankenship addresses the historical accounting statements and actual Test Year data used in the SFRs. Mr. Snook focuses on the jurisdictional allocation of APS revenues, costs and rate base items for the actual Test Year and all the pro forma adjustments.

A. *Summary Schedules*

Q. PLEASE DESCRIBE THE PROJECTED INFORMATION ON SFR SCHEDULES A-2 THRU A-5.

A. These summary schedules provide the "Summary Results of Operations," the "Summary Capital Structure," the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service," and the "Summary Changes in Financial Position" for the Test Year and the next three calendar years. These schedules also include historical information. I am sponsoring the forecasted data for the future calendar years. Ms. Blankenship is sponsoring the Test Year and historical information on these schedules.

As Line 13 of Schedule A-2 shows, if the Company's rate and accounting requests are granted effective July 1, 2017, Total Company ROE on end-of-year equity will be 9.7% at December 31, 2017 (a year in which new rates will have been in effect for only six months) and 9.8% in 2018.

B. *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 forecast data in this schedule. SFR Schedule D-2 presents supporting detail for the long-term debt summarized on SFR Schedule D-l. Again, I sponsor the projected data in this schedule. SFR Schedule D-3 addresses preferred stock. Although the Company did not have any outstanding preferred stock as of the end of the Test Year, it has included Schedule D-3 nonetheless for the sake of completeness. SFR Schedule D-4 addresses the Company's cost of common equity, and is sponsored by Ms. Blankenship.

C. *Projected Financial Information*

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULES F-1 THROUGH F-4.

A. SFR Schedule F-1 presents income statements for projected calendar years, and for actual Test Year results, at present and proposed rates. I sponsor the projected information contained on these schedules, while Ms. Blankenship sponsors the historical and actual Test Year information.

As I have previously indicated, Schedule F-1, like Schedule A-2, shows key information relating to the Company's actual and projected ROE. As Schedule F-1 shows, under APS's present rates, the Company's ROE on end-of-year equity falls from 9.7% at the end of the Test Year to 9.1% at year-end 2016, 9.0% in 2017, and to 8.4% in 2018 — well below any reasonable ROE required to maintain the financial health of APS and ensure access to capital necessary for a robust electric system. The Company's proposed rates and accounting adjustments would bring the Company's ROE to 9.7% in 2017 and 9.8% by year end 2018. As PME-2DR shows, the calculated ROE improves when considering only those items that fall within the Commission's regulatory jurisdiction, partly because the ACC-jurisdictional analysis removes all of the Company's below the line expenses.

SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years and the Test Year, at present and proposed rates. SFR Schedule F-3 presents projected annual construction requirements, by property classification, for three years subsequent to the Test Year. I sponsor the projected data on this schedule. Finally, SFR Schedule F-4 presents the key assumptions used in developing these projections.

VI. 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 reduce the base fuel rate from 3.21¢/kWh, authorized by the Commission in Decision No. 73183, to 2.99¢/kWh. This adjustment lowers the annual base rate revenue requirement by approximately $62 million (at Test Year sales levels). Of the total proposed adjustment, $20 million reflects costs that are already reflected in the Test Year and the remaining $42 million is for costs that are normalized to 2017 levels, the time when rates from this request are likely to take effect. Attachment PME-3DR shows the results of the proposed adjustment on Test Year expenses.

Q. WHAT FACTORS ARE BEHIND YOUR PROPOSED ADJUSTMENT?

A. The most dominant driver of changes in the Company's average fuel costs is a dramatic decline in natural gas prices and the associated decline in wholesale power prices. The current market price (as of February 29, 2016) for delivered natural gas in 2017 is $2.64/mmBtu, which reflects a 40% reduction from the $4.39/mmBtu price last used to establish the Base Fuel Rate. Additionally, costs for purchased capacity are lower due to the expiration of a long-term capacity contract, which is expected to be replaced by a summer-only and smaller capacity purchase. Partially offsetting these reductions is a change in the mix of resources being used to provide our customers' power needs. Relative to the prior calculation of the Base Fuel Rate, the share of production derived from purchases of renewable energy is increasing by 4.8% and the share provided by natural gas and conventional purchased power is higher by 11%. Both of these resources are displacing coal-based generation, and the net effect is an increase of $36 million in Total Company fuel expense. Other sources of increases in fuel expenses include the contractual escalation in coal prices and the increase in average renewables purchase costs.

Each of these factors represents changes in conditions since the last time the Company's base fuel rate was set (at 3.21¢/kWh). At that time, the Company relied on forward market expectations from September 2011 for the year 2012. The current estimates are based on February 2016 expectations for the year 2017.

Attachment PME-4DR shows the average fuel cost for the Company's major resource types embedded in the current authorized and proposed base fuel rates, and embedded in the average fuel cost in the Test Year.

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, 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, net of reductions due to continued expansion of EE and penetration of DG;
- Lower commodity market prices for natural gas and power;
- Expected benefits from APS's participation in the Energy Imbalance Market beginning in October 2016;
- Higher coal prices due to standard contract escalators;
- Higher nuclear prices largely offset by a refund of a spent fuel regulatory liability;
- Normalized maintenance and unplanned outage times;
- The expiration of a year-round capacity power contract and its replacement with a summer-only capacity contract;

- The installation of a new 40 MW grid-scale PV solar facility by early 2017;
- Other miscellaneous items, such as broker fees, third-party wheeling expenses, fixed natural gas transportation expense and other short- and long-term capacity costs.

For the Test Year ending December 31, 2015, the Company's actual average base fuel and purchased power expense, excluding the impact of the period's non-cash fuel cost deferrals, was 3.14¢/kWh. Attachment PME-4DR shows the components that make up this cost level.

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 four rate cases. Under that approach, the impacts of the adjustments I mentioned above were simulated 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 February 29, 2016 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 difference between the projected average cost and the average cost from the Company's Test Year is multiplied by the adjusted Test Year retail sales amounts to produce the appropriate adjustment for the Test Year pro forma. This calculation is shown on Attachment PME-3DR. Attachment PME-4DR shows the major components of the proposed base fuel rate of 2.99¢/kWh, the realized Test Year fuel costs of 3.14¢/kWh, and the current authorized level of 3.21¢/kWh. This

base fuel rate results in a decrease to Test Year fuel and purchased power costs of $41,625, 000 (see SFR Schedule C-2, page 2, column 6).

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 $168 million net of the value of the Company's hedge contracts. At the close of the market on February 29, 2016, delivered natural gas prices for calendar year 2017 averaged $2.64/mmBtu. These prices represent a 40% 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 PVNGS for calendar year 2017 averaged under $25/MWh on February 29, 2016, a 36% decrease from the level currently being recovered in base rates.

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 $24.55/MWh. In 2017, the average production cost is expected to be $27.29/MWh.

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 a couple of normalizing adjustments. First, there are differences in the capacity available to the Company under long term contracts in 2017 compared to the Test Year and the amounts included in the current authorized base fuel rate. A 10-year contract for 500 MW of tolled natural gas expires in mid-2017. Because this contract will not be available beyond 2017, the capacity has been removed from the normalized 2017 resource plan and the capacity payments have been removed from the estimation of the Base Fuel Cost. However, additional capacity will still be required to meet the Company's peak demand in 2017. The 2017 resource plan has been normalized to include 300 MW of summer-only capacity to replace the absence of the tolling agreement and the related (lower) capacity payments have been added to the Base Fuel Cost.

Second, the Company is constructing the Red Rock Solar Plant, a 40 MW grid-scale photovoltaic solar facility, which is planned to be on-line in early 2017. This facility will contribute both energy and some contribution to meeting the Company's peak demand which displaces more conventional resources. The Red Rock Solar Plant is one of the Company's capital investments included in the addition of post-Test Year Plant. This important investment is further described in the testimony of APS witness Scott Bordenkircher. The net effect of these capacity changes, when put on an average cost basis and applied to 2015 Test Year normalized sales, is a decrease of $34 million as can be seen in Attachment PME-1DR.

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. Consistent with past practice, the projected unplanned outage time for 2017 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.

VII. 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-5DR 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 SO2 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 3, column 7.

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 2017 and beyond. The combined pre-tax impact of these adjustments is a reduction to fuel expense of approximately $14.9 million as shown on Attachment PME-6DR and in SFR Schedule C-2, page 3, column 8.

VIII. PSA PLAN OF ADMINISTRATION MODIFICATIONS

Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO THE PSA POA IN THIS PROCEEDING?

A. Yes. The Company is proposing three modifications to the PSA POA:

1. Include the cost associated with environmental chemical costs, primarily lime, sulfur and ammonia, in the PSA.
2. Include the costs of water to supply our generation plants.
3. Include the costs of third-party electric storage (e.g., battery) contracts, if incurred.

Q. THE COMPANY IS REQUESTING TO INCLUDE ENVIRONMENTAL 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, activated carbon 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 SO2 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 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 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 almost $14 million in power production-related environmental chemical costs during the Test Year. The lion's share of this amount was for lime used at the Four Corners and Cholla coal-fired generating stations. Another $551,000 was incurred for sulfur at the coal plants. These amounts divided by the adjusted Test Year native load sales of 27,031 GWh yields an average Base Cost of Allowable Chemicals of 0.0500¢/kWh.

Q. THE COMPANY IS REQUESTING TO INCLUDE WATER COSTS IN THE PSA. PLEASE EXPLAIN.

A. The Company uses water to produce steam, which is used to produce power, at several of its generating plants, and this water consumption and the chemicals, chemical processes and purification processes used to treat the water vary directly with the amount of electricity being produced at the plants on an annual basis. As production from these power plants varies, so too does the amount of water and water-related

chemicals used. The Company therefore proposes that annual changes in the water-related purchase expense associated with power plant production be included in the calculation of the PSA deferrals and rate recovery.

Q. PLEASE EXPLAIN HOW THE WATER COSTS WILL RUN THROUGH THE PSA.

A. The Company is proposing that water costs be treated in the PSA in a similar fashion to how SO2 emission allowance sales margins are treated. The water-related 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 Water Cost. Upon approval in this proceeding, the Company will begin deferring any difference between the actual production-related water costs incurred each month and the amount recovered in base rates through the Base Water Cost. These differences can be positive or negative, and the deferrals will apply to the Company's 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 water costs and water 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 WATER COSTS?

A. The Company incurred more than $16 million in power production-related water costs during the Test Year. About half this amount, almost $8 million, was for water used at PVNGS. These amounts divided by the Test Year native load sales of 27,031 GWh yields an average Base Water Cost of 0.0606¢/kWh.

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL MODIFICATIONS TO THE PSA IN THIS PROCEEDING?

A. Yes. In addition to adding as allowable cost components in the PSA the FERC accounts in which production-related environmental chemical costs and water costs are recorded (Accounts 502, 519, and 549), the Company also proposes to add Account 550. To the extent that the Company may find an opportunity to contract with third-party suppliers of electric storage (e.g., batteries) in the near future, Account 550 is the FERC account in which those rent or capacity payments will likely be recorded. Modifying the PSA POA in this proceeding will enable the Company to seamlessly add such storage capacity costs to its PSA recovery if and when such transactions occur.

In addition to the modifications already mentioned, several small language adjustments have been made to the POA to provide greater clarity of subject matter and/or intent. A redlined PSA POA showing the proposed changes from the current version and a clean version of the PSA POA is included in the Standard Filing Requirement Information under "Redlined Plans of Administration" and "Plans of Administration."

IX. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS hopes to continue working with the Commission and other stakeholders to achieve a strong, sustainable energy future for Arizona. However, it is quickly losing the financial support provided by the Settlement Agreement that allows it to do so. To continue building a bright energy future, APS will need rate relief adequate to compensate it for the significant amount of capital that has been and will be invested in the business. APS additionally needs the support of the requested accounting orders and the step rate increase in 2019 to mitigate the effects of regulatory lag in between rate

cases from the completion of such large capital projects as the Four Corners SCRs and the OMP.

The Commission and other stakeholders in the last two rate case settlements found workable and creative solutions to help improve the Company's financial standing and that improvement has allowed APS to access the capital markets on more reasonable terms than in prior years. APS's customers have benefited from these developments. APS encourages the Commission to remain committed to maintaining a constructive regulatory framework that facilitates the required investment in Arizona's energy future on favorable terms for customers.

The marked decline in market prices for natural gas and wholesale power, partially offset by a changing composition of the Company's fuel sources, has modestly reduced the Company's cost of fuel, and it is appropriate to lower the Company's Base Fuel Cost to 2.9882¢/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 Cost.

Certain chemical costs (lime, sulfur, ammonia) at the power plants and water and water-related chemical consumption, particularly at PVNGS, vary directly with the generation of electricity and can therefore be volatile much like fuel costs. Differences between actual generation-related chemical and water expenses and the amounts in the Test Year should be recovered or refunded through the PSA. Base costs in the PSA POA should be updated to adjusted Test Year levels.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Summary of Base Fuel Cost Changes

	Current Authorized Level (2012 Conditions)	Proposed Proforma Level (2017 Conditions)	Proforma vs. Current Authorized
Base Fuel Cost (¢/kWh)	3.2071	2.9882	(0.2189)
Test Year Period Normalized Sales (GWh)	28,182	28,182	
Base Fuel Expense ($000,000)	903.8	842.1	**(61.7)**

Reasons for Change ($000,000)	
Prices for Hedged Natural Gas, Purchased Power	(168.3)
Capacity Costs	(33.8)
Higher Renewables, Natural Gas Share of Production	36.4
Coal Price	96.8
All Other Items	7.3
Total	**(61.7)**

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED INCOME STATEMENTS
WITH PROPOSED RATE INCREASE EFFECTIVE JULY 1, 2017
(Dollars in Thousands)

Line No.	Description	Projected Year - Total Company			Projected Year - ACC Jurisdiction			Line No.
		Year Ended 12/31/2016 (A)	Year Ended 12/31/2017 (B)	Year Ended 12/31/2018 (C)	Year Ended 12/31/2016 (D)	Year Ended 12/31/2017 (E)	Year Ended 12/31/2018 (F)	
1.	Electric operating revenues	$ 3,459,020	$ 3,621,913	$ 3,797,016	$ 3,418,130	$ 3,591,029	$ 3,767,624	1.
2.	Fuel and purchased power	1,033,688	999,589	1,011,177	1,288,323	1,283,702	1,325,791	2.
3.	Operating revenues less fuel and purchased power	2,425,332	2,622,324	2,785,839	2,129,807	2,307,327	2,441,833	3.
	Other Operating Expenses:							
4.	Operations and maintenance excluding fuel and purchased power *	938,487	950,306	970,117	873,319	867,519	885,247	4.
5.	Depreciations and Amortization	475,329	533,701	591,683	418,517	474,969	528,936	5.
6.	Income taxes	248,802	279,172	294,990	202,743	241,676	248,894	6.
7.	Other taxes	170,900	191,766	217,439	139,629	158,827	182,418	7.
8.	Operating income	591,814	667,379	711,610	495,599	564,335	596,339	8.
	Other Income (Deductions):							
9.	Income taxes	10,236	14,086	12,515	150	(427)	(574)	9.
10.	Allowance for equity funds used during construction	36,400	44,691	43,440	31,511	39,946	39,123	10.
11.	Other income	5,923	2,519	3,006	-	1,118	1,502	11.
12.	Other expenses	(17,200)	(23,824)	(20,364)	(389)	-	-	12.
13.	Total	35,359	37,472	38,597	31,271	40,637	40,051	13.
14.	Income Before Interest Deductions	627,173	704,851	750,207	526,870	604,972	636,390	14.
	Interest Deductions							
15.	Interest on long-term debt	198,110	221,097	241,440	166,002	185,427	202,023	15.
16.	Interest on short-term borrowings	4,588	5,928	5,756	3,845	4,973	4,818	16.
17.	Debt discount, premium and expense	4,836	5,086	5,376	4,054	4,306	4,570	17.
18.	Allowance for borrowed funds used during construction	(17,700)	(21,771)	(21,232)	(15,329)	(19,463)	(19,123)	18.
19.	Total	$ 189,834	$ 210,340	$ 231,340	$ 158,572	$ 175,242	$ 192,288	19.
20.	Net Income	$ 437,339	$ 494,511	$ 518,867	$ 368,298	$ 429,731	$ 444,101	20.
21.	Return on Average Common Equity	9.2%	10.0%	10.0%	9.3%	10.3%	10.2%	21.
22.	Average Common Equity	4,746,996	4,950,768	5,202,312	3,969,928	4,152,667	4,354,542	22.
22.	Return on Year End Common Equity	9.1%	9.7%	9.8%	9.1%	10.1%	10.0%	22.
23.	Year End Common Equity	4,814,739	5,086,797	5,317,826	4,048,541	4,256,794	4,452,290	23.

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Base Fuel and Purchased Power Costs
	Adjusted Test Year Fuel and Purchased Power Costs (¢/kWh):	
1.	Normalized 2017 Fuel and Purchased Power Costs	2.9882
2.	Test Year Fuel and Purchased Power Costs	3.1359
3.	Adjustment to Fuel and Purchased Power Costs	(0.1477)
	Adjusted Test Year Retail Sales (MWh):	
4.	Test Year Retail Sales	27,950,491
	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh):	
5.	To Adjust to Normal Weather	116,300
6.	To Annualize to December 31, 2015 Customer Level	115,621
7.	Adjusted Test Year Retail Sales (MWh) (Line 4 + Line 5 + Line 6)	28,182,412
8.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 3 * Line 7)	(41,625)
9.	Operating Income Before Income Tax	41,625
10.	Income Tax at 38.10% (Line 9 * 38.1%)	15,859
11.	Net Income (Line 9 - Line 10)	$ 25,766

Adjustment to Test Year operations to include 2017 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

Components of APS Base Fuel Rate
Actuals TME 12/31/2015

	Fuel Expense ($000)	Production (GWH)	Native Load Sales [1] (GWH)	Share of Production (%)	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [2]	77,620	9,464	8,522	31.5%	0.91	0.2872
Coal [3]	206,187	8,397	7,561	28.0%	2.73	0.7628
Natural Gas [4]	222,526	7,736	6,966	25.8%	3.19	0.8232
Purchased Power [5]	172,312	2,100	1,891	7.0%	9.11	0.6375
Renewable [6, 7]	131,037	2,323	2,091	7.7%	6.27	0.4848
Fixed Gas Transport and Fuel Handling	76,382	-	-	0.0%		0.2826
Total Native Load	886,063	30,019	27,031	100.0%		3.2780
Off System Margin Credit to Retail	(38,414)		27,031			(0.1421)
Net Retail Fuel Cost	847,649		27,031			**3.1359**

1 - Excludes sales to E-36XL customers, AG-1 customers, and City of Williams (CoW)
2 - Excludes fixed ISFSI expense
3 - Excludes coal reclamation costs
4 - Includes fuel costs associated with long-term tolling arrangements
5 - Includes native load hedge liquidation costs and excludes purchases for AG-1 customers
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 2/29/16 Market Prices

	Fuel Expense ($000)	Production (GWH)	Native Load Sales [1] (GWH)	Share of Production %	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [2]	70,423	9,290	8,682	30%	0.81	0.2466
Coal [3]	226,444	8,297	7,755	27%	2.92	0.7928
Natural Gas [4]	192,238	9,343	8,732	31%	2.20	0.6731
Purchased Power [5, 6]	130,251	837	782	3%	16.65	0.4560
Renewable [7, 8]	164,610	2,792	2,609	9%	6.31	0.5763
Fixed Gas Transport and Fuel Handling	86,220	-	-	0%		0.3019
Total	870,187	30,560	28,561	100%		3.0468
Off System Margin Credit	(16,727)		28,561			(0.0586)
Net Retail Fuel Cost	853,460		28,561			**2.9882**

Native Load Sales	
Retail Sales	28,561
Sales for Resale	-
Pacificorp Supplemental Sales	-
Total Native Load Sales	28,561

1 - Excludes sales to City of Williams (CoW)
2 - Excludes fixed ISFSI expense
3 - Excludes coal reclamation costs
4 - Includes fuel costs associated with long-term tolling arrangements
5 - Includes native load hedge liquidation costs
6 - Includes fixed capacity contract costs
7 - Excludes costs for above market purchase premiums which are recovered through RES
8 - Includes generation associated with company owned facilities

Components of APS Base Fuel Rate
Current Authorized Rates From 2012 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]	79,784	9,264	8,642	30%	0.92	0.2814
Coal [2]	243,737	12,521	11,681	41%	2.09	0.8596
Natural Gas [3]	273,386	5,547	5,175	18%	5.28	0.9641
Purchased Power [4, 5]	179,430	1,566	1,461	5%	12.28	0.6328
Renewable [6, 7]	71,171	1,497	1,396	5%	5.10	0.2510
Fixed Gas Transport and Fuel Handling	77,128	-	-	0%		0.2720
Total Native Load	924,636	30,394	28,355	100%		3.2609
Off System Margin Credit	(15,266)		28,355			(0.0538)
Net Retail Fuel Cost	909,370		28,355			**3.2071**

Native Load Sales

Billed Retail Sales	28,008
Traditional Sales for Resale	244
Pacificorp Supplemental Sales	103
Total Native Load Sales	28,355

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
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Test Year PSA Revenue & Deferred Fuel Amortization
	Revenues	
1.	Remove Test Year PSA Billed & Unbilled Revenue	$ (1,554)
	Expenses	
2.	Remove Test Year PSA Fuel Expense Deferral Amortization	(1,579)
3.	Operating Revenues less Fuel and Purchased Power Costs (Line 1 - Line 2)	25
	Operations & Maintenance	
4.	Remove Test Year PSA SO2 Margin Deferral Amortization	(25)
5.	Operating Income Before Income Tax (Line 3 - Line 4)	50
6.	Income Tax at 38.10% (Line 5 * 38.1%)	19
7.	Net Income (Line 5 - Line 6)	$ 31

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.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals
	Fuel and Purchased Power Cost	
1.	Remove Current Period Retail PSA Fuel Expense Deferral	$ (14,899)
2.	Remove Deferred Mark to Market on Native Load Hedge	(44,106)
3.	Total Test Year PSA Fuel Expense Deferral (Line 1 + Line 2)	(59,005)
4.	Remove Non-cash Hedge-Related MTM Accruals	44,106
5.	Pro Forma Adjustment to Fuel & Purchased Power Costs (Line 3 + Line 4)	(14,899)
6.	Operating Income Before Income Tax	14,899
7.	Income Tax at 38.10% (Line 6 * 38.1%)	5,677
8.	Operating Income After Tax	$ 9,222

Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and non-cash mark-to-market accruals.

DIRECT TESTIMONY OF BENTE VILLADSEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF BENTE VILLADSEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Bente Villadsen and my business address is The Brattle Group, 44 Brattle Street, Cambridge, Massachusetts 02138, USA.

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

A. I have been asked by Arizona Public Service Company (APS or Company) to determine and present APS's cost of equity and recommend the return on equity that should be included in its rates. I have also been asked to discuss how decoupling affect the cost of equity. Finally, my testimony offers an opinion on the fair value of APS's rate base and an appropriate fair value rate of return.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. I am a principal of The Brattle Group and have more than 15 years of experience working with regulated utilities on cost of capital and related matters. My practice focuses on cost of capital, regulatory finance and accounting issues. I have testified or filed expert reports on cost of capital in Alaska, Alberta, Arizona, California, New Mexico, Oregon as well as before the Bonneville Power Administration and the Surface Transportation Board. I have provided white papers on cost of capital to the British Columbia Utilities Commission and the Canadian Transportation Agency as well as to European and Australian regulators on cost of capital. I have testified or filed testimony on regulatory accounting issues before the Federal Energy Regulatory Commission (FERC), the Michigan Public Service Commission as well as in international and U.S. arbitrations and regularly advice utilities on regulatory matters as well as risk

management. I have previously testified on cost of capital before the Arizona Corporation Commission (Commission or ACC). I hold a Ph.D. from Yale University and a BS/MS from University of Aarhus, Denmark. Appendix A contains more information on my professional qualifications as well as a list of my prior testimonies.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. To determine APS's cost of equity I selected a relevant sample of integrated electric utilities that are subject to regulation as well as a utility sample, whose assets are similar to those of APS. I calculated the cost of equity for the sample using standard Capital Asset Pricing Models (CAPM), Discounted Cash Flow (DCF) models and a risk premium model. Having estimated the cost of equity for the sample, I then considered specific risks of APS to derive a range of cost of equity estimates for the Company. I concluded that a range of reasonable return on equity (ROE) estimates are as indicated below:

Return on Equity

	Reasonable Range for Proxy Group
CAPM-based Methods	10.0% - 10.5%
DCF-based Methods	9.9% - 10.8%
Risk Premium Method	10.3%

I conclude that APS should be in the upper half of the range because, among other things, of its significant portfolio of nuclear generation. I also note that APS has been unable to earn its allowed ROE since 2002.

For these reasons and because APS's revised rates are expected to be in effect beginning in 2017, I believe that APS should be placed in the upper end of the range and recommend that a ROE of 10.5% is appropriate for setting rates in this case.

As I mentioned, in my testimony I also discuss the relationship between decoupling of rates and cost of capital. The majority of the utilities in my sample have a decoupling mechanism in place, consequently, the impact, if any, of decoupled rates would already be captured and reflected in the cost of equity ranges that I have provided. Further, additional research has shown that decoupling does not measurably impact the cost of capital. Therefore, I conclude that decoupling does not affect the cost of equity.

Finally, I discuss the fair value rate base for APS and the return hereon. I find that the fair value rate base claimed by APS, which is the average of original and reconstruction cost new is a reasonable if conservative estimation of fair value in the economic sense. Further, a FVROR on the incremental rate base (Fair Value Increment) of up 6.04% (calculated as the inflation adjusted ROR) would be reasonable, as would applying the weighted cost of capital of 8.13% to the entire FVRB. Thus, the Company's request of a return on the Fair Value Increment of 1%, as well as an overall FVROR of 5.84% is conservative.

II. APPROACH TO ESTIMATING THE COST OF CAPITAL

A. *Preliminary Comments*

Q. WHAT ARE THE GUIDING PRINCIPLES FOR DETERMINING A JUST AND REASONABLE RATE OF RETURN ON UTILITY INVESTMENTS?

A. Fortunately, there has been a lot of guidance provided on this topic over the years. Perhaps the seminal guidance was provided by the U.S. Supreme Court in the Hope and Bluefield cases, which found that:[1]

[1] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) (Bluefield), and *Federal Power Com'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (Hope).

1. The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;[2]
2. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility; and
3. The return should be adequate, under efficient and economical management for the utility to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[3]

Q. PLEASE DESCRIBE HOW YOU CONDUCTED YOUR COST OF EQUITY ANALYSIS.

A. I selected a sample of regulated electric utilities that are comparable to APS, estimated the return that investors required to provide capital for those utilities and reviewed the return on equity authorized in other jurisdictions. I also reviewed the specific risks for APS including business, financial, and regulatory risk.

In order to provide additional support for my recommendation, I undertake several analyses. Specifically, I use the CAPM, DCF and Risk Premium analyses; all of which are widely used in the utility and ratemaking setting. The wisdom of employing multiple methodologies has been acknowledged by the Commission in prior decisions.[4]

To arrive at my final ROE recommendation, I considered (i) the ranges of my cost of equity numbers, (ii) the current economic outlook, (iii) the financial risk differences, (iv) the business risks of APS relative to that of the benchmark samples, (v) the regulatory environment in which APS operates. Based upon my analyses of those

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[2] *Hope.*
[3] *Bluefield.*
[4] For example, Decision 71914, p. 34.

factors, I determined that a reasonable range of ROE was between 10.25% and 10.75% and concluded that a recommended ROE of 10.5% was appropriate.

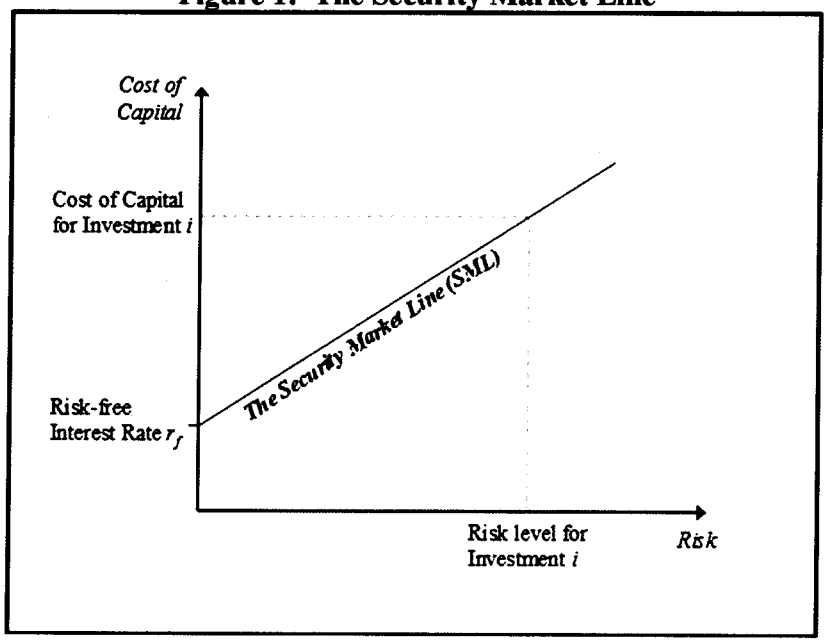
1. Cost of Capital and Risk

Q. HOW IS THE "COST OF CAPITAL" DEFINED?

A. The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line" or "Security Market Line" for short. This line is depicted in Figure 1 below. The higher the risk, the higher the cost of capital required.

Figure 1: The Security Market Line



Q. WHY IS THE COST OF CAPITAL RELEVANT IN RATE REGULATION?

A. The "cost of capital" is the return that investors expect to earn on investments of comparable risk[5] and is one of the relevant factors set forth in the Hope and Bluefield cases.

Q. WHAT DOES THIS MEAN FROM AN ECONOMIC PERSPECTIVE?

A. From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. A utility's ability to attract capital and maintain its financial integrity requires that the combined equity return and equity ratio be such that not only is the expected return commensurate with that of other enterprises, but it also meets the expectations of credit market participants.

[5] *See also* Stewart C. Myers, "The Application of Finance Theory to Public Utility Rate Cases," *The Bell Journal of Economics & Management Science* 3:58-97 (1972).

More important for customers, however, are the broader economic consequences of providing an inadequate return to the company's investors. In the short run, deviations from the expected rate of return on the rate base from the cost of capital may seemingly create a "zero-sum game"—investors gain if customers are overcharged, and customers gain if investors are shortchanged. In the longer term, inadequate returns are likely to cost customers—and society generally—far more than may be saved in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. Without access to investor capital, the company may be forced to forgo opportunities to maintain, upgrade, and expand its systems and facilities in ways that decrease long run costs. Indeed, the cost to consumers of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. This is especially true in capital-intensive industries (such as the electric and gas utility industry), which feature systems that take a time to decay. Such long-lived infrastructure assets cannot be repaired or replaced overnight, because of the time necessary to plan and construct the facilities. Thus, it is in customers' interest not only to make sure the expected return of the investors does not exceed the cost of capital, but also that the expected return does not fall short of the cost of capital.

2. The Impact of Risk on the Cost of Capital

Q. PLEASE SUMMARIZE HOW YOU FACTORED RISK WHEN DETERMINING THE COST OF CAPITAL.

A. I analyzed the difference in leverage among the sample utilities and the benchmark equity percentage of APS. To determine where in the estimated range APS's ROE reasonably falls, I compared the business risk of APS relative to the sample utilities and also the capital markets.

Q. WHY IS CAPITAL STRUCTURE IMPORTANT FOR THE DETERMINATION OF THE COST OF EQUITY?

A. Shareholders in a company with more debt face more equity risk and therefore the return on equity needs to be greater.[6] There are several manners in which the impact of financial risk can be taken into account in an analysis of cost of equity. One way is to determine the after-tax weighted-average cost of capital for the entities and let that figure be constant between the estimate obtained for the sample and the entity to which it is applied. This assumes that the after-tax weighted-average cost of capital is constant for a range that spans the capital structures used to estimate the cost of equity and the regulatory capital structure. A second approach was developed by Professor Hamada, who unlevered the beta estimates in the CAPM to obtain a so-called all-equity or assets beta and then re-levered the beta to determine the beta associated with the target regulatory capital structure. This requires an estimate of the systematic risk associated with debt (i.e., the debt beta), which is usually quite small. In Appendix B, I set forth additional technical details related to methods to account for financial risk when estimating the cost of capital.

Q. PLEASE IDENTIFY THE APS OR ARIZONA-SPECIFIC RISK FACTORS.

A. First, APS's generation capacity includes 27% nuclear, which is substantially higher than the average among my sample companies (about 13%).[7] The magnitude and composition of generating facilities matter because capital-intensive investments increase the fixed cost component and hence the operating leverage of a company.[8] Nuclear generation not only has very large fixed costs, but also large operating risks and

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[6] Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," *The Journal of Finance* 24: 13-31 (March 1969).

[7] *See* Figure 4 below for details.

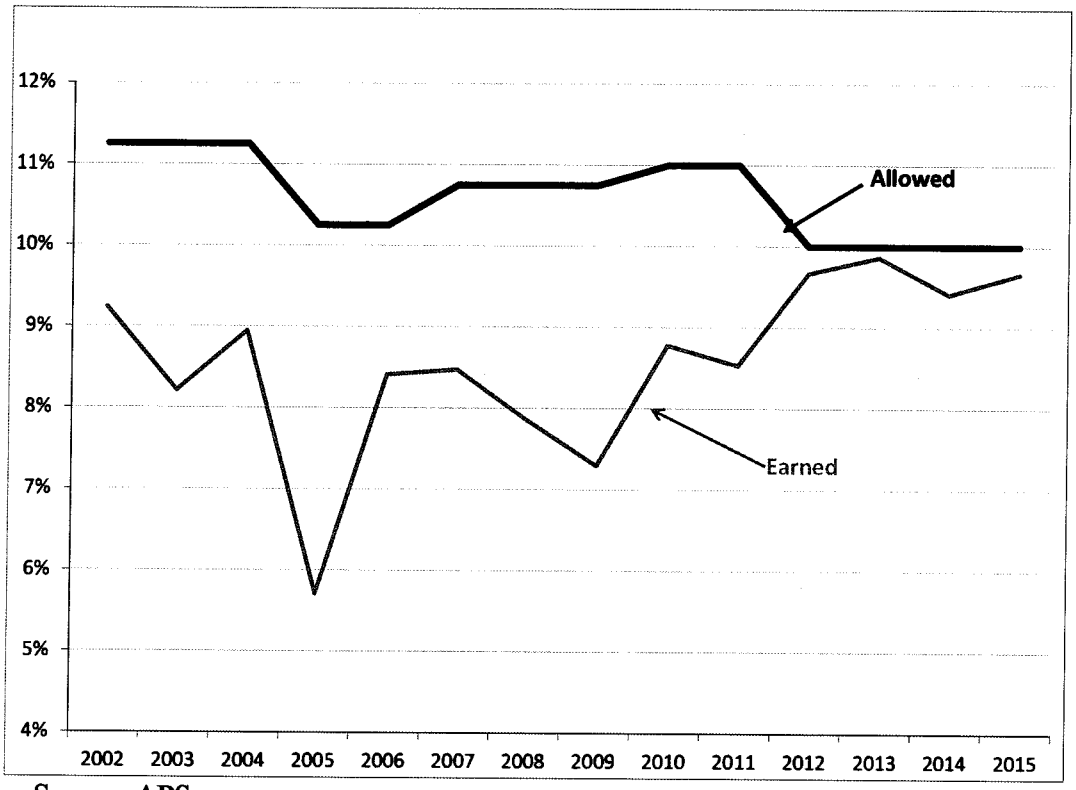
[8] For an exposition of this, *see* Richard A. Brealey, Stewart C. Myers, and Franklin Allen, "*Principles of Corporate Finance*," 11th Edition, 2014 (Brealey, Myers & Allen 2014), pp. 227-228.

APS is the operator of the largest nuclear generating facility in the country, Palo Verde units 1, 2 and 3. Second, APS has not earned its allowed ROE since 2002 and the earned ROE has been substantially below the allowed ROE during several years. This is illustrated in Figure 2 below (*see* Attachment BV-2DR). Third, the majority of the publicly traded electric utilities in the U.S. are larger than APS. The average market capitalization and annual revenue of my sample companies are twice that of Pinnacle West Capital Corporation (Pinnacle West), the parent of APS.[9] Empirical studies have shown that investors require a higher premium to invest in smaller companies than in larger ones. The single-jurisdiction, comparatively smaller size of Pinnacle West means that the Company has less diversification and hence has a more concentrated risk exposure to, for example, adverse local conditions. Finally, I note that decoupling mechanisms are available to the majority of companies in my sample as well as in the majority of U.S. states. Also, decoupling has been shown to have no detectable impact on the return on equity.[10] Therefore, should the Commission in the future implement a decoupling mechanism, it should not affect the ROE.

[9] APS represents a very large proportion of the revenue, income, assets and equity comprising the Pinnacle West Corporation according to Pinnacle West's 2014 Annual Report's income statements and balance sheets for the corporation and the utility. Figure 8 summarizes the size and other facts about the sample companies and APS.

[10] Joe Wharton & Michael J. Vilbert, "Decoupling and the Cost of Capital," *The Electricity Journal*, vol. 28, 2015, pp. 19-28.

Figure 2: APS Earned and Allowed ROE: 2002-2015



Source: APS.

I note that APS obtained an A2 rating from Moody's in June 2015 following an upgrade to A3 in January 2014,[11] while Standard & Poor's upgraded APS to A- in December 2013.[12] The improved rating, which lowers debt costs, coincides with the closing of the gap between the allowed and earned ROE. I note that the financial improvements coincide with regulatory initiatives, so that (ignoring the height of the financial crisis in 2008-09), APS's financial performance has improved after the upgrade of the regulatory environment in Arizona to Average / 3 by Regulatory Research Associates[13] and further with the approval of several rate mechanisms from 2012 onwards that aim to recover

[11] Moody's, "Moody's upgrades Pinnacle West Capital and Arizona Public Service; outlooks are stable," June 2, 2015 and https://www.moodys.com/credit-ratings/Arizona-Public-Service-Company-credit-rating-62000.

[12] Standard & Poor's.

[13] SNL, "Commissions," Reviewed March 5, 2016.

costs more quickly.[14] It is important to continue these efforts to ensure the utility and customers have access to debt capital at relatively low cost.

Q. HOW DID YOU FACTOR THE ADDITIONAL CAPITAL MARKET INFORMATION INTO YOUR ANALYSIS?

A. The return that investors require to provide equity capital depends not only on the relative risk of the investment being considered but also on the return generally available in the market for investments with comparable risk. Therefore, I felt that it was essential to consider prevailing conditions and trends in financial markets when determining inputs to the models used to estimate the cost of equity and when evaluating the reasonableness of the estimates.

III. IMPACT OF THE ECONOMY AND MARKETS ON THE COST OF EQUITY

A. *Interest Rates*

Q. WHAT ARE THE RELEVANT DEVELOPMENTS REGARDING INTEREST RATES?

A. Recent interest rates and especially government bond yields have been low. However, the spread between utility bond yields and government bond yields of the same maturity is higher than they have been historically; both when measured over the long run and more recently.

Figure 3 below shows the development in BBB rated utility and Government bond yields from 1999 to today.[15] It is evident that the yield spread (the difference between

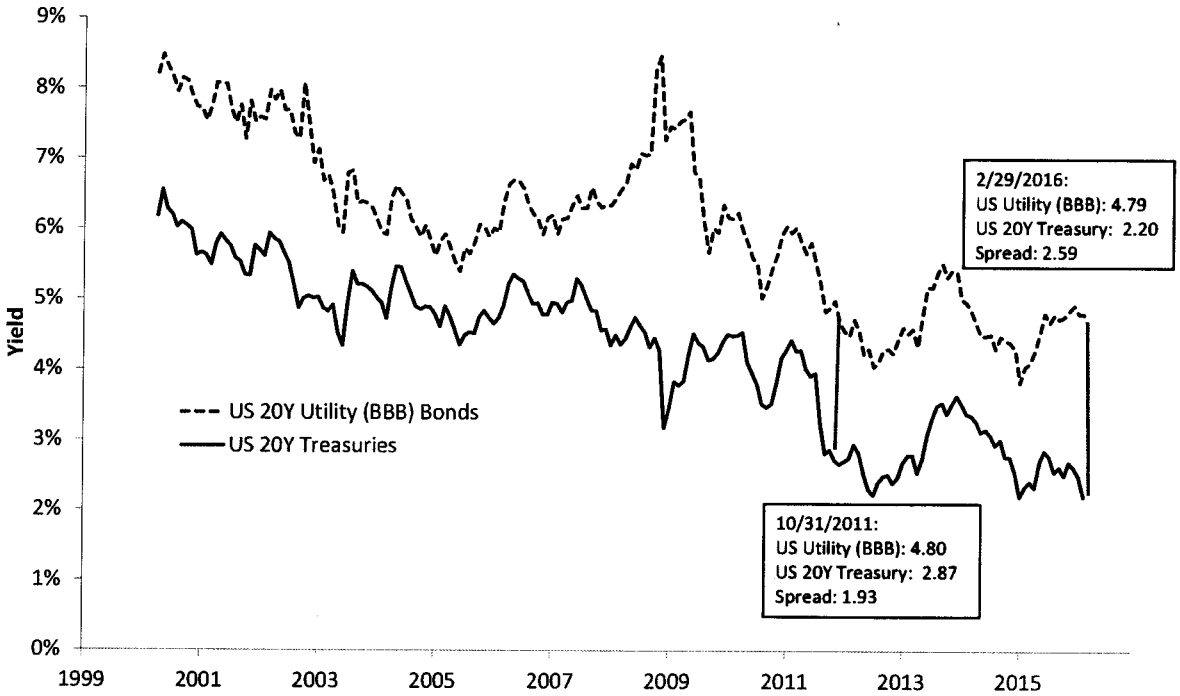
[14] *Ibid.* For example, a Lost Fixed Cost Recovery mechanism was initially approved in 2012 and effective beginning in 2015 a Four Corners Adjustment rider that will allow APS to recover costs associated with APS share in Four Corners.

[15] For clarity "BBB rated" refer to bonds in the range of BBB- through BBB+ and "A rated" reference bonds in the range of A- through A+. The majority of electric utilities are low A or high BBB rated.

the yield on BBB rated utility bonds and government bonds) has increased both relative to its historical average and relative to the Company's most recent rate case filing (Docket No. E-01345A-11-0224).

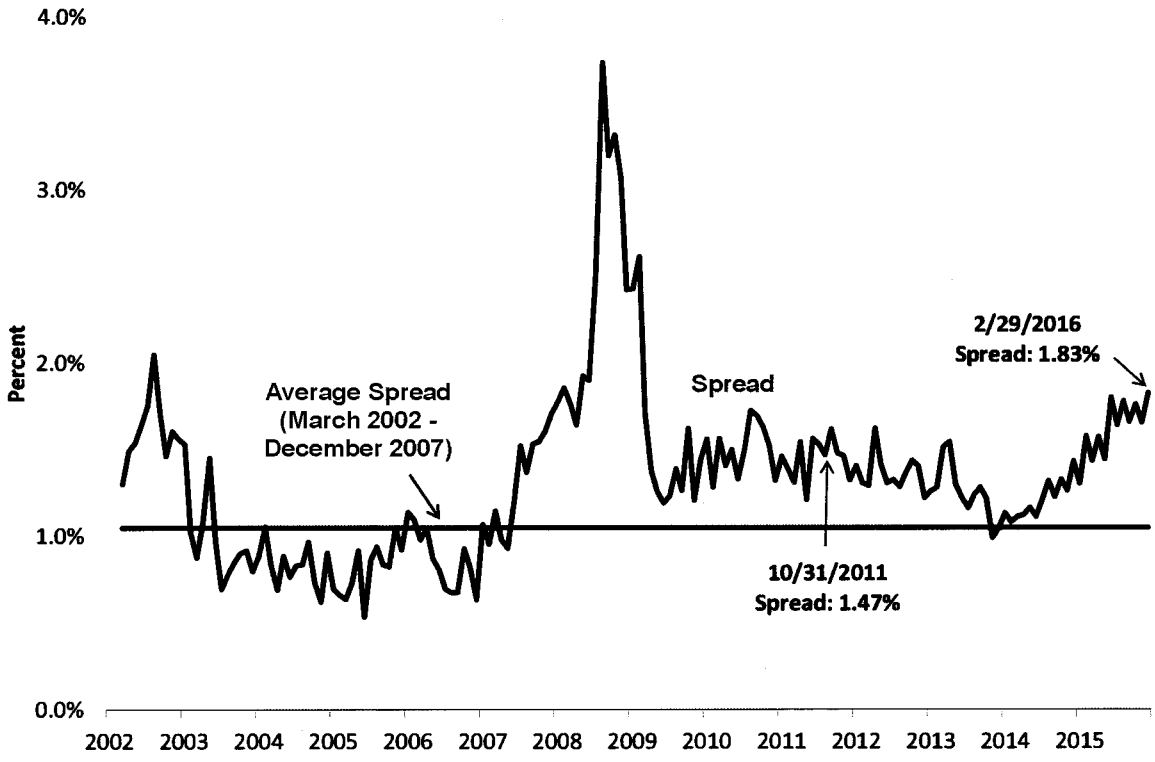
Figure 4 shows the spread between A rated utility bonds and government bond yields along with the average spread prior to the financial crisis. Again, it is evident that the spread is greater. Thus, a review of both BBB rated and A rated bonds clearly illustrates the increase in the spread between the utility bond yield and government bond yields.

Figure 3: BBB Utility and Government Bond Yields



Source: Bloomberg

Figure 4: Spread between A Rated Utility and 20-Year Government Bond Yield



Source: Bloomberg.

Q. HOW DOES THE CURRENT SPREAD BETWEEN UTILITY AND GOVERNMENT BOND YIELDS COMPARE TO THE HISTORICAL SPREAD?

A. As shown in Figure 3 and Figure 4 above, the spread between BBB rated utility bond yields or between A rated utility bond yields and government bond yields has grown. At the end of February, 2016 the BBB spread stood at 2.56%, which is approximately 136 basis points higher than prior to the 2008-09 financial crisis. At the same time the A rated utility bond yield was 1.83% for an increase of about 90 basis points over the pre-crisis level. Not only is the yield spread increased relative to its pre-crisis levels, but it is also greater relative to the level in the more recent past as illustrated in the figures above. (*see* Attachment BV-3DR)

Q. HOW ARE INTEREST RATES EXPECTED TO TREND GOING FORWARD?

A. Blue Chip Economic Indicators expects that the yield on 10-year Treasury Notes will increase by about 120 basis points by 2017 and the publication forecasts addition increases for 2018 and beyond.[16] Comparably, Consensus Forecast expect the 10-year yield to increase by 130 basis points by 2017 and by an additional 50 basis point by 2019, while the Congressional Budget Office predicts an increase of approximately 200 basis points over the coming years.[17] These expectations are consistent with the current downward pressure on Government bond yields, which has largely been caused by the Federal Reserve's quantitative easing program and general stimuli of the U.S. economy.[18]

Q. HOW DO THESE DEVELOPMENTS IMPACT THE COST OF EQUITY ANALYSIS?

A. There are several ways in which the current interest rate environment affects the cost of equity analysis. First and most directly, the CAPM utilizes as one of its inputs a measure of the risk-free rate (*see* Figure 1). I used the yield on a US government bond as a proxy for the risk-free rate. The estimated cost of equity using the CAPM increases (decreases) by 1% when the relied upon risk-free rate (e.g., the government bond rate) increases (decreases) by 1%. Therefore, to the extent that the government bond rate is driven by monetary policy rather than market factors, so is the CAPM estimate. Importantly, if the government bond rate is downward (upward) biased, then the CAPM estimate will be downward (upward) biased. When that is the case, it is necessary to normalize the relied upon government bond rate, so that the resulting CAPM estimate reflects a non-biased government bond rate.

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[16] Blue Chip Economic Indicators, January 2016 and October, 2015.

[17] Consensus Forecasts, October 2015. Congressional Budget Office, "The Budget and Economic Outlook: 2015-2025," January 2015, p. 53.

[18] For a summary of the magnitude of the Federal Reserve's purchase program, see, for example, Bloomberg, "The Fed Eases Off," September 16, 2015.

Second and as a further indication of a potential bias, if the spread between the yield on utility (or corporate) bonds and government bonds (the "yield spread") widens, it indicates that the premium that investors require for holding securities other than government bonds has increased. Thus, there is evidence that the market equity risk premium has increased. A higher than normal yield spread is one indication of the higher risk premiums currently prevailing in capital markets. Investors consider a risk-return tradeoff (like the one displayed in Figure 1 above) and select investments based upon the desired level of risk. Higher yield spreads reflect the fact that the return on corporate debt is higher relative to government bond yields than is normally the case, even for regulated utilities. Because equity is more risky than debt, this means that the spread between the cost of equity and government bond yields must also be higher; i.e., the premium required to hold equity (the Market Risk Premium or MRP) rather than government bonds has increased. If this fact is not recognized, then the traditional cost of capital estimation models will underestimate the cost of capital prevailing in the capital markets.

Third, in times of economic uncertainty (such as the present) investors seek to reduce their exposure to market risk. This precipitates a so-called "flight to safety," wherein demand for low-risk government bonds rises at the expense of demand for stocks. If yields on bonds are extraordinarily low, however, any investor seeking a higher expected return must choose alternative investments such as stocks, real estate, gold or collectibles. Of course, all of these investments are riskier than government bonds, and investors demand a risk premium (perhaps an especially high one in times of economic uncertainty) for investing in them. But short of accepting meager returns, investors simply have few alternatives to returning to the stock market. Utility stocks may have experienced the "flight to safety" phenomenon to a larger degree than other stock because they traditionally have paid a substantial portion of their earnings as dividends.

Therefore, investors who have sought income from their investments and found government bonds too unattractive may have accepted a higher risk and invested in utility stock with the goal of receiving periodic dividend payments.

One possible explanation of the current elevated level of the yield spread is that current and near-term expected levels of government bond yields are artificially depressed due to monetary policy.[19] I emphasize that the U.S. government bond yields (as well as that of many other western countries) is expected to increase substantially over the next several years.[20]

Q. WHAT ARE THE IMPLICATIONS OF ELEVATED YIELD SPREADS TO THE COST OF EQUITY?

A. The increase in the yield spread indicates that (i) the current long-term government bond yields are depressed relative to their normal levels; and/or (ii) investors are demanding a premium higher than the historical premium to hold securities that are not risk free. The latter is an indication that the market equity risk premium may be elevated relative to its historical level. Regardless of the interpretation, the consequence is that if cost of equity is estimated using the current risk-free rate and a market equity risk premium based on historical data, then it will be downward biased. Hence, it is necessary to "normalize" the risk-free rate, take into account the current (rather than historical) market equity risk premium, or a combination of these two interpretations.[21]

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[19] As of year-end 2014, the Federal Reserve held approximately $1.8 trillion of mortgage-backed securities, whereas the magnitude was less than $0.5 trillion in mid-2009. Source: Bloomberg, "The Fed Eases Off," September 16, 2015.

[20] If investors' believe the yield on government bonds will soon elevate, they may demand higher yields on corporate debt relative to the prevailing government bond yields, thus widening the yield spread.

[21] I note that if a combination interpretation is used, it becomes important to make sure that the overall (total) "normalization" takes into account the elevated yield spread once and only once.

B. *Market Volatility*

Q. HOW DID YOU FACTOR THE STOCK MARKET'S VOLATILITY INTO YOUR ANALYSIS?

A. Academic research has found that investors expect a higher risk premium during more volatile periods. The higher the risk premium, the higher the required return on equity. For example, French, Schwert & Stambaugh (1987) found a positive relationship between the expected market risk premium (MRP) and volatility:

> We find evidence that the expected market risk premium (the expected return on a stock portfolio minus the Treasury bill yield) is positively related to the predictable volatility of stock returns. There is also evidence that unexpected stock returns are negatively related to the unexpected change in the volatility of stock returns. This negative relation provides indirect evidence of a positive relation between expected risk premiums and volatility.[22]

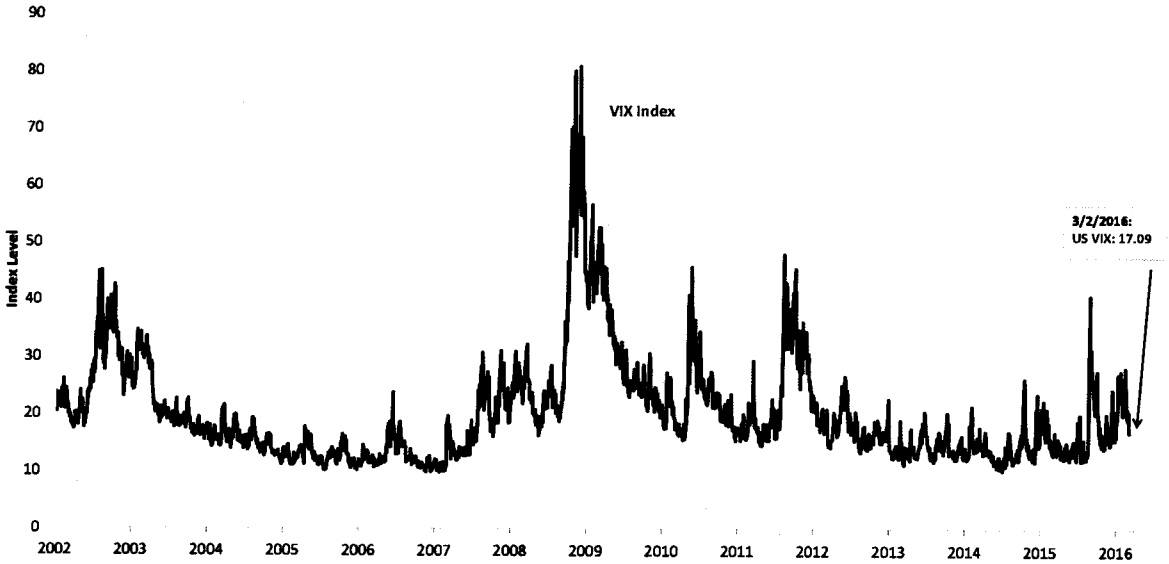
One implication of this finding is that the MRP tends to increase when market volatility is high, even when investors' level of risk aversion remains unchanged.

A measure of the market's expectations for volatility is the VIX index, which measures the 30-day implied volatility of the S&P 500 index. These indices are also referenced as the "investor fear gauge." While the long-term average for the VIX is about 20, the current level is elevated and was above 28 on February 11, 2016.[23] During the more recent period, the VIX spiked in August at about 40. Thus, the market volatility has higher in the early part of 2016 than it has been in recent periods. (*See* Attachment BV-4DR.)

[22] K. French, W. Schwert and R. Stambaugh (1987), "Expected Stock Returns and Volatility," *Journal of Financial Economics*, Vol. 19, p. 3.

[23] Yahoo Finance. It has since declined.

Figure 5: Volatility Index



Source: Bloomberg.

Q. WHAT DO YOU MEAN BY THE TERM "RISK AVERSION?"

A. Risk aversion is the recognition that investors dislike risk, which means that for any given level of risk, investors must expect to earn an appropriate return to be induced to invest. An increase in risk aversion means that investors now require a higher return for that same level of risk.

Q. DO YOU HAVE ANY EVIDENCE THAT THE RETURN PREMIUM DEMANDED BY INVESTORS FOR TAKING RISK IS HIGHER THAN IT WAS PRIOR TO THE 2008-09 FINANCIAL CRISIS?

A. Yes. Looking to forecasted MRPs, both academic research and financial data services such as Bloomberg have found an increase in the expected MRP compared to prior to the financial crisis. Not only did the expected MRP increase but it remains above the historical level. For example, Bloomberg's expected MRP exceeds the historical

average MRP and currently stands at about 8%, while the historical arithmetic average MRP from 1926 to 2014 is 7%.[24]

Q. HAS THE MRP INCREASED SINCE THE 2008-09 FINANCIAL CRISIS?

A. Yes. A recently updated analysis by Duarte and Rosa of the Federal Reserve of New York aggregates the results of many models of the required MRP in the U.S. and tracks them over time. This analysis finds a very high MRP in recent years.

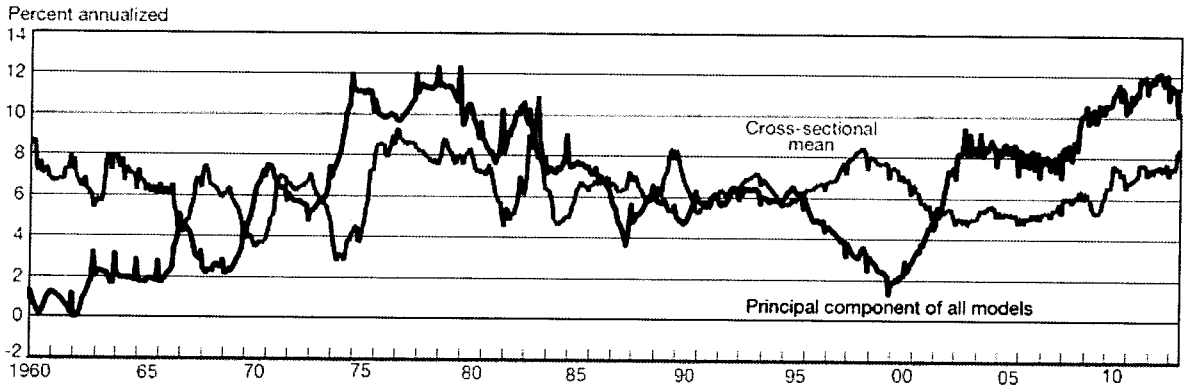
The analysis estimates the MRP that results from a range of models each year from 1960 through the present.[25] The analysis then reports the average as well as the first principal component of results.[26] The analysis then finds that the models used to determine the risk premium are converging to provide more comparable estimates and that the average annual estimate of the MRP was at an all-time high in 2013. These estimates are reasonably consistent with those obtained from Bloomberg and the consistent elevation of the MRP over the historical figure indicates that the elevated level is persistent. Figure 6 below shows Duarte and Rosa's summary results.

[24] Bloomberg and Duff & Phelps, "*2015 Valuation Handbook: Guide to Cost of Capital*," 2015, pp. 3-24.

[25] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Review of Models," *Federal Reserve Bank of New York*, December 2015 (Duarte & Rosa 2015).

[26] Duarte & Rosa emphasize the "first principal component" of the 20 models. This means that the authors used statistics to compute the weighted average combination of the models that captures the most variability among the 20 models over time.

Figure 6
Duarte and Rosa's Chart 3
One-Year Ahead MERP and Cross-Sectional Mean of Models



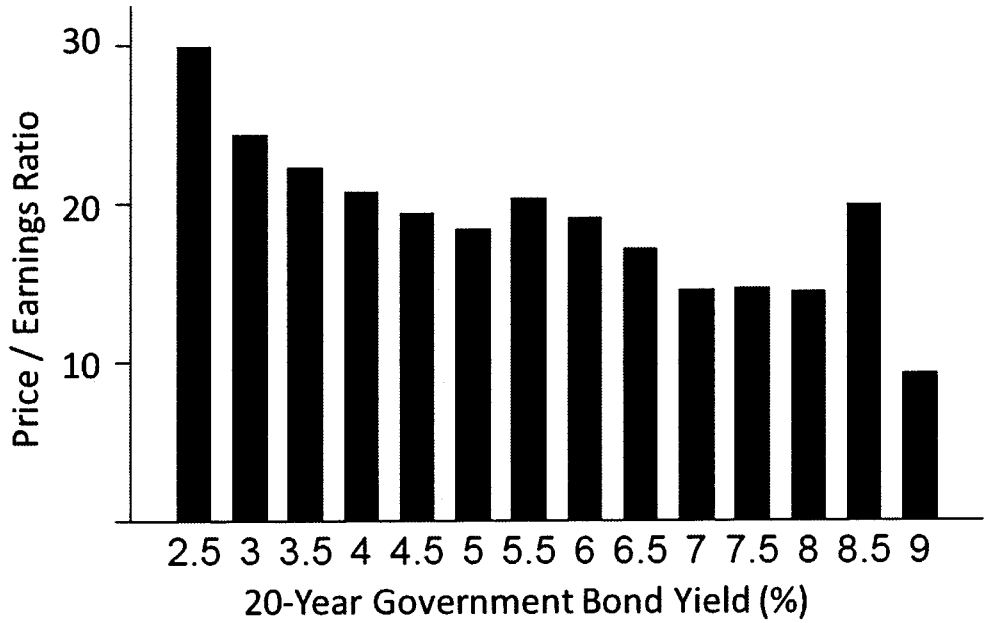
Q. ARE THERE OTHER REASONS WHY CAPITAL MARKETS MAY CONTINUE TO EXHIBIT HIGH VOLATILITY?

A. Yes, the early part of 2016 saw very large market declines across the globe and trading on the Chinese market was halted. For example, the New York Stock Index is down by about 8.5% during the first 6 weeks of 2016 with significant increases and decreases. At the same time, expected market volatility is high as illustrated in Figure 5. Further, oil prices are currently very low by historic standards – with a substantial impact on oil producing countries and regions. Finally, unrest in the Middle East (e.g., Syria and Saudi Arabia/Iran) has contributed to continued uncertainty and thereby an increase in the market equity risk premium that investors require. Lastly, it appears that the Euro zone once again may need to deal with the Greek debt situation.

Q. ARE THERE OTHER FEATURES OF FINANCIAL MARKETS THAT ARE CURRENTLY UNUSUAL?

A. Yes. The current level of many companies, including utilities, Price-to-Earnings (P/E) ratio is higher than what has been experienced historically. Empirically, the P/E ratio increases when interest rates decline. This is shown in Figure 7 below.

Figure 7: Average Price / Earnings Ratio of Comparable Electric Utilities vs. 20-Year Treasury Bond Yield



Source: Bloomberg (using quarterly data from 1990 through 2015)

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN THE P/E RATIO AND THE 20-YEAR GOVERNMENT BOND YIELD OF INTEREST IN YOUR ANALYSIS.

A. The dividend yield, which is calculated as Dividends divided by Price (D/P), is closely related to the P/E ratio as dividends are paid out of earnings. If the P/E ratio is very high (low), then the Earnings-to-Price ratio is low (high) and so is the dividend yield (D/P). The average electric utility pays approximately 60% of its earnings as dividends,[27] so if the P/E ratio increases from, for example, 15 to 17 (13.3%), then the Earnings / Price ratios declines by 0.79% (from 6.67% to 5.88%) and the dividend yield decline by 0.47%. Therefore, if the 20-year government bond yield is artificially depressed and expected to increase, then the dividend yield is also artificially depressed and expected

[27] Value Line Investment Survey as of December 2015 for 2016. Summarized in Attachment BV-11DR.

to increase. As a result, the results from the standard dividend discount models are likely to underestimate the cost of equity that will prevail going forward.

Q. WHAT DO YOU CONCLUDE FROM THIS INFORMATION?

A. The increase in the spread between the yield on utility and government bonds indicates that the premium investors require to hold assets that are not risk-free has increased. Likewise, the recent trends in preferred equity yields confirm that the premium on assets other than government bonds has increased. Similarly, the forecasted MRP is high relative to its recent past and the volatility index is higher than any time since 2012. All of these factors point to a relatively high degree of market volatility and that investors' required premia to hold assets that are not risk-free is elevated. Similarly, the very low risk-free rate are likely to have led to higher P/E ratios due to the flight to quality discussed above and consequently an lower than "normal" dividend yields.

C. *Impact On Roe Estimation*

Q. PLEASE SUMMARIZE HOW THE ECONOMIC DEVELOPMENTS DISCUSSED ABOVE HAVE AFFECTED THE RETURN ON EQUITY AND DEBT THAT INVESTORS REQUIRE.

A. Utilities rely on investors in capital markets to provide funding to support their capital expenditure program and efficient business operations, and investors consider the risk return tradeoff in choosing how to allocate their capital among different investment opportunities. It is therefore important to consider how investors view the current economic conditions; including the plausible development in the risk-free rate and the current MRP.

These investors have been dramatically affected by the credit crisis and ongoing market volatility, so there are reasons to believe that their risk aversion remains elevated relative to pre-crisis periods.

Likewise, the effects of the Federal Reserve's monetary policy have artificially lowered the risk-free rate. As a result, yield spreads on utility debt, including top-rated instruments, have remained elevated. The evidence presented above demonstrates that the equity risk premium is higher today than it was prior to the crisis for all risky investments. This is true even for investments of lower-than-average risk, such as the equity of regulated utilities.

Q. DOES YOUR ANALYSIS CONSIDER THE CURRENT ECONOMIC CONDITIONS?

A. Yes. In implementing the CAPM and risk premium models, I considered the downward biased risk-free rate as well as the elevated MRP. Specifically, I relied on two sets of inputs for the CAPM: I consider the elevated spread between utility and government bond yields and either (i) normalize the risk-free rate to reflect the currently downward bias of the yields and combine that with the historical MRP; or (ii) rely on Blue Chip's 2017 government bond yield forecast for the risk-free rate and combine that with a MRP that reflects the strong evidence that risk premiums are elevated relative to their long-term historical average. Similarly, I consider the impact on the dividend yield from the discussion above, which indicate that dividend yields will increase with increasing interest rates and hence be higher going forward than they are today.

IV. ANALYZING THE COST OF EQUITY

A. *Approach*

Q. PLEASE OUTLINE YOUR APPROACH FOR DETERMINING THE COST OF EQUITY FOR APS.

A. As described above in Section II.A, the standard for establishing a fair rate of return on equity requires that a regulated utility be allowed to earn a return equivalent to what an investor could expect to earn on an alternative investment of equivalent risk. Therefore,

my approach to estimating the cost of equity for APS focuses on measuring the expected returns required by investors to invest in companies that face business and financial risks comparable to those faced by APS. Because the models I rely upon most heavily require market data, my consideration of comparable companies is restricted to those that have publicly traded stock.

To this end, I have selected a sample of publicly-traded companies that primarily provide regulated electric utility services.

For this sample and a subsample, I derive estimates of the representative cost of equity according to standard financial models including two versions of the CAPM and two versions of DCF model. I further review results based on one version of the so-called risk premium model, as well as summary analysis of allowed ROEs for integrated electric utilities. The latter analysis is conducted using allowed returns on equity and associated allowed equity ratios rather than market data; the results of these analyses are used as a test on the reasonableness of my market-based results.

As the cost of equity for the CAPM and DCF based models are derived from market data that reflect the capital that investors hold in the sample companies, I consider the impact of any difference between the financial risk inherent in the cost of equity estimates and the capital structure to which it is assigned using several methods to avoid any one method biasing the results.

B. *Sample Selection*

Q. WHY DO YOU APPLY YOUR COST OF CAPITAL MODELS TO A SAMPLE OF COMPARABLE COMPANIES INSTEAD OF ESTIMATING THE COST OF CAPITAL FOR APS DIRECTLY?

A. It is a well-established point of finance theory (and practice) that the cost of capital depends on the use—not the source—of the invested capital. This means that if a diversified company has subsidiary parts engaged in distinct lines of business, the cost of capital for each part is specifically dependent on the risks inherent in its own line of business, not on the risks of the consolidated company as a whole.

APS is not publicly traded (although its parent Pinnacle West is), so it is not possible to directly estimate the cost of equity using the CAPM or DCF models. This is because these models rely on market information (such as stock prices, betas based on historical stock returns, and growth rate estimates) to estimate the expected returns required by equity investors.

Nor would it be appropriate to infer the appropriate cost of equity for APS based solely on the measured cost of equity of Pinnacle West as (1) a sample of one is simply too small; and (2) Pinnacle West have other lines of business albeit relatively small.

That is why I develop samples of publicly traded companies that are as analogous as possible to APS in terms of business risk, and apply the models to those samples as proxies for the APS. Subsequently, I discuss APS and Arizona-specific risks and place APS relative to the estimated cost of equity.

Q. HOW DO YOU IDENTIFY SAMPLE COMPANIES?

A. APS is an integrated electric utility, so I start with the universe of publicly traded utilities classified as electric utilities in Value Line. I then eliminated companies

engaged in substantial merger and acquisition (M&A) activities over the past 5-years and companies with less than 50% of its assets subject to regulation. Further, I require that the companies have an investment grade credit rating, no recent dividend cuts, more than $300 million in revenues to ensure liquidity, and generally have data available for estimation (*see* Attachment BV-6DR).

Q. WHAT ARE THE CHARACTERISTICS OF THE ELECTRIC SAMPLE?

A. The Electric sample comprises electric companies whose primary source of revenues and majority of assets are in the regulated portion of the electric industry. The final sample consists of the 27 electric utilities listed in Figure 8 below. These companies own regulated electric utility subsidiaries in many states, and some also provide electric transmission service regulated by the U.S. FERC.[28] Therefore, the Electric sample is broadly representative of the regulated electric utility industry from a business risk perspective. Further, the majority of the utilities own or lease generation albeit their generation mix may differ from that of APS.

Figure 8 reports the sample companies' annual revenues for the trailing twelve months ended September 2015 and the percentage of their assets devoted to regulated electric operations according to Edison Electric Institute's (EEI) classifications of electric utilities as being either regulated (R), having greater than 80% regulated electric assets or mostly regulated (MR), having 50-80% regulated electric assets. It also displays each company's Market Capitalization and the S&P Credit Rating in 2015, as well as its Value Line beta and the consensus long-term (3- to 5-year) earnings growth rate estimate for the company from Thomson Reuters IBES and Value Line. (*See* Attachment BV-6DR.)

[28] None of the included entities are primarily electric transmission entities.

Figure 8
Electric Sample Companies

Company	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2015 Q3 (USD million)	Betas	S&P Credit Rating (2015)	Long Term Growth Est.	Nuclear Generation (%)
	[3]	[4]	[5]	[6]	[7]	[8]	[9]
ALLETE	$1,500	R	$2,393	0.80	BBB+	4.2%	0.0%
Alliant Energy	$3,254	R	$6,434	0.80	A-	5.6%	17.0%
Amer. Elec. Power	$16,034	R	$27,037	0.70	BBB	4.4%	0.0%
Ameren Corp.	$6,098	R	$9,802	0.75	BBB+	7.1%	21.0%
CenterPoint Energy	$7,386	M	$7,692	0.85	A-	1.6%	-
CMS Energy Corp.	$6,146	R	$9,338	0.75	BBB+	6.3%	0.0%
Consol. Edison	$12,554	R	$18,927	0.60	A-	3.0%	-
Dominion Resources	$11,195	M	$41,040	0.70	A-	5.8%	33.0%
DTE Energy	$9,919	R	$13,951	0.75	BBB+	5.1%	17.0%
Edison Int'l	$11,452	R	$19,740	0.70	BBB+	0.3%	6.0%
El Paso Electric	$686	R	$1,432	0.75	BBB	8.0%	47.0%
Entergy Corp.	$11,203	R	$11,376	0.70	BBB	-2.6%	33.0%
G't Plains Energy	$2,502	R	$3,964	0.85	BBB+	6.2%	13.0%
IDACORP Inc.	$991	R	$3,087	0.80	BBB	3.1%	0.0%
MGE Energy	$564	M	$1,396	0.75	AA-	6.4%	0.0%
NextEra Energy	$17,216	M	$44,783	0.75	A-	7.0%	23.0%
OGE Energy	$2,197	R	$5,399	0.95	A-	3.2%	0.0%
Otter Tail Corp.	$783	R	$972	0.85	BBB	7.4%	0.0%
PG&E Corp.	$16,908	R	$24,840	0.70	BBB	8.2%	21.0%
Pinnacle West Capital	$3,501	R	$6,850	0.75	A-	4.8%	27.0%
Portland General	$1,912	R	$3,155	0.80	BBB	4.6%	0.0%
Public Serv. Enterprise	$9,896	M	$20,317	0.75	BBB+	1.7%	28.0%
SCANA Corp.	$4,163	M	$7,565	0.75	BBB+	4.3%	19.0%
Sempra Energy	$10,171	M	$22,956	0.80	BBB+	9.9%	0.0%
Vectren Corp.	$2,435	M	$3,324	0.75	A-	6.1%	0.0%
Westar Energy	$2,438	R	$5,239	0.75	BBB+	4.7%	8.0%
Xcel Energy Inc.	$11,024	R	$17,219	0.65	A-	4.8%	12.0%
Average	$6,820		$12,601	0.76		4.9%	13.0%
APS	3,501	R	n/a	n/a	A-	n/a	27.0%

Q. HOW DOES THE ELECTRIC SAMPLE COMPARE TO APS?

A. The Electric sample consists of 27 electric utilities from which I also create a subsample of companies that report between 17% and 37% of their generation capacity is nuclear. This sample consists of Alliant, Ameren, Dominion, DTE Energy, Entergy, NextEra, PG&E, Pinnacle West (albeit I consider the results without the parent of APS), PSE&G, and SCANA. The subsample intends to capture any nuclear related risks and therefore includes companies, whose nuclear generation percentage is within +/- 10% of APS's proportion of nuclear generation (*see* Attachment BV-7DR).

I note further that the average sample company (subsample) company has twice (three times) as much revenue as does APS and the average market capitalization is twice that of Pinnacle West. Thus, APS is smaller than the average sample company.

APS currently has a slightly higher credit rating than the average sample company, but (1) the difference is on average one notch (A- versus BBB+) and therefore small, (2) APS only achieved an A- rating in 2014 and was thus BBB+ rated during part of the estimation period, and (3) credit rating measure default risk rather than the cost of equity. Therefore, the impact of a slightly higher credit rating is simply that the Company has slightly lower default risk than the average sample company, which may be reflected in lower interest rates, which benefits customers. It does not, however, affect the cost of equity.

Finally, I note that the majority of the sample companies listed in Figure 8 have operating companies that have some form of decoupling mechanism. I discuss decoupling in more detail in Section VI.

Q. ARE THERE ANY DIFFERENCES IN THE REGULATORY ENVIRONMENT IN WHICH THE COMPARABLE COMPANIES AND APS OPERATES?

A. While all jurisdictions to a degree are unique, I did note several factors that impact more specifically APS's business risk. For example, APS has experienced larger than average penetration of distributed generation for a loss in load. I also note that Arizona operates with a historic test year.[29] This contrast to other states, where 32 states allow a future or

[29] I understand that the ACC has authorized APS to implement a rider to reflect in rates the costs associated with the Company's acquisition of a share of the coal-fired Four Corners Unit 4 and 5.

hybrid test year.[30] One issue associated with the use of historic test years is that it can become difficult to earn the allowed ROE during times of construction. As shown in Figure 2, APS has not earned its allowed ROE in the most recent 13 years.

It is essential that the Commission take APS-specific risks into account when determining the appropriate risk-adjusted cost of equity that APS should be allowed.

C. *The CAPM Based Cost Of Equity Estimates*

Q. PLEASE BRIEFLY EXPLAIN THE CAPM.

A. In the CAPM the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (*see* Figure 1 in Section II), in which the required expected return on an asset is proportional to that asset's relative risk as measured by that asset's so-called "beta."

More precisely, the CAPM states that the cost of capital for an investment, S (e.g., a particular common stock), is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \qquad (1)$$

where $\boldsymbol{r_S}$ is the cost of capital for investment S;

$\boldsymbol{r_f}$ is the risk-free interest rate;

$\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and

$\boldsymbol{MRP}$ is the market equity risk premium.

[30] Joe Wharton, Bente Villadsen, and Heidi Bishop, "Alternative Regulation and Ratemaking: Approaches for Water Companies," prepared for the *National Association of Water Companies*, September 2013, p. 43.

The CAPM is a "risk-positioning model" that relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. It says that an investment whose returns do not vary relative to market returns should receive the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 1). Further, it says that the risk premium of a security over the risk-free rate equals the product of the beta of that security and the Market Risk Premium: the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

1. Inputs to the CAPM

Q. WHAT INPUTS DOES YOUR IMPLEMENTATION OF THE CAPM REQUIRE?

A. As demonstrated by equation (1), estimating the cost of equity for a given company requires a measure of the risk-free rate of interest and the market equity risk premium (MRP), as well as a measurement of the stock's beta. There are many methodological choices and sources of data that inform the selection of these inputs. I discuss these issues, along with the finance theory underlying the CAPM, in Appendix B to my written evidence. I performed multiple CAPM calculations corresponding to distinct "scenarios" reflecting different values of the inputs. This allowed me to derive a range of reasonable estimates for the cost of equity capital implied by each of my samples.

Q. WHAT VALUES DID YOU USE FOR THE RISK-FREE RATE OF INTEREST?

A. I used the yield on a 20-year Government Bond as the risk-free asset for purposes of my analysis. Recognizing the fact that the cost of capital set in this proceeding will be in place over the next several years, I rely on a forecast of what Government bond yields will be one year out. Specifically, Blue Chip predicts that the yield on a 10-year

Government Bond will be 3.4% by Q4, 2017.[31] I use year-end 2017 as the benchmark as rates are expected to be in effect well beyond that date. I adjust this value upward by 53 basis points, which is my estimate of the representative maturity premium for the 20-year over the 10-year Government Bond.[32] This gives me a lower bound on the risk-free rate of 3.93%.

I also considered a scenario in which the appropriate risk-free rate of interest is 4.73%, which adds a portion of the increase in yield spread to the risk-free rate to take the downward pressure on the government bond yield into account. An alternative is to increase the MRP to reflect the widening of the yield spread.[33] The baseline Government bond yield of 3.93% reflects that Government bond yields are expected to increase substantially through 2020, where the Blue Chip forecast indicates a yield around 4.5%.[34]

Q. WHAT VALUES DID YOU USE FOR THE MARKET EQUITY RISK PREMIUM (MRP)?

A. Like the cost of capital itself, the market equity risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable, and must be inferred or forecasted based on known market information. One commonly used method for estimating the

[31] Blue Chip Economic Indicators, Consensus Forecasts, October 2015.

[32] This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year Government Bonds over the period 1990 - 2015, using data from Bloomberg.

[33] As of February 29, 2016, the spread between A rated utility and government bond yields was elevated by 90 basis points relative to the historical norm, so the application of only 80 basis points as an upward adjustment to the risk-free interest rate is conservative.

[34] Blue Chip Economic Indicators, October 10, 2015 has a consensus forecast for the 10-year government bond yield of 4.0%, so if the maturity premium remains at 0.53% the 20-year government bond is forecasted to be about 4.5%.

MRP is to measure the historical average premium of market returns over the income returns on government bonds over some long historical period. *Duff and Phelps* performs such a calculation of the MRP. The average market risk premium from 1926 to the present (2014) is 7.0%.[35] I used this value of the MRP in one input scenario to my CAPM analyses.

However, investors may require a higher or lower risk premium, reflecting the investment alternatives and aggregate level of risk aversion at any given time. As explained in Section III, there is substantial evidence that investors' level of risk aversion remains elevated relative to the time before the global financial crisis and ensuing recession that commenced in 2008. In recognition of this evidence, together with forward-looking measurements of the expected market equity risk premium that are higher than the long-term historical average, I also performed CAPM calculations using 8% for the market equity risk premium. The 8% forecasted MRP is consistent with Bloomberg's current forecast.[36]

Q. WHAT IS THE BASIS FOR STATING THAT THE CURRENT MRP IS HIGHER THAN ITS HISTORICAL AVERAGE?

A. Academic articles that were written in the late 1990s or early 2000s often found that the U.S. MRP at the time was lower than the its historical average based on various forward-looking models, such as market-wide versions of the DCF model. A recent article by Duarte and Rosa of the Federal Reserve of New York summarizes many of these models and also estimates the MRP from the models each year from 1960 through

[35] *See Duff and Phelps 2015 Valuation Handbook*, pp. 3-19.

[36] Bloomberg currently forecast the U.S. MRP at 8.5% over a 10-year Government bond, so using a maturity premium of about 0.5%; the forecasted MRP is approximately 8% over a 20-year government bond.

the present.[37] The authors find that the models are converging to provide more consensus around the estimate and that the average annual estimate of the MRP is consistent with the academic literature and with forward-looking estimates such as Bloomberg's. Their analysis shows that the U.S. MRP was lower than its long-term historical average in the early 2000s, but is currently at an all-time high. Chart 3 from Duarte & Rosa 2015 was re-produced in Figure 6, which shows the average estimated MRP (over 30-day T-bills) for 20 models.

These findings are broadly consistent with the forward-looking MRP's calculated by Bloomberg albeit a bit higher even after downward adjustment for the maturity premium. I also note that the approximately 80 basis points elevation in the yield spread indicate a substantial elevation in the MRP.[38] However, I conservatively relied on the historical average MRP of 7% and a forward-looking MERP of 8% in my CAPM analysis.[39]

Q. WHAT BETAS DID YOU USE FOR THE COMPANIES IN YOUR SAMPLE?

A. I used Value Line betas, which are estimated using five years of weekly data, which is consistent with the regulatory practice in Arizona.

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[37] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Consensus of Models," *Federal Reserve Bank of New York*, December 2015 (Duarte & Rosa 2015).

[38] *See* Appendix B, Section II for details.

[39] Following the evidence in standard finance textbooks, I rely on the arithmetic average for the historic market risk premium. See, for example, Brealey, Myers and Allen, "Principles of Corporate Finance," 11th Edition, 2014 pp. 162-163 and Ross, Westerfield and Jaffe, "Corporate Finance," 10th Edition, 2013 pp. 322-323.

2. The Empirical CAPM

Q. DID YOU USE ANY OTHER CAPM-BASED MODEL?

A. Yes. Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted.[40] A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

The second variation on the CAPM that I employed makes use of these empirical findings. It estimated the cost of capital with the equation,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S \times (MRP - \alpha)} \qquad (2)$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (*see* equation (2) above).

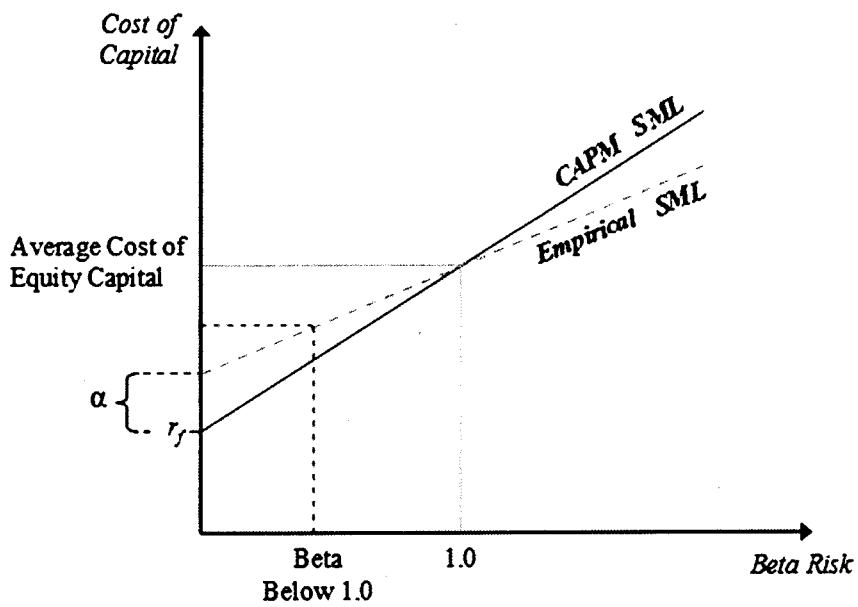
I call this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 1, which results in a Security Market Line that more closely matches the results of empirical tests. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

[40] *See* Figure A-4 in Appendix B for references to relevant academic articles.

Q. WHY DO YOU USE THE ECAPM?

A. Research shows that the analysis performs better empirically performs better, when paired with the ECAPM, which recognizes the consistent empirical observation that the CAPM underestimates the cost of capital for low beta stocks. In other words, the ECAPM is based on recognizing that the actual observed risk-return line is flatter and has a higher intercept than that predicted by the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact, which has been established by repeated empirical tests of the CAPM. Appendix B discusses the empirical findings that have tested the CAPM and also provides documentation for the magnitude of the adjustment, (α).

Figure 9: The Empirical Security Market Line



3. Results from the CAPM Based Models

Q. PLEASE SUMMARIZE THE PARAMETERS OF THE SCENARIOS AND VARIATIONS YOU CONSIDERED IN YOUR CAPM AND ECAPM ANALYSES.

A. The parameters for the two scenarios are displayed in Figure 10 below. The basis for using the scenarios is the empirical observation that the yield spread is higher than normal as is the forecasted MRP. The increased yield spread could reflect the increase

in the MRP or downward pressure on the yield of government bonds due to a flight to quality or other factors. Therefore, I used the unadjusted forecast risk-free rate with a higher estimate of the MRP, and the unadjusted historical average MRP with the increased estimate of the risk-free interest rate as illustrated in Figure 10. This is a conservative approach as it is plausible that both downward pressure on the risk-free rate and upward pressure on the MRP could simultaneously occur. Scenario 1 normalizes the risk-free rate and uses a historical MRP while Scenario 2 uses an unadjusted forecast of the risk-free rate and a forecasted MRP. Because I did not simultaneously normalize both the government bond rate and the MRP, my estimates are more likely to be downward than upward biased.

Figure 10: Parameters Used in CAPM-based Models

	Scenario 1	Scenario 2
Risk-Free Interest Rate	4.7%	3.9%
Market Equity Risk Premium	7.0%	8.0%

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE DATA RELIED UPON TO ESTIMATE THE COST OF EQUITY AND THE REGULATORY RATE BASE TO WHICH THE COST OF EQUITY IS APPLIED.

A. Both the CAPM and the DCF models rely on market data to estimate the cost of equity for the sample companies, so the results reflect the value of the capital that investors hold during the estimation period (market values). The allowed return on equity is applied to the fair value rate base, which could be financed differently than the sample companies.

Q. WHY IS THIS DIFFERENCE IMPORTANT TO THE ESTIMATION OF THE COST OF EQUITY?

A. Taking differences in financial leverage into consideration does not change the value of the rate base, but it does consider the fact that the more debt a company has, the higher

is the financial risk associated with an equity investment.[41] To see this I constructed a simple example below, where only the financial leverage of a company varies. I assumed the return on equity is 11% at a 50% equity capital structure and determine the return on equity that would result in the same overall return if the percentage of equity in the capital structure were reduced to 45%.

Figure 11
Illustration of Impact of Financial Risk on Allowed ROE

	Company A (50% Equity)	Company B (40% Equity)
Rate Base	$1,000	$1,000
Equity	$500	$450
Debt	$500	$550
Cost of Debt (5%)	$25	$27.5
Return on Equity	$55	$42.5
Total Cost of Capital (7.5%)	**$80**	**$80**
ROE / Implied ROE	11%	11.67%

The table above illustrates how financial risk affects returns and also the allowed ROE: the overall return does not change, but the allowed ROE required to produce the same return goes up in recognition of the increased risk to equity investors caused by the higher degree of financial leverage.

The principle illustrated in Figure 11 is exemplary of the adjustments I performed to account for differences in financial risk when conducting estimates of the cost of equity applicable to APS. I considered financial risk using several commonly used methods

[41] *See* Appendix B for a description of common practice and underlying finance principles related to the impact of financial risk on the cost of equity.

including the Hamada method to avoid undue influence from any one set of assumptions.[42] The details of these methods are included in Appendix B.

Q. CAN YOU SUMMARIZE THE RESULTS FROM APPLYING THE CAPM-BASED METHODOLOGIES?

A. Yes. The results are presented in Figure 12 below.[43] Note that I included estimates from both the full Electric sample as well as from the sub-sample, whose inclusion of nuclear generation in its generation mix is comparable to that of APS.

[42] These methods include calculating the ROE implied by the overall cost of capital as illustrated in Figure 10, as well as two versions of the so-called Hamada method for levering and unlevering betas in the CAPM and ECAPM. *See* Appendix B for further discussion and detail.

[43] Tables and supporting schedules detailing my cost of capital calculations for Electric sample are contained in Attachment BV-6DR.

Figure 12: Electric Sample CAPM-Based Results

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Full Sample		
Financial Risk Adjusted Method		
CAPM	10.2%	10.1%
ECAPM (α = 1.5%)	10.5%	10.5%
Hamada Adjustment Without Taxes		
CAPM	10.2%	10.2%
ECAPM (α = 1.5%)	10.5%	10.5%
Hamada Adjustment With Taxes		
CAPM	10.1%	10.1%
ECAPM (α = 1.5%)	10.5%	10.4%
Nuclear Subsample		
Financial Risk Adjusted Method		
CAPM	10.1%	10.0%
ECAPM (α = 1.5%)	10.5%	10.4%
Hamada Adjustment Without Taxes		
CAPM	10.1%	10.1%
ECAPM (α = 1.5%)	10.4%	10.4%
Hamada Adjustment With Taxes		
CAPM	10.0%	10.0%
ECAPM (α = 1.5%)	10.4%	10.3%

Q. HOW DO YOU INTERPRET THE RESULTS OF YOUR CAPM AND ECAPM ANALYSES?

A. The results indicate an ROE range of 10.0% to 10.5% for a company with 56% equity. Because studies have found that the ECAPM empirically perform better, the ECAPM results deserve higher weight for a range of 10.3% to 10.5%. As seen in Table 12, there is little difference between the estimation results for the full sample and the subsample of entities, whose generation capacity includes 17-37% nuclear generation.

D. *The DCF Based Estimates*

1. Single- and Multi-Stage DCF Models

Q. CAN YOU DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY?

A. The DCF model attempts to estimate the cost of capital for a given company directly, rather than based on its risk relative to the market as the CAPM does. The DCF method simply assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow—literally a stream of expected "cash flows" discounted at a risk-appropriate discount rate. When the cash flows are dividends, that discount rate is the cost of equity capital:

$$\boldsymbol{P_0} = \frac{\boldsymbol{D_1}}{\boldsymbol{1+r}} + \frac{\boldsymbol{D_2}}{\boldsymbol{(1+r)^2}} + \frac{\boldsymbol{D_3}}{\boldsymbol{(1+r)^3}} + \cdots + \frac{\boldsymbol{D_T}}{\boldsymbol{(1+r)^T}} \qquad (3)$$

Where $\boldsymbol{P_0}$ is the current market price of the stock;

$\boldsymbol{D_t}$ is the dividend cash flow expected at the end of period $\boldsymbol{t}$;

$\boldsymbol{T}$ is the last period in which a dividend cash flow is to be received; and

$\boldsymbol{r}$ is the cost of equity capital.

Importantly, this formula implies that if the current market price and the pattern of expected dividends are known, it is possible to "solve for" the discount rate, r, that makes the equation true. In this sense, a DCF analysis can be used to estimate the cost of equity capital implied by the market price of a stock and market expectations for its future dividends.

Many DCF applications make the assumption the growth rate last forever, so the formula can be rearranged to estimate the cost of capital. Specifically, the implied DCF

cost of equity can then be calculated using the well-known "DCF formula" for the cost of capital:

$$r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1 + g) + g \qquad (4)$$

where D_0 is the current dividend, which investors expect to increase at rate g by the end of the next period, and over all subsequent periods into perpetuity.

Equation (4) says that if equation (3) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the single-stage DCF model; it is also known as the Gordon Growth model.

Q. ARE THERE DIFFERENT VERSIONS OF THE DCF MODEL?

A. Yes. There are many alternative versions, notably (i) multi-stage models, (ii) models that use cash flow rather than dividends, or versions that combine aspects of (i) and (ii).[44]

I do not present evidence on these models in this proceeding, because a model that uses dividends as the only source of cash, current GDP growth forecasts, and current dividend yields would yield unreasonable results.

[44] For example, the Surface Transportation Board uses a cash flow based model with three stages. *See*, for example, Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009.

2. DCF Inputs and Results

Q. WHAT GROWTH RATE INFORMATION DID YOU USE?

A. I looked to a sample of investment analysts' forecasted earnings growth rates from for companies in my samples. I used investment analyst forecasts of company-specific growth rates sourced from *Value Line* and Thomson Reuters *IBES*.

Additionally, I relied on the dividend yield of the companies, which I estimate using the most recently available dividend information (currently) and the average of the last 15 days of stock prices. Because of the stock price of utilities currently is higher than they historically have been and because some companies engage in share buybacks, the dividend yield underestimates the yield on cash distributions to investors.

Q. PLEASE ADDRESS THE INPUT DATA IN THE DCF MODEL.

A. The Gordon Growth / single-stage DCF models require forecast growth rates that reflect investor expectations about the pattern of dividend growth for the companies over a sufficiently long horizon, but estimates are typically only available for 3-5 years.

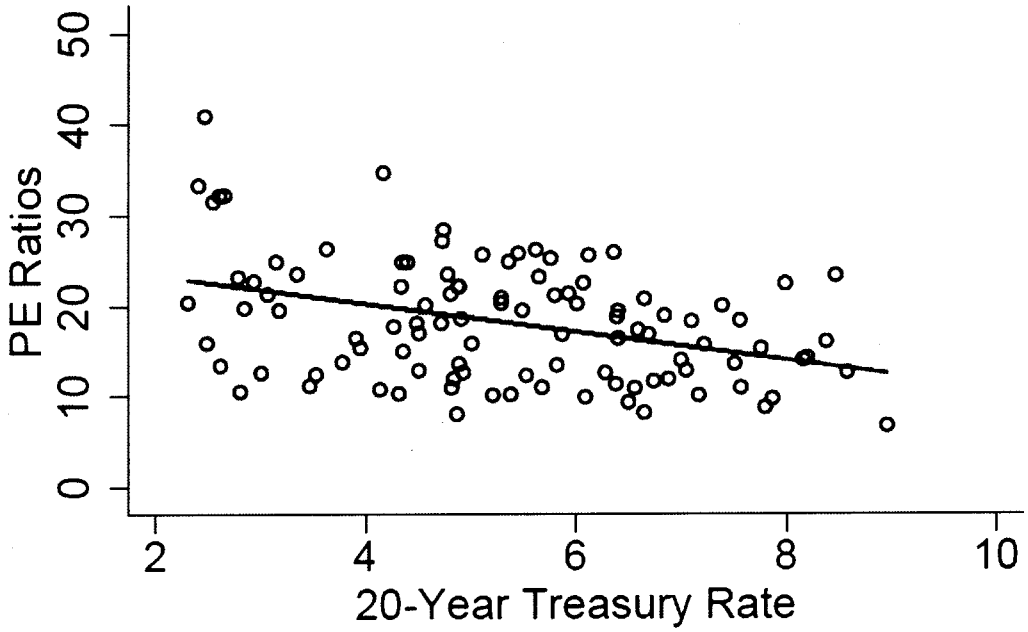
One issue with the data is that it includes solely dividend payments as cash distributions to shareholders, while some companies also use share repurchases to distribute cash to shareholders. To the extent that companies in my samples use share repurchases, the DCF model using dividend yields will under estimate the cost of equity for these companies. While there are companies in my sample that have engaged in share buybacks in the past, the magnitude is currently not large.

A second issue is that the flight to quality has resulted in higher than usual stock prices for electric utilities and hence lower than usual dividend yields. As a result, the dividend yield may be downward biased.

Q. HAVE YOU ATTEMPTED TO DETERMINE THE EFFECT OF THESE ASPECTS OF THE DATA ON YOUR ANALYSIS?

A. Yes. As discussed previously, the Price / Earnings (P/E) ratio for utilities appears to have an inverse relationship to the long-term government bond yield. I therefore regressed the P/E ratios of the companies in my sample as well as the average and median for both the sample and subsample on the 20-year government bond yield. This regression is illustrated in Figure 13 below. Specifically, I regressed the average and median P/E ratio for the sample and subsample on the 20-year government bond yield using quarterly data from 1990-2015.

Figure 13 2: Regression of Average P/E Ratio for Sample Companies on 20-Year Government Bond Yield



My statistical analysis found that the median P/E ratio increases by 0.89 and 1.04 for the full sample and nuclear subsample, when the 20-year government bond yield decline by 1%, respectively. The average impact is higher at 1.31 to 1.55,[45] but these figures cover a relatively wide range across individual companies. Using this range and a generic dividend payout ratio of 60% (the average for my sample is a little over 60%, so the

[45] *See* Attachment BV-11DR.

assumption is conservative), I find that if the P/E ratio increases by, for example, 1.3 for each 1% decline in the government bond yield, then the E/P ratio declines by 0.77 (=1/1.77) for each 1% decline in the yield and if the dividend payout ratio is 60%, the dividend yield would decline by about 46 basis points (=60% × 0.77). Thus, the dividend yield would be understated by an amount relative to what it would be during more normal government bond yields.[46] This is an example of the flight to quality discussed above. I consider the impact of this phenomena below, when discussing my DCF results.[47]

Q. WHAT ARE THE DCF BASED COST OF EQUITY ESTIMATES FOR THE SAMPLES?

A. The results are presented in Figure 14 below.[48] I show both the raw results from the DCF model and the results that would prevail if the interest impact is considered. As for the CAPM, I show the results for the full sample and for the nuclear subsample.

Figure 143: Electric Sample's DCF Results

	Interest Rate Impact not Considered	Interest Rate Impact Considered
Full Sample	9.9%	10.3% - 10.4%
Nuclear Sample	10.4%	10.8% - 10.9%

Q. HOW DO YOU INTERPRET THE RESULTS OF YOUR DCF ANALYSES?

[46] This is consistent with a recent paper by Philip U. Straehl and Roger G. Ibbotson, "The Supply of Stock Returns: Adding Back Buybacks," Morningstar, 2015, who find that "the dividend discount model (DDM), based on current dividend yields and historical per-share growth rates, significantly underestimates expected returns relative to the total payout model."

[47] I note that according to Morningstar, the most commonly used return model determine expected return as dividend yield plus earnings per share growth plus Change in P/E. Morningstar, "Meet CAPE's Older Sister CATY: Using "Total Payout Yield" to Derive Better Equity Return Forecasts" by Philip Straehl, 2016.

[48] Tables and supporting schedules detailing my cost of capital calculations are included in Attachment BV-6DR.

A. The DCF results indicate an ROE of 10.3% to 10.9% once the impact of elevated P/E ratio is considered. Because of the elevated P/E ratios and because APS's assets are more aligned with the assets of the nuclear subsample, I believe the DCF results indicate an ROE well above 10% and in line with to slightly higher than the CAPM-based results reported in Figure 12. Notably, the results from the nuclear subsample are higher than those for the full sample.

E. *Risk Premium Model Estimates*

Q. DID YOU ESTIMATE THE COST OF EQUITY THAT RESULTS FROM AN ANALYSIS OF RISK PREMIUMS IMPLIED BY ALLOWED ROES IN PAST UTILITY RATE CASES?

A. Yes. In this type of analysis, sometimes called the "risk premium model," the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted. These estimates add a "risk premium" implied by this relationship to the relevant (prevailing or forecast) risk-free interest rate:

$$Cost\ of\ Equity = r_f + Risk\ Premium$$

Q. WHAT ARE THE MERITS OF THIS APPROACH?

A. First, it estimates the cost of equity from regulated entities as opposed to holding companies, so that the relied upon figure is directly applicable to a rate base. Second, the allowed returns are clearly observable to market participants, who will use this data one input to making investment decisions, so that the information is at the very least a good check on whether the return is comparable to that of other investments. Third, I analyze spread between the allowed ROE at a given time and the then prevailing interest rate to ensure that I properly consider the interest rate regime at the time the ROE was awarded. This implementation ensures that I can compare allowed ROE granted at different times and under different interest rate regimes.

Q. HOW DID YOU USE RATE CASE DATA TO ESTIMATE THE RISK PREMIUMS FOR YOUR ANALYSIS?

A. Using quarterly data from Regulatory Research Associates from Q1 1990 to Q4 2015,[49] I compared (statistically) the average allowed rate of return on equity granted by U.S. state regulatory agencies in integrated electric utility rate cases to the average 20-year Treasury bond yield that prevailed in each quarter. I calculated the allowed utility "risk premium" in each quarter as the difference between allowed returns and the Treasury bond yield, since this represents the compensation for risk allowed by regulators. Then I used the statistical technique of ordinary least squares (OLS) regression to estimate the parameters of the linear equation:

$$Risk\ Premium = A_0 + A_1 \times (Treausury\ Bond\ Yield) \qquad (5)$$

I derived my estimates of A_0 and A_1 using standard statistical methods (OLS regression) and find that the regression has a high degree of explanatory power in a statistical sense (R^2=0.79) and the parameter estimates, A_0=8.886% and A_1= -0.593, are statistically significant. The negative slope coefficient reflects the empirical fact that regulators grant smaller risk premiums when risk-free interest rates (as measured by Treasury bond yields) are higher. This is consistent with past observations that the premium investors require to hold equity over government bonds increases as government bond yields decline. In the regression described above, the allowed ROE on average declined by 59 basis point when the government bond yield declined by 100 basis points. This relationship is illustrated graphically in Attachment BV-8DR, which contains my risk premium analysis.

[49] SNL Financial as of 1/7/2016.

Q. WHAT RESULT DID YOUR RISK PREMIUM ANALYSIS PROVIDE FOR THE APS'S COST OF EQUITY?

A. To estimate a cost of equity, I apply my regression equation at the normalized risk-free interest of 4.7%.[50] The calculation is shown below and gives a cost of equity estimate of 10.8% for the sample:

$$\boldsymbol{Risk\ Premium} = 8.886\% - 0.593 \times 4.7\% = \mathbf{6.32}\%$$

$$\boldsymbol{Cost\ of\ Equity} = 4.7\% + 6.32\% = \mathbf{10.8}\%$$

I note that the average equity percentage for integrated electric utilities recently has been about 51%, so if I take the financial risk into account, the risk premium model indicates an ROE of 10.3% for an entity with 56% equity (*see* Attachment BV-8DR).

Q. WHAT CONCLUSIONS DID YOU DRAW FROM YOUR RISK PREMIUM ANALYSIS?

A. Although risk premium models based on historical allowed returns are not underpinned by fundamental finance principles in the manner of the CAPM or DCF models, I believe they can provide useful benchmarks for evaluating appropriate rates of return. My risk premium model cost of equity estimates demonstrate that the results of my DCF and CAPM analyses are in line with the actions of utility regulators. Because the risk premium analysis as implemented takes into account the interest rate prevailing during the quarter the decision was issued, it provides a useful benchmark for the cost of equity in any interest environment.

[50] As discussed above, this represents the Blue Chip estimate for the 10-year Government Bond yield at the end of 2017, adjusted upward by 53 basis points to account for the maturity premium between 10- and 20-yr government bonds and by a further 80 basis points to account for the elevated levels of utility yield spreads.

V. RISK CHARACTERISTICS AND THE COST OF EQUITY

A. *BACKGROUND*

Q. PLEASE SUMMARIZE YOUR ROE EVIDENCE.

A. Based on my analysis, I find the range of ROE estimates displayed in Figure 15 below.[51]

Figure 15: Range of ROE Estimates

	Full Sample	Nuclear Sample
	[1]	[2]
CAPM	10.1% - 10.2%	10.0% - 10.1%
ECAPM	10.4% - 10.5%	10.3% - 10.5%
Simple DCF	9.9%	10.4%
DCF Considering Interest Rates	10.3% - 10.4%	10.8% - 10.9%
Risk Premium	10.3%	n/a

I note that in considering the impact of interest rates on the DCF estimates, I rely on the current widening of the spread between utility and government bonds of 80 basis points. An alternative would be to use the difference between the forecasted government bond yield and the current bond yield of almost 110 basis points (3.4% in Q4, 2017 versus the December 2015 yield of 2.24%). Thus, my estimates use the more conservative estimate. Based on the data above, I consider a **reasonable range for the sample** to be 10.0% to 10.8% (excluding the highest and lowest estimate) and will next address APS specific risks and its ROE relative to the sample.

B. *APS And Arizona-Specific Risks*

Q. PLEASE IDENTIFY THE APS AND ARIZONA-SPECIFIC RISKS THAT YOU ANALYZED.

A. My analysis included the following APS and Arizona-specific risk factors: (i) APS relies to a larger degree than the sample companies on nuclear generation, (ii) the magnitude and growth in distributed generation is higher than in most states (iii) APS has been

[51] I acknowledge that some companies in the subsample (e.g., Dominion, NextEra, PSE&G, and Scana) have non-trivial non-regulated activities.

unable to earn its allowed ROE in the last 13 years, and (iv) APS is smaller than the average company in my sample. All of these characteristics add to APS's risk.

Q. PLEASE DISCUSS THE IMPACT OF BEING MORE DEPENDENT ON NUCLEAR GENERATION THAN ITS PEERS.

A. Figure 16 below summarizes the generation composition in my sample and Attachment BV-7DR provides details.

Figure 16: Generation Composition

	APS	Subsample	Sample
[1]	[2]	[3]	[4]
Nuclear	27%	24%	13%
Coal	34%	33%	39%
Natural Gas	17%	21%	21%
Other (incl. purchases)	22%	21%	27%

Sources:
Value Line and SEC 2014 Form 10-Ks.

It is evident from Figure 16 that APS relies more heavily on nuclear generation than the sample and more heavily on nuclear and coal than the subsample, but the Company's generation mix is closer to that of the subsample. There are at least three reasons why nuclear generation and to a degree coal impacts the utility's risk. First, nuclear generation (and coal more than natural gas) has very large fixed costs relative to their variable costs, which means that the operating leverage is higher. As a result, the asset risk (beta) increases relative to that of an asset with less operating leverage. Simply put, the costs associated with operating a nuclear facility cannot readily be reduced simply because demand is reduced. Second, nuclear facilities tend to be very large and indeed APS operates the largest nuclear generating facility in the country, Palo Verde units 1, 2 and 3 but is a much smaller utility than the majority of those included in my sample / nuclear subsample. Because the generation facility is one large unit (as opposed to

many smaller units), the operation has less flexibility than other types of generation. Third, nuclear facilities are subject to substantial scrutiny and decommissioning costs are significant. This again adds to the risk profile and certainly the subsample results may be more representative than those of the sample.[52]

Q. HOW DOES THE MAGNITUDE AND GROWTH IN DISTRIBUTED GENERATION IMPACT APS?

A. APS has more distributed generation in its service territory than the majority of U.S. utilities; including those in my sample. Photovoltaic capacity constitute .82% of the total installed capacity in Arizona and is among the sample companies only exceeded by the magnitude installed in California and New Jersey with the latter being a deregulated state (*see* Attachment BV-9DR). Therefore, it is imperative that the utility's rates are structured so that it does not undermine its ability to earn the allowed ROE or APS will face asymmetric risk of earning below its allowed ROE.

Q. WHY IS AN ANALYSIS OF THE EARNED VS. ALLOWED ROE RELEVANT TO A DETERMINATION OF THE ROE IN THIS CASE?

A. Based on data obtained from APS, I have calculated the degree to which the company has under earned its allowed ROE since 2002. I found that APS has under earned its allowed ROE every year since 2002 and by a substantial amount as the average under earning is close to 2%. While APS's ability to earn its allowed ROE has improved in recent years, the fact that it has under earned in the most recent 13 years indicates that absent constructive rate making, the Company may be facing an asymmetric risk. There are two consequences to this observation. First, I recommend that the barriers to earning the allowed ROE be removed if possible and second, if it is not possible to remove the

[52] I acknowledge that some companies in the subsample (e.g., Dominion, NextEra, PSE&G, and Scana) have non-trivial non-regulated activities.

barriers to on average earn the allowed ROE, it may be necessary to provide APS with a cushion to ensure it earns its allowed ROE. Put differently, it would be misguided to award APS an ROE towards the lower end of what is reasonable because providing an inadequate return because a return below the cost of capital may adversely affect the utility's ability to provide stable and favorable rates because some potential efficiency investments may be delayed and the company may be forced to file more frequent rate cases. Moreover, in the long run, inadequate returns are likely to cost customers—and society generally—far more than may be saved in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. Without access to investor capital, the company may be forced to forgo opportunities to maintain, upgrade, and expand its systems and facilities in ways that decrease long run costs. Indeed, the cost to consumers of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. This is especially true in capital-intensive industries (such as the electric utility industry), which feature systems that take a long time to decay. Such long-lived infrastructure assets cannot be repaired or replaced overnight, because of the time necessary to plan and construct the facilities. Thus, it is in customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that the return does not fall short of the cost of capital.

Q. HOW DOES APS'S SMALLER SIZE AFFECT INVESTORS' EXPECTED RETURN?

A. Empirical studies have shown that the return investors require depend on the size of the company in which they invest and that the required return is larger the smaller the company is.[53] As APS is approximately half the size of the average sample company as

[53] Duff & Phelps, "2014 Valuation Handbook: Guide to Cost of Capital," (Duff & Phelps (2014), pp. 7-2.

measured by revenue and Pinnacle West is half (one third) of the sample's (subsample's) size as measured by market capitalization, it is evident that APS is smaller than the average sample / subsample company. Duff & Phelps looks at 25 deciles of companies by market capitalization size and report the average premium that a company requires based on the decile in which the company's capitalization falls. Based on the market capitalization of Pinnacle West, which predominantly is APS, and that of the subsample (sample), APS's size merits a size premium. Looking to Duff & Phelp (2014) risk premia by market capitalization, APS smaller size would merit a size premium of up to 75 basis points over the average sample company.[54] Because there are companies in the sample (subsample), who are of the same size as APS, I do not simply add 75 basis points to APS's ROE but instead use this information to place APS relative to the estimates displayed in Section V.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE ANALYSIS ABOVE?

A. As APS faces larger operating leverage from nuclear generation than the sample, is of a smaller size than the sample, have a larger exposure to distributed generation, and may be subject to asymmetric risk in earning its allowed ROE, I submit that a lower bound on APS's cost of equity is the upper half of the estimated range; i.e., 10.25% – 10.75%. I recommend that APS be allowed a ROE at the midpoint of the range; 10.5% as the Company's smaller size and operating leverage increases its cost of capital over that of the sample. I further note that it is important that any obstacles to APS earning its allowed ROE be removed as credit rating agencies look to earned returns and investors ultimately are paid from earned returns.

[54] Duff & Phelps (2014), Appendix A-3.

VI. DECOUPLING AND ROE

Q. PLEASE EXPLAIN DECOUPLING.

A. Decoupling is a regulated ratemaking approach that severs the direct link and relationship between level of unit sales (kilowatt-hours) to consumers and the level of base revenues that are approved for through the collection of volumetric rates. Specific decoupling mechanisms are in place in 28 states.[55]

Q. WHY DO YOU CONSIDER THE IMPACT OF DECOUPLING ON COST OF CAPITAL?

A. Because decoupling has the effect of reducing the volatility of the utility's revenue, some have argued that it reduces the cost of capital. The basis for the assumption was that volatility is related to risk, so a reduction in revenue volatility could impact the utility's risk and hence it's cost of capital.

Q. WHAT IS THE EVIDENCE REGARDING THE RELATIONSHIP BETWEEN DECOUPLING AND COST OF CAPITAL?

A. First, the majority of the companies in my sample have some form of decoupling for some subsidiaries, so any impact on the cost of capital would already be captured in the data displayed in Section V. Second, empirical studies have shown that there is no impact of decoupling on the cost of capital among U.S. electric utilities (or gas utilities). Third, finance theory holds that only systematic (or non-diversifiable) risk affects the cost of equity, so only if decoupling affected the systematic risk would it impact the cost of equity. I discuss each of these in turn below.

[55] Joe Wharton & Michael J. Vilbert, "Decoupling and the Cost of Capital," *The Electricity Journal*, vol. 28, 2015, pp. 19-28.

Q. PLEASE SUMMARIZE THE PREVALENCE OF DECOUPLING MECHANISMS AMONG YOUR SAMPLE COMPANIES.

A. Figure 17 below shows the prevalence of decoupling mechanisms among the sample companies and subsample companies. In the table, I also indicate in parentheses restructured states where the utility operates as well as any decoupled gas operations.

From the table, it appears that of the 10 companies in the subsample, 7 have some form of decoupling in place and among the 27 sample companies only 7 have no decoupling of which some operations are in restructured states, where the operating utility owns no generation. Thus, both the sample and the subsample has a substantial amount of decoupling and much of the effect decoupling, if any, would be captured in the estimation results (*see* Attachment BV-10DR).

Figure 17: Decoupling Mechanisms Among Sample Companies

Company	Decoupling	No Decoupling	Restructured States
[1]	[2]	[3]	[4]
ALLETE		MN	
Alliant Energy		IA, (IA), WI, (WI)	
Amer. Elec. Power	AR*, IN*, KY*, LA*, OH*, OK*	MI, TN, TX, VA, WV	OH, TX
Ameren Corp.	MO*	IL, (IL), (MO)	IL
CenterPoint Energy	(AR), (LA)*, (MN), (OK)*	TX, (TX)	TX
CMS Energy Corp.		MI, (MI)	
Consol. Edison	NY, (NY)	NJ	NJ
Dominion Resources		NC, (OH), VA, (WV)	OH
DTE Energy	(MI)*	MI	
Edison Int'l	CA		
El Paso Electric		NM, TX	TX
Entergy Corp.	AR*, LA*, (LA), MS*	TX	TX
G't Plains Energy	MO*	KS	
IDACORP Inc.	ID*	OR	
MGE Energy		WI, (WI)	
NextEra Energy		FL, TX	TX
OGE Energy	AR*, OK*		
Otter Tail Corp.		MN, ND	
PG&E Corp.	CA, (CA)		
Pinnacle West Capital	AZ*		
Portland General	OR*		
Public Serv. Enterprise	(NJ)*	NJ	NJ
SCANA Corp.	(NC), (SC)*	SC	
Sempra Energy	(AL)*, CA, (CA)		
Vectren Corp.	IN*, (IN)	(OH)	OH
Westar Energy	KS*		
Xcel Energy Inc.	(CO)*, SD*	CO, MN, (MN), NM, ND, (ND), TX, WI, (WI)	TX

Sources/Notes:
Regulatory Research Associates, "Adjustment Clauses," October 2, 2015.
Highlighted companies are included in our subsample of utilities with 17% to 37% nuclear generation.
"*" indicates partial decoupling.
"( )" indicates decoupling status for associated gas operations.

Q. PLEASE DISCUSS THE EMPIRICAL EVIDENCE YOU MENTIONED REGARDING DECOUPLING.

A. Empirical studies of the effect of decoupling on the cost of capital have found none. More specifically, Wharton & Vilbert (2015) studied electric utilities that introduced decoupling or had decoupling removed during the period 2007-14 using quarterly and estimated the cost of capital for those with and without decoupling. They found no

statistical evidence that decoupling affected the cost of equity.[56] A study by Michenfelder similarly found that no effect of decoupling on the cost of equity.[57] Thus, empirical studies have not found any impact of decoupling on the cost of capital.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE RELATIONSHIP BETWEEN DECOUPLING AND THE COST OF CAPITAL?

A. Yes. Finance theory holds that only systematic (non-diversifiable) risk affects the cost of capital. Therefore, decoupling only affects the cost of capital to the extent it affects systematic risk. While decoupling mechanisms vary substantially across jurisdictions, it is plausible that an investor can diversify away from any specific volumetric effect and hence diversify the risk away. If that is the case there is no impact on the cost of capital from decoupling.

Q. BASED ON THE DISCUSSION ABOVE, WHAT DO YOU CONCLUDE?

A. Because a large number of the companies in my sample have decoupling mechanisms in place, any impact on the cost of equity is already captured in my estimates. Further, empirical research have not detected any relationship between the cost of equity and decoupling, so there is no evidence that decoupling affect the cost of equity. Therefore, decoupling should not affect the allowed ROE.

VII. FAIR VALUE RATE BASE AND FAIR VALUE ROR

Q. PLEASE EXPLAIN THE FAIR VALUE RATE BASE CONCEPT.

A. According to the Arizona Constitution,

> The corporation commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the state of every

[56] Joe Wharton & Michael J. Vilbert, "Decoupling and the Cost of Capital," *The Electricity Journal*, vol. 28, 2015, pp. 19-28.

[57] Richard A. Michelfelder, "Decoupling: Impact on the Risk of Public Utility Stocks," Presentation at SURFA, April 15, 2011.

> public service corporation doing business therein; and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.[58]

Thus, the state Constitution requires Commission to determine the fair value of the property APS uses in the state of Arizona in connection with setting rates.

Q. HOW HAS THE COMMISSION IMPLEMENTED THE FAIR VALUE RATE BASE CONCEPT?

A. For decades, the Commission has determined the Fair Value Rate Base (FVRB) and the Fair Value Rate of Return (FVROR). In these cases, the Commission has determined the FVRB as the average of the Original Cost Rate Base and the Reconstruction Cost New Less Depreciation Rate Base (RCND). The latter was determined as the original cost adjusted by inflation with accumulated depreciation deducted according to the estimated useful life of the assets.

Q. DO YOU HAVE ANY COMMENTS ON THIS APPROACH?

A. Yes. Standard financial economics would define Fair Market Value (FMV) as the price at which a willing buyer and seller would exchange the assets in question. Now I know that FMV is not the same as fair value, but my analysis shows that the Commission's approach is not unreasonable, albeit likely conservative at least as to the case of APS.

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[58] Arizona Constitution, Article 15, Section 14. http://www.azleg.gov/FormatDocument.asp?inDoc=/const/15/14.htm

Q. PLEASE DISCUSS ANY ANALYSIS YOU HAVE DONE TO TEST THE REASONABLENESS OF CALCULATING THE FVRB USING THE COMMISSION'S TRADITIONAL 50/50 WEIGHTING OF ORIGINAL COST AND RECONSTRUCTION COST NEW LESS DEPRECIATION RATE BASES.

A. To determine whether the methodology described above is reasonable, I looked at investor valuations of integrated electric utilities. Specifically, I analyzed the implied value of electric utilities' assets using recent transactions multiples. Using transaction data for 2013-2016, I found that the average implied asset value of integrated electric utilities were approximately 1.89 times the book value of assets. Transactions are a direct measure of the value that investors assign to a utility. The specifics of my analysis is presented in Attachment BV-5DR.

Figure 18: Market Valuations Indications

	Integrated Elec Util	Utilities
Transactions		
Average	89%	109%
Median	93%	97%
Minimum	46%	46%
Maximum	120%	156%%

Transaction multiples generally are the best indicator of fair value, so I recommend that the fair value be measured using the transaction multiple. Consequently, an analysis of financial markets show the FMV of the adjusted jurisdictional original cost rate base of $6.771 is about $12.797 billion.[59] The Company's calculation of FVRB is $9.976 billion, which is within the range of my above estimates, albeit near the bottom.

Q. HOW DO YOU PROPOSE THAT THE FVROR IS ESTIMATED?

A. The FVRB is supported by the same capital elements as is APS's original cost rate base, and there is no reason to believe that the weighting would change simply because the dollar amount is higher. Therefore, I propose that the FVRB be allowed a ROR that is

[59] Calculated as 1.89×$6.771 billion.

the weighted average of my recommended ROE of 10.5% and the embedded cost of debt of 5.13%, or 8.13%.

Another way would be to determine a return for the Fair Value Increment on a standalone basis and simply weight it in with the debt and equity components of original cost rate base. I suggest that a return of up to the inflation adjusted ROR is appropriate for the Fair Value Increment – this figure is 6.04%.[60] This would produce an overall FVROR of 7.46% by weighting the 6.04% return by the percentage of FVRB represented by the Fair Value Increment (32.13%) and weighting the 8.13% by the remaining percent of FVRB represented by original cost (67.87%).[61] Therefore, APS's proposed FVROR of 5.84%, including only a 1% return on the Fair Value Increment, is conservative.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[60] Using Blue Chip as of October 2015, the forecasted GDP inflation is 2.1%, so FVROR can be calculated as follows: (5.13%-2.1%)×44% + (10.5% - 2.1%%)×56% = 6.04%.

[61] Numbers are taken from Schedule A-1 of the Commission's Standard Filing Requirements accompanying the Application in this case.

BEFORE THE
ARIZONA CORPORATION COMMISSION

APPENDICES
TO THE
DIRECT TESTIMONY
OF
BENTE VILLADSEN

FOR
ARIZONA PUBLIC SERVICE COMPANY

Cost of Capital

June 1, 2016

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Appendix A: Resume of Dr. Bente Villadsen

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. In the regulatory finance area, Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent accounting work, she has been involved in accounting disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions. Her testimonies and expert reports pertain to accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, she was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where she taught financial and cost accounting. She has also taught graduate classes in econometrics and quantitative methods. Dr. Villadsen also worked as a consultant for Risoe National Laboratories in Denmark.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Credit Issues in the Utility Industry
- Damages and Valuation
  - Utility valuation
  - Lost Profit
  - Stock Price Drop

EXPERIENCE

Regulatory Finance

- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board and submitted expert reports on the determination of the cost of equity for U.S. freight railroads.
- For several electric, gas and transmission utilities in Alberta, Canada, Dr. Villadsen filed evidence on the cost of equity and appropriate capital structure for 2015-17. Her evidence was filed with the Alberta Utilities Commission.
- She has estimated the cost of equity on behalf of Portland General Electric, Anchorage Water and Wastewater, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony to Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also the impact of credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.
- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.

- For utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities, transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.
- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.

- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties.
- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.

- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).

Accounting and Corporate Finance

- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.

- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.

- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.

- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.

- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.

- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.

- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.

- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.

- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

PUBLICATIONS AND REPORTS

"Report on Gas LDC multiples," with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

"Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC," prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

"Brattle Review of AE Planning Methods and Austin Task Force Report." (with Frank C. Graves) September 24, 2014.

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

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Appendix B: Technical Appendix

I. Sample Selection

To identify publicly traded companies that engaged in electric utility operations, I rely on industry classifications provided by the *Value Line Investment Survey Plus Edition. Value Line* identifies 47 companies as electric utility companies.

To include a company, I require that over a five year study period and up to the date of the analysis, the sample companies have investment grade credit ratings, a high percentage of regulated assets (greater than 50 percent),[1] no dividend cuts, and no substantial mergers and acquisitions or other activity that could cause the growth rates or beta estimates to be biased. I also require that each of the sample companies has more than $300 million in reported revenue over the last four quarters of available financial data, since very small (in terms of market capitalization) publicly traded companies have been shown to have a higher cost of equity. Finally, I require that data from S&P or Moody's, Value Line, and Bloomberg — each widely known and utilized by investors — be available for all sample companies. These screens result in a sample of 27 companies of which two (Consolidated Edison and Centerpoint) own no or minimal generation. I further consider a subsample of companies, whose nuclear generation mix is of a magnitude that is within +/- 10% of that of APS and therefore constitute 17-37% of the sample company's total generation capacity.

II. CAPM and ECAPM

A. The Capital Asset Pricing Model (CAPM)

The Capital Asset Pricing Model (CAPM) is a theoretical model stating that the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 1 in my Written Evidence), in which the required expected return on an asset is proportional to that asset's risk relative to the market

[1] I use the Edison Electric Institute's classification of electric utilities as Regulated (greater than 80 percent of total assets are regulated), Mostly Regulated (50 to 80 percent of total assets are regulated) or Diversified (less than 50% of total assets are regulated). My sample includes only electric utilities classified by EEI as Regulated or Mostly Regulated.

as measured by its "beta". More precisely, the CAPM states that the cost of capital for an investment S (e.g., a particular common stock), is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \tag{1}$$

where $\boldsymbol{r_S}$ is the required return on investment S;
$\boldsymbol{r_f}$ is the risk-free interest rate;
$\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and
$\boldsymbol{MRP}$ is the market equity risk premium.

The CAPM is based on portfolio theory, and recognizes two fundamental principles of finance: (1) investors seek to minimize the possible variance of their returns for a given level of expected returns (or alternatively, they demand higher *expected* returns when there is greater uncertainty about those returns), and (2) investors can reduce the variability of their returns by diversifying—constructing portfolios of many assets that do not all go up or down at the same time or to the same degree. Under the assumptions of the CAPM, the market participants will construct portfolios of risky investments that minimize risk for a given return so that the aggregate holdings of all investors represent the "market portfolio". The risk-return trade-off faced by investors then concerns their exposure to the risk inherent in the market portfolio, as they weight their investment capital between the portfolio of risky assets and the risk-free asset.

Because of the effects of diversification, the relevant measure of risk for an individual security is its *contribution* to the risk of the market portfolio. Therefore, beta (β) is defined to capture the sensitivity of the security's returns to the market's returns. Formally,

$$\boldsymbol{\beta_s} = \frac{covariance(\boldsymbol{r_s}, \boldsymbol{R_m})}{variance(\boldsymbol{R_m})} \tag{2}$$

where $\boldsymbol{R_m}$ is the return on the market portfolio.

Beta is usually calculated by statistically comparing (using regression analysis) the excess (positive or negative) of the return on the individual security over the government bond rate with the excess of the return on a market index such as the S&P 500 over a government bond rate.

The basic idea behind beta is the risk that cannot be diversified away in large portfolios is what matters to investors. Beta is a measure of the risks that *cannot* be eliminated by diversification. It is this non-diversifiable risk, or "systematic risk", for which investors require compensation in the form of higher expected returns. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk; its returns vary to the same degree as those on the market as a whole.

According to the CAPM, the required return demanded by investors (i.e., the cost of equity) for investing in that stock will match the expected return on the market as a whole. Similarly, stocks with betas above 1.0 have more than average risk, and so have a cost of equity greater than the expected market return; those with betas below 1.0 have less than average risk, and are expected to earn lower than market levels of return.

B. INPUTS TO THE CAPM

1. The Risk-free Interest Rate

The precise meaning of a "risk-free" asset according to the finance theory underlying the CAPM is an investment whose return is guaranteed, with no possibility that it will vary around its expected value in response to the movements of the broader market. (Equivalently, the CAPM beta of a risk-free asset is zero.) In developed economies like the U.S., government debt are generally considered have no default risk. In this sense they are "risk-free"; however, unless they are held to maturity, the rate of return on government bonds may in fact vary around their stated or expected yields.[2]

The theoretical CAPM is a single period model, meaning that it posits a relationship between risk and return over a single "holding period" of an investment. Because investors can rebalance their portfolios over short horizons, many academic studies and practical applications of the CAPM use the short-term government bond as the measure of the risk-free rate of return. However, regulators frequently use a version based on a measure of the long-term risk-free rate; e.g., a long-term government bond. In accordance with the established practice, I rely on the 20-year Treasury bond as a measure of the risk-free asset in this proceeding. I use the term "risk-free rate" as describing the yield on the 20-year Treasury bond.

However, I do not believe the *current* yield on long-term Treasury bonds is a good estimate for the risk-free rate that will prevail over the time period relevant to this proceeding as currently prevailing bond yields are near historic lows for a variety of circumstances that should not be expected to persist for the reasons discussed in my direct testimony. For this reason I rely on Blue Chip's forecast of 3.4% for the yield on a 10-year Treasury bond for Q1 2017.[3] I adjust this value upward by 53 basis points, which is my estimate of the maturity premium for the 20-year

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2 This is due to interest rate fluctuations that can change the market value of previously issued debt in relation to the yield on new issuances

3 Blue Chip Economic Indicators, January 10, 2016.

over the 10-year Treasury Bond.[4] This gives me a base input of 3.93% for the risk-free rate of interest before considering any downward pressure on government bond yields.

Additionally, it is important to recognize the implications of the elevated level of spread between yields on utility bonds and Treasury bonds of the same horizon. Figure A-1 below shows that this yield spread is about 90 basis points higher now than it was on average prior to the 2008 financial crisis. One way to account for this observation is if the prevailing and near-term expected government bond yields are artificially depressed relative to longer-term market expectations. Therefore, I consider a scenario with the risk-free rate (conservatively) 80 basis points higher at 4.73% when performing my CAPM-based analyses.

Figure A-1

Spreads between U.S. Utility Bond (20 year maturity) and U.S. Government Bond (20 year maturity) - %

Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average Apr-1991 - 2007	0.93	1.23	[1]
Period 2 - Average Aug-2008 - Feb-2016	1.54	2.00	[2]
Period 3 - Average Feb-2016	1.83	2.59	[3]
Period 4 - Average 15-Day (Mar 02, 2016 to Feb 10, 2016)	1.85	2.56	[4]
Spread Increase between Period 2 and Period 1	0.60	0.77	[5] = [2] - [1]
Spread Increase between Period 3 and Period 1	0.90	1.36	[6] = [3] - [1]
Spread Increase between Period 4 and Period 1	**0.92**	**1.33**	[7] = [4] - [1]

Sources and Notes:
Spreads for the periods are calculated from Bloomberg's yield data.
Average monthly yields for the indices were retrieved from Bloomberg as of March 2, 2016.

2. The Market Equity Risk Premium

a. *Historical Average Market Risk Premium*

Like the cost of capital itself, the market risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable, and must be inferred or forecasted based on known market information.

[4] This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year Treasury Bonds over the period 1990 - 2015, using data from Bloomberg. See BV Workpaper 1.

One commonly use method for estimating the MRP is to measure the historical average premium of market returns over the income returns on risk-free government bonds over some long historical period. *Duff and Phelps* performs such a calculation of the MRP using the traditional Ibbotson data. The arithmetic average of annual observed market equity risk premiums from 1926 to the present is 7.0%.[5]

b. Forward Looking Market Equity Risk Premium

An alternative approach to estimating the MRP eschews historical averages in favor of using current market information and forecasts to infer the expected return on the market as a whole, which can then be compared to prevailing government bond yields to estimate the equity risk premium. Bloomberg performs such estimates of country-specific MRPs by implementing the DCF model on the market as a whole—using forecast market-wide dividend yields and current level on market indexes; for the U.S. Bloomberg uses the S&P500 to infer the expected market return.

The forward-looking market-implied MRP is elevated relative to the historical MRS and currently stands at 8.47%. The Bloomberg MRP measure is over a 10-year government bond, so converting that to the forecasted MRP over a 20-year government bond results in about 8%.[6]

c. Yield Spread Adjustments to the Market Equity Risk Premium

Figure A-1 above shows that the yield spreads for A and BBB rated utility debt over Treasury bonds have increased by approximately 90 bps and 130 bps for 20-year maturities relative to its long-term average leading up to the 2008 financial crisis. This means that investors require a higher return on investment grade utility debt relative to the return on t bonds than they did before the crisis and ensuing economic turmoil.

This information can be used to provide a quantitative benchmark for the implied increase in MRP based on a paper by Edwin J. Elton, et al., which documents that the yield spread on corporate bonds is normally a combination of a default premium, a tax premium, and a systematic risk premium.[7] Of these components, it is the systematic risk premium that likely

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5 Duff & Phelps, "2015 Valuation Handbook: Guide to Cost of Capital," p. 3-24.

6 Estimates of the MRP over a 20-year bond is obtained by subtracting the maturity premium of the 20-year over the 10-year government bond from the figure reported by Bloomberg. This maturity premium is about 50 basis points in the U.S.

7 "Explaining the Rate Spread on Corporate Bonds," Edwin J. Elton, Martin J. Gruber, Deepak Agarwal, and Christopher Mann, *The Journal of Finance*, February 2001, pp. 247-277.

explains the vast majority of the yield spread increase. In other words, unless the risk-free rate is underestimated as described above, the market equity risk premium has increased relative to its "normal" level.[8] Therefore, I consider a scenario allocating the majority of the 90 bps increase in A-rated utility spreads to an increase in the MRP (which drives the increase in systematic risk premium on A rated debt). As a conservative measure I allocate 80 bps as the downward bias in the current 20-year Treasury bond yield.

Assuming a beta of 0.25 for A rated debt[9] means that an increase in the MRP of one percentage point translates into a ¼ percentage point increase in the risk premium on A rated debt (i.e., 0.25 (beta) times 1 percentage point (increase in MRP) = ¼ percentage point increase in yield spread). Thus, an 80 bps increase in the yield spread is therefore consistent with a 3.2 percentage point increase in the MRP ($\frac{0.80\%}{0.25} = 3.2\%$). I consider this evidence as confirmation that the current MRP could be much higher than the historical MRP of 7%, but use conservatively 8% based on the recent Bloomberg forecast.

C. The Empirical CAPM

1. Description of the ECAPM

Empirical research has shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

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8 In theory, some of the increase in yield spread for A rated debt may be due to an increase in default risk, but the increase in default risk for A rated debt is undoubtedly very small because utilities with A range rated debt have a low default risk. This means that the vast majority—if not all—of the increase in A rated yield spreads is due to a combination of the increased systematic risk premium and the downward pressure on the yields of government debt. Although there is no increase in the tax premium discussed in the Elton et al. paper due to coupon payments, there may be some increase due to a small tax effect resulting from the probability of increased capital gains taxes when the debt matures.

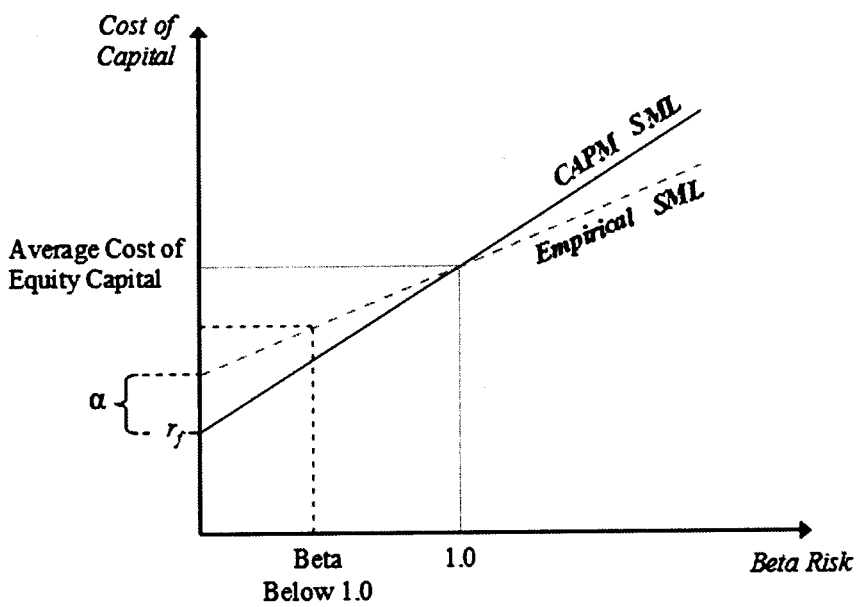
9 Elton, *et al.* estimates the average beta on BBB-rated corporate debt as 0.26 over the period of their study, and A-rated debt will have a slightly lower beta than BBB-rated debt. I note that 0.25 is a conservatively high estimate of the beta on A-rated utility debt. Most academic estimates, including those presented in *Berk & Demarzo* that I utilize for my Hamada adjustments are significantly lower: in the range of 0.0 – 0.1 percent and would result in a substantially higher MRP estimate.

The Empirical CAPM (ECAPM) makes use of these empirical findings. It estimates the cost of capital with the equation,

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \tag{3}$$

where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see Equation (1)). The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line, which results in a Security Market Line that more closely matches the results of empirical tests. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Figure A-2
The Empirical Security Market Line



2. Academic Evidence on the Alpha Term in the ECAPM

Figure A-3 below summarizes the empirical results of tests of the CAPM, including their estimates of the "alpha" parameter necessary to improve the accuracy of the CAPM's predictions of realized returns.

Figure A-3

EMPIRICAL EVIDENCE ON THE ALPHA FACTOR IN ECAPM*

AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993)[1]	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972)[2]	4.31%	1931-1965
Fama and McBeth (1972)	5.76%	1935-1968
Fama and French (1992)[3]	7.32%	1941-1990
Fama and French (2004)[4]	N/A	
Litzenberger and Ramaswamy (1979)[5]	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995)[6]	4.6%	1936-1990

*The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

[1]Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.
[2]Estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.
[3]Calculated using Ibbotson's data for the 30-day treasury yield.
[4]The article does not provide a specific estimate of alpha; however, it supports the general finding that the CAPM underestimates returns for low-beta stocks and overestimates returns for high-beta stocks.
[5]Relies on Lizenberger and Ramaswamy's before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.
[6]Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

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III. DCF Models

A. DCF Estimation of Cost of Equity

The DCF method for estimating the cost of equity capital assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \tag{4}$$

where P_0 is the current market price of the stock; D_t is the dividend cash flow expected at the end of period t; r is the cost of equity capital; and T is the last period in which a dividend cash flow is to be received. The formula simply says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received. Since the current market price is known, it is possible to infer the cost of equity that corresponds to that price and a forecasted pattern of expected future dividends. In terms of Equation (4, if P_0 is known and $D_1, D_2, \ldots D_T$ are estimated, an analyst can "solve for" the cost of equity capital r.

B. Details of the DCF Model

Perhaps the most widely known and used application of the DCF method assumes that the expected rate of dividend growth remains constant forever. In the so-called Gordon Growth Model, the relationship expressed in Equation (4) is such that the present value equation can be rearranged algebraically into a formula for estimating the cost of equity. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of the stock will be given by

$$P_0 = \frac{D_1}{r-g} \tag{5}$$

where D_1 is the dividend expected at the end of the first period, g is the perpetual growth rate, and P_0 and r are the market price and the cost of capital, as before. Equation (5) is a simplified version of Equation (4) that can be solved algebraically to yield the well-known "DCF formula" for the cost of equity capital,

$$r = \frac{D_1}{P_0} + g = \frac{D_0 \times (1+g)}{P_0} + g \tag{6}$$

There are other versions of the DCF model that relax this restrictive assumption and posit a more complex or nuanced pattern of expected future dividend payments. For example, if there is reason to believe that investors do *not* expect a company's dividends to grow at a steady rate forever, but rather have different growth rate expectations in the near term (e.g., over the next five or ten years), compared to the distant future (e.g., a period *starting* ten years from the present moment), a "multi-stage" growth pattern can be modeled in the present value formula (Equation (4)). I do not consider this model in this proceeding.

1. Dividends, Cash Flows, and Share Repurchases

In addition to the DCF model described above, there are many alternative formulations. Notable among these are versions of the model that use cash flows rather than dividends in the present value formula (Equation (4)).[10]

Because investors are interested in cash flow, it is technically important to capture *all* cash flows that are distributed to shareholders when estimating the cost of equity using the DCF method. In some circumstances, investors may expect to receive cash in forms other than dividends. An important example concerns the fact that many companies distribute cash to shareholders through share buybacks in addition to dividends. To the extent such repurchases are expected by investors, but not captured in the forecasted pattern of future dividends; a dividend-based implementation of the DCF model will <u>underestimate</u> the cost of equity.

Similarly, if investors have reason to suspect that a company's dividend payments will not reflect a full distribution of its available cash free cash flows in the period they were generated, it may be appropriate replace the forecasted dividends with estimated free cash flows to equity in the present value formula (Equation (4)). Focusing on *available* cash rather than that actually distributed in the form of dividends can help account for instances when near-term investing and financing activities (e.g., capital expenditures or asset sales, debt issuances or retirements, or share repurchases) may cause dividend growth patterns to diverge from growth in earnings.

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[10] For an example in a regulatory context, the U.S. Surface Transportation Board uses a cash flow based model with three stages to estimate the cost of equity for the railroads. See Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009.

Many utility companies such as those included in my samples have long histories of paying a dividend. In fact, as mentioned in Section I of this Appendix, one of my requirements for inclusion in my samples is that a company pays dividends for 5-years without a gap or a dividend cut (on per share basis). Additionally, although some electric utility companies have recently engaged in share repurchase programs, the companies in my samples do not distribute substantial cash flows by means other than dividends.[11]

C. DCF Model Inputs

1. Dividends and Prices

As described above, DCF models are forward-looking, comparing the *current* price of a stock to its expected *future* dividends to estimate the required expected return demanded by the market for that stock (i.e., the cost of equity). Therefore, the models demand the current market price and currently prevailing forecasts of future dividends as inputs.

The stock price input I employ for each sample company is the average of the closing stock prices for the 15 trading days ending on the date of my analysis. This guards against biases that may arise on a single trading day, yet is consistent with using current stock prices.

2. Company Specific Growth Rates

a. Analysts' Forecasted Growth Rates

Finding the right growth rate(s) is usually the "hard part" of applying the DCF model, which is sometimes criticized due to what has been called "optimism bias" in the earnings growth rate forecasts of security analysts. Optimism bias is related to the observed tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. This tendency to overestimate growth rates is perhaps related to incentives faced by analysts that provide rewards not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts the cost of capital estimates from the DCF model would be too high.

While academic researchers during the 1990s as well as in early 2000s found evidence of analysts' optimism bias, there is some evidence that regulatory reforms have eliminated the

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[11] While a number of companies in my samples have or have had share repurchase programs (e.g., El Paso), the magnitude tends to be relatively small, so that an inclusion of the cash flow from repurchases would likely have a minimal impact on the average results for the samples. However, it is clear that not including such repurchases downwardly biases the estimated cost of equity.

issue. A recent paper by Hovakimina and Saenyasiri (2010) found that recent efforts to curb analysts' incentive to provide optimistic forecasts have worked, so that "the median forecast bias essentially disappeared."[12] Thus, some recent research indicates that the analyst bias may be a problem of the past.

The findings of several academic studies[13] show that analyst earnings forecasts turn out to be too optimistic for stocks that are more difficult to value, for instance, stocks of smaller firms, firms with high volatility or turnover, younger firms, or firms whose prospects are uncertain. Coincidentally, stocks with greater analyst disagreement have higher analyst optimism bias—all of these describe companies that are more volatile and/or less transparent—none of which is applicable to the majority of utility companies with wide analyst coverage and information transparency.

b. Sources for Forecasted Growth Rates

For the reasons described above, I rely on analyst forecasts of earnings growth for the company-specific growth rate inputs to my implementations of the single- and multi-stage DCF models. All of the companies in my samples have coverage from equity analysts reporting to Thomson Reuters IBES, so I use the consensus 3-5 year EPS growth rate provided by that service. For the U.S. based samples, I supplement these consensus values with growth rates based on EPS estimates from *Value Line*.[14]

IV. Financial Risk and the Cost of Equity

A common issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated company.[15]

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[12] A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts Journal*, vol. 66, 2010.

[13] These studies include the following: (i) Hribar, P, McInnis, J. "Investor Sentiment and Analysts' Earnings Forecast Errors," *Management Science* Vol. 58, No. 2 (February 2012): pp. 293-307; (ii) Scherbina, A. (2004), "Analyst Disagreement, Forecast Bias and Stock Returns," downloaded from Harvard Business School Working Knowledge: http://hbswk.hbs.edu/item/5418.html; and (iii) Michel, J-S., Pandes J.A. (2012), "Are Analysts Really Too Optimistic?" downloaded from http://www.efmaefm.org.

[14] Specifically, I compute the growth rate implied by *Value Line*'s current year EPS estimate and its projected 3-5 year EPS estimate. I then average this in with the IBES consensus estimate as an additional independent estimate, giving it a weight of 1 and weighting the IBES consensus according to the number of analysts who contributed estimates.

[15] This is also a common valuation problem in general business contexts.

It may be tempting to simply estimate the cost of equity capital for each of the sample companies (using one of the above approaches) and average them. After-all, the companies were chosen to be comparable in their business risk characteristics, so why would an investor necessarily prefer equity in one to the other (on average)?

The problem with this argument is that it ignores the fact that underlying asset risk (i.e., the risk inherent in the lines of business in which the firm invests its assets) for each company is typically divided between debt and equity holders. The firm's debt and equity are therefore financial derivatives of the underlying asset return, each offering a differently structured claim on the cash flows generated by those assets. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders. The relative structures of debt and equity claims are such that higher degrees of debt financing increase the variability of returns on equity, *even when the variability of asset returns remains constant.* As a consequence, otherwise identical firms with different capital structures will impose different levels of risk on their equity holders. Stated differently, increased leverage adds financial risk to a company's equity.[16]

A. THE EFFECT OF FINANCIAL LEVERAGE ON THE COST OF EQUITY

To develop an intuition for the manner in which financial leverage affects the risk of equity, it is helpful to consider a concrete example. Figure A-4 and Figure A-5 below demonstrate the impact of leverage on the risk and return for equity by comparing equity's risk when a company uses no debt to finance its assets, and when it uses a 50-50 capital structure (i.e., it finances 50 percent of its assets with equity, 50 percent with debt). For illustrative purposes, the figures assume that the cash flows will be either $5 or $15 and that these two possibilities have the same chance of occurring (e.g., the chance that either occurs is ½).

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[16] I refer to this effect in terms of *financial risk* because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context financial risk is distinct from and independent of the *business risk* associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

Figure A-4: All Equity Capital Structure

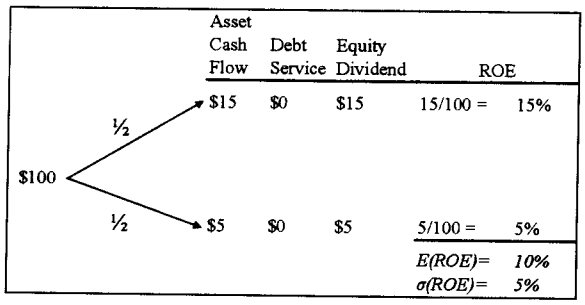
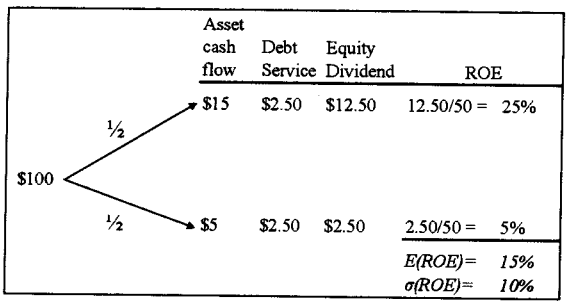


Figure A-5: 50/50 Capital Structure.



In the figures, E(ROE) indicates the mean return and σ(ROE) represents the variance. This simple example illustrates that the introduction of debt increases both the mean (expected) return to equity holders and the variance of that return, even though the firm's expected cash flows—which are a property of the line of business in which its assets are invested—are unaffected by the firm's financing choices. The "magic" of financial leverage is not magic at all—leveraged equity investors can only earn a higher return because they take on greater risk.

B. Methods to Account for Financial Risk

1. Cost of Equity Implied by the Overall Cost of Capital

If the companies in a sample are truly comparable in terms of the systematic risks of the underlying assets, then the overall cost of capital of each company should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. The intuition here is as follows. A firm's asset value (and return) is allocated between equity and debt holders.[17] The expected return to the underlying asset is therefore equal to the

[17] Other claimants can be added to the weighted average if they exist. For example, when a firm's capital structure contains preferred equity, the term $\frac{P}{V} \times r_p$ is added to the expression for the overall cost of capital shown in Equation (7), where P refers to the market value of preferred equity, r_P is the cost of preferred equity and $V = E + D + P$. In my analysis, I attribute the same implied yield to the cost of preferred equity as to the cost of debt.

value weighted average of the expected returns to equity and debt holders – which is the overall cost of capital ($\boldsymbol{r}^*$), or the expected return on the assets of the firm as a whole.[18]

$$\boldsymbol{r}^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D(1 - \tau_c) \tag{7}$$

where r_D is the market cost of debt,
r_E is the market cost of equity,
τ_c is the corporate income tax rate,
D is the market value of the firm's debt,
E is the market value of the firm's equity, and
$V = E + D$ is the total market value of the firm.

Since the overall cost of capital is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the overall cost of capital of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.[19]

The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.[20] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (i.e., the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at

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18 As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility. Note that the precise formulation of the weighted average formula representing the required return on the firm's *assets* independent of financing (sometimes called the *unlevered* cost of capital) depends on specific assumptions made regarding the value of tax shields from tax-deductible corporate debt, the role of personal income tax, and the cost of financial distress. See Taggart, Robert A., "Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management*, 1991; 20(3) for a detailed discussion of these assumptions and formulations. Equation (7) represents the overall cost of capital to the firm, which can be assumed to be constant across a relatively broad range of capital structures.

19 Empirically, companies within the same industry tend to have similar capital structures, while typical capital structures may vary between industries, so whether a leverage ratio is "unusual" depends upon the company's line of business.

20 Franco Modigliani and Merton H. Miller (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48, pp. 261-297.

all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,[21] showed that while taxes and costs to financial distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,[22] the latter can still be shown to be constant across a broad range of capital structures.[23]

This reasoning suggests that one could compute the overall cost of capital for each of the sample companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can then re-arrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis.[24]

2. Unlevering and Relevering Betas in the CAPM (Hamada Adjustment)

An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta. Notice that this means working within the CAPM framework as the methodology cannot be applied directly to the DCF models.

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21 Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

22 When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

23 This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

24 Market value capital structures are used in estimating the overall cost of capital for the sample companies.

Recognizing that under general conditions, the value of a firm can be decomposed into its value with and without a tax shield, I obtain:[25]

$$V = V_U + PV(ITS) \tag{8}$$

where $V = E + D$ is the total value of the firm as in Equation (7),

V_U is the "unlevered" value of the firm—its value if financed entirely by equity

$PV(ITS)$ represents the present value of the interest tax shields associated with debt

For a company with a fixed book-value capital structure and no additional costs to leverage, it can be shown that the formula above implies:

$$r_E = r_U + \frac{D}{E}(1 - \tau_c)(r_U - r_D) \tag{9}$$

where r_U is the "unlevered cost of capital"—the required return on assets if the firm's assets were financed with 100% equity and zero debt—and the other parameters are defined as in Equation (7).

Replacing each of these returns by their CAPM representation and simplifying them gives the following relationship between the "levered" equity beta β_L for a firm (i.e., the one observed in market data as a consequence of the firm's actual market value capital structure) and the "unlevered" beta β_U that would be measured for the same firm if it had no debt in its capital structure:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \tag{10}$$

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[25] This follows development in Fernandez (2003). Other standard papers in this area include Hamada (1972), Miles and Ezzell (1985), Harris and Pringle (1985), Fernandez (2006). (See Fernandez, P., "Levered and Unlevered Beta," IESE Business School Working Paper WP-488, University of Navarra, Jan 2003 (rev. May 2006); Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock," *Journal of Finance*, 27, May 1972, pp. 435-452; Miles, J.A. and J.R. Ezzell, "Reformulating Tax Shield Valuation: A Note," *Journal of Finance*, XL5, Dec 1985, pp. 1485-1492; Harris, R.S. and J.J. Pringle, "Risk-Adjusted Discount Rates Extensions form the Average-Risk Case," *Journal of Financial Research*, Fall 1985, pp. 237-244; Fernandez, P., "The Value of Tax Shields Depends Only on the Net Increases of Debt," IESE Business School Working Paper WP-613, University of Navarra, 2006.) Additional discussion can be found in Brealey, Myers, and Allen (2014).

where β_D is the beta on the firm's debt. The unlevered beta is assumed to be constant with respect to capital structure, reflecting as it does the systematic risk of the firm's assets. Since the beta on an investment grade firm's debt is much lower than the beta of its assets (i.e., $\beta_D < \beta_U$), this equation embodies the fact that increasing financial leverage (and thereby increasing the debt to equity ratio) increases the systematic risk of *levered* equity (β_L).

An alternative formulation derived by Harris and Pringle (1985) provides the following equation that holds when the market value capital structures (rather than book value) are assumed to be held constant:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \tag{11}$$

Unlike Equation (10), Equation (11) does not include an adjustment for the corporate tax deduction. However, both equations account for the fact that increased financial leverage increases the systematic risk of equity that will be measured by its market beta. And both equations allow an analyst to adjust for differences in financial risk by translating back and forth between β_L and β_U. In principal, Equation (10) is more appropriate for use with regulated utilities, which are typically deemed to maintain a fixed book value capital structure. However, I employ both formulations when adjusting my CAPM estimates for financial risk, and consider the results as sensitivities in my analysis.

It is clear that the beta of debt needs to be determined as an input to either Equation (10), or Equation (11). Rather than estimating debt betas, I rely on the standard financial textbook of Professors Berk & DeMarzo, who report a debt beta of 0.05 for A rated debt and a beta of 0.10 for BBB rated debt.[26]

Once a decision on debt betas is made, the levered equity beta of each sample company can be computed (in this case by Value Line) from market data and then translated to an unlevered beta at the company's market value capital structure. The unlevered betas for the sample companies are comparable on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the sample companies, independent of their financing. The unlevered betas are averaged to produce an estimate of the industry's unlevered beta. To estimate the cost of equity for the regulated target company, this estimate of unlevered beta can be "re-levered" to the

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[26] Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

regulated company's capital structure, and CAPM reapplied with this levered beta, which reflects both the business and financial risk of the target company.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada who contributed to their development[27]—are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

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[27] Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock", *The Journal of Finance*, 27(2), 1971, pp. 435-452.

	Net Income for Common Shareholders	End-of-Year Common Equity (x/NCI)	Return on EOY Equity	Allowed ROE	Under Earning
2002	199,343	2,159,312	9.2%	11.25%	$43,580
2003	180,937	2,203,630	8.2%	11.25%	$66,971
2004	199,627	2,232,402	8.9%	11.25%	$51,518
2005	170,479	2,985,225	5.7%	10.25%	$135,507
2006	269,730	3,207,473	8.4%	10.25%	$59,036
2007	283,940	3,351,441	8.5%	10.75%	$76,340
2008	262,344	3,339,150	7.9%	10.75%	$96,615
2009	251,225	3,445,355	7.3%	10.75%	$119,151
2010	335,663	3,824,953	8.8%	11.00%	$85,082
2011	336,250	3,943,007	8.5%	11.00%	$97,481
2012	395,497	4,093,000	9.7%	10.00%	$13,803
2013	424,969	4,308,884	9.9%	10.00%	$5,919
2014	421,220	4,478,243	9.4%	10.00%	$26,604
2015	450,274	4,663,057	9.7%	10.00%	$16,032
				Total	$893,637.94
				Average	$63,831.28

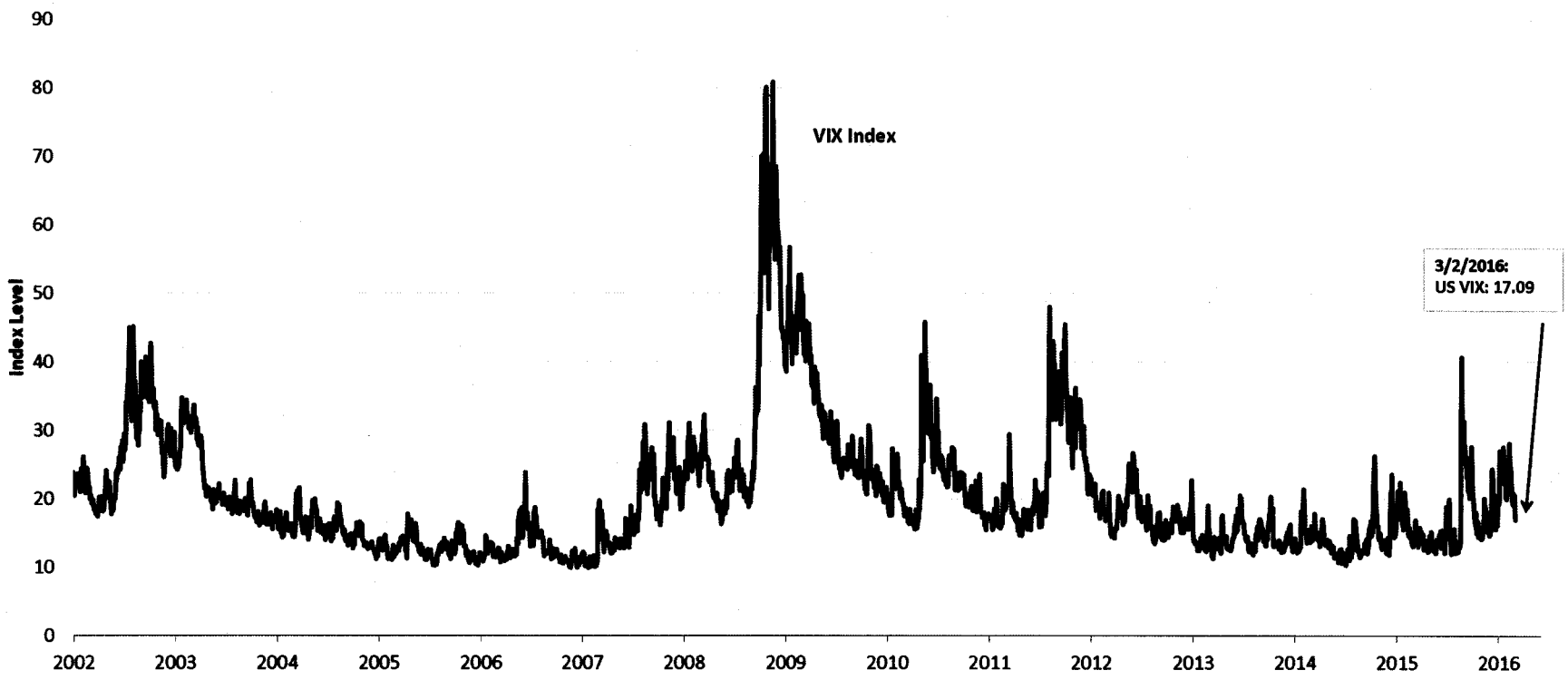
Spreads between U.S. Utility Bond (20 year maturity) and U.S. Government Bond (20 year maturity) - %

Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average Apr-1991 - 2007	0.93	1.23	[1]
Period 2 - Average Aug-2008 - Feb-2016	1.54	2.00	[2]
Period 3 - Average Feb-2016	1.83	2.59	[3]
Period 4 - Average 15-Day (Mar 02, 2016 to Feb 10, 2016)	1.85	2.56	[4]
Spread Increase between Period 2 and Period 1	0.60	0.77	[5] = [2] - [1]
Spread Increase between Period 3 and Period 1	0.90	1.36	[6] = [3] - [1]
Spread Increase between Period 4 and Period 1	**0.92**	**1.33**	[7] = [4] - [1]

Sources and Notes:

Spreads for the periods are calculated from Bloomberg's yield data.

Average monthly yields for the indices were retrieved from Bloomberg as of March 2, 2016.



Source: Bloomberg.

Company Financials ($Millions)

Company	Integrated Electric Utility	Date of M&A Announcement	Overall Premium	Gross Acquisition Value ($M)
[1]		[2]	[3]	[4]
ITC Holdings Corp		2/9/2016	154%	$11,398
Empire District Electric Co/The	Yes	2/9/2016	97%	$2,399
Questar Corp		2/1/2016	146%	$6,110
Piedmont Natural Gas Co Inc		10/26/2015	138%	$6,854
TECO Energy Inc	Yes	9/4/2015	120%	$10,582
AGL Resources Inc		8/24/2015	93%	$12,801
Oncor Electric Delivery Co LLC		8/10/2015	NA	NA
Dominion Carolina Gas Transmission LLC (a)		4/1/2015	NA	$508
UIL Holdings Corp/Old		2/25/2015	95%	$4,863
New Hampshire Gas Corp		1/2/2015	NA	$3
Dominion Carolina Gas Transmission LLC (b)		12/16/2014	NA	$493
Hawaiian Electric Industries Inc	Yes	12/3/2014	46%	$4,913
Cleco Corp	Yes	10/20/2014	109%	$4,652
Integrys Energy Group Inc	Yes	6/23/2014	75%	$8,889
Upper Peninsula Power Co	Yes	1/20/2014	NA	$299
NV Energy Inc	Yes	5/29/2013	89%	$10,588
Average of Integrated Electic Utilities			**89%**	**$6,046**
Average of All Companies			**106%**	**$5,690**

Sources/Notes:

Company financials were taken from the most recent 10-K filed prior to the acquisition date.

[2],[4]: Bloomberg.

[3]: Calculated.

Company Financials ($Millions)

Company	Integrated Electric Utility	Date of M&A Announcement	Total Assets	Total Long-Term Assets	Net PP&E	Market Cap	Revenue	Net Income	Equity %	Book Equity	Shares Outstanding	Offer Price Per Share ($)	Book Equity per Share ($)	Premium on Equity	Overall Premium	Gross Acquisition Value ($M)
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
ITC Holdings Corp		2/9/2016	$7,406	$7,187	$5,890	$5,882	$273	$66	23%	$1,682	152	$75	$11	678%	154%	$11,398
Empire District Electric Co/The	Yes	2/9/2016	$2,463	$2,262	$2,008	$1,235	$170	$25	33%	$802	44	$55	$18	299%	97%	$2,399
Questar Corp		2/1/2016	$4,187	$3,911	$3,816	$4,369	$142	$33	31%	$1,293	175	$35	$7	472%	146%	$6,110
Piedmont Natural Gas Co Inc		10/26/2015	$4,951	$4,729	$4,226	$4,580	$158	-$8	28%	$1,406	79	$87	$18	487%	138%	$6,854
TECO Energy Inc	Yes	9/4/2015	$8,838	$8,059	$7,242	$4,956	$681	$12	29%	$2,553	235	$45	$11	414%	120%	$10,582
AGL Resources Inc		8/24/2015	$13,835	$12,263	$9,379	$7,375	$674	$42	29%	$3,989	120	$107	$33	321%	93%	$12,801
Oncor Electric Delivery Co LLC		8/10/2015	$19,173	$18,331	$12,229	NA	$938	$98	39%	$7,551	NA	NA	NA	NA	NA	NA
Dominion Carolina Gas Transmission LLC (a)		4/1/2015	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	$508
UIL Holdings Corp/Old		2/25/2015	$5,112	$4,442	$3,293	$2,394	$433	$32	27%	$1,368	57	$86	$24	355%	95%	$4,863
New Hampshire Gas Corp		1/2/2015	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	$3
Dominion Carolina Gas Transmission LLC (b)		12/16/2014	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	$493
Hawaiian Electric Industries Inc	Yes	12/3/2014	$10,670	$5,818	$4,048	$2,891	$867	$48	17%	$1,836	103	$48	$18	268%	46%	$4,913
Cleco Corp	Yes	10/20/2014	$4,256	$3,776	$3,144	$3,214	$371	$71	39%	$1,639	60	$77	$27	284%	109%	$4,652
Integrys Energy Group Inc	Yes	6/23/2014	$11,802	$9,085	$6,301	$5,436	$1,638	$152	29%	$3,406	80	$112	$43	261%	75%	$8,889
Upper Peninsula Power Co	Yes	1/20/2014	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	$299
NV Energy Inc	Yes	5/29/2013	$11,879	$11,034	$9,429	$4,539	$577	$21	30%	$3,544	235	$45	$15	299%	89%	$10,588
Average of Integrated Electic Utilities			**$8,318**	**$6,672**	**$5,362**	**$3,712**	**$717**	**$55**	**29%**	**$2,297**	**$126**	**$64**	**$22**	**304%**	**89%**	**$6,046**

Sources/Notes:

Company financials were taken from the most recent 10-K filed prior to the acquisition date

[3]-[11]: Capital IQ.

[2],[16]: Bloomberg.

Financial Summary of Recent M&A Transactions

Company Name	Ticker	M&A Announce Date	Date from Latest Filing BEFORE Announcement											
			Filing Quarter	Total Long-Term Assets	Total Assets	Total Current Assets	Total PP&E	Market Cap (as of announce date)	Revenue	Operating Income	Net Income	Book Equity	Shares Outstanding	Equity %
ITC Holdings Corp	NYSE:ITC	2/9/2016	FQ3 2015	7,187	7,405.6	218.9	5,890.1	5,882.3	273.2	149.6	65.6	1,681.9	152.2	23%
Empire District Electric Co/The	NYSE:EDE	2/9/2016	FQ3 2015	2,262	2,462.8	200.8	2,008.3	1,235.2	169.7	51.6	25.3	802.5	43.8	33%
Questar Corp	NYSE:STR	2/1/2016	FQ3 2015	3,911	4,187.4	276.3	3,816.0	4,369.4	142.3	62.1	32.6	1,293.3	174.8	31%
Piedmont Natural Gas Co Inc	NYSE:PNY	10/26/2015	FQ3 2015	4,729	4,951.4	222.3	4,225.6	4,579.6	158.3	-1.9	-8.3	1,406.1	79.2	28%
TECO Energy Inc	NYSE:TE	9/4/2015	FQ2 2015	8,059	8,838.4	779.2	7,241.7	4,956.0	680.6	143.3	11.8	2,553.3	235.2	29%
AGL Resources Inc	NYSE:GAS	8/24/2015	FQ2 2015	12,263	13,835.0	1,572.0	9,379.0	7,374.6	674.0	107.0	42.0	3,989.0	120.1	29%
Oncor Electric Delivery Co LLC	IQ3062378	8/10/2015	FQ2 2015	18,331	19,173.0	842.0	12,229.0	NA	938.0	243.0	98.0	7,551.0	NA	39%
Dominion Caroline Gas Transmission LLC (a)	IQ4208869	4/1/2015	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UIL Holdings Corp/Old	IQ310736	2/25/2015	FQ4 2014	4,442	5,111.9	670.1	3,292.7	2,393.6	433.0	73.8	32.3	1,368.3	56.5	27%
New Hampshire Gas Corp	IQ268216482	1/2/2015	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dominion Caroline Gas Transmission LLC (b)	IQ4208869	12/16/2014	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Industries Inc	NYSE:HE	12/3/2014	FQ3 2014	5,818	10,670.5	4,852.8	4,048.1	2,891.2	867.1	92.0	47.8	1,835.7	102.6	17%
Cleco Corp	NYSE:CNL	10/20/2014	FQ3 2014	3,776	4,256.3	480.1	3,144.2	3,214.4	371.4	108.4	70.8	1,638.9	60.4	39%
Integrys Energy Group Inc	IQ315149	6/23/2014	FQ1 2014	9,085	11,802.2	2,717.1	6,301.2	5,436.2	1,638.0	232.3	152.4	3,406.0	79.5	29%
Pepco Holdings Inc	NYSE:POM	4/30/2014	FQ1 2014	13,540	15,004.0	1,464.0	9,906.0	6,706.6	1,330.0	173.0	75.0	4,336.0	250.6	29%
Philadelphia Gas Works operations	IQ8032486	3/3/2014	FY 2013	1,366	1,711.0	345.0	1,155.0	NA	683.5	109.5	60.6	358.6	NA	21%
Upper Peninsula Power Co	IQ4762134	1/20/2014	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NV Energy Inc	IQ109136	5/29/2013	FQ1 2013	11,034	11,878.6	844.8	9,428.8	4,539.4	577.0	99.0	21.0	3,543.9	235.4	30%
New Mexico Gas Co Inc	IQ40117829	5/28/2013	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Arizona Public Service	IQ388114	2/16/2016	FQ3 2015	13,788	14,838.1	1,050.2	11,327.5	NA	1,198.4	449.8	261.2	4,894.8	NA	33%

Sources/Notes:
Capital IQ.

Table No. BV-ELEC-1

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Table No. BV-ELEC-2

Classification of Companies by Assets

Company	Company Category
ALLETE	R
Alliant Energy	R
Amer. Elec. Power	R
Ameren Corp.	R
CenterPoint Energy	M
CMS Energy Corp.	R
Consol. Edison	R
Dominion Resources	M
DTE Energy	R
Edison Int'l	R
El Paso Electric	R
Entergy Corp.	R
G't Plains Energy	R
IDACORP Inc.	R
MGE Energy	M
NextEra Energy	M
OGE Energy	R
Otter Tail Corp.	R
PG&E Corp.	R
Pinnacle West Capital	R
Portland General	R
Public Serv. Enterprise	M
SCANA Corp.	M
Sempra Energy	M
Vectren Corp.	M
Westar Energy	R
Xcel Energy Inc.	R

Sources and Notes:
Percent regulated categories and company data are based on Edison Electric Institute: "Rate Case Summary - Q3 2015 Financial Update".
R = Regulated (greater than 80 percent of total assets are regulated).
M = Mostly Regulated (50 to 80 percent of total assets are regulated).
D = Diversified (less than 50 percent of total assets are regulated).

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel A: ALLETE

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,822	$1,822	$1,529	$1,288	$1,158	$1,051	$975	[a]
Shares Outstanding (in millions) - Common	49	49	45	41	39	37	36	[b]
Price per Share - Common	$52	$49	$46	$48	$42	$38	$36	[c]
Market Value of Common Equity	$2,540	$2,393	$2,048	$1,941	$1,616	$1,384	$1,286	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$2,540	$2,393	$2,048	$1,941	$1,616	$1,384	$1,286	[f]= [d]
Market to Book Value of Common Equity	1.39	1.31	1.34	1.51	1.40	1.32	1.32	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$403	$403	$358	$369	$278	$303	$294	[j]
Current Liabilities	$318	$318	$287	$224	$215	$122	$131	[k]
Current Portion of Long-Term Debt	$49	$49	$85	$38	$67	$13	$2	[l]
Net Working Capital	$135	$135	$156	$183	$131	$194	$165	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$3	$1	$0	$6	$1	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,549	$1,549	$1,289	$1,064	$948	$844	$784	[p]
Book Value of Long-Term Debt	$1,598	$1,598	$1,375	$1,102	$1,015	$857	$786	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,485	$1,485	$1,132	$1,144	$966	$797	$735	
Carrying Amount	$1,374	$1,374	$1,110	$1,018	$863	$785	$701	
Adjustment to Book Value of Long-Term Debt	$111	$111	$22	$126	$103	$12	$34	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,709	$1,709	$1,396	$1,228	$1,118	$869	$820	[s] = [q] + [r].
Market Value of Debt	$1,709	$1,709	$1,396	$1,228	$1,118	$869	$820	[t] = [s].
MARKET VALUE OF FIRM	$4,249	$4,102	$3,444	$3,169	$2,734	$2,253	$2,106	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.78%	58.33%	59.47%	61.26%	59.11%	61.43%	61.08%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	40.22%	41.67%	40.53%	38.74%	40.89%	38.57%	38.92%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel B: Alliant Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,745	$3,745	$3,436	$3,267	$3,116	$3,002	$2,888	[a]
Shares Outstanding (in millions) - Common	113.36	113	111	111	111	111	111	[b]
Price per Share - Common	65.26	$57	$57	$50	$44	$39	$36	[c]
Market Value of Common Equity	$7,398	$6,434	$6,291	$5,494	$4,871	$4,340	$4,001	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$7,398	$6,434	$6,291	$5,494	$4,871	$4,340	$4,001	[f]= [d]
Market to Book Value of Common Equity	1.98	1.72	1.83	1.68	1.56	1.45	1.39	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$200	$200	$200	$200	$205	$205	$244	[h]
Market Value of Preferred Equity	$200	$200	$200	$200	$205	$205	$244	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,088	$1,088	$962	$880	$1,029	$947	$1,168	[j]
Current Liabilities	$991	$991	$1,742	$1,053	$946	$774	$692	[k]
Current Portion of Long-Term Debt	$3	$3	$493	$48	$1	$1	$1	[l]
Net Working Capital	$100	$100	($287)	($124)	$84	$174	$477	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$109	$109	$354	$237	$70	$22	$0	[n]
Adjusted Short-Term Debt	$0	$0	$287	$124	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$3,856	$3,856	$2,800	$3,105	$2,828	$2,704	$2,704	[p]
Book Value of Long-Term Debt	$3,859	$3,859	$3,579	$3,278	$2,830	$2,705	$2,705	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$4,418	$4,418	$3,712	$3,861	$3,325	$2,959	$2,676	
Carrying Amount	$3,790	$3,790	$3,336	$3,138	$2,705	$2,705	$2,506	
Adjustment to Book Value of Long-Term Debt	$629	$629	$376	$722	$621	$254	$170	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$4,487	$4,487	$3,955	$4,000	$3,450	$2,959	$2,875	[s] = [q] + [r].
Market Value of Debt	$4,487	$4,487	$3,955	$4,000	$3,450	$2,959	$2,875	[t] = [s].
MARKET VALUE OF FIRM	$12,085	$11,121	$10,446	$9,694	$8,526	$7,504	$7,119	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	61.21%	57.85%	60.22%	56.68%	57.13%	57.84%	56.20%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	1.65%	1.80%	1.91%	2.06%	2.41%	2.73%	3.42%	[w] = [i] / [u].
Debt - Market Value Ratio	37.13%	40.35%	37.86%	41.26%	40.47%	39.43%	40.38%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel C: Amer. Elec. Power

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$17,699	$17,699	$16,868	$15,762	$15,306	$14,653	$13,656	[a]
Shares Outstanding (in millions) - Common	491	491	489	487	485	483	480	[b]
Price per Share - Common	$60	$55	$53	$43	$44	$38	$36	[c]
Market Value of Common Equity	$29,588	$27,037	$25,812	$21,167	$21,277	$18,174	$17,446	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$29,588	$27,037	$25,812	$21,167	$21,277	$18,174	$17,446	[f]= [d]
Market to Book Value of Common Equity	1.67	1.53	1.53	1.34	1.39	1.24	1.28	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$60	$60	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$60	$60	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,548	$4,548	$4,111	$4,317	$4,648	$4,374	$5,421	[j]
Current Liabilities	$7,058	$7,058	$7,457	$5,692	$6,795	$5,684	$6,148	[k]
Current Portion of Long-Term Debt	$1,826	$1,826	$2,381	$1,366	$2,272	$1,267	$1,286	[l]
Net Working Capital	($684)	($684)	($965)	($9)	$125	($43)	$559	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$782	$782	$1,282	$1,218	$1,216	$1,279	$1,466	[n]
Adjusted Short-Term Debt	$684	$684	$965	$9	$0	$43	$0	[o] = See Sources and Notes.
Long-Term Debt	$17,600	$17,600	$15,677	$16,202	$14,955	$15,183	$15,995	[p]
Book Value of Long-Term Debt	$20,110	$20,110	$19,023	$17,577	$17,227	$16,493	$17,281	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$21,075	$21,075	$19,672	$20,907	$19,259	$18,285	$18,479	
Carrying Amount	$18,684	$18,684	$18,377	$17,757	$16,516	$16,811	$17,498	
Adjustment to Book Value of Long-Term Debt	$2,391	$2,391	$1,295	$3,150	$2,743	$1,474	$981	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$22,501	$22,501	$20,318	$20,727	$19,970	$17,967	$18,262	[s] = [q] + [r].
Market Value of Debt	$22,501	$22,501	$20,318	$20,727	$19,970	$17,967	$18,262	[t] = [s].
MARKET VALUE OF FIRM	$52,089	$49,538	$46,130	$41,894	$41,247	$36,201	$35,768	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.80%	54.58%	55.95%	50.53%	51.58%	50.20%	48.78%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	0.17%	0.17%	[w] = [i] / [u].
Debt - Market Value Ratio	43.20%	45.42%	44.05%	49.47%	48.42%	49.63%	51.06%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel D: Ameren Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$7,014	$7,014	$6,774	$6,574	$7,874	$7,997	$7,754	[a]
Shares Outstanding (in millions) - Common	243	243	243	243	243	242	240	[b]
Price per Share - Common	$45	$40	$38	$34	$33	$30	$28	[c]
Market Value of Common Equity	$10,890	$9,802	$9,318	$8,311	$7,920	$7,286	$6,689	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$10,890	$9,802	$9,318	$8,311	$7,920	$7,286	$6,689	[f]= [d]
Market to Book Value of Common Equity	1.55	1.40	1.38	1.26	1.01	0.91	0.86	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,983	$1,983	$1,942	$3,273	$2,406	$2,680	$3,120	[j]
Current Liabilities	$2,489	$2,489	$2,119	$3,228	$1,546	$1,848	$1,914	[k]
Current Portion of Long-Term Debt	$395	$395	$119	$884	$206	$178	$354	[l]
Net Working Capital	($111)	($111)	($58)	$929	$1,066	$1,010	$1,560	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$783	$783	$753	$0	$5	$350	$125	[n]
Adjusted Short-Term Debt	$111	$111	$58	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$5,981	$5,981	$5,825	$5,274	$6,781	$6,682	$7,259	[p]
Book Value of Long-Term Debt	$6,487	$6,487	$6,002	$6,158	$6,987	$6,860	$7,613	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$7,135	$7,135	$6,584	$7,110	$7,800	$7,661	$7,717	
Carrying Amount	$6,240	$6,240	$6,038	$6,157	$6,856	$7,008	$7,315	
Adjustment to Book Value of Long-Term Debt	$895	$895	$546	$953	$944	$653	$402	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$7,382	$7,382	$6,548	$7,111	$7,931	$7,513	$8,015	[s] = [q] + [r].
Market Value of Debt	$7,382	$7,382	$6,548	$7,111	$7,931	$7,513	$8,015	[t] = [s].
MARKET VALUE OF FIRM	$18,272	$17,184	$15,866	$15,422	$15,851	$14,799	$14,704	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.60%	57.04%	58.73%	53.89%	49.97%	49.23%	45.49%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	40.40%	42.96%	41.27%	46.11%	50.03%	50.77%	54.51%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel E: CenterPoint Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$4,058	$4,058	$4,473	$4,261	$4,257	$4,207	$3,129	[a]
Shares Outstanding (in millions) - Common	430	430	430	429	427	426	423	[b]
Price per Share - Common	$18	$18	$24	$24	$21	$20	$15	[c]
Market Value of Common Equity	$7,687	$7,692	$10,424	$10,139	$8,997	$8,331	$6,514	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$7,687	$7,692	$10,424	$10,139	$8,997	$8,331	$6,514	[f]= [d]
Market to Book Value of Common Equity	1.89	1.90	2.33	2.38	2.11	1.98	2.08	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,400	$2,400	$2,576	$2,319	$2,752	$1,982	$2,143	[j]
Current Liabilities	$3,191	$3,191	$3,008	$2,595	$3,364	$2,319	$2,881	[k]
Current Portion of Long-Term Debt	$938	$938	$722	$553	$1,402	$483	$978	[l]
Net Working Capital	$147	$147	$290	$277	$790	$146	$240	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$49	$49	$80	$70	$53	$84	$73	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$7,662	$7,662	$7,797	$7,758	$8,415	$8,497	$8,267	[p]
Book Value of Long-Term Debt	$8,600	$8,600	$8,519	$8,311	$9,817	$8,980	$9,245	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$9,427	$9,427	$8,670	$10,807	$10,049	$10,071	$10,413	
Carrying Amount	$8,652	$8,652	$8,171	$9,619	$8,994	$9,303	$9,900	
Adjustment to Book Value of Long-Term Debt	$775	$775	$499	$1,188	$1,055	$768	$513	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$9,375	$9,375	$9,018	$9,499	$10,872	$9,748	$9,758	[s] = [q] + [r].
Market Value of Debt	$9,375	$9,375	$9,018	$9,499	$10,872	$9,748	$9,758	[t] = [s].
MARKET VALUE OF FIRM	$17,062	$17,067	$19,442	$19,638	$19,869	$18,079	$16,272	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	45.05%	45.07%	53.62%	51.63%	45.28%	46.08%	40.03%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	54.95%	54.93%	46.38%	48.37%	54.72%	53.92%	59.97%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel F: CMS Energy Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,902	$3,902	$3,670	$3,396	$3,196	$3,043	$2,821	[a]
Shares Outstanding (in millions) - Common	277	277	275	266	264	252	230	[b]
Price per Share - Common	$38	$34	$30	$26	$23	$20	$18	[c]
Market Value of Common Equity	$10,597	$9,338	$8,161	$7,018	$6,141	$4,997	$4,116	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$10,597	$9,338	$8,161	$7,018	$6,141	$4,997	$4,116	[f]= [d]
Market to Book Value of Common Equity	2.72	2.39	2.22	2.07	1.92	1.64	1.46	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$239	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$239	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,123	$2,123	$2,734	$2,401	$2,360	$2,860	$3,086	[j]
Current Liabilities	$1,788	$1,788	$1,648	$1,464	$1,485	$2,214	$2,297	[k]
Current Portion of Long-Term Debt	$741	$741	$690	$532	$510	$1,140	$1,031	[l]
Net Working Capital	$1,076	$1,076	$1,776	$1,469	$1,385	$1,786	$1,820	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$68	$68	$0	$0	$0	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$8,014	$8,014	$8,171	$7,229	$6,866	$6,208	$6,203	[p]
Book Value of Long-Term Debt	$8,755	$8,755	$8,861	$7,761	$7,376	$7,348	$7,234	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$9,285	$9,285	$8,368	$8,347	$8,025	$7,861	$7,013	
Carrying Amount	$8,535	$8,535	$7,642	$7,229	$7,073	$7,174	$6,567	
Adjustment to Book Value of Long-Term Debt	$750	$750	$726	$1,118	$952	$687	$446	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$9,505	$9,505	$9,587	$8,879	$8,328	$8,035	$7,680	[s] = [q] + [r].
Market Value of Debt	$9,505	$9,505	$9,587	$8,879	$8,328	$8,035	$7,680	[t] = [s].
MARKET VALUE OF FIRM	$20,102	$18,843	$17,748	$15,897	$14,469	$13,032	$12,035	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	52.72%	49.56%	45.98%	44.15%	42.44%	38.34%	34.20%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	1.99%	[w] = [i] / [u].
Debt - Market Value Ratio	47.28%	50.44%	54.02%	55.85%	57.56%	61.66%	63.82%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel G: Consol. Edison

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$13,040	$13,040	$12,707	$12,166	$11,842	$11,454	$10,630	[a]
Shares Outstanding (in millions) - Common	293	293	293	293	293	293	284	[b]
Price per Share - Common	$70	$65	$57	$56	$60	$57	$48	[c]
Market Value of Common Equity	$20,617	$18,927	$16,614	$16,301	$17,522	$16,659	$13,687	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$20,617	$18,927	$16,614	$16,301	$17,522	$16,659	$13,687	[f]= [d]
Market to Book Value of Common Equity	1.58	1.45	1.31	1.34	1.48	1.45	1.29	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$213	$213	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$213	$213	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,505	$3,505	$3,519	$3,704	$3,240	$3,458	$3,890	[j]
Current Liabilities	$4,429	$4,429	$3,873	$4,373	$3,724	$2,959	$3,147	[k]
Current Portion of Long-Term Debt	$761	$761	$210	$483	$930	$305	$5	[l]
Net Working Capital	($163)	($163)	($144)	($186)	$446	$804	$748	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,160	$1,160	$1,425	$1,220	$340	$0	$846	[n]
Adjusted Short-Term Debt	$163	$163	$144	$186	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$11,521	$11,521	$10,986	$10,495	$9,841	$10,371	$10,675	[p]
Book Value of Long-Term Debt	$12,445	$12,445	$11,340	$11,164	$10,771	$10,676	$10,680	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$13,998	$13,998	$12,082	$12,935	$12,744	$11,761	$10,585	
Carrying Amount	$12,191	$12,191	$10,974	$10,768	$10,673	$10,676	$10,585	
Adjustment to Book Value of Long-Term Debt	$1,807	$1,807	$1,108	$2,167	$2,071	$1,085	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$14,252	$14,252	$12,448	$13,331	$12,842	$11,761	$10,680	[s] = [q] + [r].
Market Value of Debt	$14,252	$14,252	$12,448	$13,331	$12,842	$11,761	$10,680	[t] = [s].
MARKET VALUE OF FIRM	$34,869	$33,179	$29,062	$29,632	$30,364	$28,633	$24,580	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.13%	57.05%	57.17%	55.01%	57.71%	58.18%	55.68%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	0.74%	0.87%	[w] = [i] / [u].
Debt - Market Value Ratio	40.87%	42.95%	42.83%	44.99%	42.29%	41.07%	43.45%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel H: Dominion Resources

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$12,592	$12,592	$11,573	$11,242	$11,818	$11,632	$12,095	[a]
Shares Outstanding (in millions) - Common	595	595	584	580	575	570	581	[b]
Price per Share - Common	$70	$69	$69	$62	$53	$50	$44	[c]
Market Value of Common Equity	$41,731	$41,040	$40,119	$35,768	$30,376	$28,377	$25,488	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$41,731	$41,040	$40,119	$35,768	$30,376	$28,377	$25,488	[f]= [d]
Market to Book Value of Common Equity	3.31	3.26	3.47	3.18	2.57	2.44	2.11	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$134	$257	$257	$257	$257	[h]
Market Value of Preferred Equity	$0	$0	$134	$257	$257	$257	$257	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,123	$4,123	$5,446	$5,210	$4,653	$5,267	$5,995	[j]
Current Liabilities	$6,746	$6,746	$7,579	$6,453	$6,562	$5,496	$4,927	[k]
Current Portion of Long-Term Debt	$1,528	$1,528	$1,591	$1,132	$2,175	$1,327	$776	[l]
Net Working Capital	($1,095)	($1,095)	($542)	($111)	$266	$1,098	$1,844	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$2,555	$2,555	$2,629	$2,145	$1,382	$783	$100	[n]
Adjusted Short-Term Debt	$1,095	$1,095	$542	$111	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$23,245	$23,245	$20,666	$18,548	$17,144	$17,153	$16,023	[p]
Book Value of Long-Term Debt	$25,868	$25,868	$22,799	$19,791	$19,319	$18,480	$16,799	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$21,881	$21,881	$19,887	$19,898	$18,936	$16,112	$15,970	
Carrying Amount	$19,723	$19,723	$18,396	$16,841	$16,264	$14,520	$14,867	
Adjustment to Book Value of Long-Term Debt	$2,158	$2,158	$1,491	$3,057	$2,672	$1,592	$1,103	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$28,026	$28,026	$24,290	$22,848	$21,991	$20,072	$17,902	[s] = [q] + [r].
Market Value of Debt	$28,026	$28,026	$24,290	$22,848	$21,991	$20,072	$17,902	[t] = [s].
MARKET VALUE OF FIRM								
	$69,757	$69,066	$64,543	$58,873	$52,624	$48,706	$43,647	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.82%	59.42%	62.16%	60.75%	57.72%	58.26%	58.40%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	0.21%	0.44%	0.49%	0.53%	0.59%	[w] = [i] / [u].
Debt - Market Value Ratio	40.18%	40.58%	37.63%	38.81%	41.79%	41.21%	41.01%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel I: DTE Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$8,812	$8,812	$8,169	$7,876	$7,389	$6,970	$6,646	[a]
Shares Outstanding (in millions) - Common	179	179	177	177	172	169	169	[b]
Price per Share - Common	$84	$78	$76	$67	$59	$49	$47	[c]
Market Value of Common Equity	$15,122	$13,951	$13,475	$11,792	$10,192	$8,372	$7,879	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$15,122	$13,951	$13,475	$11,792	$10,192	$8,372	$7,879	[f]= [d]
Market to Book Value of Common Equity	1.72	1.58	1.65	1.50	1.38	1.20	1.19	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,700	$2,700	$2,755	$2,549	$2,730	$2,911	$2,741	[j]
Current Liabilities	$2,273	$2,273	$2,805	$3,008	$2,309	$2,100	$2,513	[k]
Current Portion of Long-Term Debt	$468	$468	$274	$896	$633	$247	$923	[l]
Net Working Capital	$895	$895	$224	$437	$1,054	$1,058	$1,151	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$185	$185	$653	$271	$98	$275	$20	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$8,856	$8,856	$7,909	$6,846	$7,120	$7,497	$7,074	[p]
Book Value of Long-Term Debt	$9,324	$9,324	$8,183	$7,742	$7,753	$7,744	$7,997	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$9,503	$9,503	$8,475	$8,893	$8,757	$8,500	$8,300	
Carrying Amount	$8,606	$8,606	$8,094	$7,813	$7,682	$8,000	$8,000	
Adjustment to Book Value of Long-Term Debt	$897	$897	$381	$1,080	$1,075	$500	$300	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$10,221	$10,221	$8,564	$8,822	$8,828	$8,244	$8,297	[s] = [q] + [r].
Market Value of Debt	$10,221	$10,221	$8,564	$8,822	$8,828	$8,244	$8,297	[t] = [s].
MARKET VALUE OF FIRM	$25,343	$24,172	$22,039	$20,614	$19,020	$16,616	$16,176	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.67%	57.71%	61.14%	57.20%	53.59%	50.38%	48.71%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	40.33%	42.29%	38.86%	42.80%	46.41%	49.62%	51.29%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel J: Edison Int'l

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$11,600	$11,600	$10,736	$9,689	$10,023	$11,015	$10,634	[a]
Shares Outstanding (in millions) - Common	326	326	326	326	326	326	326	[b]
Price per Share - Common	$62	$61	$57	$46	$45	$37	$34	[c]
Market Value of Common Equity	$20,159	$19,740	$18,584	$14,938	$14,719	$12,158	$11,206	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$20,159	$19,740	$18,584	$14,938	$14,719	$12,158	$11,206	[f]= [d]
Market to Book Value of Common Equity	1.74	1.70	1.73	1.54	1.47	1.10	1.05	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$2,020	$2,020	$2,022	$1,753	$1,759	$1,029	$907	[h]
Market Value of Preferred Equity	$2,020	$2,020	$2,022	$1,753	$1,759	$1,029	$907	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,792	$3,792	$4,498	$3,603	$4,494	$4,751	$5,041	[j]
Current Liabilities	$5,239	$5,239	$5,849	$5,389	$4,274	$4,161	$3,887	[k]
Current Portion of Long-Term Debt	$295	$295	$704	$401	$565	$51	$43	[l]
Net Working Capital	($1,152)	($1,152)	($647)	($1,385)	$785	$641	$1,197	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,154	$1,154	$1,349	$1,528	$429	$560	$98	[n]
Adjusted Short-Term Debt	$1,152	$1,152	$647	$1,385	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$10,957	$10,957	$10,133	$9,232	$13,708	$13,010	$12,117	[p]
Book Value of Long-Term Debt	$12,404	$12,404	$11,484	$11,018	$14,273	$13,061	$12,160	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$12,319	$12,319	$11,084	$10,944	$10,548	$12,360	$10,452	
Carrying Amount	$10,738	$10,738	$10,426	$9,231	$8,834	$12,419	$10,814	
Adjustment to Book Value of Long-Term Debt	$1,581	$1,581	$658	$1,713	$1,714	($59)	($362)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$13,985	$13,985	$12,142	$12,731	$15,987	$13,002	$11,798	[s] = [q] + [r].
Market Value of Debt	$13,985	$13,985	$12,142	$12,731	$15,987	$13,002	$11,798	[t] = [s].
MARKET VALUE OF FIRM	$36,164	$35,745	$32,748	$29,422	$32,465	$26,189	$23,911	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	55.74%	55.22%	56.75%	50.77%	45.34%	46.42%	46.86%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	5.59%	5.65%	6.17%	5.96%	5.42%	3.93%	3.79%	[w] = [i] / [u].
Debt - Market Value Ratio	38.67%	39.12%	37.08%	43.27%	49.24%	49.65%	49.34%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel K: El Paso Electric

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,021	$1,021	$1,016	$894	$830	$813	$791	[a]
Shares Outstanding (in millions) - Common	40	40	40	40	40	40	42	[b]
Price per Share - Common	$40	$36	$37	$33	$34	$32	$23	[c]
Market Value of Common Equity	$1,624	$1,432	$1,481	$1,328	$1,356	$1,285	$987	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$1,624	$1,432	$1,481	$1,328	$1,356	$1,285	$987	[f]= [d]
Market to Book Value of Common Equity	1.59	1.40	1.46	1.49	1.63	1.58	1.25	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$202	$202	$207	$237	$176	$200	$252	[j]
Current Liabilities	$251	$251	$242	$141	$174	$187	$143	[k]
Current Portion of Long-Term Debt	$0	$0	$15	$0	$33	$33	$14	[l]
Net Working Capital	($48)	($48)	($19)	$96	$35	$46	$123	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$119	$119	$90	$15	$62	$18	$0	[n]
Adjusted Short-Term Debt	$48	$48	$19	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,134	$1,134	$985	$1,000	$850	$816	$850	[p]
Book Value of Long-Term Debt	$1,182	$1,182	$1,019	$1,000	$883	$850	$864	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,314	$1,314	$1,059	$1,182	$1,057	$883	$850	
Carrying Amount	$1,164	$1,164	$1,014	$1,022	$883	$854	$847	
Adjustment to Book Value of Long-Term Debt	$150	$150	$45	$160	$174	$28	$3	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,332	$1,332	$1,064	$1,160	$1,057	$878	$867	[s] = [q] + [r].
Market Value of Debt	$1,332	$1,332	$1,064	$1,160	$1,057	$878	$867	[t] = [s].
MARKET VALUE OF FIRM	$2,957	$2,764	$2,544	$2,487	$2,414	$2,163	$1,854	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	54.94%	51.80%	58.19%	53.38%	56.19%	59.41%	53.23%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	45.06%	48.20%	41.81%	46.62%	43.81%	40.59%	46.77%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel L: Entergy Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$9,157	$9,157	$10,149	$9,408	$9,191	$8,965	$8,732	[a]
Shares Outstanding (in millions) - Common	178	178	180	178	178	176	182	[b]
Price per Share - Common	$70	$64	$76	$64	$69	$65	$78	[c]
Market Value of Common Equity	$12,443	$11,376	$13,736	$11,359	$12,194	$11,495	$14,071	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$12,443	$11,376	$13,736	$11,359	$12,194	$11,495	$14,071	[f]= [d]
Market to Book Value of Common Equity	1.36	1.24	1.35	1.21	1.33	1.28	1.61	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$211	$211	$305	$281	$281	$311	$311	[h]
Market Value of Preferred Equity	$211	$211	$305	$281	$281	$311	$311	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,117	$4,117	$4,265	$3,490	$3,808	$4,154	$5,047	[j]
Current Liabilities	$3,454	$3,454	$4,454	$3,439	$3,924	$4,161	$2,914	[k]
Current Portion of Long-Term Debt	$281	$281	$1,117	$209	$792	$2,026	$592	[l]
Net Working Capital	$945	$945	$927	$260	$675	$2,019	$2,725	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$782	$782	$891	$1,106	$356	$145	$168	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$13,080	$13,080	$11,665	$12,308	$11,784	$10,281	$11,487	[p]
Book Value of Long-Term Debt	$13,362	$13,362	$12,782	$12,517	$12,575	$12,307	$12,080	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$13,607	$13,607	$12,440	$12,849	$12,176	$10,989	$10,728	
Carrying Amount	$13,399	$13,399	$12,596	$12,639	$12,236	$11,617	$11,418	
Adjustment to Book Value of Long-Term Debt	$208	$208	($156)	$210	($60)	($628)	($690)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$13,569	$13,569	$12,625	$12,728	$12,515	$11,679	$11,390	[s] = [q] + [r].
Market Value of Debt	$13,569	$13,569	$12,625	$12,728	$12,515	$11,679	$11,390	[t] = [s].
MARKET VALUE OF FIRM	$26,224	$25,156	$26,665	$24,367	$24,989	$23,485	$25,772	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	47.45%	45.22%	51.51%	46.62%	48.80%	48.95%	54.60%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.80%	0.84%	1.14%	1.15%	1.12%	1.32%	1.21%	[w] = [i] / [u].
Debt - Market Value Ratio	51.74%	53.94%	47.35%	52.23%	50.08%	49.73%	44.20%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
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The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel M: G't Plains Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,671	$3,671	$3,603	$3,487	$3,365	$2,983	$2,914	[a]
Shares Outstanding (in millions) - Common	154	154	154	154	153	136	136	[b]
Price per Share - Common	$28	$26	$25	$22	$22	$20	$19	[c]
Market Value of Common Equity	$4,321	$3,964	$3,813	$3,406	$3,399	$2,656	$2,561	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$4,321	$3,964	$3,813	$3,406	$3,399	$2,656	$2,561	[f]= [d]
Market to Book Value of Common Equity	1.18	1.08	1.06	0.98	1.01	0.89	0.88	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$39	$39	$39	$39	$39	$39	$39	[h]
Market Value of Preferred Equity	$39	$39	$39	$39	$39	$39	$39	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$824	$824	$753	$762	$821	$665	$693	[j]
Current Liabilities	$823	$823	$937	$689	$1,357	$1,511	$1,101	[k]
Current Portion of Long-Term Debt	$1	$1	$15	$7	$257	$951	$336	[l]
Net Working Capital	$2	$2	($169)	$80	($278)	$105	($72)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$341	$341	$396	$249	$648	$134	$327	[n]
Adjusted Short-Term Debt	$0	$0	$169	$0	$278	$0	$72	[o] = See Sources and Notes.
Long-Term Debt	$3,764	$3,764	$3,488	$3,516	$2,763	$2,750	$3,101	[p]
Book Value of Long-Term Debt	$3,765	$3,765	$3,672	$3,523	$3,298	$3,702	$3,509	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,800	$3,800	$3,700	$3,500	$3,900	$3,700	$3,400	
Carrying Amount	$3,500	$3,500	$3,500	$3,000	$3,500	$3,400	$3,200	
Adjustment to Book Value of Long-Term Debt	$300	$300	$200	$500	$400	$300	$200	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$4,065	$4,065	$3,872	$4,023	$3,698	$4,002	$3,709	[s] = [q] + [r].
Market Value of Debt	$4,065	$4,065	$3,872	$4,023	$3,698	$4,002	$3,709	[t] = [s].
MARKET VALUE OF FIRM	$8,424	$8,068	$7,725	$7,467	$7,136	$6,697	$6,309	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	51.29%	49.14%	49.37%	45.61%	47.63%	39.66%	40.59%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.46%	0.48%	0.50%	0.52%	0.55%	0.58%	0.62%	[w] = [i] / [u].
Debt - Market Value Ratio	48.25%	50.38%	50.13%	53.87%	51.83%	59.75%	58.79%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
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Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel N: IDACORP Inc.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$2,050	$2,050	$1,949	$1,860	$1,770	$1,657	$1,517	[a]
Shares Outstanding (in millions) - Common	50	50	50	50	50	50	49	[b]
Price per Share - Common	$68	$61	$55	$48	$43	$38	$35	[c]
Market Value of Common Equity	$3,440	$3,087	$2,753	$2,403	$2,151	$1,881	$1,730	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,440	$3,087	$2,753	$2,403	$2,151	$1,881	$1,730	[f]= [d]
Market to Book Value of Common Equity	1.68	1.51	1.41	1.29	1.21	1.14	1.14	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$494	$494	$475	$567	$366	$309	$468	[j]
Current Liabilities	$205	$205	$240	$335	$268	$254	$382	[k]
Current Portion of Long-Term Debt	$1	$1	$1	$71	$1	$2	$127	[l]
Net Working Capital	$290	$290	$237	$303	$99	$56	$212	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$4	$4	$32	$53	$51	$52	$4	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,742	$1,742	$1,614	$1,615	$1,537	$1,487	$1,488	[p]
Book Value of Long-Term Debt	$1,743	$1,743	$1,615	$1,686	$1,538	$1,489	$1,615	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,788	$1,788	$1,600	$1,819	$1,738	$1,623	$1,407	
Carrying Amount	$1,616	$1,616	$1,616	$1,538	$1,492	$1,614	$1,422	
Adjustment to Book Value of Long-Term Debt	$173	$173	($16)	$282	$246	$9	($15)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,916	$1,916	$1,599	$1,968	$1,784	$1,498	$1,600	[s] = [q] + [r].
Market Value of Debt	$1,916	$1,916	$1,599	$1,968	$1,784	$1,498	$1,600	[t] = [s].
MARKET VALUE OF FIRM	$5,356	$5,003	$4,353	$4,370	$3,934	$3,379	$3,329	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	64.23%	61.71%	63.26%	54.97%	54.66%	55.68%	51.95%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	35.77%	38.29%	36.74%	45.03%	45.34%	44.32%	48.05%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel O: MGE Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$689	$689	$654	$613	$578	$550	$522	[a]
Shares Outstanding (in millions) - Common	35	35	35	35	35	35	35	[b]
Price per Share - Common	$49	$40	$39	$36	$35	$27	$26	[c]
Market Value of Common Equity	$1,689	$1,396	$1,340	$1,244	$1,223	$950	$902	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$1,689	$1,396	$1,340	$1,244	$1,223	$950	$902	[f]= [d]
Market to Book Value of Common Equity	2.45	2.03	2.05	2.03	2.11	1.73	1.73	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$242	$242	$225	$214	$220	$174	$150	[j]
Current Liabilities	$74	$74	$82	$79	$60	$52	$102	[k]
Current Portion of Long-Term Debt	$4	$4	$4	$4	$3	$3	$2	[l]
Net Working Capital	$172	$172	$147	$139	$162	$124	$50	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$0	$0	$49	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$392	$392	$396	$400	$359	$362	$320	[p]
Book Value of Long-Term Debt	$396	$396	$400	$405	$362	$364	$321	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$457	$457	$432	$427	$433	$356	$340	
Carrying Amount	$400	$400	$404	$362	$364	$337	$324	
Adjustment to Book Value of Long-Term Debt	$58	$58	$28	$66	$68	$19	$16	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$454	$454	$429	$470	$430	$384	$337	[s] = [q] + [r].
Market Value of Debt	$454	$454	$429	$470	$430	$384	$337	[t] = [s].
MARKET VALUE OF FIRM	$2,143	$1,850	$1,769	$1,714	$1,653	$1,333	$1,240	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	78.81%	75.46%	75.77%	72.56%	73.97%	71.23%	72.78%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	21.19%	24.54%	24.23%	27.44%	26.03%	28.77%	27.22%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel P: NextEra Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$22,318	$22,318	$18,810	$17,409	$15,886	$14,887	$14,151	[a]
Shares Outstanding (in millions) - Common	461	461	436	431	423	423	418	[b]
Price per Share - Common	$111	$97	$95	$80	$69	$54	$54	[c]
Market Value of Common Equity	$51,122	$44,783	$41,205	$34,660	$28,988	$22,955	$22,782	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$51,122	$44,783	$41,205	$34,660	$28,988	$22,955	$22,782	[f]= [d]
Market to Book Value of Common Equity	2.29	2.01	2.19	1.99	1.82	1.54	1.61	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$6,657	$6,657	$5,633	$5,472	$4,437	$6,252	$5,776	[j]
Current Liabilities	$10,371	$10,371	$9,572	$9,213	$7,875	$7,419	$7,187	[k]
Current Portion of Long-Term Debt	$2,497	$2,497	$3,385	$3,933	$2,062	$597	$1,703	[l]
Net Working Capital	($1,217)	($1,217)	($554)	$192	($1,376)	($570)	$292	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$2,163	$2,163	$1,185	$915	$1,574	$1,835	$1,085	[n]
Adjusted Short-Term Debt	$1,217	$1,217	$554	$0	$1,376	$570	$0	[o] = See Sources and Notes.
Long-Term Debt	$25,604	$25,604	$24,853	$23,862	$22,714	$20,039	$17,680	[p]
Book Value of Long-Term Debt	$29,318	$29,318	$28,792	$27,795	$26,152	$21,206	$19,383	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$30,337	$30,337	$28,612	$28,874	$23,699	$20,756	$17,256	
Carrying Amount	$27,876	$27,876	$27,728	$26,647	$21,614	$19,929	$16,869	
Adjustment to Book Value of Long-Term Debt	$2,461	$2,461	$884	$2,227	$2,085	$827	$387	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$31,779	$31,779	$29,676	$30,022	$28,237	$22,033	$19,770	[s] = [q] + [r].
Market Value of Debt	$31,779	$31,779	$29,676	$30,022	$28,237	$22,033	$19,770	[t] = [s].
MARKET VALUE OF FIRM	$82,901	$76,562	$70,881	$64,682	$57,225	$44,988	$42,552	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	61.67%	58.49%	58.13%	53.59%	50.66%	51.02%	53.54%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	38.33%	41.51%	41.87%	46.41%	49.34%	48.98%	46.46%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel Q: OGE Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,353	$3,353	$3,243	$2,995	$2,769	$2,541	$2,226	[a]
Shares Outstanding (in millions) - Common	200	200	199	198	197	196	195	[b]
Price per Share - Common	$26	$27	$36	$36	$28	$24	$20	[c]
Market Value of Common Equity	$5,171	$5,399	$7,266	$7,104	$5,440	$4,709	$3,899	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$5,171	$5,399	$7,266	$7,104	$5,440	$4,709	$3,899	[f]= [d]
Market to Book Value of Common Equity	1.54	1.61	2.24	2.37	1.96	1.85	1.75	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$753	$753	$740	$758	$857	$727	$709	[j]
Current Liabilities	$587	$587	$869	$942	$1,196	$934	$872	[k]
Current Portion of Long-Term Debt	$110	$110	$0	$0	$0	$0	$0	[l]
Net Working Capital	$276	$276	($129)	($184)	($339)	($208)	($163)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$411	$447	$456	$289	$224	[n]
Adjusted Short-Term Debt	$0	$0	$129	$184	$339	$208	$163	[o] = See Sources and Notes.
Long-Term Debt	$2,646	$2,646	$2,510	$2,400	$2,848	$2,587	$2,373	[p]
Book Value of Long-Term Debt	$2,756	$2,756	$2,639	$2,584	$3,188	$2,795	$2,536	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,550	$2,550	$2,653	$3,397	$3,276	$2,579	$2,477	
Carrying Amount	$2,755	$2,755	$2,400	$2,849	$2,737	$2,363	$2,378	
Adjustment to Book Value of Long-Term Debt	($206)	($206)	$253	$548	$539	$216	$99	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,550	$2,550	$2,891	$3,132	$3,726	$3,011	$2,634	[s] = [q] + [r].
Market Value of Debt	$2,550	$2,550	$2,891	$3,132	$3,726	$3,011	$2,634	[t] = [s].
MARKET VALUE OF FIRM	$7,720	$7,949	$10,157	$10,236	$9,166	$7,720	$6,533	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	66.97%	67.92%	71.54%	69.41%	59.35%	61.00%	59.68%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	33.03%	32.08%	28.46%	30.59%	40.65%	39.00%	40.32%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel R: Otter Tail Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$598	$598	$563	$530	$531	$626	$637	[a]
Shares Outstanding (in millions) - Common	38	38	37	36	36	36	36	[b]
Price per Share - Common	$27	$26	$27	$28	$24	$19	$20	[c]
Market Value of Common Equity	$1,027	$972	$1,007	$1,006	$859	$703	$720	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$1,027	$972	$1,007	$1,006	$859	$703	$720	[f]= [d]
Market to Book Value of Common Equity	1.72	1.63	1.79	1.90	1.62	1.12	1.13	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$16	$16	$16	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$16	$16	$16	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$274	$274	$298	$310	$299	$372	$361	[j]
Current Liabilities	$237	$237	$200	$220	$176	$216	$246	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$0	$0	$3	$1	[l]
Net Working Capital	$37	$37	$98	$91	$123	$159	$116	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$87	$87	$39	$40	$12	$39	$94	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$498	$498	$499	$437	$422	$433	$436	[p]
Book Value of Long-Term Debt	$499	$499	$499	$437	$422	$437	$436	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$601	$601	$428	$491	$525	$473	$458	
Carrying Amount	$499	$499	$390	$422	$472	$434	$436	
Adjustment to Book Value of Long-Term Debt	$102	$102	$38	$69	$53	$39	$22	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$601	$601	$537	$507	$475	$476	$458	[s] = [q] + [r].
Market Value of Debt	$601	$601	$537	$507	$475	$476	$458	[t] = [s].
MARKET VALUE OF FIRM								
	$1,628	$1,573	$1,544	$1,513	$1,350	$1,195	$1,193	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.09%	61.81%	65.24%	66.49%	63.66%	58.84%	60.32%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	1.15%	1.30%	1.30%	[w] = [i] / [u].
Debt - Market Value Ratio	36.91%	38.19%	34.76%	33.51%	35.19%	39.86%	38.38%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel S: PG&E Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$16,568	$16,568	$15,779	$14,008	$13,133	$11,959	$11,023	[a]
Shares Outstanding (in millions) - Common	490	490	475	449	429	405	392	[b]
Price per Share - Common	$55	$51	$46	$41	$43	$42	$45	[c]
Market Value of Common Equity	$26,781	$24,840	$21,682	$18,575	$18,401	$17,105	$17,699	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$26,781	$24,840	$21,682	$18,575	$18,401	$17,105	$17,699	[f]= [d]
Market to Book Value of Common Equity	1.62	1.50	1.37	1.33	1.40	1.43	1.61	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$252	$252	$252	$252	$252	$252	$252	[h]
Market Value of Preferred Equity	$252	$252	$252	$252	$252	$252	$252	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$6,131	$6,131	$6,071	$5,522	$5,593	$5,877	$5,751	[j]
Current Liabilities	$6,108	$6,108	$5,726	$7,644	$5,436	$6,818	$7,184	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$1,288	$110	$468	$899	[l]
Net Working Capital	$23	$23	$345	($834)	$267	($473)	($534)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$881	$881	$426	$953	$397	$1,137	$1,076	[n]
Adjusted Short-Term Debt	$0	$0	$0	$834	$0	$473	$534	[o] = See Sources and Notes.
Long-Term Debt	$15,545	$15,545	$14,555	$11,918	$12,915	$11,626	$11,255	[p]
Book Value of Long-Term Debt	$15,545	$15,545	$14,555	$14,040	$13,025	$12,567	$12,688	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$16,203	$16,203	$13,798	$14,317	$13,356	$12,559	$12,189	
Carrying Amount	$14,128	$14,128	$12,684	$11,994	$11,317	$11,620	$11,050	
Adjustment to Book Value of Long-Term Debt	$2,075	$2,075	$1,114	$2,323	$2,039	$939	$1,139	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$17,620	$17,620	$15,669	$16,363	$15,064	$13,506	$13,827	[s] = [q] + [r].
Market Value of Debt	$17,620	$17,620	$15,669	$16,363	$15,064	$13,506	$13,827	[t] = [s].
MARKET VALUE OF FIRM	$44,653	$42,712	$37,603	$35,190	$33,717	$30,863	$31,778	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.98%	58.16%	57.66%	52.78%	54.57%	55.42%	55.70%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.56%	0.59%	0.67%	0.72%	0.75%	0.82%	0.79%	[w] = [i] / [u].
Debt - Market Value Ratio	39.46%	41.25%	41.67%	46.50%	44.68%	43.76%	43.51%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel T: Pinnacle West Capital

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$4,654	$4,654	$4,492	$4,276	$4,056	$3,894	$3,717	[a]
Shares Outstanding (in millions) - Common	111	111	110	110	110	109	109	[b]
Price per Share - Common	$66	$62	$56	$55	$53	$43	$41	[c]
Market Value of Common Equity	$7,355	$6,850	$6,196	$6,003	$5,792	$4,719	$4,456	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$7,355	$6,850	$6,196	$6,003	$5,792	$4,719	$4,456	[f]= [d]
Market to Book Value of Common Equity	1.58	1.47	1.38	1.40	1.43	1.21	1.20	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,062	$1,062	$1,041	$1,350	$1,099	$1,591	$1,243	[j]
Current Liabilities	$1,523	$1,523	$1,449	$1,447	$949	$1,783	$968	[k]
Current Portion of Long-Term Debt	$411	$411	$369	$566	$90	$876	$239	[l]
Net Working Capital	($50)	($50)	($39)	$470	$240	$684	$514	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$57	$57	$19	$0	$0	$0	$0	[n]
Adjusted Short-Term Debt	$50	$50	$19	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$3,257	$3,257	$3,038	$2,820	$3,339	$3,047	$3,463	[p]
Book Value of Long-Term Debt	$3,719	$3,719	$3,426	$3,387	$3,429	$3,923	$3,702	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,839	$3,839	$3,579	$3,875	$3,926	$3,913	$3,774	
Carrying Amount	$3,415	$3,415	$3,337	$3,322	$3,496	$3,678	$3,648	
Adjustment to Book Value of Long-Term Debt	$424	$424	$242	$553	$430	$235	$126	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$4,143	$4,143	$3,668	$3,940	$3,859	$4,158	$3,828	[s] = [q] + [r].
Market Value of Debt	$4,143	$4,143	$3,668	$3,940	$3,859	$4,158	$3,828	[t] = [s].
MARKET VALUE OF FIRM	$11,498	$10,993	$9,864	$9,943	$9,651	$8,877	$8,284	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.97%	62.31%	62.81%	60.38%	60.01%	53.16%	53.79%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	36.03%	37.69%	37.19%	39.62%	39.99%	46.84%	46.21%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel U: Portland General

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$2,232	$2,232	$1,889	$1,792	$1,717	$1,653	$1,585	[a]
Shares Outstanding (in millions) - Common	89	89	78	78	76	75	75	[b]
Price per Share - Common	$39	$36	$33	$28	$27	$24	$20	[c]
Market Value of Common Equity	$3,447	$3,155	$2,567	$2,212	$2,059	$1,798	$1,525	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,447	$3,155	$2,567	$2,212	$2,059	$1,798	$1,525	[f]= [d]
Market to Book Value of Common Equity	1.54	1.41	1.36	1.23	1.20	1.09	0.96	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$605	$605	$542	$565	$784	$740	$750	[j]
Current Liabilities	$465	$465	$482	$380	$648	$511	$520	[k]
Current Portion of Long-Term Debt	$0	$0	$70	$50	$200	$0	$0	[l]
Net Working Capital	$140	$140	$130	$235	$336	$229	$230	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$0	$0	$20	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,204	$2,204	$2,251	$1,761	$1,536	$1,798	$1,808	[p]
Book Value of Long-Term Debt	$2,204	$2,204	$2,321	$1,811	$1,736	$1,798	$1,808	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,901	$2,901	$2,074	$1,949	$2,091	$1,968	$1,818	
Carrying Amount	$2,501	$2,501	$1,916	$1,636	$1,735	$1,808	$1,744	
Adjustment to Book Value of Long-Term Debt	$400	$400	$158	$313	$356	$160	$74	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,604	$2,604	$2,479	$2,124	$2,092	$1,958	$1,882	[s] = [q] + [r].
Market Value of Debt	$2,604	$2,604	$2,479	$2,124	$2,092	$1,958	$1,882	[t] = [s].
MARKET VALUE OF FIRM	$6,051	$5,759	$5,046	$4,336	$4,151	$3,756	$3,407	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.97%	54.79%	50.87%	51.02%	49.60%	47.87%	44.76%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	43.03%	45.21%	49.13%	48.98%	50.40%	52.13%	55.24%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel V: Public Serv. Enterprise

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$12,933	$12,933	$12,083	$11,338	$10,806	$10,159	$9,557	[a]
Shares Outstanding (in millions) - Common	505	505	506	506	506	506	506	[b]
Price per Share - Common	$41	$40	$38	$33	$32	$34	$32	[c]
Market Value of Common Equity	$20,749	$20,317	$18,979	$16,702	$16,052	$17,084	$16,359	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$20,749	$20,317	$18,979	$16,702	$16,052	$17,084	$16,359	[f]= [d]
Market to Book Value of Common Equity	1.60	1.57	1.57	1.47	1.49	1.68	1.71	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,204	$3,204	$3,846	$3,741	$3,978	$4,970	$3,671	[j]
Current Liabilities	$3,604	$3,604	$3,136	$3,235	$3,039	$3,692	$3,018	[k]
Current Portion of Long-Term Debt	$1,106	$1,106	$574	$1,010	$975	$1,489	$1,004	[l]
Net Working Capital	$706	$706	$1,284	$1,516	$1,914	$2,767	$1,657	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$20	$20	$0	$0	$16	$298	$390	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$8,132	$8,132	$8,389	$7,476	$7,334	$7,480	$8,152	[p]
Book Value of Long-Term Debt	$9,238	$9,238	$8,963	$8,486	$8,309	$8,969	$9,156	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$10,149	$10,149	$9,061	$9,324	$9,283	$9,836	$8,973	
Carrying Amount	$9,144	$9,144	$8,643	$7,939	$8,094	$8,940	$8,166	
Adjustment to Book Value of Long-Term Debt	$1,005	$1,005	$418	$1,385	$1,189	$896	$807	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$10,243	$10,243	$9,381	$9,871	$9,498	$9,865	$9,963	[s] = [q] + [r].
Market Value of Debt	$10,243	$10,243	$9,381	$9,871	$9,498	$9,865	$9,963	[t] = [s].
MARKET VALUE OF FIRM	$30,992	$30,560	$28,360	$26,573	$25,550	$26,949	$26,322	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	66.95%	66.48%	66.92%	62.85%	62.83%	63.39%	62.15%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	33.05%	33.52%	33.08%	37.15%	37.17%	36.61%	37.85%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel W: SCANA Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$5,419	$5,419	$4,948	$4,598	$4,095	$3,838	$3,584	[a]
Shares Outstanding (in millions) - Common	143	143	142	140	132	130	127	[b]
Price per Share - Common	$63	$53	$50	$47	$48	$40	$40	[c]
Market Value of Common Equity	$9,019	$7,565	$7,105	$6,527	$6,379	$5,168	$5,109	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$9,019	$7,565	$7,105	$6,527	$6,379	$5,168	$5,109	[f]= [d]
Market to Book Value of Common Equity	1.66	1.40	1.44	1.42	1.56	1.35	1.43	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,221	$1,221	$1,359	$1,351	$1,361	$1,421	$1,476	[j]
Current Liabilities	$1,294	$1,294	$1,536	$1,203	$1,411	$1,686	$1,968	[k]
Current Portion of Long-Term Debt	$16	$16	$52	$19	$176	$285	$631	[l]
Net Working Capital	($57)	($57)	($125)	$167	$126	$20	$139	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$264	$264	$487	$378	$394	$581	$335	[n]
Adjusted Short-Term Debt	$57	$57	$125	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$6,018	$6,018	$5,681	$5,431	$4,976	$4,376	$3,865	[p]
Book Value of Long-Term Debt	$6,091	$6,091	$5,858	$5,450	$5,152	$4,661	$4,496	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$6,592	$6,592	$5,916	$6,115	$5,479	$4,841	$4,726	
Carrying Amount	$5,697	$5,697	$5,449	$5,121	$4,653	$4,488	$4,511	
Adjustment to Book Value of Long-Term Debt	$895	$895	$467	$994	$826	$352	$215	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$6,986	$6,986	$6,325	$6,444	$5,978	$5,013	$4,711	[s] = [q] + [r].
Market Value of Debt	$6,986	$6,986	$6,325	$6,444	$5,978	$5,013	$4,711	[t] = [s].
MARKET VALUE OF FIRM	$16,005	$14,551	$13,430	$12,971	$12,358	$10,181	$9,821	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.35%	51.99%	52.90%	50.32%	51.62%	50.76%	52.03%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	43.65%	48.01%	47.10%	49.68%	48.38%	49.24%	47.97%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
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Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel X: Sempra Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$11,625	$11,625	$11,333	$10,909	$10,082	$9,630	$8,802	[a]
Shares Outstanding (in millions) - Common	248	248	246	244	242	240	242	[b]
Price per Share - Common	$94	$93	$105	$86	$65	$51	$53	[c]
Market Value of Common Equity	$23,364	$22,956	$25,772	$21,032	$15,801	$12,326	$12,924	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$23,364	$22,956	$25,772	$21,032	$15,801	$12,326	$12,924	[f]= [d]
Market to Book Value of Common Equity	2.01	1.97	2.27	1.93	1.57	1.28	1.47	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$20	$20	$20	$20	$99	$99	$179	[h]
Market Value of Preferred Equity	$20	$20	$20	$20	$99	$99	$179	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,606	$3,606	$4,414	$3,712	$3,078	$2,938	$2,495	[j]
Current Liabilities	$5,118	$5,118	$4,292	$4,530	$4,349	$3,995	$3,777	[k]
Current Portion of Long-Term Debt	$1,168	$1,168	$188	$1,441	$709	$137	$313	[l]
Net Working Capital	($344)	($344)	$310	$623	($562)	($920)	($969)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,097	$1,097	$1,309	$522	$584	$641	$574	[n]
Adjusted Short-Term Debt	$344	$344	$0	$0	$562	$641	$574	[o] = See Sources and Notes.
Long-Term Debt	$12,527	$12,527	$12,437	$10,478	$11,193	$10,033	$8,032	[p]
Book Value of Long-Term Debt	$14,039	$14,039	$12,625	$11,919	$12,464	$10,811	$8,919	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$13,699	$13,699	$12,676	$13,243	$11,047	$8,883	$8,572	
Carrying Amount	$12,347	$12,347	$12,022	$11,873	$9,826	$8,330	$8,004	
Adjustment to Book Value of Long-Term Debt	$1,352	$1,352	$654	$1,370	$1,221	$553	$568	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$15,391	$15,391	$13,279	$13,289	$13,685	$11,364	$9,487	[s] = [q] + [r].
Market Value of Debt	$15,391	$15,391	$13,279	$13,289	$13,685	$11,364	$9,487	[t] = [s].
MARKET VALUE OF FIRM	$38,775	$38,367	$39,071	$34,341	$29,585	$23,789	$22,590	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	60.26%	59.83%	65.96%	61.25%	53.41%	51.81%	57.21%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.05%	0.05%	0.05%	0.06%	0.33%	0.42%	0.79%	[w] = [i] / [u].
Debt - Market Value Ratio	39.69%	40.12%	33.99%	38.70%	46.26%	47.77%	42.00%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
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Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel Y: Vectren Corp.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,650	$1,650	$1,581	$1,532	$1,506	$1,452	$1,411	[a]
Shares Outstanding (in millions) - Common	83	83	83	82	82	82	81	[b]
Price per Share - Common	$42	$40	$40	$33	$28	$27	$25	[c]
Market Value of Common Equity	$3,475	$3,324	$3,336	$2,736	$2,334	$2,222	$2,061	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$3,475	$3,324	$3,336	$2,736	$2,334	$2,222	$2,061	[f]= [d]
Market to Book Value of Common Equity	2.11	2.02	2.11	1.79	1.55	1.53	1.46	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$539	$539	$493	$608	$569	$623	$506	[j]
Current Liabilities	$619	$619	$427	$607	$783	$699	$545	[k]
Current Portion of Long-Term Debt	$88	$88	$5	$30	$132	$138	$48	[l]
Net Working Capital	$8	$8	$71	$31	($82)	$62	$9	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$111	$111	$62	$249	$316	$216	$157	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$82	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,523	$1,523	$1,572	$1,627	$1,454	$1,581	$1,590	[p]
Book Value of Long-Term Debt	$1,611	$1,611	$1,577	$1,657	$1,667	$1,719	$1,639	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,755	$1,755	$1,895	$1,873	$1,804	$1,841	$1,720	
Carrying Amount	$1,577	$1,577	$1,807	$1,660	$1,622	$1,716	$1,640	
Adjustment to Book Value of Long-Term Debt	$177	$177	$88	$214	$182	$125	$80	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,788	$1,788	$1,665	$1,871	$1,850	$1,844	$1,719	[s] = [q] + [r].
Market Value of Debt	$1,788	$1,788	$1,665	$1,871	$1,850	$1,844	$1,719	[t] = [s].
MARKET VALUE OF FIRM	$5,263	$5,112	$5,001	$4,606	$4,184	$4,066	$3,780	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	66.03%	65.03%	66.70%	59.39%	55.80%	54.64%	54.52%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	33.97%	34.97%	33.30%	40.61%	44.20%	45.36%	45.48%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel Z: Westar Energy

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,663	$3,663	$3,265	$3,033	$2,887	$2,588	$2,385	[a]
Shares Outstanding (in millions) - Common	141	141	131	127	126	117	111	[b]
Price per Share - Common	$44	$37	$35	$31	$29	$26	$24	[c]
Market Value of Common Equity	$6,146	$5,239	$4,550	$3,885	$3,718	$3,076	$2,667	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$6,146	$5,239	$4,550	$3,885	$3,718	$3,076	$2,667	[f]= [d]
Market to Book Value of Common Equity	1.68	1.43	1.39	1.28	1.29	1.19	1.12	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$21	$21	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$21	$21	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$758	$758	$749	$694	$678	$605	$586	[j]
Current Liabilities	$879	$879	$801	$854	$741	$888	$634	[k]
Current Portion of Long-Term Debt	$28	$28	$28	$278	$27	$28	$30	[l]
Net Working Capital	($93)	($93)	($24)	$118	($36)	($255)	($17)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$304	$304	$202	$52	$215	$392	$163	[n]
Adjusted Short-Term Debt	$93	$93	$24	$0	$36	$255	$17	[o] = See Sources and Notes.
Long-Term Debt	$3,080	$3,080	$3,382	$3,164	$3,062	$2,742	$2,779	[p]
Book Value of Long-Term Debt	$3,201	$3,201	$3,434	$3,442	$3,124	$3,025	$2,826	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,488	$3,488	$3,294	$3,179	$2,624	$2,571	$2,528	
Carrying Amount	$3,105	$3,105	$3,103	$2,703	$2,373	$2,373	$2,374	
Adjustment to Book Value of Long-Term Debt	$383	$383	$192	$476	$251	$197	$155	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,584	$3,584	$3,625	$3,918	$3,375	$3,222	$2,981	[s] = [q] + [r].
Market Value of Debt	$3,584	$3,584	$3,625	$3,918	$3,375	$3,222	$2,981	[t] = [s].
MARKET VALUE OF FIRM	$9,730	$8,824	$8,175	$7,803	$7,093	$6,319	$5,669	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.16%	59.38%	55.65%	49.79%	52.42%	48.67%	47.04%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	0.34%	0.38%	[w] = [i] / [u].
Debt - Market Value Ratio	36.84%	40.62%	44.35%	50.21%	47.58%	50.99%	52.58%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel AA: Xcel Energy Inc.

($MM)

	DCF Capital Structure	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	3rd Quarter, 2011	3rd Quarter, 2010	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$10,545	$10,545	$10,155	$9,547	$8,850	$8,431	$7,606	[a]
Shares Outstanding (in millions) - Common	507	507	505	498	488	485	460	[b]
Price per Share - Common	$38	$34	$31	$28	$28	$25	$23	[c]
Market Value of Common Equity	$19,349	$17,219	$15,664	$13,799	$13,528	$12,021	$10,539	[d] = [b] x [c].
Market Value of GP Equity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity	$19,349	$17,219	$15,664	$13,799	$13,528	$12,021	$10,539	[f]= [d]
Market to Book Value of Common Equity	1.83	1.63	1.54	1.45	1.53	1.43	1.39	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$105	$105	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$105	$105	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,344	$3,344	$3,197	$3,121	$3,371	$2,861	$2,530	[j]
Current Liabilities	$3,085	$3,085	$3,471	$2,839	$3,161	$2,653	$2,199	[k]
Current Portion of Long-Term Debt	$457	$457	$258	$281	$859	$462	$414	[l]
Net Working Capital	$717	$717	($17)	$562	$1,070	$671	$744	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$64	$64	$697	$302	$304	$50	$40	[n]
Adjusted Short-Term Debt	$0	$0	$17	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$12,691	$12,691	$11,502	$10,914	$10,106	$9,450	$8,865	[p]
Book Value of Long-Term Debt	$13,148	$13,148	$11,776	$11,195	$10,965	$9,913	$9,279	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$13,360	$13,360	$11,879	$12,208	$11,735	$10,225	$9,026	
Carrying Amount	$11,757	$11,757	$11,192	$10,402	$9,908	$9,319	$8,432	
Adjustment to Book Value of Long-Term Debt	$1,603	$1,603	$687	$1,806	$1,826	$906	$594	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$14,751	$14,751	$12,463	$13,001	$12,792	$10,819	$9,873	[s] = [q] + [r].
Market Value of Debt	$14,751	$14,751	$12,463	$13,001	$12,792	$10,819	$9,873	[t] = [s].
MARKET VALUE OF FIRM	$34,100	$31,970	$28,128	$26,800	$26,319	$22,945	$20,517	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.74%	53.86%	55.69%	51.49%	51.40%	52.39%	51.37%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	0.46%	0.51%	[w] = [i] / [u].
Debt - Market Value Ratio	43.26%	46.14%	44.31%	48.51%	48.60%	47.15%	48.12%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of February 10, 2016
Capital structure from 3rd Quarter, 2015 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2015 balance sheet information and a 15-trading day average closing price ending on 2/10/2016.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2014 10-K.

Table No. BV-ELEC-4

Capital Structure Summary

Company	DCF Capital Structure			5-Year Average Capital Structure		
	Common Equity - Value Ratio [1]	Preferred Equity - Value Ratio [2]	Debt - Value Ratio [3]	Common Equity - Value Ratio [4]	Preferred Equity - Value Ratio [5]	Debt - Value Ratio [6]
ALLETE	59.8%	0.0%	40.2%	60.2%	0.0%	39.8%
Alliant Energy	61.2%	1.7%	37.1%	57.8%	2.3%	39.9%
Amer. Elec. Power	56.8%	0.0%	43.2%	52.0%	0.0%	48.0%
Ameren Corp.	59.6%	0.0%	40.4%	52.6%	0.0%	47.4%
CenterPoint Energy	45.1%	0.0%	54.9%	47.8%	0.0%	52.2%
CMS Energy Corp.	52.7%	0.0%	47.3%	42.6%	0.2%	57.2%
Consol. Edison	59.1%	0.0%	40.9%	56.9%	0.2%	42.9%
Dominion Resources	59.8%	0.0%	40.2%	59.6%	0.4%	40.0%
DTE Energy	59.7%	0.0%	40.3%	55.1%	0.0%	44.9%
Edison Int'l	55.7%	5.6%	38.7%	50.1%	5.2%	44.7%
El Paso Electric	54.9%	0.0%	45.1%	55.9%	0.0%	44.1%
Entergy Corp.	47.5%	0.8%	51.7%	49.2%	1.2%	49.7%
G't Plains Energy	51.3%	0.5%	48.2%	45.4%	0.5%	54.0%
IDACORP Inc.	64.2%	0.0%	35.8%	57.1%	0.0%	42.9%
MGE Energy	78.8%	0.0%	21.2%	73.5%	0.0%	26.5%
NextEra Energy	61.7%	0.0%	38.3%	53.9%	0.0%	46.1%
OGE Energy	67.0%	0.0%	33.0%	65.0%	0.0%	35.0%
Otter Tail Corp.	63.1%	0.0%	36.9%	63.1%	0.6%	36.3%
PG&E Corp.	60.0%	0.6%	39.5%	55.5%	0.7%	43.8%
Pinnacle West Capital	64.0%	0.0%	36.0%	58.9%	0.0%	41.1%
Portland General	57.0%	0.0%	43.0%	49.8%	0.0%	50.2%
Public Serv. Enterprise	66.9%	0.0%	33.1%	64.1%	0.0%	35.9%
SCANA Corp.	56.4%	0.0%	43.6%	51.5%	0.0%	48.5%
Sempra Energy	60.3%	0.1%	39.7%	58.2%	0.3%	41.6%
Vectren Corp.	66.0%	0.0%	34.0%	59.3%	0.0%	40.7%
Westar Energy	63.2%	0.0%	36.8%	51.9%	0.1%	47.9%
Xcel Energy Inc.	56.7%	0.0%	43.3%	52.7%	0.1%	47.1%
Average	59.6%	0.3%	40.1%	55.5%	0.4%	44.0%
Nuclear Subsample Average	59.7%	0.3%	40.0%	55.8%	0.5%	43.7%

Sources and Notes:
[1], [4]: Supporting Schedule #1 to Table No. BV-ELEC-4.
[2], [5]: Supporting Schedule #2 to Table No. BV-ELEC-4.
[3], [6]: Supporting Schedule #3 to Table No. BV-ELEC-4.
Values in this table may not add up exactly to 100% because of rounding.

Table No. BV-ELEC-5

Estimated Growth Rates

Company	ThomsonOne IBES Estimate		Value Line			Combined Growth Rate
	Long-Term Growth Rate	Number of Estimates	EPS Year 2015 Estimate	EPS Year 2018-2020 Estimate	Annualized Growth Rate	
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	5.0%	1	$3.50	$4.00	3.4%	4.2%
Alliant Energy	5.6%	2	$3.65	$4.55	5.7%	5.6%
Amer. Elec. Power	4.6%	5	$3.70	$4.25	3.5%	4.4%
Ameren Corp.	6.0%	2	$2.45	$3.50	9.3%	7.1%
CenterPoint Energy	0.4%	3	$1.10	$1.35	5.3%	1.6%
CMS Energy Corp.	6.7%	4	$1.88	$2.25	4.6%	6.3%
Consol. Edison	2.9%	5	$3.95	$4.50	3.3%	3.0%
Dominion Resources	5.5%	6	$3.50	$4.75	7.9%	5.8%
DTE Energy	5.0%	5	$4.60	$5.75	5.7%	5.1%
Edison Int'l	-0.5%	5	$4.40	$5.25	4.5%	0.3%
El Paso Electric	7.0%	1	$1.95	$2.75	9.0%	8.0%
Entergy Corp.	-2.5%	5	$6.00	$5.25	-3.3%	-2.6%
G't Plains Energy	4.8%	3	$1.35	$2.00	10.3%	6.2%
IDACORP Inc.	4.0%	1	$3.90	$4.25	2.2%	3.1%
MGE Energy	4.0%	1	$2.25	$3.15	8.8%	6.4%
NextEra Energy	7.1%	5	$6.05	$7.75	6.4%	7.0%
OGE Energy	2.2%	3	$1.75	$2.25	6.5%	3.2%
Otter Tail Corp.	6.0%	1	$1.60	$2.25	8.9%	7.4%
PG&E Corp.	5.8%	6	$1.90	$4.25	22.3%	8.2%
Pinnacle West Capital	4.9%	4	$3.85	$4.50	4.0%	4.8%
Portland General	4.1%	4	$2.15	$2.75	6.3%	4.6%
Public Serv. Enterprise	1.4%	3	$3.15	$3.50	2.7%	1.7%
SCANA Corp.	4.5%	2	$3.85	$4.50	4.0%	4.3%
Sempra Energy	9.4%	2	$4.80	$7.25	10.9%	9.9%
Vectren Corp.	5.0%	2	$2.35	$3.25	8.4%	6.1%
Westar Energy	3.5%	3	$2.25	$3.10	8.3%	4.7%
Xcel Energy Inc.	4.7%	3	$2.05	$2.50	5.1%	4.8%

Sources and Notes:

[1] - [2]: Updated from ThomsonOne as of Feb 10, 2016.

[3] - [4]: From Valueline Investment Analyzer as of Feb 09, 2016.

[5]: ([4]/[3])^(1/4) - 1, where 4 is the number of years between 2019, the middle year of Value Line's 3-5 year forecast, and our study year 2015.

[6]: Weighted average growth rate.

Table No. BV-ELEC-6

DCF Cost of Equity of the U.S. Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price [1]	Most Recent Dividend [2]	Quarterly Dividend Yield (t+1) [3]	Combined Long-Term Growth Rate [4]	Quarterly Growth Rate [5]	DCF Cost of Equity [6]
ALLETE	$51.84	$0.51	0.98%	4.2%	1.0%	8.3%
Alliant Energy	$65.26	$0.59	0.91%	5.6%	1.4%	9.4%
Amer. Elec. Power	$60.29	$0.56	0.94%	4.4%	1.1%	8.3%
Ameren Corp.	$44.89	$0.43	0.96%	7.1%	1.7%	11.2%
CenterPoint Energy	$17.87	$0.25	1.39%	1.6%	0.4%	7.4%
CMS Energy Corp.	$38.24	$0.31	0.82%	6.3%	1.5%	9.8%
Consol. Edison	$70.35	$0.65	0.93%	3.0%	0.7%	6.9%
Dominion Resources	$70.14	$0.65	0.94%	5.8%	1.4%	9.8%
DTE Energy	$84.26	$0.73	0.88%	5.1%	1.3%	8.8%
Edison Int'l	$61.87	$0.48	0.78%	0.3%	0.1%	3.5%
El Paso Electric	$40.31	$0.30	0.75%	8.0%	1.9%	11.2%
Entergy Corp.	$69.76	$0.85	1.21%	-2.6%	-0.7%	2.2%
G't Plains Energy	$27.99	$0.26	0.95%	6.2%	1.5%	10.2%
IDACORP Inc.	$68.34	$0.51	0.75%	3.1%	0.8%	6.2%
MGE Energy	$48.72	$0.30	0.61%	6.4%	1.6%	9.0%
NextEra Energy	$110.89	$0.77	0.71%	7.0%	1.7%	10.0%
OGE Energy	$25.89	$0.28	1.07%	3.2%	0.8%	7.7%
Otter Tail Corp.	$27.22	$0.31	1.17%	7.4%	1.8%	12.5%
PG&E Corp.	$54.64	$0.46	0.85%	8.2%	2.0%	11.8%
Pinnacle West Capital	$66.36	$0.63	0.95%	4.8%	1.2%	8.8%
Portland General	$38.83	$0.30	0.78%	4.6%	1.1%	7.8%
Public Serv. Enterprise	$41.06	$0.39	0.95%	1.7%	0.4%	5.6%
SCANA Corp.	$63.12	$0.55	0.87%	4.3%	1.1%	7.9%
Sempra Energy	$94.21	$0.70	0.76%	9.9%	2.4%	13.2%
Vectren Corp.	$42.02	$0.40	0.97%	6.1%	1.5%	10.2%
Westar Energy	$43.50	$0.36	0.84%	4.7%	1.2%	8.2%
Xcel Energy Inc.	$38.14	$0.32	0.85%	4.8%	1.2%	8.3%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-ELEC-6.
[2]: Supporting Schedule #2 to Table No. BV-ELEC-6.
[3]: ([2] / [1]) x (1 + [5]).
[4]: Table No. BV-ELEC-5, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {([3] + [5] + 1) ^ 4} - 1.

Table No. BV-ELEC-7

Overall After-Tax DCF Cost of Capital of the U.S. Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	3rd Quarter, 2015 Bond Rating [1]	3rd Quarter, 2015 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	APS Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE	BBB	-	8.3%	59.8%	-	0.0%	4.7%	40.2%	39.5%	6.10%
Alliant Energy	A	A	9.4%	61.2%	4.1%	1.7%	4.1%	37.1%	39.5%	6.77%
Amer. Elec. Power	BBB	-	8.3%	56.8%	-	0.0%	4.7%	43.2%	39.5%	5.94%
Ameren Corp.	BBB	-	11.2%	59.6%	-	0.0%	4.7%	40.4%	39.5%	7.83%
CenterPoint Energy	A	-	7.4%	45.1%	-	0.0%	4.1%	54.9%	39.5%	4.69%
CMS Energy Corp.	BBB	-	9.8%	52.7%	-	0.0%	4.7%	47.3%	39.5%	6.49%
Consol. Edison	A	-	6.9%	59.1%	-	0.0%	4.1%	40.9%	39.5%	5.08%
Dominion Resources	A	-	9.8%	59.8%	-	0.0%	4.1%	40.2%	39.5%	6.86%
DTE Energy	BBB	-	8.8%	59.7%	-	0.0%	4.7%	40.3%	39.5%	6.39%
Edison Int'l	BBB	BBB	3.5%	55.7%	4.7%	5.6%	4.7%	38.7%	39.5%	~~2.3%~~
El Paso Electric	BBB	-	11.2%	54.9%	-	0.0%	4.7%	45.1%	39.5%	7.41%
Entergy Corp.	BBB	BBB	2.2%	47.5%	4.7%	0.8%	4.7%	51.7%	39.5%	~~2.6%~~
G't Plains Energy	BBB	BBB	10.2%	51.3%	4.7%	0.5%	4.7%	48.2%	39.5%	6.62%
IDACORP Inc.	BBB	-	6.2%	64.2%	-	0.0%	4.7%	35.8%	39.5%	4.99%
MGE Energy	AA	-	9.0%	78.8%	-	0.0%	3.9%	21.2%	39.5%	7.58%
NextEra Energy	A	-	10.0%	61.7%	-	0.0%	4.1%	38.3%	39.5%	7.10%
OGE Energy	A	-	7.7%	67.0%	-	0.0%	4.1%	33.0%	39.5%	5.98%
Otter Tail Corp.	BBB	-	12.5%	63.1%	-	0.0%	4.7%	36.9%	39.5%	8.91%
PG&E Corp.	BBB	BBB	11.8%	60.0%	4.7%	0.6%	4.7%	39.5%	39.5%	8.22%
Pinnacle West Capital	A	-	8.8%	64.0%	-	0.0%	4.1%	36.0%	39.5%	6.50%
Portland General	BBB	-	7.8%	57.0%	-	0.0%	4.7%	43.0%	39.5%	5.67%
Public Serv. Enterprise	BBB	-	5.6%	66.9%	-	0.0%	4.7%	33.1%	39.5%	~~4.69%~~
SCANA Corp.	BBB	-	7.9%	56.4%	-	0.0%	4.7%	43.6%	39.5%	5.70%
Sempra Energy	BBB	BBB	13.2%	60.3%	4.7%	0.1%	4.7%	39.7%	39.5%	9.05%
Vectren Corp.	A	-	10.2%	66.0%	-	0.0%	4.1%	34.0%	39.5%	7.61%
Westar Energy	BBB	-	8.2%	63.2%	-	0.0%	4.7%	36.8%	39.5%	6.23%
Xcel Energy Inc.	A	-	8.3%	56.7%	-	0.0%	4.1%	43.3%	39.5%	5.81%
Simple Full Sample Average			9.3%	59.9%	4.5%	0.1%	4.4%	40.0%	39.5%	6.65%
Simple Nuclear Subsample Average			9.7%	60.3%	4.4%	0.3%	4.4%	39.4%	39.5%	6.92%

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-ELEC-6; Panel A, [6].
[4]: Table No. BV-ELEC-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[6]: Table No. BV-ELEC-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel B.
[8]: Table No. BV-ELEC-4, [3].
[9]: APS Effective Corporate Tax Rate.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 100 basis points.

Table No. BV-ELEC-8

DCF Cost of Equity at Representative Deemed Capital Structure

	Overall After -Tax Cost of Capital [1]	APS Representative Base Deemed % Debt [2]	Representative Cost of A Rated Utility Debt [3]	APS Representative Income Tax Rate [4]	APS Representative Base Deemed % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	6.6%	44.0%	4.1%	39.5%	56.0%	9.9%
Nuclear Subsample						
Simple DCF Quarterly	6.9%	44.0%	4.1%	39.5%	56.0%	10.4%

Sources and Notes:
[1]: Table No. BV-ELEC-7; Panels A-B, [10].
[2]: APS Assumed Capital Structure.
[3]: Based on an A rating. Yield from Bloomberg as of February 10, 2016.
[4]: APS Effective Corporate Tax Rate.
[5]: APS Assumed Capital Structure.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Table No. BV-ELEC-9

Risk Free Rate

[1]	Consensus 10-Year Forecast	3.40%
	U.S. Government Bond Yields	
[2]	20-Year	5.21%
[3]	10-Year	4.68%
[4]	Maturity Premium	0.53%
[5]	Consensus 10-Year Forecast Adjusted to 20-year Horizon	3.93%

Sources and Notes:

[1]: Bluechip Consensus Forecast in January 2016.

[2]-[3]: Supporting Schedule # 1 to Table No. BV-ELEC-9. Averages of monthly bond yields from January 1991 through January 2016.

[4]: [2] - [3].

[5]: [1] + [4].

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.73%, Long-Term Market Risk Premium of 7.00%

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE	4.73%	0.80	7.00%	10.3%	10.6%
Alliant Energy	4.73%	0.80	7.00%	10.3%	10.6%
Amer. Elec. Power	4.73%	0.70	7.00%	9.6%	10.1%
Ameren Corp.	4.73%	0.75	7.00%	10.0%	10.4%
CenterPoint Energy	4.73%	0.85	7.00%	10.7%	10.9%
CMS Energy Corp.	4.73%	0.75	7.00%	10.0%	10.4%
Consol. Edison	4.73%	0.60	7.00%	8.9%	9.5%
Dominion Resources	4.73%	0.70	7.00%	9.6%	10.1%
DTE Energy	4.73%	0.75	7.00%	10.0%	10.4%
Edison Int'l	4.73%	0.70	7.00%	9.6%	10.1%
El Paso Electric	4.73%	0.75	7.00%	10.0%	10.4%
Entergy Corp.	4.73%	0.70	7.00%	9.6%	10.1%
G't Plains Energy	4.73%	0.85	7.00%	10.7%	10.9%
IDACORP Inc.	4.73%	0.80	7.00%	10.3%	10.6%
MGE Energy	4.73%	0.75	7.00%	10.0%	10.4%
NextEra Energy	4.73%	0.75	7.00%	10.0%	10.4%
OGE Energy	4.73%	0.95	7.00%	11.4%	11.5%
Otter Tail Corp.	4.73%	0.85	7.00%	10.7%	10.9%
PG&E Corp.	4.73%	0.70	7.00%	9.6%	10.1%
Pinnacle West Capital	4.73%	0.75	7.00%	10.0%	10.4%
Portland General	4.73%	0.80	7.00%	10.3%	10.6%
Public Serv. Enterprise	4.73%	0.75	7.00%	10.0%	10.4%
SCANA Corp.	4.73%	0.75	7.00%	10.0%	10.4%
Sempra Energy	4.73%	0.80	7.00%	10.3%	10.6%
Vectren Corp.	4.73%	0.75	7.00%	10.0%	10.4%
Westar Energy	4.73%	0.75	7.00%	10.0%	10.4%
Xcel Energy Inc.	4.73%	0.65	7.00%	9.3%	9.8%
Average				10.0%	10.4%
Nuclear Subsample Average				9.9%	10.3%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Bloomberg as of February 10, 2016.
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.93%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE	3.93%	0.80	8.00%	10.3%	10.6%
Alliant Energy	3.93%	0.80	8.00%	10.3%	10.6%
Amer. Elec. Power	3.93%	0.70	8.00%	9.5%	10.0%
Ameren Corp.	3.93%	0.75	8.00%	9.9%	10.3%
CenterPoint Energy	3.93%	0.85	8.00%	10.7%	11.0%
CMS Energy Corp.	3.93%	0.75	8.00%	9.9%	10.3%
Consol. Edison	3.93%	0.60	8.00%	8.7%	9.3%
Dominion Resources	3.93%	0.70	8.00%	9.5%	10.0%
DTE Energy	3.93%	0.75	8.00%	9.9%	10.3%
Edison Int'l	3.93%	0.70	8.00%	9.5%	10.0%
El Paso Electric	3.93%	0.75	8.00%	9.9%	10.3%
Entergy Corp.	3.93%	0.70	8.00%	9.5%	10.0%
G't Plains Energy	3.93%	0.85	8.00%	10.7%	11.0%
IDACORP Inc.	3.93%	0.80	8.00%	10.3%	10.6%
MGE Energy	3.93%	0.75	8.00%	9.9%	10.3%
NextEra Energy	3.93%	0.75	8.00%	9.9%	10.3%
OGE Energy	3.93%	0.95	8.00%	11.5%	11.6%
Otter Tail Corp.	3.93%	0.85	8.00%	10.7%	11.0%
PG&E Corp.	3.93%	0.70	8.00%	9.5%	10.0%
Pinnacle West Capital	3.93%	0.75	8.00%	9.9%	10.3%
Portland General	3.93%	0.80	8.00%	10.3%	10.6%
Public Serv. Enterprise	3.93%	0.75	8.00%	9.9%	10.3%
SCANA Corp.	3.93%	0.75	8.00%	9.9%	10.3%
Sempra Energy	3.93%	0.80	8.00%	10.3%	10.6%
Vectren Corp.	3.93%	0.75	8.00%	9.9%	10.3%
Westar Energy	3.93%	0.75	8.00%	9.9%	10.3%
Xcel Energy Inc.	3.93%	0.65	8.00%	9.1%	9.7%
Average				10.0%	10.4%
Nuclear Subsample Average				9.9%	10.2%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Bloomberg as of February 10, 2016.
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 4.73%, Long-Term Market Risk Premium of 7.00%

Company	CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	APS Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
ALLETE	10.3%	10.6%	60.2%	-	0.0%	4.65%	39.8%	39.5%	7.3%	7.5%
Alliant Energy	10.3%	10.6%	57.8%	4.34%	2.3%	4.34%	39.9%	39.5%	7.1%	7.3%
Amer. Elec. Power	9.6%	10.1%	52.0%	4.65%	0.0%	4.65%	48.0%	39.5%	6.4%	6.6%
Ameren Corp.	10.0%	10.4%	52.6%	-	0.0%	4.65%	47.4%	39.5%	6.6%	6.8%
CenterPoint Energy	10.7%	10.9%	47.8%	-	0.0%	4.34%	52.2%	39.5%	6.5%	6.6%
CMS Energy Corp.	10.0%	10.4%	42.6%	-	0.2%	4.65%	57.2%	39.5%	5.9%	6.0%
Consol. Edison	8.9%	9.5%	56.9%	4.13%	0.2%	4.13%	42.9%	39.5%	6.2%	6.5%
Dominion Resources	9.6%	10.1%	59.6%	4.13%	0.4%	4.13%	40.0%	39.5%	6.8%	7.0%
DTE Energy	10.0%	10.4%	55.1%	-	0.0%	4.65%	44.9%	39.5%	6.8%	7.0%
Edison Int'l	9.6%	10.1%	50.1%	4.65%	5.2%	4.65%	44.7%	39.5%	6.3%	6.5%
El Paso Electric	10.0%	10.4%	55.9%	-	0.0%	4.65%	44.1%	39.5%	6.8%	7.0%
Entergy Corp.	9.6%	10.1%	49.2%	4.65%	1.2%	4.65%	49.7%	39.5%	6.2%	6.4%
G't Plains Energy	10.7%	10.9%	45.4%	4.65%	0.5%	4.65%	54.0%	39.5%	6.4%	6.5%
IDACORP Inc.	10.3%	10.6%	57.1%	-	0.0%	4.65%	42.9%	39.5%	7.1%	7.3%
MGE Energy	10.0%	10.4%	73.5%	-	0.0%	3.86%	26.5%	39.5%	8.0%	8.2%
NextEra Energy	10.0%	10.4%	53.9%	-	0.0%	4.13%	46.1%	39.5%	6.5%	6.7%
OGE Energy	11.4%	11.5%	65.0%	-	0.0%	4.34%	35.0%	39.5%	8.3%	8.4%
Otter Tail Corp.	10.7%	10.9%	63.1%	4.65%	0.6%	4.65%	36.3%	39.5%	7.8%	7.9%
PG&E Corp.	9.6%	10.1%	55.5%	4.65%	0.7%	4.65%	43.8%	39.5%	6.6%	6.9%
Pinnacle West Capital	10.0%	10.4%	58.9%	-	0.0%	4.44%	41.1%	39.5%	7.0%	7.2%
Portland General	10.3%	10.6%	49.8%	-	0.0%	4.65%	50.2%	39.5%	6.6%	6.7%
Public Serv. Enterprise	10.0%	10.4%	64.1%	-	0.0%	4.65%	35.9%	39.5%	7.4%	7.6%
SCANA Corp.	10.0%	10.4%	51.5%	-	0.0%	4.65%	48.5%	39.5%	6.5%	6.7%
Sempra Energy	10.3%	10.6%	58.2%	4.65%	0.3%	4.65%	41.6%	39.5%	7.2%	7.4%
Vectren Corp.	10.0%	10.4%	59.3%	-	0.0%	4.13%	40.7%	39.5%	6.9%	7.2%
Westar Energy	10.0%	10.4%	51.9%	4.65%	0.1%	4.65%	47.9%	39.5%	6.5%	6.7%
Xcel Energy Inc.	9.3%	9.8%	52.7%	4.13%	0.1%	4.13%	47.1%	39.5%	6.1%	6.4%
Full Sample Average	10.0%	10.4%	55.5%	4.5%	0.4%	4.5%	44.0%	39.5%	6.8%	7.0%
Nuclear Subsample Average	9.9%	10.3%	55.8%	4.4%	0.5%	4.5%	43.7%	39.5%	6.7%	7.0%

Sources and Notes:

[1]: Table No. BV-ELEC-10; Panel A, [4].
[2]: Table No. BV-ELEC-10; Panel A, [5].
[3]: Table No. BV-ELEC-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-ELEC
[5]: Table No. BV-ELEC-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-ELEC-11, P
[7]: Table No. BV-ELEC-4, [6].
[8]: APS Effective Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.

[9]-[10] A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 100 basis points

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 3.93%, Long-Term Market Risk Premium of 8.00%

Company	CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	APS Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
ALLETE	10.3%	10.6%	60.2%	-	0.0%	4.65%	39.8%	39.5%	7.3%	7.5%
Alliant Energy	10.3%	10.6%	57.8%	4.34%	2.3%	4.34%	39.9%	39.5%	7.1%	7.3%
Amer. Elec. Power	9.5%	10.0%	52.0%	4.65%	0.0%	4.65%	48.0%	39.5%	6.3%	6.5%
Ameren Corp.	9.9%	10.3%	52.6%	-	0.0%	4.65%	47.4%	39.5%	6.6%	6.8%
CenterPoint Energy	10.7%	11.0%	47.8%	-	0.0%	4.34%	52.2%	39.5%	6.5%	6.6%
CMS Energy Corp.	9.9%	10.3%	42.6%	-	0.2%	4.65%	57.2%	39.5%	5.8%	6.0%
Consol. Edison	8.7%	9.3%	56.9%	4.13%	0.2%	4.13%	42.9%	39.5%	6.0%	6.4%
Dominion Resources	9.5%	10.0%	59.6%	4.13%	0.4%	4.13%	40.0%	39.5%	6.7%	7.0%
DTE Energy	9.9%	10.3%	55.1%	-	0.0%	4.65%	44.9%	39.5%	6.7%	6.9%
Edison Int'l	9.5%	10.0%	50.1%	4.65%	5.2%	4.65%	44.7%	39.5%	6.3%	6.5%
El Paso Electric	9.9%	10.3%	55.9%	-	0.0%	4.65%	44.1%	39.5%	6.8%	7.0%
Entergy Corp.	9.5%	10.0%	49.2%	4.65%	1.2%	4.65%	49.7%	39.5%	6.1%	6.4%
G't Plains Energy	10.7%	11.0%	45.4%	4.65%	0.5%	4.65%	54.0%	39.5%	6.4%	6.5%
IDACORP Inc.	10.3%	10.6%	57.1%	-	0.0%	4.65%	42.9%	39.5%	7.1%	7.3%
MGE Energy	9.9%	10.3%	73.5%	-	0.0%	3.86%	26.5%	39.5%	7.9%	8.2%
NextEra Energy	9.9%	10.3%	53.9%	-	0.0%	4.13%	46.1%	39.5%	6.5%	6.7%
OGE Energy	11.5%	11.6%	65.0%	-	0.0%	4.34%	35.0%	39.5%	8.4%	8.5%
Otter Tail Corp.	10.7%	11.0%	63.1%	4.65%	0.6%	4.65%	36.3%	39.5%	7.8%	8.0%
PG&E Corp.	9.5%	10.0%	55.5%	4.65%	0.7%	4.65%	43.8%	39.5%	6.6%	6.8%
Pinnacle West Capital	9.9%	10.3%	58.9%	-	0.0%	4.44%	41.1%	39.5%	7.0%	7.2%
Portland General	10.3%	10.6%	49.8%	-	0.0%	4.65%	50.2%	39.5%	6.6%	6.7%
Public Serv. Enterprise	9.9%	10.3%	64.1%	-	0.0%	4.65%	35.9%	39.5%	7.4%	7.6%
SCANA Corp.	9.9%	10.3%	51.5%	-	0.0%	4.65%	48.5%	39.5%	6.5%	6.7%
Sempra Energy	10.3%	10.6%	58.2%	4.65%	0.3%	4.65%	41.6%	39.5%	7.2%	7.4%
Vectren Corp.	9.9%	10.3%	59.3%	-	0.0%	4.13%	40.7%	39.5%	6.9%	7.1%
Westar Energy	9.9%	10.3%	51.9%	4.65%	0.1%	4.65%	47.9%	39.5%	6.5%	6.7%
Xcel Energy Inc.	9.1%	9.7%	52.7%	4.13%	0.1%	4.13%	47.1%	39.5%	6.0%	6.3%
Full Sample Average	10.0%	10.4%	55.5%	4.5%	0.4%	4.5%	44.0%	39.5%	6.8%	7.0%
Nuclear Subsample Average	9.9%	10.2%	55.8%	4.4%	0.5%	4.5%	43.7%	39.5%	6.7%	6.9%

Sources and Notes:
[1]: Table No. BV-ELEC-10; Panel B, [4].
[2]: Table No. BV-ELEC-10; Panel B, [5].
[3]: Table No. BV-ELEC-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-ELEC
[5]: Table No. BV-ELEC-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-ELEC-11, P
[7]: Table No. BV-ELEC-4, [6].
[8]: APS Effective Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[9]-[10] A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 100 basis points

Table No. BV-ELEC-12

Risk Positioning Cost of Equity at Representative Deemed Capital Structure

	Overall After-Tax Cost of Capital (Scenario 1) [1]	Overall After-Tax Cost of Capital (Scenario 2) [2]	APS Representative Base Deemed % Debt [3]	Representative Cost of A-Rated Utility Debt [4]	APS Representative Income Tax Rate [5]	APS Representative Base Deemed % Equity [6]	Estimated Return on Equity (Scenario 1) [7]	Estimated Return on Equity (Scenario 2) [8]
Full Sample:								
CAPM	6.8%	6.8%	44.0%	4.1%	39.5%	56.0%	10.2%	10.1%
ECAPM (1.50%)	7.0%	7.0%	44.0%	4.1%	39.5%	56.0%	10.5%	10.5%
Nuclear Subsample:								
CAPM	6.7%	6.7%	44.0%	4.1%	39.5%	56.0%	10.1%	10.0%
ECAPM (1.50%)	7.0%	6.9%	44.0%	4.1%	39.5%	56.0%	10.5%	10.4%

Sources and Notes:

[1]: Table No. BV-ELEC-11; Panel A, [9] - [10].

[2]: Table No. BV-ELEC-11; Panel B, [9] - [10].

Scenario 1: Long-Term Risk Free Rate of 4.73%, Long-Term Market Risk Premium of 7.00%.

Scenario 2: Long-Term Risk Free Rate of 3.93%, Long-Term Market Risk Premium of 8.00%.

[3]: APS Assumed Capital Structure.

[4]: Based on a A rating. Yield from Bloomberg as of February 10, 2016.

[5]: APS Effective Corporate Tax Rate.

[6]: APS Assumed Capital Structure.

[7]: {[1] - ([3] x [4] x (1 - [5])}/ [6].

[8]: {[2] - ([3] x [4] x (1 - [5]))}/ [6].

Table No. BV-ELEC-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company	Value Line Betas [1]	Debt Beta [2]	5-Year Average Common Equity to Market Value Ratio [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	5-Year Average Debt to Market Value Ratio [5]	APS Representative Income Tax Rate [6]	Asset Beta: Without Taxes [7]	Asset Beta: With Taxes [8]
ALLETE	0.80	0.10	60.2%	0.0%	39.8%	39.5%	0.52	0.60
Alliant Energy	0.80	0.07	57.8%	2.3%	39.9%	39.5%	0.49	0.57
Amer. Elec. Power	0.70	0.10	52.0%	0.0%	48.0%	39.5%	0.41	0.48
Ameren Corp.	0.75	0.10	52.6%	0.0%	47.4%	39.5%	0.44	0.52
CenterPoint Energy	0.85	0.07	47.8%	0.0%	52.2%	39.5%	0.44	0.54
CMS Energy Corp.	0.75	0.10	42.6%	0.2%	57.2%	39.5%	0.38	0.46
Consol. Edison	0.60	0.05	56.9%	0.2%	42.9%	39.5%	0.36	0.43
Dominion Resources	0.70	0.05	59.6%	0.4%	40.0%	39.5%	0.44	0.51
DTE Energy	0.75	0.10	55.1%	0.0%	44.9%	39.5%	0.46	0.54
Edison Int'l	0.70	0.10	50.1%	5.2%	44.7%	39.5%	0.40	0.46
El Paso Electric	0.75	0.10	55.9%	0.0%	44.1%	39.5%	0.46	0.54
Entergy Corp.	0.70	0.10	49.2%	1.2%	49.7%	39.5%	0.39	0.47
G't Plains Energy	0.85	0.10	45.4%	0.5%	54.0%	39.5%	0.44	0.53
IDACORP Inc.	0.80	0.10	57.1%	0.0%	42.9%	39.5%	0.50	0.58
MGE Energy	0.75	0.05	73.5%	0.0%	26.5%	39.5%	0.56	0.62
NextEra Energy	0.75	0.05	53.9%	0.0%	46.1%	39.5%	0.43	0.51
OGE Energy	0.95	0.07	65.0%	0.0%	35.0%	39.5%	0.64	0.73
Otter Tail Corp.	0.85	0.10	63.1%	0.6%	36.3%	39.5%	0.57	0.65
PG&E Corp.	0.70	0.10	55.5%	0.7%	43.8%	39.5%	0.43	0.50
Pinnacle West Capital	0.75	0.08	58.9%	0.0%	41.1%	39.5%	0.47	0.55
Portland General	0.80	0.10	49.8%	0.0%	50.2%	39.5%	0.45	0.54
Public Serv. Enterprise	0.75	0.10	64.1%	0.0%	35.9%	39.5%	0.52	0.59
SCANA Corp.	0.75	0.10	51.5%	0.0%	48.5%	39.5%	0.43	0.51
Sempra Energy	0.80	0.10	58.2%	0.3%	41.6%	39.5%	0.51	0.59
Vectren Corp.	0.75	0.05	59.3%	0.0%	40.7%	39.5%	0.46	0.54
Westar Energy	0.75	0.10	51.9%	0.1%	47.9%	39.5%	0.44	0.52
Xcel Energy Inc.	0.65	0.05	52.7%	0.1%	47.1%	39.5%	0.37	0.44
Full Sample Average	0.76	0.08	55.5%	0.4%	44.0%	39.5%	0.46	0.54
Nuclear Subsample Average	0.74	0.09	55.8%	0.5%	43.7%	39.5%	0.45	0.53

Sources and Notes:

[1]: Supporting Schedule # 1 to Table No. BV-ELEC-10, [1].
[2]: Supporting Schedule #1 to Table No. BV-ELEC-13, [7].
[3]: Table No. BV-ELEC-4, [4].
[4]: Table No. BV-ELEC-4, [5].
[5]: Table No. BV-ELEC-4, [6].
[6]: APS Effective Corporate Tax Rate
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Table No. BV-ELEC-14

Sample Average Asset Beta Relevered at Representative Deemed Capital Structure

	Asset Beta [1]	Assumed Debt Beta [2]	APS Representative Base Deemed % Debt [3]	APS Representative Income Tax Rate [4]	APS Representative Base Deemed % Equity [5]	Estimated Equity Beta [6]
Full Sample:						
Asset Beta Without Taxes	0.46	0.05	44.0%	39.5%	56.0%	0.78
Asset Beta With Taxes	0.54	0.05	44.0%	39.5%	56.0%	0.77
Nuclear Subsample:						
Asset Beta Without Taxes	0.45	0.05	44.0%	39.5%	56.0%	0.77
Asset Beta With Taxes	0.53	0.05	44.0%	39.5%	56.0%	0.75

Sources and Notes:

[1]: Table No. BV-ELEC-13, [7] - [8].

[2]: Debt Beta estimate for A-rated entities.Corporate Finance, Berk and Demarzo, Second Edition, p. 389.

[3]: APS Assumed Capital Structure.

[4]: APS Effective Corporate Tax Rate.

[5]: APS Assumed Capital Structure.

[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.73%, Long-Term Market Risk Premium of 7.00%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Full Sample:				capmlt	ecapmlt2
Asset Beta Without Taxes	4.73%	0.78	7.00%	10.2%	10.5%
Asset Beta With Taxes	4.73%	0.77	7.00%	10.1%	10.5%
Nuclear Subsample:					
Asset Beta Without Taxes	4.73%	0.77	7.00%	10.1%	10.4%
Asset Beta With Taxes	4.73%	0.75	7.00%	10.0%	10.4%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.93%, Long-Term Market Risk Premium of 8.00%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Full Sample:				capmlt	ecapmlt2
Asset Beta Without Taxes	3.93%	0.78	8.00%	10.2%	10.5%
Asset Beta With Taxes	3.93%	0.77	8.00%	10.1%	10.4%
Nuclear Subsample:					
Asset Beta Without Taxes	3.93%	0.77	8.00%	10.1%	10.4%
Asset Beta With Taxes	3.93%	0.75	8.00%	10.0%	10.3%

Sources and Notes:
[1]: Villadsen Direct Testimony.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Breakdown of Generation Capacity

Ticker	Company		Nuclear	Coal	Natural Gas	Other	Source
ALE	ALLETE	[a]	0%	56%	0%	44%	Value Line
LNT	Alliant Energy	[b]	17%	47%	4%	32%	Value Line
AEP	Amer. Elec. Power	[c]	0%	83%	13%	4%	2014 10-K, p. 48
AEE	Ameren Corp.	[d]	21%	74%	0%	5%	Value Line
CNP	CenterPoint Energy	[e]	-	-	-	-	2014 10-K
CMS	CMS Energy Corp.	[f]	0%	44%	6%	50%	Value Line
ED	Consol. Edison	[g]	-	-	-	-	Value Line
D	Dominion Resources	[h]	33%	30%	15%	22%	Value Line
DTE	DTE Energy	[i]	17%	67%	1%	15%	Value Line
EIX	Edison Int'l	[j]	6%	0%	8%	86%	Value Line
EE	El Paso Electric	[k]	47%	5%	35%	13%	Value Line
ETR	Entergy Corp.	[l]	33%	11%	28%	28%	Value Line
GXP	G't Plains Energy	[m]	13%	64%	1%	22%	Value Line
IDA	IDACORP Inc.	[n]	0%	34%	7%	59%	Value Line
MGEE	MGE Energy	[o]	0%	48%	6%	46%	Value Line
NEE	NextEra Energy	[p]	23%	5%	67%	5%	Value Line
OGE	OGE Energy	[q]	0%	44%	23%	33%	Value Line
OTTR	Otter Tail Corp.	[r]	0%	69%	13%	17%	2014 10-K, p. 6
PCG	PG&E Corp.	[s]	21%	0%	7%	72%	Value Line
PNW	Pinnacle West Capital	[t]	27%	34%	17%	22%	Value Line
POR	Portland General	[u]	0%	21%	16%	63%	Value Line
PEG	Public Serv. Enterprise	[v]	28%	18%	46%	8%	2014 10-K, p. 6
SCG	SCANA Corp.	[w]	19%	48%	28%	5%	Value Line
SRE	Sempra Energy	[x]	0%	0%	100%	0%	2014 10-K, p.14
VVC	Vectren Corp.	[y]	0%	77%	23%	0%	2014 10-K, p.7
WR	Westar Energy	[z]	8%	48%	44%	0%	Value Line
XEL	Xcel Energy Inc.	[aa]	12%	46%	21%	21%	2014 10-K, p. 30

Sources/Notes:

Value Line and 10-K reports.

[e]: According to their 2014 10-K, CNP does not own or operate any power generation facilities.

[g],[j],[n],[s],[u]: Purchase most of their power as reported by Value Line in 2015.

[x]: According to page 12 of their 2014 10-K, Sempra Energy purchases most of its power. However, all owned generation consists of gas-fired power plants.

[aa]: Percentages are based on total 2014 generation reported in Xcel Energy's 2014 10k as a proxy for generation capacity.

Companies with 17%-37% Nuclear Generation	
Ticker	Company
LNT	Alliant Energy
AEE	Ameren Corp.
D	Dominion Resources
DTE	DTE Energy
ETR	Entergy Corp.
NEE	NextEra Energy
PCG	PG&E Corp.
PNW	Pinnacle West Capital
PEG	Public Serv. Enterprise
SCG	SCANA Corp.

Risk Premiums Determined by Relationship Between Authorized ROEs[1] and Long-term Treasury Bond Rates During the Period 1990-2015 - Electric Vertically Integrated Only

Formula: Risk Premium = A_0 + (A_1 x Treasury bond Rate)

R Squared		0.79		
Estimate of intercept (A_0)		8.8860%		
Estimate of slope (A_1)		-0.593		
Equity Cost Estimate for Vertically Integrated Electric		Predicted Risk Premium		Expected Treasury Bond Rate[2]
10.8%	=	6.08%	+	4.73%

Sources and Notes:

[1]: Source of ROE Data: SNL Financia

[2]: 2016 Consensus Forecast Risk-Free Rate + Expected Maturity Premium

See regression results on [Regressions] tab

Amount of Distributed PV Generation by State in 2014

Abbr.	State	Total Distributed PV Generation (GWh)	Total Utility-Scale Generation (GWh)	Percent of Total Utility-Scale Generation (%)
[1]	[2]	[3]	[4]	[5]=[3]/[4]
AL	Alabama	0	149,339	0.00%
AK	Alaska	0	6,042	0.00%
AZ	Arizona	916	112,257	0.82%
AR	Arkansas	2	61,591	0.00%
CA	California	3,862	198,808	1.94%
CO	Colorado	353	53,848	0.66%
CT	Connecticut	103	33,677	0.31%
DE	Delaware	60	7,704	0.78%
FL	Florida	102	230,014	0.04%
GA	Georgia	85	125,838	0.07%
HI	Hawaii	532	10,205	5.21%
ID	Idaho	1	15,185	0.01%
IL	Illinois	19	202,145	0.01%
IN	Indiana	10	115,396	0.01%
IA	Iowa	20	56,853	0.04%
KS	Kansas	0	49,728	0.00%
KY	Kentucky	12	90,897	0.01%
LA	Louisiana	101	104,231	0.10%
ME	Maine	12	13,249	0.09%
MD	Maryland	207	37,834	0.55%
MA	Massachusetts	503	31,118	1.62%
MI	Michigan	34	106,817	0.03%
MN	Minnesota	18	56,998	0.03%
MS	Mississippi	0	55,127	0.00%
MO	Montana	11	30,257	0.04%
MT	Missouri	112	87,836	0.13%
NE	Nebraska	0	39,431	0.00%
NV	Nevada	85	36,001	0.24%
NH	New Hampshire	12	19,539	0.06%
NJ	New Jersey	1,106	68,052	1.63%
NM	New Mexico	117	32,307	0.36%
NY	New York	291	137,123	0.21%
NC	North Carolina	73	128,144	0.06%
ND	North Dakota	0	36,464	0.00%
OH	Ohio	71	134,478	0.05%
OK	Oklahoma	0	70,158	0.00%
OR	Oregon	78	60,119	0.13%
PA	Pennsylvania	211	221,060	0.10%
RI	Rhode Island	12	6,283	0.19%
SC	South Carolina	0	97,159	0.00%
SD	South Dakota	0	10,994	0.00%
TN	Tennessee	60	79,507	0.08%
TX	Texas	140	437,631	0.03%
UT	Utah	39	43,785	0.09%
VT	Vermont	33	7,032	0.47%
VA	Virginia	22	77,138	0.03%
WA	Washington	32	116,335	0.03%
WV	West Virginia	0	81,059	0.00%
WI	Wisconsin	23	61,065	0.04%
WY	Wyoming	0	49,695	0.00%
	United States	**9,536**	**4,093,607**	**0.23%**

Sources/Notes:
EIA Electric Power Monthly, Jan. 2016.
Highlighted states have significant amounts of distributed PV generation relative to total utility-scale generation in the state.

Sample Companies
Amount of Distributed PV Generation
in States with Decoupling

Company	States with Decoupling	Total Dist. PV Generation as a % of Total Utility-Scale Generation within State
[1]	[2]	[3]
ALLETE		
Alliant Energy		-
Amer. Elec. Power	AR*	0.00%
	IN*	0.01%
	KY*	0.01%
	LA*	0.10%
	OH*	0.05%
	OK*	0.00%
Ameren Corp.	MO*	0.04%
CenterPoint Energy	(AR)	0.00%
	(LA)*	0.10%
	(MN)	0.03%
	(OK)*	0.00%
CMS Energy Corp.		-
Consol. Edison	NY, (NY)	0.21%
Dominion Resources		-
DTE Energy	(MI)*	0.03%
Edison Int'l	CA	1.94%
El Paso Electric		-
Entergy Corp.	AR*	0.00%
	LA*, (LA)	0.10%
	MS*	0.00%
G't Plains Energy	MO*	0.04%
IDACORP Inc.	ID*	0.01%
MGE Energy		-
NextEra Energy		-
OGE Energy	AR*	0.00%
	OK*	0.00%
Otter Tail Corp.		-
PG&E Corp.	CA, (CA)	1.94%
Pinnacle West Capital	AZ*	0.82%
Portland General	OR*	0.13%
Public Serv. Enterprise	(NJ)*	1.63%
SCANA Corp.	(NC)	0.06%
	(SC)*	0.00%
Sempra Energy	(AL)*	0.00%
	CA, (CA)	1.94%
Vectren Corp.	IN*, (IN)	0.01%
Westar Energy	KS*	0.00%
Xcel Energy Inc.	(CO)*	0.66%
	SD*	0.00%

Sources/Notes:
Regulatory Research Associates, "Adjustment Clauses," October 2, 2015.
Highlighted companies are included in our subsample of utilities with 17% to 37% nuclear generation.
"*" indicates partial decoupling.
"( )" indicates decoupling status for associated gas operations.

Regression Output: PE Ratio vs. 20-Year Treasury Rate

	20-Year Treasury				Constant					
	Coef	Std. Error	T-Stat	P-Value	Coef	Std. Error	T-Stat	P-Value	N	R-Squared
Group Results										
Electric (Average)	(1.55)	0.36	(4.26)	0.00	26.40	2.03	13.01	0.000	104	15%
Electric (Median)	(0.89)	0.24	(3.76)	0.00	19.23	1.32	14.52	0.000	104	12%
Nuclear (Average)	(1.31)	0.44	(3.00)	0.00	24.80	2.44	10.18	0.000	104	8%
Nuclear (Median)	(1.04)	0.29	(3.65)	0.00	20.42	1.59	12.82	0.000	104	12%
Individual Results										
Ameren Corp.	(2.47)	2.43	(1.02)	0.312	34.53	11.34	3.04	0.003	66	2%
Amer. Elec. Power	(2.27)	1.31	(1.74)	0.086	29.34	7.31	4.01	0.000	96	3%
ALLETE	(2.78)	0.62	(4.47)	0.000	26.70	3.48	7.68	0.000	103	16%
CMS Energy Corp.	(1.24)	0.96	(1.30)	0.197	23.39	5.25	4.45	0.000	83	2%
CenterPoint Energy	0.42	0.80	0.53	0.599	13.09	4.50	2.91	0.005	88	0%
Dominion Resources	(1.92)	0.63	(3.06)	0.003	29.32	3.53	8.31	0.000	93	9%
DTE Energy	(1.89)	0.59	(3.21)	0.002	24.50	3.30	7.43	0.000	100	10%
Consol. Edison	(0.60)	0.62	(0.96)	0.337	20.68	3.48	5.95	0.000	104	1%
El Paso Electric	(6.71)	1.92	(3.49)	0.001	54.05	9.34	5.79	0.000	72	15%
Edison Int'l	(0.93)	0.56	(1.67)	0.099	19.24	3.17	6.06	0.000	93	3%
Entergy Corp.	(0.53)	0.82	(0.64)	0.522	18.99	4.59	4.14	0.000	95	0%
G't Plains Energy	(2.99)	1.29	(2.31)	0.023	37.99	7.31	5.20	0.000	94	5%
IDACORP Inc.	(1.12)	0.72	(1.56)	0.122	23.53	4.02	5.86	0.000	101	2%
Alliant Energy	(0.69)	0.78	(0.87)	0.384	21.52	4.42	4.86	0.000	96	1%
MGE Energy	(0.71)	0.44	(1.59)	0.114	21.76	2.48	8.78	0.000	103	2%
NextEra Energy	0.00	0.47	0.01	0.994	16.95	2.60	6.52	0.000	101	0%
OGE Energy	(1.07)	1.38	(0.78)	0.439	30.41	7.54	4.03	0.000	90	1%
Otter Tail Corp.	(4.29)	1.05	(4.09)	0.000	44.81	5.92	7.57	0.000	101	14%
PG&E Corp.	(4.08)	1.35	(3.02)	0.003	39.74	7.57	5.25	0.000	98	9%
Public Serv. Enterprise	(0.31)	0.36	(0.87)	0.386	15.12	2.00	7.57	0.000	99	1%
Pinnacle West Capital	(2.15)	2.04	(1.05)	0.295	37.87	11.61	3.26	0.002	92	1%
Portland General	0.20	1.40	0.14	0.888	15.27	5.31	2.88	0.007	37	0%
SCANA Corp.	0.17	0.45	0.38	0.707	14.68	2.47	5.93	0.000	98	0%
Sempra Energy	(2.76)	0.93	(2.97)	0.004	27.32	4.28	6.38	0.000	71	11%
Vectren Corp.	6.15	3.70	1.66	0.102	2.73	16.21	0.17	0.867	60	5%
Westar Energy	(2.04)	1.26	(1.62)	0.109	30.84	7.02	4.39	0.000	95	3%
Xcel Energy Inc.	(0.06)	0.67	(0.09)	0.931	17.36	3.76	4.62	0.000	101	0%

Significant at 5% Level.

DIRECT TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

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 Rate Strategy for Arizona Public Service Company (APS or Company). I have management responsibility for all aspects relating to rate strategy and specific rates and prices.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My background and experience are set forth in Attachment LRS-1DR to this testimony.

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

A. My testimony provides:

1. Certain Standard Filing Requirement provisions of APS's rate case filing;
2. APS's request for Accounting Deferral Orders and a step increase;
3. APS's Cost of Service Study (COSS) in this proceeding;
4. APS's proposed changes to the Lost Fixed Cost Recovery Mechanism (LFCR), Environmental Improvement Surcharge (EIS) and Transmission Cost Adjustor (TCA);
5. APS's fair value increment;
6. The Company's Long Range Rate Plan;
7. A new Extra-High Load Factor rate for extra-large customers;
8. An economic development service schedule; and
9. APS's proposed termination of the AG-1 buy-through rate program.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony addresses certain Standard Filing Requirements (SFR) exhibits including Schedule A-1 that calculates the net increase in base rate revenue requirements of $433,434,000 that is sought by the Company. This amount includes a $267,551,000 increase in rates resulting from moving various adjustor amounts from the respective adjustor mechanisms into base rates. These adjustor transfers are revenue neutral and does not change the amount collected – it only changes where the amounts will be collected on customer's bills. These adjustor transfers are:

1. The portion of transmission revenue requirements that is presently collected in the TCA, in the amount of $128,602,000 (ACC Jurisdiction);
2. The portion of the lost fixed costs that are presently collected in the LFCR, in the amount of $45,988,000 (ACC Jurisdiction);
3. The portion of environmental compliance revenue requirements that is presently collected in the EIS, in the amount of $2,456,000 (ACC Jurisdiction);
4. An increase in the portion of energy efficiency expense to be collected in base rates from the Demand Side Management Adjustment Clause (DSMAC), in the amount of $9,979,000 (ACC Jurisdiction);
5. The revenue requirement of Arizona Sun-related renewable generation, the Schools and Governments Program and the Community Power Project will be transferred from the Renewable Energy Adjustment Charge (REAC) into base rates, collectively this transfer totals $37,543,000 (ACC Jurisdiction);
6. The portion of APS's acquisition of Southern California Edison's share of Four Corners currently collected in the Four Corners Rate Rider, in the amount of $57,588,000 (ACC Jurisdiction);

7. The portion of the System Benefits reduction that went into effect January 1, 2016 to reflect Palo Verde Unit 2 being fully funding in the nuclear decommissioning trust in the amount of ($14,604,000) (ACC Jurisdiction); and

8. A net decrease to the fuel-related component of rates in the amount of $61,691,000 (ACC Jurisdiction), in re-setting the Power Supply Adjustment (PSA) to zero.

The components of the base rate increase inclusive of Adjustor transfers are as follows:

Overview of Rate Increase ($ in Millions)		
Total Stated Base Rate Increase (inclusive of existing adjustor transfers)	$433.434	15.00%
Less: Transfer to base rates of various adjustors already in effect	$267.551	9.26%
Net Customer Bill Impact	**$165.883**	**5.74%**

If proposed rates are effective on July 1, 2017, customers will experience a net base rate increase of $433,434,000. This additional revenue will allow APS to earn a rate of return of 5.84% on a Fair Value Rate Base (FVRB) of $9,976,023,000. The additional revenue excluding "fair value increment" results in an 8.13% rate of return on an adjusted Original Cost Rate Base (OCRB) of $6,771,151,000.

My testimony includes APS's request for Accounting Deferral Orders from the Commission regarding two large generation related investments APS will make in the next several years:

- The Ocotillo Modernization Project (OMP) in Tempe, Arizona, where APS will replace some aging steam-based natural gas units with modern, fast-ramping jet-engine technology; and

- The installation of Selective Catalytic Reduction (SCR) emissions control technology at the Four Corners Power Plant to comply with Federal environmental law.

Authorizing these deferral orders will allow APS to avoid immediately filing another rate case either prior to the conclusion of this rate case or shortly after its conclusion. In addition to the deferral orders, I describe APS's request to hold the Decision in this case open for the limited purpose of a step-increase related to the SCRs at Four Corners.

My testimony describes the COSS that is used to support the Company's rate designs in the Company's Application as well as the jurisdictional allocation of costs. It also explains why it is appropriate to place residential customers taking service under APS's Net Metering Rate Rider today into a separate sub-class of customers. My COSS testimony also explains why the revenue responsibility for the proposed revenue increase is higher for residential customers broadly as APS rebalances the cost of service, primarily driven by the cost shift that has been created by residential rooftop solar since APS's last rate case.

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 Arizona Corporation Commission (ACC or Commission) Staff and adopted by the Commission in the 2007 Test Year and 2010 Test Year rate filings made by APS that resulted in Decision Nos. 71448 (December 30, 2009) and 73183 (May 24, 2012).

Additionally, my testimony describes the merits of a rate stabilizing decoupling mechanism. Conceptually, this Rate Stabilization Mechanism (RSM) would replace the Company's current LFCR mechanism. However, through the stakeholder process

leading up to this rate case filing, parties gave APS feedback on this approach and the Company determined to continue with its current LFCR mechanism with proposed modifications. The discussion of the RSM in this filing is to provide more detail on how such a mechanism would be mutually beneficial to both APS and its customers.

I discuss APS's proposed modifications to its existing EIS mechanism. These modifications will provide additional room to recover environmental costs between rate case filings, within a structured cap, to account for increasing costs required to comply with Federal and State environmental laws.

I also discuss APS's proposed modifications to its existing TCA mechanism. These modifications will add a balancing account for the amounts collected through the adjustor, consistent with all of APS's other adjustor mechanisms.

My testimony includes APS's Long-Range Rate Plan in compliance with the APS Settlement Agreement which resulted in ACC Decision No. 73183 (May 24, 2012).

I am also sponsoring APS's proposed Extra-High Load Factor general service rate, which APS intends to make generally available to large commercial customers that meet the load characteristics and other requirements of the rate schedule. And I am sponsoring APS's proposed Service Schedule 9, an Economic Development service schedule that will provide some structure within APS's service territory which encourages economic development.

My testimony discusses APS's analysis of the experimental AG-1 rate program, which is a buy-through rate option for some of APS's large and extra-large general service customers. After a near-five year pilot, APS analyzed the cost implications of the AG-1

rate experiment to other customers and can only conclude that it should not be renewed. However, in the event that a new buy-through rate offering were to be created, I describe the minimum modifications necessary to protect other customers.

III. STANDARD FILING REQUIREMENT SCHEDULES

Q. ARE YOU SPONSORING ANY 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. I have also attached a SFR index that lists the APS witnesses responsible for the preparation of the SFRs or elements of the SFRs (Attachment LRS-2DR).

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 COSS 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 3.15% on a FVRB of $9,976,023,000. The rate of return on FVRB resulting from the requested increase of $433,434,000 is 5.84%.

The calculation of the Company's FVRB was based on the average of 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 to establish new base

rates. In addition to the determination of FVRB, Attachment LRS-03DR 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 Barbara Lockwood 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. This is due to the presence of various other rate mechanisms, and that in this rate Application, APS is proposing to move revenue collection that currently occurs through certain adjustor mechanisms to revenue collection through base rates as described below.

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 COSS.

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 COSS. These schedules address existing and expected percentages of cost to serve and rates of return by sub-class, show pro forma adjusted amounts of OCRB and operating expenses allocated to ACC jurisdictional customers, and lists the allocation factors used in preparing the study.

Q. WHY DID APS NOT USE FVRB 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 OCRB amounts are to be used. Had the Company used FVRB, 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 percentage of cost to serve and rate-of-return at existing rates by customer class, based on the adjusted Test Year COSS.
- SFR Schedule G-2 is similar to Schedule G-1, except it reflects percentage of cost to serve and 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 COSS.

Q. DO YOU SPONSOR ANY ADDITIONAL SCHEDULES RELATED TO THE COST OF SERVICE?

A. Yes. Attachment LRS-4DR to my testimony is the COSS Schedule, which is a summary showing:

1. The jurisdictional separation of rate base costs, revenues, and operating expenses between ACC and All Other jurisdictions;
2. The further allocation by retail customer class, of total ACC allocated costs and the percentage of cost to serve paid by each major customer class;
3. The same information by each general service sub-class; and,
4. The same information by each residential service sub-class, including the Net Energy Metering Customers (NEM) solar energy and demand rate sub-classes.

IV. OCOTILLO DEFERRAL REQUEST

Q. PLEASE DESCRIBE THE COMPANY'S OCOTILLO DEFERRAL REQUEST.

A. APS is constructing and will place into service a modernized Ocotillo Generating Facility. The OMP involves retiring 220 MWs of existing steam generation and replacing them with 510 MW of state-of-the-art combustion turbine generation. New Ocotillo Units 6 and 7 will go into service in the fall of 2018, and Units 3, 4, and 5 will go into service in the spring of 2019. APS estimates that the total direct construction cost of the OMP will be approximately $500 million. In this filing, APS requests permission to defer for potential future recovery until APS's next general rate case all non-fuel costs of owning, operating and maintaining the OMP.

Q. PLEASE EXPLAIN WHY THE COMPANY IS REQUESTING A DEFERRAL FOR THE OMP.

A. As discussed in the testimony of APS witness James Wilde, the OMP is an important step in actively managing the changing reality of the electrical grid. It is needed for three main reasons: (1) it helps APS meet its peak capacity needs; (2) it provides flexible fast-ramping generation that can react quickly to an evolving system load shape; and (3) it integrates renewable energy resources. For these reasons and others described by Mr. Wilde, APS cannot postpone its modernization of the Ocotillo Generating Facility.

The OMP, however, represents a significant financial investment by the Company. The timing of this investment and the construction of the Project is designed to coincide with when APS needs fast-ramping, flexible gas generation to serve customers. But the timing does not coincide with this rate case. Without a deferral, APS would be faced with incurring significant financial obligations without rate relief. This would potentially force APS to file a rate case almost immediately after this rate case concludes, potentially causing APS's rates to increase sooner than they would otherwise need to. An additional rate case filed to capture the costs of a specific project, on the immediate heels of this rate case, unnecessarily exposes customers to the possibility of a rate increase. With a deferral, APS can make the investment in modernizing Ocotillo without using a concurrent rate proceeding to reflect the investment in rates. And, because APS only seeks a deferral order, the prudency of the OMP will still be subject to review by the Commission in APS's next rate case. APS witness Peter Ewen quantifies the financial impacts if APS were not authorized to defer costs for the OMP.

Q. HAS THE COMMISSION GRANTED A SIMILAR DEFERRAL BEFORE?

A. Yes, the Commission has historically approved accounting orders in appropriate circumstances, such as these. For example, the Commission granted APS an accounting order that allowed the Company to defer the costs of owning, operating, and maintaining Sundance Generating Station (a simple cycle natural gas plant) when APS acquired that facility in 2005. *See* Decision No. 67504 (January 20, 2005). Authorizing the requested deferral, the Commission expressly recognized that the "PSA's cost/savings sharing component . . . coupled with the timing of the acquisition in relation to the pending rate case, could create a potential for inequity that justifies the creation of a deferral in this case." *Id.* at 25.

The Commission similarly granted APS two accounting deferral orders so that the Company would be able manage the financial impact of rising costs associated with owning new generation at Palo Verde Unit 2 and Palo Verde Unit 3. *See* Decision Nos. 55325 (December 5, 1986) and 55939 (April 6, 1988). In both of these instances, the Commission found the financial burden on APS, absent the ability to defer the costs of owning and operating Palo Verde Units 2 and 3 and the essential inequity of the mismatch between cost recovery by APS and benefits realized by APS customers, as sufficient reasons to grant the Company's request.[1]

Most recently, in connection with APS acquiring Southern California Edison's share of Four Corners, the Commission granted permission for APS to defer for potential future recovery the costs of acquiring the Four Corners share and the costs of retiring Four Corners Units 1-3.[2] This deferral order permitted APS to take advantage of the opportunity to acquire SCE's share while providing APS the financial support to make that acquisition and also preserving the Commission's ability to fully assess the prudency of the Company's investment.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW THE OCOTILLO DEFERRAL WILL BE CALCULATED.

A. APS requests that the Commission grant an accounting deferral order that will authorize APS to defer and capitalize for potential future recovery through rates all non-fuel costs of (i) owning, operating, and maintaining the new generating assets at the Ocotillo site; and (ii) retiring the existing steam generation. The costs to be deferred include

[1] The Commission also granted APS an accounting order, as part of the 2009 Settlement Agreement that permitted APS to defer higher employee benefit costs. *See* Decision No. 71448 (Dec. 30, 2009) at Exhibit A, Paragraph 9. Previous Commission decisions similarly authorized APS to defer costs associated with net metering and vegetation management. *See* Decision Nos. 69663 (June 27, 2007) at 89 and 67744 at Attachment A, Paragraphs 110 and 111, respectively.

[2] *See* Decision No. 73130 (Apr. 24, 2012).

depreciation, operations and maintenance, property taxes, capital carrying charges and other miscellaneous costs. For purposes of the cost deferral, APS will calculate the capital carrying charge using the embedded cost of debt established in this proceeding. The property taxes deferred will be based on actual property taxes that APS pays on the facility. APS will calculate depreciation using the estimated depreciable life of these assets in accordance with Generally Accepted Accounting Principles (GAAP). APS proposes amortizing the deferral over five years. Including depreciation expense, property taxes, and a carrying cost return, APS estimates a total deferral cost for all five units through 2019 will be approximately $45 million.

Q. WHAT IS AN ACCOUNTING ORDER?

A. An accounting order is a ratemaking mechanism that provides APS the ability to defer costs that would otherwise be expensed using GAAP. In this case, such an order will address the timing mismatch between costs and benefits that occurs from when APS incurs the costs to build the OMP to when APS is allowed to recover the asset in rates. It also provides important financial support to APS during this same period.

Q. WILL THE OCOTILLO DEFERRAL AFFECT THE REVENUE REQUIREMENT IN THIS RATE CASE?

A. No. The deferral would not increase customer bills today, but would simply provide a mechanism for APS to seek future recovery of the costs related to the OMP and mitigate the impact of the transaction on the Company's financial condition.

Q. IS THERE ANY SPECIFIC LANGUAGE REQUIRED TO PROVIDE THE DEFERRAL ORDER FOR ACCOUNTING PURPOSES?

A. Yes. GAAP requires that the regulatory authorization of the deferral include language that provides APS and its auditors with reasonable assurance that the Company will

recover prudently incurred costs in future rates. In order for the Company to recognize an accounting deferral on its books of account, the Commission language authorizing such a deferral must be clear and unequivocal about what is being deferred and the potential for the deferral's recovery in rates in a specific future rate proceeding. Thus, APS urges that any Order granting the Company's related request for an accounting deferral order contain language substantially as follows as part of its ordering language:

> IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein) of owning, operating, and maintaining the Ocotillo Modernization Project and retiring the existing steam generation at Ocotillo. Nothing in this Decision shall be construed in any way to limit this Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision.

V. FOUR CORNERS SCR DEFERRAL AND STEP INCREASE REQUEST

Q. PLEASE DESCRIBE THE COMPANY'S SCR DEFERRAL AND STEP INCREASE REQUEST.

A. To comply with federal environmental standards, APS must install selective catalytic reduction equipment, or SCRs, at its Four Corners Generating Facility. This equipment will significantly reduce fossil emissions of nitrogen oxides, while permitting APS to continue supplying its customers with inexpensive fossil base load generation. APS must install these SCRs in time to meet upcoming compliance deadlines. The first SCR will be installed on Four Corners Unit 5 and placed in service in late 2017 and the second SCR will be installed on Four Corners Unit 4 and placed in service in Spring 2018.

APS estimates the direct construction cost for the SCRs to be approximately $400 million. Although APS will begin installing the SCRs and incurring the related costs, the SCRs will not be in service in time to be included in rate base in this proceeding as post-Test Year plant. If APS is not granted a deferral and step increase, APS would need to

file an immediate "pancaked" rate case to recover the costs associated with the SCR project. As previously discussed in connection with the OMP, the filing of general rate cases to only capture the costs associated with a specific project unnecessarily exposes customers to the possibility of higher rates sooner than otherwise necessary. Moreover, because APS will have already begun installing the SCRs, it is appropriate to increase the revenue requirement authorized in this proceeding to reflect the SCR deferral as a step increase mechanism in the same manner as the step increase contemplated in *Arizona Community Action Association v. Arizona Corporation Commission*.[3]

Q. PLEASE EXPLAIN WHY THE COMPANY IS REQUESTING A DEFERRAL FOR THE SCR PROJECT.

A. As discussed by APS witness John Lucas, to comply with federal environmental requirements, APS must install and begin operating the first SCR by March 31, 2018 and install and begin operating the second SCR by July 31, 2018. And while APS must install and begin operating the SCRs by these dates, it cannot include the costs to do so in this rate case. A deferral and step increase is the only alternative to mitigate the financial impacts of incurring such a substantial expense to comply with federal environmental requirements without immediately filing a new rate case. APS witness Peter Ewen quantifies the financial implications if APS were not authorized to defer costs and implement a step increase for the SCRs.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW THE SCR DEFERRAL AND STEP INCREASE WILL BE CALCULATED.

A. APS proposes that the deferral occur from when the SCRs are in service through December 2018, and that the step increase occur in January 2019. APS proposes

[3] 123 Ariz. 228, 599 P.2d 184 (1979).

amortizing the deferral over 5 years. Including depreciation expense, property taxes, and a capital carrying charge (APS will calculate this charge using the embedded cost of debt established in this proceeding), APS estimates the total deferral costs for both SCRs would be approximately $30 million. After the step increase occurs, the annual revenue requirement associated with projects would be $62 million. This includes the depreciation expense, property taxes, debt and equity return, and the taxes associated with the equity return. The combined bill impact from the deferral and the ongoing revenue requirement for an average residential customer would be slightly over 2%.

Q. WILL THE SCR DEFERRAL AFFECT THE REVENUE REQUIREMENT IN THIS RATE CASE?

A. APS proposes that the effective date of new rates reflecting the revenue requirement authorized in this proceeding be July 1, 2017. This revenue requirement would not include the SCR deferral. Under APS's proposal, the step increase would take effect in January 2019, and rates established in this proceeding would be adjusted upward at that time to reflect the addition of the SCR deferral and project costs to the revenue requirement. This would occur in the same manner as the step increase that followed APS's acquisition of SCE's interest in Four Corners.[4]

Q. IS THERE ANY SPECIFIC LANGUAGE REQUIRED TO PROVIDE THE DEFERRAL ORDER FOR ACCOUNTING PURPOSES?

A. Yes. As noted previously, language authorizing a deferral must be clear and unequivocal about what is being deferred and the potential for the deferral's recovery in rates in a specific future rate proceeding for the Company to be able to recognize an accounting deferral on its books of account. Thus, APS urges that any accounting deferral order

[4] *See* Decision No. 74876 at p. 9 (Dec. 23, 2014).

contain language regarding the SCR deferral substantially as follows as part of the Commission's decision in this matter:

> IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein) of owning, operating, and maintaining the Selective Catalytic Reduction ("SCR") environmental controls at the Four Corners Power Plant. Nothing in this Decision shall be construed in any way to limit this Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision.

Q. IS THERE ANY SPECIFIC LANGUAGE TO INCLUDE ON THE STEP INCREASE?

A. Yes. APS requests language be included in the Commission's decision in this matter as follows:

> This rate case shall remain open for the sole purpose of allowing APS to file a request, no later than July 1, 2018, that its rates be adjusted to reflect the revenue requirement and deferral costs associated with the Selective Catalytic Reduction ("SCR") environmental controls at the Four Corners Power Plant. Specifically, APS may within ten (10) business days after in-service operation of the second SCR, but no later than July 1, 2018, file an application with the Commission seeking to reflect in rates the rate base and expense effects associated with the installation of SCRs on Four Corners Units 4 and 5, and any cost deferral authorized in this Decision APS's rates shall be adjusted only if, and to the extent the Commission finds the Four Corners SCR project costs and deferred amounts to be prudent.
>
> Any filing seeking a rate adjustment related to the SCRs pursuant to this Decision shall include at a minimum the following schedules: (1) the most current APS balance sheet at the time of filing; (2) the most current APS income statement at the time of filing; (3) an earnings schedule that demonstrates that the operating income resulting from the rate adjustment does not result in a return on rate base in excess of that authorized by this Agreement in the period after the rate adjustment becomes effective; (4) a revenue requirement calculation, including the amortization of any deferred costs; (5) an adjustment rider that recovers the rate base and non-fuel operating costs of the SCRs, including amortization of deferred amounts on an equal percentage basis across all rate schedules which shall not become effective before January 1, 2019; (6) an adjusted rate base schedule; and (7) a typical bill analysis under present and filed rates.

VI. APS RED ROCK REGULATORY LIABILITY ACCOUNT

Q. PLEASE EXPLAIN THE POST TEST-YEAR PLANT TREATMENT FOR THE RED ROCK SOLAR FACILITY AND THE REGULATORY LIABILITY ACCOUNT.

A. APS is constructing a 40 MW solar facility at its Saguaro Generating Station location in Pinal County, which will be named the Red Rock Solar Generating Station. Arizona State University (ASU) and PayPal have agreed to purchase an equivalent amount of the anticipated renewable energy and environmental attributes from the Red Rock facility. All costs associated with the development and operation of the new solar plant over the life of the agreements, together with the cost of firming and load-shaping, will be paid by ASU and PayPal through the sale of renewable energy and environmental attributes. In the initial years, the revenues from ASU and PayPal will not cover the full revenue requirement. As the revenue requirement declines over time, the amounts paid by ASU and PayPal will exceed the revenue requirement. APS has included the costs of the new solar facility in its post-Test Year plant adjustment through the testimony of APS witness Scott Bordenkircher. The revenue from ASU and PayPal will be treated as a revenue credit to the overall APS revenue requirement. APS has made a pro forma revenue adjustment in the amount of $2,511,000 to reflect an annualized level of revenue as an offsetting adjustment to the Renewables, Microgrid & Technology Innovation post-Test Year plant pro forma adjustment (*see* SFR Schedule C-2, page 2, column 5).

Q. ARE THERE SAFEGUARDS TO ENSURE THAT REVENUE FROM ASU AND PAYPAL COVERS THE FULL COST OF THE RED ROCK FACILITY?

A. Yes. To ensure that APS's other customers are not disadvantaged through the agreements between APS and ASU and PayPal, the Commission required APS to create a balancing account to track the difference between: 1) the cost of the Red Rock facility as reflected in APS's rates, and 2) the total revenue for green energy from those specific

customers. This balancing account will commence upon effectiveness of new rates that include the agreements and is anticipated to initially create a regulatory liability for APS that will be reversed over the term of the customer agreements. Once the balancing account balance reaches zero, the regulatory liability will be eliminated and the balancing account will cease to exist. Within 45 days following each anniversary of the balancing account (until elimination), APS will file the amount of the regulatory liability and the accounting entries for that year. Within 45 days following the regulatory liability reaching zero, APS will file the final entries related thereto and confirmation that going forward the annual revenues will exceed the revenue requirement.

VII. COST OF SERVICE STUDY

Q. WHAT IS A COSS?

A. A COSS is the fundamental tool for allocating a utility's costs among its customers based upon their responsibility for incurring such costs. It is foundational in developing appropriate pricing structures that align the rates customers pay for the services received with the customers who are driving the costs. This is often described as the "cost causation principle."

A COSS is a detailed analysis of audited financial information and actual customer load data that assesses the responsibility of each customer group for the costs incurred to provide service during the relevant time period. The COSS functionalizes, classifies, and then allocates costs and revenues, beginning with wholesale and retail customers, then continuing the process with various broad classes of retail service and finally to sub-classes within each retail class.

The cost-allocation study enables APS to determine its unit costs, by function, incurred to provide energy, demand, and customer services to each customer class and sub-class,

as well as, the support to those costs that each customer group presently contributes through their rates.

The ACC, and public utility commissions across the country, use cost-of-service studies developed in this manner to set rates for most public utilities, including water, electric, and gas utilities.

Q. WHAT TIMEFRAME DID THE COMPANY USE FOR THE COSS THAT IT FILED IN THIS DOCKET?

A. APS conducted an embedded COSS using data from the most-recent calendar year available — the twelve-month period ending December 31, 2015 — as the test period (Test Year).[5] The Company analyzed its costs, customer class sales and load characteristics during this period — the number of customers and their demand and energy usage is commonly referred to as "Billing Determinants" — and used those results to allocate the various plant and operating expenses to each customer class through a rigorous process of functionalization, classification, and allocation of costs. The study results allow APS to derive the percentage of cost to serve that is being recovered under current rates, based on original cost, by class and sub-class.

Q. WHAT DO YOU MEAN BY EMBEDDED COSS?

A. An embedded COSS is based on the historical costs and operating experience of the utility during the selected Test Year. Rate-making in Arizona is based on this historical Test Year and embedded cost approach. Under this method, rates are based on actual incurred costs as verified through audited financial data.

[5] As the year immediately preceding APS's rate case filing, 2015 is the most recent full calendar year upon which to base rates and is the appropriate test year for the rate case.

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 consistent with Commission-approved methods.

Functionalization refers to the process of attributing each rate base or expense item to a particular function — namely Production (generation of electricity), Transmission, Distribution or Customer Service (e.g., metering and billing) — in the provision of electric service. An example is assigning the costs of building and operating the Company's generation 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 to serve is driven by the amount of kWh energy consumed, such as fuel cost, it is classified as Energy.
- If a cost is driven by the rate at which energy is consumed, or kW capacity, it is classified as Demand.
- If a cost is driven by the number of customers taking service on the APS system irrespective of either the kW demand or kWh energy, it is classified as Customer.

Allocation occurs after a cost has been functionalized and classified. This is the process in which allocation factors — such as class coincident peak demand contribution at the time of system peak, non-coincident class peak (NCP) or the sum of individual peaks, energy or number of customers — are applied to allocate the costs to particular jurisdictions, customer classes, and rate schedules or sub-classes. A simple example is the allocation of energy-related costs by kWh consumption to different customer classes.

In summary, in the COSS, the expense and rate-base items that comprise all of 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, Distribution or Customer related costs, then classified as Demand, Energy, or Customer-related. Allocation factors based on kW, kWh and number of customers were then developed so that the functionalized and classified costs could be allocated to the ACC retail 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 four summer months of June, July, August, and September (referred to as 4CP) to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its rate cases before FERC, and creates jurisdictional alignment to ensure the right proportion of cost is being allocated to each jurisdiction. It also eliminates the potential that costs, due to differences in allocation methods, 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. This is a method required by the Commission in Decision No. 69663 (June 28, 2007). AED uses the sum of two demand allocators:

1. **NCP Average Demand allocator**, which uses each class's NCP demand weighted by the class load factor calculated using the class energy and the NCP demand.
2. **System Peak Excess Demand allocator**, which is determined by first calculating the NCP Excess Demand, which is the difference between each class's NCP and that class's average demand. Second, the sum of NCP Average Demands is subtracted from the single system peak demand to derive the System Peak Excess Demand, which is then allocated to each class based on the proportionate share of the sum of NCP Excess Demands.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the COSS. A portion of transmission costs are brought back into the ACC jurisdictional cost of service to offset the existing Open Access Transmission Tariff (OATT) revenues to ensure there is no double-counting of transmission costs between the ACC and non-ACC jurisdictions. This also effectively assumes that each customer class pays the cost of transmission service even though this is demonstrably not the case for solar customers. To address this mismatch, APS reallocated the direct assigned cost responsibility to residential customers using each residential sub-class's 4CP.

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 NCP loads. 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 (Sum of Individual Max). Each of these allocation methods has traditionally been used by APS and accepted by the Commission for many years.

Q. HOW DID YOU DETERMINE IT WAS APPROPRIATE TO CREATE A SEPARATE RESIDENTIAL SUB-CLASS FOR NEM ENERGY AND NEM DEMAND CUSTOMERS WITHIN THE RESIDENTIAL CUSTOMER CLASS?

A. It can be appropriate to create a new class or sub-class of customers for purposes of a COSS or setting rates if the service, load, or cost characteristics of the customer sub-group in question are sufficiently different from their current customer classification. Upon reviewing these characteristics for customers with solar, I determined that sufficient differences exist for creating this sub-class of residential customers.

When evaluating the load characteristics of residential customers with and without rooftop solar, the peak demand — CP, NCP and Sum of Individual Max — and energy characteristics are very different for solar customers. In the 2015 Test-Year, the typical residential solar customer still needs about 71% of the capacity they used before they adopted solar and 32% of the energy. This is a significantly different profile than residential customers without solar, regardless of size.

Second, in the 2015 Test-Year, APS had 35,988 solar customers on an energy rate and almost 1,311 solar customers on a demand rate by year's end. The size of this residential solar customer sub-group, combined with its vastly different load characteristics, warrant evaluating them as a separate sub-class.

Q. PLEASE EXPLAIN THE PROCESS THAT APS USED TO CREATE A UNIQUE RESIDENTIAL SUB-CLASS FOR NEM CUSTOMERS.

A. Consistent with the methodology I previously discussed:

1. APS grouped NEM customers currently on energy-based rate schedules, which includes customers both on inclining block and time-of-use rate schedules.
2. APS separately grouped NEM customers on demand-based time-of-use rate schedules.

3. APS used the data for the NEM customer's entire load at the home — load served both by APS and the customer's rooftop solar system — as the starting point for cost allocation to develop the CP, NCP and Sum of Individual Max demand allocations, as well as the energy allocations.

4. APS then explicitly credited the customer for:

- All their self-provided production capacity based on a comparison to the APS-delivered customer load using both the four summer sub-class CPs and NCPs;
- Their entire energy production, including both what the customer consumes on site and what is delivered from the NEM customer to the grid;
- The avoided transmission cost based on a comparison to the APS-delivered customer load at the time of the four summer CPs;
- The avoided primary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class NCPs; and,
- The avoided secondary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class Sums of Individual Max.

This approach fully credits residential solar customers for all cost savings resulting from the capacity (production, transmission and distribution) and energy supplied to the grid by their rooftop solar systems. The result is that the COSS analysis only allocates capacity and energy costs to NEM customers based on what APS has to provide. This analytical approach also captures the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation,

including support for the starting of motors (e.g. the inrush current associated with the starting of an air conditioning unit, which cannot be met by a solar array).

Q. BY USING AN NEM CUSTOMERS ENTIRE LOAD AT THE HOUSE AS A STARTING POINT, AREN'T YOU CHARGING FOR SERVICES APS DOES NOT PROVIDE?

A. No, in fact the exact opposite is true. It is true that APS does not supply the energy service when an NEM customer's self-generation is supplying energy. But the crediting process described above fully accounts for the customer's self-supply of this energy service. Moreover, although the NEM customer supplies some of their own energy, APS continues to supply a host of back-up and ancillary services that in turn require APS to build, operate and maintain the bulk of its fixed infrastructure required to serve that NEM customer. Beginning with an NEM customer's entire site load and then explicitly crediting to that customer the value of the energy and capacity that they supply from their own rooftop solar system, is the only transparent way to balance the benefits provided by rooftop solar systems on residential rooftops and the costs required to continue serving those customers with rooftop systems.

Q. PLEASE EXPLAIN FURTHER HOW THIS APPROACH COMPENSATES NEM CUSTOMERS FULLY FOR THE BENEFITS THEY PROVIDE TO APS.

A. By comparing the entire load at the home to the remaining household load served by APS, we can determine the infrastructure that APS no longer needs to provide as a result of the solar system. Although solar installation will have a certain maximum-production capability, that capability will only be realized at mid-day and only on sunny days. The load information reveals what actually occurred when the customer was consuming energy in contrast with the solar production at the same time. The alignment between when a residential customer needs power and when the solar system operates is not

significant in APS's service territory. APS's peak loads persist in the summer months beyond sunset, and the maximum peak load occurs closer to sunset than mid-day.

The appropriate level of compensation for offsetting demand-driven infrastructure costs should be based on how effective the NEM customer's solar system is at offsetting APS's peak loads. For example, the COSS indicates for a solar customer on energy based rates, the appropriate level of production demand credit is 28.8%, transmission capacity credit is 45.6%, distribution primary and substations capacity credit is 12% and distribution secondary capacity credit is 16.2%.

Likewise, the energy compensation in a COSS should reflect the actual fuel costs that APS avoids when a solar customer consumes less energy. The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system, which is a conservative proxy for the actual costs saved by APS.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COSS.

A. APS makes sales to parties that are not traditional APS retail customers, such as sales to Rate Schedule E-36 XL customers for station service power to large generation plants owned by other parties. 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 that APS realizes from these non-retail transactions is attributed to each class through the revenue credit, benefiting 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. 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. The COSS only addresses the base rate portion of the cost to serve. The revenues from adjustors are a revenue credit to the COSS revenue requirement. When the revenue from adjustors is included in the overall calculation, an additional shortfall from rooftop solar customers is included in cost recovery. For a full determination of costs that will otherwise be shifted to customers without solar, this shortfall should be added to the COSS results.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND PERCENT OF COST TO SERVE BASED ON THE 2015 TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functional allocations and the Demand, Energy, and Customer classifications for each class of retail customers, the percentage of cost to serve for each class under Test Year rates appears in the Summary Schedules.

Q. BASED ON THE RESULTS OF YOUR 2015 TEST YEAR COST OF SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

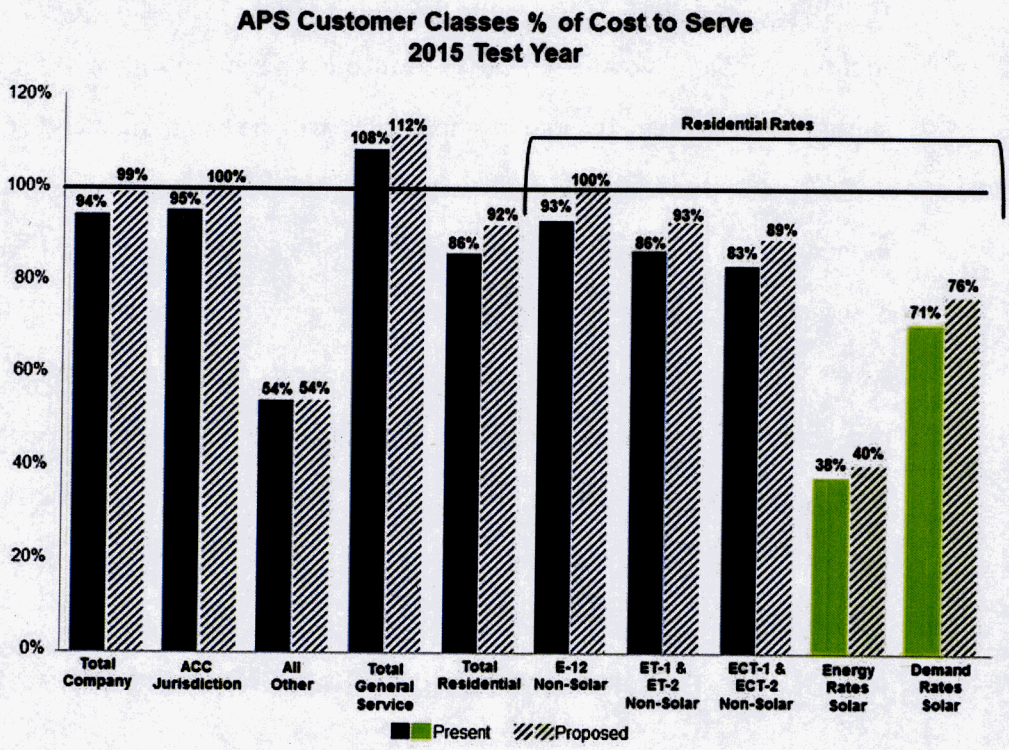
A. The Summary and COSS Schedules plainly show disparities in the ratio of the allocated cost for APS to actually provide service and what customer classes and sub-classes pay for the services APS provides. The residential class contributes less toward the cost to serve than the general service class. Specifically, under current rates, the revenue from

the residential class covers approximately 86% of the cost to serve while the general service class covers 108% of the cost to serve.

Within the residential class, there is further disparity within the sub-classes:

- NEM customers on energy-based rates cover only approximately 38% of the cost to serve;
- NEM customers on demand rates cover around 71% of the cost to serve; and,
- Other non-solar residential customer sub-classes cover a range from 83% to 93% of the cost to serve.

APS is proposing to rebalance revenue responsibility in this rate case based on the results. In this rebalancing, residential customers have been adjusted up to 92% of the cost to serve, which is more in line with historical norms. Approximately 57% of the additional revenue responsibility is directly related to the cost shift resulting from residential rooftop solar installed since APS's last rate case test year. Figure 1 below illustrates the percent of cost to serve by customer group in the test year and based on APS's proposed revenue responsibility in this rate case.



Q. BASED ON THE PERCENTAGE OF COST TO SERVE RESULTS, WHAT IS THE COST SHIFT THAT HAS OCCURED ON A PER CUSTOMER BASIS?

A. By paying 38% of the cost to serve instead of the new residential average target of 92%, each NEM customer on an energy-based rate avoids $72.11 per month and each NEM customer on a demand-based rate avoids $27.65 per month. For solar customers on energy-based rates, the annual cost shift in APS's territory is approximately $865. This represents the total amount shifted, which includes both the amount in base rates determined by the COSS and the amount from APS's adjustor mechanisms.

Q. BASED ON THE COST SHIFT OF $865 ANNUALLY PER SOLAR CUSTOMER, WHAT IS THE TOTAL COST SHIFT OVER THE LIFE OF THE ROOFTOP SOLAR SYSTEMS?

A. Assuming the cost shift is grandfathered, the 35,988 NEM customers on an energy rate and the 1,311 NEM customers on a demand rate at the end of 2015 will increase the

revenue to be collected from all other residential customers by approximately $31.6 million per year. Over the typical 20 year life of a rooftop solar system, the total amount shifted to customers without rooftop solar will be approximately $631.5 million. In addition, APS is adding approximately 1,300 new residential rooftop solar customers per month. In just the time it takes to process this case, the cost shift will grow by more than $20.1 million and the 20-year cost shift will grow by more than $401 million. In other words, assuming all residential DG systems installed through mid-2017 are grandfathered, the annual residential cost shift is $51.6 million, in addition to what is already being collected through the LFCR, and the 20-year cost shift will be over $1 billion.[6]

Q. IS THE COST-SHIFT CAUSED BY THE PREDOMINANT VARIABLE KWH DESIGN OF APS'S RATES?

A. Yes. In the COSS, costs are allocated based on the true-cost drivers. APS's infrastructure costs are predominantly driven by capacity needs — which do not vary with kWh consumption. Said another way, infrastructure, and the related costs are a function of demand, rather than energy. The residential NEM customer significantly changes their energy profile by taking less energy during the day. This customer does not change their demand profile to the same degree. APS must still meet the customer's demand later after the sun has set, but when the customer is still significantly relying on the grid. As a result, APS must still incur much of the capacity-related production, transmission and distribution costs needed to provide service to the NEM customer. The mismatch in the most-common residential rates used by NEM customers results from the fact the price to the customer is overwhelmingly based on their consumed kWh

[6] In APS's Application for the Grid Access Charge filed on April 2, 2015 in Docket No. E-01345A-13-0248, APS indicated a cost shift of over $800 million over 20 years if all systems installed through mid-2017 were grandfathered. This amount has grown as the pace of installations has increased.

energy, rather than capacity. Thus, NEM customers pay less under variable, kWh—based rate design, but do not provide a commensurate cost savings.

Q. ARE THERE OTHER POTENTIAL COST SHIFTS IN RESIDENTIAL RATES?

A. Yes. As discussed previously, APS's residential rates in total are lower today than the COSS's calculated cost to serve, and commercial rates are correspondingly higher. APS is proposing to rebalance this to more historical norms that have been in existence in APS's service territory. Limited-income discounts are another specific cost shift that have been purposefully established.

Q. ARE THERE RESIDENTIAL RATE DESIGN ALTERNATIVES THAT COULD ADDRESS THE FACT THAT SOLAR CUSTOMERS ARE PAYING A MUCH LOWER PORTION OF THE COST TO PROVIDE SERVICE THAN NON-SOLAR RESIDENTIAL CUSTOMERS?

A. Yes. APS is proposing residential rate designs in this case that are better aligned with cost drivers. Thus, these new rate schedules will do a better job of recovering the cost of providing electric service from the customers driving the cost. APS witness Charles Miessner discusses the details of APS's residential rate proposals, including the implementation of nearly universal three-part rates that include a demand charge for capacity related costs. Residential three-part rates will provide better price information to customers to help them manage their demand in addition to their energy consumption. A demand rate that focuses on the on-peak time period further enhances this price information. Based on the COSS results, APS's proposals also require rooftop solar customers to be on the three-part rate with a demand charge that most accurately reflects the cost of providing service to this specific customer sub-class.

VIII. FAIR VALUE RATE OF RETURN

Q. WHAT IS APS'S FVRB AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR 2015?

A. As can be seen on SFR Schedule A-1, APS's FVRB is $9,976,023,000 and the rate of return is 5.52% 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 Commission-approved methodology of averaging the OCRB and the RCND.

Q. DID APS PERFORM AN INCREMENTAL CALCULATION TO ADDRESS THE APPROPRIATE LEVEL OF RETURN ON FVRB?

A. Yes. A calculation of the after tax return on the fair value increment was performed. *See* Attachment LRS-3DR and SFR Schedule A-1, Line 9.

Q. IS THIS TREATMENT CONSISTENT WITH THE METHOD USED IN APS'S LAST RATE CASE?

A. Yes. In APS's most recent rate case, Decision No. 73183, the Commission applied a 1.0% 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 recommended by APS witness Dr. Bente Villadsen for the reasons further described by APS witness Barbara Lockwood.

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 LRS-3DR 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 (44%) by the OCRB; 3) Equity component of OCRB, calculated by multiplying the Company's adjusted test year equity percentage (56%) 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, 5.13% return on the debt component and 10.5% 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 of $381,568,000 reflected on SFR Schedule A-1, Line 8. The difference between those two values results in the after tax return on the fair value increment of $51,866,000 reflected on SFR Schedule A-1, Line 9.

IX. THE POTENTIAL MERITS OF A RATE STABILIZATION MECHANISM AND THE PROPOSED MODIFICATIONS TO THE LFCR MECHANISM

Q. WHAT DOES APS SEE AS THE POTENTIAL MERITS OF A RSM?

A. With a full revenue per customer decoupling mechanism, customers and the Company alike benefit from consistency and stability. The purpose of the RSM would be to help protect customers and the Company from uncertainty inherent during the transition period to the new rate structure. A mechanism of this type would help mitigate risks of

revenues resulting from the transition being either too high or too low as a result of the new suite of rate offerings. As customers are adapting to APS's proposed rate design, there is naturally some uncertainty. It is our belief that customers want options, and at the same time bill stability. We believe a mechanism like the RSM would work well in tandem with our proposed rate design. The purpose of a mechanism of this type is to reduce the variability in the customer's bills and at the same time provide a consistent stream of revenue to the utility. A RSM would ensure that customers only pay what the Commission agrees they should pay in the rate case, no more, no less. A RSM has a number of positive features:

- It would align the customers' and Company's interests by updating customer billing determinants annually in a simple and straightforward manner in alignment with the currently proposed three part rate structure;
- It is a mechanism that has been commonly applied within the electric and gas utility industries; and
- It would properly remove the link between volumetric sales and revenue collection, thus eliminating the disincentive associated with implementing programs that would otherwise reduce the volume of energy sold, instead allowing a utility to willingly engage in and promote these programs.

Q. IF THE RSM HAS THESE BENEFITS, WHY IS APS NOT PROPOSING THE RSM IN THIS FILING?

A. Throughout the stakeholder process leading up to this filing, APS heard concerns from various stakeholders about the RSM, particularly in combination with APS's residential rate reform proposals. While APS believes the RSM would be a complement to its rate reform proposals, a number of other parties see it differently. APS listened during the stakeholder process to these concerns and determined this case was not the appropriate time to propose the RSM. Instead, APS will propose modifications to its existing LFCR

mechanism that is currently used for the purpose of recovering lost fixed costs resulting from sales reductions resulting from energy efficiency (EE) and customer-sited rooftop solar.

Q. WHAT MODIFICATIONS ARE YOU PROPOSING TO THE EXISTING LFCR MECHANISM?

A. First, similar to APS's PSA mechanism where the new PSA rate filed on December 31st becomes effective on February 1st unless suspended by the Commission, the Company is proposing that the LFCR rate filed on January 15th become effective on the first billing cycle in March each year unless the Commission takes specific action on the LFCR compliance filing. Second, the Company is also proposing to increase the year over year cap to 2%. Third, APS is proposing to update the costs eligible for recovery. Today 50% of distribution and transmission costs collected through demand based (or kW) charges, and 100% of generation costs are excluded, regardless of whether they are demand or energy based. APS is proposing that the LFCR be modified such that 100% of transmission,[7] distribution and generation costs collected through energy charges are included and 50% of transmission, distribution and generation costs collected through demand charges are included. Fourth, APS is proposing to remove the LFCR opt-out rate option, which has proven unnecessary. Last, the adjustment will be no longer be applied to customers' bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand. The revised LFCR Plan of Administration is provided in the Standard Filing Requirement Book under "Plans of

[77] APS has proposed to move all TCA revenue into base rates and has also proposed a balancing account in the TCA adjustor mechanism. If the Commission approves this treatment, the inclusion of transmission costs in the LFCR mechanism is unnecessary.

Administration." The sales associated with customers who are exempt from the LFCR will continue to be excluded from the derivation of the annual adjustments.

Q. WHY IS THE COMPANY PROPOSING THESE MODIFICATIONS?

A. APS is proposing these modifications to the LFCR so that the mechanism more accurately reflects the fixed and demand related costs that go unrecovered as a result of EE and residential rooftop solar. While the Company has the potential to engage in a wholesale transaction with generation capacity that is no longer needed by retail customers, any margins on wholesale sales are credited to the PSA mechanism, thus benefitting retail customers. They are not retained by APS. Therefore, it is appropriate to include lost generation capacity costs.

X. <u>EIS MODIFICATIONS</u>

Q. PLEASE DESCRIBE THE CURRENT EIS MECHANISM AND PROCESS?

A. The EIS is a mechanism that currently allows 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 EIS Plan of Administration describes in detail the "Qualified Investments" allowed under the mechanism. Please see the Standard Filing Requirement Book, under "Plans of Administration" for the EIS Plan of Administration.

The EIS mechanism addresses cost recovery for Qualified Investments which occur outside of a rate case and are therefore, not reflected in base rates. Annually, APS calculates the EIS adjustment based on the investments that were actually placed in-service during the preceding calendar year and applies the adjustment on an equal percentage basis to all retail 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. The EIS recovers the revenue requirement or carrying costs of Qualified Investments. Items APS currently includes in the EIS are:

- A return on EIS 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
- O&M expenses.

For more information regarding each of these components, please see the EIS Plan of Administration provided in the Standard Filing Requirement Book.

Q. PLEASE DESCRIBE THE MODIFICATIONS THAT APS IS PROPOSING TO MAKE TO THE EIS?

A. APS is proposing to make the following changes to the EIS:

- Change the structural cap on cost recovery from a rate to a dollar amount ($0.00016 per kWh to $10M year-over-year). This change will provide a more transparent and simplified calculation. More importantly, the change will allow for a more timely and sufficient recovery of these large capital investments to ensure safe, reliable, environmentally-compliant and cost effective generation.
- Provide for the ability to carry over into subsequent periods any excess EIS adjustment over the annual cap. This addition is consistent with APS's other adjustment mechanisms, including a nominal interest component.
- Inclusion of a balancing account. The purpose of the balancing account is to account for any differences between the allowable EIS adjustment and actual

revenues received by the Company through the EIS during the recovery period. In the event that the annual EIS adjustment is more or less than the revenues collected, the over or under collection will be applied to the annual EIS adjustment in the subsequent period.

The proposed changes to the EIS, as stated above, provide for a more complete mechanism which better aligns the customer's and Company's needs.

Q. WHY IS APS PROPOSING TO INCREASE THE CAP ON THE EIS?

A. APS assessed the current mechanism and determined the cap structure could be insufficient to keep pace with environmental obligations. In the most recent filing, the Company exceeded the current cap and was unable to recover the full costs incurred to comply with environmental regulations. Increasing the cap on the EIS will allow the Company to continue to remain in compliance with environmental regulations without any financial harm. The project investments that APS includes in the EIS are placed in service after new rates go into effect. Increasing the cap will more accurately align the customers' and Company's interests in environmental compliance.

Q. WHY IS A $10 MILLION YEAR OVER YEAR CAP A MORE APPROPRIATE AMOUNT THAN $0.00016 PER KWH?

A. 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 and sufficient recovery of required environmental improvement projects, the EIS better enables APS to secure capital at a reasonable cost and make these capital investments, thus, passing these savings onto customers. Changing the cap structure from a kWh amount to a set dollar amount will provide a more transparent and

simplified calculation, reflecting the exact recovery of capital costs necessary. It also provides for more consistency among the components within the EIS, aligning how the Qualified Investments and capital carrying costs are tracked, analyzed and presented.

Additionally, the Company will be spending significant capital in the near future given the increasingly stringent environmental rules. As one example of the escalated environmental requirements and resulting increased capital costs required, the Company will be installing the mandated SCR's on the Four Corners power plant. While it is clear that these costs qualify as environmental improvement projects and therefore would be Qualified Investments under the EIS mechanism, we are proposing that they be treated separately given the magnitude of the anticipated costs for these projects. Although APS requests separate treatment for the SCR project, it is just one of many examples of how the environmental rules are increasing the required capital and recovery necessary to comply.

The EIS continues to provide the Commission multiple opportunities to review the projects included in the Qualified Investments as part of the annual filing. 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, under the Integrated Resource Plan rules, the Commission acknowledges the Company's resource plan every two years. This filing allows the Commission to review APS's current and proposed resource mix and any external items, such as new environmental rules, that would affect generating resources.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE CALCULATION OF THE EIS RATE?

A. No. It will continue to be calculated as currently approved and applied to customers' bills equally through a dollar per kWh rate, which is calculated by dividing the total EIS revenue requirement by the annual Total Company Revenues as defined in the Plan of Administration.

XI. TCA MODIFICATIONS

Q. PLEASE DESCRIBE THE MODIFICATIONS THAT APS IS PROPOSING TO MAKE TO THE TCA?

A. APS is proposing to modify the TCA by including a balancing account. The purpose of the balancing account is to account for any differences between the calculated TCA rates and actual revenues received by the Company through the TCA during the recovery period (June through May). In the event that the TCA is more or less than the revenues collected, the over or under collection will be applied to the TCA calculation in the subsequent period. This proposed change will provide for a more complete mechanism which better aligns the customer's and Company's needs.

XII. APS RATE PLAN

Q. PLEASE EXPLAIN THE PURPOSE OF THE APS RATE PLAN.

A. Attachment K to the Settlement Agreement approved in Decision No. 73183 states:

> APS shall prepare and file a rate plan as proposed by Staff to provide information on such issues as tiered conservation rates, time-of-use and other demand response rates, plans for cancelling rates, ideas for new rate offerings and other relevant rate design issues. The timing of the plan will be revised in the Settlement. In addition, APS and Staff will identify current rate related compliance reports that can be consolidated into this rate plan.

This concept was originally described by the Commission Staff's witness on Rate Design, Howard Solganick, where in his Direct Testimony, he stated:

> The Company has not conducted any specific rate research other than as part of its usual rate design process. As recommended in the Staff decoupling testimony, the Company should plan and perform rate research. The Company has a wide range of rate schedules, including some that are frozen, and it continues to experiment with new concepts.

Mr. Solganick went on to suggest:

> The plan should at a minimum include:
>
> Reviewing or justifying the existing blocks and tiers within rate schedules in light of recent load research, appliance saturation, new uses such as heat pump water heaters, energy efficient computers, televisions and the penetration of energy efficient appliances
>
> Providing the timing or triggers for the elimination of existing frozen rates
>
> Determining analysis methods and standards for making an experimental rate permanent or withdrawing that rate
>
> Determining whether adjustors should be embedded within, partially embedded or separate from existing rates
>
> Analyzing whether more complicated and/or varied rate forms are productive and understood by customers
>
> Determining if, when and how distribution (delivery) rates might shift from volumetric to demand based to eliminate the need for a decoupling mechanism

Also, in Mr. Solganick's Decoupling testimony, he stated:

> The Company is proposing a number of modifications to individual rate schedules along with the elimination of some schedules that are used by few customers. However, in light of its installation of AMI, I am surprised that the Company has not presented a rate research plan to determine how the more detailed metering information can be used.

and;

> While the Company characterizes decoupling as modernizing the rate structure it is merely a band-aid on an old rate structure. The Company does offer demand based rate structures for some rate classes and subclasses but with the advent of AMI it now has the technical capability to change its rate structure. Changing the foundation of the rate structure requires research and an effective customer education plan to demonstrate to customers that they have the capability to reduce both their demand and energy consumption and a corresponding rate structure that accurately charges for those elements. Over time a

modern rate structure could obviate the need for a decoupling mechanism.

The APS Rate Plan responds to the issues addressed by Mr. Solganick and lays the foundation for a modernized rate structure for APS's residential customers. The APS Rate Plan is attached to my testimony as Attachment LRS-5DR.

XIII. RATE DESIGN REQUESTS

A. *APS's Experimental AG-1 Rate*

Q. PLEASE DESCRIBE APS'S EXPERIMENTAL AG-1 RATE PROGRAM.

A. As part of the Settlement Agreement approved in Decision No. 73183, APS offered an experimental buy-through rate for the generation portion of the bill for large and extra-large commercial and industrial customers. The program was limited to 200 MW of total participation, to ideally be split equally between the large and extra-large customer groups. Because customer interest in the program exceeded the program size limits, APS conducted a lottery to select participants for the experimental program. The program is fully subscribed. Initially, the program had a sunset date of June 30, 2016, but the date was extended by the Commission by Decision No. 75322 (November 25, 2015) to coincide with the ultimate rate effective date of the Decision in this rate case. The same Decision also granted APS a deferral mechanism for the lost margins after June 30, 2016.

The parties to the Settlement Agreement agreed to allow APS to mitigate the anticipated foregone margins on generation service by allowing APS to share in the wholesale margins that credit the PSA fuel expense. This crediting occurred on a pro-rata basis, based on the ratio of displaced retail sales over the total volume of short-term wholesale sales. To date, the mitigation has been $24,427,000 less than the lost margins on a cumulative basis.

The Settlement Agreement further required APS to evaluate and file a report on the experimental AG-1 program results and propose whether to discontinue or modify the program going forward. APS's detailed report on the experimental AG-1 program is attached to my testimony as Attachment LRS-06DR.

Q. WHAT IS APS'S RECOMMENDATION FOR AG-1, GIVEN THE EXPERIENCE WITH THE PROGRAM TO DATE?

A. Based on the evaluation of the experimental program, for the reasons discussed in the AG-1 report, APS is not proposing to renew the AG-1 program. APS believes the program has significant flaws and, based on past experience, will shift unreasonable revenue responsibility to other customers. Although the Commission's decisions regarding AG-1 prevent APS's residential customers from bearing the cost of AG-1, the same is not true for other commercial and industrial customers. APS has had unmitigated lost margins from the program every year it has been in place. This revenue shortfall annually has ranged in magnitude from $4.5 million to $11.7 million per year. APS anticipates that under the current program design and based on today's natural gas price forecasts, this shortfall will only continue to grow. APS does not view this as a sustainable program.

Q. WHAT PROGRAM CHANGES WOULD BE NECESSARY, AT A MINIMUM, IF THE COMMISSION WERE TO CONCLUDE IN THIS RATE CASE THAT A PROGRAM LIKE AG-1 SHOULD CONTINUE TO BE OFFERED?

A. At a minimum, several modifications would be necessary to ensure that AG-1 customers directly pay a greater share of the cost of providing them service, rather than relying solely on the demonstrably inadequate mechanism of PSA off-system margin mitigation:

1. The capacity reserve charge is presently set at 15% of the customer's monthly demand. This percentage is applied to an APS cost-based generation rate on file

at FERC, which may be amended from time-to-time. This FERC rate is the reservation charge for firm capacity at the wholesale level, which is what APS continues to provide to AG-1 customers. Presently, the full FERC filed charge is $6.985 per kW per month, and AG-1 participants pay 15% of this amount. APS believes, if AG-1 were to continue, participants should be required to pay 100% of this cost-based FERC approved charge.

2. The Administrative Management Fee is presently $0.60 per MWh, which does not cover the cost of administering the program. This should be increased to at least three times the current charge per MWh to cover the actual cost of administration.

3. The energy imbalance charges must be revised to reflect the load following nature of the energy deliveries. Presently, the AG-1 program uses a FERC protocol for wholesale transactions which is designed for block sales, with a constant MW delivery. The intent of this protocol is to compensate a counter-party when a delivery cannot be completed as originally agreed. However, in AG-1, the generation provider should follow the customer's load, moment by moment and the FERC protocol is not appropriate for this situation. Because APS is not proposing to renew the AG-1 program, the retail energy imbalance protocol has not been completely designed. The attached report describes the short-comings of the FERC protocol in detail.

4. The PSA mitigation tool would need to continue, to provide the Company with an opportunity to mitigate additional program losses.

Q. IF THE COMMISSION APPROVED THE MODIFICATIONS TO AG-1 DESCRIBED ABOVE, WOULD APS SUPPORT RENEWING AG-1?

A. It is very difficult to precisely quantify the impact a modified AG-1 program would have on other customers. The consequences for other customers were significantly

underestimated when AG-1 was created. And under a modified AG-1, no matter how well designed, no party can guarantee that there will be no costs shifted to other customers. As a result, even if modified as described above, APS does not believe that the benefits of a renewed AG-1 program outweigh the risks.

B. *New Commercial and Industrial Rate Offerings for Extra-High Load Factor Industrial Customers and an Economic Development Service Schedule*

Q. PLEASE PROVIDE AN OVERVIEW OF THE EXTRA-HIGH LOAD FACTOR (XHLF) RATE OFFERING.

A. APS has determined that several of its extra-large customers have load factors that are significantly higher than the average load factor of the extra-large customer class. As a result, APS has evaluated this group separately from a cost of service standpoint and developed a cost-based rate for this customer sub-class. APS also has a second tier of high load factor customers, which, with a tangible price signal, may be able to use technology, process controls or make operational adjustments that would allow them to meet the stringent qualifications of the new rate offering.

Q. WHAT CRITERIA HAS APS DETERMINED IS APPROPRIATE FOR THE XHLF RATE?

A. For a customer to qualify for the XHLF rate, the customer must have a monthly average load factor of 92% in nine of the last twelve months, on a rolling basis. In addition, different than other extra-large rate schedules, the minimum size qualification is 5,000 kW or greater, rather than 3,000 kW. A few additional features of the XHLF rate would be available to customers with a minimum size of 15,000 kW. For example, APS is proposing the option of qualifying for transmission level service through a contribution in aid of construction (CIAC), rather than outright purchase of the facilities, at the 15,000 kW threshold. This option will require the customer to also enter into a

maintenance contract and share in the cost of replacing any equipment that is necessary. As part of this option, APS will also offer to finance the CIAC at APS's WACC established in its most recent rate case for a period not to exceed ten years. APS's proposed XHLF Rate Schedule is provided in the Standard Filing Requirement Information, under "General Service."

Q. IS XHLF CONCEPTUALLY SIMILAR TO SPECIAL CONTRACTS THAT APS HAS FILED OVER THE LAST SEVERAL YEARS WITH CUSTOMERS WITH THESE HIGH LOAD FACTOR CHARACTERISTICS?

A. Yes. APS's has filed two agreements that have been approved by the Commission for customers of this nature, and has filed one recently which is not yet approved. Through these special contracts, APS has gained experience and continues to believe customers with a very high load factor have a reduced cost to provide service.

Q. PLEASE DESCRIBE APS'S PROPOSED ECONOMIC DEVELOPMENT SERVICE SCHEDULE, SERVICE SCHEDULE 9.

A. The proposed Service Schedule 9 is intended to support commercial and industrial economic development in the APS service territory. The Company proposes to provide a bill discount over a period up to six 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 1,000 kW for existing customers and 2,000 kW for new customers, and monthly average load factors of at least 55%. The discount would be specific to each customer, within the following parameters: 1) the discount does not exceed 25% and 2) is no less than APS's marginal cost of providing service. APS will file agreements executed under Service Schedule 9 with the Commission Staff in a compliance filing. APS envisions that the discount would typically be structured on a declining annual basis over the term. The eligible customer would also be encouraged to participate in the Company's energy efficiency program, demand response program, or

renewable energy programs 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 in the Standard Filing Requirement Information, under "Service Schedule 9."

XIV. CONCLUSION

Q. WHAT CONCLUSIONS DO YOU HAVE BASED ON YOUR TESTIMONY?

A. My testimony sponsors APS's Schedule A-1, which supports APS's request in this rate case for a net increase in base rate revenue requirements of $433,434,000. This amount includes a $165,883,000 increase in rates resulting from transferring various adjustor amounts from the respective adjustor mechanisms into base rates. This transfer has no bill impact overall, and instead, only reclassifies where the charges will show up on customer's bills.

My testimony also describes why the Commission should approve APS's request for Accounting Deferral Orders regarding two large generation-related investments APS will make in the next several years:

- The OMP in Tempe, Arizona, where APS will replace some aging steam-based natural gas units with modern, fast-ramping jet-engine technology; and
- The installation of SCR emissions control technology at the Four Corners Power Plant to comply with Federal environmental law.

Authorizing these deferral orders will allow APS to avoid immediately filing another rate case either prior to the conclusion of this rate case or shortly after its conclusion.

The Commission should also approve APS's request to hold the Decision in this case open for the limited purpose of a step-increase related to the SCRs at Four Corners.

The Commission should approve APS's COSS that is used to support the Company's rate designs in the Company's Application as well as the jurisdictional allocation of costs.

The Commission should approve APS's conservative 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 and 2010 Test Year rate filings made by APS that resulted in Decision Nos. 71448 (December 30, 2009) and 73183 (May 24, 2012).

The Commission should approve APS's proposed modifications to its LFCR, EIS and TCA adjustor mechanisms. The Commission should also approve APS's proposed new XHLF general service rate, which APS intends to make generally available to large commercial customers that meet the load characteristics and other requirements of the rate schedule. The Commission should approve APS's proposed Service Schedule 9, an Economic Development service schedule that will provide some structure within APS's service territory which encourages economic development.

Lastly, based on the results of a near-five year pilot, the Commission should not renew the experimental AG-1 rate program.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Statement of Qualifications

Leland R. Snook

Leland R. Snook is Arizona Public Service Company's Director, Rates and Rate Strategy. 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 contracts, cost recovery mechanisms, fair value of utility property, rate schedules and pricing. 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 has held his current position at Arizona Public Service Company for approximately seven years. Prior to assuming that position, he served as the Director of Federal Regulation for APS. Before joining APS, Mr. Snook had a 22-year career with Tucson Electric Power Company, where he served in various professional and leadership roles.

Standard Filing Requirements Index for Sponsorship

A-1	Snook		
A-2 A-3 A-4 A-5	Blankenship Ewen	Historical Projected	
B-1*	Blankenship		
B-2* B-3*	Lucas/Blankenship	Column	2
	Cadogan/Blankenship	Column	3
	Tetlow/Blankenship	Column	4
	Derstine/Blankenship	Column	5
	Bordenkircher/Blankenship	Column	6
	Miessner	Column	7
	Blankenship	Columns	8-10
B-4 B-5	Blankenship		
C-1*	Blankenship		
C-2*	Lucas/Blankenship	Column	1
	Cadogan/Blankenship	Column	2
	Tetlow/Blankenship	Column	3
	Derstine/Blankenship	Column	4
	Bordenkircher/Snook/Blankenship	Column	5
	Ewen	Columns	6-8
	Miessner	Columns	9-14
	Blankenship	Columns	15-47
C-3	Blankenship		
D-1 D-2 D-3	Blankenship Ewen	Historical Projected	
D-4	Blankenship		

E-1 E-2 E-3 E-4 E-5 E-6 E-7 E-8 E-9	Blankenship	
F-1 F-2 F-3	Blankenship Ewen	Historical Projected
F-4	Ewen	
G-1 G-2 G-3 G-4 G-5 G-6 G-7	Snook	
H-1 H-2 H-3 H-4 H-5	Miessner	

*Leland Snook sponsors the ACC jurisdictional amounts that are computed, via the Cost of Service Study.

Calculation of Fair Value Increment

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 3,728,555	44.20%	5.13%	2.27%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	4,706,351	55.80%	10.50%	5.86%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 8,434,906	100.00%		8.13%

	Capital Structure with 1.0% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 2,992,849	30.00%	5.13%	1.54%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	3,778,302	37.87%	10.50%	3.98%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	3,204,872	32.13%	1.00%	0.32%
11.	Total	$ 9,976,023	100.00%		5.84%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 9,976,023	$ 6,771,151
13.	Rate of Return	5.84%	8.13%
14.	Required Operating Income	$ 582,600	$ 550,495
15.	Adjusted Operating Income	$ 314,303	$ 314,303
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 268,297	$ 236,192
17.	Revenue Conversion Factor	1.6155	1.6155
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 433,434	$ 381,568
19.	Fair Value Increment	$ 51,866	

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ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RETAIL: RESIDENTIAL	RETAIL: GENERAL SERVICE	RETAIL: E-221 (Water Pumping)	RETAIL: Street Lighting	RETAIL: Dusk to Dawn
DEVELOPMENT OF RATE BASE									
ELECTRIC PLANT IN SERVICE	$ 15,326,435,253	$ 12,962,340,167	$ 2,364,095,086	$ 12,962,340,167	$ 8,099,051,086	$ 4,554,842,478	$ 122,239,296	$ 133,850,295	$ 52,557,042
GENERAL & INTANGIBLE PLANT	1,509,541,568	1,400,428,100	109,113,468	1,400,428,100	913,116,365	464,148,198	11,777,899	7,325,948	4,061,919
LESS: RESERVE FOR DEPRECIATION	(6,402,411,202)	(5,632,319,059)	(770,092,143)	(5,632,319,059)	(3,511,914,009)	(2,002,097,799)	(52,785,504)	(47,533,720)	(17,988,630)
OTHER DEFERRED CREDITS	(1,337,180,000)	(1,292,836,371)	(44,341,629)	(1,292,836,371)	(768,219,184)	(503,174,681)	(12,884,195)	(8,801,831)	(1,978,480)
WORKING CASH	(113,623,376)	(93,558,549)	(20,064,827)	(93,558,549)	(58,288,888)	(32,917,889)	(893,500)	(1,054,520)	(403,975)
MATERIALS, SUPPLIES & PREPAYMENTS	436,428,790	398,788,143	39,656,647	398,788,143	225,856,546	164,897,889	4,153,353	3,670,544	980,029
ACCUM. DEFERRED TAXES	(2,873,411,027)	(2,359,729,334)	(513,681,693)	(2,359,729,334)	(1,503,979,442)	(798,948,649)	(21,719,932)	(28,283,829)	(10,819,481)
REGULATORY ASSETS	310,940,000	250,199,222	60,740,778	250,199,222	181,817,468	63,623,483	1,701,159	1,762,326	1,294,787
DECOMMISSIONING FUND	735,196,000	731,225,942	3,970,058	731,225,942	434,549,532	285,209,677	7,291,629	3,632,160	551,943
MISCELLANEOUS DEFERRED DEBITS	121,338,000	113,265,656	8,072,344	113,265,656	71,286,870	40,082,726	1,006,096	594,776	295,186
OPEB	182,625,115	168,753,227	13,871,888	168,753,227	110,070,359	55,890,824	1,418,175	882,962	490,906
CUSTOMER ADVANCES	(115,609,383)	(94,903,242)	(20,706,141)	(94,903,242)	(49,850,247)	(44,794,989)	(138,265)	(149,958)	(683)
CUSTOMER DEPOSITS	(72,621,690)	(72,621,690)	-	(72,621,690)	(36,578,117)	(32,616,324)	(706,920)	(511,132)	(209,197)
PROFORMA ADJUSTMENTS	302,154,000	292,140,717	10,013,283	292,140,717	183,586,173	101,925,712	2,404,099	2,808,171	1,316,052
TOTAL RATE BASE	**8,011,888,846**	**6,771,158,929**	**1,240,649,118**	**6,771,158,929**	**4,288,514,538**	**2,317,691,836**	**63,173,842**	**71,913,882**	**38,156,619**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	2,909,647,523	2,865,563,427	44,084,096	2,865,563,427	1,468,282,584	1,338,700,733	29,914,733	29,979,131	8,586,247
PROFORMA TO BASE REVENUES FROM RATES	23,340,145	23,340,145	-	23,340,145	18,295,059	5,225,194	(275,293)	163,126	(7,912)
SURCHARGE & OTHER ELECTRIC REVENUES	582,709,014	570,735,507	11,973,507	570,735,507	316,626,510	243,272,570	7,471,258	2,579,858	785,311
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(412,607,651)	(412,186,408)	(421,243)	(412,186,408)	(236,567,673)	(167,894,771)	(5,888,781)	(1,888,885)	(578,518)
TOTAL OPERATING REVENUES	**3,103,088,031**	**3,047,452,671**	**55,636,360**	**3,047,452,671**	**1,566,646,481**	**1,419,303,685**	**30,541,917**	**31,973,450**	**8,787,128**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	1,804,920,730	1,968,657,996	(163,737,266)	1,968,657,996	1,014,500,495	918,921,396	23,390,694	9,396,642	2,439,861
ADMINISTRATIVE & GENERAL	193,799,761	176,678,975	17,120,787	176,678,975	115,813,186	57,912,694	1,473,481	948,786	532,876
DEPRECIATION & AMORT EXPENSE	456,219,756	402,496,860	53,722,896	402,496,860	252,267,709	141,405,047	3,731,763	3,614,227	1,478,115
AMORTIZATION ON GAIN	(4,626,993)	(4,601,933)	(25,060)	(4,601,933)	(2,729,002)	(1,800,561)	(45,991)	(22,862)	(3,477)
REGULATORY ASSETS	17,910,882	17,910,882	-	17,910,882	10,643,995	6,985,797	178,893	88,967	13,519
PROFORMA ADJUSTMENTS	(55,126,400)	(63,537,447)	8,411,047	(63,537,447)	(8,349,831)	(53,840,271)	(1,961,467)	259,069	155,052
TAXES OTHER THAN INCOME	171,499,317	139,384,353	32,114,964	139,384,353	88,501,094	47,275,162	1,289,515	1,633,384	685,199
INCOME TAX	256,174,789	224,294,040	33,880,749	224,294,040	81,012,406	137,531,830	1,939,519	2,449,827	1,360,456
PROFORMA INCOME TAX ADJUSTMENTS	(131,826,847)	(128,134,190)	(3,692,657)	(128,134,190)	(62,116,783)	(43,413,146)	(1,555,648)	(745,634)	(302,771)
TOTAL OPERATING EXPENSES	**2,710,944,995**	**2,733,148,538**	**(22,204,543)**	**2,733,148,538**	**1,488,842,242**	**1,211,177,887**	**28,448,362**	**17,536,186**	**6,358,831**
OPERATING INCOME	**392,144,036**	**314,303,133**	**77,840,902**	**314,303,133**	**97,804,239**	**208,125,798**	**2,101,555**	**4,443,264**	**2,428,297**
RATE OF RETURN (PRESENT)	**4.89%**	**4.64%**	**6.27%**	**4.64%**	**2.28%**	**8.99%**	**3.33%**	**6.20%**	**9.89%**
INDEX RATE OF RETURN (PRESENT)	**1.00**	**0.95**	**1.28**	**0.95**	**0.46**	**1.84**	**0.68**	**1.27**	**1.85**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**3,483,616,357**	**3,322,337,237**	**91,279,120**	**3,322,337,237**	**1,938,207,779**	**1,329,288,269**	**34,121,433**	**23,898,561**	**8,853,294**
% OF TOTAL COST OF SERVICE (PRESENT)	**94.83%**	**95.01%**	**54.24%**	**95.01%**	**95.93%**	**108.20%**	**93.73%**	**92.44%**	**100.43%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**96.91%**	**100.00%**	**54.24%**	**100.00%**	**92.87%**	**111.53%**	**98.56%**	**97.28%**	**106.68%**

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ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	TOTAL GENERAL SERVICE	GENERAL SERVICE										
		E-20 (Church Rate)	E-32 TOU (0-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35
DEVELOPMENT OF RATE BASE											
ELECTRIC PLANT IN SERVICE	$ 4,554,842,478	$ 35,879,010	$ 11,427,670	$ 20,564,527	$ 64,756,490	$ 58,758,131	$ 1,899,623,772	$ 1,072,049,524	$ 921,369,172	$ 211,511,818	$ 458,742,564
GENERAL & INTANGIBLE PLANT	464,146,198	3,096,845	1,201,647	2,129,615	6,436,253	4,973,372	183,186,867	101,163,889	90,080,364	21,631,237	50,308,479
LESS: RESERVE FOR DEPRECIATION	(2,002,097,799)	(15,470,138)	(4,994,616)	(9,037,865)	(28,494,203)	(25,311,933)	(742,135,274)	(466,327,986)	(404,726,918)	(95,082,278)	(210,566,576)
OTHER DEFERRED CREDITS	(503,174,881)	(3,176,214)	(1,261,919)	(2,344,793)	(7,577,244)	(5,563,302)	(174,836,524)	(115,346,984)	(106,632,714)	(25,812,080)	(61,620,927)
WORKING CASH	(32,917,889)	(209,576)	(82,118)	(147,940)	(467,074)	(449,091)	(12,247,905)	(7,841,230)	(6,673,444)	(1,517,850)	(3,230,853)
MATERIALS, SUPPLIES & PREPAYMENTS	194,697,889	859,954	422,710	794,980	2,699,246	1,954,020	54,689,014	38,122,227	35,881,386	8,596,074	21,117,046
ACCUM. DEFERRED TAXES	(798,946,049)	(6,677,850)	(2,600,773)	(3,558,989)	(11,039,551)	(10,885,464)	(306,382,380)	(187,883,232)	(158,185,267)	(35,718,544)	(74,797,389)
REGULATORY ASSETS	63,623,483	545,521	171,513	275,748	714,988	743,620	31,198,115	12,939,718	10,319,839	2,289,123	4,515,297
DECOMMISSIONING FUND	285,209,677	2,188,437	887,285	1,261,536	4,183,938	3,652,953	98,600,144	67,083,645	59,438,957	14,638,980	33,445,123
MISCELLANEOUS DEFERRED DEBITS	40,082,726	238,784	103,947	187,843	582,882	498,367	15,032,013	8,824,886	8,076,128	1,950,371	4,679,805
OPEB	55,890,824	372,625	144,745	256,485	774,820	588,328	22,071,526	12,189,983	10,843,402	2,693,520	6,095,480
CUSTOMER ADVANCES	(44,764,989)	(141,280)	(138,627)	(228,624)	(697,879)	(375,661)	(17,171,511)	(10,472,745)	(9,068,278)	(1,911,801)	(4,538,383)
CUSTOMER DEPOSITS	(32,616,324)	(101,767)	(101,918)	(168,738)	(508,722)	(272,140)	(12,521,197)	(7,630,243)	(6,620,434)	(1,380,579)	(3,302,587)
PROFORMA ADJUSTMENTS	101,925,712	726,988	292,993	488,979	1,441,798	1,194,698	39,288,482	23,289,994	20,288,055	4,847,718	10,358,928
TOTAL RATE BASE	2,317,891,836	16,671,358	5,841,548	10,494,234	32,716,925	28,333,448	878,252,053	548,842,255	485,288,308	108,427,380	231,224,888
DEVELOPMENT OF RETURN											
BASE REVENUES FROM RATES	1,336,700,733	4,178,910	4,183,191	6,843,561	20,879,912	11,189,889	513,918,578	313,174,826	271,728,356	57,074,785	135,551,017
PROFORMA TO BASE REVENUES FROM RATES	5,225,184	(107,847)	(15,624)	(69,241)	(334,450)	175,286	(2,421,480)	(4,532,152)	2,082,092	2,788,532	7,882,056
SURCHARGE & OTHER ELECTRIC REVENUES	243,272,570	1,080,040	794,728	1,184,024	3,141,198	2,347,088	103,074,982	57,784,217	42,240,994	9,789,280	21,865,031
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(187,894,771)	(831,475)	(609,842)	(902,479)	(1,875,840)	(1,753,228)	(80,163,849)	(49,247,364)	(24,894,779)	(5,549,498)	(10,976,510)
TOTAL OPERATING REVENUES	1,416,303,696	4,317,628	4,361,161	7,195,864	21,811,820	11,958,917	534,408,231	326,178,526	291,156,663	64,082,199	154,121,395
OPERATING EXPENSES											
OPERATION & MAINTENANCE	918,921,386	3,531,858	2,345,456	4,274,865	13,886,183	7,782,889	294,906,617	203,788,681	208,829,304	50,044,593	131,530,986
ADMINISTRATIVE & GENERAL	57,912,864	381,904	150,079	285,032	797,201	624,691	23,054,380	12,584,849	11,172,043	2,875,339	6,187,346
DEPRECIATION & AMORT EXPENSE	141,405,047	1,046,385	357,855	644,381	2,018,088	1,727,203	52,921,086	32,711,089	28,530,249	6,841,891	14,805,049
AMORTIZATION ON GAIN	(1,800,561)	(13,867)	(4,345)	(8,107)	(26,488)	(22,922)	(621,071)	(423,373)	(375,914)	(92,580)	(212,083)
REGULATORY ASSETS	6,985,797	53,604	16,835	31,380	102,483	89,477	2,415,143	1,643,168	1,455,917	358,564	819,216
PROFORMA ADJUSTMENTS	(53,640,271)	(133,586)	(222,461)	(270,388)	(756,168)	(281,910)	(27,248,308)	(13,417,589)	(9,287,093)	(863,822)	(1,381,128)
TAXES OTHER THAN INCOME	47,275,162	362,023	119,764	213,163	661,837	618,446	18,112,874	11,137,510	9,440,218	2,116,235	4,473,071
INCOME TAX	137,531,830	(202,248)	710,850	906,493	2,237,191	784,190	78,827,798	37,252,798	17,836,975	1,050,418	(1,981,635)
PROFORMA INCOME TAX ADJUSTMENTS	(43,413,146)	(311,879)	(157,886)	(248,109)	(583,950)	(518,340)	(22,027,283)	(12,442,782)	(5,473,611)	(863,549)	(783,588)
TOTAL OPERATING EXPENSES	1,211,177,987	4,746,394	3,315,837	5,818,731	18,336,369	10,623,763	438,443,236	272,844,172	260,128,088	61,276,208	153,447,288
OPERATING INCOME	205,125,709	(428,766)	1,045,323	1,376,133	3,474,451	1,115,114	113,965,793	53,334,354	31,028,574	2,775,991	674,109
RATE OF RETURN (PRESENT)	8.85%	(2.57%)	17.89%	12.78%	10.62%	3.88%	12.98%	9.88%	6.67%	2.61%	0.29%
INDEX RATE OF RETURN (PRESENT)	1.84	(0.48)	3.86	2.61	2.17	0.78	2.65	2.02	1.36	0.53	0.06
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	1,329,288,289	7,275,363	3,289,625	6,086,691	19,473,523	13,621,836	449,437,691	297,488,615	288,283,888	70,129,941	174,217,487
% OF TOTAL COST OF SERVICE (PRESENT)	100.20%	62.28%	136.89%	119.59%	111.14%	91.96%	123.57%	111.72%	99.78%	89.87%	86.87%
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	111.53%	67.32%	137.58%	124.68%	117.26%	96.10%	123.61%	115.87%	106.56%	94.58%	91.13%

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ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	TOTAL RESIDENTIAL	RESIDENTIAL				
		Solar Energy Rates (E-12, ET-1 & ET-2)	Solar Demand Rates (ECT-1 & ECT-2)	E-12	ET-1 & ET-2	ECT-1 & ECT-2
DEVELOPMENT OF RATE BASE						
ELECTRIC PLANT IN SERVICE	$ 8,099,051,086	$ 359,317,931	$ 18,729,906	$ 2,181,586,792	$ 3,967,361,127	$ 1,572,055,331
GENERAL & INTANGIBLE PLANT	913,116,365	47,816,295	2,225,146	286,622,522	420,071,880	156,380,511
LESS: RESERVE FOR DEPRECIATION	(3,511,914,006)	(159,178,281)	(8,201,318)	(956,881,871)	(1,711,729,418)	(676,123,118)
OTHER DEFERRED CREDITS	(766,219,184)	(35,053,127)	(1,827,958)	(212,176,542)	(370,936,142)	(146,223,415)
WORKING CASH	(56,288,886)	(2,511,313)	(133,460)	(15,263,080)	(26,854,289)	(11,526,704)
MATERIALS, SUPPLIES & PREPAYMENTS	225,856,546	9,723,164	533,017	61,674,894	109,299,722	44,625,752
ACCUM. DEFERRED TAXES	(1,503,979,442)	(67,476,186)	(3,469,949)	(406,316,946)	(735,904,774)	(289,107,563)
REGULATORY ASSETS	181,817,466	10,423,768	446,856	61,829,875	80,998,943	28,127,225
DECOMMISSIONING FUND	434,549,532	18,565,663	1,012,884	106,810,613	217,388,521	88,771,851
MISCELLANEOUS DEFERRED DEBITS	71,286,870	3,631,865	173,502	22,036,643	32,952,466	12,490,395
OPEB	110,070,359	5,767,796	288,279	34,575,849	50,820,945	18,837,500
CUSTOMER ADVANCES	(49,850,247)	(679,199)	(76,618)	(15,137,036)	(24,414,448)	(9,542,946)
CUSTOMER DEPOSITS	(38,578,117)	(513,379)	(58,959)	(11,736,668)	(18,889,435)	(7,379,687)
PROFORMA ADJUSTMENTS	183,586,173	8,837,439	432,202	53,914,535	87,104,240	33,397,757
TOTAL RATE BASE	4,288,514,539	188,678,442	10,683,393	1,181,738,891	2,075,387,345	812,882,888
DEVELOPMENT OF RETURN						
BASE REVENUES FROM RATES	1,468,282,584	19,538,888	2,243,989	446,697,353	718,931,632	280,870,762
PROFORMA TO BASE REVENUES FROM RATES	18,285,059	3,192,150	122,785	8,426,843	5,908,510	644,792
SURCHARGE & OTHER ELECTRIC REVENUES	316,626,510	7,335,485	526,527	95,982,097	152,180,429	80,628,053
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(236,557,673)	(4,087,358)	(327,941)	(74,221,785)	(113,053,421)	(44,267,189)
TOTAL OPERATING REVENUES	1,566,646,481	25,979,885	2,566,319	476,884,527	763,367,150	297,876,418
OPERATING EXPENSES						
OPERATION & MAINTENANCE	1,014,599,495	21,689,164	1,457,780	289,912,447	494,405,939	207,134,166
ADMINISTRATIVE & GENERAL	115,813,168	6,086,865	282,200	36,459,360	53,226,580	19,758,152
DEPRECIATION & AMORT EXPENSE	252,267,709	11,640,073	591,459	79,592,332	121,750,792	47,693,143
AMORTIZATION ON GAIN	(2,729,002)	(116,504)	(6,363)	(883,914)	(1,384,850)	(557,570)
REGULATORY ASSETS	10,843,995	454,753	24,810	2,665,242	5,324,784	2,174,406
PROFORMA ADJUSTMENTS	(8,349,831)	1,920,634	68,473	(5,827,017)	(3,634,086)	(877,834)
TAXES OTHER THAN INCOME	88,501,094	3,966,033	204,165	24,214,339	43,159,527	16,957,029
INCOME TAX	81,012,406	(8,080,177)	(3,030)	35,688,734	41,710,202	11,678,677
PROFORMA INCOME TAX ADJUSTMENTS	(82,116,793)	(1,928,775)	(195,279)	(23,580,578)	(40,731,889)	(16,679,496)
TOTAL OPERATING EXPENSES	1,469,842,242	36,552,087	2,514,214	429,446,948	713,647,338	287,287,673
OPERATING INCOME	97,804,239	(10,573,891)	46,105	47,423,579	49,719,812	10,588,745
RATE OF RETURN (PRESENT)	2.28%	(5.32%)	0.45%	3.98%	2.39%	1.30%
INDEX RATE OF RETURN (PRESENT)	0.46	(1.08)	0.09	0.81	0.49	0.27
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	1,926,287,779	67,443,433	3,691,777	544,231,449	933,436,087	377,485,114
% OF TOTAL COST OF SERVICE (PRESENT)	85.93%	37.53%	70.60%	93.01%	86.42%	83.30%
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	92.87%	40.21%	76.46%	99.77%	92.84%	88.99%

APS LONG-RANGE RATE PLAN

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EXECUTIVE SUMMARY

This Retail Rate Plan ("Plan") outlines a pathway to sustainable, adaptable rates for our customers and our Company with a focus on clean energy, customers, innovation and sustainability. It seeks to establish an "ideal" rate structure that accomplishes several objectives, including:

1. Modernizing rates to enable new technologies and reflect the continued value of the electricity delivery system;

2. Improving rate fairness among customers by aligning rates with the cost of service, minimizing/eliminating embedded subsidies;

3. Providing rate gradualism and bill stability for customers by managing overall rate levels and thoughtfully transitioning to new rate designs; and

4. Enhancing customer satisfaction by providing fewer but more meaningful rate choices and simplifying rate schedules and bill presentation.

This Plan provides a brief history of APS's current rate structure and then discusses the evolution to the "ideal" rate structure, which should diversify the recovery of fixed costs through both a basic service charge and a demand component, recovering only fuel costs through the more traditional volumetric energy rate. This basic form of rate design already exists for APS's larger commercial and industrial customers as well as over 11% of our current residential customers.

DEFINITION OF KEY TERMS

Automated Metering Infrastructure ("AMI"): a metering technology whose metering information can be remotely accessed for billing purposes. AMI also facilitates remote connection and disconnection of service and more granular customer consumption data for use in customer load research and rate design.

Basic Service Charge ("BSC") or Customer Charge: a fixed monthly component of a customer's electricity bill that covers a portion of fixed costs (such as metering, billing, etc.) – costs that do not vary depending on usage.

Behind-the-Meter ("BTM"): an adjective that describes equipment installed on the customer side of the utility's electric meter. Such equipment, for example, could take the form of various generation or storage technologies that modify the shape of the customer's utility metered load.

Billing Determinants: the various elements that are used to determine charges in accordance with the provisions of a rate schedule or contract. For example, APS uses data regarding the number of customers, kWh energy sales and kW demand as billing determinants in designing rates and developing a proof of revenue.

Demand Charge: the sum to be paid by an electricity customer for its peak usage level during any set period. A demand charge is based on capacity usage rather than energy usage, and is thus one tool to recover the fixed costs associated with serving that customer.
Demand-Related Costs: costs that vary based on the capacity requirements based on the rate of consumption, such as carrying costs and taxes associated with generation, transmission and distribution infrastructure.

Fixed Costs: costs that do not fluctuate with the amount of energy produced and consumed, or with the capacity requirements based on the rate of consumption (demand) such as the meter, the customer information and billing system, customer service and the service drop to a customer's premise.

Inclining Block Rates: a rate design that is intended to encourage customer conservation of energy by increasing the energy price associated with successive blocks of monthly energy consumption.

Kilowatt ("kW"): a measure of 1,000 watts of electrical power. In the rate design context, a kW charge is often referred to as a demand charge.

Kilowatt-Hour ("kWh"): a measure of electrical energy equivalent to a power consumption of 1,000 watts for 1 hour. Often in rate design, a kWh charge is called an energy or volumetric charge.

Lost Fixed Cost Recovery ("LFCR"): a rate mechanism that provides for the recovery of lost fixed costs, as measured by revenue, associated with the amount of EE savings and distributed generation that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the portion of transmission costs included in base rates and a portion of distribution costs, other than what is already recovered by (1) the Basic Service Charge and (2) 50% of demand revenues associated with distribution. This adjustor typically goes into effect in March.

Time-of-Use ("TOU"): a rate design that varies the customer energy price by the time of day. Typical time periods are designated as on-peak or off-peak, with higher prices set for on-peak time periods. TOU pricing and time period definitions may also vary seasonally. Shoulder or super-peak time periods may also be defined and priced separately.

Variable Costs: costs that fluctuate with the amount of energy produced and consumed, such as fuel expense.

BACKGROUND ON THE PLAN

Attachment K to the Settlement Agreement approved in Decision No 73183 states:

> APS shall prepare and file a rate plan as proposed by Staff to provide information on such issues as tiered conservation rates, time-of-use and other demand response rates, plans for cancelling rates, ideas for new rate offerings and other relevant rate design issues. The timing of the plan will be revised in the Settlement. In addition, APS and Staff will identify current rate related compliance reports that can be consolidated into this rate plan.

This concept was originally described by the Arizona Corporation Commission Staff's witness on Rate Design, Howard Solganick, where in his Direct Testimony, he stated:

> The Company has not conducted any specific rate research other than as part of its usual rate design process. As recommended in the Staff decoupling testimony, the Company should plan and perform rate research. The Company has a wide range of rate schedules, including some that are frozen, and it continues to experiment with new concepts.

Mr. Solganick went on to suggest:

> The plan should at a minimum include:
>
> Reviewing or justifying the existing blocks and tiers within rate schedules in light of recent load research, appliance saturation, new uses such as heat pump water heaters, energy efficient computers, televisions and the penetration of energy efficient appliances
>
> Providing the timing or triggers for the elimination of existing frozen rates
>
> Determining analysis methods and standards for making an experimental rate permanent or withdrawing that rate
>
> Determining whether adjustors should be embedded within, partially embedded or separate from existing rates
>
> Analyzing whether more complicated and/or varied rate forms are productive and understood by customers
>
> Determining if, when and how distribution (delivery) rates might shift from volumetric to demand based to eliminate the need for a decoupling mechanism

In Mr. Solganick's Decoupling testimony, he stated:

> Q. The Company describes its decoupling proposal as "modernizing" its rate structure. Is this accurate?
>
> A. No. The Company is not proposing to significantly change its rate structure. For example it is not proposing to use any of the capabilities of its investment in advanced metering infrastructure ("AMI") to measure demand and apply a new distribution rate form to additional customers, instead its EIA proposal is a band-aid.

and;

> Q. Has the Company provided a long-term plan to modernize its rate structure?
>
> A. The Company is proposing a number of modifications to individual rate schedules along with the elimination of some schedules that are used by few customers. However, in light of its installation of AMI, I am surprised that the Company has not presented a rate research plan to determine how the more detailed metering information can be used.

and;

> Q. How long should decoupling (whether an EIA or a LFCR) remain in place?
>
> A. While the Company characterizes decoupling as modernizing the rate structure it is merely a band-aid on an old rate structure. The Company does offer demand based rate structures for some rate classes and subclasses but with the advent of AMI it now has the technical capability to change its rate structure. Changing the foundation of the rate structure requires research and an effective customer education plan to demonstrate to customers that they have the capability to reduce both their demand and energy consumption and a corresponding rate structure that accurately charges for those elements. Over time a modern rate structure could obviate the need for a decoupling mechanism.

APS RETAIL RATE HISTORY

Over its 130 year history, APS has predominantly relied on volumetric rates to recover its costs. Over that time, only a few significant rate design changes occurred. In the first half of the century, for example, kW based demand charges were introduced for larger business customers in order to better recover the fixed and demand-related costs associated with serving that customer class. In the late 1970s, in response to the energy crisis, conservation rates were developed to incent lower levels of electricity consumption. These rate structures moved away from charging flat or declining energy prices and instead incorporated inclining block and TOU energy pricing. Nevertheless, with some exceptions, APS's rates remain primarily volumetric-based and fundamental rate designs have been relatively static over the last 30 years.

A. Volumetric Rates Shift Costs Between Customer Groups

This is particularly true for the residential class, for which more than 70% of fixed and demand-related infrastructure costs are recovered through volumetric rates. Under a volumetric rate structure, the more energy that a customer conserves or self-supplies, the less they contribute to pay for the fixed and demand-related costs of the electric system – a system they still use. These costs are ultimately reallocated to other customers in the context of a rate case (this phenomenon is sometimes referred to as a "cost shift" between program participants and non-participants). This rate structure is unsustainable because it creates a hidden subsidy for any behind-the-meter resource – a subsidy that must be remedied so that those who cannot or do not want to conserve or self-supply energy are not paying for others' use of the electric system. Addressing this issue through rate design will address the cost-shift and allow all emerging behind-the-meter technologies to compete with each other on equal footing.

The rates established for commercial and industrial customers better recover fixed and demand-related costs through fixed and demand charges, and therefore do not have the same "cost-shift" impact for behind-the-meter technologies described above. However, there are other concerns with today's commercial rate designs that should be addressed. Commercial and industrial customers are typically placed on a rate schedule based strictly on their load size. While APS offers TOU rates for business customers, adoption rates are low because many businesses are unable for business reasons to curtail their usage during peak hours.

B. APS's Long History with Residential Demand Charges and Other Innovative Rate Designs

While there have only been a few opportunities in the history of the electric utility industry for major evolution in rate design, interestingly, APS has been at the cutting edge of innovation. In the 1970s, when the wider acceptance of residential home central air conditioning occurred, APS saw a significant increase in its peak demand. As a result, in August of 1977, APS filed a proposed "Electric Capacity – 1" rate ("EC-1"), for residential customers. This rate had three components: a basic service charge, which recovered costs associated with metering, meter-reading, billing and the service line to the home; a kWh energy charge that recovered fuel costs, as well as a small portion of the generation, transmission and distribution-related fixed infrastructure costs; and a demand charge that recovered fixed infrastructure costs based on the number of kW used during the highest hour of demand in the customer's billing period.

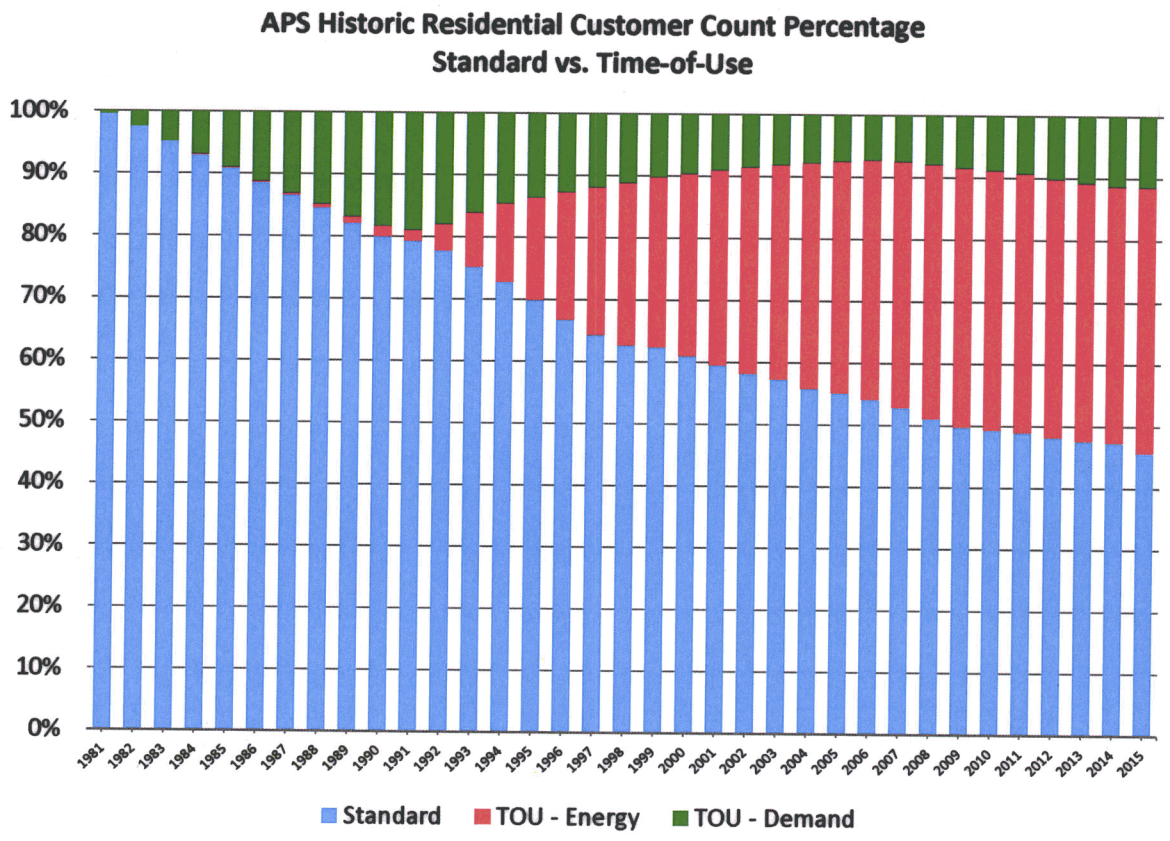
The Order adopting the residential three-part rate[1] stated that a residential rate based primarily on each customer's electricity consumption "ignores the fact that the cost of providing electric service is increasingly a function [of] the demand for electricity place[d] on the system rather than the total power consumed."[2] The Commission further recognized that including a demand component in the residential customers' bills would provide "an incentive to customers to manage their electric load in a manner that can result in lower electric bills for the individual customers." "Equally important," the Commission reasoned, if customers were to modify their behavior in response to the price signals sent by a demand charge, the utility could see a reduction in peak demand "which can have the effect of

[1] ACC Decision No. 51472, October 21, 1980.
[2] *See id.* at Finding of Fact 1.

reducing the need for expensive additional generating facilities."[3] For those reasons, the Commission approved the residential demand rate as mandatory for all new customers with central air conditioning and optional for existing customers.

As a result of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"), APS proposed a rate called ECT-1 as a TOU version of the EC-1 rate. In turn, the ACC Staff proposed a TOU energy rate called ET-1. Both ET-1 and ECT-1 were approved by the ACC in November 1981 as pilot programs limited to 1,000 customers each. APS's current inclining block rate, E-12 was first approved in July of 1983, at which time, EC-1 became optional. *See Figure 1*, which depicts APS's residential customer participation rates by three rate schedule categories from 1981 through 2014 and provides a visual snapshot of how quickly customers adopted TOU rates and rate schedules with demand charges. APS presently has the highest participation levels in the nation for residential TOU at approximately 53% and demand rates at approximately 11%.

Figure 1



C. With Advancements in Distributed Technologies, Modernizing Rate Design is Essential

[3] See *id.* at Finding of Fact 3.

Undoubtedly, air conditioning transformed the desert's energy landscape. Arizona has grown tremendously since 1980. APS's customer base has grown by approximately 290 percent, and residential demand today has increased 370 percent from 1980. Similar to air conditioning at the tail of the last century, today's new technology innovations installed on the customer's side of the electric meter have changed not only how people use electricity, but how they use the electric grid, making the residential demand rate a more important regulatory tool than ever.

Historically, power flow moved in one direction, from the utility to customers. Since customers purchased all of their electric energy needs from the utility, a consumption-based rate was generally workable: when everyone buys all of their electricity needs from the utility, the difference between the energy product sold and the grid services provided is generally unimportant. The utility can pro-rate the cost of the grid services into the energy product and come out even financially. Thus, while rates with a demand feature would more precisely assign cost responsibility to the cost causer, they were not essential to promote an economically efficient transaction.

Today, however, advancements in customer-sided technology, such as rooftop solar systems, have turned customers into what some in the industry are calling "prosumers" – individuals who both produce and consume energy.[4] As a result, the electric grid has evolved to a system of two-way power flow: customers take energy from the system at times, and send it back at others. Given this fundamental change in how the system operates, the difference between the energy product that the utility sells and the grid services it provides has become critical. Customers with behind-the-meter generation may not always rely on the utility for electricity supply, but they still require grid services every hour of every day of the year. The intermittency of customer-sided distributed generation and the dynamic nature of two-directional power flow makes managing the electric system physics more challenging than ever for the utility. In many cases it also requires additional operational attention and grid infrastructure support in order to keep the lights on and power quality high.

While the way customers use the energy product and grid services has changed, rate design generally has not. Rates are still based on the amount of electricity that customers purchase from the utility, with no consideration paid to the grid services that the utility provides. Most of what it takes today to provide reliable electric service to customers depends on utility infrastructure such as poles, wires, transformers and power plants. On the other hand, the bulk of a customer's electric bill reflects how much of the energy product they bought, which is generally a function of the fuel cost to produce the energy.

Today, almost 70 percent of the costs to serve APS's residential customers are fixed and demand-related infrastructure costs – the cost of its reliability service. Only about 30 percent of those costs are driven by the cost of generating energy. On the other hand, only 10 percent of a customer's bill pays for service-related fixed and demand-related infrastructure. A full 90 percent of the bill is based on the amount of the energy product a customer purchases. Put another way, if a customer does not buy the utility's product, they do not pay for the grid services – even though they continue to use them. *See* Figure 2.

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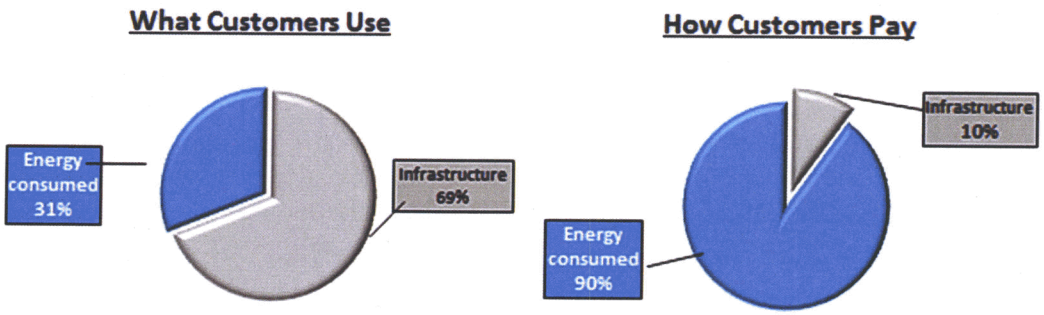
[4] *See, e.g.,* Hertzog, Christina, "What Is Prosumer Value to the Utilities?," March 3, 2014. Found at http://www.theenergycollective.com/christine-hertzog/2200061/what-prosumer-value-utilities.

Figure 2



- Most of what it takes to provide reliable electric service to customers depends on utility infrastructure
- But most of the customer's bill reflects how much of the energy product they bought

The lack of alignment between costs and charges in an era of distributed generation causes problems for customers and utilities alike, an issue that has been the subject of several regulatory decisions and industry publications.[5] The issue, however, is not one of intentional cost-avoidance. It is fundamentally a pricing problem. Utility rate design must evolve to reflect the distinction between the utility's energy product and grid services, so that customers pay for what they use.

RATE REFORM OBJECTIVES

APS currently serves over one million residential customers with a variety of rate schedules and options including an inclining block rate, two time-of-use energy rates, two TOU demand rates, a super peak TOU rate, two dynamic rate options, and a TOU rate for electric vehicles. Optional rider rates are available for special requirements or services such as on site renewable generation, green power, limited income and medical equipment discounts, and other specialized or experimental programs. It is imperative that APS adopts new rate designs that incent rational adoption of technologies by providing accurate price signals for incenting how and when customers use electricity. These rate designs need to accurately reflect the types of services provided by the utility and the costs for those services and provide opportunities for customers to save on their bill without shifting costs to other customers. All of these factors will result in the improved use of and funding for the electrical grid.

Residential rates and costs are currently misaligned because they rely on volumetric kWh energy charges to recover grid investment costs – wires, poles, transformers, and

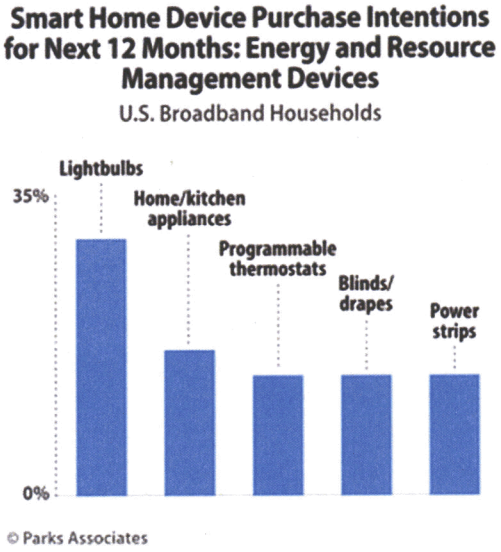
[5] *See, e.g.*, David B. Raskin, *The Regulatory Challenge of Distributed Generation*, 4 HARV. BUS. L. REV. ONLINE 38 (2013); Ashley Brown and Jillian Bunyan, *Valuation of Distributed Solar: A Qualitative View*, The Electricity Journal, Vol. 27 (December 2014); Ryan Hledik, *Rediscovering Residential Demand Charges*, The Electricity Journal, Vol. 27 (July 2014).

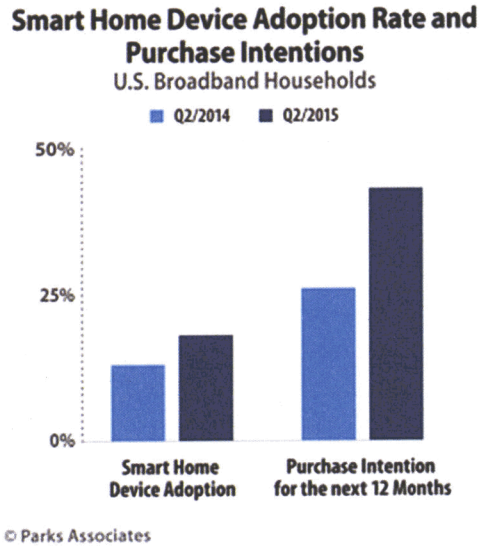
generating plants, which are by far the predominant cost to serve residential customers. In contrast, most non-residential customers like businesses, schools, colleges, hospitals and government buildings use kW demand charges or monthly service charges to recover these grid costs.

Customers today have meaningful opportunities to invest in distributed generation, energy storage, electric vehicles, smart thermostats and appliances, home energy controls, advanced HVAC systems and other new technologies. In addition, the wide spread adoption of AMI has allowed significant flexibility in residential rate designs and energy usage information to be integrated with home controls and smart appliances.

Adoption of new technologies

Parks Associates consumer research found that in the 4Q of 2015, 19% of US broadband households owned a smart home device, many of which offer energy management capabilities and associated value-added services[6]. Connected products and services are being sold through multiple channels and companies, using different business models to win consumer interest. Consumers are gaining familiarity with smart home devices, which drives adoption. The smart appliances and smart home devices/services sector is one of the fastest growing markets in the United States.





Smart energy devices include smart thermostats, smart light bulbs, smart plugs/adapter modules, home energy controls, advanced HVAC systems and much more. Ownership of all smart home products, as well as the number of products owned per household, will continue to increase at a rapid pace every year. For example, Parks Associates found that over 40% of US broadband households planned to buy at least 1 of these devices within 12 months of when they were surveyed[7]. Both owners and intenders showed interest in energy

[6] *See* Tom Kerber, *Smart Homes Open Their Doors to Utilities*, ITC Solutions and Education, (April 2016).
[7] *Id.*

management capabilities. US consumers are increasingly aware of the value of reducing home energy use. APS plans to modernize its rates to accommodate and encourage the adoption of new technologies.

To meet the changing customer needs and modernize rates, APS developed four overarching objectives to guide the rate transformation. They are:

1. **Modernize rates to enable new technologies and reflect the continued value of the electricity delivery system.**

   APS's rates should be functional regardless of the existence or type of technology employed by customers. The recent rapid increased adoption of photovoltaic generation by APS customers has demonstrated the kind of problems that arise when rates are not appropriately designed to be indifferent or neutral to customer technologies – a cost shift between customers occurs. Creating sustainable rates that can adapt to new technologies will (1) send better and appropriate price information to customers who, now or in the future, may employ these technologies, and (2) allow those customers who do not participate to avoid bearing the burden of those unrecovered fixed and demand-related costs. Further, a universal approach to rate design will provide better price information to all residential customers regardless of whether they participate in energy efficiency or install a behind-the-meter technology.

2. **Improve rate fairness among customers by aligning rates with the cost of service, thereby minimizing/eliminating embedded subsidies.**

   Currently, the manner in which APS incurs costs to serve its discrete customer classes does not align with how it charges those costs to customers. For example, fixed or demand related costs that have little variation with monthly energy consumption should be recovered through fixed basic service charges or demand charges. Likewise, volumetric kWh charges should recover variable costs that proportionally change with the volume of energy consumed (an example of this type of costs is fuel). A misalignment of costs and cost recovery creates several key problems, such as customer inequity in who pays for the costs of service, improper price information for customers, the need for more frequent rate cases, and upward pressure on average prices over time. The modernized rates should revise pricing designs to better align the charge types with cost drivers and increase the recovery of fixed and demand related costs with fixed or demand-type, non-energy based charges.

   In addition, embedded subsidies in rate structures should generally be eliminated to provide greater pricing transparency. Some subsidies result from using volumetric pricing to recover fixed costs, while others result from political or social considerations (such as limited income discounts). Regardless of the reason for their existence, subsidies should be able to be evaluated to determine whether they should be modified or not. To do so, rates need to better align prices with the cost to serve so as to make any remaining subsidies transparent, well understood, and driven by clear policy objectives.

3. **Provide rate gradualism and bill stability for customers by managing the overall rate levels and thoughtfully transitioning to new rate designs.**

   APS believes it is important to provide consumer education on new rate offerings and implement universal residential demand rate offerings in a gradual way to help customers transition more seamlessly. APS will evaluate the impact of rate changes that will result from new designs, and if customer usage patterns remain the same. In particular, we will evaluate where changes result in large impacts, absent any changes in customer usage patterns.

4. **Enhancing customer satisfaction by providing fewer but more meaningful rate choices, simplifying rate schedules and bill presentation.**

   APS currently has a wide variety of offerings– so much so that it is often difficult for a customer to discern which rate is the best option. APS strives to provide meaningful rate choices to our customers. We want to condense the number of rate offerings and revive the simplified bill presentation filed with the Commission to make the options and calculation of a rate more customer-centric and understandable. APS analyzes these rates through a variety of different criteria including whether the rates have significant flaws, unintended consequences and customer adoption levels. If APS determines that a rate should be discontinued, APS evaluates the customer impact and creates a thoughtful transition plan. Finally, APS continuously strives to make the bill and rate schedules more user-friendly and comprehensible.

KEY RATE PLAN INITIATIVES

Residential Class

APS is continuously evaluating whether current rate options are meaningful to our customers. APS believes that there is a need for modern rates that provide customers more options to control and manage how they use energy. These modern rates will be more reflective of APS's costs, and also provide customers more meaningful information and options geared towards customers' lifestyles. APS will continue to emphasize time-of-use (TOU) rate options and plans on proposing universal three-part rates, which include an additional way to measure and charge for infrastructure costs, using the customer's maximum measured use in a single on-peak hour (commonly referred to as kW demand) to determine a portion of the bill. The rate reforms proposed will impact each of the Company' existing residential rates and be accompanied by a transition plan that identifies how APS would implement this proposal in a thoughtful way, mindful of customer education and how a new rate design would impact various customers.

All things being equal, the modern rate design is revenue neutral to the Company. It is important to note that as a demand charge is introduced, the energy charges will be correspondingly decreased. As part of the thoughtful transition, APS will evaluate how the structure change will impact its residential customers and implement the transition over a period of time. A transition to more sophisticated pricing is attainable, but will require careful planning. For example, pricing options could include a default pricing option that gradually changes to become more sophisticated over time, while providing alternative pricing structures that are more or less sophisticated than the default for customers who

want or need such choices. The type of rate offerings should match the evolving needs and interests of our customers. As the interest to be more efficient with energy usage and adoption of technologies has grown, the type of rate offerings must also change.

Moving Away from Volumetric Pricing

The majority of residential customers currently receive a bill that is primarily determined through a per-kWh energy consumption charge, along with a small fixed charge per month. This approach has worked fairly well until now. We could make needed grid investments and recover our costs, and customers benefited from stable bills while being incentivized to conserve energy. However, the reality is that the cost of energy and all the associated attributes do significantly vary by time, location and other dimensions not reflected in bundled, volumetric, block pricing. As the needs of our customers change and the adoption of distributed energy resources increases, it becomes imperative for us to send clear signals and incentives to customers so they know how to align technological deployment with maximizing grid value. Customers are becoming increasingly individualized, depending on whether they have rooftop solar, on-site storage, an electric vehicle, smart thermostats, or other technologies. These technologies change the way the customer uses the grid and may require varied energy, capacity and ancillary services than a customer without those technologies. Those differences are not reflected in block, volumetric rates.

Inclining Block is a rate design that is intended to encourage customer conservation of energy by increasing the energy price associated with successive blocks of monthly energy consumption. Inclining Block rates for APS customers was first established in 1983. At the time, the Commission wanted to encourage conservation. This was during a period without the advantage of AMI meters, and inclining block was a rate option that helped boost conservation. However, now that AMI meters are wide spread, APS must re-evaluate whether inclining block is still a good rate option.

Inclining block does not send the proper price signals since it punishes a customer for using more energy but does not distinguish when the customer is using that energy. For example, if a customer was to use very little energy during the peak when energy prices are high, and uses a large amount during the nighttime when energy prices are low, if the overall amount of energy is high, the customer is penalized for using a lot of energy in total. On the other hand if another customer used very little total energy, but used all of that energy during peak times, that customer would be underpaying their fair share of the cost of maintaining, upgrading and expanding the utility's fixed infrastructure.

Inclining block is an outdated rate design and although it may have been appropriate during a time where advanced metering was cost prohibitive or unavailable, there are rate design options available to better incentivize conservation and properly align costs. APS plans on eliminating the use of inclining block rates in the near future. Moving away from block volumetric pricing will allow APS to more efficiently incentivize the adoption of distributed energy resources in various combinations (ie. solar paired with storage) to deliver a broader and more valuable set of attributes to the grid.

Focusing on Time Varying Pricing

Time varying pricing can help to communicate to retail customers the higher costs of energy demands during periods when the costs of energy, capacity, and system losses are greatest. It helps promote economically efficient behavior by allowing customers to decide whether they would prefer to pay the high costs of on-peak consumption or to reduce or defer consumption when the value of electricity to the customer is less than the capital and operating costs of additional electricity production and delivery.

Time-of-Use is a rate design that varies the customer energy price by the time of day. Typical time periods are designated as on-peak or off-peak, with higher prices set for on-peak time periods. TOU pricing and time period definitions may also vary seasonally. Shoulder or super-peak time periods may also be defined and priced separately. APS currently has eight TOU rate options available for our customers to choose from. This includes two frozen rates and various rates with differing peak hours with and without demand components.

APS plans on streamlining the TOU rate options and revise on/off peak price differences to better match costs. The number of TOU rate offerings should be reduced to be more cohesive and to provide more meaningful choices to customers. APS continues to evaluate how best to match APS' coincident system and non-coincident residential class peak demands

Two-part TOU rates are better than inclining block rates but still do not properly align costs. Infrastructure costs do not vary with electricity consumption and cannot be recovered adequately through a volumetric rate such as TOU. The consequence of fixed charges being collected through volumetric rates creates an inevitable cost shift from customers with lower load factors to customers with higher load factors. With a lower load factor, customers paying for electricity under a volumetric rate design contribute less to the electric grid's fixed costs. Customers with high load factors wind up paying more under a volumetric rate design for comparable service. Additionally, two-part TOU rates would not incent the type of technology or electrical appliance choices that are focused on reducing the home's electrical infrastructure requirements. Therefore, from a cost causation standpoint, the most efficient way to represent kilowatt based costs is through a kilowatt based charge, such as a demand charge.

A Necessary Move Toward Three-Part Rates

Fixed costs, such as metering, billing and customer service, should be collected through a fixed monthly service charge. Demand-driven costs, such as capacity costs, should be collected through a demand charge. Lastly, variable costs, such as fuel and power grid operations and maintenance, should be collected through a variable charge (as known as an energy charge). The demand charge should be designed to cover demand driven costs, such as transmission, distribution and generation capacity. It is typically applied to an individual customer's maximum demand during a defined on peak period. Three-part rates properly align the rate design with costs.

A more cost reflective rate design will also encourage the adoption of emerging energy technologies and changes in energy consumption behavior that will lead to more efficient use of power grid infrastructure and resources. Three-part rates would provide customers with a price signal that includes a component for demand and encourage the adoption of technologies that are designed to smooth out a customer's load profile. Load control technologies, such as programmable communicating thermostats, demand limiters, and smart appliances could help customers manage their electricity demand.

Although there are theoretical arguments that would support measuring demand over shorter time intervals and also distinguishing non-coincident demand from coincident demand, these refinements to the traditional three-part rate are probably not well-suited for residential customers. Thus, APS plans to continue its historical practice with demand rates of using a one-hour time period for measuring demand (more lenient in contrast to the 15 minute period used for business customers) and measuring the demand only in the on-peak time period. This would provide a significant number of hours, including weekends, that are off-peak and would not create a billing demand. Also, as a transition mechanism, APS plans

on proposing an extra-small residential customer rate and a minimum load factor provision for very low load factor customers. As customers become increasingly accustomed to three-part rates, more sophisticated rate structures could be created to further maximize a customer's control over their bill.

APS has found that customers can and do manage demand. Some customers maximize their experience and bill savings by actively managing their demand through investments in home energy controls, efficient appliances, HVAC systems and other devices. Others are generally aware of the new charge on their bill and try to reduce it by changing their energy usage behavior and patterns, such as avoiding using major appliances at the same time to lower the home's maximum electrical draw. There are some customers who are not interested in any of the specific components of the electric bill and are only concerned that the total seems to be reasonable. However, all of these customers have the opportunity to save on their bill under a demand rate.

Encouraging Customer Adoption of Demand Response

Demand response is a reduction in demand designed to reduce peak demand or avoid system emergencies. Current demand response programs use dedicated control systems to shed loads in response to a request by a utility. Services are reduced according to a preplanned load prioritization scheme during the critical time frames. Under conditions of tight electricity supply, demand response can significantly decrease the peak price.

Technologies are available, and more are under development, to automate the process of demand response. Such technologies detect the need for load shedding, communicate the demand to participating users, automate load shedding, and verify compliance with demand-response programs. The process may involve turning down or off certain appliances during periods of high demand. For example, a thermostat may be turned up, delaying the energy draw by an air conditioning unit until a peak in usage has passed. The success of such programs depends on the development of appropriate technology, a suitable pricing system for electricity and the cost of the underlying technology.

Promoting Conservation through Decoupling

The purpose of a decoupling mechanism is to reduce the variability in the customer's bills and at the same time provide a consistent stream of revenue to the utility. Decoupling ensures that customers only pay what the Commission agrees they should pay in the rate case, no more, no less. A full revenue per customer decoupling mechanism is most appropriate because it aligns the customers' and the Company's interests by updating customer billing determinants annually in a simple and straightforward manner. Full revenue per customer decoupling properly removes the link between volumetric sales and revenue collection, thus eliminating the disincentive associated with implementing energy efficiency or rooftop solar programs and instead allows a utility to willing engage in and promote them. Additionally, full revenue per customer decoupling enables a utility to collect its authorized allowed cost of service associated with both existing and future customers regardless of sales levels.

APS wants to both encourage and promote customer energy efficiency and conservation through established programs and transparency in the new rates, which would benefit the customer by allowing them to manage their bills. Revenue decoupling would encourage the company to manage costs as actual profits recognized by the Company are directly linked to the ability of APS to reduce costs. The Lost Fixed Cost Recovery Mechanism accomplishes similar goals to decoupling but limits recovery to only sales reductions resulting from demand side management and distributed generation. Full revenue decoupling would take

into account all fluctuations in sales, regardless of the cause. Unlike full revenue decoupling, the LFCR will never result in a reduction to customer bills.

Customer Education of Rate Offerings

APS believes that it is important to educate customers about all components of their bill, how the bill is calculated and the actions they can take to save and mitigate potential impacts from rate changes. For example, this education can emphasize that under a three-part time-of-use rate, the customer would have three ways to save on their bill. Customer education would also focus on the use of modern technologies such as home energy monitors and controls, smart thermostats, advanced air conditioners, battery storage and smart inverters. These devices help manage and reduce peak usage, thus allowing customers to better manage and reduce their bills.

Business Class

APS's commercial rate structures for customers are for the most part well-balanced from a cost-causation and charge alignment perspective. Therefore, APS's plan is to focus on developing more tailored options for commercial customers to provide them with greater control of their energy management and potentially lower their bills. APS plans on revising its commercial TOU rates to be more accessible, by reducing the defined on-peak time period definition to be more in step with today's system and class peaks.

In addition to tracking cost causation, an important consideration for business customers is the overall competitiveness of APS rates as compared with utilities serving other parts of the state or the country. APS needs to keep this factor in mind in creating a menu of general service rates that not only reflect cost of service but provide comparative value to business customers. As the needs of our business customers change, we look to create rate options that would be beneficial to our business customers and provide meaningful and cost-effective options from which to choose.

APS AG-1 PROGRAM EVALUATION

aps®

Arizona Public Service
Alternative Generation Program Evaluation
June 1, 2016

Key Findings and Recommendations

- The Alternative Generation Program (AG-1) has resulted in significant financial losses from its inception in 2012. Overall loses through 2015 are in excess of $24 million. This figure will grow as a result of the program being extended through APS's current rate case.

- The losses result from program participants still relying on, but only partially paying for, APS generation. Participants rely on APS for load following service, back-up service, and a long term option to hedge against rising wholesale prices. Furthermore, participating customers are not interruptible, or in some cases even capable of being interrupted if their provider fails to deliver power, which makes it difficult for APS to remove them from long-term generation capacity requirements.

- Although wholesale sales were intended to blunt losses, wholesale margins in Arizona have been low relative to APS's retail margins that fund existing generation capacity costs.

- Program operations such as power scheduling, settlements, information exchanges and billing were generally successful. Improvements could be made to these operations, including more automation.

- The energy imbalance protocols rely on an existing wholesale arrangement, which is not adequate for a retail program.

- Because of the adverse financial impacts, APS recommends that the program not be renewed.

- If the program is renewed, it must be substantially revised to address the issues detailed in this report.

Background

The experimental AG-1 program was approved by the Arizona Corporation Commission in Decision No. 73183, as part of the Settlement Agreement in APS's last general rate case. The program was limited to 200 MW of load for large and extra-large customers with aggregate accounts of 10 MW or more. It was originally set to terminate on June 30, 2016, but was extended until APS's next general rate case by Decision No. 75322.

As required by the Settlement Agreement, APS must evaluate the pilot program and now files this report with its findings and a recommendation regarding the future of AG-1.

Program Concept and Participation

The AG-1 program allows customers to obtain generation services from a third party generation service provider (GSP) under negotiated prices, while continuing to receive all other services, such as transmission, local delivery, metering and billing, from APS under their normal tariffed rate. The GSP is required to schedule and deliver the power necessary to meet the customer's load and settle with APS each month for any hourly deviations between load and power supply. The GSP sells the power to APS and indicates what amount APS should pass through to each APS customer.

To help mitigate financial impacts from the program, the AG-1 program permits APS to retain a portion of the margins from short-term wholesale sales equal to a pro-rata share of the displaced retail sales from the program in comparison to the total short-term wholesale sales volume.

The program has eight participating customers, which were selected by lottery, and five GSPs.

Program Evaluation Objectives

The program evaluation assessed the financial impacts of the program, as well as the key operational aspects, including power scheduling, settlements of imbalances, information exchanged, and billing. It also evaluates the overall program concept to develop a recommendation regarding the program's future.

The program losses also result from program participants still relying on, but not fully paying for, APS generation services. For example, participants rely on APS generation for load following and back-up service. The cost of providing these services exceeds the revenue resulting from the program's capacity reserve and energy imbalance charges.

In addition, APS must continue to include AG-1 customers in APS's generation supply planning requirements. This is necessary for two reasons:1) AG-1 customers can return to APS's generation service within one year with a six month notice, meaning participants can rely on APS generation as a long-term option in case wholesale prices increase above APS's costs, which requires APS to plan their generation resources to accommodate this potential; and 2), the participating customer's load is not interruptible if their GSP fails to deliver power at any time. As a result, APS is on call to serve participants load if their GSPs fail to deliver.

Power Scheduling and Delivery

The GSPs provide hourly schedules for their portfolio of customers on a monthly basis to APS, who serves as the schedule coordinator. They also have the flexibility to provide day-ahead hourly deviations to this schedule. The GSP also provides physical path information and other details necessary for the power scheduling.

Overall, the power scheduling process for the program has worked satisfactorily during the experimental period.

Load Following

GSPs are required to provide generation service for the total load of their customer, including the hourly deviations as the load ramps up and down over the day, month, and year. This appears to be difficult for most, if not all, GSPs, because they may not own or control generating plants capable of ramping up and down to meet the customer hourly load or do not have real-time controls in place to provide this service. GSPs have relied on standard, traded energy products that are set blocks of power over a month, quarter, or year. These blocks do not vary hour by hour, except that they may be available for certain on-peak and off-peak periods. Therefore, it is impossible to follow the customer's load with this type of supply arrangement. Some GSPs have scheduled on-peak and off-peak blocks that better match a customer's typical daily load profile and some have varied any block purchases by month according to the customers expected seasonal loads.

Some GSPs have made better attempts to match supply with load than others. However, no GSP has followed the retail load profile of their customers. This aspect of the program has not been successful.

Imbalance and Settlements

The energy imbalance process addresses the payment and penalties for the deviations between hourly scheduled energy and the customer's actual hourly load for each GSP's portfolio of customers they serve. As indicated in the load following discussion, energy imbalance occurs in virtually every hour, because GSPs are not matching supply to load on a real-time basis. These deviations are settled each month based on an index of wholesale market transaction prices in Arizona. If the deviations are large enough certain penalties may also apply.

While the settlement process has been generally successful, the specific protocols have not. The current protocols were designed for large wholesale block transactions and therefore are not adequate for smaller retail transactions with varying hourly loads. The current wholesale protocol has proven to be inappropriate for retail load following transactions and does not track the cost of actually providing the retail service. A retail energy imbalance protocol would be required to appropriately reflect imbalance costs and to provide meaningful incentives to GSPs to schedule accurately. In addition, the protocols, the settlement systems, while adequate for the limited AG-1 program, would have to be more automated to accommodate a larger program.

Billing

APS performs the customer billing for both the GSP's generation charges and APS's retail rates for transmission, local delivery and other relevant services. The customer's payment for generation is subsequently remitted to the GSP.

The customer billing process has been successful.

Data Exchanges

Information exchanges and processes, especially for settlements and billing have been successful.

Recommendation

Based on the evaluation of the experimental AG-1 program, APS recommends that the program not be renewed. The AG-1 program has resulted in significant financial impacts for APS and is not sustainable in its current form without shifting costs to non-participating customers.

If the ACC were to renew the program, the program would require significant revisions. These include:

- The Capacity Reserve Charge should apply to 100% of the customer's load, rather than 15%.
- Increase the program management fee so that it sufficiently covers incremental program operating costs and the cost of any new required logistical systems.
- Retain the current mitigation of sharing in short-term wholesale sales margins resulting from displaced AG-1 retail sales.
- Create a new retail energy imbalance protocol suitable for retail transactions.
- Program participation would still need to be capped at the current level of 200 MW with a 10 MW minimum per customer group.

DIRECT TESTIMONY OF AHMAD FARUQUI

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF AHMAD FARUQUI
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Ahmad Faruqui. I am a Principal with The Brattle Group. My business address is 201 Mission Street, Suite 2800, San Francisco, California 94105. I am filing testimony on behalf of Arizona Public Service Company (APS or Company).

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I have 40 years of academic, consulting and research experience as an energy economist. During my career, I have advised 135 clients in the energy industry, including utilities, regulatory commissions, government agencies, transmission system operators, private energy companies, equipment manufacturers, and IT companies. Besides the U.S., my clients have been located in Australia, Canada, Chile, Egypt, Hong Kong, Jamaica, Philippines, Saudi Arabia, South Africa, and Vietnam. I have advised them on a wide range of issues including rate design, load forecasting, demand response, energy efficiency, distributed energy resources, cost-benefit analysis of emerging technologies, integration of retail and wholesale markets, and integrated resource planning. I have testified or appeared before several state, provincial and federal regulatory commissions and legislative bodies. I have been an invited speaker at major energy conferences in Africa, Asia, Australia, Europe, North America and South America. Finally, I have authored, co-authored or co-edited more than 150 articles, books, editorials, papers and reports on various facets of energy economics. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Attachment AJF-1DR.

Q. WHAT ARE YOUR RESPONSIBILITIES AS A PRINCIPAL WITH THE BRATTLE GROUP?

A. I lead the firm's practice in helping clients understand and manage the changing needs of energy consumers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. Yes. I testified in the UNS Electric rate case on the 18th of March, 2016. I have also spoken at a technical workshop before the Commission on the 20th of March, 2014. My presentation discussed the impact of changing customer energy use patterns on utilities. The workshop was entitled, "In the Matter of the Commission's Inquiry into Potential Impacts to the Current Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy."[1]

II. OVERVIEW AND ORGANIZATION OF TESTIMONY

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

A. The purpose of my direct testimony is to comment on the merits of APS's proposal to make demand charges a standard rate feature of the residential rate. The scope of my testimony is focused on the structure, advantages, and rationale for three-part rates. I do not address the specific prices that are being proposed or other rate options that have been proposed.

[1] Docket No. E-00000J-13-0375, Substantive Workshop No. 1(a) Special Open Meeting, March 20, 2014.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony begins with a discussion of ratemaking principles and the necessity of replacing two-part rates with three-part rates. An overriding principle of electric rate design is that of cost causation, i.e., the structure of rates should follow the structure of costs. For a variety of reasons, the standard residential rate design in the United States has not followed this basic precept. A very large share of utility costs is fixed. Of the remainder, some vary with peak demand and some vary with energy consumption. Yet most of the fixed and demand-driven costs are recovered through volumetric rates (expressed in cents/kWh). It is possible that in response to rising energy prices, some customers might reduce the volume of electricity they consume but not reduce the demand they place on the grid, since they never see a price for demand. Consequently, much of the fixed costs required to meet their demand would go unpaid. The net result is that cost-causers would not pay for all of the costs they create. Those unrecovered costs would be shifted to customers who use more volume, creating inequities and cross subsidies between customers.

The cost shift from lower load factor customers to higher load factor customers is a structural inefficiency that can be ameliorated through a rate design that includes three parts: a fixed charge, a demand charge, and a volumetric charge. With a three-part rate design, customers would more efficiently use the electric grid in a way that would also reduce the cost shift. In addition, demand rates would provide a price signal that would incentivize the introduction of technologies that reduce demand. If policy-makers wish to encourage innovative distributed technologies, demand rates offer an efficient and equitable method of doing so.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into several sections. Section III reviews the principles of rate design and the advantages of three-part rates. Section IV summarizes APS's rate design proposal and evaluates the proposal in light of the generally accepted ratemaking principles and the opportunities offered by three-part rates. Section V concludes the testimony.

Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY?

A. Yes, I sponsor the following attachments to my testimony:

- Attachment AJF-1DR: Statement of Qualifications
- Attachment AJF-2DR: Summary of Residential Demand Rates
- Attachment AJF-3DR: Illustrative Example of Cross-Subsidy

III. PRINCIPLES OF RATE DESIGN

Q. PLEASE PROVIDE A HISTORICAL PERSPECTIVE ON THE THEORY OF ELECTRIC RATE DESIGN.

A. The principles that guide electric rate design have evolved over time. Many authorities have contributed to their development, beginning with the legendary British rate engineer John Hopkinson in the late 1800's.[2] Hopkinson introduced demand charges into electricity rates. Subsequently, Henry L. Doherty proposed a three-part tariff, consisting of a fixed service charge, a demand charge and an energy charge.[3] The demand charge was based on the maximum level of demand which occurred during the

[2] John R. Hopkinson, "On the Cost of Electricity Supply," *Transactions of the Junior Engineering Society*, Vol. 3, No. 1 (1892), pp.1-14

[3] Henry L. Doherty, *Equitable, Uniform and Competitive Rates,* Proceedings of the National Electric Light Association (1900), pp.291-321

billing period. Some versions of the three-part tariff also feature seasonal or time-of-use (TOU) variation corresponding to the variations in the costs of energy supply.[4]

In the decades that followed, a number of British, French and U.S. economists and engineers made further enhancements to the original three-part rate design.[5] In 1961, Professor James C. Bonbright coalesced their thinking in his canon, *Principles of Public Utility Rates*,[6] which was reissued in its second edition in 1988.[7] Some of these ideas were further expanded upon by Professor Alfred Kahn in his treatise, *The Economics of Regulation*.[8]

Q. WHAT ARE THE GENERALLY ACCEPTED RATE DESIGN PRINCIPLES?

A. In the first edition of his text, Bonbright propounded eight principles which were expanded into ten principles in the second edition. These are almost universally cited in rate proceedings throughout the U.S. and are often used as a foundation for designing rates. For ease of exposition, I have grouped these into five core principles:

1. Economic Efficiency. The price of electricity should convey to the customer the cost of producing it, ensuring that resources consumed in the production and delivery of electricity are not wasted. If the price is set equal to the cost of providing a kWh, customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the development and adoption of energy technologies that are capable

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[4] *See*, for example, Michael Veall, "Industrial Electricity Demand and the Hopkinson Rate: An Application of the Extreme Value Distribution," *Bell Journal of Economics*, Vol. 14, Issue No. 2 (1983).

[5] The most notable names include Maurice Allais, Marcel Boiteux, Douglas J. Bolton, Ronald Coase, Jules Dupuit, Harold Hotelling, Henrik Houthakker, W. Arthur Lewis, I. M. D. Little, James Meade, Peter Steiner and Ralph Turvey.

[6] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition.

[7] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, 2nd ed. (Arlington, VA: Public Utility Reports, 1988).

[8] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, rev. ed. (MIT Press, June 1988).

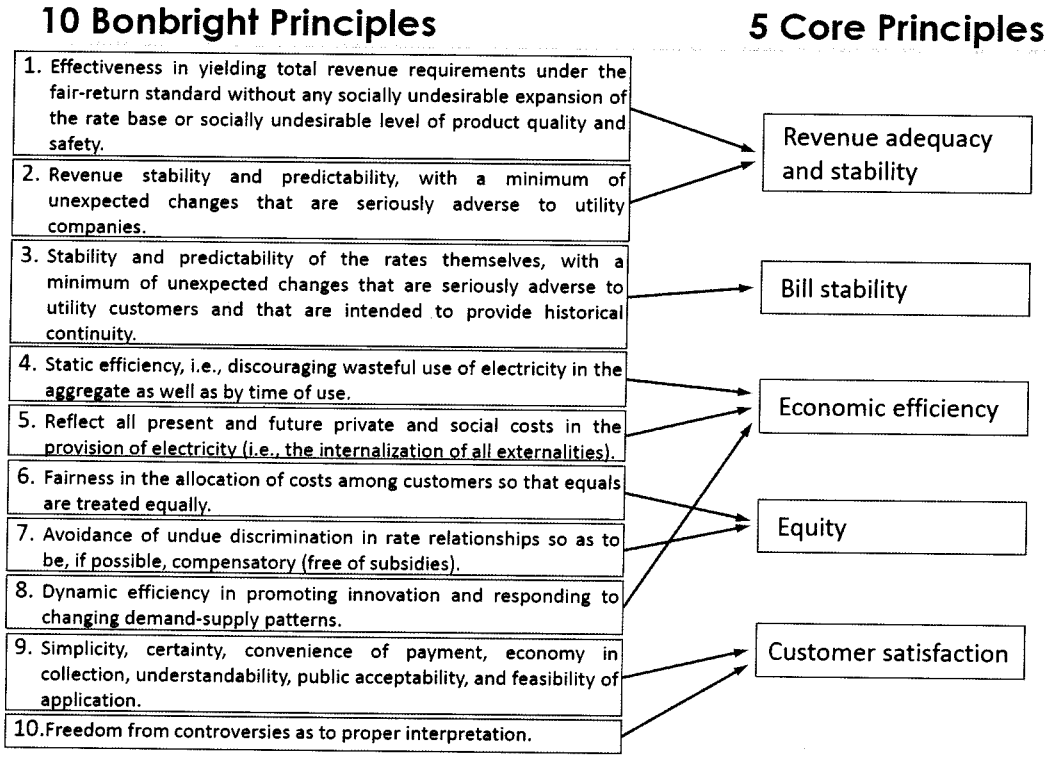
of providing the most valuable services to the power grid, and thus the greatest benefit to electric customers as a whole.

2. Equity. There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat rate pricing structures (*i.e.*, cents/kWh). Since customers have different load profiles, "peaky" customers, who use more electricity when it is most expensive, are subsidized by less "peaky" customers who overpay for cheaper off-peak electricity. Note that equity is not the same as social justice, which is related to inequities in socioeconomic status rather than cost. The pursuit of one is not necessarily the pursuit of the other, and vice versa.
3. Revenue adequacy and stability. Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective.
4. Bill stability. Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time. For example, if fixed infrastructure costs are spread over a certain number of kWh's in Year 1, and the number of kWh's halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure cost of the utility.

Customer satisfaction. Rates should enhance customer satisfaction. Because most residential customers devote relatively little time to reading their electric bills, rates need to be relatively simple so that customers can understand them and perhaps respond to

the rates by modifying their energy use patterns. Giving customers meaningful cost-reflective rate choices helps enhance customer satisfaction. Figure 1 illustrates my grouping of Bonbright's original ten principles.

Figure 1: Deriving the Five Core Principles of Rate Design



Q. DID PROFESSOR BONBRIGHT DISCUSS THE CONCEPT OF COST CAUSATION IN DESIGNING RATES?

A. Yes. In the first edition, an entire chapter is devoted to this topic. It is entitled: "Cost of Service as the Basic Standard of Reasonableness." In the chapter, he states: "One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or

prudently incurred."[9] Later, he states that "The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle of consumer sovereignty."[10] He also cites another benefit of the cost-price standard when he says that "an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to 'account' for this draft by the surrender of a cost-equivalent opportunity to use his cash income for the purchase of other things."[11] Later in Chapter XVI, where he discusses the "criteria of a sound rate structure," he says that a purely volumetric rate assumes that the total cost of the utility varies directly with the changes in the kWh output of energy. He calls this "a grossly false assumption" and says such a rate "violates the most widely accepted canon of fair pricing, the principle of service at cost." Later, while discussing the Hopkinson rate, he says that such a "rate distinguishes between the two most important cost functions of an electric-utility system: between those costs that vary with changes in the system's output of energy, and those costs that vary with plant capacity and hence with the maximum demands on the system (and subsystems) that the company must be prepared to meet in planning its construction program."[12]

Q. PLEASE DISCUSS FURTHER HOW THE CONCEPT OF COST CAUSATION FLOWS OUT OF THE BONBRIGHT PRINCIPLES.

A. The Bonbright principles of economic efficiency and equity in particular embody the concept of cost causation. Economic efficiency is achieved by having cost-reflective prices. This ensures that products are only consumed by those customers who value them at more than they cost to produce. Pricing below cost is wasteful because

[9] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition, Chapter IV, p. 67.
[10] Op. cit., p. 69.
[11] Op. cit., p. 70.
[12] Op. cit., p. 310.

customers will purchase and consume products that they would not choose to consume if faced with the full cost. Similarly, pricing above cost is wasteful because customers who would get a net benefit from consuming the product at its cost of production lose out on that benefit. Respecting the equity principle requires that the tariff's design not result in unintended cross-subsidies between customers. This differs from a public policy that seeks to intentionally subsidize certain customers through the tariff. Prices that are cost reflective minimize unintentional subsidies.

Q. GIVEN BONBRIGHT'S EMPHASIS ON COST CAUSATION, WHY DOES HIS FIFTH PRINCIPLE CALL FOR REFLECTING SOCIAL COSTS (OR EXTERNALITIES) IN ELECTRIC RATES?

A. Each of Professor Bonbright's principles should be read in conjunction with the others. Reading a single principle in isolation from the others ensures that it will be taken out of context, resulting in a misleading use of his rate design philosophy. The cost of service is Professor Bonbright's *basic standard* for designing rates, and it is clear from his writings that above all, rates should be cost-based. This is easily squared with the principle of reflecting social costs in the provision of electricity. If a price has been assigned to a certain externality, in other words, if it has been internalized, and that price is part of the utility's cost structure, then it is economically efficient to reflect the price of that externality in rates for all customers. However, it would violate the core principles of ratemaking if only certain customers or technologies were charged or compensated for their impact on those externalities. For instance, compensating owners of only one specific technology for reductions in emissions would lead to inefficient levels of investment in that technology when there may be other options which, if similarly compensated, would provide even greater environmental benefits. All technologies and customers should be on a level playing field when developing residential rate design.

Q. WHAT IS THE STANDARD RATE STRUCTURE FOR RESIDENTIAL CUSTOMERS?

A. The standard rate structure for residential customers in much of the U.S. consists of two parts, a monthly service charge and a volumetric (kilowatt-hour, or kWh) energy charge. Most of the revenue is collected from the volumetric charge. The monthly service charge does not come close to reflecting the full amount of the fixed costs that are incurred in keeping a customer connected to the grid.

Q. DOES THE COLLECTION OF REVENUES ON A VOLUMETRIC BASIS ALIGN WITH THE ACTUAL NATURE OF UTILITY COSTS?

A. No. The collection of utility revenues through volumetric charges does not comport with the underlying cost structure of providing electricity to customers. Most of the costs do not vary with the volume of electricity that is produced and delivered to the customer, but do vary with peak demand. And some are absolutely fixed, varying neither with energy consumed or peak demand.

It is well known that in order to provide electricity to a customer, a utility must bear – directly or indirectly – costs related to energy, generation, transmission, distribution, metering, and customer service. Generation energy costs vary with kWh electricity consumption. But generation capacity costs do not; they vary with system peak demand. Similarly, transmission costs also vary with system peak demand while distribution and transmission costs vary with maximum demand that is local to the customer and to the neighborhood in which the customer resides. Metering, billing, customer care, and other connection/hookup costs are a fixed cost per each customer of a particular class. Some of these costs vary across time. Generation costs will vary from hour to hour depending on the marginal generation source. Distribution and transmission networks, while used year round, are generally sized to meet class and system peak demand, respectively.

Q. HOW SHOULD THESE COSTS TRANSLATE INTO RATES?

A. According to the notion of cost causation, the rate structure should reflect the nature of the costs. To address the deficiencies of current two-part rates, I support the institution of a three-part rate design, consisting of a fixed monthly service charge, a demand charge, and a volumetric charge. The fixed charge should be designed to cover the fixed costs such as metering, billing, and customer care. Sometimes it also covers the cost of the line drop and the associated transformer. The demand charge should be designed to cover demand-driven costs, such as transmission, distribution, and generation capacity. It is typically applied to the individual customer's maximum demand, either during a defined on-peak period, or regardless of time of occurrence, or based on a combination of the two. While the concept of demand is instantaneous, in implementation demand is usually measured over 15-minute, 30-minute or 60-minute intervals. The energy charge covers the cost of the fuels that are used to generate electricity, as well as power grid operations and maintenance (O&M). The demand charge and the energy charge might vary with the time of use of electricity and have different seasonal and/or peak/off-peak charges. Such three-part rates align the rate design with costs, a fundamental tenet of rate design.

Q. WHAT IS THE CONSEQUENCE OF DEMAND-RELATED COSTS BEING COLLECTED THROUGH VOLUMETRIC RATES?

A. This mismatch between cost structure and rate structure creates an inevitable and indisputable cost shift from customers with lower load factors (i.e., high peak demand relative to total electricity consumption) to customers with higher load factors. Customers might reduce their load factor if, for instance, they install rooftop solar. With a lower load factor, customers paying for electricity under a flat volumetric rate design will reduce their bill without providing a proportionate reduction in system costs.

Inevitably, customers with high (i.e., beneficial) load factors who are paying for electric service under a volumetric rate design wind up paying more for comparable service.

To illustrate this point, I have created a simplified example with "Utility X" to show how two-part rates create cross-subsidies between customer classes. Utility X is authorized to collect $120 million in revenue per year from the 100,000 households in its service area. There are three types of households: low usage households consume 500 kWh/month, standard usage households consume 1,000 kWh/month and high usage households consume 1,500 kWh/month. This is shown in Table 1.

Table 1: Characteristics of Utility X

Input	Value	Units
Revenue Requirement	120,000,000	($/year)
Households	100,000	(households)
Average Usage		
Low-users	500	(kWh/mo)
Standard-users	1,000	(kWh/mo)
High-users	1,500	(kWh/mo)

Utility X collects its revenue requirement from customers with a two-part rate. Under its two-part rate, the utility collects ten percent of its revenue requirement with a fixed charge and ninety percent with a variable energy charge. However, the structure of Utility X's costs differs from its revenues. Fixed costs account for 25 percent of Utility X's total costs, variable energy costs account for 25 percent, and demand-related costs account for 50 percent. Table 2 summarizes this common misalignment of costs and rates.[13]

[13] Low-usage customers' demand is assumed to be 3 kW, standard-usage demand is assumed to be 5 kW, and high-usage demand is assumed to be 7 kW. These illustrative assumptions can be modified in the Microsoft Excel model, which has been provided as Attachment AJF-3DR.

Table 2: Revenue and Cost Structure for Utility X (per Customer)

	Revenue Structure	Cost Structure	Rate	Cost
Fixed	10%	25%	$10 / mo	$75 / mo
Variable	90%	25%	$0.09 / kWh	$0.025 / kWh
Demand	0%	50%	-	$10.00 / kW

Table 3 illustrates how Utility X's two-part rate structure can create a cross-subsidy when households vary in consumptive use. In this example, low-usage customers are subsidized by high-usage customers. Low-usage customers benefit from a cross-subsidy because the revenue from their low monthly usage does not balance with the fixed costs and demand-related costs required to serve them. As a result, the high-usage customers in this example are on the hook for the subsidies to low-usage customers.

Table 3: Illustration of Cross-Subsidization Under a Two-Part Rate

Customer Class	Monthly Usage (kWh)	Demand (kW)	Fixed ($/mo)	Variable ($/mo)	Demand ($/mo)	Monthly Bill ($/mo)	Yearly Bill ($/yr)	Number of Households	Total to Utility ($/yr)
Standard household	**1,000**	**5.00**						**33,333**	
Revenue			10	90	-	100	1,200		40,000,000
Cost			25	25	50	100	1,200		40,000,000
Over (Under) Payment			(15)	65	(50)	-	-		-
Low-usage household	**500**	**3.00**						**33,333**	
Revenue			10	45	-	55	660		22,000,000
Cost			25	13	30	68	810		27,000,000
Over (Under) Payment			(15)	33	(30)	(13)	(150)		(5,000,000)
High-usage household	**1,500**	**7.00**						**33,333**	
Revenue			10	135	-	145	1,740		58,000,000
Cost			25	38	70	133	1,590		53,000,000
Over (Under) Payment			(15)	98	(70)	13	150		5,000,000
Total			**(45)**	**195**	**(150)**	**-**	**-**	**100,000**	**120,000,000**

I have provided this illustrative cross-subsidy model as Attachment AJF-3DR, which also includes details on how cross-subsidization can be alleviated by appropriately matching Utility X's rates with its cost of service.

Q. DID PROFESSOR BONBRIGHT SUPPORT THE USE OF THREE-PART RATES?

A. Yes. Professor Bonbright opposed largely volumetric rates since they treat "the total cost of the business as if it varied directly with changes in in the kilowatt-hour output of energy – a grossly false assumption – it violates the most widely accepted canon of fair pricing, the principle of service at cost."[14]

According to his widely cited text, Professor Bonbright believed that three-part rates mirrored the structure of utility costs and cited their widespread deployment to medium and large commercial and industrial rates.[15] In support of three-part rates, Bonbright cites an earlier text by the British engineer D. J. Bolton,[16] who states:

> "More accurate costing has shown that, on the average, only one-quarter of the total costs of electricity supply are represented by coal[17] or items proportional to energy, while three-quarters are represented by fixed costs or items proportional to power, etc. If therefore only one rate is to be levied it would appear more logical to charge for power and neglect the energy, were it not for certain practical difficulties of which the following are two. In the first place the effective power demand on the system made by any particular consumer is extremely difficult to estimate, and is very different from the individual maximum demand metered at the consumer's terminals. Secondly, a purely power tariff would probably lead to a waste of energy to a greater extent than a purely energy tariff leads to waste of power."[18]

Of course, with the arrival of smart meters, customer demand at times of system and distribution peak can be accurately recorded. And the choice is no longer a binary one of imposing either a demand-only rate or an energy-only rate. The time is ripe for

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[14] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Second Edition, Public Utility Reports, Inc., 1988, p. 397.

[15] James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961.

[16] Bonbright says that "On many technical issues, no American treatise on electric utility rates can equal that by the distinguished British rate engineer D. J. Bolton." Page 289, n. 3.

[17] Coal was the dominant fuel for generating electricity in the United Kingdom in 1938 when the book was first published.

[18] D. J. Bolton, *Costs and Tariffs in Electricity Supply*, Chapman & Hall Ltd., 1951, p. 59.

deploying a three-part pricing structure that better reflects the cost of providing electric services in the APS service territory.

Interestingly, when Bonbright discusses a two-part rate structure, he is referring to what he characterizes as "the two most important cost functions of an electric-utility system"[19] -- demand and energy charges. When he moves into a discussion of three-part rate structures, he adds truly fixed charges, customer charges, to the two-part rate concept. Beginning on page 346, three-part rates are discussed extensively in the Bonbright canon.[20]

Q. HOW HAS THE PRINCIPLE OF COST CAUSATION AND THREE-PART RATES BEEN APPLIED IN PRACTICE?

A. Many commercial and industrial (C&I) customers across the U.S. are served under three-part rate structures. Indeed, it can be said that those structures have been the norm for these customer classes for decades in much of the U.S.

In Arizona, for instance, other than a couple of small electric cooperatives, all utilities for which I was able to find rate information utilize demand charges for some or all of their C&I customers.[21] In fact, many U.S. utilities offer these rates on a mandatory basis to their large C&I customers and a few, such as PacifiCorp's Utah service territory and Duke Energy's North Carolina service territory, offer them on a mandatory basis to even their smaller C&I customers.

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[19] Bonbright, p. 310.

[20] Bonbright, second edition, page 401, credits Doherty with extending the Hopkinson two-part rate into a three part rate. Henry L. Doherty, "Equitable, Uniform and Competitive Rates," Proceedings of the National Electric Light Association, 1900, pp. 291-321.

[21] The small utilities without demand charges are Columbus Electric Cooperative and Graham County Electric Cooperative. Both utilities sell less than 200,000 MWh of electricity per year.

Q. HAVE THREE-PART RATES BEEN OFFERED TO RESIDENTIAL CUSTOMERS IN OTHER U.S. JURISDICTIONS?

A. Yes. There are at least 20 utilities in 14 states that offer a three-part rate to residential customers, including APS, which has almost 120,000 of its customers on a three-part rate. In most cases, the rates are available to all customers on an opt-in basis. In the case of Salt River Project (SRP), a three-part rate is mandatory for all residential customers who choose to install a new grid-connected DG PV system.[22] All residential customers of Mid-Carolina Electric Cooperative and Butler Rural Electric Cooperative also face a mandatory demand charge.

Q. WHAT HAS PREVENTED THREE-PART RATES FROM BEING MORE BROADLY DEPLOYED TO RESIDENTIAL CUSTOMERS?

A. Until recently, metering technology for residential customers has been a significant technological hurdle. The traditional electromechanical meters that were installed in most homes only measured the customer's cumulative electricity consumption and not the customer's demand. Without the ability to meter demand, utilities could not cost-effectively offer three-part rates to these customers. Advances in metering technology have changed this situation.

Q. HOW HAVE ADVANCES IN METERING TECHNOLOGY CHANGED THE UTILITY'S ABILITY TO OFFER THREE-PART RATES?

A. With the deployment of automated meters (sometimes also referred to as advanced metering infrastructure, or AMI), consumption can be recorded in intervals of an hour or less. This allows the utility to collect the consumption data necessary to incorporate demand charges into rates. It has removed a large barrier to the wider dissemination of

[22] SRP website: http://www.srpnet.com/prices/home/customergenerated.aspx.

cost-reflective rates to residential customers. Given these technological developments, rate structures for residential customers should be changed.

Q. SHOULD UTILITIES OFFER THREE-PART RATES TO RESIDENTIAL CUSTOMERS?

A. Yes. The timing is propitious for making cost-reflective three-part rates the standard offering for all residential customers. These rates will recover costs from customers in an equitable manner by more accurately charging customers for their use of the power grid. A more cost-reflective rate will also encourage the adoption of emerging energy technologies and changes in energy consumption behavior that will lead to more efficient use of power grid infrastructure and resources.

Q. HOW WOULD A THREE-PART RATE ENCOURAGE THE ADOPTION OF EMERGING ENERGY TECHNOLOGIES?

A. By providing customers with a price signal that includes a component for demand, a three-part rate would encourage the adoption of technologies that are designed to smooth out a customer's load profile. Behind-the-meter battery storage, for example, could be used to release electricity during hours of high electricity demand and store electricity during hours of low electricity demand. Load control technologies, such as programmable communicating thermostats, demand limiters, and digital controls built into smart appliances, could also help customers manage their electricity demand. If a customer took service under a three-part rate, the use of battery storage, or other demand-reducing technologies, would reduce the customer's bill. This reduction in the customer's bill is an economic value that forms the basis of the price signal created by three-part rates.

In the same vein, introducing a demand charge and reducing the volumetric charge would decrease the economic attractiveness of energy technologies that cannot provide energy savings during those peak hours when the energy reductions are most valuable to the system. This simply means that the three-part rate structure is encouraging adoption of those technologies that are most beneficial to the power grid and to customers. It is important to take this broader view of energy technologies to avoid overstating the importance of one particular option that may not be the most beneficial.

Q. ASIDE FROM TRANSMITTING PRICE SIGNALS THAT ENCOURAGE TECHNOLOGICAL INNOVATION, WOULD THREE-PART RATES PROVIDE OTHER BENEFITS TO RESIDENTIAL CUSTOMERS?

A. Three-part rates will incentivize customers to smooth their energy consumption profile – and therefore reduce their electricity bills - even if they are not equipped with enabling technologies. There is a widespread misperception that customers do not respond to changing electricity prices. This is contradicted by empirical evidence derived from more than 40 pilots and full-scale rate deployments involving over 200 innovative rate offerings over roughly the past dozen years. The pilots have found that customers can and do respond to new price signals by changing their energy consumption pattern.[23]

Further, there is evidence that customers respond not just to changes in the rate structure generally, but specifically to demand charges. The following studies arrived at this conclusion after careful empirical analysis:

- Caves, D., Christensen, L., Herriges, J., 1984. "Modeling alternative residential peak-load electricity rate structures." *J. Econometrics*. Vol 24, Issue 3, 249-268.

[23] Some of these studies are summarized in Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, (August/September 2013). Similar results were obtained from an earlier generation of 14 pricing pilots that were funded in the late seventies and early eighties by the U.S. Federal Energy Administration (later part of the Department of Energy). *See* Ahmad Faruqui and Bob Malko, "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," *Energy*, Vol. 8, No. 10, (1983).

- Stokke, A., Doorman, G., Ericson, T., 2009, January. "An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector," Discussion Paper 574, Statistics Norway Research Department.
- Taylor, Thomas N., 1982. "Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak." Award Papers in Public Utility Economics and Regulation. Institute of Public Utilities, Michigan State University, East Lansing, Michigan.
- Taylor, T., Schwartz, P., 1986, April. "A residential demand charge: evidence from the Duke Power time-of-day pricing experiment." *Energy Journal.* (2), 135–151.

Q. IS THERE ANY SPECIFIC EVIDENCE THAT APS CUSTOMERS WILL RESPOND TO DEMAND CHARGES?

A. Yes. As described in APS witness Miessner's direct testimony in this proceeding, 60 percent of a sample of APS's customers on a three-part rate reduced their demand after switching to the three-part rate, with those who actively manage their demand achieving demand savings of 9 percent to 20 percent or more.

IV. APS'S RATE PROPOSAL

Q. WHAT IS THE DESIGN OF APS'S CURRENT RATES FOR RESIDENTIAL CUSTOMERS?

A. APS currently offers five rate options to residential customers, one of which includes a demand charge.[24] The rate options are described briefly as follows:

[24] APS also has a frozen residential rate option that is a three-part rate with a demand charge and an on-peak TOU period of 9:00 a.m. to 9:00 p.m. However, this rate is not open to new enrollment. APS offers some pilot rates with limited enrollment as well.

- Standard Rate: Two-part rate with a four-tiered inclining block volumetric charge in the summer and a flat volumetric charge in the winter.
- Time Advantage (7 p.m. to noon): Two-part rate with a two-period TOU volumetric charge with prices that vary seasonally.
- Combined Advantage (7 p.m. to noon): Three-part rate with a demand charge and a two-period TOU volumetric charge. Prices in the TOU charge and the demand charge vary seasonally. The demand charge is based on maximum demand during the billing cycle as measured only during the peak period.
- Time Advantage Super Peak (7 p.m. to noon): Two-part rate with a three-period TOU volumetric charge with prices that vary seasonally. The super peak period is constrained to a three-hour window (3 p.m. to 6 p.m.) during a subset of summer months (June, July, and August).
- Critical Peak Pricing: This is a rider that can be combined with the Standard Rate described above. Customers experience a higher price during a five-hour period (2 p.m. to 7 p.m.) on between six and 18 days of the year. In return, customers receive a significant rate discount during all other hours for the months of June through September.

Q. HAVE YOU REVIEWED HOW APS IS PROPOSING TO REDESIGN ITS RESIDENTIAL RATES?

A. Yes. APS is proposing several changes to its residential rate offerings. Most notably, it is proposing to make demand charges the standard feature of all rates offered to residential customers, with the exception of a subset of small usage customers who will have the option to choose a rate that does not include a demand charge. The peak period will be redefined to start at 3 p.m. and end at 8 p.m. for each of the offerings.

Q. WHAT IS YOUR VIEW OF THE EXPERIENCE THAT APS HAS HAD WITH RESIDENTIAL DEMAND CHARGES UP TO THIS POINT?

A. APS has the most highly subscribed residential three-part rate in the U.S., with almost 120,000 customers on its Combined Advantage tariff. This represents more than 10 percent of its residential customer base and over 20 percent of its residential energy sales. When new rate designs are introduced on a voluntary basis, they rarely achieve enrollment levels in excess of 10 percent.[25] Considering that APS has been offering its three-part rate on a voluntary basis among several other rate options, and considering that enrollment in the three-part rate has grown significantly over the past several years, this is a very strong indication that APS's customers are interested in and prepared for rates with demand charges.

Q. DO YOU AGREE WITH APS'S PROPOSAL TO MAKE DEMAND CHARGES A STANDARD RATE FOR RESIDENTIAL CUSTOMERS?

A. Yes. For the reasons I discussed previously in this testimony, the introduction of a cost-based demand charge is a significant and necessary improvement over two-part rate offerings. About 120,000 APS customers have shown a preference for receiving their electric service on a three-part rate. There is no reason why a demand charge cannot be included in the standard rate for residential customers.

Q. HOW DOES APS'S PROPOSED DEMAND CHARGE COMPARE TO THAT OF OTHER RESIDENTIAL THREE-PART RATE OFFERINGS?

A. The residential rate offerings of other U.S. utilities provide precedent for each of the elements in APS's proposed demand charge. For instance, APS is proposing to measure

[25] For information on residential demand response program participation, *see* FERC reports on advanced metering and demand response: http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

average demand over a 60-minute interval. Five of the residential three-part rates offered by U.S. utilities measure demand over a 60-minute interval. Table 4 below summarizes each element of APS's proposal and identifies the number of residential demand rate offerings in the U.S that include this element. Further information about all of the residential demand charge offerings in the U.S. that I have identified is provided in Attachment AJF-2DR.

Table 4: Features of APS's Proposed Three-Part Rate Offering

Features of APS's Proposed Three-Part Rate Offering	Number of Rates Offered by Other U.S. Utilities that Share this Characteristic
Seasonal variation in demand charge	12
Includes time-varying energy charge	7
Demand measured during peak period	6
60-minute demand measurement interval	5
Universal demand charge	4

Note: The features listed for APS are elements of at least one of its proposed three-part rate offerings.

Q. ARE APS'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF EQUITY AND FAIRNESS?

A. Yes. Each customer imposes costs on the system, some of which are fixed and the rest of which are demand-driven and energy-driven. Under purely volumetric tariffs, customers with high demand, but low monthly consumption, would not be paying their fair share of the cost of maintaining, upgrading, and expanding the utility's generation, transmission and distribution system. Instead, lower-demand customers would be covering the deficit and paying more than their fair share. Each of APS's proposed three-part rates more closely match demand, fixed, and variable costs with demand,

fixed, and variable charges and will reduce this inequity so that all customers will pay their fair share of the costs associated with the generation of electricity, its delivery through utility's transmission and distribution system, and customer service.

Q. ARE APS'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF ECONOMIC EFFICIENCY?

A. Yes. As I discussed previously, the cost-based price signals in the three-part rates proposed by APS provide customers with the financial incentive to make investments in technologies or otherwise change their behavior in ways that are most beneficial to the system. Technologies and behaviors that reduce a customer's demand should ultimately lead to a more efficient use of the grid, reduced costs, and lower bills.

A careful reading of the text by Bonbright suggests that, when he discusses efficiency, he means economic efficiency in the broad sense of the term and not just energy efficiency. The attainment of economic efficiency requires that resources are used in the least wasteful way possible. If a product is being consumed by someone who values that product at less than it costs to produce, then that consumption is wasteful and society would be better off on aggregate redeploying those resources elsewhere. In a decentralized market economy, prices are used to guide efficient resource use. Thus if a good is priced correctly, consumers who value it at less than its cost will not purchase it and an efficient outcome is achieved. In discussions about electricity consumption, the conversation often focuses on just one dimension of economic efficiency – energy conservation, which entails reducing the amount of electricity consumed. However there are other dimensions, where electricity consumption may be very inefficient, such as in demand. If capacity is essentially given away for free, then customers, who may place a very low value on capacity, will consume it, even if its cost to society (ultimately them and other customers) is very high.

Q. ARE APS'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF CUSTOMER SATISFACTION?

A. Yes. APS is proposing to offer a diverse portfolio of rate options to residential customers. Having a meaningful choice of cost-based pricing products is a benefit to customers.

Q. ARE APS'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF BILL STABILITY?

A. For the residential class as a whole, there will be no change in electric bills. That would also be true for customers whose load profile is similar to that of the class average. Customers whose load factors are higher than the class average will experience lower bills. Customers whose load factor is worse than the class average, because they have been subsidized for years by the customers whose load factor was higher than the class average, will experience higher bills, since the change in rates will remove that subsidy. However, they will have an opportunity to lower their bills by reducing their demand. And that would also be true for customers who are automatically seeing lower bills. They will have an opportunity to further lower their bills by reducing their demand.

Q. ARE APS'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF REVENUE ADEQUACY AND STABILITY?

A. Yes. The introduction of a three-part rate will not change the utility's revenues. A properly designed three-part rate will be revenue neutral for the class as a whole and therefore collect the same revenue as the otherwise applicable two-part rates. The main reason for moving to three-part rates is the ability to more accurately recover costs from those customers who are imposing costs on the system, and to provide customers with an incentive to consume electricity in a more efficient manner.

While Professor Bonbright says that rates should be stable and predictable, he does not say that rate structures should remain frozen in time. In the U.S., there is an ineluctable movement towards cost-reflective rates brought about by the rollout of AMI and by the increased availability and customer adoption of a wide range of digital end-use technologies such as smart appliances, smart thermostats, home energy management systems, battery storage systems, electric vehicles and rooftop solar panels. APS's three-part rate proposal is designed to provide stability in this new environment.

V. CONCLUSION

Q. WHAT ARE YOUR CONCLUSIONS ABOUT APS'S THREE-PART RATE DESIGN PROPOSALS?

A. APS has put forward a cost-based three-part rate proposal that is consistent with the Bonbright principles. I support the Company's plan to make this the standard rate for all its residential customers (with an exception for small consumers of electricity). The two-part rate which is presently employed by APS, and throughout the industry, is inefficient, inequitable and unsustainable. It must give way to three-part rates. Not only are two-part rates ineffective at providing the proper pricing signals, they do not facilitate the integration of distributed energy resources with the grid, nor do they stimulate the deployment of other innovative technologies such as customer-situated battery storage and plug-in electric vehicles. In addition, they only provide customers at most two ways of reducing their bills, by reducing or shifting energy consumption. With three-part rates, customers would have up to three ways in which to lower their bills: by reducing demand, by reducing energy consumption, or by moving consumption or demand or both from peak to off-peak periods.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Public Service Company

Docket No. E-01345A-16-0036

PREPARED DIRECT TESTIMONY OF

AHMAD FARUQUI

Attachment AJF-1DR: Statement of Qualifications

Dr. Ahmad Faruqui is an economist with 40 years of academic, consulting and research experience in the efficient use of energy. He has assisted clients in the conceptualization, design, analysis, and evaluation of a wide range of programs related to advanced metering infrastructure, conservation voltage reduction, combined heat and power, demand charges, distributed energy resources, dynamic pricing, demand response, energy efficiency and newly emerging technologies, such as plug-in electric vehicles, rooftop solar, and distributed generation. He has provided regulatory support and testimony in proceedings related to these issues in 34 states, the District of Columbia and Canada.

Two of Dr. Faruqui's dynamic experiments have won professional awards, and he was named one of the world's Top 100 experts on the smart grid by Greentech Media.

He has consulted with more than 135 energy organizations around the globe and testified or appeared before a dozen state and provincial commissions and legislative bodies in the United States and Canada. He has also advised the Alberta Utilities Commission, the Edison Electric Institute, the Electric Power Research Institute, FERC, the Institute for Electric Efficiency, the Ontario Energy Board, the Saudi Electricity and Co-Generation Regulatory Authority, and the World Bank. His research on the energy behavior of consumers has been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, Fortune, the San Francisco Chronicle, the San Jose Mercury News, the Wall Street Journal, The Times (London) and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America.

Dr. Faruqui is the author, co-author or co-editor of four books and more than 150 articles, papers, and reports on efficient energy use. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, and the Journal of Regulatory Economics and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He has taught economics at San Jose State University, the University of California at Davis and the University of Karachi. He holds a an M.A. in agricultural economics and a Ph. D. in economics from The University of California at Davis, where he was a Regents Fellow, and B.A. and M.A. degrees in economics from The University of Karachi, where he was awarded the Rashid Minhas Gold Medal in economics and the Government of Pakistan Overseas Scholarship.

AREAS OF EXPERTISE

- *Innovative pricing.* He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as three-part rates, including fixed monthly charges, demand charges and time-varying energy charges; dynamic pricing rates, including critical peak pricing, variable peak pricing and real-time pricing; time-of-use pricing; and inclining block rates.
- *Rate design.* He has helped design forward-looking programs and services that exploit recent advances in rate design and digital technologies in order to lower customer bills and improve utility earnings while lowering the carbon footprint and preserving system reliability.
- *Cost-benefit analysis of advanced metering infrastructure.* He has assessed the feasibility of introducing smart meters and other devices, such as programmable communicating thermostats that promote demand response, into the energy marketplace, in addition to new appliances, buildings, and industrial processes that improve energy efficiency.
- *Demand forecasting and weather normalization.* He has pioneered the use of a wide variety of models for forecasting product demand in the near-, medium-, and long-term, using econometric, time series, and engineering methods. These models have been used to bid into energy procurement auctions, plan capacity additions, design customer-side programs, and weather normalize sales.
- *Customer choice.* He has developed methods for surveying customers in order to elicit their preferences for alternative energy products and alternative energy suppliers. These methods have been used to predict the market size of these products and to estimate the market share of specific suppliers.
- *Hedging, risk management, and market design.* He has helped design a wide range of financial products that help customers and utilities cope with the unique opportunities and challenges posed by a competitive market for electricity. He conducted a widely-cited market simulation to show that real-time pricing of electricity could have saved Californians millions of dollars during the Energy Crisis by lowering peak demands and prices in the wholesale market.
- *Competitive business strategy.* He has helped clients develop and implement competitive marketing strategies by drawing on his knowledge of the energy needs

of end-use customers, their values and decision-making practices, and their competitive options. He has helped companies reshape and transform their marketing organization and reposition themselves for a competitive marketplace. He has also helped government-owned entities in the developing world prepare for privatization by benchmarking their planning, retailing, and distribution processes against industry best practices, and suggesting improvements by specifying quantitative metrics and follow-up procedures.

- *Design and evaluation of marketing programs.* He has helped generate ideas for new products and services, identified successful design characteristics through customer surveys and focus groups, and test marketed new concepts through pilots and experiments.

- *Expert witness.* He has testified or appeared before state commissions in Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, Illinois, Indiana, Iowa, Kansas, Michigan, Maryland, Minnesota, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania and Texas. He has assisted clients in submitting testimony in Georgia. He has presented to the California Energy Commission, the California Senate, the Congressional Office of Technology Assessment, the Kentucky Commission, the Minnesota Department of Commerce, the Minnesota Senate, the Missouri Public Service Commission, and the Electricity Pricing Collaborative in the state of Washington. In addition, he has led a variety of professional seminars and workshops on public utility economics around the world and taught economics at the university level.

EXPERIENCE

Innovative Pricing

- **Report examining the costs and benefits of dynamic pricing in the Australian energy market.** For the Australian Energy Market Commission (AEMC), developed a report that reviews the various forms of dynamic pricing, such as time-of-use pricing, critical peak pricing, peak time rebates, and real time pricing, for a variety of performance metrics including economic efficiency, equity, bill risk, revenue risk, and risk to vulnerable customers. It also discusses ways in which dynamic pricing can be rolled out in Australia to raise load factors and lower average energy costs for all consumers without harming vulnerable

consumers, such as those with low incomes or medical conditions requiring the use of electricity.

- **Whitepaper on emerging issues in innovative pricing.** For the Regulatory Assistance Project (RAP), developed a whitepaper on emerging issues and best practices in innovative rate design and deployment. The paper includes an overview of AMI-enabled electricity pricing options, recommendations for designing the rates and conducting experimental pilots, an overview of recent pilots, full-deployment case studies, and a blueprint for rolling out innovative rate designs. The paper's audience is international regulators in regions that are exploring the potential benefits of smart metering and innovative pricing.
- **Assessing the full benefits of real-time pricing.** For two large Midwestern utilities, assessed and, where possible, quantified the potential benefits of the existing residential real-time pricing (RTP) rate offering. The analysis included not only "conventional" benefits such as avoided resource costs, but under the direction of the state regulator was expanded to include harder-to-quantify benefits such as improvements to national security and customer service.
- **Pricing and Technology Pilot Design and Impact Evaluation for Connecticut Light & Power (CL&P).** Designed the Plan-It Wise Energy pilot for all classes of customers and subsequently evaluated the Plan-It Wise Energy program (PWEP) in the summer of 2009. PWEP tested the impacts of CPP, PTR, and time of use (TOU) rates on the consumption behaviors of residential and small commercial and industrial customers.
- **Dynamic Pricing Pilot Design and Impact Evaluation: Baltimore Gas & Electric.** Designed and evaluated the Smart Energy Pricing (SEP) pilot, which ran for four years from 2008 to 2011. The pilot tested a variety of rate designs including critical peak pricing and peak time rebates on residential customer consumption patterns. In addition, the pilot tested the impacts of smart thermostats and the Energy Orb.
- **Impact Evaluation of a Residential Dynamic Pricing Experiment: Consumers Energy (Michigan).** Designed the pilot and carried out an impact evaluation with the purpose of measuring the impact of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. The pilot also

tested the influence of switches that remotely adjust the duty cycle of central air conditioners.

- **Impact Simulation of Ameren Illinois Utilities' Power Smart Pricing Program.** Simulated the potential demand response of residential customers enrolled to real- time prices. Results of this simulation were presented to the Midwest ISO's Supply Adequacy Working Group (SAWG) to explore alternative ways of introducing price responsive demand in the region.

- **The Case for Dynamic Pricing: Demand Response Research Center.** Led a project involving the California Public Utilities Commission, the California Energy Commission, the state's three investor-owned utilities, and other stakeholders in the rate design process. Identified key issues and barriers associated with the development of time-based rates. Revisited the fundamental objectives of rate design, including efficiency and equity, with a special emphasis on meeting the state's strongly-articulated needs for demand response and energy efficiency. Developed a score-card for evaluating competing rate designs and applied it to a set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.

- **Developed a Customer Price Response Model: Consolidated Edison**. Specified, estimated, tested, and validated a large-scale model that analyzes the response of some 2,000 large commercial customers to rising steam prices. The model includes a module for analyzing conservation behavior, another module for forecasting fuel switching behavior, and a module for forecasting sales and peak demand

- **Design and Impact Evaluation of the Statewide Pricing Pilot: Three California Utilities.** Working with a consortium of California's three investor-owned utilities to design a statewide pricing pilot to test the efficacy of dynamic pricing options for mass-market customers. The pilot was designed using scientific principles of experimental design and measured changes in usage induced by dynamic pricing for over 2,500 residential and small commercial and industrial customers. The impact evaluation was carried out using state-of-the-art econometric models. Information from the pilot was used by all three utilities in their business cases for advanced metering infrastructure (AMI). The project was

conducted through a public process involving the state's two regulatory commissions, the power agency, and several other parties.

- **Economics of Dynamic Pricing: Two California Utilities.** Reviewed a wide range of dynamic pricing options for mass-market customers. Conducted an initial cost-effectiveness analysis and updated the analysis with new estimates of avoided costs and results from a survey of customers that yielded estimates of likely participation rates.
- **Economics of Time-of-Use Pricing: A Pacific Northwest Utility.** This utility ran the nation's largest time-of-use pricing pilot program. Assessed the cost-effectiveness of alternative pricing options from a variety of different perspectives. Options included a standard three-part time-of-use rate and a quasi-real time variant where the prices vary by day. Worked with the client in developing a regulatory strategy. Worked later with a collaborative to analyze the program's economics under a variety of scenarios of the market environment.
- **Economics of Dynamic Pricing Options for Mass Market Customers – Client: A Multi-State Utility.** Identified a variety of pricing options suited to meet the needs of mass-market customers, and assessed their cost-effectiveness. Options included standard three-part time-of-use rates, critical peak pricing, and extreme-day pricing. Developed plans for implementing a pilot program to obtain primary data on customer acceptance and load shifting potential. Worked with the client in developing a regulatory strategy.
- **Real-Time Pricing in California – Client: California Energy Commission.** Surveyed the national experience with real-time pricing of electricity, directed at large power customers. Identified lessons learned and reviewed the reasons why California was unable to implement real-time pricing. Catalogued the barriers to implementing real-time pricing in California, and developed a program of research for mitigating the impacts of these barriers.
- **Market-Based Pricing of Electricity – Client: A Large Southern Utility.** Reviewed pricing methodologies in a variety of competitive industries including airlines, beverages, and automobiles. Recommended a path that could be used to transition from a regulated utility environment to an open market environment featuring customer choice in both wholesale and retail markets. Held a series of seminars for senior management and their staffs on the new methodologies.

- **Tools for Electricity Pricing – Client: Consortium of Several U.S. and Foreign Utilities.** Developed Product Mix, a software package that uses modern finance theory and econometrics to establish a profit-maximizing menu of pricing products. The products range from the traditional fixed-price product to time-of-use prices to hourly real-time prices, and also include products that can hedge customers' risks based on financial derivatives. Outputs include market share, gross revenues, and profits by product and provider. The calculations are performed using probabilistic simulation, and results are provided as means and standard deviations. Additional results include delta and gamma parameters that can be used for corporate risk management. The software relies on a database of customer load response to various pricing options called StatsBank. This database was created by metering the hourly loads of about one thousand commercial and industrial customers in the United States and the United Kingdom.

- **Risk-Based Pricing – Client: Midwestern Utility.** Developed and tested new pricing products for this utility that allowed it to offer risk management services to its customers. One of the products dealt with weather risk; another one dealt with risk that real-time prices might peak on a day when the customer does not find it economically viable to cut back operations.

Demand Response

- **National Action Plan for Demand Response: Federal Energy Regulatory Commission.** Led a consulting team developing a national action plan for demand response (DR). The national action plan outlined the steps that need to be taken in order to maximize the amount of cost-effective DR that can be implemented. The final document was filed with U.S. Congress in June 2010.

- **National Assessment of Demand Response Potential: Federal Energy Regulatory Commission.** Led a team of consultants to assess the economic and achievable potential for demand response programs on a state-by-state basis. The assessment was filed with the U.S. Congress in 2009, as required by the Energy Independence and Security Act of 2007.

- **Evaluation of the Demand Response Benefits of Advanced Metering Infrastructure: Mid-Atlantic Utility.** Conducted a comprehensive assessment of the benefits of advanced metering infrastructure (AMI) by developing dynamic

pricing rates that are enabled by AMI. The analysis focused on customers in the residential class and commercial and industrial customers under 600 kW load.

- **Estimation of Demand Response Impacts: Major California Utility.** Worked with the staff of this electric utility in designing dynamic pricing options for residential and small commercial and industrial customers. These options were designed to promote demand response during critical peak days. The analysis supported the utility's advanced metering infrastructure (AMI) filing with the California Public Utilities Commission. Subsequently, the commission unanimously approved a $1.7 billion plan for rolling out nine million electric and gas meters based in part on this project work.

Smart Grid Strategy

- **Development of a smart grid investment roadmap for Vietnamese utilities.** For the five Vietnamese power corporations, developed a roadmap to guide future smart grid investment decisions. The report identified and described the various smart grid investment options, established objectives for smart grid deployment, presented a multi-phase approach to deploying the smart grid, and provided preliminary recommendations regarding the best investment opportunities. Also presented relevant case studies and an assessment of the current state of the Vietnamese power grid. The project involved in-country meetings as well as a stakeholder workshop that was conducted by Brattle staff.
- **Cost-Benefit Analysis of the Smart Grid: Rocky Mountain Utility.** Reviewed the leading studies on the economics of the smart grid and used the findings to assess the likely cost-effectiveness of deploying the smart grid in one geographical location.
- **Modeling benefits of smart grid deployment strategies.** Developed a model for assessing benefits of smart grid deployment strategies over a long-term (e.g., 20-year) forecast horizon. The model, called iGrid, is used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, PHEVs) against seven key metrics of value (e.g., avoided resource costs, improved reliability).
- **Smart grid strategy in Canada.** The Alberta Utilities Commission (AUC) was charged with responding to a Smart Grid Inquiry issued by the provincial

government. Advised the AUC on the smart grid, and what impacts it might have in Alberta.

- **Smart grid deployment analysis for collaborative of utilities.** Adapted the iGrid modeling tool to meet the needs of a collaborative of utilities in the southern U.S. In addition to quantifying the benefits of smart grid programs and technologies (e.g., advanced metering infrastructure deployment and direct load control), the model was used to estimate the costs of installing and implementing each of the smart grid programs and technologies.
- **Development of a smart grid cost-benefit analysis framework.** For the Electric Power Research Institute (EPRI) and the U.S. DOE, contributed to the development of an approach for assessing the costs and benefits of the DOE's smart grid demonstration programs.
- **Analysis of the benefits of increased access to energy consumption information.** For a large technology firm, assessed market opportunities for providing customers with increased access to real time information regarding their energy consumption patterns. The analysis includes an assessment of deployments of information display technologies and analysis of the potential benefits that are created by deploying these technologies.
- **Developing a plan for integrated smart grid systems.** For a large California utility, helped to develop applications for funding for a project to demonstrate how an integrated smart grid system (including customer-facing technologies) would operate and provide benefits.

Demand Forecasting

- **Comprehensive Review of Load Forecasting Methodology: PJM Interconnection.** Conducted a comprehensive review of models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the RTO system.
- **Analyzed Downward Trend: Western Utility.** We conducted a strategic review of why sales had been lower than forecast in a year when economic activity had been brisk. We developed a forecasting model for identifying what had caused the drop in sales and its results were used in an executive presentation to the

utility's board of directors. We also developed a time series model for more accurately forecasting sales in the near term and this model is now being used for revenue forecasting and budgetary planning.

- **Analyzed Why Models are Under-Forecasting: Southwestern Utility.** Reviewed the entire suite of load forecasting models, including models for forecasting aggregate system peak demand, electricity consumption per customer by sector and the number of customers by sector. We ran a variety of forecasting experiments to assess both the ex-ante and ex-post accuracy of the models and made several recommendations to senior management.
- **U.S. Demand Forecast: Edison Electric Institute.** For the U.S. as a whole, we developed a base case forecast and several alternative case forecasts of electric energy consumption by end use and sector. We subsequently developed forecasts that were based on EPRI's system of end-use forecasting models. The project was done in close coordination with several utilities and some of the results were published in book form.
- **Developed Models for Forecasting Hourly Loads: Merchant Generation and Trading Company.** Using primary data on customer loads, weather conditions, and economic activity, developed models for forecasting hourly loads for residential, commercial, and industrial customers for three utilities in a Midwestern state. The information was used to develop bids into an auction for supplying basic generation services.
- **Gas Demand Forecasting System – Client: A Leading Gas Marketing and Trading Company, Texas.** Developed a system for gas nominations for a leading gas marketing company that operated in 23 local distribution company service areas. The system made week-ahead and month-ahead forecasts using advanced forecasting methods. Its objective was to improve the marketing company's profitability by minimizing penalties associated with forecasting errors.

Demand Side Management

- **The Economics of Biofuels.** For a western utility that is facing stringent renewable portfolio standards and that is heavily dependent on imported fossil fuels, carried out a systematic assessment of the technical and economic ability of biofuels to replace fossil fuels.

- **Assessment of Demand-Side Management and Rate Design Options: Large Middle Eastern Electric Utility.** Prepared an assessment of demand-side management and rate design options for the four operating areas and six market segments. Quantified the potential gains in economic efficiency that would result from such options and identified high priority programs for pilot testing and implementation. Held workshops and seminars for senior management, managers, and staff to explain the methodology, data, results, and policy implications.

- **Likely Future Impact of Demand-Side Programs on Carbon Emissions – Client: The Keystone Center.** As part of the Keystone Dialogue on Climate Change, developed scenarios of future demand-side program impacts, and assessed the impact of these programs on carbon emissions. The analysis was carried out at the national level for the U.S. economy, and involved a bottom-up approach involving many different types of programs including dynamic pricing, energy efficiency, and traditional load management.

- **Sustaining Energy Efficiency Services in a Restructured Market – Client: Southern California Edison.** Helped in the development of a regulatory strategy for implementing energy efficiency strategies in a restructured marketplace. Identified the various players that are likely to operate in a competitive market, such as third-party energy service companies (ESCOS) and utility affiliates. Assessed their objectives, strengths, and weaknesses and recommended a strategy for the client's adoption. This strategy allowed the client to participate in the new market place, contribute to public policy objectives, and not lose market share to new entrants. This strategy has been embraced by a coalition of several organizations involved in the California PUC's working group on public purpose programs.

- **Organizational Assessments of Capability for Energy Efficiency – Client: U.S. Agency for International Development, Cairo, Egypt.** Conducted in-depth interviews with senior executives of several energy organizations, including utilities, government agencies, and ministries to determine their goals and capabilities for implementing programs to improve energy end-use efficiency in Egypt. The interviews probed the likely future role of these organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.

- **Enhancing Profitability Through Energy Efficiency Services – Client: Jamaica Public Service Company.** Developed a plan for enhancing utility profitability by providing financial incentives to the client utility, and presented it for review and discussion to the utility's senior management and Jamaica's new Office of Utility Regulation. Developed regulatory procedures and legislative language to support the implementation of the plan. Conducted training sessions for the staff of the utility and the regulatory body.

Advanced Technology Assessment

- **Competitive Energy and Environmental Technologies – Clients: Consortium of clients, led by Southern California Edison, Included the Los Angeles Department of Water and Power and the California Energy Commission**. Developed a new approach to segmenting the market for electrotechnologies, relying on factors such as type of industry, type of process and end use application, and size of product. Developed a user-friendly system for assessing the competitiveness of a wide range of electric and gas-fired technologies in more than 100 four-digit SIC code manufacturing industries and 20 commercial businesses. The system includes a database on more than 200 end-use technologies, and a model of customer decision making.
- **Market Infrastructure of Energy Efficient Technologies – Client: EPRI.** Reviewed the market infrastructure of five key end-use technologies, and identified ways in which the infrastructure could be improved to increase the penetration of these technologies. Data was obtained through telephone interviews with equipment manufacturers, engineering firms, contractors, and end-use customers.

TESTIMONY

Arizona

Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application for UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to the its Operations Throughout the State of Arizona, and for Related Approvals, Docket No. E-04204A-15-0142, December 9, 2015.

California

Rebuttal Testimony before the Public Utilities Commission of the State of California, Pacific Gas and Electric Company Joint Utilities on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, in the Matter of Rulemaking 12-06-013, October 17, 2014.

Testimony before the Public Utilities Commission of the State of California on behalf of Pacific Gas and Electric Company on rate relief, Docket No. A.10-03-014, summer 2010.

Testimony before the Public Utilities Commission of the State of California, on behalf of Southern California Edison, Edison SmartConnect™ Deployment Funding and Cost Recovery, exhibit SCE-4, July 31, 2007.

Testimony on behalf of the Pacific Gas & Electric Company, in its application for Automated Metering Infrastructure with the California Public Utilities Commission. Docket No. 05-06-028, 2006.

Colorado

Rebuttal Testimony before the Public Utilities Commission of the State of Colorado in the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise its Colorado PUC No.7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009. Docket No. 09al-299e, November 25, 2009.

Testimony before the Public Utilities Commission of the State of Colorado, on behalf of Public Service Company of Colorado, on the tariff sheets filed by Public Service Company of Colorado with advice letter No. 1535 – Electric. Docket No. 09S-__E, May 1, 2009.

Connecticut

Testimony before the Department of Public Utility Control, on behalf of the Connecticut Light and Power Company, in its application to implement Time-of-Use , Interruptible Load Response, and Seasonal Rates- Submittal of Metering and Rate Pilot Results- Compliance Order No. 4, Docket no. 05-10-03RE01, 2007.

District of Columbia

Testimony before the Public Service Commission of the District of Columbia on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an

Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group, case no. 1056, May 2009.

Illinois

Testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.

Testimony before the State of Illinois – Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.

Rebuttal Restimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

Indiana

Testimony before the State of Indiana, Indiana Utility Regulatory Commission, on behalf of Vectren South, on the smart grid. Cause no. 43810, 2009.

Kansas

Testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, March 2, 2015.

Maryland

Testimony before the Maryland Public Service Commission, on behalf of Potomac Electric Power Company in the matter of the application of Potomac Electric Power Company for adjustments to its retail rates for the distribution of electric energy, April 19, 2016.

Rebuttal testimony, before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company in the matter of the application of Baltimore Gas and Electric Company for adjustments to its electric and gas base rates, Case No. 9406, March 4, 2016.

Testimony before the Public Service Commission of Maryland, on behalf of Potomac Electric Power Company and Delmarva Power and Light Company, on the deployment of Advanced Meter Infrastructure, Case no. 9207, September 2009.

Testimony before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company, on the findings of BGE's Smart Energy Pricing ("SEP") Pilot program. Case No. 9208, July 10, 2009.

Minnesota

Rebuttal Testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, March 25, 2013.

Testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, November 2, 2012.

Nevada

Rebuttal Testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy, in the matter of net metering and distributed generation cost of service and tariff design, Docket Nos. 15-07041 and 15-07042, November 3, 2015.

Testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company d/b/a NV Energy, in the matter of the application for approval of a cost of service study and net metering tariffs, Docket No. 15-07, July 31, 2015.

New Mexico

Testimony before the New Mexico Regulation Commission on behalf of Public Service Company of New Mexico in the matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507, Case No. 14-00332-UT, December 11, 2014.

Pennsylvania

Testimony before the Pennsylvania Public Utility Commission, on behalf of PECO on the Methodology Used to Derive Dynamic Pricing Rate Designs, Case No. M-2009-2123944, October 28, 2010.

Oklahoma

Rebuttal Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an order of the Commission authorizing applicant to modify its rates, charges and tariffs for retail electric service in Oklahoma, Cause No. PUD 201500273, April 11, 2016.

Direct Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an order of the Commission authorizing applicant to modify its rates, charges and tariffs for retail electric service in Oklahoma, Cause No. PUD 201500273, December 3, 2015.

Responsive Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Brandy L. Wreath, Director of the Public Utility Division, for Determination of the Calculation of Lost Net Revenues and Shared Savings Pursuant to the Demand Program Rider of Oklahoma Gas and Electric Company, Cause No. PUD 201500153, May 13, 2015.

REGULATORY APPEARANCES

Arkansas

Presented before the Arkansas Public Service Commission, "The Emergence of Dynamic Pricing" at the workshop on the Smart Grid, Demand Response, and Automated Metering Infrastructure, Little Rock, Arkansas, September 30, 2009.

Delaware

Presented before the Delaware Public Service Commission, "The Demand Response Impacts of PHI's Dynamic Pricing Program" Delaware, September 5, 2007.

Kansas

Presented before the State Corporation Commission of the State of Kansas, "The Impact of Dynamic Pricing on Westar Energy" at the Smart Grid and Energy Storage Roundtable, Topeka, Kansas, September 18, 2009.

Ohio

Presented before the Ohio Public Utilities Commission, "Dynamic Pricing for Residential and Small C&I Customers" at the Technical Workshop, Columbus, Ohio, March 28, 2012.

Texas

Presented before the Public Utility Commission of Texas, "Direct Load Control of Residential Air Conditioners in Texas," at the PUCT Open Meeting, Austin, Texas, October 25, 2012.

PUBLICATIONS

Presentations

1. "Time Variant Electricity Pricing: Theory and Implementation," Georgetown University's CSIS. A 90-minute panel session on time-variant pricing. Washington, DC, April 20, 2016. https://www.youtube.com/watch?v=0p6ZHaXszRQ
2. "Residential Demand Charges: An Overview," presented to EEI Rate Committee Meeting, Charlotte, NC, March 15, 2016.
3. "A Conversation About Standby Rates," presented to Standby Rate Working Group, Michigan Public Service Commission, Lansing, Michigan, January 20, 2016.
4. "Imaging the Utility of the Future," presented to Commonwealth Edison Company, January 12, 2016.
5. "The Movement Towards Deploying Demand Charges for Residential Customers," NARUC 127th Annual Meeting, Austin, Texas, November 8, 2015.
6. "Comments on the Straw Proposal on behalf of the California Water Association," presented at the CPUC Workshop on Balanced Rates Rulemaking (R.) 11-11-0008, San Francisco, October 13, 2015.
7. "A Global Perspective on Time-Varying Rates," presented at the Stanford Bits & Watts Program, August 12, 2015. http://www.brattle.com/system/publications/pdfs/000/005/183/original/A_global_perspective_on_time-varying_rates_Faruqui_061915.pdf?1436207012
8. "The Case for Introducing Demand Charges in Residential Tariffs," presented to the Harvard Electricity Policy Group 79th Plenary Session, Washington, D.C., June 25, 2015.
9. "A Global Perspective on Time-Varying Rates," presented to the CAMPUT Energy Regulation Course, Kingston, Ontario, June 23, 2015.

10. "The Global Movement Toward Cost-Reflective Tariffs," presented at the EUCI Residential Demand Charges Summit, Denver, Colorado, May 14, 2015.

11. "Currents of Change in the Design of Tariffs for Distribution Networks," presented at Energy Network Association: Energy Transformed, Sydney, Australia, May 7, 2015.

12. "Points of Inflection Loom Ahead for Demand Response and Distributed Generation," presented at the Comverge Utility Conference, St. Petersburg, Florida, April 10, 2015.

13. "Time-Variant Pricing (TVP) in New York," presented at the Time-Variant Pricing Forum, NYU School of Law, New York, New York, March 31, 2015. http://www.sallan.org/Sallan_In-the-Media/2015/04/rev_agenda_time_variant_p.php

14. "The Evolving Futures of Demand Response and Distributed Generation," presented to Eastern Interconnection States Planning Council, Newark, New Jersey, March 5, 2015.

15. "The Impact of Distributed Generation on Electric Sales," resented to Eastern Interconnection States Planning Council, Newark, New Jersey, March 5, 2015.

16. "The Five Forces Shaping the Future of Demand Response (DR)," presented at the Demand Response Virtual Summit 2015, February 19, 2015.

17. "The Impact of an Uncertain Economic Outlook on Electric Utilities," presented at the New Mexico Economic Outlook Conference 2015, January 15, 2015. http://www.bizjournals.com/albuquerque/news/2015/01/15/see-one-economists-view-on-why-electric-utilities.html

18. "The Re-emergence of Combined Heat and Power (CHP), presented at the NRRI Teleseminar, August 27, 2014.

19. "Moving Demand Response Back to the Demand Side," presented at the IEEE Power & Energy Society General Meeting, Harbor, Maryland, July 28, 2014.

20. "Price-Enabled Demand Response," presented to the Thai Energy Regulatory Commission, OERC, and Utilities Delegation, Boston, Massachusetts, July 16, 2014.

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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Public Service Company

Docket No. E-01345A-16-0036

PREPARED DIRECT TESTIMONY OF

AHMAD FARUQUI

Attachment AJF-2DR: Summary of Residential Three-Part Tariffs

Summary of Residential Three-Part Tariffs

#	Utility	Utility Ownership	State	Residential Customers Served	Fixed charge ($/month)	Demand Charge ($/kW-month) Summer	Demand Charge ($/kW-month) Winter	Timing of demand measurement	Demand interval	Combined with Energy TOU?	Applicable Residential Customer Segment	Mandatory or Voluntary
[1]	Alabama Power	Investor Owned	AL	1,241,998	14.50	1.50	1.50	Any time	15 min	Yes	All	Voluntary
[2]	Alaska Electric Light and Power	Investor Owned	AK	13,968	11.49	6.72	11.11	Any time	Unknown	No	All	Voluntary
[3]	Arizona Public Service	Investor Owned	AZ	1,019,292	16.96	13.50	9.30	Peak Coincident	60 min	Yes	All	Voluntary
[4]	Black Hills Power	Investor Owned	SD	54,617	13.00	8.10	8.10	Any time	15 min	No	All	Voluntary
[5]	Black Hills Power	Investor Owned	WY	2,153	15.50	8.25	8.25	Any time	15 min	No	All	Voluntary
[6]	Butler Rural Electric Cooperative	Cooperative	KS	7,000	25.00	5.00	5.00	Any time	60 min	No	All	Mandatory
[7]	City of Fort Collins Utilities	Municipal	CO	60,464	5.37	2.50	2.50	Any time	Unknown	No	All	Voluntary
[8]	City of Kinston	Municipal	NC	9,776	14.95	9.35	9.35	Peak Coincident	15 min	No	All	Voluntary
[9]	City of Longmont	Municipal	CO	34,697	15.40	5.75	5.75	Any time	15 min	No	All	Voluntary
[10]	Dakota Electric Association	Cooperative	MN	94,924	12.00	14.70	11.10	Any time	15 min	No	All	Voluntary
[11]	Dominion	Investor Owned	NC	101,158	16.39	8.25	4.83	Peak Coincident	30 min	Yes	All	Voluntary
[12]	Dominion	Investor Owned	VA	2,105,500	12.00	5.68	3.95	Peak Coincident	30 min	Yes	All	Voluntary
[13]	Duke Energy Carolinas, LLC	Investor Owned	NC	1,608,151	13.38	7.77	3.88	Peak Coincident	30 min	Yes	All	Voluntary
[14]	Duke Energy Carolinas, LLC	Investor Owned	SC	460,178	9.93	8.15	4.00	Peak Coincident	30 min	Yes	All	Voluntary
[15]	Fort Morgan	Municipal	CO	5,273	6.13	10.22	10.22	Unknown	Unknown	No	All	Voluntary
[16]	Georgia Power	Investor Owned	GA	2,072,622	10.00	6.64	6.64	Any time	30 min	Yes	All	Voluntary
[17]	Mid-Carolina Electric Cooperative	Cooperative	SC	55,000	24.00	12.00	12.00	Any time	60 min	No	All	Mandatory
[18]	Midwest Energy Inc	Cooperative	KS	29,951	22.00	6.40	6.40	Any time	15 min	No	All	Voluntary
[19]	Otter Tail Power Company	Investor Owned	MN	47,699	16.00	6.08	5.11	Any time	60 min	No	All	Voluntary
[20]	Otter Tail Power Company	Investor Owned	ND	44,910	18.38	6.52	2.63	Any time	60 min	No	All	Voluntary
[21]	Otter Tail Power Company	Investor Owned	SD	8,648	13.00	7.05	5.93	Any time	60 min	No	All	Voluntary
[22]	Salt River Project	Political Subdivision	AZ	891,668	32.44 or 45.44	9.59 to 34.19	3.41 to 9.37	Peak Coincident	30 min	Yes	DG only	Mandatory
[23]	Swanton Village Electric Department	Municipal	VT	3,208	26.57	6.77	6.77	Any time	Unknown	No	All	Mandatory
[24]	Westar Energy	Investor Owned	KS	700,000	16.50	6.78	2.09	Any time	30 min	No	All	Voluntary
[25]	Xcel Energy (PSCo)	Investor Owned	CO	1,182,093	12.25	8.57	6.59	Any time	15 min	No	All	Voluntary

Sources: Utility tariffs as of April 2016, and "Form EIA-861 2013 data files, EIA_861_Retail_Sales_2013.xls" (for Utility ownership and Residential Customers Served columns).

Notes:

Peak periods are applicable from Monday through Friday excluding holidays. For some utilities, the monthly fixed charge has been calculated by multiplying a daily charge by 30.5.

[2]: Mandatory if customer consumes more than 5,000 kWh per month for three consecutive months or has a recorded peak demand of 20 KW for three consecutive months.

[3]: The monthly fixed charge is a daily basic service charge multiplied by 30.5 days.

[4]-[5]: Black Hills also offers an optional time-of-use rate that includes both energy and demand charges for customers owning demand controllers.

[12]: Demand charge is the sum of the distribution demand charge and the generation demand charge. The distribution demand charge is $1.612/kW and the generation demand charge is $4.070/kW for the summer and $2.334/kW for the winter.

[15]: The timing of demand measurement and the demand interval are not explicitly identified in the publicly available information we have reviewed.

[18]: The demand charge is based on the greater of the highest average 15 minute kW demand measured during the period for which the bill is rendered, and 80% of the average 15 minute maximum demand for the last three summer months.

[19]-[21]: Demand is measured as the maximum winter demand for the most recent 12 months. New customers have an assumed demand of 3 kW for their first year. Fixed charge for MN is customer charge per month plus facilities charge per month. Fixed charge for ND and SD is just customer charge per month.

[22]: Customers below 200 amps pay a fixed charge of $32.55 per month and customers above 200 amps pay $45.44 per month. Demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). The summer demand charges shown here apply for the On-Peak Summer period. The (on-peak) summer demand charge is $9.59 for up to 3kW of demand, 17.82 for the next 7kW, and 34.19 for over 10kW. The winter demand charge is $3.41 for up to 3kW, 5.46 for the next 7kW, and $9.37 over 10kW. The utility is experimentally offering the rate plan to a limited number of non-DG customers.

[23]: The demand charge is based on the greater of the measured demand for the current month and 85% of the highest recorded demand established during the preceding eleven months. The rate is mandatory for all residential customers with monthly consumption equal to or greater than 1,800 kWh, measured on a rolling 12 month average basis.

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Public Service Company

Docket No. E-01345A-16-0036

PREPARED DIRECT TESTIMONY OF

AHMAD FARUQUI

Attachment AJF-3DR: Illustrative Example of Cross-Subsidy

The cross-subsidy illustrative model is provided separately in a Microsoft Excel file titled "Cross-Subsidy Model.xls."

DIRECT TESTIMONY OF CHARLES A. MIESSNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF CHARLES A. MIESSNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

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 Manager of Rates for Arizona Public Service Company (APS or Company).

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. My qualifications are provided in Attachment CAM-01DR, 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 first and foremost support the Company's proposed changes to retail rates. I explain how the proposed rate changes are consistent with APS's long-term rate plan, discussed by APS witness Leland Snook. My testimony further explains why there is a compelling need to restructure rates for residential and small-business customers as well as providing the specific proposals for new rates.

Aside from residential and small commercial rate design, I will describe how the proposed revenue is allocated to individual rate classes and demonstrate that the proposed rate changes achieve the proposed overall increase in revenue.

My testimony will further provide a detailed explanation of the proposed changes to existing rate schedules, adjustment schedules, plans of administration (POA) and service

schedules. Finally, I will support certain pro forma adjustments to Test Year revenue and sponsor Standard Filing Requirements (SFR Schedules H-1, H-2, H-3, H-4, and H-5).

III. SUMMARY OF DIRECT TESTIMONY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. In my Direct Testimony, I discuss APS's overall requested revenue increase of $165.9 million, which results in a 5.74% bill impact to retail customers. APS is also requesting to transfer $267.6 million in revenue that is currently being recovered through annual adjustor rates to be recovered through general (base) retail rates. This transfer results in an overall requested increase in base retail rates of $433.4 million, or 15%, and a reduction in adjustor rates of $267.6 million, resulting in the net increase of 5.74% noted above. I provide the net increase by customer class, which ranges from 3.34% for the general service class to 7.96% for the residential class, where the different increases reflect the relative revenue deficiencies during the Test Year for each class. I explain that the requested net increase for the residential class of 7.96% is 2.22% higher than the overall average net increase of 5.74%, and this difference is substantially caused by the cost shift from the solar net metering program, where subsidized bill savings for solar customers create higher rates for everyone else. I also provide the requested increases in base rates for each class, including the adjustor transfers, which range from 10.10% for the outdoor lighting class to 19.30% for the residential class. The requested base rate increases reflect both the relative revenue deficiencies for each class, as discussed, as well as the relative amount of adjustors that were transferred into base rates for each class. For example, as shown in Figure 1, for the residential class, the requested increase in base rates is 19.30%, which includes 11.34% for adjustor revenue that is being transferred from adjustor rates to base rates, for a net increase to the customer's bill of 7.96%.

Figure 1 Requested Rate Increase and Net Impact to Customers

Class	Requested Increase to Retail Revenue	Transfers from Adjustor Rates to Base Rates	Requested Increase to Base Rates	Net Impact
Residential	7.96%	11.34%	19.30%	7.96%
General Service	3.29%	7.03%	10.32%	3.29%
Total Retail	5.74%	9.26%	15.00%	5.74%

I also provide the proposed changes to residential rate schedules, which include a continued emphasis on time-of-use rates. The three primary rate options proposed for residential customers will have lower kilowatt-hours (kWh) charges, a higher basic service charge, and a demand charge. The time-of-use on-peak hours will be revised to 3 p.m. to 8 p.m. weekdays to better reflect the highest system load hours and to help address the "duck curve" issue, i.e., low loads at mid-day with rapid load building in the late afternoon and early evening, which has arisen in the Western power markets in non-summer months. The time-of-use kWh charges will also be revised to better reflect the cost of service by reducing the difference between the on-peak and off-peak rates.

Specifically, the three primary residential rate options are three-part rates which include a service charge, a kW demand charge applied to on-peak hours, and time-of-use kWh energy charges. The proposed charges for rates R-1, R-2, and R-3 are shown in Figure 2.

Figure 2 Proposed Rates for Residential Customers

		Rate R-1	Rate R-2	Rate R-3
1. Basic Service Charge	($-day)	0.789	0.477	0.789
for typical month	($-month)	24.00	14.50	24.00
2. Demand Charge				
Summer on-peak	($-kW)	6.60	8.40	16.40
Winter on-peak	($-kW)	6.60	8.40	11.50
3. Energy Charges				
Summer on-peak	($-kWh)	0.15160	0.15160	0.09090
Summer off-peak	($-kWh)	0.08070	0.08080	0.05475
Winter on-peak	($-kWh)	0.12730	0.12730	0.06670
Winter off-peak	($-kWh)	0.08070	0.08080	0.05475

In addition, customers with extra-small usage below 600 kWh per month — customers in apartments, manufactured homes, or other small dwellings — will have an additional rate option, R-XS, having a basic service charge of $18 per month on average, no demand charge and a flat energy charge of $0.10234 per kWh for all hours and seasons. Rates R-1 and R-2, and R-XS will not be available to new partial requirements customers (customers with on-site generation).

APS expects to recommend incremental increases in these demand charges in future rate cases to a level closer to the third residential rate option.

For all three rate options, the demand charge is based on the maximum usage averaged over one hour during the 3 p.m. to 8 p.m. on-peak hours. Weekday off-peak hours, weekends and designated holidays would be exempt from any demand charges.

APS is also requesting changes to specialty rates and rate rider options. First, APS proposes to simplify the discount structure for the limited-income bill discount program and provide for increased program funding through a pro forma adjustment to Test Year revenue. APS also proposes to consolidate experimental rate schedule CMPW-01 with the Solar Partners Program described by APS witness Scott Bordenkircher. A new section to Service Schedule 1 addressing Automated Metering Infrastructure (AMI) opt-out is also proposed. I discuss APS's outlook for the optional Peak Event Pricing dynamic-rate program. APS's proposal for new solar customers includes a modified net metering program and service under the third rate option, rate R-3, outlined above. APS also proposes to grandfather qualifying existing solar customers to remain on their current rate with the frozen net metering program in place today.

I provide the proposed rate changes for business customers, which include:

- Improving the time-of-use rate options to work better with the operating schedules of many businesses;
- Introducing a generation aggregation pricing option for large customers with multiple sites;
- Introducing a high load factor rate for the Company's largest customers and an economic development service schedule as sponsored by Mr. Snook;
- Increasing basic service charges; and
- Adding a demand charge component for extra-small business customers.

Street lighting rates will be revised to emphasize adoption of new LED lighting fixtures and to encourage more customers to own and maintain their street lighting equipment. Existing high pressure sodium and low pressure sodium fixtures offered under rates E-47 and E-58 will be frozen and will not be available to new customers.

Most of our other business rates today already include a demand charge component and generally provide effective price signals for new technology. Therefore, APS is only proposing modest changes to these rates.

All of the proposed changes are significant first steps consistent with APS's Long Range Rate Plan sponsored by Mr. Snook. This plan envisions a future where homes and businesses are effective resources for providing future power needs and reducing the need for additional central station power plants and other grid investments. The resource potential includes customers' adoption of a variety of new and continually improving technologies such as home energy controls, integrated thermostats and appliances, advanced air-conditioning and other equipment, distributed generation with energy storage systems, and electric vehicles.

To make this work, APS must provide effective prices that both reflect cost and incent the right technologies — those that provide flexibility for APS generation requirements and are most effective in reducing APS summer peak demand, which drives so much of the Company's grid costs. With effective price signals, APS can create a solid platform supporting new technologies for homes and businesses and enable effective transactions that are beneficial to all customers.

The Company's current residential rates do not provide effective price signals for new technologies or provide a platform for using the home as a future resource. They are based on decades-old designs that were developed when metering equipment was more limited and customers had few, if any, options to invest in home technologies.

I discuss that these old rate designs do not adequately reflect the costs or even the services that utilities provide. The latter include basic services for accessing the grid

and receiving electrical service each month, a demand or capacity service for the grid infrastructure investments like power plants, transmission lines, substations, and local distribution equipment necessary to serve the customer's load, and an energy service for the fuel and other variable costs of the actual electricity consumed in a month.

The grid infrastructure is sized to accommodate the customer's maximum electrical draw or "demand" in any hour, as measured in kW, not the total monthly energy consumption, which is measured in kWh. Old two-part rate structures include a monthly service charge and a kWh charge that are misaligned with the utility's costs to serve customers because they attempt to recover all of the grid investment costs and some of the basic service costs with volumetric kWh energy charges, instead of kW demand charges and monthly service fees. By doing so, the charges on the bill do not accurately reflect the services provided to the customer.

In contrast, a three-part rate rewards customers for reducing both their energy and their demand. Furthermore, under the three-part rate, the bill savings for the demand and energy charges will be linked to reductions in both the utility's grid costs and energy costs and therefore will reduce any adverse impacts on other customers. Conversely, under a two-part rate the customer's bill savings are not linked to the utility's total cost savings, but only to the energy savings, which will result in un-recovered grid costs that are shifted to other customers in the form of higher rates.

From the customer's perspective, a two-part rate typically only provides one opportunity for a customer to save on their bill — by reducing their total kWh consumption. If the kWh charges vary by time-of-use, then the customer can also save by shifting their usage to off-peak hours. Under a three part time-of-use rate the customer has three opportunities to save — reduce consumption, shift kWh and kW demand to off-peak

hours, and lower the on-peak demand through simple behavioral changes such as staggering the use of major appliances or by load savings devices such as load controllers, smart thermostats and other technologies.

In short, the old two-part rate designs are economically inefficient, ineffective in reducing a utility's total costs to serve customers, and ultimately unfair.

- **Economically inefficient.** Two-part rate designs are inefficient because they do not provide the right price signals for when and how customers use electricity. Nor do they provide the correct incentives for customers desiring to invest in distributed technologies because such technologies will not be rewarded for, or focused on, reducing demand-related grid costs. Both of these issues will result in the inefficient use of and inadequate funding for the grid.
- **Ineffective.** For similar reasons, the two-part rates are also ineffective in reducing a utility's overall costs because they do not effectively incent customers to lower their monthly demand. As a result, the rates would likely only reduce the utility's energy-related costs, such as fuel, and not the demand-related costs, which include all of the extensive grid investment costs.
- **Unfair.** The two-part rates are ultimately unfair because they result in one group of customers paying the costs to serve another group of customers. This is a direct result of using two billing elements to recover the cost of three discreet and different utility services: basic services; demand-related grid services; and energy-related services.

APS has extensive experience with residential three-part demand rates. APS has offered a three-part demand rate to residential customers for decades and is currently serving approximately 120,000 customers on the rate. Customers on these rates have demonstrated they can respond to demand charges and manage their monthly demand on

their bill. When customers switch to the rate, they typically reduce both their demand and energy consumption.

I conclude that residential rates should be reformed and modernized to better align rates with costs, provide appropriate price signals to customers, and improve the efficient use of, and funding for, the grid.

Another part of my testimony reviews APS's current cost of service, rates and proposed revisions. I note that the costs to serve residential customers include:

- **Basic service costs** such as meters, point of delivery equipment, transformers, and billing and customer service costs;
- **Demand-related costs** such as capital infrastructure investments for power plants and the transmission and distribution grid; and
- **Energy-related costs** such as fuel and purchased power.

However, APS's current residential rates recover some of the basic service costs and all of the demand costs through kWh energy charges, rather than monthly service charges and kW demand charges respectively.

APS's proposed revisions to residential rates are consistent with the objectives of our Long Range Rate Plan. For example, the proposed rate designs improve the recovery of basic service costs through the monthly service charge, rather than through a kWh energy charge and expand the use of kW demand charges to recover a portion of demand-related costs.

APS also proposes to implement the new rates over a transition period to allow time to inform customers about the rate changes. Meanwhile, APS's existing rates would be

revised to reflect the allocated revenue increase awarded in the rate case. Details of the transition plan are provided by APS witness Stacy Derstine.

IV. REQUESTED INCREASE AND ALLOCATION TO RATE CLASSES

Q. WHAT IS THE COMPANY REQUESTING FOR AN OVERALL INCREASE IN RETAIL REVENUE?

A. As provided in SFR H-1, APS is requesting an overall increase in retail revenue of $165.9 million or 5.74%. The Company is also requesting to transfer $267.6 million of retail revenue that is currently recovered in annual adjustor rates to base rates. This results in a total increase in base rate revenue of $433.4 million which is a 15% increase over adjusted Test Year base revenues. Because this transfer of adjustor revenue to base rates has no net impact on the overall retail revenue, the overall net increase to retail revenue is 5.74%.

Q. HOW IS THIS REQUESTED INCREASE IN REVENUE ALLOCATED TO THE VARIOUS RATE CLASSES?

A. The requested increase in retail revenue, the transfer of adjustor revenue into base rates and the resulting increase in base rates for each major customer rate class are provided in Table 1. Additional detail for each specific retail rate is provided in SFR Schedule H-1. As shown in Table 1, APS is requesting an average revenue increase in base rates of 19.30% for residential rates, 10.32% for general service, 17.02% for water pumping, and 10.10% for dusk to dawn area lighting and street lighting service. The requested increases for individual rate schedules within these classes also vary from the overall class average.

Table 1 Requested Increase in Retail Revenue, Base Rates, and Net Impact

(% Adjusted Test Year Revenue)

Class	Requested Increase to Retail Revenue	Transfers from Adjustor Rates to Base Rates	Requested Increase to Base Rates	Net Impact
Residential	7.96%	11.34%	19.30%	7.96%
General Service:				
Extra-small, Small	0.04%	8.57%	8.61%	0.04%
Medium	4.04%	7.64%	11.68%	4.04%
Large	6.04%	5.09%	11.13%	6.04%
Extra-large	6.14%	4.70%	10.84%	6.14%
GS – Schools	6.04%	9.34%	15.38%	6.04%
House of Worship	9.04%	11.32%	20.31%	8.99%
Subtotal	3.29%	7.03%	10.32%	3.29%
Irrigation	5.74%	11.28%	17.02%	5.74%
Outdoor Lighting	5.74%	4.36%	10.10%	5.74%
Total Retail	5.74%	9.26%	15.00%	5.74%

Q. WHAT FACTORS WERE CONSIDERED IN DETERMINING THIS ALLOCATION OF REVENUE RESPONSIBILITY?

A. APS was guided by the overall public interest in deriving the proposed rate increases for each customer class. This included the cost of service and the revenue deficiency, or the percent of cost of service recovered by the revenue, which 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.

Q. HOW DID THE COST OF SERVICE FACTOR INTO THE ALLOCATION OF RATE INCREASES?

A. In the cost of service study (COSS) sponsored by Mr. Snook, 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 percent of cost to serve, which is the revenue divided by the cost of service, was derived for each class as discussed and provided by Mr. Snook.

In general, rate classes which were most deficient in recovering their cost of service, or which had the lowest percent of cost to serve, received a relatively higher increase. Conversely, rate classes that were least deficient in cost recovery and had higher percent recoveries of cost to serve received a relatively lower allocated increase. The requested base rate increases and percent recovery of cost to serve by class both before and after the rate increase are provided in Attachment CAM-02DR.

Q. DID THE COST SHIFT FROM SOLAR NET METERING IMPACT THE REVENUE ALLOCATION?

A. Yes. A large part of the revenue deficiency for the residential class was the result of cost shifts from solar net metering customers to all other residential customers. The revenue deficiency from solar net metering during the Test Year was $18.5 million, which consists of the cost shift from new residential solar customers since 2010, the Test Year from the last rate case to 2015, the current Test Year. This deficiency causes a 1.25% increase in base rates above any other recovery of cost increases sought in this rate case. As shown in Table 1, the overall requested increase for the residential class was 2.22% above the average increase for all customers. This difference was, therefore, significantly impacted by the solar cost shift.

Q. IS THERE A SIMILAR IMPACT FROM ENERGY EFFICIENCY?

A. Typically, yes. But the net bill impact on other customers is likely to be relatively lower than the impact from rooftop solar. Under a two-part rate structure, residential energy efficiency programs also create a revenue deficiency which is shifted to other customers. Some programs however, can reduce peak demand, including, for example, programs that focus on efficient air-conditioning. Such programs limit the revenue deficiency by reducing both fuel costs and grid capacity costs.

Moreover, because the participation in energy efficiency programs is more widely spread across all customers, compared with rooftop solar, and the reduction in monthly energy consumption and the resulting bill savings from the typical customer is considerably less, the effective cost shift to others from a customer that adopts energy efficiency is likely to be much lower than the impact from rooftop solar.

Q. WHAT IMPACT IS THERE ON CLASS REVENUE REQUIREMENTS FROM THE RESIDENTIAL RATE DESIGN REFORMS DESCRIBED LATER IN YOUR DIRECT TESTIMONY?

A. None. The reforms are revenue neutral on a class basis. That is, there is no net impact on the residential customer class.

Q. PLEASE EXPLAIN HOW GRADUALISM FACTORED INTO THE PROPOSED RECOMMENDATION.

A. As mentioned, APS applied 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 19.30% in base rates for the residential class, which is a 7.96% overall impact after the reduction in adjustor rates. This requested increase is above the proposed system-average increase, but will still leave residential customers below the cost of service. The goal is to gradually bring residential customers more in line with cost of service over time. This type of tradeoff in rate design objectives 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.

V. KEY RETAIL RATE PROPOSALS

Q. PLEASE SUMMARIZE APS'S MAJOR RATE PROPOSALS.

A. In general, APS proposes the following changes to retail rates:

1. Streamlined rate choices for residential customers, which include three time-of-use rate options, and a non-time-of-use rate option for customers with extra-small usage;
2. Revisions to kWh charges for residential rates to better reflect costs;
3. Increases in basic service charges to better reflect costs;
4. Expanded use of a demand charge for residential and extra-small business customers;
5. New rate options for general service customers that include an improved time-of-use rate for small, medium, and large business customers, a rate for extra-high load factor customers and an aggregation rate discount for large business customers with multiple accounts;
6. A menu of options for outdoor lighting customers that focus on new LED technologies; and
7. Modification of the net metering program going forward, while providing a grandfathering program for qualifying customers with existing rooftop solar.

Q. HOW DO THE PROPOSED RATE CHANGES REFLECT THE LONG RANGE RATE PLAN?

A. APS's proposed rates reflect the principals in the plan because they seek to:

- Modernize rates to enable new technologies and reflect the continued value of the electricity delivery system;
- Improve rate fairness among customers by aligning rates with the cost of service, minimizing/eliminating embedded subsidies;
- Provide rate gradualism and bill stability for customers by managing overall rate levels and thoughtfully transitioning to new rate designs; and
- Enhance customer satisfaction by providing fewer but more meaningful rate choices.

VI. RESIDENTIAL RATE REFORM

Q. WHY SHOULD RESIDENTIAL RATES BE REFORMED?

A. Today, most, if not all, electric utilities have residential rates that are not aligned with the types of costs necessary to serve the customers. Rather, rates reflect aging, outmoded designs that may have made sense in the past when metering technology was limited and customers had no interest or options to invest in distributed technologies. However, today automated meter infrastructure (AMI) offers significant flexibility in residential rate design and allows energy-usage information to be integrated with home controls and smart appliances. Also, customers now have meaningful opportunities to invest in distributed generation, energy storage, electric vehicles, smart thermostats and appliances, home energy controls, advanced HVAC systems, and other new technologies.

It is imperative that APS has new rate designs that:

- Incent the technologies that reduce both demand and energy;

- Provide accurate price signals for incenting how and when customers use electricity;
- Reflect the types of services provided by the utility and the costs for those services; and,
- Provide opportunities for customers to save on their bill without shifting costs to other customers.

All of these factors will result in the improved use of, and funding for, the electrical grid.

Q. HOW ARE RESIDENTIAL RATES AND COSTS CURRENTLY MISALIGNED?

A. Residential rates and costs are currently misaligned because they rely on volumetric kWh energy charges to recover demand-related costs — grid investments, like wires, poles, transformers, and generating plants, which are by far the predominant cost to serve residential customers. In contrast, these grid costs are recovered through kW demand charges or monthly service charges for most non-residential customers like businesses, schools, colleges, hospitals, and government buildings.

Q. WHAT IS THE DIFFERENCE BETWEEN ENERGY AND DEMAND?

A. Energy is the total consumption of electricity over a billing month, measured in kWh (1,000 Watt-hours). Demand is the instantaneous electrical draw of a customer's load at a single point in time, measured in kW (1,000 Watts).

If you turned on ten 100-Watt lightbulbs at the same time they would draw (or demand) 1 kW at that instant. If you left them all on for five hours they would consume five kWh of energy (1 kW used over five hours).

Q. WHY IS THIS DISTINCTION IMPORTANT?

A. Demand and energy drive different costs of service, both of which are necessary to serve customers. The size of the grid necessary to serve the home is driven by the home's kW demand. This includes infrastructure investments in power plant capacity, wires, poles, substations, transformers, and other capital equipment.

For example, a home that draws a maximum load of 8.0 kW in one hour requires 8.0 kW of grid investment to serve it, regardless of the overall energy consumption during the month.

Other costs, such as fuel and variable operation and maintenance costs, are largely driven by a customer's total kWh energy consumption over the month. In this same home, the customer's average load over all of the hours in a month may be more like 2.5 kW per hour, which would equate to 1,825 kWh (2.5 kW x 730 hours in a month).

Suppose the customer goes on vacation for two weeks and reduces their monthly kWh energy consumption but still drew 8.0 kW demand sometime during the other two weeks. What costs would they reduce? They would certainly reduce the fuel and other variable costs needed to serve them because of the reduction in monthly kWh. However, they would still require 8.0 kW of grid services for the home because they still drew 8.0 kW of demand during some hour before the vacation. Stated another way, the fixed infrastructure doesn't go away just because the customer leaves for a couple of weeks.

Q. HOW DOES THIS TRANSLATE TO THE RATES?

A. In a sense, the utility provides the customer with three types of services: basic services for connection to the grid each month, kWh energy, and kW demand. Today, business

customers, other than extremely small accounts, are charged separately for these services through a three-part rate. The customer pays for basic services through a monthly service charge, energy services through a kWh energy charge, and demand services through a kW demand rate.

In contrast, residential customers are typically billed through a two-part energy rate, where the energy services, demand services, and some of the basic services are billed with a kWh energy charge, and a portion of the basic services with a monthly service charge.

VII. APS'S RESIDENTIAL THREE-PART DEMAND RATES

Q. WHAT IS APS'S EXPERIENCE WITH RESIDENTIAL DEMAND RATES?

A. APS has significant experience with residential three-part demand rates. We currently have 120,000 customers, or 11.5% of total customers, on a demand rate.

Q. HOW LONG HAS APS OFFERED THESE RATES?

A. APS has offered residential demand rates for more than 35 years.

Q. WHY WERE DEMAND RATES FIRST ADOPTED?

A. APS's earliest three-part demand rate dates back to 1981. At that time, the Arizona Corporation Commission (ACC or Commission) in approving the rate, stated that a residential rate based primarily on each customer's kWh energy consumption "ignores the fact that the cost of providing electric service is increasingly a function the demand for electricity places on the system rather than total power consumed."[1]

[1] ACC Decision No. 51472 at Finding of Fact No. 1 (October 21, 1980).

The Commission further recognized that including a demand component in the residential customers' bills would provide "an incentive to customers to manage their electric load in a manner that can result in lower electric bills for the individual customers and equally important, a reduction in APS peak demand which can have the effect of reducing the need for expensive additional generating facilities."[2]

"Due to the introduction of an explicit demand charge, residential air-conditioning customers who are billed under the EC-1 rates have a price signal that higher use at any particular time will result in higher bills. In response, over 7,000 EC-1 customers installed load control devices during 1986. Since much residential use is at the system peak, these customers reduced APS's summer peak demand by 10.8 MW."[3]

Q. CAN CUSTOMERS RESPOND TO DEMAND CHARGES?

A. Yes. While the experience varies for each customer, we have found that customers do respond to demand price information. Some customers maximize their bill savings by actively managing their demand through investments in home energy controls, efficient appliances, HVAC systems, and other devices. Others reduce their demand by changing their energy usage behavior and patterns, such as avoiding using major appliances at the same time to lower the maximum electrical draw of the home during the month.

There are admittedly some customers who are not interested in any of the specific components of the electric bill, including the demand charge; they are only concerned that the total seems to be reasonable and comports to some typical expected amount. These customers do not try to actively manage their bill. However, many of these customers still save on their bill under a demand rate because their electrical usage

[2] *Id.* at Finding of Fact No. 3.
[3] *Arizona Pub. Serv. Co.*, 91 P.U.R.4th 337, 377 (Ariz. C.C. Apr. 1, 1988).

patterns naturally benefit from a demand charge. For example, they may have a lower maximum kW draw in any hour in relation to their monthly kWh energy consumption.

Q. WHAT KIND OF DEMAND SAVINGS HAVE CUSTOMERS ACHIEVED?

A. It varies by home. We looked at a large group of customers[4] that switched to the three-part demand rate and found that on average customers on the three-part rate reduce their monthly demand by 3% to 4% depending on the season. And, those that actively manage their demands have achieved demand savings of 10% to 20% or more. These customers also tend to save on their on-peak and monthly kWh usage through the various measures deployed and behavior responses to the rate.

Q. HAVE CUSTOMERS ON DEMAND RATES SAVED ON THEIR BILL?

A. Typically, yes. APS found that more than 90% of the customers in our study group that switched to the demand rate saved on their monthly bill. Sixty percent of the customer in the study saved on their demand and energy. The average bill savings was 9% and the top 25% saved more than 20% on average (excluding taxes and adjustments).

Q. WHAT CAUSES THESE BILL SAVINGS?

A. The three-part rate structure rewards customers for reducing both their demand and energy. And because it's a time-of-use rate it also provides savings for shifting usage to the off-peak hours. In essence, APS's three-part rate provides customers three opportunities to save on their bill. In comparison, the Company's two-part inclining block rate only provides one opportunity to save — namely, reducing the total monthly kWh energy usage.

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[4] The group included all customers residing in the phoenix metro region that switched from a two-part time-of-use energy rate to a three-part time-of-use demand rate between 2012 and 2014 with at least one year of billing information under both rates. The group was approximately 1,000 customers.

Q. IS THIS A WIN-WIN SITUATION OR ARE THESE BILL SAVINGS SHIFTED TO OTHER CUSTOMERS?

A. As discussed earlier, when a customer reduces their demand and energy they reduce both future grid investment costs and the fuel and other variable costs necessary to serve them. If the service charge and demand charges in the three-part rate fully recover the grid investment costs to serve the customer, then the bill savings of one customer would not shift costs to other customers.

In contrast, as discussed, a two-part rate only incents a customer to reduce their monthly kWh consumption, not their demand. In this case, only the fuel and other variable costs are reduced, typically not the grid investment costs. But the customer is rewarded as if they had reduced both types of costs. This "over-reward" is paid for by other APS customers, hence a cost shift.

VIII. RESIDENTIAL RATES

Q. PLEASE DESCRIBE APS'S CURRENT RESIDENTIAL RATES.

A. APS currently serves more than one million residential customers with a variety of rate schedules and options including:

- Inclining block rate;
- Two time-of-use (TOU) energy rates;
- Two TOU demand rates;
- Super peak TOU rate;
- Two dynamic rate options; and
- TOU rate for electric vehicles.

Optional Rider Rates are available for special requirements or services such as on-site renewable generation, green power, limited-income, and medical equipment discounts,

and other specialized or experimental programs. A complete list of the current and proposed rate schedules and riders are provided in the SFR Index to Rate Schedules.

Q. CAN CUSTOMERS CHOOSE A RATE PLAN?

A. Yes. Residential customers can choose from any of the options listed above including a non-time-of-use rate, a TOU energy rate, and a TOU demand rate. In fact, approximately 11.5% of APS's customers have chosen a TOU demand rate and another 43% a TOU energy rate.

Q. PLEASE DESCRIBE THE COSTS TO SERVE RESIDENTIAL CUSTOMERS.

A. The COSS provided in SFR "G Schedules" and other relevant information shows that APS's costs to serve residential customers include power supply and fuel costs, transmission infrastructure investments and ancillary services, local grid infrastructure cost for delivering the energy to the home and hookup costs such as some secondary service costs, meters, meter reading, billing and customer care.

Q. ARE APS'S CURRENT RESIDENTIAL RATE STRUCTURES ALIGNED WITH THE COST OF SERVICE?

A. No. While the overall proposed level of cost recovery for each residential rate class appears to be somewhat consistent with the overall class cost of service, the current residential rate structures are not aligned with the different costs or services provided, as discussed. Specifically, the two-part rate structures recover grid infrastructure investments through volumetric kWh charges, even though the costs are determined by the size of the home's electrical draw (or demand), not the monthly kWh consumption. Likewise, even some of the basic service costs are recovered through kWh charges rather than through the basic service charge.

Q. DO THE CURRENT RATES PROVIDE ADEQUATE INFORMATION FOR CUSTOMERS WISHING TO INVEST IN HOME TECHNOLOGIES?

A. No. At best that information is only partial.

Q. PLEASE EXPLAIN.

A. The current two-part inclining block rate, for example, has a kWh price that increases with higher levels of monthly kWh energy usage. Customers with higher than average monthly usage pay a rate that is higher than average; customers with lower usage pay a rate that is lower than average. Therefore, the incentive for customers to adopt technologies that reduce energy usage varies considerably for each customer.

In addition, this inclining block rate structure does not reflect cost of service – the cost of service is not higher for homes with higher monthly kWh usage on a per unit basis. A large car may consume more gas, but the cost per gallon is the same for all cars (for the same octane product).

The existing two-part time-of-use energy rates are an improvement over the inclining-block rate because they incent technologies that focus on reducing energy consumption during on-peak hours. However, this is still only a partial improvement because, like the inclining block rate, the time-of-use energy rates fail to provide any incentive for reducing kW demand, which is a key driver of infrastructure capacity costs. As a result, the home technologies incented by the current inclining block and time-of-use energy rates are not likely to result in meaningful reductions in future infrastructure costs. They will reduce the future fuel costs for generating electricity, but not the cost for the power plant itself. Any impacts on the latter will only occur by happenstance or luck.

Q. HOW ABOUT THE EXISTING TIME-OF-USE DEMAND RATES?

A. They are better aligned with COS. The existing three-part time-of-use demand rates also provide the best incentives for home energy technologies. They incent technologies that focus on reducing both on-peak energy usage and on-peak demand, thus providing a much higher resource value.

Q. WHAT CHANGES TO RESIDENTIAL RATES DOES APS PROPOSE IN THIS RATE CASE?

A. APS proposes the following specific changes to residential rates:

1. Cancel the inclining block rate E-12.
2. Revise the current TOU energy rates as follows:
   - Consolidate TOU rate schedules ET-1, ET-2, ET-Super Peak, and ET-EV for electric vehicles into one TOU rate with a small demand charge;
   - Revise the on-peak hours to 3 p.m. to 8 p.m. weekdays, excluding designated holidays, for both winter and summer seasons;
   - Increase the number of off-peak holidays;
   - Reduce the difference in on-peak and off-peak prices from 4:1 to 2:1 in the summer months;
   - Increase the basic service charge;
   - Add a small demand charge;
   - Reduce the average kWh charges; and,
   - This rate is not available to partial requirements customers (with on-site generation).
3. Create a new TOU demand rate option with the following features:
   - A lower service charge and a demand charge in between the other two TOU demand rates;

- The same on-peak hours of 3 p.m. to 8 p.m. as the other proposed rates; and
- This rate is not available to partial requirements customers.

4. Revise the current TOU demand rates as follows:
   - Consolidate the TOU demand rates ECT-2 and ECT-1R into one TOU demand rate;
   - Revise the on-peak hours to 3 p.m. to 8 p.m., consistent with the other proposed TOU demand rates;
   - Increase the basic service charge; and
   - Retain a moderate demand charge.
5. Create a new rate option for extra-small customers like apartments, manufactured homes, and other small dwellings with the following features:
   - A service charge;
   - A flat kWh charge for each season;
   - No TOU or demand charges;
   - Eligibility only for customers with average monthly usage of 600 kWh or less; and
   - This rate is not available to partial requirements customers.
6. Allow qualifying grandfathered customers with renewable generation to stay on a current rate structure as follows:
   - The current rate design options E-12 inclining block, ET-1 and ET-2 time-of-use energy and ECT-1R and ECT-2 time-of-use demand rates will be available through the grandfathering period.
   - All of the charges (the basic service charge, kWh charges, and demand charge, if applicable) will be increased by an equal percent to reflect the targeted revenue increase for the residential class.

- Grandfathered customers will be able to stay on the current frozen net metering program or move to the modified net metering program for solar customers during the grandfathering period.

7. Simplify the discount programs for limited income customers and provide increased funding for growth in participation.
8. Continue the peak event pricing program, revised with new critical hours of 3 p.m. to 8 p.m., to be consistent with the proposed time-of-use hours; cancel peak time rebates.
9. Offer alternative metering service for customers that do not want to be served with the AMI metering and remote meter reading communication system; customers will be charged a one-time installation fee and a monthly meter reading fee.
10. Cancel the optional LFCR opt-out having a higher basic service charge.
11. Modify the net metering program for new solar customers.
12. Convert the Flagstaff solar experiment into the Solar Partners Program and discontinue Rate Rider Schedule CMPW.

Q. WHAT IS THE PROPOSED NEW MENU OF RATE CHOICES?

A. Specifically, the three primary residential rate options are three-part rates which include a service charge, a kW demand charge applied to on-peak hours, and time-of-use kWh energy charges as follows:

Figure 2 Proposed Rates for Residential Customers

		Rate R-1	Rate R-2	Rate R-3
1. Basic Service Charge	($-day)	0.789	0.477	0.789
for typical month	($-month)	24.00	14.50	24.00
2. Demand Charge				
Summer on-peak	($-kW)	6.60	8.40	16.40
Winter on-peak	($-kW)	6.60	8.40	11.50
3. Energy Charges				
Summer on-peak	($-kWh)	0.15160	0.15160	0.09090
Summer off-peak	($-kWh)	0.08070	0.08080	0.05475
Winter on-peak	($-kWh)	0.12730	0.12730	0.06670
Winter off-peak	($-kWh)	0.08070	0.08080	0.05475

Extra-small customers like apartments or mobile homes can choose any of these three options along with an additional extra-small rate that has a service charge that is increased over current average levels, no demand charge and no time-of-use pricing.

R-1, R-2, and R-XS are not available to partial requirement customers with on-site generation.

Q. WHAT ARE THE PROPOSED DEMAND CHARGES AND HOW WILL THEY BE MEASURED?

A. As shown in Figure 2 above, Rate R-1 will have a demand charge of $6.60 per kW. Rate R-2 will have a demand charge of $8.40 per kW. Rate R-3 will have a demand charge of $16.40 per kW in the summer season and $11.50 per kW in the winter season.

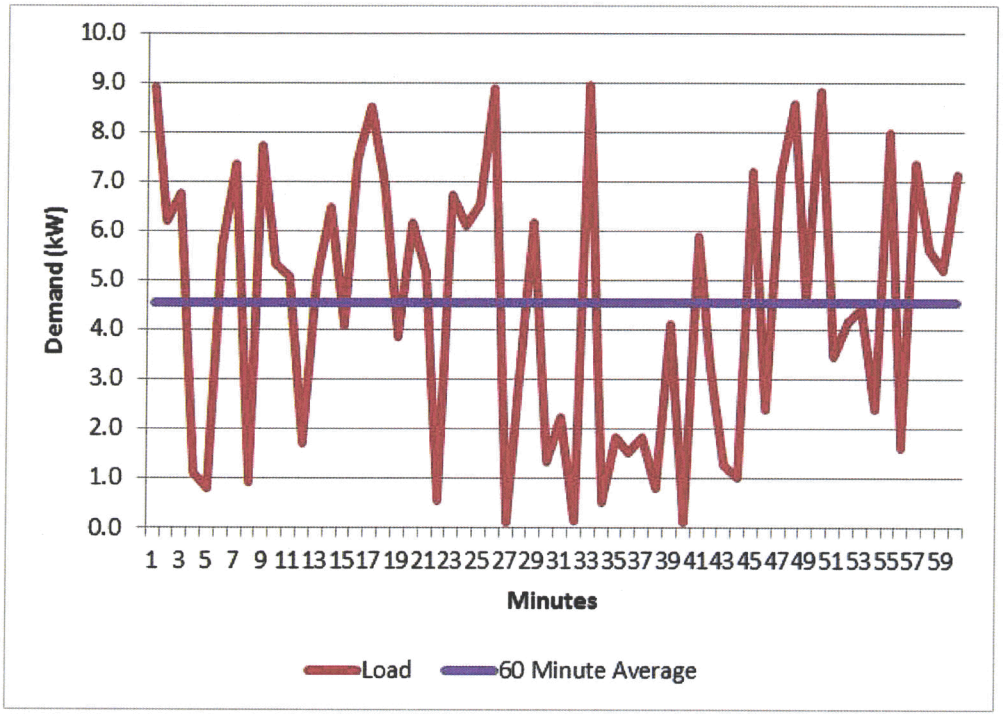
The demand charges for all of the rates will only be applied to the on-peak hours, which are 3 p.m. to 8 p.m. weekdays. Off-peak hours including the mornings, early afternoon, nighttime, weekends, and designated holidays will be exempt from demand charges.

In addition, the billed demand will be calculated on the highest demand averaged over a one-hour period during the month. In contrast, the billing demand is calculated over a 15 minute period for all business customers excepting E-32 XS. The one-hour demand calculation for residential customers is much more forgiving and should reduce the variability in monthly demands. In addition, there will not be any type of ratchet provision, which is commonly used for larger business customers.

Q. PLEASE GIVE AN EXAMPLE OF THE ONE-HOUR DEMAND CALCULATION?

A. Figure 3 provides an illustrative example of a customer's instantaneous demand, or draw from APS's grid, over an hour. As illustrated, the instantaneous demand can vary significantly throughout an hour, as motor loads start-up and then cycle or as various appliances and devices are used for a few minutes or less. In this example, the instantaneous demand varies from zero to 9 kW over the hour, while the average demand, depicted by the horizontal line, is approximately 4.5 kW. Therefore, as stated, using a one-hour demand calculation, as APS proposes for residential customers, will lower the average billed demands, lower the variability of monthly billed demands, and reduce the potential risk to customers from inadvertently setting a high demand.

Figure 3 Illustrative Example of Instantaneous Versus One-Hour Demands



Q. IS APS PROPOSING ANY ADDITIONAL MEASURES TO ENABLE A SMOOTH IMPLEMENTATION OF THE NEW TOU DEMAND RATES?

A. Yes. APS proposes a demand limiter, based on a 15% monthly load factor, to protect customers that set a high demand in relation to their overall energy usage in a particular month. For example, if a customer using 1,000 kWh a month typically uses a demand 5.5 kW but inadvertently sets a very high demand of 10 kW, this mechanism would bill them for a lower moderated kW. APS believes that this type of inadvertent high demand would be very unlikely given our experience with residential demand rates and the one-hour calculation discussed above. Nevertheless, the Company proposes this demand limiter mechanism as a "safety valve" for customers as demand charges are proposed for a much wider group of customers.

The proposal sets a ceiling for the kW billed in any month, based a 15% load factor calculation, which is an index of the relationship between kW demand and monthly

kWh consumption. In this example, the 5.5 kW demand with 1,000 kWh monthly consumption represents a 25% load factor [1,000 kWh / (5.5 kW X 730 hours in a month)]. The proposed mechanism would limit this customer using 1,000 kWh to a 9.1 kW billed demand, which is a 15% load factor. Therefore, even though their metered demand was 10 kW, they would only be billed for the maximum amount of 9.1 kW. The load factor index adjusts this maximum billed kW to the level of monthly kWh usage – customers with higher usage would have a higher maximum billed demand – and the number of billing days in a month.

This demand limiter will not be applicable to partial requirements customers with on-site generation.

Q. HOW DOES THE PROPOSED DEMAND CHARGES HELP CUSTOMERS GET USED TO THE DEMAND CONCEPT?

A. The $6.60 per kW demand charge for rate R-1 will only be about 21% of the total monthly bill for most customers. For example, an average customer on R-1 using 850 kWh and 4.5 kW demand per month would be billed $30 per month out of a total bill of $150.

For a higher load factor customer (lower demand for the same 850 kWh energy usage), the demand charge may be just 18% of the bill. Thus, if a customer inadvertently draws more demand in a given month, the bill impact would typically not be significant. In addition, APS's proposal to only measure demand during on-peak hours and to take the average over a one-hour time increment also helps to moderate any adverse bill impacts.

Q. WHY IS APS OFFERING THREE DIFFERENT TOU RATES WITH DEMAND CHARGES?

A. The three proposed demand rates will provide options for customers depending on how actively they want to manage their monthly demands. For example, Rate R-3 has demand charges that are about the same level as the current optional TOU demand rate, ECT-2. This rate is designed for customers to actively manage their monthly demands as another way of saving on their bill. The demand charges are more closely aligned with the overall infrastructure investments required to serve a residential customer. Therefore, it is closer to the ultimate ideal rate aligned with cost of service.

On the other hand, the Rate R-1 with a lower demand charge is targeted at customers that may not actively manage their monthly demands. And Rate R-2 has a demand charge between the other two rates.

Q. WHAT ARE THE NEW BASIC SERVICE CHARGES PROPOSED BY APS?

A. As shown in Figure 2, APS proposes the following basic service charges: for the extra-small rate, R-XS, $0.592 per day, which is $18 per month on average; rate R-1 - 0.789 per day ($24 per month); rate R-2 - $0.477 per day ($14.52 per month); and rate R-3 - 0.789 per day ($24 per month). Currently customers pay service charges ranging from $0.285 to $0.556 per day ($8.67 to $16.91 per month).

Q. WHAT COSTS DOES APS SEEK TO RECOVER THROUGH THE BASIC SERVICE CHARGE?

A. As discussed above, the service charge is appropriate for recovering standard costs needed to serve the home — costs that don't vary with the home's month kWh consumption or kW demand. These costs include, for example, the service drop and point-of-delivery equipment, the meter and meter reading system, the billing system and

related costs needed to produce a monthly bill, the customer care system and related operating costs. Furthermore, overhead costs such as grid operations, communications and cyber security equipment should also be recovered through the service charge because they are not driven by the size of a customer's electrical usage.

In addition, there is certain grid equipment, such as the distribution transformer on the pole behind the house, which is appropriate to recover through the basic service charge. While to some extent this equipment may vary with the potential electrical load in the home, it is nonetheless dedicated to serve the particular home. If a customer reduces their load in a particular month the excess capacity cannot be practically downsized or temporarily moved to serve another customer.

Q. DO THE PROPOSED BASIC SERVICE CHARGES RECOVER ALL OF THESE COSTS?

A. No. The proposed basic service charges recover more, but not all, of these standard service costs. The basic service charge would have to be increased above the requested amounts to recover all of these costs.

Q. WHY IS APS PROPOSING TO DISCONTINUE THE INCLINING BLOCK RATE?

A. APS's current inclining block rate (rate E-12) has four pricing blocks in the summer season ranging from $0.097 to $0.173 per kWh; the highest block price is about 80% higher than the first block. As discussed above, this price difference is not based on any difference in cost of service — it does not cost more per kWh to serve a larger user than a smaller one. In fact, the larger user has a lower unit (per kWh) cost of service. Rather, the difference only has the effect of discouraging customers with larger usage from using this rate.

In addition, the block pricing structure provides inaccurate and ineffective pricing information to incent customer investment in the types of home energy technologies that provide resource value to help meet future energy needs.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE TOU PRICES AND ON-PEAK HOURS.

A. APS currently has two TOU energy rates, ET-1 and ET-2, with on-peak hours of 9 a.m. to 9 p.m. and noon to 7 p.m., respectively. The difference in on-peak and off-peak prices varies by season and rate, ranging from on-peak prices that are 2.6 to 4.0 times the off-peak prices.

APS proposes to consolidate the on-peak hours to 3 p.m. to 8 p.m. weekdays, excluding designated holidays, and to reduce the TOU price difference so that on peak prices are 1.2 to 1.9 times the off-peak prices for the various rate options.

The proposed change in price differences will better reflect the difference in on-peak and off-peak costs and provide more-accurate information for customers making technology investments that help enable them to reduce kWh usage during the on-peak hours or potentially shift it to the off-peak period.

The proposed change in on-peak and off-peak hours will better reflect APS's system peak hours in the core summer months — the typical peak hours for residential distribution feeder lines and substations. It will also address the worsening "duck curve" issue in winter months, which I define below.

APS's total retail load peaks in the late afternoon to early evening in the core summer months, June, July, and August. However, during high-demand days the loads remain

very high well into the mid to late evening, e.g., 7, 8, and even 9 p.m. In addition, many residential distribution feeders peak in the mid evening, e.g., 7 to 8 p.m.

While the on-peak period could be extended to 9 p.m. due to the high loads in core summer months during that time, APS only proposes an on-peak period that extends to 8 p.m. to make it more user friendly for customers and provide a better opportunity to shift load to off-peak hours.

Q. HOW DO THE PROPOSED TOU HOURS ADDRESS THE "DUCK CURVE" ISSUE?

A. The proposed TOU hours are designed to address the "duck curve"[5] issues that have emerged in the Southwest power market in recent years. This phenomenon, which is caused by a dramatic increase in solar production across the desert southwest region, results in an overabundance of excess power production during the day. This is the belly of the duck. This phenomenon is also characterized by a rapid increase in generation requirements typically starting about 4 p.m. as solar production rapidly ramps down, while customer load increases. That's the neck of the duck. This rapid change cannot be efficiently handled with base load coal and nuclear resources. Instead it requires more flexible natural gas units with fast-ramping capabilities.

In addition during mid-day in the non-summer periods of the year, solar production is high, but customer electrical requirements are low. This results in power prices during late morning and afternoons that are very low or even negative, meaning that utilities are actually paying other power companies to offload excess power during these hours.

[5] The "duck curve" is also addressed in the testimony of APS witness James Wilde.

The proposed TOU hours of 3 p.m. to 8 p.m. will address the "duck curve" by encouraging usage to be shifted to the belly of the duck — Noon to 3 p.m., and discourage usage during the neck of the duck, 4 p.m. to 7 p.m. in non-summer months.

Q. WHAT ADDITIONAL HOLIDAYS IS APS ADDING TO THE RESIDENTIAL TIME-OF-USE RATES?

A. Currently, there are 6 holidays that are included in the off-peak hours for some residential time-of-use rates: New Year's Day, Memorial Day, Labor Day, Independence Day, Thanksgiving, and Christmas. These holidays will be applied to all of the new residential time-of-use rates along with four new holidays: Martin Luther King Day, Presidents Day, Cesar Chavez Day, which is March 31, and Veterans Day.

Q. WHY DOES APS PROPOSE TO CONSOLIDATE THE ELECTRIC VEHICLE RATE INTO THE TOU DEMAND RATES?

A. The current electrical vehicle rate, ET-EV, is designed to encourage customers to charge their vehicles during the nighttime and early-morning hours. It does so by creating a super off-peak period — 11 p.m. to 5 a.m. weekdays — with a low kWh energy price. The concern is that, under the other existing rate options, customers may come home and begin charging their electrical vehicles at 7 p.m. and put significant pressure on the transformer and distribution feeder capacity in their neighborhood.

APS believes that the proposed demand rate options will provide ample incentive for customers to delay charging their electric vehicles until after 8 p.m. Therefore, a special electric vehicle rate is no longer needed.

Q. DO YOU BELIEVE THESE RATE CHANGES WILL IMPROVE THE ALIGNMENT OF THEIR RESIDENTIAL RATES AND COSTS?

A. Yes I do. I believe our proposed revisions to the residential rates will result in substantial improvements in aligning the rate structures to costs and to the services provided.

For example, they improve the basic service costs that are recovered through the monthly service charge, rather than through a kWh energy charge, for all residential rates. They also expand the use of three-part rates consistent with the type of design that I detailed in the rate reform discussion. This rate design recovers basic services with a monthly service charge, demand services with a kW demand charge, and energy services with a kWh energy charge, which results in bills that are highly aligned with the costs and services provided.

Q. WHAT ARE THE BENEFITS OF THESE PROPOSED CHANGES?

A. As discussed above, rate structures that are better aligned with costs will provide much better price signals for customers that wish to invest in distributed technologies, smart appliances, and energy controls in their home, and result in a more efficient use of and funding for the grid. In particular, the three-part rate will provide an opportunity for customers to save on both the demand and energy components on their bill. And these bill savings will be aligned with a reduction in APS's demand- and energy-related costs, which will minimize or eliminate any adverse impact on the rates of other customers.

Furthermore, because the proposed three-part rates will more closely match the cost of service with the monthly bill for each customer the rates will be fairer for everyone.

Q. WILL THE PROPOSED RATES FULLY ADDRESS THESE ISSUES?

A. Not entirely, but it's a good start. As rates are restructured from two-part rates to three-part rates, more of these grid investment costs are recovered through monthly service charges and demand charges, rather than kWh energy charges. As a result, the rate subsidy for renewable generation, or any other home-energy technology for that matter, will be addressed. APS's proposed rates recover some, but not all, of the grid investments through service charges and demand charges. Therefore, the issue is reduced, but not eliminated.

Q. PLEASE EXPLAIN.

A. As discussed above, 75% of APS's costs to serve residential customers are grid investments, which comprise about $105 per month of the average customer bill of $140. The monthly costs for metering, billing, connecting a customer to the grid and other basic services is in the range of $25 to $30 per month, depending on what's included. The remaining infrastructure and fixed budget items would require a monthly demand charge of approximately $15 per kW per month. Therefore, APS's proposed monthly service charge of $24 and demand charge of $6.60 per kW for rate R-1 and monthly service charge of $14.50 and demand charge of $8.40 per kW for rate R-2 recover some, but not all, of these costs. The proposed rate R-3 with a $24 monthly service charge and seasonal demand charges of $16.40 and $11.50 recovers a higher percentage of these fixed costs and is an even better alignment with the cost of service.

Q. WHY ISN'T APS PROPOSING RATES THAT ARE FULLY ALIGNED WITH THE COST OF SERVICE?

A. APS believes that the proposed rates will provide a significant step toward improved alignment with cost of service while allowing customers time to get used to the new rates, especially the demand charge component. The three-part rate structure will put

residential rates on a path consistent with the Long Range Rate Plan, while incremental improvements can be made in future rate cases.

IX. SPECIAL RESIDENTIAL RATES AND RIDERS

Q. WHAT IS A RATE RIDER?

A. A Rate Rider is an addendum to a retail rate that provides additional charges, credits, or special billing provisions for specific programs or customer circumstances. Examples of APS's Rate Riders include limited-income discount programs, optional green power programs, dynamic rates like peak event discounts, and net metering and net billing programs for customers with renewable generation.

Q. PLEASE DESCRIBE APS'S LIMITED-INCOME BILL DISCOUNT PROGRAMS.

A. APS provides two bill-discount programs for customers with limited income. The E-3 rate rider provides bill discounts for customers that are within 150% of the federal poverty level. The E-4 rate rider provides a higher bill discount for similarly situated customers with certain qualifying medical equipment that uses a lot of electricity.

Q. WHAT IS THE CURRENT PARTICIPATION AND FUNDING FOR THESE PROGRAMS?

A. The E-3 and E-4 programs had a combined participation of more than 88,000 customers and funding of $35.6 million for 2015, with the predominate share in the E-3 program.

Q. HAVE THESE PROGRAMS GROWN IN RECENT YEARS?

A. Yes, the participation and funding for the limited-income discount programs have grown significantly in recent years. For example, in 2010 the program participation was 64,000 customers with total discounts of $11 million. Thus the participation has

increased by 37% while the program funding has more than tripled from 2010 to the 2015 Test Year.

Q. DOES APS ANTICIPATE CONTINUED GROWTH IN THE PROGRAM?

A. Yes. Given the poverty levels in Arizona and the growth over the last five years, APS anticipates continued growth in participation and funding requirements in the future.

Q. HOW WILL APS SUSTAIN FUNDING FOR THE PROGRAM GROWTH?

A. APS proposes pro forma adjustments to Test Year revenue and costs to provide funding for program growth through mid-year 2017 when new rates are expected to be implemented. This sustained funding results in an additional revenue requirement of $12.7 million. This funding consists of an $11.9 million revenue adjustment for additional discounts and an $800,000 cost adjustment for additional administration and marketing costs, which includes income verification expenses to ensure that the program participants are qualified. APS proposes to recover these costs from all customer classes, allocated on kWh, and collected through the System Benefits Charge, which is the current mechanism for recovering these program costs.

Q. DOES APS ALSO PROPOSE TO REVISE THE DISCOUNT STRUCTURE?

A. Yes. Currently, the discount rate, which is a percentage of the customer's bill, varies depending on the customer's monthly kWh usage. Customers with lower usage (and bills) get a higher percent discount than those with higher usage, while customers with monthly usage over 1,200 kWh receive a flat dollar discount amount, which is $31.75 for the E-3 program. The average monthly discount for all E-3 customers was approximately $34 during the Test Year.

APS proposes to replace this rather complicated discount structure with a flat $34 discount per month for all customers during the Test Year. Similarly the tiered discounts for the E-4 program will be converted to a flat $57 discount per month, which also reflects the average discount for that program today. In addition, the discounts will be converted to daily discount amounts of $1.12 and $1.87 respectively and capped at 80% of the customer's bill before taxes and other governmental fees.

Q. HOW DO APS'S LIMITED-INCOME DISCOUNTS COMPARE WITH OTHER ARIZONA UTILITIES?

A. APS's current and proposed discounts are far greater than other Arizona utilities. For example SRP offers a discount of $21 per summer and summer peak billing cycles, and a $20 discount per winter billing cycle. Tucson Electric Power Company currently has a $9 discount or a grandfathered discounted limited income retail rate and has proposed to increase this discount to $15 in their most recent rate case.[6]

Q. PLEASE DESCRIBE APS'S CURRENT EXPERIMENTAL DYNAMIC RATE RIDERS.

A. APS currently offers two "dispatchable" dynamic rate riders, peak event pricing and peak time rebate, which provide an extra incentive for customers to be able to respond to extremely high load conditions and system emergencies during core summer months. Both programs apply a price signal or incentive during a limited number of critical days as determined by the Company. Customers can save on their bill by reducing usage during these critical periods, beyond what they are already reducing through their time-of-use or demand rate. I also note that dynamic riders like this are not a substitute for the pricing reforms APS has proposed. Dynamic rate programs assist the company

[6] *See* Craig A. Jones Direct Test. 58:8-59:24, *In re* Tucson Electric Power Co., Docket No. E-01933A-15-0322 (Ariz. Corp. Comm'n Nov. 5, 2015).

operationally but do not defer capacity in the long term because of the limited number of hours in the program.

Over the past several summers, APS has been testing these two rate concepts along with a super-peak time-of-use rate that focuses a higher time-of-use price in the late afternoon and early evening every day during core summer months. The objective was to determine which, if any, of the three competing programs would be continued in the future.

Q. WHAT DOES APS PROPOSE FOR THESE DYNAMIC RATE RIDER OPTIONS?

A. As a result of our experiment, APS proposes to retain the peak event pricing rate rider and discontinue the peak time rebate rider and the super peak time-of-use rate. The peak event pricing concept produced better demand response during the critical hours compared with the other options and was easier to implement than the peak event pricing concept. The critical hours will be revised to 3 p.m. to 8 p.m. from the current hours of 2 p.m. to 7 p.m. to be consistent with the new proposed time-of-use on-peak hours.

Q. WHY IS APS PROPOSING TO CANCEL THE LFCR OPT-OUT OPTION?

A. APS currently offers an option for customers to pay a higher monthly basic service charge instead of paying the Lost Fixed Cost Recovery (LFCR) adjustor rate. APS is cancelling this option because it is typically not beneficial to customers, it is not widely subscribed, and, in APS's opinion, unnecessary. APS's proposal for the LFCR is provided by Mr. Snook.

Q. PLEASE EXPLAIN APS'S RECOMMENDATION FOR THE FLAGSTAFF SOLAR EXPERIMENTAL RATE RIDER.

A. The Flagstaff solar experiment tested the impacts of a high concentration of solar generation on a residential feeder. The experiment involves 125 residential customers on a single feeder in our Northern region. APS installed and owns the rooftop solar units, which are hooked up directly to the grid and do not serve the load in the home. The program has been ongoing for approximately five years, and APS has completed the grid impact assessments. Therefore, APS proposes to consolidate the Flagstaff Solar Experiment into the Solar Partner Program, with the $30 per month bill credit for renting the customer's roof. Because of the consolidation, APS proposes to cancel the Flagstaff experimental Rate Schedule CMPW-01.

Q. IS APS PROPOSING ANY NEW RATE RIDERS?

A. Yes. APS is proposing an experimental flat bill option which allows customers to receive a set bill each month, based on their usage in the prior year with a "hedge" premium.

Q. PLEASE DESCRIBE THE EXPERIMENTAL FLAT BILL OPTION.

A. The flat bill is a billing option that can work with any of the retail rates. Under the program, customers pay a pre-determined, flat bill each month that is based on their underlying retail rate, the billing determinants from the prior year and any expected increases in annual adjustor rates. The bill also includes a 15% "hedge premium" to reflect potential increases in kWh usage or kW demand during the year. The flat bill would be re-calculated each year based on the customer's new prior year kWh and kW billing determinants and the new expected adjustor rates.

There is no true-up at the end of the year to the customer's underlying calculated bill that would have occurred absent the program. However, APS will track the difference between the flat bill and the underlying calculated bill each month. If this difference exceeds a 30% threshold on a cumulative month basis, the customer's flat bill amount will be reset for the remainder of the year to reflect this difference.

The program will be administered on a calendar year cycle; customers can enroll in, or drop out of, the program during the open enrollment period in the fourth quarter each year. The customer's flat bill will be computed based on their prior 12 monthly billing information.

Q. WHO IS ELIGIBLE FOR THE EXPERIMENTAL FLAT BILL RIDER?

A. The flat bill rider is available to customers on Rates R-1, R-2, R-3, and R-XS. In addition, the customer must have an AMI meter and be in good credit standing. The option is not available to partial requirements customers with on-site generation, customers on a limited-income discount, customers with less than 12 months of AMI billing history, and certain extremely large and extremely small customers because their bill may be too difficult to predict.

Q. DOES APS PROPOSE TO LIMIT THE PARTICIPATION IN THE FLAT BILL OPTION?

A. Temporarily, yes. APS proposes to initially limit the participation in the flat bill option to 10,000 customers in order to test out the concept. However, APS could raise or eliminate the cap with notification to Staff.

X. CUSTOMERS WITH RENEWABLE GENERATION

Q. PLEASE DESCRIBE APS'S CURRENT NET METERING AND NET BILLING PROGRAMS.

A. APS provides two special billing programs for customers with on-site renewable generation such as rooftop solar. Rate Rider EPR-2, which is a net billing program, allows customers to offset their retail load with their own renewable generation and credits any instantaneous excess power that flows back to the grid at an avoided cost rate. Alternatively, the net metering program, Rate Rider EPR-6, allows customers to bank the excess kWh and use it to offset metered kWh supplied by APS, either within the current billing month or in a subsequent month.

Q. WHAT IS THE CURRENT PARTICIPATION IN THESE PROGRAMS?

A. As of the end of 2015 there were 37,204 residential customers participating in the net metering program and 95 in net billing.

Q. ARE THESE PROGRAMS SUBSIDIZED?

A. Yes. Both programs are subsidized in that they allow customers to offset all of their retail kWh charges with the renewable generation — including the kWh charges that pay for various grid investments like substations and transformers that are still needed to serve the home. The net metering program provides an additional subsidy by crediting the excess power that flows back to the grid at the full retail kWh rates. Additional substantial subsidies are provided through federal and state tax credit programs.

As discussed above, the cost of service model in this rate case indicates that net metering customers paid about 38% of their cost of service during the Test Year, compared with 88% for other residential customers. The resulting direct rate subsidy of $18.5 million resulted in a 1.25% rate increase for all residential customers.

Q. WHAT DOES APS PROPOSE FOR THE NET METERING PROGRAM?

A. Because of the magnitude of the current subsidy and the prospect for continued high growth in the subsidy, APS proposes to modify the net metering program for new residential and non-residential solar customers (or other qualifying net metering customers) that do not meet the grandfathering provisions discussed below. Qualifying new solar customers with installed generation of 100 kW or less will be served under a revised net metering rate rider EPR-6S. Customers with new solar generation that do not qualify for EPR-6S will be served under the existing rate rider E-56R. The current net metering rate rider schedule EPR-6 will be frozen.

Q. DOES APS PROPOSE ANY CHANGES TO THE PURCHASE RATES UNDER THE MODIFIED NET METERING PROGRAM FOR NEW SOLAR CUSTOMERS?

A. Yes. Under the modified net metering program, the purchase rates compensate customers with on-site generation for any instantaneous excess generation that flows back to the grid. These rates are based on near term avoided costs that are reduced due to the excess generation. These solar purchase rates are provided in rate rider EPR-6S.[7]

Q. WILL THE ENERGY PURCHASES WHICH OCCUR UNDER THE COMPANY'S PROPOSED EPR-6S BE RECOVERED THROUGH THE PSA?

A. Yes. Expenses for these purchases will be recorded in FERC Account 555 and recovered through the PSA.

[7] APS recognizes that the amount paid for energy exported to the grid by customers with distributed generation, and the structure of that payment, could be impacted by the proceeding in Commission Docket No. E-00000J-14-0023.

Q. DOES APS PROPOSE TO GRANDFATHER SOLAR CUSTOMERS?

A. Yes. APS proposes to grandfather existing partial requirements customers with qualifying renewable generation, such as solar, under the following terms:

- Existing solar customers with systems interconnected to the Company's distribution grid prior to July 1, 2017;
- Customers who (i) submit a complete application for interconnection to APS by July 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application being accepted;
- The grandfather period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located;
- Customers may not add additional solar to their home or facility;
- Customers may not move their solar generation unit to another site;
- The grandfathering may be transferred to a new customer purchasing the home;
- The customer may remain on their current retail rate but may not move between alternative grandfathered retail rates;
- The customer will be subject to changes in annual adjustor rates including the rate structure and level;
- Any existing charges specific to partial requirements customers, such as grid access charges, will continue to apply; and
- The annual purchase rates for net metering will continue to be based on near term avoided costs as revised from time to time.

XI. CUSTOMER BILL IMPACTS

Q. HAS APS ASSESSED THE POTENTIAL BILL IMPACTS OF ITS RATE PROPOSALS?

A. Yes. The bill for a typical residential customer using 1083 kWh per month will increase from $139.32 to $150.41, which is an increase of $11.09 or 7.96%. Additional bill impacts for various usage levels and retail rates are provided in Attachment CAM-03DR.

XII. PROPOSED TRANSITION

Q. HOW DOES APS PROPOSE TO IMPLEMENT THESE RATE CHANGES?

A. APS proposes to implement the new residential rates over a transition period in order to inform customers about the new rates and implement the rates in a structured manner. The details of this transition strategy are provided by Ms. Derstine.

Q. HOW WILL APS BILL RESIDENTIAL CUSTOMERS DURING THIS TRANSITION?

A. During the transition period, residential customers will be billed under the current rate schedules, which will be revised to reflect the increased revenue requirement approved for the residential class. All customers will initially be served under the corresponding transitional rate - E-12 customers on the E-12 transitional rate and so on. So there will be no need to immediately place a customer on a new rate at the conclusion of the rate case. The rates will be frozen so that once a customer either chooses a new rate option or is placed on one, they may not return to the frozen rate. After the transition period, the transitional rates will be cancelled. The revised existing rate schedules are provided as part of the Company's SFRs.

Q. WHAT ABOUT GENERAL SERVICE CUSTOMERS?

A. Extra-small general service customers served under rates E-32 XS and E-32TOU XS will be served under transitional rates during the transition period, similar to residential customers, because the Company is also proposing to introduce demand charges to these customers. Other general service customers will not need a transitional rate because their rate structures are not being revised in any significant way.

XIII. GENERAL SERVICE RATES

Q. WHAT IS A GENERAL SERVICE CUSTOMER?

A. The general service customer class includes all non-residential customers except irrigation and outdoor lighting customers. Businesses, schools, universities, hospitals, manufacturers, and governmental accounts are examples of general service customers.

Q. PLEASE DESCRIBE APS'S CURRENT GENERAL SERVICE RATES.

APS offers a number of rate offerings for general service customers including:

- Standard rates for extra-small, small, medium, large, and extra-large customers (E-32);
- Time-of-use rates for these same customer groups (E-32 TOU);
- Time-of-use rates for schools (GS-Schools M and L);
- A frozen time-of-use rate for houses of worship (E-20);
- Rates for power plants that uses some retail service (E-36 XL and M); and
- An unmetered service rate (E-30).

APS also offers several rate riders for general service customers:

- Rate Rider Schedules E-56 and E-56 R for partial requirements service;
- Rate Rider Schedules EPR-2 and EPR-6 for partial requirements service for certain qualifying renewable generation;

- Experimental Rate Rider AG-1;
- Rate Rider Schedule PPR for preference power;
- Rate Rider Schedule IRR for interruptible rates; and
- Rate Rider Schedule SGSP, a schools and government solar program.

Q. WHAT IS THE COMPANY PROPOSING FOR GENERAL SERVICE RATES?

A. APS proposes the following revisions and additions to general service rates:

- Increase the rates to reflect the requested increase in revenue requirements for the class;
- Increase the basic service charges;
- Modify rates E-32 XS (extra-small) and E-32TOU XS by including a modest demand charge and simplify the kWh charges by eliminating the second tier rates. Also, change the qualification for these rates to be consistent with other general service rates;
- Reduce the number of on-peak hours for the E-32 TOU rates;
- Reduce the gap to cost of service for rates E-20 and reduce the difference from the alternative E-32 rate options;
- Cancel rate rider E-54 for seasonal service;
- The AG-1 experimental rate rider for buy-through power will not be renewed;
- Add a new optional aggregation discount for large customers with multiple sites; and
- Add a new rate for customers with extra high load factors.

Q. WHY IS THE COMPANY PROPOSING DEMAND CHARGES FOR E-32 XS AND E-32TOU XS CUSTOMERS?

A. Similar to residential rates, APS's current rates for extra-small general service customers are misaligned with the cost of service because most of the grid infrastructure

investment costs are recovered through kWh energy charges. Therefore, the Company proposes to add a modest demand charge of $6.90 per kW per month for secondary level service and to increase the basic service charge from $20.44 to $35.28. The demand charge will comprise about 18% of the base bill for the typical customer. The demand charges for E-32TOU XS will be $4.546 on-peak and 2.599 off-peak for secondary service.

Q. WHY IS APS PROPOSING TO ELIMINATE THE SECOND TIER KWH CHARGES FOR THE EXTRA-SMALL GENERAL SERVICE RATES?

A. Currently, the extra-small general service rates have a first-tier kWh charge for the first 5,000 kWh in a month and a lower second-tier charge for all other kWh consumption. APS is proposing to reduce the first-tier kWh charge and eliminate the second because very few extra-small customers reach the 5,000 kWh threshold in a month. Therefore, the second tier is unnecessary and only adds undue complexity to the rates.

Q. HOW WILL THE ANNUAL PLACEMENT WORK GOING FORWARD FOR SMALL AND EXTRA-SMALL GENERAL SERVICE CUSTOMERS?

A. Extra-small general service customers have monthly demands of 20 kW or less; small have demands of 21 kW to 100 kW. Currently, this determination is made each month, which means that some customers close to the 20 kW thresholds can float between the two rates on a monthly basis, potentially causing bill instability and confusion. APS proposes to place customers on either of the two rates annually, based on their average monthly demand for the previous summer months, which is consistent with the placement for other general service rates.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE TIME-OF-USE HOURS FOR GENERAL SERVICE RATES.

A. APS proposes that the on-peak hours for the E-32 time-of-use rates be reduced from the current period of 11 a.m. to 9 p.m. to the new period of 3 p.m. to 8 p.m. weekdays, without any holiday exemptions. The reasons for this proposed change is consistent with the discussion on the proposed change to residential time-of-use hours in the residential rate section on my testimony.

APS does not propose any changes to the time-of-use hours in rate E-35 for extra-large general service customers in this rate case because they typically have high load factors and use energy more consistently throughout the day. Therefore, the 3 p.m. to 8 p.m. on-peak hours may not incent any additional load shifting to the off-peak hours and may only have unintended bill impacts for this group of customers.

Q. WHAT DOES APS PROPOSE FOR THE GS-SCHOOLS RATES?

A. APS proposes a rate increase for the GS-Schools rates that is similar to the E-32 L class increase. This amount is slightly higher than the overall average retail rate increase due to the recovery of deferred costs from the extension of the AG-1 program.

Q. WHY IS APS PROPOSING TO CANCEL RATE RIDER E-54?

A. The Company proposes to cancel rate rider E-54, our seasonal service alternative minimum bill rider because it is no longer necessary or beneficial to customers given the changes to rate E-32 L in APS's last general rate case. There are currently no customers participating in this rate rider.

Q. WHY DOES APS PROPOSE TO NOT RENEW THE AG-1 EXPERIMENTAL PROGRAM?

A. A detailed discussion of this recommendation is provided by Mr. Snook.

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT FOR THE AG-1 DEFERRAL.

A. As part of the program extension, APS was allowed to defer the program losses for recovery in this rate case over the extension period. The deferral consists of the lost retail margin, which is the reduction in retail revenue less fuel costs, net of the wholesale margins from APS's mitigation efforts. APS is allowed to defer 90% of the first $10 of this net loss, and 100% of any amounts above $10 million.

This net deferral is projected to be $8.6 million addition to rate base, which results in an annual revenue requirement of $3.8 million, including the amortization of and return on the $8.6 million deferral. (*See* Attachments CAM-04DR and CAM-05DR, SFR Schedule B-2, page 3, column 7 and Schedule C-2, page 5, column 14.)

Q. HOW WILL THIS AMOUNT BE RECOVERED?

A. APS proposes that the AG-1 deferral will be recovered over 5 years from all non-residential customer classes, except the street and area lighting customer classes. The amount is allocated to each class based on adjusted Test Year kWh.

Q. PLEASE DESCRIBE THE PROPOSED EXTRA HIGH LOAD FACTOR RATE.

A. The benefits and rational for the extra high load factor rate are provided by Mr. Snook.

Q. WHAT IS THE PROPOSED AGGREGATION RATE DISCOUNT?

A. The Company serves customers with multiple sites that individually do not qualify for the extra-large rates and the associated lower costs, but as an aggregated group would. In addition, some of these customers are large national chain accounts or similar type of entities that receive bulk purchasing power for wholesale electricity, natural gas, and other commodities. The aggregation rate discount addresses this issue by extending extra-large level pricing for the unbundled generation portion of the bill to these customers.

Qualifying customers receive a $0.0024 per kWh reduction in the unbundled generation rate, which reflects the average cost difference from the extra-large customer class. This discount results in a 4.0% reduction in generation costs and 2.5% bill savings for the typical customer. Furthermore, because the discount is based on a kWh charge, the bill savings will be higher for higher load factor customers and vice versa. The customer would continue to pay for transmission, delivery and other services according to their retail rate, at no discount, because the prices for these services appropriately reflect the cost of service for the individual sites.

Q. WHO CAN QUALIFY FOR THE AGGREGATION DISCOUNT?

A. Qualifying customers must have individual accounts served under the E-32 L and E-32TOU L rates with a combined load of at least 5 MW. The discount will be reflected as a reduction in the E-32 L unbundled generation kWh charge.

XIV. IRRIGATION RATES

Q. WHAT DOES APS PROPOSE FOR THE IRRIGATION AND WATER PUMPING RATES?

A. The Company is proposing to increase the base rates for the irrigation class by 17% which results in a 5.7% bill impact after considering the adjustor transfers. This net bill impact is roughly equal to the average amount for all customer classes. APS is also proposing to increase the demand charge for irrigation rate E-221 to be more consistent with the cost of service and to simplify the rate by eliminating the third tier kWh charge.

XV. OUTDOOR LIGHTING RATES

Q. WHAT MODIFICATIONS IS APS PROPOSING FOR LIGHTING SCHEDULES E-47 AND E-58?

A. APS proposes to freeze the offerings for older street lighting technologies such as high-pressure sodium, low-pressure sodium, metal halide, and fluorescent type lamps. This means that the Company will continue to serve the current customer light fixtures with the older technologies, but no new fixtures will be installed. The Company proposes to instead emphasize new LED technologies (light emitting diode) in our outdoor lighting offerings going forward. The LED lamps are more energy efficient, more reliable, and require less maintenance than the older street lighting technologies. In addition, LED fixtures are rapidly becoming a very important part of the lighting market both in terms of customer preferences and the products supported by manufacturers.

APS also proposes to base the rates for any new LED fixtures offered in the future on a 15 year amortization life, rather than the 25 year level that is currently used. This will make the lighting charges more consistent with the typical term of lighting contracts and reduce any adverse impacts on other lighting customers if a customer discontinues lighting service before the fixture is fully amortized.

Q. PLEASE EXPLAIN.

A. Currently when a customer signs up for outdoor lighting service, they commit to a certain length service in a lighting contract. This term can vary, but typically is around 6 years. If a customer drops their lighting service after the contract term but before the 25 year amortization period it creates a potential stranded cost issue because the fixtures cannot typically be used for another customer or economically resold to a third party.

In the past, this risk was relatively small because the outdoor lighting industry and technology were generally static so that customers were not compelled to change out their existing fixtures prior to the 25 year life. Today, more and more customers are interested in changing out their existing fixtures for LED lighting which increases this risk significantly.

In light of today's more dynamic lighting market the effective life of an installed lamp is considerably less than the theoretic physical life if the fixture remains installed and used in the same facility for 25 years. Therefore, APS proposes to base the rates of future fixtures on a 15 year effective life and also seek to increase the contract term to at least 10 years. Both of these changes will reduce the stranded cost issue associated with outdoor lighting. The revised rate formula for new lighting equipment included in rates E-58 and E-47, which reflect the 15 year amortization and financial information proposed in this rate case, in the proposed rate schedules. This formula will be subsequently finalized with the relevant financial information, such as cost of capital, approved in this case.

Q. WHY IS APS PROPOSING THESE CHANGES?

A. The Company proposes these changes because the new LED lamps are more energy efficient, more reliable, and require less maintenance than the older street lighting

technologies. In addition, LED fixtures are rapidly becoming a very important part of the lighting market both in terms of customer preferences and the products supported by manufacturers. The proposed lighting focus and amortization life will help support this growing market.

XVI. SERVICE SCHEDULES

Q. WHICH SERVICE SCHEDULES IS APS PROPOSING TO REVISE?

A. APS is proposing to revise:

- Service Schedule 1: Terms and Conditions for Standard Offer and Direct Access;
- Service Schedule 3: Conditions Governing Extensions of Electric Distribution Lines and Services;
- Service Schedule 4: Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service;
- Service Schedule 6: Interconnection Services and Fees for Non-FERC Wholesale Generation Facilities;
- Service Schedule 7: Electric Meter Testing and Maintenance Plan; and
- Rewrite all service schedules so that they are easier to read and understand.

Q. WHAT ARE THE COMPANY'S PROPOSED REVISIONS TO SERVICE SCHEDULE 1?

A. Schedule 1, which provides the general terms and conditions for electrical service, was substantially reorganized and rewritten to make it easier to understand. Some terms were clarified; others were revised to reflect changes in business practice. In addition the charges were reviewed for consistency with cost of service and revised where needed. New charges and terms were added to accommodate customers desiring to opt-out of service with a standard AMI meter. A summary of the proposed changes, explanations and the reasons for the changes are provided in Attachment CAM-06DR.

Q. CAN YOU SUMMARIZE THE CHANGES IN THE SCHEDULE 1 CHARGES?

A. Certainly. The current and proposed Schedule 1 charges are shown in Table 3. Some of the charges are delineated for customers with AMI meters and those that voluntarily opt-out to a non-standard solid state meter. Some of the charges are substantially reduced because of operating cost savings from AMI metering. For example, the charge to establish a new residential customer account is reduced from $25 to $8, because the necessary work can now be performed remotely and, therefore, does not require a field trip to the customer's home. Other charges have increased due to, among other things, higher operating costs. Overall, the charges are anticipated to result in approximately $3.9 million in reduced annual revenue, which is reflected in the pro forma adjustment to Test Year revenue detailed in Attachment CAM-07DR.

Table 3 Schedule 1 Charges

Service Schedule 1 - Statement of Charges - Proposed Changes			
Description	**Proposed Charges**	**Current Charges**	**Difference**
Residential Service Establishment Charge	$ 8.00	$ 25.00	$ (17.00)
Nonresidential Service Establishment Charge	$ 33.00	$ 35.00	$ (2.00)
After hours Charge –Residential Standard Metering	$ 8.00	$ 75.00	$ (67.00)
After hours Charge –Residential Non-Standard Metering	$ 137.00	$ 75.00	$ 62.00
After hours Charge –Nonresidential	$ 164.00	$ 75.00	$ 89.00
Same Day Connect Charge	$ 87.00	$ 75.00	$ 12.00
Non-standard Connect Charge (per crew person, per hour)	$ 164.00	$ 75.00	$ 89.00
Electronically Transmitted Payment Discount	$ (0.48)	$ (0.48)	$ -
Dishonored Payment Fee	$ 15.00	$ 15.00	$ -
Field Call Charge	$ 10.00	$ 15.00	$ (5.00)
Overhead Reconnection Charge	$ 89.00	$ 96.50	$ (7.50)
Underground Reconnection Charge	$ 135.00	$115.00	$ 20.00
Non-Standard Metering- Monthly Meter Reading	$ 15.00		$ 15.00
Set-up fee for customer with existing AMI meter	$ 70.00		$ 70.00
Set-up fee for customer without existing AMI meter	$ 50.00		$ 50.00
Meter Reread	$ 14.00	$ 16.50	$ (2.50)

Meter test in shop	$ 44.00	$ 30.00	$ 14.00
Meter test at site	$ 93.00	$ 50.00	$ 43.00
Trip Charge - Residential	$ 22.00	$ 16.00	$ 6.00
Trip Charge - Nonresidential	$ 26.00	$ 16.00	$ 10.00

Q. PLEASE DESCRIBE THE PROPOSED AMI OPT-OUT OPTION.

A. The AMI opt-out option allows customers to be served with a digital meter and manual meter reading instead of the AMI system. Details of the meter technology and related program information are provided in the Direct Testimony of Mr. Scott Bordenkircher. There are additional charges to cover the one-time special installation cost and the monthly cost of reading the meter manually with APS personnel rather than automatically through the AMI communication network. The one-time installation charge is $70, while the on-going meter reading charge is $15 per month. These charges can be found in Service Schedule 1.

Q. WHAT ARE THE COMPANY'S PROPOSED REVISIONS TO SERVICE SCHEDULE 3?

A. Schedule 3, which provides the conditions and terms for line extensions, was also reorganized and rewritten to be easier to understand. A definitions section was added to clarify current business practices and the implementation of certain terms. A summary of the proposed changes, explanations and the reasons for the changes are provided in Attachment CAM-06DR.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO SERVICE SCHEDULE 8?

A. Not in this rate case. Service Schedule 8 is being separately considered in Docket E-01345A-15-0386 and, therefore, APS is not proposing any additional changes in this rate case filing.

Q. DOES THE COMPANY HAVE ANY ADDITIONAL PROPOSED CHANGES TO SERVICE SCHEDULES?

A. Yes. APS's additional service schedules were rewritten for clarity. It was not APS's intent to make any substantive changes in such schedules. I have included in Attachment CAM-06DR a table of specific changes for these schedules as well as the ones previously discussed in my testimony. Additionally APS is proposing a new Service Schedule 9 for economic development sponsored by Mr. Snook.

XVII. PRO FORMA ADJUSTMENTS TO TEST YEAR REVENUE

Q. WHICH ADJUSTMENTS TO TEST YEAR REVENUE ARE YOU SPONSORING?

A. I sponsor the following adjustments to Test Year revenue:

- Limited Income Discount (E-3/E-4) - Attachment CAM-08DR (*see also*, SFR Schedule C-2, page 4, column 11);
- AG-1 Adjustment - Attachment CAM-09DR (*see also*, SFR Schedule C-2, page 5, column 13);
- Normalize Weather Conditions – Attachment CAM-10DR (*see also*, SFR Schedule C-2, page 3, column 9); and
- Annualize Customer Levels – Attachment CAM-11DR (*see* also, SFR Schedule C-2, page 4, column 10).

Q. PLEASE EXPLAIN THESE ADJUSTMENTS.

A. The adjustment to Test Year revenue for the limited income program provides funding for growth in the E-3 and E-4 bill discount programs from the Test Year to mid-year 2017 when new rates are expected to be implemented. This adjustment results in a reduction of Test Year revenue of $11.9 M and an increase in Test Year costs of

$764,000 million. A more detailed discussion of these programs and the adjustment is provided in the residential rates section of this testimony.

The Alternative Generation program adjustment increases Test Year revenue resulting from the program not being renewed. This adjustment results in a net reduction of Test Year revenue of $11.9 million and an increase in Test Year costs of $194,000. Details of the program and the adjustment are provided in the general service rates section on this testimony.

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT.

A. Test Year revenue is adjusted for normal weather to ensure that the final approved level of revenue from this rate case 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 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 pro forma 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 $10.5 million for the weather normalization pro forma.

Q. WHAT IS THE CUSTOMER ANNUALIZATION REVENUE PRO FORMA?

A. The customer annualization revenue pro forma 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 (2015) from December of the previous year (2014). 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 resulted in a pro forma adjustment to Test Year revenues of $10.3 million.

XVIII. STANDARD FILING REQUIREMENTS

Q. WHICH STANDARD FILING REQUIREMENTS (SFR) AND TARIFFS ARE YOU SUPPORTING?

A. I am sponsoring the following 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;
- Service schedules; and
- Proof of revenue.

Q. WOULD YOU PLEASE DESCRIBE THESE SFRS?

A. Yes.

- 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 major rate classes.
- Schedule H-3 lists all of the current and 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 by usage level for each major rate.

I also sponsor an index of all rate schedules and service schedules, along with all of the schedules.

Q. WOULD YOU PLEASE DESCRIBE THE PROOF OF REVENUE?

A. Yes. APS's Proof of Revenue is a validation of the billing determinates used in the Test Year. By billing out current rates against these billing determinates we see that we match our current Test Year revenue. This check shows that we can build new rates using these billing determinates and create a reasonable expectation of what revenue they will produce.

XIX. CONCLUSION

Q. PLEASE SUMMARIZE APS'S REQUEST TO THE COMMISSION DISCUSSED IN YOUR DIRECT TESTIMONY.

A. APS requests that the Commission:

- Approve the requested increases for each customer class;
- Approve the proposed rate designs for residential customers, the improved changes to the time-of-use rates, the simplification of the rate designs, and the use of demand charges for most customers;
- Approve the proposed changes for the limited income discount programs and the request for additional funding for program growth;
- Approve the continuance of the critical peak pricing program and the cancellation of the peak time rebate program;
- Approve the modification of the net metering program for new partial requirement customer (EPR-6S), and the requested program to grandfather existing solar customers on their current rate with EPR-6;
- Approve the proposed rate changes for general service customers including the improved changes to the time-of-use rates, the simplification of some of the rate designs, and the introduction of demand charges for extra-small customers;
- Approve the proposed new rate for extra-high load factor customers and the aggregation discount for large customers with multiple sites;
- Approve the expiration of the experimental alternative generation rate AG-1;
- Approve the cancellation of rate rider schedule E-54 for seasonal service;
- Approve the proposed revisions to the irrigation rate E-221, which simplify the rate and increase the demand charge;
- Approve the proposed changes to the outdoor lighting rates E-47 and E-58, which emphasizes new LED fixtures, freezes the other existing fixtures, such as sodium vapor technology, and recovers the costs for new LED fixtures over 15

years vs the current 20 year period to lower the risk of stranded costs and increased lighting rates;

- Approve the proposed changes to Service Schedule 1 including the provision for customers who desire to opt-out of service with AMI metering;
- Approve the requested changes to other service schedules; and
- Approve the re-writing of rate schedules and service schedules to make them clearer and more readable.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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

Proposed Increase to Base Rate & Net Impact

Class	Base Rates ATY Revenue	Present % COS	Class Specific Requested Increase	Adjustor Transfers	Requested Increase with Adjustor Transfers	Adjustor Transfer	Net Impact	Proposed % COS	Requested Revenue from Base Rates
Residential	1,486,577,640	85.9%	7.96%	11.34%	19.30%	168,606,794	7.96%	92.1%	1,773,473,497
GS - XS,S	515,621,307	123.7%	0.04%	8.57%	8.61%	44,209,882	0.04%	123.7%	560,030,957
GS - M	316,428,191	111.9%	4.04%	7.64%	11.68%	24,187,289	4.04%	116.0%	353,419,408
GS - L	293,386,250	100.5%	6.04%	5.09%	11.13%	14,943,234	6.04%	106.3%	326,044,915
GS - XL	203,076,401	87.0%	6.14%	4.70%	10.84%	9,547,611	6.14%	92.1%	225,094,215
GS - schools	11,344,975	91.1%	6.04%	9.34%	15.38%	1,059,278	6.04%	96.1%	13,090,980
GS - worship	4,069,264	62.3%	9.04%	11.32%	20.36%	460,711	9.04%	67.3%	4,895,766
Irrigation	28,739,440	93.7%	5.74%	11.28%	17.02%	3,243,093	5.74%	98.6%	33,630,812
Lighting	29,660,294	94.6%	5.74%	4.36%	10.10%	1,293,263	5.74%	99.8%	32,656,614
Total	2,888,903,762	95.0%	5.74%	9.26%	15.00%	267,551,155	5.74%	100.0%	3,322,337,164

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of 2015 TY Rate Case
- Increase in Base Rates
- Reduction in Adjustor Rates
- Net Bill Impact

AVERAGE MONTHLY BILL IMPACTS
FOR TYPICAL CUSTOMER

	Current Bill	Proposed Bill	Change	% Change
Residential (Avg - All Rates)				
Average kWh per Month	1,084			
Base Rates	120.24	143.45	23.21	19.30%
Adjustors	19.08	6.96	(12.12)	
Total Bill	139.32	150.41	11.09	7.96%
Commercial XS (E-32)				
Average kWh per Month	1,240			
Base Rates	177.78	193.09	15.31	8.61%
Adjustors	26.24	10.86	(15.38)	
Total Bill	204.02	203.95	(0.07)	-0.03%
Commercial S (E-32)				
Average kWh per Month	12,846			
Average kW per Month	43			
Base Rates	1,507.61	1,637.42	129.81	8.61%
Adjustors	269.05	140.45	(128.60)	
Total Bill	1,776.66	1,777.87	1.21	0.07%
Commercial M (E-32)				
Average kWh per Month	61,963			
Average kW per Month	179			
Base Rates	6,201.86	6,926.24	724.38	11.68%
Adjustors	853.99	414.90	(439.09)	
Total Bill	7,055.85	7,341.14	285.29	4.04%
Commercial L (E-32)				
Average kWh per Month	300,972			
Average kW per Month	743			
Base Rates	25,601.70	28,451.17	2,849.47	11.13%
Adjustors	2,606.78	1,462.38	(1,144.40)	
Total Bill	28,208.48	29,913.55	1,705.07	6.04%
Commercial XL (E-34, E-35)				
Average kWh per Month	3,693,933			
Average kW per Month	6,370			
Base Rates	251,228.00	278,461.12	27,233.12	10.84%
Adjustors	24,968.17	14,692.94	(10,275.23)	
Total Bill	276,196.17	293,154.06	16,957.89	6.14%

Notes:
(1) The bill excludes regulatory assessment charge, taxes and fees.
(2) Current bill includes adjustor rates in effect May 15, 2016.
(3) Total bill Impact includes the requested increase in base rates and the reduced adjustor rates from the transfer of adjustor revenues to base rates.

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Pro forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Include AG-1 Deferral Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation & Amort.	-
3.	Net Utility Plant in Service	-
4.	Less: Total Deductions	5,309
5.	Total Additions	13,935
6.	Total Rate Base	$ 8,626

Adjustment to Test Year rate base to include the estimated AG-1 deferral amount from 6/30/2016 to 6/30/2017 per Decision No. 75322.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Include Amortization of AG-1 Deferral
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	2,787
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	2,787
15.	Operating Income Before Income Tax	(2,787)
16.	Interest Expense	196
17.	Taxable Income	(2,983)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(1,136)
19.	Operating Income (line 15 minus line 18)	$ (1,651)

Adjustment to Test Year operations to include the estimated amortization of the AG-1 deferral amount from 6/30/2016 to 6/30/2017 per Decision No. 75322 over a 3 year period.

Schedule #	New Rule #	Old Rule #	What changed	Why
1	1.	N/A	NEW: Added "Before supplying service APS will verify the identity of Applicant."	Clarify expectation that APS must do its due diligence and verify who we are serving.
1	1.	N/A	NEW: Added "If there is no signed application or contract for service APS's standard contract terms apply"	Clarifying a current business practice. An application/contract document serves the purpose of informing customers of the terms for service. If a customer does not return a signed copy to APS, standard terms still apply.
1	1.1(H)	2.4.8 & 2.4.9	No change to policy – two sections were combined and reworded	Clarity.
1	1.1(J)	2.4.10	Added "current" local construction and safety codes	Clarity.
1	2.2	2.2.2	**After-hours Charge**: The Customer must also pay an after-hours charge ~~of $75.00 plus applicable adjustments~~ if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $8.00 plus applicable adjustments for residential with standard metering, $137.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.	After-hours charge will be based on type of service (residential or non-residential) and whether the customer has a standard AMI meter or a non-standard meter.
1	2.3	2.2.3	**Same-Day Connect Charge**: The Customer must also pay a same-day connect charge of $87.00 plus applicable adjustments if the Customer has non-standard metering, as described in section 8.2, and requests	The same-day connect charge will only apply to sites with non-standard metering that require a field visit to complete the work.

Schedule #	New Rule #	Old Rule #	What changed	Why
			service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by Company, waive the same-day fee.	
1	3.3(B)	N/A	NEW: Added "Company may choose to accept less than the full deposit required at time of service establishment based on Customer's financial condition."	In addition to considering the average bills for the premises, APS will also take into consideration the Customer's credit score and may request a lower than required (2x average) deposit from Customers with good credit scores.
1	3.4	2.7.6	Deleted "1 time the highest bill"	APS no longer uses this criterion to determine deposit amounts.
1	3.7	2.7.6.1	Deleted "automatically"	Clarity. This is not an "automatic" process.
1	4.3	3.3	Added "reprogramed"	Clarity. Rate changes may require a meter reprogramming rather than a meter exchange.
1	5.2	N/A	NEW: Added "**Failure to receive bills or notices** (including notices of disconnection) which have been properly placed in the United States mail or sent through alternative billing forms, such as electronic mail, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the customer of their obligations."	To clarify Arizona Administrative Code [Rule 210 (D) (3)] that the presumption that bills placed in the United States mail and received by customers will also be applied to alternative forms of rendering bills such as electronic mail.
1	5.5	4.3.2.2	When corrected charges are for under billings we added the customer will pay the back bill "in equal monthly	APS works with customers to establish reasonable payment arrangements. This addition establishes a baseline that customer

Schedule #	New Rule #	Old Rule #	What changed	Why
			installments."	should pay corrected charges in equal monthly installments rather than waiting to pay as a lump sum at the end of the extended pay period.
1	5.7	4.3.2.4	Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the effort required.	Currently, APS is allowed to forgo correcting an under billing if the amount is small and does not justify the effort required. We are requesting to have the same consideration for overbilled amounts.
1	5.6(C)	4.3.2.3.3	Added: "APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with Customer to establish a payment plan that is acceptable to Company."	APS works with customers to establish reasonable payment arrangements. This is no different in cases of energy diversion or meter tampering, however, the back billing for diversion or tampering can be for extended periods of times, often multiple years, therefore APS should not be obligated to extend arrangements for an equal length of time.
1	6.2	4.2.1	Clarified that late charges may apply to past due security deposits.	In APS's new Customer Information Billing system Company will bill deposits rather than requiring they be paid before establishment of service. This change clarifies that late charges may apply to past due deposits.
1	7.1	N/A	Added clarification that Company may also require payment of Same-Day Connect Charge or After-Hours Charge prior to restoring service.	Clarifying a current business practice.
1	7.3	7.1.2.1 & 7.1.2.2	Create a separate section for rules addressing that no additional notice will	Clarity.
1	8.	N/A	NEW: **8.1 Standard Metering –** The Company's standard method of measuring energy usage is through the use of Automated Metering	Outline the circumstances under which APS will accommodate a customer who does not wish to be served by the Company's standard AMI metering equipment

Schedule #	New Rule #	Old Rule #	What changed	Why
			Infrastructure (AMI) metering equipment. All customers will be served using the Company's standard metering equipment unless: **(A)** The customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used. **(B)** The customer meets all eligibility requirements and voluntarily requests non-standard metering. **8.2 Non-Standard Metering** – The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to customers who select a non-standard meter. **8.3 Non-Standard Metering Eligibility** - Only residential customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or customers with newly installed rooftop solar, are not eligible for non-standard metering. **8.4 Non-Standard Metering Charges** – The following charges will apply when a customer voluntarily requests, and is	

Schedule #	New Rule #	Old Rule #	What changed	Why
			granted, non-standard metering: **(A)** Monthly Meter Reading Charge: $15.00 **(B)** Non-Standard Metering Set-up Fee: A $70.00 one-time charge for customers with existing AMI meter or $50.00 one-time charge for customers without existing AMI meter. **8.5 Discontinuation of Non-Standard Metering** - The Company may replace a non-standard meter with a standard meter, without notifying the customer prior to replacement, under any of the following conditions: **(A)** Company employees observe or have evidence of a safety hazard to employees, customers, or Company or customer property. **(B)** Company employees observe or have evidence of meter tampering, energy diversion, or fraud. **(C)** Company has evidence of unauthorized resale of electricity. **(D)** Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to Company equipment, and physical threats such as weapons or dogs. **(E)** All terms and conditions in Section 7, regarding termination of service, will also apply.	
1	10.5	2.2.1	**Trip Charge** – ~~The Customer must pay~~ A trip charge of $~~16~~22.00 for residential	The trip charge will be priced based on whether the service is residential or non-residential.

Schedule #	New Rule #	Old Rule #	What changed	Why
			or $26.00 for non-residential, plus applicable adjustments will be assessed each time ~~when~~ an authorized Company representative travels to ~~the Customer's~~ a site and is unable to complete a Customer's service requested ~~ed service~~ because of lack of access to the Point of Delivery.	
1	15	Various	Explaining that Direct Access is not currently available in APS Service Territory.	Referencing Direct Access rules alongside Standard Offer regulations when DA is not available in APS territory is misleading and can create unnecessary confusion.
1	15.2	3.4	Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.	Add the word "calendar" a second time for consistency and clarity.
1	Deleted	Section 6.6	Deleted entire Master Metering Section.	The same information is already covered in Schedule 3.
1	Definitions and Statement of Charges	Definitions and Statements of Charges	Definitions and Statement of Charges moved to back of document.	These are for reference purposes only.
3	1.2, 1.4, 1.14, 1.18, 1.23 & 1.25	N/A	1.2 **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks,	Adding new definitions for clarity of current business practices and interpretations.

Schedule #	New Rule #	Old Rule #	What changed	Why
			manholes, switching cabinets and capacitor banks. 1.4 **Conversion** means converting overhead distribution facilities to underground facilities. 1.14 **Master Meter** means a meter 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. 1.18 **Relocation** means moving a distribution line or facilities from its current location to a new location. 1.23 **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed. 1.25 **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3-phase).	
3	1.10 & 1.15	1.8	1.10 **High Rise** ~~**and/or Mix Use**~~ **Development** means a building built with four or more floors (usually using elevators for accessing floors) ~~or any mixed use development~~ that may consist of ~~either~~ residential or non-residential use, or a combination of both residential and non-residential uses. ~~such as a building where the first level is for commercial purposes and the upper floors are residential.~~	To minimize confusion, split "High Rise Development" and "Mixed Use Development" into two different definitions. Later in the document they are also treated as two separate sections.

Schedule #	New Rule #	Old Rule #	What changed	Why
			1.15 **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.	
3	1.19 & 1.22	1.14 & 1.17	1.19 **Residential "Lot Sale" Development** means a tract of land that has been divided into four (4) or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for the construction of a residential home and the costs to provide service, which may include backbone, transformer and service. 1.22 **Residential Subdivision** means a tract of land which has been divided into four (4) or more contiguous lots with an average size of one acre or less in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the ~~construction of~~ residential homes or permanent manufactured or mobile home sites.	To allow any developer's project to go in under Subdivisions if the project qualifies under Subdivision and the developer pays for the installation of all the facilities, including services, no matter who may build the homes later.
3	1.20	1.15	1.20 **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with	Clarify current practice.

Schedule #	New Rule #	Old Rule #	What changed	Why
			less than 4 floors.	
3	2	New & 1.8, 6, 5, 7.14 and 7.5	New Section: "General Provisions for General Service"	This new section provides clarity by defining the Residential and Nonresidential classifications and better organizes several general provisions under one common section.
3	2.1	New	Outline Residential and General Service Classifications.	Clarity and document organization.
3	2.2	1.18	Explanation and conditions for the Schedule of Charges moves from definitions to its own section under the new section "General Provisions for Service." (G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.	Clarity and document organization. Added exception where SOC is not applicable. This is the current practice for Rev 12 (and Rev 11).
3	4.1(B)	2.2.2	The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing an approved plat prior to project design. If final approved plat is different from what was originally submitted to APS it may cause time delays and additional cost for redesign.	Subdivision Development Plat requires approved plat from county planner. The timeline to get approval isn't always feasible. This clarifies expectation that a change in the final plan may cause time delays and added cost if a redesign is necessary.
3	5.4 & 12.6	2.3.5 & 3.3.6	Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections	Clarify current business practice that future extensions for Conduit Only Designs must follow the original design plan.

Schedule #	New Rule #	Old Rule #	What changed	Why
			that may be required. Future extensions in the development will be required to follow the original conduit only design plan.	
3	7.6	2.5.5	The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter installed for a permanent residential structure over a five (5) year period.	Clarify current business practice that it must be a permanent residential structure to be counted for refund purposes.
3	9	3.1	Renamed: Basic General Service	Clarity. To avoid confusion with other types of General Service Projects.
3	9.2, 12.2 & 16.1	3.1, 3.2, 7.11	Clarify that costs for Basic General Service, Corporate Business & Industrial Park Developments and Change in applicant requirements may also be based on a "Project-Specific Cost Estimate"	Clarify current business practice.
3	10 & 11	3.2	High Rise and Mixed Use sections are now split into 2 separate sections.	Clarity.
3	10.1(C) & 11.1(C)	3.2.1	The residential units are ~~privately owned and~~ either individually metered or master metered in accordance with Section 21.	Clarify residential units in a High Rise Development and Mixed Use Developments do not have to be privately owned.
3	10.1(D)	3.2.2	Extension Facilities will be installed to designated points of delivery in accordance with APS' Electric Service Requirements Manual (ESRM),~~and i~~ It is the applicant's responsibility to provide and maintain the electrical facilities within the building.	This is current standard practice for APS.
3	12.3 & 12.4	3.1.3 & 3.1.4	Clarify how cost will be calculated for Corporate Business and Industrial Park Developments.	Clarity.
3	17	7.9	Reorganized entire section for	Clarity.

Schedule #	New Rule #	Old Rule #	What changed	Why
			upgrades, relocations and conversions.	
3	21.3	7.10.3	**Multi-Unit High Rise Residential Developments** Company will allow master metering for privately-owned, high rise residential units under the following conditions: ~~(A) where the residential units are privately owned provided~~ The building will be served by a centralized heating, ventilation and~~/or~~ air conditioning system. ~~and~~ if (B) Each residential unit will ~~shall~~ be individually sub-metered and responsible for energy consumption of that unit. (C) Sub-metering will be provided and maintained by the builder or homeowners association. (D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.	Clarity.
3	24.1	7.3	Before Company begins construction of Extension Facilities, all suitable easements or rights-of-way required for any portion of the extension, will be obtained by applicant and provided to Company in Company's name without cost to, or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will	Reworded for clarity. Also stipulates current business practice that Company's standard easement form will be used.

Schedule #	New Rule #	Old Rule #	What changed	Why
			utilize Company's standard easement form which contains the terms and conditions that are acceptable to Company.	
3	Attachment 1 – Statement of Charges	Attachment 1 – Statement of Charges	Both Statements of Charges for Single-phase and Three-phase extensions have been updated. New proposed charge for pole interset is in red. All charges that decreased are highlighted in yellow. Charges that have increased or stayed the same are not highlighted.	PRIMARY WIRE (costs have trended down): The costs at the time the estimates were performed in 2009 for 1100 wire and 3-4/0 wire were significantly higher because they were a new product at that time. Today, APS is using more this type of wire and the Company has negotiated costs based on our increased usage. SECONDARY WIRE (costs have trended up): There are no new variables in the type of wire APS is using (like above). The general increase is due to normal increased year over year cost of living adjustments. TRANSFORMERS (costs have trended down): APS is getting a better price on transformers due to expanding our RFP to other vendors. We have negotiated better prices to ensure we keep the costs as low as possible.
3	Examples to Section 3 Free Footage Illustrative Example	Examples to Section 2.1 Free Footage Illustrative Example	Illustrative Examples	Updated illustrative examples based on revised Statement of Charges.
4	1.1(A) & (B)	Intro – 2nd paragraph and embedded (A, B, C)	Definitions.	Clarity.

Schedule #	New Rule #	Old Rule #	What changed	Why
4	1.2	NEW	Added definition: Virtual Totalizing.	APS now offers virtual totalizing for sites where metering technology is not available to totalize adjacent or remotely.
5	5.1 & 5.2	5.1, 5.2, 5.3 & 5.4	Deleted 5.1 through 5.4 and replaced with more current NERC Standards and Requirements.	Pre-contingent risk mitigation steps in accordance with NERC and WECC Requirements.
6	1.1, 3, and Terms and Conditions	1.1, 1.2, 2.4, 4, and 5	Reorganized for clarity.	Clarity.
6	1.2	1.3	This schedule will ~~shall~~ not apply to a generating facility that is interconnected at less than 1MW on the load side of an APS retail customer's meter and is primarily intended to serve the customer's electricity requirements, including, for example, a net metering facility as defined in A.A.C. R14-2-2302.	Reorganized for clarity and added "at less than 1 MW" to clarify charges outlined in this Schedule apply to all generator project above 1 MW.
6	2	2 & 3	Information on study services and fees was reorganized and combined in one section for clarity and readability.	Clarity.
7	1.1	2 & 4	No change to rules – combining single and three phase self-contained solid state into one section.	Clarity and simplicity.
7	1.2(A)	1.1	Added reference to ANSI C12.1 – 2008.	For clarity (sample program is based on this standard).
7	1.2(B)	1.2	Changed ANSI (American National Standard for Electric Meters) reference from "1995" to "2008."	Updated to current ANSI document and match Arizona Administrative Code requirement 14-2-209(E)(1).
7	1.3	3. (3.1-3.3)	Deleted 3.2 Three-phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years and 3.3 Three-phase lagged-demand meters: 8 years.	As of May 2016 less than 200 of these meters remain in APS service territory. APS is working to replace these meters with AMI meters by Q4 2016.

Schedule #	New Rule #	Old Rule #	What changed	Why
7	1.4	5	Based on the current requirements, the title of this section was changed to "Transformer-Rated Meter Installations." Deleted "three-phase" and "solid state hybrid" references.	The meter is either solid state or hybrid. Additionally, APS has remove from service all of the non-solid state meters on accounts less than 500 kW, therefore we have updated the title to be simply "Transformer Rated Meter Installations." This expands the section so that it also covers Single-Phase Transformer Rated Installations.
7	1.4(A)	New	Adding new section for installations with less than 500 kW.	APS already monitors performance of these types of meters through the Company's Metering and Billing systems.
10	NEW	8.2.9	Delete "blue"	Blue color seals are now being used for AMI Opt-out. A different color seal would need to be identified based on availability at time of implementation.
10	NEW	8.6.2	Add "AMI"	Updated to reflect APS is primarily using AMI meters.
10	NEW	8.7.2	Added "AMI meters"	Updated to reflect APS is primarily using AMI meters.
10	NEW	8.16.2	~~Pursuant to~~ Under guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data ~~shall~~ will be available by 3:00 p.m. Local Arizona Time (MST) on the ~~third~~ second, working day after the scheduled read ~~date or~~ has been completed. ~~the close date.~~	APS has shortened the window from three days to two days for validating meter read data.
15	5-21	4-16	Section 4 was divided into additional sections and all subsequent sections were renumbered accordingly.	Clarity.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Service Schedule Adjustment
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	
3.	Other Electric Revenues	(3,934)
4.	Total Electric Operating Revenues	(3,934)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(3,934)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total	-
15.	Operating Income Before Income Tax	(3,934)
16.	Interest Expense	-
17.	Taxable Income	(3,934)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(1,499)
19.	Operating Income (line 15 minus line 18)	$ (2,435)

Adjustment to Test Year operating other revenues to reflect changes in service schedule charges.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Limited Income Discount (E-3/E-4)
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ (11,900)
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(11,900)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(11,900)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	764
9.	Subtotal	764
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	764
15.	Operating Income Before Income Tax	(12,664)
16.	Interest Expense	-
17.	Taxable Income	(12,664)
18.	Current Income Tax Rate 38.10% (line 17 * 38.1%)	(4,825)
19.	Operating Income (line 15 minus line 18)	$ (7,839)

Adjustment to Test Year operating revenues to reflect the increase in limited income customer discounts from the Test Year through 6/30/2017.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Alternative Generation-1 Program
	Revenue	
1.	AG-1 Lost Generation Revenues	$ 55,468
2.	Revenues Collected for Generation Service Provider (GSP)	(40,826)
3.	Revenues Collected for Management & Reserve Capacity Fee	(2,753)
4.	Pro Forma Adjustment to Revenues	11,889
	Expense	
5.	Fuel Cost	33,411
6.	Purchased Power Costs Related to GSP	(40,826)
7.	Off-System Margin Credit	7,609
8.	Pro Forma Adjustment to Expense	194
9.	Operating Income Before Income Tax (Line 4 - Line 8)	11,695
10.	Income Tax at 38.10% (Line 9 * 38.1%)	4,456
11.	Net Income (Line 9 - Line 10)	$ 7,239

Adjustment to Test Year retail revenue to adjust for AG-1 customers unrecovered revenues.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description		Normalize Weather Conditions
	Revenues		
1.	Operating Revenue	$	10,514
2.	Adjustment for Difference Between Weather Normalized Sales & Actual Sales (MWh)		116,300
	Fuel and Purchased Power Expenses		
3.	Adjustment to Sales (MWh)		116,300
4.	Test Year Fuel & Purchased Power Costs (¢/kWh)		3.136
5.	Proforma Adjustment to Fuel & Purchased Power Expenses ((Line 3 * Line 4)/100)		3,647
6.	Operating Revenues Less Fuel & Purchased Power Expenses (Line 1 - Line 5)		6,867
7.	Operating Income Before Income Tax		6,867
8.	Income Tax at 38.10% (Line 7 * 38.1%)		2,616
9.	Net Income (Line 7 - Line 8)	$	4,251

Adjustment to Test Year operating revenues to reflect normal weather conditions for the ten years ended 12/31/2015.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Annualize Customer Levels
	Revenues	
1.	Operating Revenue	$ 10,326
2.	Adjustment for Difference Between Customer Annualized Sales & Actual Sales (MWh)	115,621
	Fuel and Purchased Power Expenses	
3.	Adjustment to Sales (MWh)	115,621
4.	Test Year Fuel & Purchased Power Costs (¢/kWh)	3.136
5.	Proforma Adjustment to Fuel & Purchased Power Expenses ((Line 3 * Line 4)/100)	3,626
6.	Operating Revenues Less Fuel & Purchased Power Expenses (Line 1 - Line 5)	6,700
7.	Operating Income Before Income Tax	6,700
8.	Income Tax at 38.10% (Line 7 * 38.1%)	2,553
9.	Net Income (Line 7 - Line 8)	$ 4,147

Adjustment to Test Year operating revenues to reflect the annualization of customer levels at 12/31/2015.

DIRECT TESTIMONY OF ELIZABETH A. BLANKENSHIP

On Behalf of Arizona Public Service Company

Docket No. E-01345A-16-0036

June 1, 2016

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DIRECT TESTIMONY OF ELIZABETH A. BLANKENSHIP
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-16-0036)

I. INTRODUCTION

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

A. My name is Elizabeth A. Blankenship. I am the Director of Accounting Operations for Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West Capital Corporation (Pinnacle West). I am primarily responsible for overseeing the accounting functions of the generation, transmission, distribution, customer service, and corporate resource areas. I also oversee the accounting systems and budget governance functions at Pinnacle West and APS. My business address is 400 N. 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 Arkansas State University in 1993. From 1993 to 2000, I was employed as an Accountant for two companies in the long-term healthcare service industry. I joined APS in October 2000 as a senior accountant and spent the past 16 years working for APS in the Financial Reporting Department, Accounting Operations Department, and the Revenue/Regulatory Accounting Department.

Prior to my current position as the Director of Accounting Operations, I was responsible for the revenue and regulatory accounting, asset accounting, accounts receivable and cash control functions at APS as the manager of the Revenue/Regulatory Accounting Department. I am a Certified Public Accountant, a member of the Arizona Society of Certified Public Accountants and a member of the Edison Electric Institute's Property 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, 2015, which was used as the Test Year (the Test Year) in this proceeding and any prior years presented on the following SFR Schedules (APS witness Peter Ewen 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:

- Adjust Rate Base for Post-Test Year Plant Additions
- Include West Phoenix Unit 4 Regulatory Disallowance
- Include Property Tax Deferral
- Adjust Cash Working Capital for Cost of Service

Additionally, I will be sponsoring the "Total Company" columns for the following pro formas on SFR Schedule C-2:

- Remove Amortization of Pension/ Other Post-retirement Employee Benefits (OPEB) Deferral
- Amonix, Star Center Patent Rights and Sale of Kyrene to Knox Amortization
- Office Closure and Paystation Fee Socialization
- Remove Test Year Regulatory Assessment
- Remove and Transfer Test Year Transmission Cost Adjustor (TCA) to Base Rates
- Remove and Transfer Test Year Lost Fixed Cost Recovery Mechanism (LFCR) to Base Rates
- Remove and Transfer Test Year Environmental Improvement Surcharge (EIS) to Base Rates
- Remove and Transfer a Portion of Test Year Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense to Base Rates
- Remove and Transfer a Portion of Test Year Renewable Energy Adjustment Clause (REAC) to Base Rates
- Remove and Transfer Test Year Rate Rider Four Corners Revenue to Base Rates
- Four Corners Deferral True-Up
- Remove Cholla Unit 2 Non-Fuel/Non-Payroll Costs
- Adjust Cholla Unit 2 Regulatory Asset Amortization
- Include West Phoenix Unit 4 Regulatory Disallowance
- Include Interest Expense on Customer Deposit
- Adjust Depreciation Expense – 2016 Depreciation Rate Study
- Adjust for Post-Test Year Plant Additions
- Adjust Decommissioning and Spent Fuel Costs
- Annualize Payroll Expense
- Normalize Employee Benefits
- Remove Supplemental Excess Benefit Retirement Plan Expense (SERP)

- Remove Stock Compensation
- Normalize Cash Incentive
- Normalize Income Tax Expense/Interest Synchronization
- Annualize Property Tax Expense
- Amortize Property Tax Deferral Amortization
- Annualize Four Corners Coal Reclamation Costs
- Annualize Navajo Power Reclamation Costs
- Adjust Cash Working Capital for Cost of Service
- Transfer Palo Verde Unit 2 Lease Reduction to Base Rates
- Normalize Nuclear Maintenance Expense
- Normalize Fossil Maintenance Expense
- Annualize Solar Partner Program Expense
- 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 adjusted Test Year federal and state statutory income tax rates, expected to be in place when new retail rates go into effect. The SFR Schedule C-2 pro formas that have a related Rate Base pro forma also include a calculation for synchronization of interest expense 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. Also, I will 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. Ewen 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 APS witness Dr. Bente Villadsen, 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. Ewen 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) which is required by the SEC. 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.[1]

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 income statements. The lease expense is currently being recovered through rates. The Test Year financial information will continue to portray the operating lease treatment reflected on APS's unconsolidated income statement.

In large part, my testimony supports the testimony of other APS witnesses. The direct testimony of Mr. Ewen addresses financial projections to actual Test Year data. APS witness Leland Snook focuses on the jurisdictional allocation of APS revenues, costs, and Rate Base items for the actual Test Year and all pro forma adjustments. Dr. Villadsen'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

[1] See A.A.C. R14-2-212(G)(2).

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. Ewen 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. Snook 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, 2015, APS is proposing a Total Company Adjusted Original Cost Rate Base (OCRB) of $8,011,800,000. This represents an increase of $302,154,000 over the unadjusted amount. The amount of the adjusted OCRB allocated to the ACC jurisdiction is $6,771,151,000. The requested adjustments to the Test Year amounts are summarized in SFR Schedule B-2, page 4 of 4.

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 "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 by performing an RCN study using Handy-Whitman indices (or CPI indices for transportation equipment and general plant). Using these indices has been a long standing practice accepted by the Commission and the industry in general for determining the RCN amount.

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 $35.0 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, the RCN column (A) is multiplied by a "condition percent," also known as a net book value percent, which is shown in column (B). The RCND is shown in column (C). The condition percent used to convert RCN to RCND is calculated by first determining the net book value (original cost less accumulated depreciation and

removal costs) for all depreciable plant by each FERC plant account. This amount is then divided by the original cost by each FERC account to arrive at the condition percent. In other words, the condition percent is the percentage that results when comparing net book value to the original cost of plant in service.

For example, assume that distribution lines have an original cost of $400,000, and accumulated depreciation and removal costs of $250,000. The net book value 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 and removal costs by original cost, or $150,000/$400,000, resulting in a condition percent of 37.5%. Multiplying the RCN of $632,000 by the condition percent of 37.5% yields $237,000 of RCND.

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, 2015. Column (A) presents data for Total RCND Rate Base. Mr.

Snook 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 9 THROUGH 28 OF SFR SCHEDULE B-4A?

A. The amounts shown on lines 9 through 28 of SFR Schedule B-4A for other Rate Base elements were obtained from SFR Schedule B-1, page 2 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, 2015. 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 pro formas are 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 $15.6 billion. This is shown on SFR Schedule B-4a, column (A), line 31.

Q. PLEASE EXPLAIN THE COMPUTATION OF WORKING CAPITAL ON SFR SCHEDULE B-5.

A. SFR Schedule B-5 outlines the computation of the allowance for working capital of $324,803,000 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 2015 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* Section IV "Pro Forma Adjustments").

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 1.6155 (line 5) is an algebraic transformation of APS's adjusted Test Year composite federal and state income tax rate of 38.10% (line 3). 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, 2015. 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 8.13% as set forth on SFR Schedule D-1 (line 5), page 1 of 2.

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 92% of APS's outstanding long-term debt consisted of unsecured debt with a weighted average interest rate of approximately 5.13%. Most of the remaining long-term debt consisted of tax-advantaged pollution control bonds. This debt has a weighted average interest rate of approximately 3.5%.

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 $8.41 billion. This amount includes approximately $3.73 billion in long-term debt (including current

maturities) and approximately $4.68 billion in common equity. APS's adjusted capital structure at the end of the Test Year was approximately 44.2% debt and 55.8% equity.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE CAPITAL STRUCTURE?

A. I have applied two pro forma adjustments to the December 31, 2015 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. Villadsen concludes in her testimony that the fair rate of return on equity for APS ranges from 10.25% to 10.75%. For the purpose of this filing, the Company is proposing a return on common equity of 10.5 %.

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, plant held for future use and plant acquisition adjustment. 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 in the Company's Form 10-K for 2015. The footnotes include, but are not limited to, the Company's accounting policies for depreciation, allowance for funds used during construction 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. Ewen will address the projected data on these same schedules.

Q. PLEASE DISCUSS SFR SCHEDULE F-3.

A. SFR Schedule F-3 presents projected annual capital expenditure requirements for the Test Year and the three subsequent years. I am sponsoring the actual Test Year information. Again, Mr. Ewen 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 Year period are ongoing and must be adjusted to reflect their impact over an entire 12 month period. One example of an annualization is for the payroll increases. 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" OR MISCELLANEOUS 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. Miscellaneous

adjustments remove costs out of the Test Year for items which the Company doesn't intend to collect from customers.

B. *Pro Forma Adjustment Descriptions*

1. Remove Amortization of Pension/OPEB Deferral

Q. PLEASE DESCRIBE THE ADJUSTMENT TO REMOVE THE AMORTIZATION OF THE PENSION AND OPEB DEFERRAL.

A. Commission Decision No. 71448 allowed the Company to defer for future recovery a portion of its Pension and OPEB costs above or below the 2007 Test Year level ($23,949,000 in that case) in 2011 and 2012, subject to limitations.[2] The Company proposed and received authorization to recover this deferral balance over a three-year period in Decision No. 73183. The amortization concluded June 30, 2015; therefore, this adjustment removes the six months of amortization from the Test Year. This adjustment results in an increase to pre-tax operating income of $4,238,000 (*see* Attachment EAB-1DR and SFR Schedule C-2, page 5, column 15).

2. Amonix, Star Center Patent Rights and Sale of Kyrene to Knox Amortization

Q. PLEASE DESCRIBE THE ADJUSTMENT TO AMORTIZE GAINS RELATED TO THE SALE OF AMONIX, STAR CENTER PATENT RIGHTS AND SALE OF KYRENE TO KNOX TRANSMISSION LINE.

A. APS sold three of its assets and deferred half of the gains in accordance with ACC requirements. The deferred gains totaled $12,114,000. APS proposes to amortize this balance to operating income over three years resulting in an increase to pre-tax operating

[2] 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 in 2012; the deferral cannot exceed $29,000,000 of the cost above Test Year level.

income of $4,038,000 (*see* Attachment EAB-2DR and SFR Schedule C-2, page 6, column 16).

3. Office Closure and Paystation Fee Socialization

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE OFFICE CLOSURE AND PAYSTATION FEE SOCIALIZATION EXPENSES.

A. The pro forma removes from expense the associated cost reduction from the closure of Customer Service offices partially offset by the cost increase of kiosk installations. This adjustment results in an increase to pre-tax operating income of $1,064,000. (*See* Attachment EAB-3DR and SFR Schedule C-2, page 6, column 17.)

4. Remove Test Year Regulatory Assessment

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE TEST YEAR REGULATORY ASSESSMENTS FROM BOTH REVENUES AND EXPENSES.

A. The adjustment is made to exclude from revenue and expense the amounts collected during the Test Year under Regulatory Assessments. Regulatory Assessments are not collected as part of base rates, so they must be excluded from Test Year revenue to calculate new base rates. The pro forma also removes from expense the associated costs incurred. This results in a zero change in pre-tax operating income, because an equal amount is removed from both revenue and expense. (*See* Attachment EAB-4DR and SFR Schedule C-2, page 6, column 18.)

5. Remove and Transfer Test Year Transmission Cost Adjustor to Base Rates

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSFER TEST YEAR TRANSMISSION COST ADJUSTOR TO BASE RATES.

A. The adjustment is made to transfer amounts collected during the Test Year under the Transmission Cost Adjustor to base rates. This adjustor is not currently collected as part of base rates, so the related revenue must be excluded from Test Year revenue to calculate new base rates. This results in a reduction to pre-tax operating income of $128,782,000. (*See* Attachment EAB-5DR and SFR Schedule C-2, page 7, column 19.)

Q. PLEASE EXPLAIN WHY THERE IS NOT IS AN OFFSETTING AMOUNT OF EXPENSES REMOVED FROM THIS ADJUSTMENT.

A. APS is resetting the TCA and moving costs into base rates. By removing only the revenue from the Test Year, the current level of costs will be recovered over the current level of sales, resetting the base retail rate.

6. Remove and Transfer Test Year Lost Fixed Cost Recovery Mechanism to Base Rates.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSFER TEST YEAR LOST FIXED COST RECOVERY TO BASE RATES.

A. The adjustment is made to transfer the amounts collected during the Test Year under the LFCR Mechanism to base rates. This revenue is not currently collected as part of base rates, so it must be excluded from Test Year revenue to calculate new base rates. This adjustment results in a reduction to pre-tax operating income of $45,988,000 (*see* Attachment EAB-6DR and SFR Schedule C-2, page 7, column 20).

Q. PLEASE EXPLAIN WHY THERE IS NOT IS AN OFFSETTING AMOUNT OF EXPENSES REMOVED FROM THIS ADJUSTMENT.

A. APS is resetting the LFCR and moving costs into base rates. By removing only the revenue from the Test Year, the current level of costs will be recovered over the current level of sales, resetting the base retail rate. Similar to the settlement in the last retail rate

case, there will be no lost fixed costs at the time rates are reset. Fixed costs are lost on a prospective basis as sales decrease due to energy efficiency or distributed generation which causes a decrease in sales.

7. Remove and Transfer Test Year Environmental Improvement Surcharge to Base Rates

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSFER TEST YEAR ENVIRONMENTAL IMPROVEMENT SURCHARGE TO BASE RATES.

A. The adjustment is made to transfer the amounts collected during the Test Year under the EIS. This surcharge is not currently collected as part of base rates, so it must be excluded from Test Year revenue to calculate new base rates. This results in a reduction to pre-tax operating income of $2,461,000 (*see* Attachment EAB-7DR and SFR Schedule C-2, page 7, column 21).

Q. PLEASE EXPLAIN WHY THERE IS NOT AN OFFSETTING AMOUNT OF EXPENSES REMOVED FROM THIS ADJUSTMENT.

A. APS is resetting the EIS and moving costs into base rates. By removing only the revenue from the Test Year, the current level of costs will be recovered over the current level of sales, resetting the base retail rate.

8. Remove and Transfer a Portion of Test Year Demand Side Management Adjustment Clause Revenue & Expense to Base Rates.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSFER A PORTION OF TEST YEAR DEMAND SIDE MANAGEMENT ADJUSTMENT CLAUSE TO BASE RATES.

A. The adjustment is made to exclude a portion of revenue and expense amounts collected during the Test Year under the DSMAC. These revenues are not collected as part of base rates, so they must be excluded from Test Year revenue to calculate new base rates.

The pro forma also removes from expense the costs not being transferred to base rates. The result is a reduction to pre-tax operating income of $10,000,000 (*see* Attachment EAB-8DR and SFR Schedule C-2, page 8, column 22).

9. Remove and Transfer a Portion of Test Year Renewable Energy Adjustment Clause to Base Rates.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSFER A PORTION OF TEST YEAR RENEWABLE ENERGY ADJUSTMENT CLAUSE REVENUES AND EXPENSES TO BASE RATES.

A. The adjustment is made to exclude a portion of revenue and expense amounts collected during the Test Year under the REAC. These revenues are not collected as part of base rates, so they must be excluded from Test Year revenue to calculate new base rates. The pro forma also removes from expense the costs not being transferred to base rates. This results in a reduction to pre-tax operating income of $37,557,000 (*see* Attachment EAB-9DR and SFR Schedule C-2, page 8, column 23).

10. Remove and Transfer Test Year Rate Rider Four Corners Revenue to Base Rates.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSFER TEST YEAR FOUR CORNERS RATE RIDER REVENUES TO BASE RATES.

A. The adjustment is made to move the Four Corners Rate Rider into base rates. By removing the revenue amounts collected during the Test Year under the Four Corners Rate Rider, the costs will be recovered in base retail rates. This results in a reduction to pre-tax operating income of $57,675,000 (*see* Attachment EAB-10DR and SFR Schedule C-2, page 8, column 24).

Q. PLEASE EXPLAIN WHY THERE IS NOT IS AN OFFSETTING AMOUNT OF EXPENSES REMOVED FROM THIS ADJUSTMENT.

A. APS is resetting the Four Corners and moving costs into base rates. By removing only the revenue from the Test Year, the current level of costs will be recovered over the current level of sales, resetting the base retail rate.

11. Four Corners Deferral True-Up

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRUE-UP THE FOUR CORNERS DEFERRAL.

A. The adjustment is made to true-up the estimated Four Corner Deferral to the actual amount deferred in accordance with Decision No. 73130 that authorized APS to defer all non-fuel costs of owning, operating, and maintaining the acquired Southern California Edison interest in Four Comers Units 4 and 5 and associated facilities, as well as, all unrecovered costs associated with Four Corners Units 1, 2, and 3 and additional costs incurred in connection with the closure of Units 1-3.[3] The Four Corners Rate Rider filing included an estimate of deferred costs. This estimate was used to set the Rate Rider revenue equal to an estimated level of amortization. The actual amount deferred was $10,351,000 higher than the estimate due to a delay in the rate order and other factors. This adjustment proposes recovery of this additional deferral over approximately 7.5 years (the remaining life of the original amortization period), resulting in a reduction to pre-tax operating income of $1,388,000 (*see* Attachment EAB-11DR and SFR Schedule C-2, page 9, column 25).

[3] On page 4 of my Direct Testimony in the Four Corners Rate Rider proceeding, I stated that "To the extent that even these updated costs are different than those actually incurred through the rate effective date, APS proposes to deal with balance (plus or minus) in its next general rate case." The pro forma adjustment reflects this true-up.

12. Remove Cholla Unit 2 Non-Fuel/Non-Payroll Costs.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE CHOLLA UNIT 2 COSTS.

A. The adjustment is made to remove the O&M and property taxes for Cholla Unit 2 and associated facilities since the unit was shut down on October 1, 2015. After considering the costs to comply with environmental regulations, on September 11, 2014, APS announced that it would close Cholla Unit 2. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering depreciation, a return on the net book value and the unit's retirement related costs. APS seeks to continue recovery of the remainder of these costs over the same previous estimated life, which is discussed in the next pro forma. The shutdown resulted in a current reduction of O&M, depreciation, and property taxes, resulting in an increase to pre-tax operating income of $17,355,000 (*see* Attachment EAB-12DR and SFR Schedule C-2, page 9, column 26).

13. Adjust Cholla Unit 2 Regulatory Asset Amortization.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REFLECT THE CHOLLA UNIT 2 REGULATORY ASSET AMORTIZATION.

A. As mentioned above, APS shut down Cholla Unit 2 on October 1, 2015. When APS shut down that unit, it was transferred from plant in service to a regulatory asset. The regulatory asset includes the remaining net book value of Cholla Unit 2 and the accrual of remaining removal costs for final retirement and dismantlement. APS is proposing to keep the plant life assumption of 2033 from Decision No. 73183 for the amortization period of the Cholla Unit 2 regulatory asset. This will result in a reduction to pre-tax operating income of $7,890,000 (*see* Attachment EAB-13DR and SFR Schedule C-2, page 9, column 27).

14. Include 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, 2015 is $6,515,000 (*see* Attachment EAB-14DR and SFR Schedule B-2, page 3, column 8).

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 EAB-15DR and SFR Schedule C-2, page 10, column 28).

15. 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 used by the Commission in the Company's previous rate cases. This adjustment was calculated by applying the 0.61% annual 2016 interest rate to the December 31, 2015 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 4, 2016), as published on the Federal Reserve website. The result of this pro forma is a reduction to pre-tax operating income of $443,000 (*see* Attachment EAB-16DR and SFR Schedule C-2, page 10, column 29).

16. Adjust Depreciation Expense – 2016 Depreciation Rate Study

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO DEPRECIATION AND AMORTIZATION EXPENSE?

A. For this filing, APS witness Dr. Ronald White performed a 2016 Depreciation Rate Study using data as of December 31, 2015. Using Dr. White's study, APS has updated depreciation rates from the rates authorized in Decision No. 73183 (May 24, 2012). 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 increases depreciation expense and thus results in a reduction to pre-tax operating income of $75,989,000 (*see* Attachment EAB-17DR and SFR Schedule C-2, page 10, column 30).

Q. DOES THIS PRO FORMA INCREASE MATCH THE 2016 DEPRECIATION RATE STUDY AS SHOWN IN APS WITNESS DR. RONALD WHITES'S TESTIMONY?

A. No, it does not match Dr. Ronald White's 2016 Depreciation Rate Study, nor should it. The difference between the 2016 Depreciation Rate Study adjustment of $71 million and the pro forma adjustment can be attributed to the annualization of depreciation expense as well as the inclusion of depreciation/amortization expense for some General & Intangible assets not included in Dr. White's study, such as software.

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.

17. 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 John Lucas, John Cadogan, Jacob Tetlow, Stacy Derstine, and Scott Bordenkircher 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 (January 1, 2016 to June 30, 2017). 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, 2015 for non-transmission plant that is expected to go into service prior to July 1, 2017 (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, 2017 was compiled (both projects in CWIP at December 31, 2015 and projects that begin after December 31, 2015);

Step 3: The plant was classified by functional area: fossil generation, nuclear generation; distribution, general and intangible plant; renewables, modern grid, technology innovation, and customer service;

Step 4: Annual accumulated depreciation and amortization, net of accumulated deferred income taxes and tax credits (where applicable) 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 deferred income taxes, is presented by functional unit and included in the Rate Base pro forma adjustments that increase Rate Base at December 31, 2015 by $295,082,000 (*see* Attachment EAB-18DR and SFR Schedule B-2, pages 1 and 2, columns 2 to 6); and

Step 6: Property and income taxes, and depreciation expenses were calculated and reflected as a reduction to pre-tax operating income of $67,632,000 (*see* Attachment EAB-19DR and SFR Schedule C-2, pages 1 and 2, columns 1-5).

APS will true-up this adjustment with actual plant placed in service, net of retirements, throughout the case. APS will provide the first update to the post-Test Year plant information using actual data as of August 31, 2016 to all interveners no later than September 30, 2016.

18. Adjust 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, PV 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 "tax-qualified" decommissioning trust. A trust is "tax-qualified" to the extent it meets certain requirements set forth in the Internal Revenue Code and related regulations. A "tax-qualified" decommissioning trust is

afforded income tax benefits versus non tax-qualified trusts. This favorable tax treatment is twofold. 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 U.S. Secretary of the Treasury a new schedule of ruling amounts upon each renewal of the operating license of the nuclear power plant. 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 "tax-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 "tax-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. 73183, APS was ordered to file a request to adjust the System Benefit Charge (SBC) to reflect the reduction in decommissioning trust funding obligations to reflect full funding of PV Unit 2. APS made its filing and the reduced change went into effect on January 1, 2016. APS is proposing this pro forma to reflect this adjustment in base rates since this happened after the Test Year. The Sale-Leaseback agreement contained a provision that required Unit 2 trust funds to be fully funded by the end of the lease. When the end of the lease arrived, Unit 2 was fully funded in the sense that the assets in the "tax-qualified" and "non-tax-qualified" trust were equal to or greater than the estimated decommissioning cost as of December 31, 2015. However, Unit 2 will remain fully funded only so long as the earnings on the trust are greater than the escalation rate in decommissioning costs. The situation is compounded because the Sale-Leaseback agreement requires that the decommissioning trusts for Unit 2 be 100%

invested in fixed income securities. But if the return on a portfolio of fixed income securities does not exceed the escalation rate in decommissioning costs, at some point what might have been a fully funded trust will require additional funding.

This is the expected case with the Unit 2 decommissioning trusts. Given the fixed income portfolio assumed return compared to the assumed escalation rate in decommissioning costs, Unit 2 will continue to need funding to meet the Sale-Leaseback requirement that the Unit 2 trusts be fully funded.

In addition to the reduction for Unit 2 funding per Decision No. 73183, two basic components associated with determining the annual amounts to deposit into the decommissioning fund have changed: earnings assumptions and revised decommissioning study cost estimates. The pro forma proposes keeping the funding level, net of the Decision No. 73183 Unit 2 reduction, the same at $2,281,000, but with a different allocation of funding to each of the three units within the trust. The revised decommissioning funding and expense estimates reflect a 2013 study performed by TLG Services, Inc. The decommissioning costs in this study are presented in 2013 dollars. An escalation rate is used to account for the inflation that will occur between now and the time of decommissioning. The escalation rate reflects expected increases in decommissioning costs.

Q. HOW DO THE ASSUMED EARNINGS AND ESCALATION RATES COMPARE?

A. 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 4.94% for PV Units 1 and 3 up to 5 years prior to each Unit's respective license expiration date and 3.30%, thereafter. APS is also proposing to use an

after-tax earnings assumption of 3.30% for PV Unit 2. The assumed escalation rate in decommissioning costs is 4%. The earnings assumption for Units 1 and 3 was determined using pre-tax investment return assumptions for fixed income of 4.15% for the "tax qualified" trusts and 3.85% for the "non-tax qualified" trusts and pre-tax equity returns of 8.00%. Using a 60% stocks and 40% bonds asset allocation up to 5 years prior to each Unit's respective license expiration date and a 100% bonds asset allocation thereafter and the applicable tax rates the "tax qualified" and "non-tax qualified" trusts, a 4.94% after-tax earnings assumption was calculated for up to five years prior to each Unit's respective license expiration date, and 3.30% thereafter. The Unit 2 assumption was also determined using a pre-tax investment return assumption for fixed income of 4.15% for the "tax qualified" trust and 3.85% for the "non-tax qualified" trust. 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 3.30%.

Q. WHAT IS THE PRO FORMA ADJUSTMENT REQUIRED TO REFLECT NEW LEVELS OF DECOMMISSIONING TRUST FUNDING?

A. Based on the reduction for the PV Unit 2 funding in compliance with Decision No. 73183 and the change in assumptions described above, the annual level of funding required is $2,281,000. This results in an increase to pre-tax operating income of $14,345,000 (*see* Attachments EAB-20DR and SFR Schedule C-2, page 11, column 31).

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 from the U.S. Secretary of the Treasury upon each renewal of the operating license of the plant. 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."

19. Annualize Payroll Expense

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ANNUALIZE PAYROLL EXPENSE.

A. This pro forma adjustment increases Test Year expense mainly as a result of an increase in wage levels, partially offset by lower employee levels. This pro forma adjustment annualizes the Test Year payroll and payroll tax expense to March 2016 employee and wage levels for non-union employees and March 2017 employee and wage levels for union employees (per the current union contract finalized in 2015 and in effect until 2018). This results in a reduction to pre-tax operating income of $5,328,000 (*see* Attachments EAB-21DR and SFR Schedule C-2, page 11, column 32).

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 total payroll and payroll taxes were allocated to O&M based on the same Test Year O&M percentage payroll amounts.

20. 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 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 Nos. 71448 and 73183.

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 2016 level of that expense, as determined by our actuaries, Willis 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 APS allocation factor was calculated and applied to the total Pinnacle West change in benefit expenses. This allocation factor was determined by dividing APS's 2015 actual O&M employee benefits by the total actual employee benefit costs for Pinnacle West in 2015. This results in a reduction to pre-tax operating income of $8,400,000 (*see* Attachment EAB-22DR and SFR Schedule C-2, page 11, column 33).

21. Remove Supplemental Excess Benefit Retirement Plan Expense

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO REMOVE SERP.

A. Also discussed by APS witness Barbara Lockwood, the pro forma removes from expense the associated costs of Test Year operations SERP. This results in an increase

to pre-tax operating income of $7,808,000 (*see* Attachment EAB-23DR and SFR Schedule C-2, page 12, column 34).

22. Remove Stock Compensation

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO REMOVE STOCK COMPENSATION.

A. Also discussed by APS witness Barbara Lockwood, 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 $15,753,000 (*see* Attachment EAB-24DR and SFR Schedule C-2, page 12, column 35).

23. Normalize Cash Incentive.

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT TO NORMALIZE CASH INCENTIVE.

A. The pro forma removes from expense the associated costs of Test Year operations to normalize the cash incentive program over a three year period. This results in an increase to pre-tax operating income of $3,007,000 (*see* Attachment EAB-25DR and SFR Schedule C-2, page 12, column 36).

24. 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 2015 levels of various tax credits and other permanent tax items, adjusted for known changes (e.g., the statutory tax rate reduction as a result of Arizona's 2014-2017 phased-in rate reduction), 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 decreases income tax expense by $3,874,000 (*see* Attachment EAB-26DR and SFR Schedule C-2, page 13, column 37).

25. 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, 2015 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, 2015 property values as filed with the Arizona Department of Revenue in April 2016. 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. This pro forma does not reflect the reduction in property tax expense related to Cholla Unit 2's shutdown, since that was already reflected in the "Remove Cholla Unit 2 Costs" pro forma above. APS will update the expected composite tax rate with the actual rate when it becomes available near the end of the third quarter of 2016. This adjustment results in a reduction to pre-tax operating income of $28,494,000 (*see* Attachment EAB-27DR and SFR Schedule C-2, page 13, column 38).

26. Amortize Property Tax Deferral

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR THE PROPERTY TAX DEFERRAL.

A. In the 2012 Settlement Agreement (Decision No. 73183), APS was allowed to defer for later recovery a portion of the changes its Arizona property taxes (*see* Section 12 of the Settlement Agreement). The terms from Section 12.1 were as follows:

> APS shall be allowed to defer for future recovery, in accordance with the provisions of Accounting Standards Codification ("ASC") 980 (formerly SFAS No. 71), the following portions of Arizona property tax expense above or below the test year level of $141.5 million caused by changes to the applicable Arizona composite property tax rate (not changes in the assessed value of property).
>
> (a) When the property tax rate increases:
>
> - For 2012: 25% (prorated with an assumed July 1 rate effective date);
> - For 2013: 50%; and
> - For 2014 and all subsequent years: 75%.
>
> (b) When the property tax rate decreases: 100% in all years.
>
> No interest shall be applied to the deferred balance.

APS is including the amount of the deferral to what it will be at June 30, 2017. Accordingly, the Rate Base addition for the property tax deferral at June 30, 2017 is $23,849,000 (*see* Attachment EAB-28DR and SFR Schedule B-2, page 3, column 9).

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE PROPERTY TAX DEFERRAL ADJUSTMENT?

A. Yes. The operating income pro forma reflects adjustment to amortize the property tax deferral over ten years, as authorized in Decision No. 73183. This results in a decrease to pre-tax operating income of $8,898,000 (*see* Attachment EAB-29DR and SFR Schedule C-2, page 13, column 39).

27. Annualize Four Corners Coal Reclamation Costs

Q. PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE FOUR CORNERS COAL RECLAMATION COSTS.

A. 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 1-5. The estimate for final reclamation costs was revised based on a study performed by Golder Associates as of December 2014. The estimate increased due to higher environmental costs for increased bond premiums, higher indirect costs for administration, depreciation and security offset by a decrease in materials and supplies and labor costs. The costs within this recent Golder Associates study were presented on a December 2014 dollar basis. Due to the long term nature of these costs, APS escalated the cost estimates for Units 1-5 through June 2038. The Company is using an amortization period for Units 1-5 to June 2038. Prior to this study we accelerated the amortization for Units 1-3 through September 2012 because the prior coal supply agreement would have required funding of final coal reclamation obligation upon closure of the Unit. The current coal supply agreement requires annual funding over the term of the agreement. This resulted in an increase to pre-tax operating income of $6,559,000 (*see* Attachment EAB-30DR and SFR Schedule C-2, page 14, column 40).

Q. HOW WAS THE ESCALATION CALCULATED?

A. Total estimated costs from the Golder Associates study were used to derive APS's share of Four Corners coal reclamation (in 2015 dollars). The reclamation costs for Units 1-5 are inflated using an annual rate of 4% over 16.5 years to adjust the 2015 dollar basis to second quarter 2038. The final reclamation costs for Units 1-5 are amortized through June 2038. Per the current coal supply agreement, APS shall fund Final Reclamation in thirteen (13) equal annual installments, on August 1 of each Contract Year into an irrevocable escrow account, solely dedicated to the Final Reclamation Costs of the

Navajo Mine (the Escrow Account). The first funding will be on August 1, 2016. The funding will be based on the initial final reclamation estimates with true-ups for updates of estimates made periodically.

28. Annualize Navajo Coal Reclamation Costs

Q. PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE NAVAJO COAL RECLAMATION COSTS.

A. This pro forma adjustment for Navajo coal reclamation annualizes the estimate for final reclamation costs, the costs to account for growth, and the amortization period. The estimate for final reclamation costs is based on a study performed by Weir International, Inc. as of August 2005. The calculation of the estimate for final reclamation costs uses the Weir study, net of any prior negotiated settlements or funding, and updated for the composite index change and the earnings rate. The final reclamation estimate is amortized over the coal supply agreement to April 30, 2016. Payments are made monthly to Peabody based on costs and coal usage. This results in a reduction to pre-tax operating income of $653,000 (*see* Attachment EAB-31DR and SFR Schedule C-2, page 14, column 41).

Q. HOW WAS THE ESCALATION CALCULATED?

A. Total estimated costs from the 2005 Weir study were used to derive APS's share of Navajo coal reclamation costs (adjusted for composite index changes and earning rate for 2015 dollars). The reclamation costs are inflated using an annual rate of 2.7% to 2026. The final reclamation costs are amortized through April 2026. Payments are made monthly to Peabody based on reclamation obligation and coal usage.

29. Adjust Cash Working Capital for Cost of Service.

Q. PLEASE DESCRIBE THE PRO FORMA TO ADJUST CASH WORKING CAPITAL FOR COST OF SERVICE PRO FORMAS.

A. 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, 2015 by $18,888,000 (*see* Attachment EAB-32DR and SFR Schedule B-2, page 4, column 10).

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 $163,000 (*see* Attachment EAB-33DR and SFR Schedule C-2, page 14, column 42).

30. Transfer Palo Verde Unit 2 Lease Reduction to Base Rates.

Q. PLEASE DESCRIBE THE PRO FORMA TO ADJUST PV UNIT 2 LEASE EXPENSE.

A. On July 7, 2014, APS notified the PV Unit 2 lessor trust entities of APS's intent to exercise the fixed rate renewal options in the leases. The length of the renewal options will result in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. APS will be required to make lease payments of approximately $23 million annually for the period 2016 through 2023, and about $16 million annually for

the period 2024 through 2033. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors. This adjustment results in an increase to pre-tax operating income of $16,917,000, reflecting the decrease from the $40 million lease expense (net of the related gain amortization) in the Test Year to the new annual lease expense amount of $23 million effective January 1, 2016. (*See* Attachment EAB-34DR and SFR Schedule C-2, page 15, column 43.)

31. Normalize Fossil and Nuclear Maintenance Expense.

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. APS adjusted Test Year O&M expenses to normalize maintenance levels for the Company's production plant in service at December 31, 2015. This was done separately for the Company's nuclear facilities and its fossil facilities. The nuclear generation maintenance adjustment reduces pre-tax operating income by $248,000 and the fossil generation maintenance adjustment reduces pre-tax operating income by $1,285,000. The O&M expense adjustments include the impacts of the outage time normalization for all of the units. (*See* Attachments EAB-35DR and EAB-36DR and SFR Schedule C-2, page 15, columns 44 and 45.)

Q. HOW DID YOU ADJUST THE OUTAGE TIME TO NORMALIZE THE TEST YEAR RESULTS?

A. Planned maintenance time for each non-nuclear 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 specific six-year period applicable to the normalization includes the historical years of 2010-2015.

Normalized PV outage time is calculated in a similar manner, using a three-year period spanning 2013-2015, but the rationale is slightly different than the one applicable to the coal plant outage time normalization. The nuclear units are each on an 18-month refueling cycle, so a three-year period ensures that each unit's maintenance time is reflected in equal proportion in the normalization period. 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 historical maintenance expense at each power plant using the six-year average maintenance cycle. Normal PV expenses are based on historical expense 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 relevant Handy-Whitman cost indices.

32. Annualize Solar Partner Program Expense.

Q. PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE SOLAR LEASE PAYMENTS.

A. This pro forma annualizes the lease expense associated with the solar partner program operations authorized in Decision No. 74878. This adjustment results in a reduction to pre-tax operating income of $528,000 (*see* Attachment EAB-37DR and SFR Schedule C-2, page 16, column 46).

33. Remove Out of Period and Miscellaneous Items.

Q. PLEASE DESCRIBE THE PRO FORMA TO REMOVE MISCELLANEOUS AND OUT OF PERIOD ITEMS.

A. 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. For the 2015 Test Year, APS is removing costs associated with consulting fees, miscellaneous advertising and other general expenses as they are not reflective of on-going costs or are costs that APS does not intend to collect from customers. This adjustment, for the sake of simplicity, combines several smaller entries that fit this description and are shown in aggregate in the pro forma. This adjustment results in an increase to pre-tax operating income of $1,633,000 (*see* Attachment EAB-38DR and SFR Schedule C-2, page 16, column 47).

V. REQUEST FOR PROPERTY TAX DEFERRAL

Q. IS APS PROPOSING TO RECEIVE AUTHORIZATION FOR A PROPERTY TAX DEFERRAL?

A. Yes, the property tax deferral approved in the last Settlement was very beneficial and helped to alleviate risk of changes in property tax rates within Arizona. For most companies, the assessed value of property rises and falls with its market value. As values fall, the state and local taxing entities raise rates in an attempt to maintain revenues. An increase in the property tax rate to account for any lower assessed value would not necessarily change that non-utility taxpayer's tax payment. For APS, however, the assessed value of APS property is based on its book value – a value that in total is usually steady or rising. Thus, when a taxing entity increases or decreases its tax rate, APS's tax payment necessarily rises or falls accordingly. APS is concerned that its property tax rate and related property tax expense could increase significantly during the course of the Settlement stay-out period, much like it has over the past few years. APS proposes to continue the Arizona property tax deferral and structure it similarly to that in the last rate case.

Q. PLEASE DESCRIBE THE PROPOSED PROPERTY TAX DEFERRAL TERMS.

A. APS proposes to be allowed to defer for future recovery, in accordance with the provisions of Accounting Standards Codification (ASC) 980 (formerly SFAS No. 71), 100% of all changes to Arizona property tax expense above or below the Adjusted Test Year level of $181 million caused by changes to the applicable Arizona composite property tax rate (not changes in the assessed value of property). APS will track and record the deferral in the same manner as it currently is and propose the recovery of the deferred balance in the next rate case. Similarly to that in the Settlement Section 12.2, APS proposes to recover any positive balance from customers over ten years and any negative balance will be refunded to customers over three years.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove Amortization of Pension/OPEB Deferral
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(4,238)
8.	Maintenance	-
9.	Subtotal	(4,238)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	4,238
16.	Interest Expense	-
17.	Taxable Income	4,238
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	1,615
19.	Operating Income (line 15 minus line 18)	$ 2,623

Adjustment to Test Year operations to remove 6 months of amortization of the Pension/OPEB deferral authorized in Decision No. 71448.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Amonix, Star Center Patent Rights and Sale of Kyrene to Knox Amortization
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(4,038)
8.	Maintenance	-
9.	Subtotal	(4,038)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(4,038)
15.	Operating Income Before Income Tax	4,038
16.	Interest Expense	-
17.	Taxable Income	4,038
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	1,538
19.	Operating Income (line 15 minus line 18)	$ 2,500

Adjustment to amortize the gain of the Amonix and Star Center Patent investment over 3 years. This adjustment also includes the amortization of the deferred gain on the Kyrene to Knox transmission line transaction as authorized in Decision No. 74991.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Office Closure and Paystation Fee Socialization
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	(14)
4.	Total Electric Operating Revenues	(14)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(14)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(1,033)
8.	Maintenance	-
9.	Subtotal	(1,033)
10.	Depreciation and Amortization	(27)
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	(18)
14.	Total Other Operating Expense	(1,078)
15.	Operating Income Before Income Tax	1,064
16.	Interest Expense	-
17.	Taxable Income	1,064
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	405
19.	Operating Income (line 15 minus line 18)	$ 659

Adjustment to Test Year operations for reduced expenses related to closure of Customer Service offices and for the increase cost of paystation fees.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove Test Year Regulatory Assessment
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	(7,545)
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(7,545)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(7,545)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(7,545)
8.	Maintenance	-
9.	Subtotal	(7,545)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(7,545)
15.	Operating Income Before Income Tax	-
16.	Interest Expense	-
17.	Taxable Income	-
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	-
19.	Operating Income (line 15 minus line 18)	$ -

Adjustment to Test Year operations to remove the Regulatory Assessment surcharges from revenues and expenses.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove and Transfer Test Year Transmission Cost Adjustor (TCA)
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	(128,782)
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(128,782)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(128,782)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	(128,782)
16.	Interest Expense	-
17.	Taxable Income	(128,782)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(49,066)
19.	Operating Income (line 15 minus line 18)	$ (79,716)

Adjustment to Test Year operations to remove the Transmission Cost Adjustor from operating revenues and transfer it to base rates.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove and Transfer Test Year Lost Fixed Cost Recovery Mechanism (LFCR)
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	(45,988)
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(45,988)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(45,988)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	(45,988)
16.	Interest Expense	-
17.	Taxable Income	(45,988)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(17,521)
19.	Operating Income (line 15 minus line 18)	$ (28,467)

Adjustment to Test Year operations to remove the LFCR mechanism from operating revenues and transfer it to base rates.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove and Transfer Test Year Environmental Improvement Surcharge (EIS)
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	(2,461)
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(2,461)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(2,461)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	(2,461)
16.	Interest Expense	-
17.	Taxable Income	(2,461)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(938)
19.	Operating Income (line 15 minus line 18)	$ (1,523)

Adjustment to Test Year operations to remove the EIS from operating revenues and transfer it to base rates.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove and Transfer a Portion of Test Year Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	(51,369)
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(51,369)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(51,369)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(41,369)
8.	Maintenance	-
9.	Subtotal	(41,369)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(41,369)
15.	Operating Income Before Income Tax	(10,000)
16.	Interest Expense	-
17.	Taxable Income	(10,000)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(3,810)
19.	Operating Income (line 15 minus line 18)	$ (6,190)

Adjustment to Test Year operations to remove the DSMAC from revenues and transfer a portion of it to base rates.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove and Transfer a Portion of Test Year Renewable Energy Adjustment Clause (REAC)
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	(113,286)
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(113,286)
5.	Electric Fuel and Purchased Power Costs	(44,870)
6.	Oper Rev Less Fuel & Purch Pwr Costs	(68,416)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(30,859)
8.	Maintenance	-
9.	Subtotal	(30,859)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(30,859)
15.	Operating Income Before Income Tax	(37,557)
16.	Interest Expense	-
17.	Taxable Income	(37,557)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.10%)	(14,309)
19.	Operating Income (line 15 minus line 18)	$ (23,248)

Adjustment to Test Year operations to remove the REAC from operating revenues and transfer a portion of the expenses related to AZ Sun, Schools and Government and the Community Power Project to base rates.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove and Transfer Test Year Rate Rider Four Corners Revenue
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	(57,675)
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	(57,675)
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(57,675)
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	(57,675)
16.	Interest Expense	-
17.	Taxable Income	(57,675)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(21,974)
19.	Operating Income (line 15 minus line 18)	$ (35,701)

Adjustment to Test Year operations to remove the Four Corners Rate Rider from operating revenues and transfer a portion to base rates.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Four Corners Deferral True Up
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	1,388
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	1,388
15.	Operating Income Before Income Tax	(1,388)
16.	Interest Expense	-
17.	Taxable Income	(1,388)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(529)
19.	Operating Income (line 15 minus line 18)	$ (859)

Adjustment to Test Year operations to include the true-up of the Four Corners deferral balance.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove Cholla Unit 2 Non-Fuel / Non-Payroll Costs
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(5,656)
8.	Maintenance	(2,219)
9.	Subtotal	(7,875)
10.	Depreciation and Amortization	(7,144)
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	(2,336)
14.	Total Other Operating Expense	(17,355)
15.	Operating Income Before Income Tax	17,355
16.	Interest Expense	-
17.	Taxable Income	17,355
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	6,612
19.	Operating Income (line 15 minus line 18)	$ 10,743

Adjustment to Test Year operations to remove Cholla Unit 2 costs due to the shut down of the unit in October of 2015.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Adjust Cholla Unit 2 Regulatory Asset Amortization
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	7,890
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	7,890
15.	Operating Income Before Income Tax	(7,890)
16.	Interest Expense	-
17.	Taxable Income	(7,890)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(3,006)
19.	Operating Income (line 15 minus line 18)	$ (4,884)

Adjustment to Test Year operations to include the amortization costs related to the closure of Cholla Unit 2 and the accrual of remaining removal costs for final retirement in 2033.

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Include West Phoenix Unit 4 Regulatory Disallowance Total Co.
1.	Gross Utility Plant in Service	$ (13,833)
2.	Less: Accumulated Depreciation & Amort.	(5,280)
3.	Net Utility Plant in Service	(8,553)
4.	Less: Total Deductions	(2,038)
5.	Total Additions	-
6.	Total Rate Base	$ (6,515)

Adjustment to Test Year rate base to reflect depreciation of regulatory disallowance of West Phoenix Unit 4 per Decisions Nos. 67744 and 69663.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description		Include West Phoenix Unit 4 Regulatory Disallowance
	Electric Operating Revenues		
1.	Revenues from Base Rates		$ -
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization		(329)
11.	Amortization of Gain		-
12.	Administrative and General		-
13.	Other Taxes		-
14.	Total Other Operating Expense		(329)
15.	Operating Income Before Income Tax		329
16.	Interest Expense	Total Rate Base * Long Term Debt	(148)
17.	Taxable Income		477
18.	Current Income Tax Rate -	38.10% (line 17 * 38.1%)	182
19.	Operating Income (line 15 minus line 18)		$ 147

Adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by previous Decision Nos. 67744 and 69663.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Include Interest Expense on Customer Deposits
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	443
8.	Maintenance	-
9.	Subtotal	443
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	443
15.	Operating Income Before Income Tax	(443)
16.	Interest Expense	-
17.	Taxable Income	(443)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(169)
19.	Operating Income (line 15 minus line 18)	$ (274)

Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits using January 2016 interest rates.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Adjust Depreciation Expense - 2016 Depreciation Rate Study
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	75,989
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	75,989
15.	Operating Income Before Income Tax	(75,989)
16.	Interest Expense	-
17.	Taxable Income	(75,989)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(28,952)
19.	Operating Income (line 15 minus line 18)	$ (47,037)

Adjustment to Test Year operations to reflect depreciation expense based on the 2016 Depreciation Rate Study.

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Fossil Generation	Nuclear Generation	Distribution and IT/Facilities Additions	Customer Service Addition	Renewables, Microgird & Technology Innovation Additions	Total Company Amount
1.	Gross Utility Plant in Service	$ 160,635	$ 123,961	470,386	$ 120,485	$ 238,509	$ 1,113,976
2.	Less: Accumulated Depreciation and Amortization	218,381	74,294	383,258	6,050	50,830	732,813
3.	Net Utility Plant in Service	(57,746)	49,667	87,128	114,435	187,679	381,163
4.	Less: Total Deductions	(19,967)	1,583	11,672	6,426	93,391	93,105
5.	Total Additions	-	-	-	-	7,024	7,024
6.	**Total Rate Base**	**$ (37,779)**	**$ 48,084**	**$ 75,456**	**$ 108,009**	**$ 101,312**	**$ 295,082**

ARIZONA PUBLIC SERVICE COMPANY

Income Statement Pro Forma Adjustment
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description		Fossil Post-Test Year Plant Additions	Nuclear Post-Test Year Plant Additions	Distribution and IT/Facilities Post-Test Year Plant Additions	Customer Service Post-Test Year Plant Additions	Renewables, Microgrid and Technology Innovation Post-Test Year Plant Additions	Total Company Post-Test Year Plant Additions
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ 2,511	$ 2,511
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	2,511	2,511
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	2,511	2,511
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		6,876	2,008	24,244	12,048	8,915	54,091
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		1,118	866	9,420	2,353	2,295	16,052
14.	Total Other Operating Expense		7,994	2,874	33,664	14,401	11,210	70,143
15.	Operating Income Before Income Tax		(7,994)	(2,874)	(33,664)	(14,401)	(8,699)	(67,632)
16.	Interest Expense	2.27%	(858)	1,092	1,713	2,452	2,300	6,699
17.	Taxable Income		(7,136)	(3,966)	(35,377)	(16,853)	(10,999)	(74,331)
18.	Current Income Tax Rate	38.10%	(2,719)	(1,511)	(13,479)	(6,421)	(4,191)	(28,320)
19.	Operating Income (line 15 minus line 18)		$ (5,275)	$ (1,363)	$ (20,185)	$ (7,980)	$ (4,508)	$ (39,312)

Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil, Nuclear, Distribution and IT/Facilities, Customer Service, Renewables, Microgrid and Technology Innovation Post-Test Year Plant Additions.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Adjust Decommissioning and Spent Fuel Costs
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	(962)
6.	Oper Rev Less Fuel & Purch Pwr Costs	962
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	(13,383)
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(13,383)
15.	Operating Income Before Income Tax	14,345
16.	Interest Expense	-
17.	Taxable Income	14,345
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	5,465
19.	Operating Income (line 15 minus line 18)	$ 8,880

Adjustment to Test Year operations to reflect updated decommissioning funding levels for Palo Verde and updated ISFSI expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Annualize Payroll Expense
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	4,236
8.	Maintenance	1,092
9.	Subtotal	5,328
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	5,328
15.	Operating Income Before Income Tax	(5,328)
16.	Interest Expense	-
17.	Taxable Income	(5,328)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(2,030)
19.	Operating Income (line 15 minus line 18)	$ (3,298)

Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2016 employee levels for performance review and March 2017 Union employees.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Normalize Employee Benefits
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	8,400
8.	Maintenance	-
9.	Subtotal	8,400
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	8,400
15.	Operating Income Before Income Tax	(8,400)
16.	Interest Expense	-
17.	Taxable Income	(8,400)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(3,200)
19.	Operating Income (line 15 minus line 18)	$ (5,200)

Adjustment to Test Year operations to reflect the current December 2015 actuarial valuation of retirement program expenses.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove Supplemental Excess Benefit Retirement Plan Expense (SERP)
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(7,808)
8.	Maintenance	-
9.	Subtotal	(7,808)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(7,808)
15.	Operating Income Before Income Tax	7,808
16.	Interest Expense	-
17.	Taxable Income	7,808
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	2,975
19.	Operating Income (line 15 minus line 18)	$ 4,833

Adjustment to Test Year operations to remove Supplemental Excess Benefit Retirement Plan Expense ("SERP").

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove Stock Compensation
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(15,753)
8.	Maintenance	-
9.	Subtotal	(15,753)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(15,753)
15.	Operating Income Before Income Tax	15,753
16.	Interest Expense	-
17.	Taxable Income	15,753
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	6,002
19.	Operating Income (line 15 minus line 18)	$ 9,751

Adjustment to Test Year operations to remove Stock Compensation expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Normalize Cash Incentive
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(2,029)
8.	Maintenance	(50)
9.	Subtotal	(2,079)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	(928)
13.	Other Taxes	-
14.	Total Other Operating Expense	(3,007)
15.	Operating Income Before Income Tax	3,007
16.	Interest Expense	-
17.	Taxable Income	3,007
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	1,146
19.	Operating Income (line 15 minus line 18)	$ 1,861

Adjustment Test Year operations to normalize the cash incentive program over a 3 year period.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Normalize Income Tax Expense/Interest Synchronization
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	-
16.	Interest Expense	10,169
17.	Taxable Income	(10,169)
18.	Current Income Tax Rate - 38.1% (line 17 * 38.1%)	(3,874)
19.	Operating Income (line 15 minus line 18)	$ 3,874

Adjustment to Test Year operations for top down income tax true-ups consistent with Decision Nos. 69663, 71448 and 73183 using the 12/31/2015 rate base and cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Annualize Property Tax Expense
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	28,494
14.	Total Other Operating Expense	28,494
15.	Operating Income Before Income Tax	(28,494)
16.	Interest Expense	-
17.	Taxable Income	(28,494)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(10,856)
19.	Operating Income (line 15 minus line 18)	$ (17,638)

Adjustment to Test Year operations to annualize property taxes calculated using the anticipated 2016 tax assessment ratio and tax rate.

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Include Property Tax Deferral Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation & Amort.	-
3.	Net Utility Plant in Service	-
4.	Less: Total Deductions	14,680
5.	Total Additions	38,529
6.	Total Rate Base	$ 23,849

Adjustment to Test Year rate base to include the deferred property tax amounts from 1/1/2016 - 6/30/2017 per Decision No. 73183.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Amortize Property Tax Deferral
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	8,898
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	8,898
15.	Operating Income Before Income Tax	(8,898)
16.	Interest Expense	541
17.	Taxable Income	(9,439)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(3,596)
19.	Operating Income (line 15 minus line 18)	$ (5,302)

Adjustment to amortize the property tax deferral as authorized in Decision No. 73183 over 10 years.
Pro forma adjusted as shown on Schedule B-2, page 3, column 9.

100000262

ADAM LEBRECHT,

a witness herein, having been first duly sworn by the Certified Court Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. SCOTT:

Q. Okay. Mr. Lebrecht, I have handed you what I have asked to be marked as S-10 and S-11.

A. Yes.

Q. First of all, for the record, could you please state your name and business address.

A. My name is Adam Lebrecht. Last name is spelled L-E-B-R-E-C-H-T. My business address is 1200 West Washington Street, Phoenix, Arizona, 85007.

Q. And by whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission. And I currently have the title of Executive Consultant I.

Q. And with respect to the S-10 and S-11, could you please identify those for the record?

A. S-10 is a copy of the testimony which I wrote regarding this matter. And S-11 is a copy of the errata which I wrote regarding this matter.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description		Annualize Navajo Power Plant Coal Reclamation Costs
	Electric Operating Revenues		
1.	Revenues from Base Rates		$ -
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		653
6.	Oper Rev Less Fuel & Purch Pwr Costs		(653)
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization		-
11.	Amortization of Gain		-
12.	Administrative and General		-
13.	Other Taxes		-
14.	Total Other Operating Expense		-
15.	Operating Income Before Income Tax		(653)
16.	Interest Expense		-
17.	Taxable Income		(653)
18.	Current Income Tax Rate -	38.10% (line 17 * 38.1%)	(249)
19.	Operating Income (line 15 minus line 18)		$ (404)

Adjustment to Test Year operations to reflect the most recent Navajo Power Plant coal reclamation study.

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Adjust Cash Working Capital for Cost of Service Pro Formas Total Co.
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	(18,888)
6.	Total Rate Base	$ (18,888)

Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description			Adjust Cash Working Capital for Cost of Service Pro Formas
	Electric Operating Revenues			
1.	Revenues from Base Rates			$ -
2.	Revenues from Surcharges			-
3.	Other Electric Revenues			-
4.	Total Electric Operating Revenues			-
5.	Electric Fuel and Purchased Power Costs			-
6.	Oper Rev Less Fuel & Purch Pwr Costs			-
	Other Operating Expenses:			
7.	Operations Excluding Fuel Expense			-
8.	Maintenance			-
9.	Subtotal			-
10.	Depreciation and Amortization			-
11.	Amortization of Gain			-
12.	Administrative and General			-
13.	Other Taxes			-
14.	Total Other Operating Expense			-
15.	Operating Income Before Income Tax			-
16.	Interest Expense	Rate Base * Long Term Debt		(429)
17.	Taxable Income			429
18.	Current Income Tax Rate -	38.10%	(line 17 * 38.1%)	163
19.	Operating Income (line 15 minus line 18)			$ (163)

Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Transfer Palo Verde Unit 2 Lease Reduction to Base Rates
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(21,491)
8.	Maintenance	-
9.	Subtotal	(21,491)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	4,574
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(16,917)
15.	Operating Income Before Income Tax	16,917
16.	Interest Expense	-
17.	Taxable Income	16,917
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	6,445
19.	Operating Income (line 15 minus line 18)	$ 10,472

Adjustment to the Test Year operation to include the net expense associated with the reduced Palo Verde Unit 2 lease amount.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description			Normalize Nuclear Maintenance Expense
	Electric Operating Revenues			
1.	Revenues from Base Rates			$ -
2.	Revenues from Surcharges			-
3.	Other Electric Revenues			-
4.	Total Electric Operating Revenues			-
5.	Electric Fuel and Purchased Power Costs			-
6.	Oper Rev Less Fuel & Purch Pwr Costs			-
	Other Operating Expenses:			
7.	Operations Excluding Fuel Expense			-
8.	Maintenance			248
9.	Subtotal			248
10.	Depreciation and Amortization			-
11.	Amortization of Gain			-
12.	Administrative and General			-
13.	Other Taxes			-
14.	Total Other Operating Expense			-
15.	Operating Income Before Income Tax			(248)
16.	Interest Expense			-
17.	Taxable Income			(248)
18.	Current Income Tax Rate -	38.10%	(line 17 * 38.1%)	(94)
19.	Operating Income (line 15 minus line 18)			$ (154)

Adjustment to Test Year operations to reflect normalization of nuclear production maintenance expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Normalize Fossil Maintenance Expense
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	1,285
9.	Subtotal	1,285
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	(1,285)
16.	Interest Expense	-
17.	Taxable Income	(1,285)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(490)
19.	Operating Income (line 15 minus line 18)	$ (795)

Adjustment to Test Year operations to reflect normalization of fossil production maintenance expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Annualize Solar Partner Program Expense
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	528
8.	Maintenance	-
9.	Subtotal	528
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	528
15.	Operating Income Before Income Tax	(528)
16.	Interest Expense	-
17.	Taxable Income	(528)
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	(201)
19.	Operating Income (line 15 minus line 18)	$ (327)

Adjustment to test year operations to annualize solar partner program bill credit expense as authorized in Decision No. 74878.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description	Remove Out of Period and Miscellaneous Items
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	(1,633)
13.	Other Taxes	-
14.	Total Other Operating Expense	(1,633)
15.	Operating Income Before Income Tax	1,633
16.	Interest Expense	-
17.	Taxable Income	1,633
18.	Current Income Tax Rate - 38.10% (line 17 * 38.1%)	622
19.	Operating Income (line 15 minus line 18)	$ 1,011

Remove Out of Period and Miscellaneous Items from the Test Year period including consulting fees, miscellaneous advertising, other general expenses, etc.

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-16-0036

April 2016

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REW–2DR: 2016 DEPRECIATION RATE STUDY

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-16-0036

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am President of Foster Associates Consultants, LLC. Foster Associates is a public utility economic consulting firm 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 office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND.

A. I earned a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. degree 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 Foster Associates.

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 Direc-

tors 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, 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 30 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–1DR.

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 2016 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 Arizona Corporation Commission (ACC) pursuant to a Settlement Agreement in Docket No. E–01345A–11–0224. (Decision No. 73183, dated May 24, 2012).

II. Development of Depreciation Rates

Q. 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 regulation, 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. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, internally generated funds incur no financing costs and 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. PLEASE DESCRIBE THE PRINCIPAL STEPS 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 cost of removal. 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 re-

maining 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 most often obtained 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 baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from net salvage observed in the past. Among the factors that 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 indicator of the adequacy (or inadequacy) of recorded depreciation reserves. Differences between theoretical recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments requiring 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 estimate of service lives, retirement dispersion and net salvage rates. 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 below.

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

The above 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.

III. 2016 Depreciation Rate Study

Q. DID APS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2016 DEPRECIATION STUDY?

A. Yes. Service life statistics estimated in the 2016 study were derived from plant accounting transactions recorded over the period 1971 through 2015. 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 2011 study was updated for the current study by appending additional plant and net salvage transactions for activity years 2011–2015 and age distributions of surviving plant at December 31, 2015. The accuracy and completeness of the assembled database was verified for activity years 2011 through 2015 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 2011 were verified in the 2011 study. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2015 were used in the 2016 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–2DR, 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 was expressed as a survivorship function, which was numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function was 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 expecta-

tions 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 2016 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 2016 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.

Independent contractors were retained by APS between 2013 and 2015 to develop cost estimates for the demolition and abatement of steam and other production units. Costs estimated for dismantling these units were used in the current depreciation study to formulate average and future net salvage rates. Attachment REW–2DR, Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for these production facilities.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Statement C of Attachment REW–2 provides a comparison of recorded, computed and redistributed reserves at December 31, 2015. The recorded reserve was $4,948,691,413 or 37.3 percent of the depreciable plant investment. The corresponding computed reserve is $4,347,225,218 or 32.8 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of

$601,466,194 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.

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. 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 2016 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 2016 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 2016 depreciation study.

Function	Accrual Rate			2016 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	2.59%	4.50%	1.91%	$45,674,490	$79,327,361	$33,652,871
Nuclear	1.45%	1.62%	0.17%	41,019,920	45,907,574	4,887,654
Other	2.80%	3.82%	1.02%	65,921,138	89,917,256	23,996,118
Transmission	2.40%	2.00%	-0.40%	3,052,162	2,538,360	(513,802)
Distribution	2.30%	2.45%	0.15%	125,923,089	134,193,094	8,270,005
General Plant	6.11%	6.20%	0.09%	43,639,012	44,318,029	679,017
Total	2.45%	2.99%	0.54%	$325,229,811	$396,201,674	$70,971,863

Table 2. Current and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.99 percent. Depreciation expense is currently accrued at rates that composite to 2.45 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.54 percentage points.

A continued application of current rates would provide annualized depreciation expense of $325,229,811 compared with an annualized expense of $396,201,674 using the rates developed in this study. The proposed 2016 expense increase is $70,971,863. The computed change in annualized accruals includes a reduction of $7,982,016 attributable to an amortization of a $601,466,194 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2016 study.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Ronald E. White, Ph.D.

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

2015 - Present Foster Associates Consultants, LLC
President

2007 - 2015 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. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01933A–12–0126, Tucson Electric Power Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01933A–15–0322, Tucson Electric Power 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 Corporation Commission, Docket No. E–04204A–15–0142, 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.

Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1115, 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. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.

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. ER11-3638-000, Arizona Public Service 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. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements 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. 9096, Baltimore Gas and Electric Company; 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. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 15–155, Massachusetts Electric Company/Nantucket Electric Company; 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–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Table 2. Generation Facilities

Name	No. of Units	% Owned (a)	Principal Fuels Used	Primary Dispatch Type	Owned Capacity (MW)
Nuclear:					
Palo Verde (b)	3	29.1%	Uranium	Base Load	1,146
Total Nuclear					1,146
Steam:					
Four Corners 4, 5 (c)	2	63%	Coal	Base Load	970
Cholla (d)	2		Coal	Base Load	387
Navajo (e)	3	14%	Coal	Base Load	315
Ocotillo	2		Gas	Peaking	220
Total Steam					1,892
Combined Cycle:					
Redhawk	2		Gas	Load Following	984
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,871
Combustion Turbine:					
Ocotillo	2		Gas	Peaking	110
Saguaro 1, 2	2		Gas/Oil	Peaking	110
Saguaro 3	1		Gas	Peaking	79
Douglas	1		Oil	Peaking	16
Sundance	10		Gas	Peaking	420
West Phoenix	2		Gas	Peaking	110
Yucca 1, 2, 3	3		Gas/Oil	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	96
Total Combustion Turbine					1,088
Solar:					
Cotton Center	1		Solar	As Available	17
Hyder	1		Solar	As Available	16
Paloma	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	19
Gila Bend	1		Solar	As Available	32
Hyder II	1		Solar	As Available	14
Foothills	1		Solar	As Available	35
Luke AFB	1		Solar	As Available	10
Desert Star	1		Solar	As Available	10
APS Owned Distributed Energy			Solar	As Available	15
Multiple facilities			Solar	As Available	4
Total Solar					189
Total Capacity					6,186

(a) 100% unless otherwise noted.

(b) The other participants are Salt River Project (17.49%), SCE (15.8%), El Paso (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water & Power (5.7%). The plant is operated by APS.

(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), Tucson Electric Power Company (7%) and El Paso (7%). The plant is operated by APS.

(d) Cholla Unit 2's last day of service was on October 1, 2015.

(e) The other participants are Salt River Project (21.7%), Nevada Power Company (11.3%), the United States Government (24.3%), Tucson Electric Power Company (7.5%) and Los Angeles Department of Water & Power (21.2%). The plant is operated by Salt River Project.

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 2016 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 2015. 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 2011 study was updated for the current study by appending additional plant and net salvage transactions for activity years 2011–2015 and age distributions of surviving plant at December 31, 2015. The accuracy and completeness of the assembled database was verified for activity years 2011 through 2015 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 2011 were verified in the 2011 study. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2015 were used in the 2016 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 expected

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 2015 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 functions. The functions used in this study are the Iowa–type curves which are mathe-

matically described by the Pearson frequency curve family. Observed life tables were 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 was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life for each plant account. The smoothed survivorship function was 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 2016 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.

Independent contractors were retained by APS between 2013 and 2015 to develop cost estimates for the demolition and abatement of steam and other production units. Costs estimated for dismantling these units were used in the current depreciation study to formulate average and future net salvage rates. Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for these production facilities.[2]

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation

[2]The firm of Burns & McDonnell was retained in 2013 to conduct a decommissioning cost study of generation assets located at Cholla, Ocotillo and Saguaro. The firm was retained in 2014 to conduct a decommissioning cost evaluation for Foothills Solar Plant and in 2015 to conduct a cost evaluation for Luke Solar Plant and Desert Star Solar Plant.

Shaw Environmental Inc. was retained by Arizona Public Service Company to estimate demolition costs in 2015 dollars for the Four Corners Generating Station of which APS holds 63 percent ownership interest in Units 4 and 5, and 63 percent ownership of Common Facilities.

The firm of Sargent & Lundy was retained by Tucson Electric Power to conduct dismantlement studies at the Navajo Generating Station in which APS holds 7.5 percent ownership interest in Units 1, 2, 3 and Common Facilities.

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 2016 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 pe-

riodically 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, 2015. The recorded reserve was $4,948,691,413 or 37.3 percent of the depreciable plant investment. The corresponding computed reserve is $4,347,225,218 or 32.8 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $601,466,194 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 2016 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, computed and redistributed 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, 2015.
- 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, 2015. 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 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	2.52%	0.30%	2.82%	5.01%	0.42%	5.43%
312.00 Boiler Plant Equipment	2.17%	0.32%	2.49%	3.78%	0.39%	4.17%
314.00 Turbogenerator Units	2.51%	0.33%	2.84%	4.45%	0.50%	4.95%
315.00 Accessory Electric Equipment	2.27%	0.34%	2.61%	4.50%	0.47%	4.97%
316.00 Miscellaneous Power Plant Equipment	2.46%	0.33%	2.79%	4.77%	0.59%	5.36%
Total Steam Production Plant	2.27%	0.32%	2.59%	4.08%	0.42%	4.50%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	1.64%	0.01%	1.65%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	1.55%	0.06%	1.61%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	1.64%	0.03%	1.67%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	1.28%	0.02%	1.30%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.92%	0.04%	1.96%
Total Nuclear Production Plant	1.42%	0.03%	1.45%	1.59%	0.03%	1.62%
OTHER PRODUCTION						
341.00 Structures and Improvements	3.04%	-0.09%	2.95%	3.60%	0.26%	3.86%
342.00 Fuel Holders, Products and Accessories	3.14%	-0.15%	2.99%	3.62%	0.19%	3.81%
343.00 Prime Movers	2.40%	-0.10%	2.30%	3.28%	0.15%	3.43%
344.00 Generators and Devices	3.30%	-0.32%	2.98%	3.86%	0.12%	3.98%
345.00 Accessory Electric Equipment	3.11%	-0.06%	3.05%	3.71%	0.24%	3.95%
346.00 Miscellaneous Power Plant Equipment	3.35%	-0.15%	3.20%	4.08%	0.21%	4.29%
Total Other Production Plant	3.02%	-0.22%	2.80%	3.67%	0.15%	3.82%
TRANSMISSION PLANT						
352.02 Structures and Improvements	2.67%		2.67%	2.51%		2.51%
353.00 Station Equipment	2.31%	0.11%	2.42%	1.91%	0.09%	2.00%
354.00 Towers and Fixtures	1.84%		1.84%	1.78%		1.78%
355.00 Poles and Fixtures	1.86%	0.37%	2.23%	1.85%	0.37%	2.22%
356.00 Overhead Conductors and Devices	1.75%	0.33%	2.08%	1.74%	0.33%	2.07%
Total Transmission Plant	2.29%	0.11%	2.40%	1.91%	0.09%	2.00%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.57%	0.07%	1.64%	1.61%	0.09%	1.70%
362.00 Station Equipment	2.19%	-0.20%	1.99%	2.25%	0.08%	2.33%
363.00 Storage Battery Equipment	6.67%		6.67%	9.26%		9.26%
364.01 Poles, Towers and Fixtures - Wood	2.29%	-0.02%	2.27%	2.16%	0.41%	2.57%
364.02 Poles, Towers and Fixtures - Steel	2.55%	0.26%	2.81%	1.97%	0.19%	2.16%
365.00 Overhead Conductors and Devices	1.98%	-0.08%	1.90%	1.95%	0.43%	2.38%
366.00 Underground Conduit	1.57%	0.08%	1.65%	1.61%	0.17%	1.78%
367.00 Underground Conductors and Devices	2.63%	0.09%	2.72%	2.41%	0.21%	2.62%
368.00 Line Transformers	1.68%	0.07%	1.75%	1.75%	0.06%	1.81%
369.00 Services	2.20%	0.10%	2.30%	2.07%	0.95%	3.02%
370.01 Meters - Electronic	3.68%		3.68%	5.59%	-0.03%	5.56%
370.03 Meters - AMI	3.82%		3.82%	4.84%		4.84%
371.00 Installations on Customers' Premises	2.34%	0.34%	2.68%	2.15%	0.32%	2.47%
373.00 Street Lighting and Signal Systems	1.72%	0.13%	1.85%	1.77%	0.08%	1.85%
Total Distribution Plant	2.25%	0.05%	2.30%	2.22%	0.23%	2.45%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.19%	0.13%	2.32%	2.52%	0.17%	2.69%
391.CM Office Furn. and Equip. - Computer	12.08%	0.02%	12.10%	12.86%	0.02%	12.88%
397.00 Communication Equipment	5.35%		5.35%	4.83%		4.83%
Total Depreciable	6.30%	0.04%	6.34%	6.40%	0.06%	6.46%

ARIZONA PUBLIC SERVICE COMPANY
Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
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	4.86%		4.86%	4.87%	-0.01%	4.86%
Total General Plant	6.07%	0.04%	6.11%	6.16%	0.04%	6.20%
TOTAL UTILITY	2.42%	0.03%	2.45%	2.80%	0.19%	2.99%
STEAM PRODUCTION (by Unit)						
Cholla						
311.00 Structures and Improvements	2.85%	0.14%	2.99%	7.05%	0.50%	7.55%
312.00 Boiler Plant Equipment	3.56%	0.25%	3.81%	7.02%	0.57%	7.59%
314.00 Turbogenerator Units	3.53%	0.18%	3.71%	6.64%	0.46%	7.10%
315.00 Accessory Electric Equipment	2.55%	0.14%	2.69%	6.10%	0.43%	6.53%
316.00 Miscellaneous Power Plant Equipment	3.00%	0.20%	3.20%	7.37%	0.55%	7.92%
Total Cholla	3.36%	0.22%	3.58%	6.90%	0.54%	7.44%
Cholla Unit 1						
311.00 Structures and Improvements	3.60%	0.17%	3.77%	5.36%	0.44%	5.80%
312.00 Boiler Plant Equipment	4.22%	0.26%	4.48%	6.04%	0.65%	6.69%
314.00 Turbogenerator Units	4.59%	0.24%	4.83%	6.37%	0.58%	6.95%
315.00 Accessory Electric Equipment	3.65%	0.19%	3.84%	5.48%	0.48%	5.96%
316.00 Miscellaneous Power Plant Equipment	3.45%	0.19%	3.64%	5.15%	0.45%	5.60%
Total Cholla Unit 1	4.22%	0.25%	4.47%	6.02%	0.61%	6.63%
Cholla Unit 3						
311.00 Structures and Improvements	2.19%	0.10%	2.29%	7.02%	0.46%	7.48%
312.00 Boiler Plant Equipment	3.40%	0.25%	3.65%	7.28%	0.55%	7.83%
314.00 Turbogenerator Units	3.04%	0.15%	3.19%	6.72%	0.39%	7.11%
315.00 Accessory Electric Equipment	2.16%	0.12%	2.28%	5.99%	0.42%	6.41%
316.00 Miscellaneous Power Plant Equipment	2.48%	0.15%	2.63%	7.24%	0.52%	7.76%
Total Cholla Unit 3	3.15%	0.21%	3.36%	7.05%	0.51%	7.56%
Cholla Common						
311.00 Structures and Improvements	2.94%	0.15%	3.09%	7.19%	0.52%	7.71%
312.00 Boiler Plant Equipment	3.32%	0.25%	3.57%	7.27%	0.60%	7.87%
314.00 Turbogenerator Units	2.67%	0.13%	2.80%	8.50%	0.63%	9.13%
315.00 Accessory Electric Equipment	2.96%	0.18%	3.14%	7.29%	0.47%	7.76%
316.00 Miscellaneous Power Plant Equipment	3.16%	0.22%	3.38%	7.89%	0.59%	8.48%
Total Cholla Common	3.12%	0.20%	3.32%	7.31%	0.56%	7.87%
Four Corners						
311.00 Structures and Improvements	1.35%	0.51%	1.86%	2.36%	0.26%	2.62%
312.00 Boiler Plant Equipment	0.85%	0.37%	1.22%	1.52%	0.26%	1.78%
314.00 Turbogenerator Units	0.95%	0.42%	1.37%	1.60%	0.30%	1.90%
315.00 Accessory Electric Equipment	1.40%	0.56%	1.96%	2.59%	0.39%	2.98%
316.00 Miscellaneous Power Plant Equipment	1.09%	0.29%	1.38%	2.30%	0.39%	2.69%
Total Four Corners	0.94%	0.39%	1.33%	1.69%	0.28%	1.97%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Four Corners Units 4-5						
311.00 Structures and Improvements	0.98%	0.52%	1.50%	1.75%	0.31%	2.06%
312.00 Boiler Plant Equipment	0.77%	0.36%	1.13%	1.40%	0.24%	1.64%
314.00 Turbogenerator Units	0.92%	0.43%	1.35%	1.55%	0.30%	1.85%
315.00 Accessory Electric Equipment	1.06%	0.57%	1.63%	2.12%	0.41%	2.53%
316.00 Miscellaneous Power Plant Equipment	0.54%	0.18%	0.72%	2.02%	0.40%	2.42%
Total Four Corners Units 4-5	0.80%	0.38%	1.18%	1.50%	0.26%	1.76%
Four Corners Common						
311.00 Structures and Improvements	2.23%	0.48%	2.71%	3.81%	0.16%	3.97%
312.00 Boiler Plant Equipment	2.09%	0.49%	2.58%	3.44%	0.44%	3.88%
314.00 Turbogenerator Units	1.65%	0.28%	1.93%	2.87%	0.27%	3.14%
315.00 Accessory Electric Equipment	2.39%	0.53%	2.92%	3.93%	0.36%	4.29%
316.00 Miscellaneous Power Plant Equipment	2.50%	0.58%	3.08%	3.03%	0.34%	3.37%
Total Four Corners Common	2.21%	0.50%	2.71%	3.50%	0.35%	3.85%
Navajo Units 1-3						
311.00 Structures and Improvements	3.34%	0.24%	3.58%	3.78%	0.20%	3.98%
312.00 Boiler Plant Equipment	3.42%	0.28%	3.70%	3.52%	0.19%	3.71%
314.00 Turbogenerator Units	2.71%	0.20%	2.91%	2.72%	0.15%	2.87%
315.00 Accessory Electric Equipment	2.93%	0.21%	3.14%	3.06%	0.17%	3.23%
316.00 Miscellaneous Power Plant Equipment	3.75%	0.29%	4.04%	4.19%	0.29%	4.48%
Total Navajo Units 1-3	3.33%	0.26%	3.59%	3.49%	0.19%	3.68%
Ocotillo Units 1-2						
311.00 Structures and Improvements	4.91%	0.88%	5.79%	10.65%	2.28%	12.93%
312.00 Boiler Plant Equipment	3.41%	0.65%	4.06%	8.89%	1.97%	10.86%
314.00 Turbogenerator Units	4.74%	0.88%	5.62%	9.88%	2.25%	12.13%
315.00 Accessory Electric Equipment	4.55%	0.84%	5.39%	12.68%	2.76%	15.44%
316.00 Miscellaneous Power Plant Equipment	5.80%	1.10%	6.90%	13.34%	2.76%	16.10%
Total Ocotillo Units 1-2	4.30%	0.80%	5.10%	10.17%	2.23%	12.40%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	1.64%	0.01%	1.65%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	1.55%	0.06%	1.61%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	1.64%	0.03%	1.67%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	1.28%	0.02%	1.30%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.92%	0.04%	1.96%
Total Palo Verde	1.42%	0.03%	1.45%	1.59%	0.03%	1.62%
Palo Verde Unit 1						
321.00 Structures and Improvements	1.13%		1.13%	1.15%		1.15%
322.00 Reactor Plant Equipment	1.45%	0.04%	1.49%	1.45%	0.02%	1.47%
323.00 Turbogenerator Units	1.41%	0.02%	1.43%	1.58%	0.04%	1.62%
324.00 Accessory Electric Equipment	1.11%	0.01%	1.12%	1.15%	0.01%	1.16%
325.00 Miscellaneous Power Plant Equipment	1.29%	0.02%	1.31%	1.30%	0.03%	1.33%
Total Palo Verde Unit 1	1.34%	0.03%	1.37%	1.37%	0.02%	1.39%
Palo Verde Unit 2						
321.00 Structures and Improvements	1.20%	0.01%	1.21%	1.22%	0.01%	1.23%
322.00 Reactor Plant Equipment	1.52%	0.08%	1.60%	1.66%	0.05%	1.71%
323.00 Turbogenerator Units	1.41%	0.01%	1.42%	1.76%	0.03%	1.79%
324.00 Accessory Electric Equipment	1.25%	0.01%	1.26%	1.30%	0.01%	1.31%
325.00 Miscellaneous Power Plant Equipment	1.45%	0.02%	1.47%	1.45%	0.03%	1.48%
Total Palo Verde Unit 2	1.41%	0.05%	1.46%	1.55%	0.04%	1.59%

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Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Palo Verde Unit 3						
321.00 Structures and Improvements	1.22%		1.22%	1.23%	0.01%	1.24%
322.00 Reactor Plant Equipment	1.56%	0.05%	1.61%	1.59%	0.07%	1.66%
323.00 Turbogenerator Units	1.48%	0.02%	1.50%	1.59%	0.01%	1.60%
324.00 Accessory Electric Equipment	1.24%	0.01%	1.25%	1.30%	0.02%	1.32%
325.00 Miscellaneous Power Plant Equipment	1.36%	0.02%	1.38%	1.41%	0.03%	1.44%
Total Palo Verde Unit 3	1.44%	0.03%	1.47%	1.48%	0.05%	1.53%
Palo Verde Water Reclamation						
321.00 Structures and Improvements	1.69%	0.02%	1.71%	2.26%	0.03%	2.29%
322.00 Reactor Plant Equipment	2.01%	0.03%	2.04%	2.99%	0.03%	3.02%
323.00 Turbogenerator Units	1.45%	0.01%	1.46%	1.74%	0.14%	1.88%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	1.43%	0.05%	1.48%	2.38%		2.38%
Total Palo Verde Water Reclamation	1.69%	0.02%	1.71%	2.26%	0.03%	2.29%
Palo Verde Common						
321.00 Structures and Improvements	1.30%	0.02%	1.32%	1.94%	0.02%	1.96%
322.00 Reactor Plant Equipment	1.22%	0.06%	1.28%	1.71%	0.30%	2.01%
323.00 Turbogenerator Units	2.15%	0.04%	2.19%	2.62%	0.17%	2.79%
324.00 Accessory Electric Equipment	1.21%	0.01%	1.22%	1.77%	0.02%	1.79%
325.00 Miscellaneous Power Plant Equipment	1.64%	0.06%	1.70%	2.37%	0.05%	2.42%
Total Palo Verde Common	1.40%	0.04%	1.44%	2.04%	0.06%	2.10%
OTHER PRODUCTION (by Unit)						
Douglas CT						
341.00 Structures and Improvements	5.13%	-0.26%	4.87%	16.13%	0.81%	16.94%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.01%	0.89%	24.09%	1.08%	25.17%
343.00 Prime Movers	-0.25%	0.02%	-0.23%	11.37%	-9.17%	2.20%
344.00 Generators and Devices	-0.28%	0.01%	-0.27%	18.97%	0.95%	19.92%
345.00 Accessory Electric Equipment	0.02%	0.02%	0.04%	23.54%	1.09%	24.63%
346.00 Miscellaneous Power Plant Equipment	0.70%	-0.03%	0.67%	24.08%	1.28%	25.36%
Total Douglas CT	-0.10%	0.01%	-0.09%	14.16%	-6.05%	8.11%
Ocotillo CT Units 1-2						
341.00 Structures and Improvements	4.19%	-0.20%	3.99%	5.50%	0.48%	5.98%
342.00 Fuel Holders, Products and Accessories	2.07%	-0.10%	1.97%	3.72%	0.19%	3.91%
343.00 Prime Movers	0.73%	-0.03%	0.70%	5.41%	0.70%	6.11%
344.00 Generators and Devices	3.44%	-0.61%	2.83%	4.73%	0.25%	4.98%
345.00 Accessory Electric Equipment	1.60%	-0.06%	1.54%	4.84%	0.27%	5.11%
346.00 Miscellaneous Power Plant Equipment	2.14%	-0.09%	2.05%	4.18%	0.20%	4.38%
Total Octillo CT Units 1-2	1.91%	-0.23%	1.68%	5.07%	0.48%	5.55%
Redhawk CC Units 1-2						
341.00 Structures and Improvements	3.13%	-0.12%	3.01%	4.00%	0.20%	4.20%
342.00 Fuel Holders, Products and Accessories	3.63%	-0.18%	3.45%	4.37%	0.23%	4.60%
343.00 Prime Movers	3.11%	-0.08%	3.03%	3.97%	0.26%	4.23%
344.00 Generators and Devices	3.33%	-0.83%	2.50%	4.33%	-0.11%	4.22%
345.00 Accessory Electric Equipment	3.11%	-0.10%	3.01%	3.97%	0.19%	4.16%
346.00 Miscellaneous Power Plant Equipment	3.60%	-0.18%	3.42%	4.41%	0.20%	4.61%
Total Redhawk CC Units 1-2	3.27%	-0.56%	2.71%	4.21%	0.02%	4.23%

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Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.71%	-0.03%	0.68%	4.09%	0.47%	4.56%
344.00 Generators and Devices	2.92%	-0.19%	2.73%	2.97%	0.15%	3.12%
345.00 Accessory Electric Equipment	0.55%	-0.01%	0.54%	4.08%	0.25%	4.33%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro	2.16%	-0.13%	2.03%	3.40%	0.27%	3.67%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.45%	-0.02%	0.43%	4.10%	0.50%	4.60%
344.00 Generators and Devices	3.36%	-0.52%	2.84%	2.72%	0.15%	2.87%
345.00 Accessory Electric Equipment	0.46%	-0.01%	0.45%	4.12%	0.25%	4.37%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro CT Units 1-2	1.46%	-0.12%	1.34%	3.73%	0.38%	4.11%
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.85%	-0.14%	2.71%	3.99%	0.20%	4.19%
344.00 Generators and Devices	2.85%	-0.14%	2.71%	3.01%	0.15%	3.16%
345.00 Accessory Electric Equipment	2.85%	-0.14%	2.71%	3.00%	0.16%	3.16%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	2.85%	-0.14%	2.71%	3.07%	0.16%	3.23%
Solar Units						
341.00 Structures and Improvements						
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 Solar Units	3.36%	-0.01%	3.35%	3.58%	0.28%	3.86%
Chino Valley						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.26%	3.79%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.53%	0.26%	3.79%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
Total Chino Valley	3.33%		3.33%	3.53%	0.26%	3.79%
Cotton Center						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.24%	3.76%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.24%	3.76%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
Total Cotton Center	3.33%		3.33%	3.52%	0.24%	3.76%

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Component Accrual Rates
Current: VG Procedure / RL Technique
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Account Description	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Desert Star						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.52%	5.03%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.52%	5.03%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
Total Desert Star	3.33%		3.33%	4.51%	0.52%	5.03%
Foothills Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.48%	0.30%	3.78%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.48%	0.30%	3.78%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
Total Foothills Units 1-2	3.33%		3.33%	3.48%	0.30%	3.78%
Gila Bend						
341.05 Structures and Improvements	3.33%		3.33%	3.46%	0.36%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.46%	0.36%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
Total Gila Bend	3.33%		3.33%	3.46%	0.36%	3.82%
Hyder Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.51%	0.16%	3.67%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.50%	0.16%	3.66%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.16%	3.64%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.42%	0.15%	3.57%
Total Hyder Units 1-2	3.33%		3.33%	3.50%	0.16%	3.66%
Legacy Units						
341.00 Structures and Improvements	-3.55%	0.20%	-3.35%	1.31%	0.03%	1.34%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	3.93%	-0.86%	3.07%	3.44%	0.08%	3.52%
345.00 Accessory Electric Equipment	7.41%	-0.37%	7.04%	4.23%	0.22%	4.45%
346.00 Miscellaneous Power Plant Equipment						
Total Legacy Units	4.65%	-0.71%	3.94%	3.59%	0.12%	3.71%
Luke AFB						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.54%	5.05%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.54%	5.05%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
Total Luke AFB	3.33%		3.33%	4.51%	0.54%	5.05%

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Current: VG Procedure / RL Technique
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Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Roof Tops						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.18%	3.71%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.55%	0.18%	3.73%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.54%	0.18%	3.72%
346.05 Miscellaneous Power Plant Equipment						
Total Roof Tops	3.33%		3.33%	3.55%	0.18%	3.73%
Paloma						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.30%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.30%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
Total Paloma	3.33%		3.33%	3.52%	0.30%	3.82%
Sundance						
341.00 Structures and Improvements	2.06%	-0.10%	1.96%	2.49%	0.23%	2.72%
342.00 Fuel Holders, Products and Accessories	2.05%	-0.10%	1.95%	2.45%	0.12%	2.57%
343.00 Prime Movers	2.04%	-0.11%	1.93%	2.34%	0.12%	2.46%
344.00 Generators and Devices	2.51%	-0.13%	2.38%	4.45%	0.22%	4.67%
345.00 Accessory Electric Equipment	2.05%	-0.10%	1.95%	2.41%	0.13%	2.54%
346.00 Miscellaneous Power Plant Equipment	2.49%	-0.12%	2.37%	2.85%	0.15%	3.00%
Total Sun Dance	2.06%	-0.11%	1.95%	2.44%	0.13%	2.57%
West Phoenix						
341.00 Structures and Improvements	3.04%	-0.15%	2.89%	3.39%	0.23%	3.62%
342.00 Fuel Holders, Products and Accessories	3.67%	-0.17%	3.50%	3.81%	0.19%	4.00%
343.00 Prime Movers	2.73%	-0.09%	2.64%	3.64%	0.19%	3.83%
344.00 Generators and Devices	3.33%	-0.36%	2.97%	3.88%	0.03%	3.91%
345.00 Accessory Electric Equipment	3.51%	-0.15%	3.36%	4.53%	0.29%	4.82%
346.00 Miscellaneous Power Plant Equipment	3.80%	-0.17%	3.63%	4.45%	0.23%	4.68%
Total West Phoenix	3.18%	-0.24%	2.94%	3.84%	0.11%	3.95%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	5.00%	-0.24%	4.76%	4.03%	0.19%	4.22%
342.00 Fuel Holders, Products and Accessories	4.02%	-0.18%	3.84%	3.94%	0.20%	4.14%
343.00 Prime Movers						
344.00 Generators and Devices	4.08%	-0.65%	3.43%	4.00%	0.14%	4.14%
345.00 Accessory Electric Equipment	4.01%	-0.15%	3.86%	5.21%	0.35%	5.56%
346.00 Miscellaneous Power Plant Equipment	4.17%	-0.18%	3.99%	4.82%	0.23%	5.05%
Total West Phoenix CC Units 1-3	4.07%	-0.48%	3.59%	4.21%	0.19%	4.40%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	3.05%	-0.15%	2.90%	3.30%	0.17%	3.47%
342.00 Fuel Holders, Products and Accessories	2.98%	-0.15%	2.83%	3.21%	0.16%	3.37%
343.00 Prime Movers	2.98%	-0.15%	2.83%	3.21%	0.02%	3.23%
344.00 Generators and Devices	3.07%	-0.30%	2.77%	3.80%	0.18%	3.98%
345.00 Accessory Electric Equipment	3.57%	-0.18%	3.39%	4.00%	0.20%	4.20%
346.00 Miscellaneous Power Plant Equipment	3.72%	-0.17%	3.55%	4.50%	0.22%	4.72%
Total West Phoenix CC Unit 4	3.02%	-0.19%	2.83%	3.40%	0.08%	3.48%

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Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) 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	2.92%	-0.15%	2.77%	3.48%	0.18%	3.66%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	3.01%	-0.08%	2.93%	3.53%	0.20%	3.73%
344.00 Generators and Devices	2.97%	-0.19%	2.78%	3.76%	-0.09%	3.67%
345.00 Accessory Electric Equipment	2.91%	-0.15%	2.76%	3.52%	0.19%	3.71%
346.00 Miscellaneous Power Plant Equipment	3.40%	-0.17%	3.23%	4.12%	0.22%	4.34%
Total West Phoenix CC Unit 5	2.98%	-0.15%	2.83%	3.67%	0.03%	3.70%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	3.80%	-0.19%	3.61%	6.05%	0.46%	6.51%
342.00 Fuel Holders, Products and Accessories	0.61%	-0.03%	0.58%	3.36%	0.17%	3.53%
343.00 Prime Movers	1.00%	-0.03%	0.97%	5.03%	0.49%	5.52%
344.00 Generators and Devices	2.25%	-0.21%	2.04%	4.80%	0.29%	5.09%
345.00 Accessory Electric Equipment	0.95%	-0.04%	0.91%	2.61%	0.13%	2.74%
346.00 Miscellaneous Power Plant Equipment	3.25%	-0.16%	3.09%	3.52%	0.26%	3.78%
Total West Phoenix CT Units 1-2	1.62%	-0.10%	1.52%	4.86%	0.40%	5.26%
West Phoenix Common						
341.00 Structures and Improvements	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
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	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
Yucca						
341.00 Structures and Improvements	2.41%	-0.09%	2.32%	4.70%	0.29%	4.99%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.04%	0.86%	1.86%	0.10%	1.96%
343.00 Prime Movers	2.54%	-0.13%	2.41%	2.98%	0.19%	3.17%
344.00 Generators and Devices	1.29%	-0.24%	1.05%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	1.15%	-0.05%	1.10%	2.94%	0.27%	3.21%
346.00 Miscellaneous Power Plant Equipment	1.82%	-0.09%	1.73%	2.88%	0.15%	3.03%
Total Yucca	2.26%	-0.13%	2.13%	3.06%	0.19%	3.25%
Yucca CT Units 1-4						
341.00 Structures and Improvements	2.29%	-0.08%	2.21%	4.99%	0.31%	5.30%
342.00 Fuel Holders, Products and Accessories	0.11%		0.11%	1.42%	0.08%	1.50%
343.00 Prime Movers	-0.09%		-0.09%	2.80%	0.44%	3.24%
344.00 Generators and Devices	1.27%	-0.24%	1.03%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	0.75%	-0.03%	0.72%	2.84%	0.27%	3.11%
346.00 Miscellaneous Power Plant Equipment	1.11%	-0.06%	1.05%	2.38%	0.12%	2.50%
Total Yucca CT Units 1-4	0.80%	-0.09%	0.71%	3.12%	0.28%	3.40%
Yucca CT Units 5-6						
341.00 Structures and Improvements	2.97%	-0.15%	2.82%	3.29%	0.17%	3.46%
342.00 Fuel Holders, Products and Accessories	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
343.00 Prime Movers	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
344.00 Generators and Devices	2.97%	-0.15%	2.82%	3.14%	0.16%	3.30%
345.00 Accessory Electric Equipment	2.97%	-0.15%	2.82%	3.41%	0.23%	3.64%
346.00 Miscellaneous Power Plant Equipment	2.97%	-0.15%	2.82%	3.70%	0.19%	3.89%
Total Yucca CT Units 5-6	2.97%	-0.15%	2.82%	3.03%	0.15%	3.18%

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual Investment	Net Salvage	Total	Proposed 2016 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION								
311.00 Structures and Improvements	$ 169,959,507	$ 4,285,720	$ 509,355	$ 4,795,075	$ 8,519,119	$ 712,783	$ 9,231,902	$ 4,436,827
312.00 Boiler Plant Equipment	1,156,581,620	25,145,147	3,737,560	28,882,707	43,692,188	4,481,006	48,173,194	19,290,487
314.00 Turbogenerator Units	212,294,514	5,329,754	710,178	6,039,932	9,446,611	1,066,432	10,513,043	4,473,111
315.00 Accessory Electric Equipment	127,147,100	2,880,496	428,580	3,309,076	5,724,338	591,460	6,315,798	3,006,722
316.00 Miscellaneous Power Plant Equipment	95,057,632	2,335,965	311,735	2,647,700	4,538,833	554,591	5,093,424	2,445,724
Total Steam Production Plant	$ 1,761,040,373	$ 39,977,082	$ 5,697,408	$ 45,674,490	$ 71,921,089	$ 7,406,272	$ 79,327,361	$ 33,652,871
NUCLEAR PRODUCTION								
321.00 Structures and Improvements	$ 800,303,960	$ 10,727,268	$ 85,764	$ 10,813,032	$ 13,096,938	$ 123,310	$ 13,220,248	$ 2,407,216
322.00 Reactor Plant Equipment	1,177,440,897	17,638,606	620,479	18,259,085	18,295,675	623,581	18,919,256	660,171
323.00 Turbogenerator Units	378,902,614	5,482,642	67,858	5,550,500	6,207,376	103,050	6,310,426	759,926
324.00 Accessory Electric Equipment	286,941,496	3,401,561	28,694	3,430,255	3,678,876	40,796	3,719,672	289,417
325.00 Miscellaneous Power Plant Equipment	190,865,034	2,887,543	79,505	2,967,048	3,660,120	77,852	3,737,972	770,924
Total Nuclear Production Plant	$ 2,834,454,001	$ 40,137,620	$ 882,300	$ 41,019,920	$ 44,938,985	$ 968,589	$ 45,907,574	$ 4,887,654
OTHER PRODUCTION								
341.00 Structures and Improvements	$ 115,260,761	$ 3,501,273	$ (108,083)	$ 3,393,190	$ 4,152,260	$ 293,321	$ 4,445,581	$ 1,052,391
342.00 Fuel Holders, Products and Accessories	55,221,287	1,736,385	(80,550)	1,655,835	1,998,728	102,493	2,101,221	445,386
343.00 Prime Movers	652,662,488	15,646,368	(630,648)	15,015,720	21,406,507	977,134	22,383,641	7,367,921
344.00 Generators and Devices	1,295,258,389	42,745,962	(4,147,318)	38,598,644	50,048,588	1,492,122	51,540,710	12,942,066
345.00 Accessory Electric Equipment	209,397,328	6,512,733	(128,854)	6,383,879	7,761,268	510,398	8,271,666	1,887,787
346.00 Miscellaneous Power Plant Equipment	27,345,147	914,722	(40,852)	873,870	1,116,455	57,982	1,174,437	300,567
Total Other Production Plant	$ 2,355,145,400	$ 71,057,443	$ (5,136,305)	$ 65,921,138	$ 86,483,806	$ 3,433,450	$ 89,917,256	$ 23,996,118
TRANSMISSION PLANT								
352.02 Structures and Improvements	$ 151,995	$ 4,058	$ -	$ 4,058	$ 3,815	$ -	$ 3,815	$ (243)
353.00 Station Equipment	122,007,490	2,818,373	134,208	2,952,581	2,330,343	109,807	2,440,150	(512,431)
354.00 Towers and Fixtures	1,329,316	24,459		24,459	23,662		23,662	(797)
355.00 Poles and Fixtures	1,370,085	25,484	5,069	30,553	25,347	5,069	30,416	(137)
356.00 Overhead Conductors and Devices	1,947,677	34,084	6,427	40,511	33,890	6,427	40,317	(194)
Total Transmission Plant	$ 126,806,563	$ 2,906,458	$ 145,704	$ 3,052,162	$ 2,417,057	$ 121,303	$ 2,538,360	$ (513,802)
DISTRIBUTION PLANT								
361.00 Structures and Improvements	$ 82,271,151	$ 1,291,657	$ 57,590	$ 1,349,247	$ 1,324,566	$ 74,044	$ 1,398,610	$ 49,363
362.00 Station Equipment	494,771,283	10,835,491	(989,543)	9,845,948	11,132,354	395,817	11,528,171	1,682,223
363.00 Storage Battery Equipment	2,123,630	141,646		141,646	196,648		196,648	55,002
364.01 Poles, Towers and Fixtures - Wood	332,284,839	7,609,323	(66,457)	7,542,866	7,177,353	1,362,368	8,539,721	996,855
364.02 Poles, Towers and Fixtures - Steel	260,823,751	6,651,006	678,142	7,329,148	5,138,228	495,565	5,633,793	(1,695,355)
365.00 Overhead Conductors and Devices	355,117,540	7,031,327	(284,094)	6,747,233	6,924,792	1,527,005	8,451,797	1,704,564
366.00 Underground Conduit	685,513,670	10,762,565	548,411	11,310,976	11,036,770	1,165,373	12,202,143	891,167
367.00 Underground Conductors and Devices	1,646,381,070	43,299,822	1,481,743	44,781,565	39,677,784	3,457,400	43,135,184	(1,646,381)
368.00 Line Transformers	833,275,690	13,999,032	583,293	14,582,325	14,582,325	499,965	15,082,290	499,965

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual			Proposed 2016 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
369.00 Services	375,644,741	8,264,184	375,645	8,639,829	7,775,846	3,568,625	11,344,471	2,704,642
370.01 Meters - Electronic	17,142,724	630,852		630,852	958,278	(5,143)	953,135	322,283
370.03 Meters - AMI	274,220,605	10,475,227		10,475,227	13,272,277		13,272,277	2,797,050
371.00 Installations on Customers' Premises	43,510,997	1,018,157	147,937	1,166,094	935,486	139,235	1,074,721	(91,373)
373.00 Street Lighting and Signal Systems	74,601,787	1,283,151	96,982	1,380,133	1,320,452	59,681	1,380,133	
Total Distribution Plant	$ 5,477,683,478	$ 123,293,440	$ 2,629,649	$ 125,923,089	$ 121,453,159	$ 12,739,935	$ 134,193,094	$ 8,270,005
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$ 179,729,946	$ 3,936,086	$ 233,649	$ 4,169,735	$ 4,529,195	$ 305,541	$ 4,834,736	$ 665,001
391.CM Office Furn. and Equip. - Computer	169,141,944	20,432,347	33,828	20,466,175	21,751,654	33,828	21,785,482	1,319,307
397.00 Communication Equipment	251,017,440	13,429,433		13,429,433	12,124,142		12,124,142	(1,305,291)
Total Depreciable	$ 599,889,330	$ 37,797,866	$ 267,477	$ 38,065,343	$ 38,404,991	$ 339,369	$ 38,744,360	$ 679,017
Amortizable								
391.FE Office Furn. and Equip. - Furniture	$ 59,067,179	$ 2,941,473	$ -	$ 2,941,473	$ 2,941,473	$ -	$ 2,941,473	$ -
393.00 Stores Equipment	242,516	12,126		12,126	12,126		12,126	
394.00 Tools, Shop and Garage Equipment	37,140,670	1,852,721		1,852,721	1,852,721		1,852,721	
395.00 Laboratory Equipment	810,563	40,422		40,422	40,422		40,422	
398.00 Miscellaneous Equipment	17,446,236	726,927		726,927	726,927		726,927	
Total Amortizable	$ 114,707,164	$ 5,573,669	$ -	$ 5,573,669	$ 5,573,669	$ -	$ 5,573,669	$ -
Total General Plant	$ 714,596,494	$ 43,371,535	$ 267,477	$ 43,639,012	$ 43,978,660	$ 339,369	$ 44,318,029	$ 679,017
TOTAL UTILITY	$ 13,269,726,309	$ 320,743,578	$ 4,486,233	$ 325,229,811	$ 371,192,756	$ 25,008,918	$ 396,201,674	$ 70,971,863
STEAM PRODUCTION (by Unit)								
Cholla								
311.00 Structures and Improvements	$ 77,737,991	$ 2,217,136	$ 110,911	$ 2,328,047	$ 5,479,970	$ 392,470	$ 5,872,440	$ 3,544,393
312.00 Boiler Plant Equipment	378,495,272	13,478,776	954,263	14,433,039	26,553,415	2,192,011	28,745,426	14,312,387
314.00 Turbogenerator Units	86,113,816	3,037,597	153,569	3,191,166	5,722,198	392,364	6,114,562	2,923,396
315.00 Accessory Electric Equipment	52,313,534	1,335,318	74,215	1,409,533	3,189,007	229,406	3,418,413	2,008,880
316.00 Miscellaneous Power Plant Equipment	23,835,993	715,177	46,771	761,948	1,756,000	131,746	1,887,746	1,125,798
Total Cholla	$ 618,496,606	$ 20,784,004	$ 1,339,729	$ 22,123,733	$ 42,700,590	$ 3,337,997	$ 46,038,587	$ 23,914,854
Cholla Unit 1								
311.00 Structures and Improvements	$ 4,743,207	$ 170,755	$ 8,063	$ 178,818	$ 254,236	$ 20,870	$ 275,106	$ 96,288
312.00 Boiler Plant Equipment	80,244,501	3,386,318	208,636	3,594,954	4,846,768	521,589	5,368,357	1,773,403
314.00 Turbogenerator Units	27,503,716	1,262,421	66,009	1,328,430	1,751,987	159,522	1,911,509	583,079
315.00 Accessory Electric Equipment	9,492,908	346,491	18,037	364,528	520,211	45,566	565,777	201,249
316.00 Miscellaneous Power Plant Equipment	2,926,476	100,963	5,560	106,523	150,714	13,169	163,883	57,360
Total Cholla Unit 1	$ 124,910,808	$ 5,266,948	$ 306,305	$ 5,573,253	$ 7,523,916	$ 760,716	$ 8,284,632	$ 2,711,379

ARIZONA PUBLIC SERVICE COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual Investment	Net Salvage	Total	Proposed 2016 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Cholla Unit 3								
311.00 Structures and Improvements	$ 13,288,725	$ 291,023	$ 13,289	$ 304,312	$ 932,868	$ 61,128	$ 993,996	$ 689,684
312.00 Boiler Plant Equipment	238,165,292	8,097,620	595,413	8,693,033	17,338,433	1,309,909	18,648,342	9,955,309
314.00 Turbogenerator Units	56,834,120	1,727,757	85,251	1,813,008	3,819,253	221,653	4,040,906	2,227,898
315.00 Accessory Electric Equipment	34,832,937	752,391	41,800	794,191	2,086,493	146,298	2,232,791	1,438,600
316.00 Miscellaneous Power Plant Equipment	6,842,283	169,689	10,263	179,952	495,381	35,580	530,961	351,009
Total Cholla Unit 3	$ 349,963,357	$ 11,038,480	$ 746,016	$ 11,784,496	$ 24,672,428	$ 1,774,568	$ 26,446,996	$ 14,662,500
Cholla Common								
311.00 Structures and Improvements	$ 59,706,059	$ 1,755,358	$ 89,559	$ 1,844,917	$ 4,292,866	$ 310,472	$ 4,603,338	$ 2,758,421
312.00 Boiler Plant Equipment	60,085,479	1,994,838	150,214	2,145,052	4,368,214	360,513	4,728,727	2,583,675
314.00 Turbogenerator Units	1,775,980	47,419	2,309	49,728	150,958	11,189	162,147	112,419
315.00 Accessory Electric Equipment	7,987,689	236,436	14,378	250,814	582,303	37,542	619,845	369,031
316.00 Miscellaneous Power Plant Equipment	14,067,234	444,525	30,948	475,473	1,109,905	82,997	1,192,902	717,429
Total Cholla Common	$ 143,622,441	$ 4,478,576	$ 287,408	$ 4,765,984	$ 10,504,246	$ 802,713	$ 11,306,959	$ 6,540,975
Four Corners								
311.00 Structures and Improvements	$ 54,567,232	$ 735,500	$ 277,325	$ 1,012,825	$ 1,285,747	$ 145,070	$ 1,430,817	$ 417,992
312.00 Boiler Plant Equipment	581,513,168	4,946,090	2,139,581	7,085,671	8,865,135	1,466,607	10,331,742	3,246,071
314.00 Turbogenerator Units	83,827,121	796,291	355,303	1,151,594	1,344,672	250,451	1,595,123	443,529
315.00 Accessory Electric Equipment	47,577,191	667,269	266,289	933,558	1,230,396	188,941	1,419,337	485,779
316.00 Miscellaneous Power Plant Equipment	44,955,256	491,011	131,583	622,594	1,036,022	172,221	1,208,243	585,649
Total Four Corners	$ 812,439,968	$ 7,636,161	$ 3,170,081	$ 10,806,242	$ 13,761,972	$ 2,223,290	$ 15,985,262	$ 5,179,020
Four Corners Units 4-5								
311.00 Structures and Improvements	$ 38,507,966	$ 377,378	$ 200,241	$ 577,619	$ 673,889	$ 119,375	$ 793,264	$ 215,645
312.00 Boiler Plant Equipment	546,025,397	4,204,396	1,965,691	6,170,087	7,644,356	1,310,461	8,954,817	2,784,730
314.00 Turbogenerator Units	80,391,368	739,601	345,683	1,085,284	1,246,066	241,174	1,487,240	401,956
315.00 Accessory Electric Equipment	35,325,258	374,448	201,354	575,802	748,895	144,834	893,729	317,927
316.00 Miscellaneous Power Plant Equipment	32,289,311	174,362	58,121	232,483	652,244	129,157	781,401	548,918
Total Four Corners Units 4-5	$ 732,539,300	$ 5,870,185	$ 2,771,090	$ 8,641,275	$ 10,965,450	$ 1,945,001	$ 12,910,451	$ 4,269,176
Four Corners Common								
311.00 Structures and Improvements	$ 16,059,266	$ 358,122	$ 77,084	$ 435,206	$ 611,858	$ 25,695	$ 637,553	$ 202,347
312.00 Boiler Plant Equipment	35,487,771	741,694	173,890	915,584	1,220,779	156,146	1,376,925	461,341
314.00 Turbogenerator Units	3,435,753	56,690	9,620	66,310	98,606	9,277	107,883	41,573
315.00 Accessory Electric Equipment	12,251,933	292,821	64,935	357,756	481,501	44,107	525,608	167,852
316.00 Miscellaneous Power Plant Equipment	12,665,945	316,649	73,462	390,111	383,778	43,064	426,842	36,731
Total Four Corners Common	$ 79,900,668	$ 1,765,976	$ 398,991	$ 2,164,967	$ 2,796,522	$ 278,289	$ 3,074,811	$ 909,844

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual			Proposed 2016 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
Navajo Units 1-3								
311.00 Structures and Improvements	$ 32,849,766	$ 1,097,182	$ 78,839	$ 1,176,021	$ 1,241,721	$ 65,700	$ 1,307,421	$ 131,400
312.00 Boiler Plant Equipment	171,354,162	5,860,312	479,792	6,340,104	6,031,667	325,573	6,357,240	17,136
314.00 Turbogenerator Units	25,206,593	683,099	50,413	733,512	685,619	37,810	723,429	(10,083)
315.00 Accessory Electric Equipment	22,361,468	655,191	46,959	702,150	684,261	38,014	722,275	20,125
316.00 Miscellaneous Power Plant Equipment	19,203,553	720,133	55,690	775,823	804,629	55,690	860,319	84,496
Total Navajo Units 1-3	$ 270,975,542	$ 9,015,917	$ 711,693	$ 9,727,610	$ 9,447,897	$ 522,787	$ 9,970,684	$ 243,074
Ocotillo Units 1-2								
311.00 Structures and Improvements	$ 4,804,518	$ 235,902	$ 42,280	$ 278,182	$ 511,681	$ 109,543	$ 621,224	$ 343,042
312.00 Boiler Plant Equipment	25,219,018	859,969	163,924	1,023,893	2,241,971	496,815	2,738,786	1,714,893
314.00 Turbogenerator Units	17,146,984	812,767	150,893	963,660	1,694,122	385,807	2,079,929	1,116,269
315.00 Accessory Electric Equipment	4,894,907	222,718	41,117	263,835	620,674	135,099	755,773	491,938
316.00 Miscellaneous Power Plant Equipment	7,062,830	409,644	77,691	487,335	942,182	194,934	1,137,116	649,781
Total Ocotillo Units 1-2	$ 59,128,257	$ 2,541,000	$ 475,905	$ 3,016,905	$ 6,010,630	$ 1,322,198	$ 7,332,828	$ 4,315,923
NUCLEAR PRODUCTION (by Unit)								
Palo Verde								
321.00 Structures and Improvements	$ 800,303,960	$ 10,727,268	$ 85,764	$ 10,813,032	$ 13,096,938	$ 123,310	$ 13,220,248	$ 2,407,216
322.00 Reactor Plant Equipment	1,177,440,897	17,638,606	620,479	18,259,085	18,295,675	623,581	18,919,256	660,171
323.00 Turbogenerator Units	378,902,614	5,482,642	67,858	5,550,500	6,207,376	103,050	6,310,426	759,926
324.00 Accessory Electric Equipment	286,941,496	3,401,561	28,694	3,430,255	3,678,876	40,796	3,719,672	289,417
325.00 Miscellaneous Power Plant Equipment	190,865,034	2,887,543	79,505	2,967,048	3,660,120	77,852	3,737,972	770,924
Total Palo Verde	$ 2,834,454,001	$ 40,137,620	$ 882,300	$ 41,019,920	$ 44,938,985	$ 968,589	$ 45,907,574	$ 4,887,654
Palo Verde Unit 1								
321.00 Structures and Improvements	$ 160,238,922	$ 1,810,700	$ -	$ 1,810,700	$ 1,842,748	$ -	$ 1,842,748	$ 32,048
322.00 Reactor Plant Equipment	464,794,795	6,739,525	185,918	6,925,443	6,739,525	92,959	6,832,484	(92,959)
323.00 Turbogenerator Units	133,635,855	1,884,266	26,727	1,910,993	2,111,447	53,454	2,164,901	253,908
324.00 Accessory Electric Equipment	117,924,193	1,308,959	11,792	1,320,751	1,356,128	11,792	1,367,920	47,169
325.00 Miscellaneous Power Plant Equipment	31,243,002	403,035	6,249	409,284	406,159	9,373	415,532	6,248
Total Palo Verde Unit 1	$ 907,836,767	$ 12,146,485	$ 230,686	$ 12,377,171	$ 12,456,007	$ 167,578	$ 12,623,585	$ 246,414
Palo Verde Unit 2								
321.00 Structures and Improvements	$ 92,055,736	$ 1,104,669	$ 9,206	$ 1,113,875	$ 1,123,080	$ 9,206	$ 1,132,286	$ 18,411
322.00 Reactor Plant Equipment	249,302,485	3,789,398	199,442	3,988,840	4,138,421	124,651	4,263,072	274,232
323.00 Turbogenerator Units	87,999,272	1,240,790	8,800	1,249,590	1,548,787	26,400	1,575,187	325,597
324.00 Accessory Electric Equipment	47,992,891	599,911	4,799	604,710	623,908	4,799	628,707	23,997
325.00 Miscellaneous Power Plant Equipment	27,285,762	395,644	5,457	401,101	395,644	8,186	403,830	2,729
Total Palo Verde Unit 2	$ 504,636,146	$ 7,130,412	$ 227,704	$ 7,358,116	$ 7,829,840	$ 173,242	$ 8,003,082	$ 644,966

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual			Proposed 2016 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 Unit 3								
321.00 Structures and Improvements	$ 165,218,693	$ 2,015,668	$ -	$ 2,015,668	$ 2,032,190	$ 16,522	$ 2,048,712	$ 33,044
322.00 Reactor Plant Equipment	427,193,012	6,664,211	213,597	6,877,808	6,792,369	299,035	7,091,404	213,596
323.00 Turbogenerator Units	152,558,297	2,257,863	30,512	2,288,375	2,425,677	15,256	2,440,933	152,558
324.00 Accessory Electric Equipment	94,317,583	1,169,538	9,432	1,178,970	1,226,129	18,864	1,244,993	66,023
325.00 Miscellaneous Power Plant Equipment	28,965,542	393,931	5,793	399,724	408,414	8,690	417,104	17,380
Total Palo Verde Unit 3	$ 868,253,127	$ 12,501,211	$ 259,334	$ 12,760,545	$ 12,884,779	$ 358,367	$ 13,243,146	$ 482,601
Palo Verde Water Reclamation								
321.00 Structures and Improvements	$ 210,244,404	$ 3,553,130	$ 42,049	$ 3,595,179	$ 4,751,524	$ 63,073	$ 4,814,597	$ 1,219,418
322.00 Reactor Plant Equipment	561,290	11,282	168	11,450	16,783	168	16,951	5,501
323.00 Turbogenerator Units	217,756	3,157	22	3,179	3,789	305	4,094	915
324.00 Accessory Electric Equipment								
325.00 Miscellaneous Power Plant Equipment	165,219	2,363	83	2,446	3,932		3,932	1,486
Total Palo Verde Water Reclamation	$ 211,188,669	$ 3,569,932	$ 42,322	$ 3,612,254	$ 4,776,028	$ 63,546	$ 4,839,574	$ 1,227,320
Palo Verde Common								
321.00 Structures and Improvements	$ 172,546,205	$ 2,243,101	$ 34,509	$ 2,277,610	$ 3,347,396	$ 34,509	$ 3,381,905	$ 1,104,295
322.00 Reactor Plant Equipment	35,589,315	434,190	21,354	455,544	608,577	106,768	715,345	259,801
323.00 Turbogenerator Units	4,491,434	96,566	1,797	98,363	117,676	7,635	125,311	26,948
324.00 Accessory Electric Equipment	26,706,829	323,153	2,671	325,824	472,711	5,341	478,052	152,228
325.00 Miscellaneous Power Plant Equipment	103,205,509	1,692,570	61,923	1,754,493	2,445,971	51,603	2,497,574	743,081
Total Palo Verde Common	$ 342,539,292	$ 4,789,580	$ 122,254	$ 4,911,834	$ 6,992,331	$ 205,856	$ 7,198,187	$ 2,286,353
OTHER PRODUCTION (by Unit)								
Douglas CT								
341.00 Structures and Improvements	$ 103,952	$ 5,333	$ (270)	$ 5,063	$ 16,767	$ 842	$ 17,609	$ 12,546
342.00 Fuel Holders, Products and Accessories	137,759	1,240	(14)	1,226	33,186	1,488	34,674	33,448
343.00 Prime Movers	3,721,569	(9,304)	744	(8,560)	423,142	(341,268)	81,874	90,434
344.00 Generators and Devices	971,924	(2,721)	97	(2,624)	184,374	9,233	193,607	196,231
345.00 Accessory Electric Equipment	403,765	81	81	162	95,046	4,401	99,447	99,285
346.00 Miscellaneous Power Plant Equipment	33,564	235	(10)	225	8,082	430	8,512	8,287
Total Douglas CT	$ 5,372,533	$ (5,136)	$ 628	$ (4,508)	$ 760,597	$ (324,874)	$ 435,723	$ 440,231
Ocotillo CT Units 1-2								
341.00 Structures and Improvements	$ 1,953,223	$ 81,840	$ (3,906)	$ 77,934	$ 107,427	$ 9,375	$ 116,802	$ 38,868
342.00 Fuel Holders, Products and Accessories	1,107,461	22,924	(1,107)	21,817	41,198	2,104	43,302	21,485
343.00 Prime Movers	21,989,611	160,524	(6,597)	153,927	1,189,638	153,927	1,343,565	1,189,638
344.00 Generators and Devices	14,737,836	506,982	(89,901)	417,081	697,100	36,845	733,945	316,864
345.00 Accessory Electric Equipment	4,017,658	64,283	(2,411)	61,872	194,455	10,848	205,303	143,431
346.00 Miscellaneous Power Plant Equipment	990,572	21,198	(892)	20,306	41,406	1,981	43,387	23,081
Total Octillo CT Units 1-2	$ 44,796,361	$ 857,751	$ (104,814)	$ 752,937	$ 2,271,224	$ 215,080	$ 2,486,304	$ 1,733,367

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual Investment	Net Salvage	Total	Proposed 2016 Annualized Accrual Investment	Net Salvage	Total	Difference
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	$ 23,674,859	$ 741,023	$ (28,410)	$ 712,613	$ 946,994	$ 47,350	$ 994,344	$ 281,731
342.00 Fuel Holders, Products and Accessories	11,611,849	421,510	(20,901)	400,609	507,438	26,707	534,145	133,536
343.00 Prime Movers	132,566,124	4,122,806	(106,053)	4,016,753	5,262,875	344,672	5,607,547	1,590,794
344.00 Generators and Devices	336,601,568	11,208,832	(2,793,793)	8,415,039	14,574,848	(370,262)	14,204,586	5,789,547
345.00 Accessory Electric Equipment	23,778,511	739,512	(23,779)	715,733	944,007	45,179	989,186	273,453
346.00 Miscellaneous Power Plant Equipment	6,538,111	235,372	(11,769)	223,603	288,331	13,076	301,407	77,804
Total Redhawk CC Units 1-2	$ 534,771,022	$ 17,469,055	$ (2,984,705)	$ 14,484,350	$ 22,524,493	$ 106,722	$ 22,631,215	$ 8,146,865
Saguaro								
341.00 Structures and Improvements	$ 3,173,028	$ 145,959	$ (6,981)	$ 138,978	$ 133,267	$ 13,009	$ 146,276	$ 7,298
342.00 Fuel Holders, Products and Accessories	1,642,488	20,860	(493)	20,367	35,478	2,135	37,613	17,246
343.00 Prime Movers	17,905,173	127,116	(5,908)	121,208	731,979	83,708	815,687	694,479
344.00 Generators and Devices	32,384,680	946,763	(63,071)	883,692	961,246	48,577	1,009,823	126,131
345.00 Accessory Electric Equipment	3,384,270	18,497	(498)	17,999	138,060	8,350	146,410	128,411
346.00 Miscellaneous Power Plant Equipment	892,062	22,926	(1,070)	21,856	20,071	981	21,052	(804)
Total Saguaro	$ 59,381,701	$ 1,282,121	$ (78,021)	$ 1,204,100	$ 2,020,101	$ 156,760	$ 2,176,861	$ 972,761
Saguaro CT Units 1-2								
341.00 Structures and Improvements	$ 3,173,028	$ 145,959	$ (6,981)	$ 138,978	$ 133,267	$ 13,009	$ 146,276	$ 7,298
342.00 Fuel Holders, Products and Accessories	1,642,488	20,860	(493)	20,367	35,478	2,135	37,613	17,246
343.00 Prime Movers	15,965,868	71,846	(3,193)	68,653	654,601	79,829	734,430	665,777
344.00 Generators and Devices	4,666,538	156,796	(24,266)	132,530	126,930	7,000	133,930	1,400
345.00 Accessory Electric Equipment	3,261,717	15,004	(326)	14,678	134,383	8,154	142,537	127,859
346.00 Miscellaneous Power Plant Equipment	892,062	22,926	(1,070)	21,856	20,071	981	21,052	(804)
Total Saguaro CT Units 1-2	$ 29,601,701	$ 433,391	$ (36,329)	$ 397,062	$ 1,104,730	$ 111,108	$ 1,215,838	$ 818,776
Saguaro CT Unit 3								
341.00 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	1,939,305	55,270	(2,715)	52,555	77,378	3,879	81,257	28,702
344.00 Generators and Devices	27,718,142	789,967	(38,805)	751,162	834,316	41,577	875,893	124,731
345.00 Accessory Electric Equipment	122,553	3,493	(172)	3,321	3,677	196	3,873	552
346.00 Miscellaneous Power Plant Equipment								
Total Saguaro CT Unit 3	$ 29,780,000	$ 848,730	$ (41,692)	$ 807,038	$ 915,371	$ 45,652	$ 961,023	$ 153,985

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual Investment	Net Salvage	Total	Proposed 2016 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Solar Units								
341.00 Structures and Improvements	$ 32,510,020	$ 1,060,158	$ 652	$ 1,060,810	$ 1,160,366	$ 94,000	$ 1,254,366	$ 193,556
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	587,836,565	19,635,640	(86,977)	19,548,663	21,087,015	1,649,159	22,736,174	3,187,511
345.00 Accessory Electric Equipment	105,145,520	3,648,510	(13,346)	3,635,164	3,753,527	277,584	4,031,111	395,947
346.00 Miscellaneous Power Plant Equipment	1,557,654	51,870		51,870	61,261	5,685	66,946	15,076
Total Solar Units	$ 727,049,759	$ 24,396,178	$ (99,671)	$ 24,296,507	$ 26,062,169	$ 2,026,428	$ 28,088,597	$ 3,792,090
Chino Valley								
341.05 Structures and Improvements	$ 527,889	$ 17,579	$ -	$ 17,579	$ 18,634	$ 1,373	$ 20,007	$ 2,428
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	77,719,075	2,588,045		2,588,045	2,743,483	202,070	2,945,553	357,508
345.05 Accessory Electric Equipment	6,511,775	216,842		216,842	229,866	16,931	246,797	29,955
346.05 Miscellaneous Power Plant Equipment	216,504	7,210		7,210	7,643	563	8,206	996
Total Chino Valley	$ 84,975,243	$ 2,829,676	$ -	$ 2,829,676	$ 2,999,626	$ 220,937	$ 3,220,563	$ 390,887
Cotton Center								
341.05 Structures and Improvements	$ 1,813,500	$ 60,390	$ -	$ 60,390	$ 63,835	$ 4,352	$ 68,187	$ 7,797
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	61,593,054	2,051,049		2,051,049	2,168,076	147,823	2,315,899	264,850
345.05 Accessory Electric Equipment	15,418,050	513,421		513,421	542,715	37,003	579,718	66,297
346.05 Miscellaneous Power Plant Equipment	262,641	8,746		8,746	9,245	630	9,875	1,129
Total Cotton Center	$ 79,087,245	$ 2,633,606	$ -	$ 2,633,606	$ 2,783,871	$ 189,808	$ 2,973,679	$ 340,073
Desert Star								
341.05 Structures and Improvements	$ 1,572,235	$ 52,355	$ -	$ 52,355	$ 70,908	$ 8,176	$ 79,084	$ 26,729
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	25,365,040	844,656		844,656	1,143,963	131,898	1,275,861	431,205
345.05 Accessory Electric Equipment	3,579,659	119,203		119,203	161,443	18,614	180,057	60,854
346.05 Miscellaneous Power Plant Equipment	293,963	9,789		9,789	13,258	1,529	14,787	4,998
Total Desert Star	$ 30,810,897	$ 1,026,003	$ -	$ 1,026,003	$ 1,389,572	$ 160,217	$ 1,549,789	$ 523,786
Foothills Units 1-2								
341.05 Structures and Improvements	$ 10,906,684	$ 363,193	$ -	$ 363,193	$ 379,553	$ 32,720	$ 412,273	$ 49,080
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	105,443,248	3,511,260		3,511,260	3,669,425	316,330	3,985,755	474,495
345.05 Accessory Electric Equipment	20,815,540	693,157		693,157	724,381	62,447	786,828	93,671
346.05 Miscellaneous Power Plant Equipment	57,708	1,922		1,922	2,008	173	2,181	259
Total Foothills Units 1-2	$ 137,223,180	$ 4,569,532	$ -	$ 4,569,532	$ 4,775,367	$ 411,670	$ 5,187,037	$ 617,505

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual			Proposed 2016 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
Gila Bend								
341.05 Structures and Improvements	$ 5,018,097	$ 167,103	$ -	$ 167,103	$ 173,626	$ 18,065	$ 191,691	$ 24,588
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	89,246,612	2,971,912		2,971,912	3,087,933	321,288	3,409,221	437,309
345.05 Accessory Electric Equipment	11,096,944	369,528		369,528	383,954	39,949	423,903	54,375
346.05 Miscellaneous Power Plant Equipment	21,142	704		704	732	76	808	104
Total Gila Bend	$ 105,382,795	$ 3,509,247	$ -	$ 3,509,247	$ 3,646,245	$ 379,378	$ 4,025,623	$ 516,376
Hyder Units 1-2								
341.05 Structures and Improvements	$ 6,915,232	$ 230,277	$ -	$ 230,277	$ 242,725	$ 11,064	$ 253,789	$ 23,512
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	93,250,197	3,105,232		3,105,232	3,263,757	149,200	3,412,957	307,725
345.05 Accessory Electric Equipment	22,556,482	751,131		751,131	784,966	36,090	821,056	69,925
346.05 Miscellaneous Power Plant Equipment	206,389	6,873		6,873	7,059	310	7,369	496
Total Hyder Units 1-2	$ 122,928,300	$ 4,093,513	$ -	$ 4,093,513	$ 4,298,507	$ 196,664	$ 4,495,171	$ 401,658
Legacy Units								
341.00 Structures and Improvements	$ 325,971	$ (11,572)	$ 652	$ (10,920)	$ 4,270	$ 98	$ 4,368	$ 15,288
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	10,113,649	397,466	(86,977)	310,489	347,910	8,091	356,001	45,512
345.00 Accessory Electric Equipment	3,606,980	267,277	(13,346)	253,931	152,575	7,935	160,510	(93,421)
346.00 Miscellaneous Power Plant Equipment								
Total Legacy Units	$ 14,046,600	$ 653,171	$ (99,671)	$ 553,500	$ 504,755	$ 16,124	$ 520,879	$ (32,621)
Luke AFB								
341.05 Structures and Improvements	$ 1,566,281	$ 52,157	$ -	$ 52,157	$ 70,639	$ 8,458	$ 79,097	$ 26,940
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	24,574,551	818,333		818,333	1,108,312	132,703	1,241,015	422,682
345.05 Accessory Electric Equipment	1,330,175	44,295		44,295	59,991	7,183	67,174	22,879
346.05 Miscellaneous Power Plant Equipment	377,821	12,581		12,581	17,040	2,040	19,080	6,499
Total Luke AFB	$ 27,848,828	$ 927,366	$ -	$ 927,366	$ 1,255,982	$ 150,384	$ 1,406,366	$ 479,000

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual			Proposed 2016 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
Roof Tops								
341.05 Structures and Improvements	$ 1,582,181	$ 52,687	$ -	$ 52,687	$ 55,851	$ 2,848	$ 58,699	$ 6,012
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	51,531,113	1,715,986		1,715,986	1,829,355	92,756	1,922,111	206,125
345.05 Accessory Electric Equipment	7,714,968	256,908		256,908	273,110	13,887	286,997	30,089
346.05 Miscellaneous Power Plant Equipment								
Total Roof Tops	$ 60,828,262	$ 2,025,581	$ -	$ 2,025,581	$ 2,158,316	$ 109,491	$ 2,267,807	$ 242,226
Paloma								
341.05 Structures and Improvements	$ 2,281,950	$ 75,989	$ -	$ 75,989	$ 80,325	$ 6,846	$ 87,171	$ 11,182
342.05 Fuel Holders, Products and Accessories								
343.05 Prime Movers								
344.05 Generators and Devices	49,000,026	1,631,701		1,631,701	1,724,801	147,000	1,871,801	240,100
345.05 Accessory Electric Equipment	12,514,947	416,748		416,748	440,526	37,545	478,071	61,323
346.05 Miscellaneous Power Plant Equipment	121,486	4,045		4,045	4,276	364	4,640	595
Total Paloma	$ 63,918,409	$ 2,128,483	$ -	$ 2,128,483	$ 2,249,928	$ 191,755	$ 2,441,683	$ 313,200
Sundance								
341.00 Structures and Improvements	$ 13,336,561	$ 274,733	$ (13,337)	$ 261,396	$ 332,080	$ 30,674	$ 362,754	$ 101,358
342.00 Fuel Holders, Products and Accessories	4,629,010	94,895	(4,629)	90,266	113,411	5,555	118,966	28,700
343.00 Prime Movers	232,679,199	4,746,656	(255,947)	4,490,709	5,444,693	279,215	5,723,908	1,233,199
344.00 Generators and Devices	11,764,416	295,287	(15,294)	279,993	523,517	25,882	549,399	269,406
345.00 Accessory Electric Equipment	27,604,244	565,887	(27,604)	538,283	665,262	35,886	701,148	162,865
346.00 Miscellaneous Power Plant Equipment	2,565,605	63,884	(3,079)	60,805	73,120	3,848	76,968	16,163
Total Sun Dance	$ 292,579,035	$ 6,041,342	$ (319,890)	$ 5,721,452	$ 7,152,083	$ 381,060	$ 7,533,143	$ 1,811,691
West Phoenix								
341.00 Structures and Improvements	$ 34,253,399	$ 1,041,692	$ (50,077)	$ 991,615	$ 1,161,396	$ 80,177	$ 1,241,573	$ 249,958
342.00 Fuel Holders, Products and Accessories	30,662,633	1,126,220	(51,163)	1,075,057	1,167,136	59,113	1,226,249	151,192
343.00 Prime Movers	165,023,932	4,497,857	(155,337)	4,342,520	6,006,258	306,591	6,312,849	1,970,329
344.00 Generators and Devices	300,789,550	10,024,072	(1,074,068)	8,950,004	11,678,963	71,384	11,750,347	2,800,343
345.00 Accessory Electric Equipment	40,508,678	1,423,652	(58,950)	1,364,702	1,836,897	116,179	1,953,076	588,374
346.00 Miscellaneous Power Plant Equipment	12,626,027	480,344	(22,015)	458,329	562,483	28,842	591,325	132,996
Total West Phoenix	$ 583,864,219	$ 18,593,837	$ (1,411,610)	$ 17,182,227	$ 22,413,133	$ 662,286	$ 23,075,419	$ 5,893,192

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual Investment	Net Salvage	Total	Proposed 2016 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix CC Units 1-3								
341.00 Structures and Improvements	$ 963,966	$ 48,198	$ (2,314)	$ 45,884	$ 38,848	$ 1,832	$ 40,680	$ (5,204)
342.00 Fuel Holders, Products and Accessories	24,667,947	991,651	(44,402)	947,249	971,917	49,336	1,021,253	74,004
343.00 Prime Movers								
344.00 Generators and Devices	103,127,942	4,207,620	(670,332)	3,537,288	4,125,118	144,379	4,269,497	732,209
345.00 Accessory Electric Equipment	25,144,330	1,008,288	(37,716)	970,572	1,310,020	88,005	1,398,025	427,453
346.00 Miscellaneous Power Plant Equipment	6,536,270	272,562	(11,765)	260,797	315,048	15,033	330,081	69,284
Total West Phoenix CC Units 1-3	$ 160,440,455	$ 6,528,319	$ (766,529)	$ 5,761,790	$ 6,760,951	$ 298,585	$ 7,059,536	$ 1,297,746
West Phoenix CC Unit 4								
341.00 Structures and Improvements	$ 4,683,180	$ 142,837	$ (7,025)	$ 135,812	$ 154,545	$ 7,961	$ 162,506	$ 26,694
342.00 Fuel Holders, Products and Accessories	4,135,109	123,226	(6,203)	117,023	132,737	6,616	139,353	22,330
343.00 Prime Movers	49,464,010	1,474,027	(74,196)	1,399,831	1,587,795	9,893	1,597,688	197,857
344.00 Generators and Devices	23,653,858	726,173	(70,962)	655,211	898,847	42,577	941,424	286,213
345.00 Accessory Electric Equipment	453,669	16,196	(817)	15,379	18,147	907	19,054	3,675
346.00 Miscellaneous Power Plant Equipment	709,405	26,390	(1,206)	25,184	31,923	1,561	33,484	8,300
Total West Phoenix CC Unit 4	$ 83,099,231	$ 2,508,849	$ (160,409)	$ 2,348,440	$ 2,823,994	$ 69,515	$ 2,893,509	$ 545,069
West Phoenix CC Unit 5								
341.00 Structures and Improvements	$ 11,935,671	$ 348,522	$ (17,904)	$ 330,618	$ 415,361	$ 21,484	$ 436,845	$ 106,227
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	92,946,762	2,797,698	(74,357)	2,723,341	3,281,021	185,894	3,466,915	743,574
344.00 Generators and Devices	163,209,028	4,847,308	(310,097)	4,537,211	6,136,659	(146,888)	5,989,771	1,452,560
345.00 Accessory Electric Equipment	13,138,590	382,333	(19,708)	362,625	462,478	24,963	487,441	124,816
346.00 Miscellaneous Power Plant Equipment	4,353,879	148,032	(7,402)	140,630	179,380	9,579	188,959	48,329
Total West Phoenix CC Unit 5	$ 285,583,930	$ 8,523,893	$ (429,468)	$ 8,094,425	$ 10,474,899	$ 95,032	$ 10,569,931	$ 2,475,506
West Phoenix CT Units 1-2								
341.00 Structures and Improvements	$ 4,040,996	$ 153,558	$ (7,678)	$ 145,880	$ 244,480	$ 18,589	$ 263,069	$ 117,189
342.00 Fuel Holders, Products and Accessories	1,859,577	11,343	(558)	10,785	62,482	3,161	65,643	54,858
343.00 Prime Movers	22,613,160	226,132	(6,784)	219,348	1,137,442	110,804	1,248,246	1,028,898
344.00 Generators and Devices	10,798,722	242,971	(22,677)	220,294	518,339	31,316	549,655	329,361
345.00 Accessory Electric Equipment	1,772,089	16,835	(709)	16,126	46,252	2,304	48,556	32,430
346.00 Miscellaneous Power Plant Equipment	1,026,473	33,360	(1,642)	31,718	36,132	2,669	38,801	7,083
Total West Phoenix CT Units 1-2	$ 42,111,017	$ 684,199	$ (40,048)	$ 644,151	$ 2,045,127	$ 168,843	$ 2,213,970	$ 1,569,819
West Phoenix Common								
341.00 Structures and Improvements	$ 12,629,586	$ 348,577	$ (15,156)	$ 333,421	$ 308,162	$ 30,311	$ 338,473	$ 5,052
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	$ 12,629,586	$ 348,577	$ (15,156)	$ 333,421	$ 308,162	$ 30,311	$ 338,473	$ 5,052

ARIZONA PUBLIC SERVICE COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/15 Investment	Current 2016 Annualized Accrual			Proposed 2016 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	$ 6,255,719	$ 150,535	$ (5,754)	$ 144,781	$ 293,963	$ 17,894	$ 311,857	$ 167,076
342.00 Fuel Holders, Products and Accessories	5,430,087	48,736	(2,243)	46,493	100,881	5,391	106,272	59,779
343.00 Prime Movers	78,776,880	2,000,713	(101,550)	1,899,163	2,347,922	150,289	2,498,211	599,048
344.00 Generators and Devices	10,171,850	131,107	(24,311)	106,796	341,525	21,304	362,829	256,033
345.00 Accessory Electric Equipment	4,554,682	52,311	(2,347)	49,964	134,014	11,971	145,985	96,021
346.00 Miscellaneous Power Plant Equipment	2,141,552	38,893	(2,017)	36,876	61,701	3,139	64,840	27,964
Total Yucca	$ 107,330,770	$ 2,422,295	$ (138,222)	$ 2,284,073	$ 3,280,006	$ 209,988	$ 3,489,994	$ 1,205,921
Yucca CT Units 1-4								
341.00 Structures and Improvements	$ 5,185,290	$ 118,743	$ (4,148)	$ 114,595	$ 258,746	$ 16,074	$ 274,820	$ 160,225
342.00 Fuel Holders, Products and Accessories	3,934,860	4,328		4,328	55,875	3,148	59,023	54,695
343.00 Prime Movers	11,077,145	(9,969)		(9,969)	310,160	48,739	358,899	368,868
344.00 Generators and Devices	10,058,652	127,745	(24,141)	103,604	337,971	21,123	359,094	255,490
345.00 Accessory Electric Equipment	3,737,069	28,028	(1,121)	26,907	106,133	10,090	116,223	89,316
346.00 Miscellaneous Power Plant Equipment	1,328,508	14,746	(797)	13,949	31,618	1,594	33,212	19,263
Total Yucca CT Units 1-4	$ 35,321,524	$ 283,621	$ (30,207)	$ 253,414	$ 1,100,503	$ 100,768	$ 1,201,271	$ 947,857
Yucca CT Units 5-6								
341.00 Structures and Improvements	$ 1,070,429	$ 31,792	$ (1,606)	$ 30,186	$ 35,217	$ 1,820	$ 37,037	$ 6,851
342.00 Fuel Holders, Products and Accessories	1,495,227	44,408	(2,243)	42,165	45,006	2,243	47,249	5,084
343.00 Prime Movers	67,699,735	2,010,682	(101,550)	1,909,132	2,037,762	101,550	2,139,312	230,180
344.00 Generators and Devices	113,198	3,362	(170)	3,192	3,554	181	3,735	543
345.00 Accessory Electric Equipment	817,613	24,283	(1,226)	23,057	27,881	1,881	29,762	6,705
346.00 Miscellaneous Power Plant Equipment	813,044	24,147	(1,220)	22,927	30,083	1,545	31,628	8,701
Total Yucca CT Units 5-6	$ 72,009,246	$ 2,138,674	$ (108,015)	$ 2,030,659	$ 2,179,503	$ 109,220	$ 2,288,723	$ 258,064

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
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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
STEAM PRODUCTION							
311.00 Structures and Improvements	$ 169,959,507	$ 86,200,004	50.72%	$ 96,939,406	57.04%	$ 86,525,119	50.91%
312.00 Boiler Plant Equipment	1,156,581,620	736,602,691	63.69%	687,596,545	59.45%	750,339,971	64.88%
314.00 Turbogenerator Units	212,294,514	139,399,848	65.66%	136,344,461	64.22%	136,041,433	64.08%
315.00 Accessory Electric Equipment	127,147,100	75,731,875	59.56%	76,198,546	59.93%	69,335,347	54.53%
316.00 Miscellaneous Power Plant Equipment	95,057,632	55,992,739	58.90%	51,359,053	54.03%	51,685,285	54.37%
Total Steam Production Plant	$ 1,761,040,373	$ 1,093,927,156	62.12%	$ 1,048,438,011	59.54%	$ 1,093,927,156	62.12%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$ 800,303,960	$ 416,089,541	51.99%	$ 301,454,195	37.67%	$ 411,802,092	51.46%
322.00 Reactor Plant Equipment	1,177,440,897	649,302,681	55.15%	456,146,663	38.74%	645,948,904	54.86%
323.00 Turbogenerator Units	378,902,614	192,810,920	50.89%	140,313,747	37.03%	198,531,303	52.40%
324.00 Accessory Electric Equipment	286,941,496	182,338,231	63.55%	127,574,718	44.46%	180,910,712	63.05%
325.00 Miscellaneous Power Plant Equipment	190,865,034	77,327,486	40.51%	56,970,483	29.85%	80,675,849	42.27%
Total Nuclear Production Plant	$ 2,834,454,001	$ 1,517,868,859	53.55%	$ 1,082,459,806	38.19%	$ 1,517,868,859	53.55%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 115,260,761	$ 30,791,399	26.71%	$ 28,897,340	25.07%	$ 28,131,453	24.41%
342.00 Fuel Holders, Products and Accessories	55,221,287	22,670,453	41.05%	22,680,352	41.07%	22,342,919	40.46%
343.00 Prime Movers	652,662,488	214,894,449	32.93%	207,903,315	31.85%	228,803,364	35.06%
344.00 Generators and Devices	1,295,258,389	243,851,341	18.83%	307,544,424	23.74%	233,227,523	18.01%
345.00 Accessory Electric Equipment	209,397,328	46,292,398	22.11%	45,908,915	21.92%	44,301,534	21.16%
346.00 Miscellaneous Power Plant Equipment	27,345,147	5,197,269	19.01%	7,172,968	26.23%	6,890,517	25.20%
Total Other Production Plant	$ 2,355,145,400	$ 563,697,309	23.93%	$ 620,107,314	26.33%	$ 563,697,309	23.93%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$ 151,995	$ 145,144	95.49%	$ 116,174	76.43%	$ 105,554	69.45%
353.00 Station Equipment	122,007,490	27,588,309	22.61%	30,413,187	24.93%	27,632,965	22.65%
354.00 Towers and Fixtures	1,329,316	542,128	40.78%	606,952	45.66%	551,468	41.49%
355.00 Poles and Fixtures	1,370,085	331,528	24.20%	332,859	24.29%	302,430	22.07%
356.00 Overhead Conductors and Devices	1,947,677	598,939	30.75%	675,370	34.68%	613,631	31.51%
Total Transmission Plant	$ 126,806,563	$ 29,206,048	23.03%	$ 32,144,542	25.35%	$ 29,206,048	23.03%

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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
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$ 82,271,151	$ 18,956,898	23.04%	$ 16,951,291	20.60%	$ 19,299,909	23.46%
362.00 Station Equipment	494,771,283	99,057,304	20.02%	101,904,279	20.60%	116,023,220	23.45%
363.00 Storage Battery Equipment	2,123,630	247,881	11.67%	741,147	34.90%	843,834	39.74%
364.01 Poles, Towers and Fixtures - Wood	332,284,839	104,136,831	31.34%	104,248,457	31.37%	118,692,187	35.72%
364.02 Poles, Towers and Fixtures - Steel	260,823,751	47,528,155	18.22%	28,954,355	11.10%	32,966,010	12.64%
365.00 Overhead Conductors and Devices	355,117,540	58,041,908	16.34%	76,632,628	21.58%	87,250,156	24.57%
366.00 Underground Conduit	685,513,670	172,016,992	25.09%	148,644,595	21.68%	169,239,454	24.69%
367.00 Underground Conductors and Devices	1,646,381,070	588,572,946	35.75%	434,892,801	26.42%	495,147,639	30.07%
368.00 Line Transformers	833,275,690	237,986,280	28.56%	200,223,726	24.03%	227,964,926	27.36%
369.00 Services	375,644,741	159,459,194	42.45%	165,410,188	44.03%	188,327,937	50.13%
370.01 Meters - Electronic	17,142,724	(34,215,235)	-199.59%	2,247,047	13.11%	2,558,378	14.92%
370.03 Meters - AMI	274,220,605	37,797,690	13.78%	33,682,435	12.28%	38,349,171	13.98%
371.00 Installations on Customers' Premises	43,510,997	13,775,290	31.66%	9,302,185	21.38%	10,591,012	24.34%
373.00 Street Lighting and Signal Systems	74,601,787	23,159,812	31.04%	16,923,365	22.68%	19,268,115	25.83%
Total Distribution Plant	$ 5,477,683,478	$ 1,526,521,946	27.87%	$ 1,340,758,499	24.48%	$ 1,526,521,946	27.87%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 179,729,946	$ 30,649,534	17.05%	$ 31,937,426	17.77%	$ 30,880,031	17.18%
391.CM Office Furn. and Equip. - Computer	169,141,944	56,185,814	33.22%	67,453,807	39.88%	65,220,525	38.56%
397.00 Communication Equipment	251,017,440	79,973,072	31.86%	77,209,478	30.76%	74,653,201	29.74%
Total Depreciable	$ 599,889,330	$ 166,808,421	27.81%	$ 176,600,711	29.44%	$ 170,753,757	28.46%
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$ 59,067,179	$ 27,687,599	46.87%	$ 26,621,434	45.07%	$ 26,621,434	45.07%
393.00 Stores Equipment	242,516	82,193	33.89%	70,327	29.00%	70,327	29.00%
394.00 Tools, Shop and Garage Equipment	37,140,670	17,907,765	48.22%	15,711,089	42.30%	15,711,089	42.30%
395.00 Laboratory Equipment	810,563	409,057	50.47%	415,695	51.28%	415,695	51.28%
398.00 Miscellaneous Equipment	17,446,236	4,575,059	26.22%	3,897,791	22.34%	3,897,791	22.34%
Total Amortizable	$ 114,707,164	$ 50,661,673	44.17%	$ 46,716,336	40.73%	$ 46,716,336	40.73%
Total General Plant	$ 714,596,494	$ 217,470,093	30.43%	$ 223,317,047	31.25%	$ 217,470,093	30.43%
TOTAL UTILITY	$ 13,269,726,309	$ 4,948,691,413	37.29%	$ 4,347,225,218	32.76%	$ 4,948,691,413	37.29%

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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
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$ 77,737,991	$ 29,693,835	38.20%	$ 45,691,130	58.78%	$ 28,408,961	36.54%
312.00 Boiler Plant Equipment	378,495,272	135,674,509	35.85%	206,080,268	54.45%	138,135,146	36.50%
314.00 Turbogenerator Units	86,113,816	34,998,233	40.64%	51,403,559	59.69%	35,343,914	41.04%
315.00 Accessory Electric Equipment	52,313,534	26,740,055	51.11%	36,422,311	69.62%	24,115,354	46.10%
316.00 Miscellaneous Power Plant Equipment	23,835,993	6,825,771	28.64%	12,248,642	51.39%	7,929,026	33.26%
Total Cholla	$ 618,496,606	$ 233,932,402	37.82%	$ 351,845,910	56.89%	$ 233,932,402	37.82%
Cholla Unit 1							
311.00 Structures and Improvements	$ 4,743,207	$ 2,600,487	54.83%	$ 3,117,096	65.72%	$ 2,559,947	53.97%
312.00 Boiler Plant Equipment	80,244,501	37,762,684	47.06%	44,934,095	56.00%	36,902,578	45.99%
314.00 Turbogenerator Units	27,503,716	10,814,768	39.32%	14,535,841	52.85%	11,937,706	43.40%
315.00 Accessory Electric Equipment	9,492,908	5,087,328	53.59%	6,078,083	64.03%	4,991,687	52.58%
316.00 Miscellaneous Power Plant Equipment	2,926,476	1,768,663	60.44%	1,999,384	68.32%	1,642,014	56.11%
Total Cholla Unit 1	$ 124,910,808	$ 58,033,931	46.46%	$ 70,664,499	56.57%	$ 58,033,931	46.46%
Cholla Unit 3							
311.00 Structures and Improvements	$ 13,288,725	$ 4,481,615	33.72%	$ 7,697,929	57.93%	$ 4,891,855	36.81%
312.00 Boiler Plant Equipment	238,165,292	77,712,314	32.63%	127,245,475	53.43%	80,861,533	33.95%
314.00 Turbogenerator Units	56,834,120	23,817,285	41.91%	36,220,775	63.73%	23,017,458	40.50%
315.00 Accessory Electric Equipment	34,832,937	18,984,562	54.50%	25,734,284	73.88%	16,353,537	46.95%
316.00 Miscellaneous Power Plant Equipment	6,842,283	2,484,996	36.32%	3,708,063	54.19%	2,356,388	34.44%
Total Cholla Unit 3	$ 349,963,357	$ 127,480,771	36.43%	$ 200,606,526	57.32%	$ 127,480,771	36.43%
Cholla Common							
311.00 Structures and Improvements	$ 59,706,059	$ 22,611,732	37.87%	$ 34,876,105	58.41%	$ 20,957,160	35.10%
312.00 Boiler Plant Equipment	60,085,479	20,199,511	33.62%	33,900,698	56.42%	20,371,035	33.90%
314.00 Turbogenerator Units	1,775,980	366,179	20.62%	646,943	36.43%	388,750	21.89%
315.00 Accessory Electric Equipment	7,987,689	2,668,165	33.40%	4,609,944	57.71%	2,770,130	34.68%
316.00 Miscellaneous Power Plant Equipment	14,067,234	2,572,112	18.28%	6,541,196	46.50%	3,930,625	27.94%
Total Cholla Common	$ 143,622,441	$ 48,417,700	33.71%	$ 80,574,886	56.10%	$ 48,417,700	33.71%
Four Corners							
311.00 Structures and Improvements	$ 54,567,232	$ 31,692,203	58.08%	$ 24,480,193	44.86%	$ 32,721,458	59.97%
312.00 Boiler Plant Equipment	581,513,168	459,190,973	78.96%	334,557,309	57.53%	472,830,018	81.31%
314.00 Turbogenerator Units	83,827,121	69,525,709	82.94%	46,614,767	55.61%	65,800,766	78.50%
315.00 Accessory Electric Equipment	47,577,191	29,435,516	61.87%	18,382,537	38.64%	25,021,894	52.59%
316.00 Miscellaneous Power Plant Equipment	44,955,256	33,113,970	73.66%	20,558,784	45.73%	26,584,235	59.13%
Total Four Corners	$ 812,439,968	$ 622,958,370	76.68%	$ 444,593,590	54.72%	$ 622,958,370	76.68%

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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
Four Corners Units 4-5							
311.00 Structures and Improvements	$ 38,507,966	$ 29,322,995	76.15%	$ 20,132,490	52.28%	$ 28,792,715	74.77%
312.00 Boiler Plant Equipment	546,025,397	448,577,011	82.15%	323,843,647	59.31%	463,148,763	84.82%
314.00 Turbogenerator Units	80,391,368	67,843,123	84.39%	44,970,238	55.94%	64,314,710	80.00%
315.00 Accessory Electric Equipment	35,325,258	27,374,496	77.49%	15,974,096	45.22%	22,845,539	64.67%
316.00 Miscellaneous Power Plant Equipment	32,289,311	27,731,754	85.89%	15,206,430	47.09%	21,747,653	67.35%
Total Four Corners Units 4-5	$ 732,539,300	$ 600,849,380	82.02%	$ 420,126,901	57.35%	$ 600,849,380	82.02%
Four Corners Common							
311.00 Structures and Improvements	$ 16,059,266	$ 2,369,209	14.75%	$ 4,347,703	27.07%	$ 3,928,743	24.46%
312.00 Boiler Plant Equipment	35,487,771	10,613,961	29.91%	10,713,663	30.19%	9,681,256	27.28%
314.00 Turbogenerator Units	3,435,753	1,682,585	48.97%	1,644,529	47.87%	1,486,056	43.25%
315.00 Accessory Electric Equipment	12,251,933	2,061,020	16.82%	2,408,441	19.66%	2,176,355	17.76%
316.00 Miscellaneous Power Plant Equipment	12,665,945	5,382,216	42.49%	5,352,354	42.26%	4,836,582	38.19%
Total Four Corners Common	$ 79,900,668	$ 22,108,991	27.67%	$ 24,466,689	30.62%	$ 22,108,991	27.67%
Navajo Units 1-3							
311.00 Structures and Improvements	$ 32,849,766	$ 20,520,441	62.47%	$ 21,663,048	65.95%	$ 21,084,875	64.19%
312.00 Boiler Plant Equipment	171,354,162	116,237,675	67.83%	118,589,656	69.21%	115,424,571	67.36%
314.00 Turbogenerator Units	25,206,593	19,242,787	76.34%	19,682,834	78.09%	19,157,511	76.00%
315.00 Accessory Electric Equipment	22,361,468	16,117,792	72.08%	16,554,736	74.03%	16,112,900	72.06%
316.00 Miscellaneous Power Plant Equipment	19,203,553	11,048,429	57.53%	11,699,521	60.92%	11,387,268	59.30%
Total Navajo Units 1-3	$ 270,975,542	$ 183,167,125	67.60%	$ 188,189,795	69.45%	$ 183,167,125	67.60%
Ocotillo Units 1-2							
311.00 Structures and Improvements	$ 4,804,518	$ 4,293,525	89.36%	$ 5,105,034	106.25%	$ 4,309,825	89.70%
312.00 Boiler Plant Equipment	25,219,018	25,499,534	101.11%	28,369,312	112.49%	23,950,236	94.97%
314.00 Turbogenerator Units	17,146,984	15,633,120	91.17%	18,643,301	108.73%	15,739,242	91.79%
315.00 Accessory Electric Equipment	4,894,907	3,438,512	70.25%	4,838,962	98.86%	4,085,199	83.46%
316.00 Miscellaneous Power Plant Equipment	7,062,830	5,004,569	70.86%	6,852,106	97.02%	5,784,757	81.90%
Total Ocotillo Units 1-2	$ 59,128,257	$ 53,869,259	91.11%	$ 63,808,716	107.92%	$ 53,869,259	91.11%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$ 800,303,960	$ 416,089,541	51.99%	$ 301,454,195	37.67%	$ 411,802,092	51.46%
322.00 Reactor Plant Equipment	1,177,440,897	649,302,681	55.15%	456,146,663	38.74%	645,948,904	54.86%
323.00 Turbogenerator Units	378,902,614	192,810,920	50.89%	140,313,747	37.03%	198,531,303	52.40%
324.00 Accessory Electric Equipment	286,941,496	182,338,231	63.55%	127,574,718	44.46%	180,910,712	63.05%
325.00 Miscellaneous Power Plant Equipment	190,865,034	77,327,486	40.51%	56,970,483	29.85%	80,675,849	42.27%
Total Palo Verde	$ 2,834,454,001	$ 1,517,868,859	53.55%	$ 1,082,459,806	38.19%	$ 1,517,868,859	53.55%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Palo Verde Unit 1							
321.00 Structures and Improvements	$ 160,238,922	$ 111,343,636	69.49%	$ 77,120,682	48.13%	$ 110,166,958	68.75%
322.00 Reactor Plant Equipment	464,794,795	281,647,691	60.60%	197,552,784	42.50%	282,204,315	60.72%
323.00 Turbogenerator Units	133,635,855	72,861,040	54.52%	52,353,310	39.18%	74,786,746	55.96%
324.00 Accessory Electric Equipment	117,924,193	81,836,907	69.40%	56,626,283	48.02%	80,890,691	68.60%
325.00 Miscellaneous Power Plant Equipment	31,243,002	20,319,415	65.04%	13,972,676	44.72%	19,959,979	63.89%
Total Palo Verde Unit 1	$ 907,836,767	$ 568,008,689	62.57%	$ 397,625,735	43.80%	$ 568,008,689	62.57%
Palo Verde Unit 2							
321.00 Structures and Improvements	$ 92,055,736	$ 62,120,612	67.48%	$ 43,971,502	47.77%	$ 60,433,657	65.65%
322.00 Reactor Plant Equipment	249,302,485	130,773,605	52.46%	95,658,865	38.37%	131,471,857	52.74%
323.00 Turbogenerator Units	87,999,272	42,283,716	48.05%	31,766,573	36.10%	43,659,417	49.61%
324.00 Accessory Electric Equipment	47,992,891	30,236,127	63.00%	22,122,401	46.10%	30,404,637	63.35%
325.00 Miscellaneous Power Plant Equipment	27,285,762	16,504,484	60.49%	11,604,468	42.53%	15,948,976	58.45%
Total Palo Verde Unit 2	$ 504,636,146	$ 281,918,545	55.87%	$ 205,123,808	40.65%	$ 281,918,545	55.87%
Palo Verde Unit 3							
321.00 Structures and Improvements	$ 165,218,693	$ 105,393,310	63.79%	$ 73,081,745	44.23%	$ 104,182,173	63.06%
322.00 Reactor Plant Equipment	427,193,012	218,413,881	51.13%	152,765,586	35.76%	217,776,008	50.98%
323.00 Turbogenerator Units	152,558,297	76,703,435	50.28%	55,603,371	36.45%	79,265,760	51.96%
324.00 Accessory Electric Equipment	94,317,583	57,880,628	61.37%	40,137,750	42.56%	57,218,640	60.67%
325.00 Miscellaneous Power Plant Equipment	28,965,542	16,530,459	57.07%	11,559,788	39.91%	16,479,133	56.89%
Total Palo Verde Unit 3	$ 868,253,127	$ 474,921,714	54.70%	$ 333,148,241	38.37%	$ 474,921,714	54.70%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$ 210,244,404	$ 66,098,455	31.44%	$ 57,413,723	27.31%	$ 65,868,001	31.33%
322.00 Reactor Plant Equipment	561,290	(213,882)	-38.11%	47,808	8.52%	54,848	9.77%
323.00 Turbogenerator Units	217,756	127,261	58.44%	82,824	38.04%	95,020	43.64%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	165,219	52,959	32.05%	40,901	24.76%	46,924	28.40%
Total Palo Verde Water Reclamation	$ 211,188,669	$ 66,064,794	31.28%	$ 57,585,257	27.27%	$ 66,064,794	31.28%
Palo Verde Common							
321.00 Structures and Improvements	$ 172,546,205	$ 71,133,528	41.23%	$ 49,866,542	28.90%	$ 71,151,302	41.24%
322.00 Reactor Plant Equipment	35,589,315	18,681,385	52.49%	10,121,620	28.44%	14,441,876	40.58%
323.00 Turbogenerator Units	4,491,434	835,467	18.60%	507,669	11.30%	724,360	16.13%
324.00 Accessory Electric Equipment	26,706,829	12,384,569	46.37%	8,688,284	32.53%	12,396,743	46.42%
325.00 Miscellaneous Power Plant Equipment	103,205,509	23,920,168	23.18%	19,792,651	19.18%	28,240,837	27.36%
Total Palo Verde Common	$ 342,539,292	$ 126,955,118	37.06%	$ 88,976,765	25.98%	$ 126,955,118	37.06%

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OTHER PRODUCTION (by Unit)							
Douglas CT							
341.00 Structures and Improvements	$ 103,952	$ 41,706	40.12%	$ 38,614	37.15%	$ (141,449)	-136.07%
342.00 Fuel Holders, Products and Accessories	137,759	127,494	92.55%	95,115	69.04%	(348,424)	-252.92%
343.00 Prime Movers	3,721,569	(1,622,535)	-43.60%	(748,752)	-20.12%	2,742,816	73.70%
344.00 Generators and Devices	971,924	537,475	55.30%	473,346	48.70%	(1,733,954)	-178.40%
345.00 Accessory Electric Equipment	403,765	327,486	81.11%	270,372	66.96%	(990,422)	-245.30%
346.00 Miscellaneous Power Plant Equipment	33,564	31,136	92.77%	23,424	69.79%	(85,805)	-255.65%
Total Douglas CT	$ 5,372,533	$ (557,238)	-10.37%	$ 152,118	2.83%	$ (557,238)	-10.37%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$ 1,953,223	$ 455,707	23.33%	$ 429,793	22.00%	$ 388,251	19.88%
342.00 Fuel Holders, Products and Accessories	1,107,461	706,200	63.77%	605,128	54.64%	546,639	49.36%
343.00 Prime Movers	21,989,611	1,178,323	5.36%	4,402,875	20.02%	3,977,312	18.09%
344.00 Generators and Devices	14,737,836	7,492,673	50.84%	5,561,915	37.74%	5,024,324	34.09%
345.00 Accessory Electric Equipment	4,017,658	1,301,908	32.40%	1,438,943	35.82%	1,299,861	32.35%
346.00 Miscellaneous Power Plant Equipment	990,572	524,515	52.95%	468,190	47.26%	422,937	42.70%
Total Octillo CT Units 1-2	$ 44,796,361	$ 11,659,325	26.03%	$ 12,906,846	28.81%	$ 11,659,325	26.03%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$ 23,674,859	$ 6,830,375	28.85%	$ 7,865,373	33.22%	$ 4,090,221	17.28%
342.00 Fuel Holders, Products and Accessories	11,611,849	1,261,578	10.86%	1,971,381	16.98%	1,025,175	8.83%
343.00 Prime Movers	132,566,124	19,811,056	14.94%	42,436,535	32.01%	22,068,225	16.65%
344.00 Generators and Devices	336,601,568	54,102,294	16.07%	108,895,551	32.35%	56,628,834	16.82%
345.00 Accessory Electric Equipment	23,778,511	7,626,307	32.07%	8,289,702	34.86%	4,310,885	18.13%
346.00 Miscellaneous Power Plant Equipment	6,538,111	(943,188)	-14.43%	1,086,636	16.62%	565,082	8.64%
Total Redhawk CC Units 1-2	$ 534,771,022	$ 88,688,422	16.58%	$ 170,545,178	31.89%	$ 88,688,422	16.58%
Saguaro							
341.00 Structures and Improvements	$ 3,173,028	$ 1,321,116	41.64%	$ 1,065,739	33.59%	$ 1,247,993	39.33%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,251,522	76.20%	1,016,220	61.87%	1,190,005	72.45%
343.00 Prime Movers	17,905,173	5,696,087	31.81%	5,725,694	31.98%	6,639,364	37.08%
344.00 Generators and Devices	32,384,680	14,755,429	45.56%	13,589,147	41.96%	13,799,408	42.61%
345.00 Accessory Electric Equipment	3,384,270	1,186,434	35.06%	1,241,495	36.68%	1,444,441	42.68%
346.00 Miscellaneous Power Plant Equipment	892,062	748,220	83.88%	544,484	61.04%	637,597	71.47%
Total Saguaro	$ 59,381,701	$ 24,958,807	42.03%	$ 23,182,780	39.04%	$ 24,958,807	42.03%

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Saguaro CT Units 1-2							
341.00 Structures and Improvements	$ 3,173,028	$ 1,321,116	41.64%	$ 1,065,739	33.59%	$ 1,247,993	39.33%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,251,522	76.20%	1,016,220	61.87%	1,190,005	72.45%
343.00 Prime Movers	15,965,868	5,407,885	33.87%	5,383,886	33.72%	6,304,591	39.49%
344.00 Generators and Devices	4,666,538	3,905,233	83.69%	2,557,343	54.80%	2,994,677	64.17%
345.00 Accessory Electric Equipment	3,261,717	1,137,459	34.87%	1,192,620	36.56%	1,396,571	42.82%
346.00 Miscellaneous Power Plant Equipment	892,062	748,220	83.88%	544,484	61.04%	637,597	71.47%
Total Saguaro CT Units 1-2	$ 29,601,701	$ 13,771,434	46.52%	$ 11,760,292	39.73%	$ 13,771,434	46.52%
Saguaro CT Unit 3							
341.00 Structures and Improvements	$ -	$ -		$ -		$ -	
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	1,939,305	288,202	14.86%	341,808	17.63%	334,773	17.26%
344.00 Generators and Devices	27,718,142	10,850,196	39.14%	11,031,804	39.80%	10,804,731	38.98%
345.00 Accessory Electric Equipment	122,553	48,975	39.96%	48,876	39.88%	47,870	39.06%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$ 29,780,000	$ 11,187,373	37.57%	$ 11,422,488	38.36%	$ 11,187,373	37.57%
Solar Units							
341.00 Structures and Improvements	$ 32,510,020	$ 2,734,898	8.41%	$ 3,141,999	9.66%	$ 2,963,242	9.11%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	587,836,565	57,231,171	9.74%	60,709,452	10.33%	55,744,091	9.48%
345.00 Accessory Electric Equipment	105,145,520	9,412,616	8.95%	11,606,012	11.04%	10,660,611	10.14%
346.00 Miscellaneous Power Plant Equipment	1,557,654	107,455	6.90%	137,417	8.82%	118,195	7.59%
Total Solar Units	$ 727,049,759	$ 69,486,139	9.56%	$ 75,594,879	10.40%	$ 69,486,139	9.56%
Chino Valley							
341.05 Structures and Improvements	$ 527,889	$ 46,878	8.88%	$ 64,368	12.19%	$ 54,561	10.34%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	77,719,075	8,138,402	10.47%	9,476,723	12.19%	8,032,793	10.34%
345.05 Accessory Electric Equipment	6,511,775	578,261	8.88%	794,017	12.19%	673,036	10.34%
346.05 Miscellaneous Power Plant Equipment	216,504	19,226	8.88%	26,400	12.19%	22,377	10.34%
Total Chino Valley	$ 84,975,243	$ 8,782,767	10.34%	$ 10,361,509	12.19%	$ 8,782,767	10.34%

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Cotton Center							
341.05 Structures and Improvements	$ 1,813,500	$ 243,070	13.40%	$ 282,286	15.57%	$ 252,130	13.90%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	61,593,054	8,661,033	14.06%	9,587,460	15.57%	8,563,237	13.90%
345.05 Accessory Electric Equipment	15,418,050	2,056,544	13.34%	2,399,945	15.57%	2,143,560	13.90%
346.05 Miscellaneous Power Plant Equipment	262,641	34,795	13.25%	40,882	15.57%	36,515	13.90%
Total Cotton Center	$ 79,087,245	$ 10,995,442	13.90%	$ 12,310,573	15.57%	$ 10,995,442	13.90%
Desert Star							
341.05 Structures and Improvements	$ 1,572,235	$ 17,438	1.11%	$ 36,881	2.35%	$ 22,249	1.42%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	25,365,040	375,604	1.48%	595,011	2.35%	358,941	1.42%
345.05 Accessory Electric Equipment	3,579,659	39,702	1.11%	83,971	2.35%	50,656	1.42%
346.05 Miscellaneous Power Plant Equipment	293,963	3,261	1.11%	6,896	2.35%	4,160	1.42%
Total Desert Star	$ 30,810,897	$ 436,005	1.42%	$ 722,760	2.35%	$ 436,005	1.42%
Foothills Units 1-2							
341.05 Structures and Improvements	$ 10,906,684	$ 792,219	7.26%	$ 955,611	8.76%	$ 892,446	8.18%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	105,443,248	8,914,223	8.45%	9,238,625	8.76%	8,627,962	8.18%
345.05 Accessory Electric Equipment	20,815,540	1,517,628	7.29%	1,823,796	8.76%	1,703,245	8.18%
346.05 Miscellaneous Power Plant Equipment	57,708	4,304	7.46%	5,056	8.76%	4,722	8.18%
Total Foothills Units 1-2	$ 137,223,180	$ 11,228,375	8.18%	$ 12,023,088	8.76%	$ 11,228,375	8.18%
Gila Bend							
341.05 Structures and Improvements	$ 5,018,097	$ 265,090	5.28%	$ 268,315	5.35%	$ 265,268	5.29%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	89,246,612	4,717,950	5.29%	4,771,974	5.35%	4,717,781	5.29%
345.05 Accessory Electric Equipment	11,096,944	586,619	5.29%	593,348	5.35%	586,610	5.29%
346.05 Miscellaneous Power Plant Equipment	21,142	1,118	5.29%	1,130	5.35%	1,118	5.29%
Total Gila Bend	$ 105,382,795	$ 5,570,777	5.29%	$ 5,634,768	5.35%	$ 5,570,777	5.29%

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Hyder Units 1-2							
341.05 Structures and Improvements	$ 6,915,232	$ 641,745	9.28%	$ 783,746	11.33%	$ 721,903	10.44%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	93,250,197	10,290,617	11.04%	10,903,289	11.69%	10,042,952	10.77%
345.05 Accessory Electric Equipment	22,556,482	2,370,857	10.51%	2,752,793	12.20%	2,535,581	11.24%
346.05 Miscellaneous Power Plant Equipment	206,389	23,854	11.56%	28,919	14.01%	26,637	12.91%
Total Hyder Units 1-2	$ 122,928,300	$ 13,327,073	10.84%	$ 14,468,746	11.77%	$ 13,327,073	10.84%
Legacy Units							
341.00 Structures and Improvements	$ 325,971	$ 297,653	91.31%	$ 173,614	53.26%	$ 251,305	77.09%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	10,113,649	3,694,744	36.53%	2,191,279	21.67%	3,171,863	31.36%
345.00 Accessory Electric Equipment	3,606,980	(142,295)	-3.94%	294,947	8.18%	426,934	11.84%
346.00 Miscellaneous Power Plant Equipment							
Total Legacy Units	$ 14,046,600	$ 3,850,102	27.41%	$ 2,659,840	18.94%	$ 3,850,102	27.41%
Luke AFB							
341.05 Structures and Improvements	$ 1,566,281	$ 17,361	1.11%	$ 36,841	2.35%	$ 22,491	1.44%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	24,574,551	363,603	1.48%	578,019	2.35%	352,879	1.44%
345.05 Accessory Electric Equipment	1,330,175	14,745	1.11%	31,287	2.35%	19,101	1.44%
346.05 Miscellaneous Power Plant Equipment	377,821	4,188	1.11%	8,887	2.35%	5,425	1.44%
Total Luke AFB	$ 27,848,828	$ 399,896	1.44%	$ 655,033	2.35%	$ 399,896	1.44%
Roof Tops							
341.05 Structures and Improvements	$ 1,582,181	$ 96,551	6.10%	$ 178,801	11.30%	$ 157,027	9.92%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	51,531,113	5,076,629	9.85%	5,603,873	10.87%	4,921,431	9.55%
345.05 Accessory Electric Equipment	7,714,968	651,002	8.44%	849,132	11.01%	745,724	9.67%
346.05 Miscellaneous Power Plant Equipment							
Total Roof Tops	$ 60,828,262	$ 5,824,182	9.57%	$ 6,631,806	10.90%	$ 5,824,182	9.57%

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Paloma							
341.05 Structures and Improvements	$ 2,281,950	$ 316,892	13.89%	$ 361,535	15.84%	$ 323,862	14.19%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	49,000,026	6,998,366	14.28%	7,763,198	15.84%	6,954,252	14.19%
345.05 Accessory Electric Equipment	12,514,947	1,739,553	13.90%	1,982,775	15.84%	1,776,164	14.19%
346.05 Miscellaneous Power Plant Equipment	121,486	16,709	13.75%	19,247	15.84%	17,242	14.19%
Total Paloma	$ 63,918,409	$ 9,071,520	14.19%	$ 10,126,755	15.84%	$ 9,071,520	14.19%
Sundance							
341.00 Structures and Improvements	$ 13,336,561	$ 6,110,566	45.82%	$ 3,975,427	29.81%	$ 6,430,521	48.22%
342.00 Fuel Holders, Products and Accessories	4,629,010	2,395,874	51.76%	1,464,796	31.64%	2,369,407	51.19%
343.00 Prime Movers	232,679,199	125,640,928	54.00%	76,983,052	33.09%	124,525,287	53.52%
344.00 Generators and Devices	11,764,416	198,554	1.69%	525,764	4.47%	850,459	7.23%
345.00 Accessory Electric Equipment	27,604,244	14,251,436	51.63%	8,851,187	32.06%	14,317,393	51.87%
346.00 Miscellaneous Power Plant Equipment	2,565,605	982,751	38.30%	672,021	26.19%	1,087,039	42.37%
Total Sun Dance	$ 292,579,035	$ 149,580,108	51.12%	$ 92,472,248	31.61%	$ 149,580,108	51.12%
West Phoenix							
341.00 Structures and Improvements	$ 34,253,399	$ 12,122,673	35.39%	$ 10,897,664	31.81%	$ 11,481,231	33.52%
342.00 Fuel Holders, Products and Accessories	30,662,633	13,045,820	42.55%	14,322,607	46.71%	13,948,957	45.49%
343.00 Prime Movers	165,023,932	43,345,983	26.27%	58,567,180	35.49%	47,940,734	29.05%
344.00 Generators and Devices	300,789,550	103,714,054	34.48%	113,002,750	37.57%	97,440,046	32.39%
345.00 Accessory Electric Equipment	40,508,678	10,005,628	24.70%	12,154,792	30.01%	10,917,760	26.95%
346.00 Miscellaneous Power Plant Equipment	12,626,027	2,702,650	21.41%	3,419,443	27.08%	3,208,078	25.41%
Total West Phoenix	$ 583,864,219	$ 184,936,807	31.67%	$ 212,364,436	36.37%	$ 184,936,807	31.67%
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$ 963,966	$ 252,238	26.17%	$ 437,049	45.34%	$ 432,692	44.89%
342.00 Fuel Holders, Products and Accessories	24,667,947	10,071,539	40.83%	11,482,048	46.55%	11,367,583	46.08%
343.00 Prime Movers							
344.00 Generators and Devices	103,127,942	51,645,231	50.08%	47,998,047	46.54%	47,519,554	46.08%
345.00 Accessory Electric Equipment	25,144,330	4,526,680	18.00%	6,562,735	26.10%	6,497,311	25.84%
346.00 Miscellaneous Power Plant Equipment	6,536,270	1,487,633	22.76%	2,187,992	33.47%	2,166,180	33.14%
Total West Phoenix CC Units 1-3	$ 160,440,455	$ 67,983,322	42.37%	$ 68,667,871	42.80%	$ 67,983,322	42.37%

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West Phoenix CC Unit 4							
341.00 Structures and Improvements	$ 4,683,180	$ 1,747,459	37.31%	$ 1,902,808	40.63%	$ 1,677,639	35.82%
342.00 Fuel Holders, Products and Accessories	4,135,109	1,648,900	39.88%	1,772,531	42.87%	1,562,779	37.79%
343.00 Prime Movers	49,464,010	19,271,739	38.96%	22,772,936	46.04%	20,078,100	40.59%
344.00 Generators and Devices	23,653,858	6,720,434	28.41%	6,850,608	28.96%	6,039,941	25.53%
345.00 Accessory Electric Equipment	453,669	71,836	15.83%	108,212	23.85%	95,406	21.03%
346.00 Miscellaneous Power Plant Equipment	709,405	70,218	9.90%	87,018	12.27%	76,721	10.81%
Total West Phoenix CC Unit 4	$ 83,099,231	$ 29,530,586	35.54%	$ 33,494,113	40.31%	$ 29,530,586	35.54%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$ 11,935,671	$ 3,701,814	31.01%	$ 4,038,285	33.83%	$ 2,992,773	25.07%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	92,946,762	19,839,509	21.35%	29,512,873	31.75%	21,871,990	23.53%
344.00 Generators and Devices	163,209,028	41,026,894	25.14%	54,473,514	33.38%	40,370,321	24.74%
345.00 Accessory Electric Equipment	13,138,590	3,888,482	29.60%	4,256,443	32.40%	3,154,450	24.01%
346.00 Miscellaneous Power Plant Equipment	4,353,879	373,022	8.57%	593,964	13.64%	440,187	10.11%
Total West Phoenix CC Unit 5	$ 285,583,930	$ 68,829,721	24.10%	$ 92,875,078	32.52%	$ 68,829,721	24.10%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$ 4,040,996	$ 541,903	13.41%	$ 523,079	12.94%	$ 498,868	12.35%
342.00 Fuel Holders, Products and Accessories	1,859,577	1,325,381	71.27%	1,068,028	57.43%	1,018,595	54.78%
343.00 Prime Movers	22,613,160	4,234,734	18.73%	6,281,371	27.78%	5,990,644	26.49%
344.00 Generators and Devices	10,798,722	4,321,495	40.02%	3,680,582	34.08%	3,510,230	32.51%
345.00 Accessory Electric Equipment	1,772,089	1,518,630	85.70%	1,227,402	69.26%	1,170,593	66.06%
346.00 Miscellaneous Power Plant Equipment	1,026,473	771,777	75.19%	550,468	53.63%	524,990	51.15%
Total West Phoenix CT Units 1-2	$ 42,111,017	$ 12,713,920	30.19%	$ 13,330,929	31.66%	$ 12,713,920	30.19%
West Phoenix Common							
341.00 Structures and Improvements	$ 12,629,586	$ 5,879,259	46.55%	$ 3,996,444	31.64%	$ 5,879,259	46.55%
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	$ 12,629,586	$ 5,879,259	46.55%	$ 3,996,444	31.64%	$ 5,879,259	46.55%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2015

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
Yucca							
341.00 Structures and Improvements	$ 6,255,719	$ 1,174,360	18.77%	$ 1,482,731	23.70%	$ 1,671,442	26.72%
342.00 Fuel Holders, Products and Accessories	5,430,087	3,881,966	71.49%	3,205,104	59.02%	3,611,159	66.50%
343.00 Prime Movers	78,776,880	20,844,607	26.46%	20,536,730	26.07%	20,909,625	26.54%
344.00 Generators and Devices	10,171,850	5,819,691	57.21%	4,786,498	47.06%	5,474,314	53.82%
345.00 Accessory Electric Equipment	4,554,682	2,180,584	47.88%	2,056,412	45.15%	2,341,004	51.40%
346.00 Miscellaneous Power Plant Equipment	2,141,552	1,043,730	48.74%	821,354	38.35%	937,394	43.77%
Total Yucca	$ 107,330,770	$ 34,944,939	32.56%	$ 32,888,829	30.64%	$ 34,944,939	32.56%
Yucca CT Units 1-4							
341.00 Structures and Improvements	$ 5,185,290	$ 1,031,880	19.90%	$ 1,337,122	25.79%	$ 1,530,256	29.51%
342.00 Fuel Holders, Products and Accessories	3,934,860	3,570,478	90.74%	2,879,665	73.18%	3,295,603	83.75%
343.00 Prime Movers	11,077,145	6,327,000	57.12%	5,700,920	51.47%	6,524,360	58.90%
344.00 Generators and Devices	10,058,652	5,798,049	57.64%	4,766,218	47.38%	5,454,650	54.23%
345.00 Accessory Electric Equipment	3,737,069	2,228,751	59.64%	1,985,273	53.12%	2,272,025	60.80%
346.00 Miscellaneous Power Plant Equipment	1,328,508	1,043,730	78.56%	806,504	60.71%	922,995	69.48%
Total Yucca CT Units 1-4	$ 35,321,524	$ 19,999,888	56.62%	$ 17,475,702	49.48%	$ 19,999,888	56.62%
Yucca CT Units 5-6							
341.00 Structures and Improvements	$ 1,070,429	$ 142,480	13.31%	$ 145,609	13.60%	$ 141,187	13.19%
342.00 Fuel Holders, Products and Accessories	1,495,227	311,488	20.83%	325,440	21.77%	315,556	21.10%
343.00 Prime Movers	67,699,735	14,517,607	21.44%	14,835,810	21.91%	14,385,265	21.25%
344.00 Generators and Devices	113,198	21,642	19.12%	20,280	17.92%	19,664	17.37%
345.00 Accessory Electric Equipment	817,613	(48,167)	-5.89%	71,140	8.70%	68,979	8.44%
346.00 Miscellaneous Power Plant Equipment	813,044			14,850	1.83%	14,399	1.77%
Total Yucca CT Units 5-6	$ 72,009,246	$ 14,945,051	20.75%	$ 15,413,127	21.40%	$ 14,945,051	20.75%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2015

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	$ 169,959,507	$ 76,284,563	44.88%	$ 10,240,556	6.03%	$ 86,525,119	50.91%
312.00 Boiler Plant Equipment	1,156,581,620	645,734,163	55.83%	104,605,809	9.04%	750,339,971	64.88%
314.00 Turbogenerator Units	212,294,514	117,912,538	55.54%	18,128,895	8.54%	136,041,433	64.08%
315.00 Accessory Electric Equipment	127,147,100	61,702,016	48.53%	7,633,332	6.00%	69,335,347	54.53%
316.00 Miscellaneous Power Plant Equipment	95,057,632	45,296,121	47.65%	6,389,164	6.72%	51,685,285	54.37%
Total Steam Production Plant	$ 1,761,040,373	$ 946,929,401	53.77%	$ 146,997,755	8.35%	$ 1,093,927,156	62.12%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$ 800,303,960	$ 412,191,579	51.50%	$ (389,487)	-0.05%	$ 411,802,092	51.46%
322.00 Reactor Plant Equipment	1,177,440,897	651,851,218	55.36%	(5,902,314)	-0.50%	645,948,904	54.86%
323.00 Turbogenerator Units	378,902,614	199,921,496	52.76%	(1,390,193)	-0.37%	198,531,303	52.40%
324.00 Accessory Electric Equipment	286,941,496	180,630,318	62.95%	280,394	0.10%	180,910,712	63.05%
325.00 Miscellaneous Power Plant Equipment	190,865,034	82,144,036	43.04%	(1,468,188)	-0.77%	80,675,849	42.27%
Total Nuclear Production Plant	$ 2,834,454,001	$ 1,526,738,647	53.86%	$ (8,869,787)	-0.31%	$ 1,517,868,859	53.55%
OTHER PRODUCTION							
341.00 Structures and Improvements	$ 115,260,761	$ 27,575,181	23.92%	$ 556,272	0.48%	$ 28,131,453	24.41%
342.00 Fuel Holders, Products and Accessories	55,221,287	21,328,285	38.62%	1,014,633	1.84%	22,342,919	40.46%
343.00 Prime Movers	652,662,488	216,706,676	33.20%	12,096,687	1.85%	228,803,364	35.06%
344.00 Generators and Devices	1,295,258,389	188,436,745	14.55%	44,790,778	3.46%	233,227,523	18.01%
345.00 Accessory Electric Equipment	209,397,328	42,482,243	20.29%	1,819,290	0.87%	44,301,534	21.16%
346.00 Miscellaneous Power Plant Equipment	27,345,147	6,540,342	23.92%	350,175	1.28%	6,890,517	25.20%
Total Other Production Plant	$ 2,355,145,400	$ 503,069,473	21.36%	$ 60,627,837	2.57%	$ 563,697,309	23.93%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$ 151,995	$ 105,554	69.45%	$ -		$ 105,554	69.45%
353.00 Station Equipment	122,007,490	25,912,626	21.24%	1,720,339	1.41%	27,632,965	22.65%
354.00 Towers and Fixtures	1,329,316	551,468	41.49%			551,468	41.49%
355.00 Poles and Fixtures	1,370,085	252,025	18.39%	50,405	3.68%	302,430	22.07%
356.00 Overhead Conductors and Devices	1,947,677	497,578	25.55%	116,052	5.96%	613,631	31.51%
Total Transmission Plant	$ 126,806,563	$ 27,319,252	21.54%	$ 1,886,796	1.49%	$ 29,206,048	23.03%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2015

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
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$ 82,271,151	$ 18,452,502	22.43%	$ 847,408	1.03%	$ 19,299,909	23.46%
362.00 Station Equipment	494,771,283	105,263,344	21.28%	10,759,875	2.17%	116,023,220	23.45%
363.00 Storage Battery Equipment	2,123,630	843,834	39.74%			843,834	39.74%
364.01 Poles, Towers and Fixtures - Wood	332,284,839	83,392,463	25.10%	35,299,724	10.62%	118,692,187	35.72%
364.02 Poles, Towers and Fixtures - Steel	260,823,751	29,969,100	11.49%	2,996,910	1.15%	32,966,010	12.64%
365.00 Overhead Conductors and Devices	355,117,540	62,414,989	17.58%	24,835,167	6.99%	87,250,156	24.57%
366.00 Underground Conduit	685,513,670	156,124,477	22.77%	13,114,977	1.91%	169,239,454	24.69%
367.00 Underground Conductors and Devices	1,646,381,070	437,066,743	26.55%	58,080,895	3.53%	495,147,639	30.07%
368.00 Line Transformers	833,275,690	207,937,778	24.95%	20,027,147	2.40%	227,964,926	27.36%
369.00 Services	375,644,741	118,122,317	31.45%	70,205,620	18.69%	188,327,937	50.13%
370.01 Meters - Electronic	17,142,724	2,473,154	14.43%	85,224	0.50%	2,558,378	14.92%
370.03 Meters - AMI	274,220,605	37,249,312	13.58%	1,099,859	0.40%	38,349,171	13.98%
371.00 Installations on Customers' Premises	43,510,997	9,139,315	21.00%	1,451,698	3.34%	10,591,012	24.34%
373.00 Street Lighting and Signal Systems	74,601,787	18,159,791	24.34%	1,108,324	1.49%	19,268,115	25.83%
Total Distribution Plant	$ 5,477,683,478	$ 1,286,609,119	23.49%	$ 239,912,828	4.38%	$ 1,526,521,946	27.87%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 179,729,946	$ 31,576,455	17.57%	$ (696,424)	-0.39%	$ 30,880,031	17.18%
391.CM Office Furn. and Equip. - Computer	169,141,944	65,416,775	38.68%	(196,250)	-0.12%	65,220,525	38.56%
397.00 Communication Equipment	251,017,440	74,821,087	29.81%	(167,886)	-0.07%	74,653,201	29.74%
Total Depreciable	$ 599,889,330	$ 171,814,317	28.64%	$ (1,060,560)	-0.18%	$ 170,753,757	28.46%
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$ 59,067,179	$ 26,621,434	45.07%	$ -		$ 26,621,434	45.07%
393.00 Stores Equipment	242,516	70,327	29.00%			70,327	29.00%
394.00 Tools, Shop and Garage Equipment	37,140,670	15,711,089	42.30%			15,711,089	42.30%
395.00 Laboratory Equipment	810,563	415,695	51.28%			415,695	51.28%
398.00 Miscellaneous Equipment	17,446,236	3,897,791	22.34%			3,897,791	22.34%
Total Amortizable	$ 114,707,164	$ 46,716,336	40.73%	$ -		$ 46,716,336	40.73%
Total General Plant	$ 714,596,494	$ 218,530,653	30.58%	$ (1,060,560)	-0.15%	$ 217,470,093	30.43%
TOTAL UTILITY	$13,269,726,309	$ 4,509,196,544	33.98%	$ 439,494,868	3.31%	$ 4,948,691,413	37.29%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2015

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
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$ 77,737,991	$ 26,324,060	33.86%	$ 2,084,901	2.68%	$ 28,408,961	36.54%
312.00 Boiler Plant Equipment	378,495,272	129,342,668	34.17%	8,792,478	2.32%	138,135,146	36.50%
314.00 Turbogenerator Units	86,113,816	32,430,977	37.66%	2,912,937	3.38%	35,343,914	41.04%
315.00 Accessory Electric Equipment	52,313,534	22,412,965	42.84%	1,702,389	3.25%	24,115,354	46.10%
316.00 Miscellaneous Power Plant Equipment	23,835,993	7,349,683	30.83%	579,344	2.43%	7,929,026	33.26%
Total Cholla	$ 618,496,606	$ 217,860,353	35.22%	$ 16,072,049	2.60%	$ 233,932,402	37.82%
Cholla Unit 1							
311.00 Structures and Improvements	$ 4,743,207	$ 2,360,158	49.76%	$ 199,789	4.21%	$ 2,559,947	53.97%
312.00 Boiler Plant Equipment	80,244,501	34,807,185	43.38%	2,095,393	2.61%	36,902,578	45.99%
314.00 Turbogenerator Units	27,503,716	11,066,624	40.24%	871,082	3.17%	11,937,706	43.40%
315.00 Accessory Electric Equipment	9,492,908	4,615,291	48.62%	376,395	3.97%	4,991,687	52.58%
316.00 Miscellaneous Power Plant Equipment	2,926,476	1,511,983	51.67%	130,031	4.44%	1,642,014	56.11%
Total Cholla Unit 1	$ 124,910,808	$ 54,361,242	43.52%	$ 3,672,689	2.94%	$ 58,033,931	46.46%
Cholla Unit 3							
311.00 Structures and Improvements	$ 13,288,725	$ 4,542,653	34.18%	$ 349,202	2.63%	$ 4,891,855	36.81%
312.00 Boiler Plant Equipment	238,165,292	75,431,441	31.67%	5,430,093	2.28%	80,861,533	33.95%
314.00 Turbogenerator Units	56,834,120	21,006,357	36.96%	2,011,101	3.54%	23,017,458	40.50%
315.00 Accessory Electric Equipment	34,832,937	15,269,409	43.84%	1,084,128	3.11%	16,353,537	46.95%
316.00 Miscellaneous Power Plant Equipment	6,842,283	2,198,123	32.13%	158,265	2.31%	2,356,388	34.44%
Total Cholla Unit 3	$ 349,963,357	$ 118,447,983	33.85%	$ 9,032,788	2.58%	$ 127,480,771	36.43%
Cholla Common							
311.00 Structures and Improvements	$ 59,706,059	$ 19,421,250	32.53%	$ 1,535,910	2.57%	$ 20,957,160	35.10%
312.00 Boiler Plant Equipment	60,085,479	19,104,042	31.79%	1,266,993	2.11%	20,371,035	33.90%
314.00 Turbogenerator Units	1,775,980	357,996	20.16%	30,754	1.73%	388,750	21.89%
315.00 Accessory Electric Equipment	7,987,689	2,528,264	31.65%	241,866	3.03%	2,770,130	34.68%
316.00 Miscellaneous Power Plant Equipment	14,067,234	3,639,577	25.87%	291,048	2.07%	3,930,625	27.94%
Total Cholla Common	$ 143,622,441	$ 45,051,129	31.37%	$ 3,366,571	2.34%	$ 48,417,700	33.71%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2015

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
Four Corners							
311.00 Structures and Improvements	$ 54,567,232	$ 26,436,877	48.45%	$ 6,284,580	11.52%	$ 32,721,458	59.97%
312.00 Boiler Plant Equipment	581,513,168	387,820,463	66.69%	85,009,555	14.62%	472,830,018	81.31%
314.00 Turbogenerator Units	83,827,121	54,435,541	64.94%	11,365,225	13.56%	65,800,766	78.50%
315.00 Accessory Electric Equipment	47,577,191	20,666,816	43.44%	4,355,078	9.15%	25,021,894	52.59%
316.00 Miscellaneous Power Plant Equipment	44,955,256	22,352,641	49.72%	4,231,594	9.41%	26,584,235	59.13%
Total Four Corners	$ 812,439,968	$ 511,712,339	62.98%	$ 111,246,032	13.69%	$ 622,958,370	76.68%
Four Corners Units 4-5							
311.00 Structures and Improvements	$ 38,507,966	$ 23,766,371	61.72%	$ 5,026,344	13.05%	$ 28,792,715	74.77%
312.00 Boiler Plant Equipment	546,025,397	379,038,786	69.42%	84,109,977	15.40%	463,148,763	84.82%
314.00 Turbogenerator Units	80,391,368	53,153,612	66.12%	11,161,098	13.88%	64,314,710	80.00%
315.00 Accessory Electric Equipment	35,325,258	18,932,655	53.60%	3,912,884	11.08%	22,845,539	64.67%
316.00 Miscellaneous Power Plant Equipment	32,289,311	18,077,850	55.99%	3,669,803	11.37%	21,747,653	67.35%
Total Four Corners Units 4-5	$ 732,539,300	$ 492,969,274	67.30%	$ 107,880,105	14.73%	$ 600,849,380	82.02%
Four Corners Common							
311.00 Structures and Improvements	$ 16,059,266	$ 2,670,506	16.63%	$ 1,258,236	7.83%	$ 3,928,743	24.46%
312.00 Boiler Plant Equipment	35,487,771	8,781,677	24.75%	899,578	2.53%	9,681,256	27.28%
314.00 Turbogenerator Units	3,435,753	1,281,929	37.31%	204,127	5.94%	1,486,056	43.25%
315.00 Accessory Electric Equipment	12,251,933	1,734,161	14.15%	442,194	3.61%	2,176,355	17.76%
316.00 Miscellaneous Power Plant Equipment	12,665,945	4,274,791	33.75%	561,790	4.44%	4,836,582	38.19%
Total Four Corners Common	$ 79,900,668	$ 18,743,065	23.46%	$ 3,365,926	4.21%	$ 22,108,991	27.67%
Navajo Units 1-3							
311.00 Structures and Improvements	$ 32,849,766	$ 19,993,259	60.86%	$ 1,091,616	3.32%	$ 21,084,875	64.19%
312.00 Boiler Plant Equipment	171,354,162	108,932,918	63.57%	6,491,653	3.79%	115,424,571	67.36%
314.00 Turbogenerator Units	25,206,593	18,118,350	71.88%	1,039,161	4.12%	19,157,511	76.00%
315.00 Accessory Electric Equipment	22,361,468	15,272,891	68.30%	840,009	3.76%	16,112,900	72.06%
316.00 Miscellaneous Power Plant Equipment	19,203,553	10,876,696	56.64%	510,571	2.66%	11,387,268	59.30%
Total Navajo Units 1-3	$ 270,975,542	$ 173,194,114	63.92%	$ 9,973,010	3.68%	$ 183,167,125	67.60%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2015

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 Units 1-2							
311.00 Structures and Improvements	$ 4,804,518	$ 3,530,366	73.48%	$ 779,459	16.22%	$ 4,309,825	89.70%
312.00 Boiler Plant Equipment	25,219,018	19,638,114	77.87%	4,312,122	17.10%	23,950,236	94.97%
314.00 Turbogenerator Units	17,146,984	12,927,670	75.39%	2,811,572	16.40%	15,739,242	91.79%
315.00 Accessory Electric Equipment	4,894,907	3,349,343	68.43%	735,855	15.03%	4,085,199	83.46%
316.00 Miscellaneous Power Plant Equipment	7,062,830	4,717,101	66.79%	1,067,656	15.12%	5,784,757	81.90%
Total Ocotillo Units 1-2	$ 59,128,257	$ 44,162,595	74.69%	$ 9,706,665	16.42%	$ 53,869,259	91.11%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$ 800,303,960	$ 412,191,579	51.50%	$ (389,487)	-0.05%	$ 411,802,092	51.46%
322.00 Reactor Plant Equipment	1,177,440,897	651,851,218	55.36%	(5,902,314)	-0.50%	645,948,904	54.86%
323.00 Turbogenerator Units	378,902,614	199,921,496	52.76%	(1,390,193)	-0.37%	198,531,303	52.40%
324.00 Accessory Electric Equipment	286,941,496	180,630,318	62.95%	280,394	0.10%	180,910,712	63.05%
325.00 Miscellaneous Power Plant Equipment	190,865,034	82,144,036	43.04%	(1,468,188)	-0.77%	80,675,849	42.27%
Total Palo Verde	$ 2,834,454,001	$ 1,526,738,647	53.86%	$ (8,869,787)	-0.31%	$ 1,517,868,859	53.55%
Palo Verde Unit 1							
321.00 Structures and Improvements	$ 160,238,922	$ 109,846,626	68.55%	$ 320,332	0.20%	$ 110,166,958	68.75%
322.00 Reactor Plant Equipment	464,794,795	279,893,617	60.22%	2,310,698	0.50%	282,204,315	60.72%
323.00 Turbogenerator Units	133,635,855	75,636,820	56.60%	(850,074)	-0.64%	74,786,746	55.96%
324.00 Accessory Electric Equipment	117,924,193	80,655,867	68.40%	234,825	0.20%	80,890,691	68.60%
325.00 Miscellaneous Power Plant Equipment	31,243,002	20,100,351	64.34%	(140,371)	-0.45%	19,959,979	63.89%
Total Palo Verde Unit 1	$ 907,836,767	$ 566,133,280	62.36%	$ 1,875,409	0.21%	$ 568,008,689	62.57%
Palo Verde Unit 2							
321.00 Structures and Improvements	$ 92,055,736	$ 60,192,886	65.39%	$ 240,772	0.26%	$ 60,433,657	65.65%
322.00 Reactor Plant Equipment	249,302,485	132,200,257	53.03%	(728,400)	-0.29%	131,471,857	52.74%
323.00 Turbogenerator Units	87,999,272	44,021,790	50.03%	(362,373)	-0.41%	43,659,417	49.61%
324.00 Accessory Electric Equipment	47,992,891	30,354,432	63.25%	50,205	0.10%	30,404,637	63.35%
325.00 Miscellaneous Power Plant Equipment	27,285,762	16,035,097	58.77%	(86,121)	-0.32%	15,948,976	58.45%
Total Palo Verde Unit 2	$ 504,636,146	$ 282,804,462	56.04%	$ (885,918)	-0.18%	$ 281,918,545	55.87%

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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	$ 165,218,693	$ 103,767,105	62.81%	$ 415,068	0.25%	$ 104,182,173	63.06%
322.00 Reactor Plant Equipment	427,193,012	222,450,802	52.07%	(4,674,795)	-1.09%	217,776,008	50.98%
323.00 Turbogenerator Units	152,558,297	79,225,368	51.93%	40,391	0.03%	79,265,760	51.96%
324.00 Accessory Electric Equipment	94,317,583	57,221,455	60.67%	(2,815)	0.00%	57,218,640	60.67%
325.00 Miscellaneous Power Plant Equipment	28,965,542	16,658,830	57.51%	(179,697)	-0.62%	16,479,133	56.89%
Total Palo Verde Unit 3	$ 868,253,127	$ 479,323,560	55.21%	$ (4,401,847)	-0.51%	$ 474,921,714	54.70%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$ 210,244,404	$ 66,821,389	31.78%	$ (953,388)	-0.45%	$ 65,868,001	31.33%
322.00 Reactor Plant Equipment	561,290	54,198	9.66%	650	0.12%	54,848	9.77%
323.00 Turbogenerator Units	217,756	103,393	47.48%	(8,372)	-3.84%	95,020	43.64%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	165,219	46,595	28.20%	329	0.20%	46,924	28.40%
Total Palo Verde Water Reclamation	$ 211,188,669	$ 67,025,574	31.74%	$ (960,780)	-0.45%	$ 66,064,794	31.28%
Palo Verde Common							
321.00 Structures and Improvements	$ 172,546,205	$ 71,563,573	41.48%	$ (412,271)	-0.24%	$ 71,151,302	41.24%
322.00 Reactor Plant Equipment	35,589,315	17,252,343	48.48%	(2,810,467)	-7.90%	14,441,876	40.58%
323.00 Turbogenerator Units	4,491,434	934,125	20.80%	(209,765)	-4.67%	724,360	16.13%
324.00 Accessory Electric Equipment	26,706,829	12,398,564	46.42%	(1,821)	-0.01%	12,396,743	46.42%
325.00 Miscellaneous Power Plant Equipment	103,205,509	29,303,164	28.39%	(1,062,328)	-1.03%	28,240,837	27.36%
Total Palo Verde Common	$ 342,539,292	$ 131,451,770	38.38%	$ (4,496,652)	-1.31%	$ 126,955,118	37.06%
OTHER PRODUCTION (by Unit)							
Douglas CT							
341.00 Structures and Improvements	$ 103,952	$ (134,714)	-129.59%	$ (6,736)	-6.48%	$ (141,449)	-136.07%
342.00 Fuel Holders, Products and Accessories	137,759	(334,106)	-242.53%	(14,318)	-10.39%	(348,424)	-252.92%
343.00 Prime Movers	3,721,569	(2,306,599)	-61.98%	5,049,415	135.68%	2,742,816	73.70%
344.00 Generators and Devices	971,924	(1,651,385)	-169.91%	(82,569)	-8.50%	(1,733,954)	-178.40%
345.00 Accessory Electric Equipment	403,765	(947,812)	-234.74%	(42,609)	-10.55%	(990,422)	-245.30%
346.00 Miscellaneous Power Plant Equipment	33,564	(81,363)	-242.41%	(4,442)	-13.24%	(85,805)	-255.65%
Total Douglas CT	$ 5,372,533	$ (5,455,978)	-101.55%	$ 4,898,740	91.18%	$ (557,238)	-10.37%

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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	$ 1,953,223	$ 424,631	21.74%	$ (36,380)	-1.86%	$ 388,251	19.88%
342.00 Fuel Holders, Products and Accessories	1,107,461	520,609	47.01%	26,030	2.35%	546,639	49.36%
343.00 Prime Movers	21,989,611	5,057,096	23.00%	(1,079,784)	-4.91%	3,977,312	18.09%
344.00 Generators and Devices	14,737,836	4,825,489	32.74%	198,835	1.35%	5,024,324	34.09%
345.00 Accessory Electric Equipment	4,017,658	1,251,550	31.15%	48,311	1.20%	1,299,861	32.35%
346.00 Miscellaneous Power Plant Equipment	990,572	401,858	40.57%	21,079	2.13%	422,937	42.70%
Total Octillo CT Units 1-2	$ 44,796,361	$ 12,481,233	27.86%	$ (821,908)	-1.83%	$ 11,659,325	26.03%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$ 23,674,859	$ 3,879,387	16.39%	$ 210,834	0.89%	$ 4,090,221	17.28%
342.00 Fuel Holders, Products and Accessories	11,611,849	995,569	8.57%	29,607	0.25%	1,025,175	8.83%
343.00 Prime Movers	132,566,124	22,520,410	16.99%	(452,185)	-0.34%	22,068,225	16.65%
344.00 Generators and Devices	336,601,568	31,676,324	9.41%	24,952,510	7.41%	56,628,834	16.82%
345.00 Accessory Electric Equipment	23,778,511	4,042,189	17.00%	268,696	1.13%	4,310,885	18.13%
346.00 Miscellaneous Power Plant Equipment	6,538,111	505,088	7.73%	59,993	0.92%	565,082	8.64%
Total Redhawk CC Units 1-2	$ 534,771,022	$ 63,618,967	11.90%	$ 25,069,455	4.69%	$ 88,688,422	16.58%
Saguaro							
341.00 Structures and Improvements	$ 3,173,028	$ 1,276,827	40.24%	$ (28,834)	-0.91%	$ 1,247,993	39.33%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,138,570	69.32%	51,435	3.13%	1,190,005	72.45%
343.00 Prime Movers	17,905,173	6,976,713	38.96%	(337,349)	-1.88%	6,639,364	37.08%
344.00 Generators and Devices	32,384,680	13,165,775	40.65%	633,632	1.96%	13,799,408	42.61%
345.00 Accessory Electric Equipment	3,384,270	1,396,815	41.27%	47,626	1.41%	1,444,441	42.68%
346.00 Miscellaneous Power Plant Equipment	892,062	606,819	68.02%	30,779	3.45%	637,597	71.47%
Total Saguaro	$ 59,381,701	$ 24,561,519	41.36%	$ 397,289	0.67%	$ 24,958,807	42.03%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$ 3,173,028	$ 1,276,827	40.24%	$ (28,834)	-0.91%	$ 1,247,993	39.33%
342.00 Fuel Holders, Products and Accessories	1,642,488	1,138,570	69.32%	51,435	3.13%	1,190,005	72.45%
343.00 Prime Movers	15,965,868	6,657,882	41.70%	(353,291)	-2.21%	6,304,591	39.49%
344.00 Generators and Devices	4,666,538	2,859,516	61.28%	135,161	2.90%	2,994,677	64.17%
345.00 Accessory Electric Equipment	3,261,717	1,351,224	41.43%	45,347	1.39%	1,396,571	42.82%
346.00 Miscellaneous Power Plant Equipment	892,062	606,819	68.02%	30,779	3.45%	637,597	71.47%
Total Saguaro CT Units 1-2	$ 29,601,701	$ 13,890,838	46.93%	$ (119,404)	-0.40%	$ 13,771,434	46.52%

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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	1,939,305	318,831	16.44%	15,942	0.82%	334,773	17.26%
344.00 Generators and Devices	27,718,142	10,306,259	37.18%	498,472	1.80%	10,804,731	38.98%
345.00 Accessory Electric Equipment	122,553	45,590	37.20%	2,280	1.86%	47,870	39.06%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$ 29,780,000	$ 10,670,680	35.83%	$ 516,693	1.74%	$ 11,187,373	37.57%
Solar Units							
341.00 Structures and Improvements	$ 32,510,020	$ 2,766,058	8.51%	$ 197,185	0.61%	$ 2,963,242	9.11%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	587,836,565	51,917,703	8.83%	3,826,388	0.65%	55,744,091	9.48%
345.00 Accessory Electric Equipment	105,145,520	9,991,926	9.50%	668,685	0.64%	10,660,611	10.14%
346.00 Miscellaneous Power Plant Equipment	1,557,654	110,439	7.09%	7,756	0.50%	118,195	7.59%
Total Solar Units	$ 727,049,759	$ 64,786,125	8.91%	$ 4,700,014	0.65%	$ 69,486,139	9.56%
Chino Valley							
341.05 Structures and Improvements	$ 527,889	$ 50,802	9.62%	$ 3,759	0.71%	$ 54,561	10.34%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	77,719,075	7,479,323	9.62%	553,470	0.71%	8,032,793	10.34%
345.05 Accessory Electric Equipment	6,511,775	626,663	9.62%	46,373	0.71%	673,036	10.34%
346.05 Miscellaneous Power Plant Equipment	216,504	20,835	9.62%	1,542	0.71%	22,377	10.34%
Total Chino Valley	$ 84,975,243	$ 8,177,623	9.62%	$ 605,144	0.71%	$ 8,782,767	10.34%
Cotton Center							
341.05 Structures and Improvements	$ 1,813,500	$ 236,519	13.04%	$ 15,610	0.86%	$ 252,130	13.90%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	61,593,054	8,033,056	13.04%	530,182	0.86%	8,563,237	13.90%
345.05 Accessory Electric Equipment	15,418,050	2,010,844	13.04%	132,716	0.86%	2,143,560	13.90%
346.05 Miscellaneous Power Plant Equipment	262,641	34,254	13.04%	2,261	0.86%	36,515	13.90%
Total Cotton Center	$ 79,087,245	$ 10,314,673	13.04%	$ 680,768	0.86%	$ 10,995,442	13.90%

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Desert Star							
341.05 Structures and Improvements	$ 1,572,235	$ 19,954	1.27%	$ 2,295	0.15%	$ 22,249	1.42%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	25,365,040	321,920	1.27%	37,021	0.15%	358,941	1.42%
345.05 Accessory Electric Equipment	3,579,659	45,431	1.27%	5,225	0.15%	50,656	1.42%
346.05 Miscellaneous Power Plant Equipment	293,963	3,731	1.27%	429	0.15%	4,160	1.42%
Total Desert Star	$ 30,810,897	$ 391,036	1.27%	$ 44,969	0.15%	$ 436,005	1.42%
Foothills Units 1-2							
341.05 Structures and Improvements	$ 10,906,684	$ 821,774	7.53%	$ 70,673	0.65%	$ 892,446	8.18%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	105,443,248	7,944,716	7.53%	683,246	0.65%	8,627,962	8.18%
345.05 Accessory Electric Equipment	20,815,540	1,568,366	7.53%	134,879	0.65%	1,703,245	8.18%
346.05 Miscellaneous Power Plant Equipment	57,708	4,348	7.53%	374	0.65%	4,722	8.18%
Total Foothills Units 1-2	$ 137,223,180	$ 10,339,203	7.53%	$ 889,171	0.65%	$ 11,228,375	8.18%
Gila Bend							
341.05 Structures and Improvements	$ 5,018,097	$ 240,497	4.79%	$ 24,771	0.49%	$ 265,268	5.29%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	89,246,612	4,277,227	4.79%	440,554	0.49%	4,717,781	5.29%
345.05 Accessory Electric Equipment	11,096,944	531,831	4.79%	54,779	0.49%	586,610	5.29%
346.05 Miscellaneous Power Plant Equipment	21,142	1,013	4.79%	104	0.49%	1,118	5.29%
Total Gila Bend	$ 105,382,795	$ 5,050,568	4.79%	$ 520,209	0.49%	$ 5,570,777	5.29%
Hyder Units 1-2							
341.05 Structures and Improvements	$ 6,915,232	$ 691,478	10.00%	$ 30,425	0.44%	$ 721,903	10.44%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	93,250,197	9,619,686	10.32%	423,266	0.45%	10,042,952	10.77%
345.05 Accessory Electric Equipment	22,556,482	2,428,717	10.77%	106,864	0.47%	2,535,581	11.24%
346.05 Miscellaneous Power Plant Equipment	206,389	25,514	12.36%	1,123	0.54%	26,637	12.91%
Total Hyder Units 1-2	$ 122,928,300	$ 12,765,396	10.38%	$ 561,677	0.46%	$ 13,327,073	10.84%

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Legacy Units							
341.00 Structures and Improvements	$ 325,971	$ 236,877	72.67%	$ 14,428	4.43%	$ 251,305	77.09%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	10,113,649	2,829,615	27.98%	342,248	3.38%	3,171,863	31.36%
345.00 Accessory Electric Equipment	3,606,980	415,757	11.53%	11,177	0.31%	426,934	11.84%
346.00 Miscellaneous Power Plant Equipment							
Total Legacy Units	$ 14,046,600	$ 3,482,249	24.79%	$ 367,854	2.62%	$ 3,850,102	27.41%
Luke AFB							
341.05 Structures and Improvements	$ 1,566,281	$ 20,117	1.28%	$ 2,374	0.15%	$ 22,491	1.44%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	24,574,551	315,634	1.28%	37,245	0.15%	352,879	1.44%
345.05 Accessory Electric Equipment	1,330,175	17,085	1.28%	2,016	0.15%	19,101	1.44%
346.05 Miscellaneous Power Plant Equipment	377,821	4,853	1.28%	573	0.15%	5,425	1.44%
Total Luke AFB	$ 27,848,828	$ 357,689	1.28%	$ 42,207	0.15%	$ 399,896	1.44%
Roof Tops							
341.05 Structures and Improvements	$ 1,582,181	$ 149,549	9.45%	$ 7,477	0.47%	$ 157,027	9.92%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	51,531,113	4,687,077	9.10%	234,354	0.45%	4,921,431	9.55%
345.05 Accessory Electric Equipment	7,714,968	710,213	9.21%	35,511	0.46%	745,724	9.67%
346.05 Miscellaneous Power Plant Equipment							
Total Roof Tops	$ 60,828,262	$ 5,546,840	9.12%	$ 277,342	0.46%	$ 5,824,182	9.57%
Paloma							
341.05 Structures and Improvements	$ 2,281,950	$ 298,490	13.08%	$ 25,372	1.11%	$ 323,862	14.19%
342.05 Fuel Holders, Products and Accessories							
343.05 Prime Movers							
344.05 Generators and Devices	49,000,026	6,409,449	13.08%	544,803	1.11%	6,954,252	14.19%
345.05 Accessory Electric Equipment	12,514,947	1,637,018	13.08%	139,147	1.11%	1,776,164	14.19%
346.05 Miscellaneous Power Plant Equipment	121,486	15,891	13.08%	1,351	1.11%	17,242	14.19%
Total Paloma	$ 63,918,409	$ 8,360,848	13.08%	$ 710,672	1.11%	$ 9,071,520	14.19%

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Sundance							
341.00 Structures and Improvements	$ 13,336,561	$ 6,384,674	47.87%	$ 45,848	0.34%	$ 6,430,521	48.22%
342.00 Fuel Holders, Products and Accessories	4,629,010	2,256,578	48.75%	112,829	2.44%	2,369,407	51.19%
343.00 Prime Movers	232,679,199	118,595,512	50.97%	5,929,776	2.55%	124,525,287	53.52%
344.00 Generators and Devices	11,764,416	809,961	6.88%	40,498	0.34%	850,459	7.23%
345.00 Accessory Electric Equipment	27,604,244	13,694,579	49.61%	622,815	2.26%	14,317,393	51.87%
346.00 Miscellaneous Power Plant Equipment	2,565,605	1,035,275	40.35%	51,764	2.02%	1,087,039	42.37%
Total Sun Dance	$ 292,579,035	$ 142,776,579	48.80%	$ 6,803,529	2.33%	$ 149,580,108	51.12%
West Phoenix							
341.00 Structures and Improvements	$ 34,253,399	$ 11,340,054	33.11%	$ 141,178	0.41%	$ 11,481,231	33.52%
342.00 Fuel Holders, Products and Accessories	30,662,633	13,310,568	43.41%	638,389	2.08%	13,948,957	45.49%
343.00 Prime Movers	165,023,932	45,497,347	27.57%	2,443,388	1.48%	47,940,734	29.05%
344.00 Generators and Devices	300,789,550	82,419,654	27.40%	15,020,393	4.99%	97,440,046	32.39%
345.00 Accessory Electric Equipment	40,508,678	10,750,065	26.54%	167,695	0.41%	10,917,760	26.95%
346.00 Miscellaneous Power Plant Equipment	12,626,027	3,069,469	24.31%	138,609	1.10%	3,208,078	25.41%
Total West Phoenix	$ 583,864,219	$ 166,387,156	28.50%	$ 18,549,651	3.18%	$ 184,936,807	31.67%
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$ 963,966	$ 411,571	42.70%	$ 21,121	2.19%	$ 432,692	44.89%
342.00 Fuel Holders, Products and Accessories	24,667,947	10,852,117	43.99%	515,466	2.09%	11,367,583	46.08%
343.00 Prime Movers							
344.00 Generators and Devices	103,127,942	44,377,134	43.03%	3,142,420	3.05%	47,519,554	46.08%
345.00 Accessory Electric Equipment	25,144,330	6,520,385	25.93%	(23,073)	-0.09%	6,497,311	25.84%
346.00 Miscellaneous Power Plant Equipment	6,536,270	2,054,616	31.43%	111,564	1.71%	2,166,180	33.14%
Total West Phoenix CC Units 1-3	$ 160,440,455	$ 64,215,823	40.02%	$ 3,767,498	2.35%	$ 67,983,322	42.37%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$ 4,683,180	$ 1,600,160	34.17%	$ 77,479	1.65%	$ 1,677,639	35.82%
342.00 Fuel Holders, Products and Accessories	4,135,109	1,488,361	35.99%	74,418	1.80%	1,562,779	37.79%
343.00 Prime Movers	49,464,010	17,742,356	35.87%	2,335,744	4.72%	20,078,100	40.59%
344.00 Generators and Devices	23,653,858	5,723,503	24.20%	316,438	1.34%	6,039,941	25.53%
345.00 Accessory Electric Equipment	453,669	90,863	20.03%	4,543	1.00%	95,406	21.03%
346.00 Miscellaneous Power Plant Equipment	709,405	72,541	10.23%	4,180	0.59%	76,721	10.81%
Total West Phoenix CC Unit 4	$ 83,099,231	$ 26,717,784	32.15%	$ 2,812,802	3.38%	$ 29,530,586	35.54%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2015

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
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$ 11,935,671	$ 2,867,340	24.02%	$ 125,432	1.05%	$ 2,992,773	25.07%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	92,946,762	21,328,654	22.95%	543,337	0.58%	21,871,990	23.53%
344.00 Generators and Devices	163,209,028	28,890,873	17.70%	11,479,447	7.03%	40,370,321	24.74%
345.00 Accessory Electric Equipment	13,138,590	3,023,420	23.01%	131,030	1.00%	3,154,450	24.01%
346.00 Miscellaneous Power Plant Equipment	4,353,879	429,880	9.87%	10,307	0.24%	440,187	10.11%
Total West Phoenix CC Unit 5	$ 285,583,930	$ 56,540,167	19.80%	$ 12,289,554	4.30%	$ 68,829,721	24.10%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$ 4,040,996	$ 559,819	13.85%	$ (60,951)	-1.51%	$ 498,868	12.35%
342.00 Fuel Holders, Products and Accessories	1,859,577	970,090	52.17%	48,505	2.61%	1,018,595	54.78%
343.00 Prime Movers	22,613,160	6,426,337	28.42%	(435,693)	-1.93%	5,990,644	26.49%
344.00 Generators and Devices	10,798,722	3,428,143	31.75%	82,087	0.76%	3,510,230	32.51%
345.00 Accessory Electric Equipment	1,772,089	1,115,397	62.94%	55,195	3.11%	1,170,593	66.06%
346.00 Miscellaneous Power Plant Equipment	1,026,473	512,431	49.92%	12,559	1.22%	524,990	51.15%
Total West Phoenix CT Units 1-2	$ 42,111,017	$ 13,012,218	30.90%	$ (298,298)	-0.71%	$ 12,713,920	30.19%
West Phoenix Common							
341.00 Structures and Improvements	$ 12,629,586	$ 5,901,163	46.72%	$ (21,905)	-0.17%	$ 5,879,259	46.55%
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	$ 12,629,586	$ 5,901,163	46.72%	$ (21,905)	-0.17%	$ 5,879,259	46.55%
Yucca							
341.00 Structures and Improvements	$ 6,255,719	$ 1,638,264	26.19%	$ 33,178	0.53%	$ 1,671,442	26.72%
342.00 Fuel Holders, Products and Accessories	5,430,087	3,440,497	63.36%	170,662	3.14%	3,611,159	66.50%
343.00 Prime Movers	78,776,880	20,366,199	25.85%	543,427	0.69%	20,909,625	26.54%
344.00 Generators and Devices	10,171,850	5,273,223	51.84%	201,091	1.98%	5,474,314	53.82%
345.00 Accessory Electric Equipment	4,554,682	2,302,933	50.56%	38,071	0.84%	2,341,004	51.40%
346.00 Miscellaneous Power Plant Equipment	2,141,552	892,756	41.69%	44,638	2.08%	937,394	43.77%
Total Yucca	$ 107,330,770	$ 33,913,873	31.60%	$ 1,031,066	0.96%	$ 34,944,939	32.56%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2015

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
Yucca CT Units 1-4							
341.00 Structures and Improvements	$ 5,185,290	$ 1,503,801	29.00%	$ 26,455	0.51%	$ 1,530,256	29.51%
342.00 Fuel Holders, Products and Accessories	3,934,860	3,139,967	79.80%	155,635	3.96%	3,295,603	83.75%
343.00 Prime Movers	11,077,145	6,665,946	60.18%	(141,586)	-1.28%	6,524,360	58.90%
344.00 Generators and Devices	10,058,652	5,254,495	52.24%	200,154	1.99%	5,454,650	54.23%
345.00 Accessory Electric Equipment	3,737,069	2,226,325	59.57%	45,699	1.22%	2,272,025	60.80%
346.00 Miscellaneous Power Plant Equipment	1,328,508	879,043	66.17%	43,952	3.31%	922,995	69.48%
Total Yucca CT Units 1-4	$ 35,321,524	$ 19,669,578	55.69%	$ 330,310	0.94%	$ 19,999,888	56.62%
Yucca CT Units 5-6							
341.00 Structures and Improvements	$ 1,070,429	$ 134,463	12.56%	$ 6,723	0.63%	$ 141,187	13.19%
342.00 Fuel Holders, Products and Accessories	1,495,227	300,530	20.10%	15,026	1.00%	315,556	21.10%
343.00 Prime Movers	67,699,735	13,700,253	20.24%	685,013	1.01%	14,385,265	21.25%
344.00 Generators and Devices	113,198	18,728	16.54%	936	0.83%	19,664	17.37%
345.00 Accessory Electric Equipment	817,613	76,608	9.37%	(7,628)	-0.93%	68,979	8.44%
346.00 Miscellaneous Power Plant Equipment	813,044	13,713	1.69%	686	0.08%	14,399	1.77%
Total Yucca CT Units 5-6	$ 72,009,246	$ 14,244,295	19.78%	$ 700,756	0.97%	$ 14,945,051	20.75%

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	$ 232,525,295	$ 62,565,788	$ 169,959,507	-1.1%	-10.6%	$ (661,521)	$ (17,957,672)	$ (18,619,194)	-8.0%
312.00 Boiler Plant Equipment	1,264,641,354	108,059,734	1,156,581,620	-8.6%	-14.0%	(9,317,914)	(161,494,063)	(170,811,977)	-13.5%
314.00 Turbogenerator Units	239,274,559	26,980,045	212,294,514		-13.4%	9,226	(28,526,330)	(28,517,104)	-11.9%
315.00 Accessory Electric Equipment	136,916,497	9,769,397	127,147,100	-3.2%	-11.5%	(315,253)	(14,655,002)	(14,970,255)	-10.9%
316.00 Miscellaneous Power Plant Equipment	104,066,238	9,008,606	95,057,632	-10.7%	-13.2%	(961,067)	(12,511,168)	(13,472,234)	-12.9%
Total Steam Production Plant	$ 1,977,423,943	$ 216,383,570	$ 1,761,040,373	-5.2%	-13.4%	$ (11,246,529)	$ (235,144,234)	$ (246,390,763)	-12.5%
NUCLEAR PRODUCTION									
321.00 Structures and Improvements	$ 854,841,305	$ 54,537,345	$ 800,303,960	-5.5%	-0.4%	$ (3,000,919)	$ (3,201,216)	$ (6,202,135)	-0.7%
322.00 Reactor Plant Equipment	1,269,378,514	91,937,617	1,177,440,897	-18.8%	-1.2%	(17,283,546)	(13,664,496)	(30,948,042)	-2.4%
323.00 Turbogenerator Units	457,177,633	78,275,019	378,902,614	-4.1%	-0.4%	(3,195,211)	(1,515,610)	(4,710,822)	-1.0%
324.00 Accessory Electric Equipment	299,692,423	12,750,927	286,941,496	-5.2%	-0.4%	(661,807)	(1,147,766)	(1,809,573)	-0.6%
325.00 Miscellaneous Power Plant Equipment	237,940,621	47,075,587	190,865,034	-5.1%	-0.4%	(2,398,441)	(763,460)	(3,161,902)	-1.3%
Total Nuclear Production Plant	$ 3,119,030,496	$ 284,576,495	$ 2,834,454,001	-9.3%	-0.7%	$ (26,539,925)	$ (20,292,548)	$ (46,832,473)	-1.5%
OTHER PRODUCTION									
341.00 Structures and Improvements	$ 122,562,109	$ 7,301,348	$ 115,260,761	-17.9%	-5.8%	$ (1,305,042)	$ (6,710,402)	$ (8,015,444)	-6.5%
342.00 Fuel Holders, Products and Accessories	58,389,241	3,167,954	55,221,287	-8.7%	-5.0%	(275,111)	(2,761,064)	(3,036,175)	-5.2%
343.00 Prime Movers	784,092,884	131,430,396	652,662,488	-15.1%	-5.0%	(19,864,036)	(32,633,124)	(52,497,160)	-6.7%
344.00 Generators and Devices	1,635,653,143	340,394,754	1,295,258,389	30.8%	-6.2%	104,980,209	(80,614,990)	24,365,219	1.5%
345.00 Accessory Electric Equipment	220,293,905	10,896,577	209,397,328	-10.8%	-6.1%	(1,176,167)	(12,836,149)	(14,012,316)	-6.4%
346.00 Miscellaneous Power Plant Equipment	31,177,821	3,832,674	27,345,147	-3.0%	-5.2%	(115,961)	(1,427,667)	(1,543,627)	-5.0%
Total Other Production Plant	$ 2,852,169,103	$ 497,023,703	$ 2,355,145,400	16.5%	-5.8%	$ 82,243,894	$ (136,983,397)	$ (54,739,504)	-1.9%
TRANSMISSION PLANT									
352.02 Structures and Improvements	$ 151,995	$ -	$ 151,995			$ -	$ -	$ -	
353.00 Station Equipment	135,932,046	13,924,556	122,007,490	-0.2%	-5.0%	(27,849)	(6,100,375)	(6,128,224)	-4.5%
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	$ 140,869,761	$ 14,063,198	$ 126,806,563	-0.2%	-5.3%	$ (27,849)	$ (6,763,927)	$ (6,791,776)	-4.8%
DISTRIBUTION PLANT									
361.00 Structures and Improvements	$ 84,839,448	$ 2,568,297	$ 82,271,151	-9.0%	-5.0%	$ (231,147)	$ (4,113,558)	$ (4,344,704)	-5.1%
362.00 Station Equipment	573,040,073	78,268,790	494,771,283	3.9%	-5.0%	3,052,483	(24,738,564)	(21,686,081)	-3.8%
363.00 Storage Battery Equipment	2,123,630		2,123,630						
364.01 Poles, Towers and Fixtures - Wood	461,556,483	129,271,644	332,284,839	-7.6%	-25.0%	(9,824,645)	(83,071,210)	(92,895,855)	-20.1%
364.02 Poles, Towers and Fixtures - Steel	278,570,635	17,746,884	260,823,751	-10.5%	-10.0%	(1,863,423)	(26,082,375)	(27,945,798)	-10.0%
365.00 Overhead Conductors and Devices	436,995,930	81,878,390	355,117,540	-10.5%	-25.0%	(8,597,231)	(88,779,385)	(97,376,616)	-22.3%
366.00 Underground Conduit	724,966,115	39,452,445	685,513,670	-16.9%	-10.0%	(6,667,463)	(68,551,367)	(75,218,830)	-10.4%
367.00 Underground Conductors and Devices	1,897,475,243	251,094,173	1,646,381,070	-2.1%	-10.0%	(5,272,978)	(164,638,107)	(169,911,085)	-9.0%
368.00 Line Transformers	940,872,557	107,596,867	833,275,690	6.7%	-5.0%	7,208,990	(41,663,785)	(34,454,794)	-3.7%
369.00 Services	423,369,402	47,724,661	375,644,741	-18.5%	-50.0%	(8,829,062)	(187,822,371)	(196,651,433)	-46.4%
370.01 Meters - Electronic	139,878,489	122,735,765	17,142,724	0.6%		736,415		736,415	0.5%
370.03 Meters - AMI	290,669,314	16,448,709	274,220,605	7.7%		1,266,551		1,266,551	0.4%
371.00 Installations on Customers' Premises	53,403,482	9,892,485	43,510,997	-14.1%	-15.0%	(1,394,840)	(6,526,650)	(7,921,490)	-14.8%
373.00 Street Lighting and Signal Systems	89,373,818	14,772,031	74,601,787	-3.2%	-5.0%	(472,705)	(3,730,089)	(4,202,794)	-4.7%
Total Distribution Plant	$ 6,397,134,619	$ 919,451,141	$ 5,477,683,478	-3.4%	-12.8%	$ (30,889,056)	$ (699,717,459)	$ (730,606,515)	-11.4%

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
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$ 224,640,768	$ 44,910,822	$ 179,729,946	-13.1%	-5.0%	$ (5,883,318)	$ (8,986,497)	$ (14,869,815)	-6.6%
391.CM Office Furn. and Equip. - Computer	371,062,428	201,920,484	169,141,944	-0.3%		(605,761)		(605,761)	-0.2%
397.00 Communication Equipment	339,313,874	88,296,434	251,017,440	-0.2%		(176,593)		(176,593)	-0.1%
Total Depreciable	$ 935,017,070	$ 335,127,740	$ 599,889,330	-2.0%	-1.5%	$ (6,665,672)	$ (8,986,497)	$ (15,652,169)	-1.7%
Amortizable									
391.FE Office Furn. and Equip. - Furniture	$ 91,452,009	$ 32,384,830	$ 59,067,179			$ -	$ -	$ -	
393.00 Stores Equipment	1,650,532	1,408,016	242,516						
394.00 Tools, Shop and Garage Equipment	54,824,553	17,683,883	37,140,670						
395.00 Laboratory Equipment	2,550,670	1,740,107	810,563						
398.00 Miscellaneous Equipment	19,103,341	1,657,105	17,446,236						
Total Amortizable	$ 169,581,105	$ 54,873,941	$ 114,707,164			$ -	$ -	$ -	
Total General Plant	$ 1,104,598,175	$ 390,001,681	$ 714,596,494	-1.7%	-1.3%	$ (6,665,672)	$ (8,986,497)	$ (15,652,169)	-1.4%
TOTAL UTILITY	$ 15,591,226,097	$ 2,321,499,788	$ 13,269,726,309	0.3%	-8.3%	$ 6,874,863	$ (1,107,888,063)	$ (1,101,013,201)	-7.1%
STEAM PRODUCTION (by Unit)									
Cholla									
311.00 Structures and Improvements	$ 90,523,775	$ 12,785,784	$ 77,737,991	-2.8%	-7.4%	$ (361,402)	$ (5,746,889)	$ (6,108,291)	-6.7%
312.00 Boiler Plant Equipment	425,945,817	47,450,545	378,495,272	-15.8%	-7.7%	(7,494,932)	(29,232,085)	(36,727,017)	-8.6%
314.00 Turbogenerator Units	107,926,595	21,812,779	86,113,816	3.1%	-7.7%	675,290	(6,592,351)	(5,917,060)	-5.5%
315.00 Accessory Electric Equipment	56,165,380	3,851,846	52,313,534	-2.3%	-7.4%	(89,269)	(3,879,112)	(3,968,382)	-7.1%
316.00 Miscellaneous Power Plant Equipment	28,069,408	4,233,415	23,835,993	-6.3%	-7.6%	(264,623)	(1,813,431)	(2,078,054)	-7.4%
Total Cholla	$ 708,630,975	$ 90,134,369	$ 618,496,606	-8.4%	-7.6%	$ (7,534,936)	$ (47,263,868)	$ (54,798,804)	-7.7%
Cholla Unit 1									
311.00 Structures and Improvements	$ 4,965,111	$ 221,904	$ 4,743,207	-7.1%	-8.4%	$ (15,755)	$ (398,429)	$ (414,185)	-8.3%
312.00 Boiler Plant Equipment	84,247,608	4,003,107	80,244,501	-71.9%	-8.7%	(2,878,234)	(6,981,272)	(9,859,506)	-11.7%
314.00 Turbogenerator Units	30,723,745	3,220,029	27,503,716	-15.3%	-8.6%	(492,864)	(2,365,320)	(2,857,984)	-9.3%
315.00 Accessory Electric Equipment	9,615,546	122,638	9,492,908	-44.9%	-8.5%	(55,064)	(806,897)	(861,962)	-9.0%
316.00 Miscellaneous Power Plant Equipment	2,935,828	9,352	2,926,476	-8.8%	-8.6%	(823)	(251,677)	(252,500)	-8.6%
Total Cholla Unit 1	$ 132,487,838	$ 7,577,030	$ 124,910,808	-45.4%	-8.6%	$ (3,442,541)	$ (10,803,595)	$ (14,246,136)	-10.8%
Cholla Unit 3									
311.00 Structures and Improvements	$ 15,376,019	$ 2,087,294	$ 13,288,725	-1.0%	-7.0%	$ (20,873)	$ (930,211)	$ (951,084)	-6.2%
312.00 Boiler Plant Equipment	273,091,413	34,926,121	238,165,292	-8.9%	-7.4%	(3,108,425)	(17,624,232)	(20,732,656)	-7.6%
314.00 Turbogenerator Units	74,535,824	17,701,704	56,834,120	6.9%	-7.2%	1,221,418	(4,092,057)	(2,870,639)	-3.9%
315.00 Accessory Electric Equipment	36,338,929	1,505,992	34,832,937	-6.7%	-7.1%	(100,901)	(2,473,139)	(2,574,040)	-7.1%
316.00 Miscellaneous Power Plant Equipment	7,223,868	381,585	6,842,283	-6.7%	-7.2%	(25,566)	(492,644)	(518,211)	-7.2%
Total Cholla Unit 3	$ 406,566,053	$ 56,602,696	$ 349,963,357	-3.6%	-7.3%	$ (2,034,348)	$ (25,612,282)	$ (27,646,630)	-6.8%
Cholla Common									
311.00 Structures and Improvements	$ 70,182,645	$ 10,476,586	$ 59,706,059	-3.1%	-7.4%	$ (324,774)	$ (4,418,248)	$ (4,743,023)	-6.8%
312.00 Boiler Plant Equipment	68,606,796	8,521,317	60,085,479	-17.7%	-7.7%	(1,508,273)	(4,626,582)	(6,134,855)	-8.9%
314.00 Turbogenerator Units	2,667,026	891,046	1,775,980	-6.0%	-7.6%	(53,463)	(134,974)	(188,437)	-7.1%
315.00 Accessory Electric Equipment	10,210,905	2,223,216	7,987,689	3.0%	-7.5%	66,696	(599,077)	(532,380)	-5.2%
316.00 Miscellaneous Power Plant Equipment	17,909,712	3,842,478	14,067,234	-6.2%	-7.6%	(236,234)	(1,069,110)	(1,307,343)	-7.3%
Total Cholla Common	$ 169,577,084	$ 25,954,643	$ 143,622,441	-7.9%	-7.6%	$ (2,058,047)	$ (10,847,991)	$ (12,906,038)	-7.6%

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									
311.00 Structures and Improvements	$ 103,404,462	$ 48,837,230	$ 54,567,232	-0.6%	-17.2%	$ (289,794)	$ (9,384,707)	$ (9,674,501)	-9.4%
312.00 Boiler Plant Equipment	633,258,736	51,745,568	581,513,168	-3.3%	-20.1%	(1,705,986)	(116,775,252)	(118,481,238)	-18.7%
314.00 Turbogenerator Units	87,552,034	3,724,913	83,827,121	-0.9%	-20.0%	(32,670)	(16,724,867)	(16,757,537)	-19.1%
315.00 Accessory Electric Equipment	52,815,447	5,238,256	47,577,191	-2.7%	-17.8%	(143,984)	(8,474,024)	(8,618,008)	-16.3%
316.00 Miscellaneous Power Plant Equipment	47,079,242	2,123,986	44,955,256	-9.8%	-17.9%	(207,095)	(8,049,312)	(8,256,406)	-17.5%
Total Four Corners	$ 924,109,921	$ 111,669,953	$ 812,439,968	-2.1%	-19.6%	$ (2,379,528)	$ (159,408,161)	$ (161,787,690)	-17.5%
Four Corners Units 4-5									
311.00 Structures and Improvements	$ 41,493,006	$ 2,985,040	$ 38,507,966	-5.1%	-19.7%	$ (152,237)	$ (7,586,069)	$ (7,738,306)	-18.6%
312.00 Boiler Plant Equipment	593,519,083	47,493,686	546,025,397	-1.9%	-20.6%	(902,380)	(112,481,232)	(113,383,612)	-19.1%
314.00 Turbogenerator Units	82,991,032	2,599,664	80,391,368	-1.3%	-20.3%	(33,796)	(16,319,448)	(16,353,243)	-19.7%
315.00 Accessory Electric Equipment	36,615,421	1,290,163	35,325,258	-8.1%	-20.0%	(104,503)	(7,065,052)	(7,169,555)	-19.6%
316.00 Miscellaneous Power Plant Equipment	33,039,381	750,070	32,289,311	-20.1%	-20.3%	(150,764)	(6,554,730)	(6,705,494)	-20.3%
Total Four Corners Units 4-5	$ 787,657,923	$ 55,118,623	$ 732,539,300	-2.4%	-20.5%	$ (1,343,680)	$ (150,006,531)	$ (151,350,211)	-19.2%
Four Corners Common									
311.00 Structures and Improvements	$ 61,911,456	$ 45,852,190	$ 16,059,266	-0.3%	-11.2%	$ (137,557)	$ (1,798,638)	$ (1,936,194)	-3.1%
312.00 Boiler Plant Equipment	39,739,653	4,251,882	35,487,771	-18.9%	-12.1%	(803,606)	(4,294,020)	(5,097,626)	-12.8%
314.00 Turbogenerator Units	4,561,002	1,125,249	3,435,753	0.1%	-11.8%	1,125	(405,419)	(404,294)	-8.9%
315.00 Accessory Electric Equipment	16,200,026	3,948,093	12,251,933	-1.0%	-11.5%	(39,481)	(1,408,972)	(1,448,453)	-8.9%
316.00 Miscellaneous Power Plant Equipment	14,039,861	1,373,916	12,665,945	-4.1%	-11.8%	(56,331)	(1,494,582)	(1,550,912)	-11.0%
Total Four Corners Common	$ 136,451,998	$ 56,551,330	$ 79,900,668	-1.8%	-11.8%	$ (1,035,849)	$ (9,401,631)	$ (10,437,479)	-7.6%
Navajo Units 1-3									
311.00 Structures and Improvements	$ 33,459,466	$ 609,700	$ 32,849,766		-5.4%	$ -	$ (1,773,887)	$ (1,773,887)	-5.3%
312.00 Boiler Plant Equipment	179,914,220	8,560,058	171,354,162	0.8%	-5.8%	68,480	(9,938,541)	(9,870,061)	-5.5%
314.00 Turbogenerator Units	25,430,842	224,249	25,206,593	8.7%	-5.7%	19,510	(1,436,776)	(1,417,266)	-5.6%
315.00 Accessory Electric Equipment	22,640,841	279,373	22,361,468	-4.3%	-5.5%	(12,013)	(1,229,881)	(1,241,894)	-5.5%
316.00 Miscellaneous Power Plant Equipment	20,305,257	1,101,704	19,203,553	-31.9%	-5.7%	(351,444)	(1,094,603)	(1,446,046)	-7.1%
Total Navajo Units 1-3	$ 281,750,626	$ 10,775,084	$ 270,975,542	-2.6%	-5.7%	$ (275,466)	$ (15,473,688)	$ (15,749,154)	-5.6%
Ocotillo Units 1-2									
311.00 Structures and Improvements	$ 5,137,592	$ 333,074	$ 4,804,518	-3.1%	-21.9%	$ (10,325)	$ (1,052,189)	$ (1,062,515)	-20.7%
312.00 Boiler Plant Equipment	25,522,581	303,563	25,219,018	-61.1%	-22.0%	(185,477)	(5,548,184)	(5,733,661)	-22.5%
314.00 Turbogenerator Units	18,365,088	1,218,104	17,146,984	-53.6%	-22.0%	(652,904)	(3,772,336)	(4,425,240)	-24.1%
315.00 Accessory Electric Equipment	5,294,829	399,922	4,894,907	-17.5%	-21.9%	(69,986)	(1,071,985)	(1,141,971)	-21.6%
316.00 Miscellaneous Power Plant Equipment	8,612,331	1,549,501	7,062,830	-8.9%	-22.0%	(137,906)	(1,553,823)	(1,691,728)	-19.6%
Total Ocotillo Units 1-2	$ 62,932,421	$ 3,804,164	$ 59,128,257	-27.8%	-22.0%	$ (1,056,598)	$ (12,998,517)	$ (14,055,115)	-22.3%
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$ 854,841,305	$ 54,537,345	$ 800,303,960	-5.5%	-0.4%	$ (3,000,919)	$ (3,201,216)	$ (6,202,135)	-0.7%
322.00 Reactor Plant Equipment	1,269,378,514	91,937,617	1,177,440,897	-18.8%	-1.2%	(17,283,546)	(13,664,496)	(30,948,042)	-2.4%
323.00 Turbogenerator Units	457,177,633	78,275,019	378,902,614	-4.1%	-0.4%	(3,195,211)	(1,515,610)	(4,710,822)	-1.0%
324.00 Accessory Electric Equipment	299,692,423	12,750,927	286,941,496	-5.2%	-0.4%	(661,807)	(1,147,766)	(1,809,573)	-0.6%
325.00 Miscellaneous Power Plant Equipment	237,940,621	47,075,587	190,865,034	-5.1%	-0.4%	(2,398,441)	(763,460)	(3,161,902)	-1.3%
Total Palo Verde	$ 3,119,030,496	$ 284,576,495	$ 2,834,454,001	-9.3%	-0.7%	$ (26,539,925)	$ (20,292,548)	$ (46,832,473)	-1.5%

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
Palo Verde Unit 1									
321.00 Structures and Improvements	$ 162,664,558	$ 2,425,636	$ 160,238,922	-10.3%	-0.4%	$ (249,841)	$ (640,956)	$ (890,796)	-0.5%
322.00 Reactor Plant Equipment	491,095,224	26,300,429	464,794,795	-5.4%	-1.1%	(1,420,223)	(5,112,743)	(6,532,966)	-1.3%
323.00 Turbogenerator Units	158,213,098	24,577,243	133,635,855	-6.9%	-0.4%	(1,695,830)	(534,543)	(2,230,373)	-1.4%
324.00 Accessory Electric Equipment	120,671,318	2,747,125	117,924,193	-6.6%	-0.4%	(181,310)	(471,697)	(653,007)	-0.5%
325.00 Miscellaneous Power Plant Equipment	35,707,572	4,464,570	31,243,002	-7.7%	-0.4%	(343,772)	(124,972)	(468,744)	-1.3%
Total Palo Verde Unit 1	$ 968,351,770	$ 60,515,003	$ 907,836,767	-6.4%	-0.8%	$ (3,890,976)	$ (6,884,911)	$ (10,775,886)	-1.1%
Palo Verde Unit 2									
321.00 Structures and Improvements	$ 93,176,852	$ 1,121,116	$ 92,055,736	-0.4%	-0.4%	$ (4,484)	$ (368,223)	$ (372,707)	-0.4%
322.00 Reactor Plant Equipment	283,088,730	33,786,245	249,302,485	-10.4%	-1.2%	(3,513,769)	(2,991,630)	(6,505,399)	-2.3%
323.00 Turbogenerator Units	106,820,862	18,821,590	87,999,272	-4.2%	-0.4%	(790,507)	(351,997)	(1,142,504)	-1.1%
324.00 Accessory Electric Equipment	53,300,916	5,308,025	47,992,891	-2.5%	-0.4%	(132,701)	(191,972)	(324,672)	-0.6%
325.00 Miscellaneous Power Plant Equipment	29,620,315	2,334,553	27,285,762	-9.7%	-0.4%	(226,452)	(109,143)	(335,595)	-1.1%
Total Palo Verde Unit 2	$ 566,007,675	$ 61,371,529	$ 504,636,146	-7.6%	-0.8%	$ (4,667,913)	$ (4,012,964)	$ (8,680,877)	-1.5%
Palo Verde Unit 3									
321.00 Structures and Improvements	$ 167,714,544	$ 2,495,851	$ 165,218,693	-0.3%	-0.4%	$ (7,488)	$ (660,875)	$ (668,362)	-0.4%
322.00 Reactor Plant Equipment	456,481,070	29,288,058	427,193,012	-30.3%	-1.2%	(8,874,282)	(5,126,316)	(14,000,598)	-3.1%
323.00 Turbogenerator Units	186,266,847	33,708,550	152,558,297	-1.4%	-0.4%	(471,920)	(610,233)	(1,082,153)	-0.6%
324.00 Accessory Electric Equipment	97,321,459	3,003,876	94,317,583	-9.1%	-0.4%	(273,353)	(377,270)	(650,623)	-0.7%
325.00 Miscellaneous Power Plant Equipment	32,611,052	3,645,510	28,965,542	-9.0%	-0.4%	(328,096)	(115,862)	(443,958)	-1.4%
Total Palo Verde Unit 3	$ 940,394,972	$ 72,141,845	$ 868,253,127	-13.8%	-0.8%	$ (9,955,137)	$ (6,890,557)	$ (16,845,694)	-1.8%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$ 247,179,381	$ 36,934,977	$ 210,244,404	-5.1%	-0.4%	$ (1,883,684)	$ (840,978)	$ (2,724,661)	-1.1%
322.00 Reactor Plant Equipment	561,290		561,290		-1.2%		(6,735)	(6,735)	-1.2%
323.00 Turbogenerator Units	246,532	28,776	217,756	-51.7%	-0.4%	(14,877)	(871)	(15,748)	-6.4%
324.00 Accessory Electric Equipment									
325.00 Miscellaneous Power Plant Equipment	207,832	42,613	165,219		-0.4%		(661)	(661)	-0.3%
Total Palo Verde Water Reclamation	$ 248,195,035	$ 37,006,366	$ 211,188,669	-5.1%	-0.4%	$ (1,898,561)	$ (849,245)	$ (2,747,806)	-1.1%
Palo Verde Common									
321.00 Structures and Improvements	$ 184,105,970	$ 11,559,765	$ 172,546,205	-7.4%	-0.4%	$ (855,423)	$ (690,185)	$ (1,545,607)	-0.8%
322.00 Reactor Plant Equipment	38,152,200	2,562,885	35,589,315	-135.6%	-1.2%	(3,475,272)	(427,072)	(3,902,344)	-10.2%
323.00 Turbogenerator Units	5,630,294	1,138,860	4,491,434	-19.5%	-0.4%	(222,078)	(17,966)	(240,043)	-4.3%
324.00 Accessory Electric Equipment	28,398,730	1,691,901	26,706,829	-4.4%	-0.4%	(74,444)	(106,827)	(181,271)	-0.6%
325.00 Miscellaneous Power Plant Equipment	139,793,850	36,588,341	103,205,509	-4.1%	-0.4%	(1,500,122)	(412,822)	(1,912,944)	-1.4%
Total Palo Verde Common	$ 396,081,044	$ 53,541,752	$ 342,539,292	-11.4%	-0.5%	$ (6,127,338)	$ (1,654,872)	$ (7,782,210)	-2.0%
OTHER PRODUCTION (by Unit)									
Douglas CT									
341.00 Structures and Improvements	$ 103,952	$ -	$ 103,952		-5.0%	$ -	$ (5,198)	$ (5,198)	-5.0%
342.00 Fuel Holders, Products and Accessories	160,633	22,874	137,759	-14.8%	-5.0%	(3,385)	(6,888)	(10,273)	-6.4%
343.00 Prime Movers	4,379,356	657,787	3,721,569	-308.8%	-5.0%	(2,031,246)	(186,078)	(2,217,325)	-50.6%
344.00 Generators and Devices	971,924		971,924		-5.0%		(48,596)	(48,596)	-5.0%
345.00 Accessory Electric Equipment	427,632	23,867	403,765	-21.2%	-5.0%	(5,060)	(20,188)	(25,248)	-5.9%
346.00 Miscellaneous Power Plant Equipment	40,913	7,349	33,564		-5.0%		(1,678)	(1,678)	-4.1%
Total Douglas CT	$ 6,084,410	$ 711,877	$ 5,372,533	-286.5%	-5.0%	$ (2,039,691)	$ (268,627)	$ (2,308,318)	-37.9%

umbrella.

MR. WETHERALD: Specifically?

THE WITNESS: LiveWireNet, PCMG, as well as -- I want to make sure I don't miss any here.

MS. SCOTT: The Phone Company of Arizona?

THE WITNESS: Phone Company of Arizona obviously as well.

MR. WETHERALD: LLP or joint venture?

THE WITNESS: Not the LLP but the joint venture.

MS. SCOTT: Okay. Your Honor, the witness is available for cross.

ALJ DION: Mr. Wetherald?

CROSS-EXAMINATION

BY MR. WETHERALD:

Q. Mr. Lebrecht, since we started out with the February 24th procedural order, we will actually, we might end up jumping around your testimony just a little bit. First let me ask you a question.

I looked at some of your educational background in your testimony. You have a degree in, I think it was, geology?

A. Geography.

Q. Geography, maps and stuff like that?

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
Solar Units									
341.00 Structures and Improvements	$ 32,602,452	$ 92,432	$ 32,510,020		-7.9%	$ -	$ (2,572,865)	$ (2,572,865)	-7.9%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	599,365,775	11,529,210	587,836,565	-1.8%	-7.7%	(207,526)	(45,243,899)	(45,451,425)	-7.6%
345.00 Accessory Electric Equipment	105,899,679	754,159	105,145,520	-6.1%	-7.3%	(46,004)	(7,623,559)	(7,669,563)	-7.2%
346.00 Miscellaneous Power Plant Equipment	1,557,654		1,557,654		-8.9%		(138,292)	(138,292)	-8.9%
Total Solar Units	$ 739,425,560	$ 12,375,801	$ 727,049,759	-2.0%	-7.6%	$ (253,529)	$ (55,578,615)	$ (55,832,145)	-7.6%
Chino Valley									
341.05 Structures and Improvements	$ 527,889	$ -	$ 527,889		-7.4%	$ -	$ (39,064)	$ (39,064)	-7.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	77,719,075		77,719,075		-7.4%		(5,751,212)	(5,751,212)	-7.4%
345.05 Accessory Electric Equipment	6,511,775		6,511,775		-7.4%		(481,871)	(481,871)	-7.4%
346.05 Miscellaneous Power Plant Equipment	216,504		216,504		-7.4%		(16,021)	(16,021)	-7.4%
Total Chino Valley	$ 84,975,243	$ -	$ 84,975,243		-7.4%	$ -	$ (6,288,168)	$ (6,288,168)	-7.4%
Cotton Center									
341.05 Structures and Improvements	$ 1,813,500	$ -	$ 1,813,500		-6.6%	$ -	$ (119,691)	$ (119,691)	-6.6%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	61,593,054		61,593,054		-6.6%		(4,065,142)	(4,065,142)	-6.6%
345.05 Accessory Electric Equipment	15,418,050		15,418,050		-6.6%		(1,017,591)	(1,017,591)	-6.6%
346.05 Miscellaneous Power Plant Equipment	262,641		262,641		-6.6%		(17,334)	(17,334)	-6.6%
Total Cotton Center	$ 79,087,245	$ -	$ 79,087,245		-6.6%	$ -	$ (5,219,758)	$ (5,219,758)	-6.6%
Desert Star									
341.05 Structures and Improvements	$ 1,572,235	$ -	$ 1,572,235		-11.5%	$ -	$ (180,807)	$ (180,807)	-11.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	25,365,040		25,365,040		-11.5%		(2,916,980)	(2,916,980)	-11.5%
345.05 Accessory Electric Equipment	3,579,659		3,579,659		-11.5%		(411,661)	(411,661)	-11.5%
346.05 Miscellaneous Power Plant Equipment	293,963		293,963		-11.5%		(33,806)	(33,806)	-11.5%
Total Desert Star	$ 30,810,897	$ -	$ 30,810,897		-11.5%	$ -	$ (3,543,253)	$ (3,543,253)	-11.5%
Foothills Units 1-2									
341.05 Structures and Improvements	$ 10,906,684	$ -	$ 10,906,684		-8.6%	$ -	$ (937,975)	$ (937,975)	-8.6%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	105,443,248		105,443,248		-8.6%		(9,068,119)	(9,068,119)	-8.6%
345.05 Accessory Electric Equipment	20,815,540		20,815,540		-8.6%		(1,790,136)	(1,790,136)	-8.6%
346.05 Miscellaneous Power Plant Equipment	57,708		57,708		-8.6%		(4,963)	(4,963)	-8.6%
Total Foothills Units 1-2	$ 137,223,180	$ -	$ 137,223,180		-8.6%	$ -	$ (11,801,193)	$ (11,801,193)	-8.6%

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
Gila Bend									
341.05 Structures and Improvements	$ 5,018,097	$ -	$ 5,018,097		-10.3%	$ -	$ (516,864)	$ (516,864)	-10.3%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	89,246,612		89,246,612		-10.3%		(9,192,401)	(9,192,401)	-10.3%
345.05 Accessory Electric Equipment	11,096,944		11,096,944		-10.3%		(1,142,985)	(1,142,985)	-10.3%
346.05 Miscellaneous Power Plant Equipment	21,142		21,142		-10.3%		(2,178)	(2,178)	-10.3%
Total Gila Bend	$ 105,382,795	$ -	$ 105,382,795		-10.3%	$ -	$ (10,854,428)	$ (10,854,428)	-10.3%
Hyder Units 1-2									
341.05 Structures and Improvements	$ 6,915,232	$ -	$ 6,915,232		-4.4%	$ -	$ (304,270)	$ (304,270)	-4.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	93,250,197		93,250,197		-4.4%		(4,103,009)	(4,103,009)	-4.4%
345.05 Accessory Electric Equipment	22,556,482		22,556,482		-4.4%		(992,485)	(992,485)	-4.4%
346.05 Miscellaneous Power Plant Equipment	206,389		206,389		-4.4%		(9,081)	(9,081)	-4.4%
Total Hyder Units 1-2	$ 122,928,300	$ -	$ 122,928,300		-4.4%	$ -	$ (5,408,845)	$ (5,408,845)	-4.4%
Legacy Units									
341.00 Structures and Improvements	$ 418,403	$ 92,432	$ 325,971		-5.0%	$ -	$ (16,299)	$ (16,299)	-3.9%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	21,642,859	11,529,210	10,113,649	-1.8%	-5.0%	(207,526)	(505,682)	(713,208)	-3.3%
345.00 Accessory Electric Equipment	4,361,139	754,159	3,606,980	-6.1%	-5.0%	(46,004)	(180,349)	(226,353)	-5.2%
346.00 Miscellaneous Power Plant Equipment									
Total Legacy Units	$ 26,422,401	$ 12,375,801	$ 14,046,600	-2.0%	-5.0%	$ (253,529)	$ (702,330)	$ (955,859)	-3.6%
Luke AFB									
341.05 Structures and Improvements	$ 1,566,281	$ -	$ 1,566,281		-11.8%	$ -	$ (184,821)	$ (184,821)	-11.8%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	24,574,551		24,574,551		-11.8%		(2,899,797)	(2,899,797)	-11.8%
345.05 Accessory Electric Equipment	1,330,175		1,330,175		-11.8%		(156,961)	(156,961)	-11.8%
346.05 Miscellaneous Power Plant Equipment	377,821		377,821		-11.8%		(44,583)	(44,583)	-11.8%
Total Luke AFB	$ 27,848,828	$ -	$ 27,848,828		-11.8%	$ -	$ (3,286,162)	$ (3,286,162)	-11.8%
Roof Tops									
341.05 Structures and Improvements	$ 1,582,181	$ -	$ 1,582,181		-5.0%	$ -	$ (79,109)	$ (79,109)	-5.0%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	51,531,113		51,531,113		-5.0%		(2,576,556)	(2,576,556)	-5.0%
345.05 Accessory Electric Equipment	7,714,968		7,714,968		-5.0%		(385,748)	(385,748)	-5.0%
346.05 Miscellaneous Power Plant Equipment									
Total Roof Tops	$ 60,828,262	$ -	$ 60,828,262		-5.0%	$ -	$ (3,041,413)	$ (3,041,413)	-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
Paloma									
341.05 Structures and Improvements	$ 2,281,950	$ -	$ 2,281,950		-8.5%	$ -	$ (193,966)	$ (193,966)	-8.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	49,000,026		49,000,026		-8.5%		(4,165,002)	(4,165,002)	-8.5%
345.05 Accessory Electric Equipment	12,514,947		12,514,947		-8.5%		(1,063,770)	(1,063,770)	-8.5%
346.05 Miscellaneous Power Plant Equipment	121,486		121,486		-8.5%		(10,326)	(10,326)	-8.5%
Total Paloma	$ 63,918,409	$ -	$ 63,918,409		-8.5%	$ -	$ (5,433,065)	$ (5,433,065)	-8.5%
Sundance									
341.00 Structures and Improvements	$ 13,998,311	$ 661,750	$ 13,336,561	-43.6%	-5.0%	$ (288,523)	$ (666,828)	$ (955,351)	-6.8%
342.00 Fuel Holders, Products and Accessories	4,629,010		4,629,010		-5.0%		(231,451)	(231,451)	-5.0%
343.00 Prime Movers	235,370,995	2,691,796	232,679,199	-8.8%	-5.0%	(236,878)	(11,633,960)	(11,870,838)	-5.0%
344.00 Generators and Devices	11,911,778	147,362	11,764,416	-1.6%	-5.0%	(2,358)	(588,221)	(590,579)	-5.0%
345.00 Accessory Electric Equipment	27,995,138	390,894	27,604,244	-18.5%	-5.0%	(72,315)	(1,380,212)	(1,452,528)	-5.2%
346.00 Miscellaneous Power Plant Equipment	2,565,605		2,565,605		-5.0%		(128,280)	(128,280)	-5.0%
Total Sun Dance	$ 296,470,837	$ 3,891,802	$ 292,579,035	-15.4%	-5.0%	$ (600,074)	$ (14,628,952)	$ (15,229,026)	-5.1%
West Phoenix									
341.00 Structures and Improvements	$ 35,673,137	$ 1,419,738	$ 34,253,399	-38.8%	-5.0%	$ (551,161)	$ (1,712,670)	$ (2,263,831)	-6.3%
342.00 Fuel Holders, Products and Accessories	33,236,114	2,573,481	30,662,633	-6.9%	-5.0%	(177,570)	(1,533,132)	(1,710,702)	-5.1%
343.00 Prime Movers	202,668,326	37,644,394	165,023,932	-3.9%	-5.0%	(1,471,085)	(8,251,197)	(9,722,281)	-4.8%
344.00 Generators and Devices	357,196,856	56,407,306	300,789,550	35.9%	-5.0%	20,276,121	(15,039,478)	5,236,643	1.5%
345.00 Accessory Electric Equipment	44,821,008	4,312,330	40,508,678	-18.7%	-5.0%	(804,671)	(2,025,434)	(2,830,105)	-6.3%
346.00 Miscellaneous Power Plant Equipment	14,241,613	1,615,586	12,626,027	-7.1%	-5.0%	(114,356)	(631,301)	(745,658)	-5.2%
Total West Phoenix	$ 687,837,054	$ 103,972,835	$ 583,864,219	16.5%	-5.0%	$ 17,157,278	$ (29,193,211)	$ (12,035,933)	-1.7%
West Phoenix CC Units 1-3									
341.00 Structures and Improvements	$ 1,030,150	$ 66,184	$ 963,966	-3.2%	-5.0%	$ (2,118)	$ (48,198)	$ (50,316)	-4.9%
342.00 Fuel Holders, Products and Accessories	27,241,428	2,573,481	24,667,947	-6.9%	-5.0%	(177,570)	(1,233,397)	(1,410,968)	-5.2%
343.00 Prime Movers									
344.00 Generators and Devices	127,695,692	24,567,750	103,127,942	3.2%	-5.0%	786,168	(5,156,397)	(4,370,229)	-3.4%
345.00 Accessory Electric Equipment	28,967,424	3,823,094	25,144,330	-19.2%	-5.0%	(734,034)	(1,257,217)	(1,991,251)	-6.9%
346.00 Miscellaneous Power Plant Equipment	7,967,377	1,431,107	6,536,270	-3.7%	-5.0%	(52,951)	(326,814)	(379,764)	-4.8%
Total West Phoenix CC Units 1-3	$ 192,902,071	$ 32,461,616	$ 160,440,455	-0.6%	-5.0%	$ (180,505)	$ (8,022,023)	$ (8,202,528)	-4.3%
West Phoenix CC Unit 4									
341.00 Structures and Improvements	$ 4,706,771	$ 23,591	$ 4,683,180	-21.5%	-5.0%	$ (5,072)	$ (234,159)	$ (239,231)	-5.1%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	54,739,557	5,275,547	49,464,010	53.4%	-5.0%	2,817,142	(2,473,201)	343,942	0.6%
344.00 Generators and Devices	24,834,177	1,180,319	23,653,858	-0.4%	-5.0%	(4,721)	(1,182,693)	(1,187,414)	-4.8%
345.00 Accessory Electric Equipment	453,669		453,669		-5.0%		(22,683)	(22,683)	-5.0%
346.00 Miscellaneous Power Plant Equipment	727,934	18,529	709,405		-5.0%		(35,470)	(35,470)	-4.9%
Total West Phoenix CC Unit 4	$ 89,597,217	$ 6,497,986	$ 83,099,231	43.2%	-5.0%	$ 2,807,349	$ (4,154,962)	$ (1,347,613)	-1.5%

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
West Phoenix CC Unit 5									
341.00 Structures and Improvements	$ 12,195,324	$ 259,653	$ 11,935,671	-16.8%	-5.0%	$ (43,622)	$ (596,784)	$ (640,405)	-5.3%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	122,437,292	29,490,530	92,946,762	-9.7%	-5.0%	(2,860,581)	(4,647,338)	(7,507,920)	-6.1%
344.00 Generators and Devices	193,421,211	30,212,183	163,209,028	65.1%	-5.0%	19,668,131	(8,160,451)	11,507,680	5.9%
345.00 Accessory Electric Equipment	13,496,645	358,055	13,138,590	-17.2%	-5.0%	(61,585)	(656,930)	(718,515)	-5.3%
346.00 Miscellaneous Power Plant Equipment	4,354,226	347	4,353,879	-5621.8%	-5.0%	(19,508)	(217,694)	(237,202)	-5.4%
Total West Phoenix CC Unit 5	$ 345,904,698	$ 60,320,768	$ 285,583,930	27.7%	-5.0%	$ 16,682,835	$ (14,279,197)	$ 2,403,638	0.7%
West Phoenix CT Units 1-2									
341.00 Structures and Improvements	$ 4,185,965	$ 144,969	$ 4,040,996	-82.8%	-5.0%	$ (120,034)	$ (202,050)	$ (322,084)	-7.7%
342.00 Fuel Holders, Products and Accessories	1,859,577		1,859,577		-5.0%		(92,979)	(92,979)	-5.0%
343.00 Prime Movers	25,491,477	2,878,317	22,613,160	-49.6%	-5.0%	(1,427,645)	(1,130,658)	(2,558,303)	-10.0%
344.00 Generators and Devices	11,245,776	447,054	10,798,722	-38.8%	-5.0%	(173,457)	(539,936)	(713,393)	-6.3%
345.00 Accessory Electric Equipment	1,903,270	131,181	1,772,089	-6.9%	-5.0%	(9,051)	(88,604)	(97,656)	-5.1%
346.00 Miscellaneous Power Plant Equipment	1,192,076	165,603	1,026,473	-25.3%	-5.0%	(41,898)	(51,324)	(93,221)	-7.8%
Total West Phoenix CT Units 1-2	$ 45,878,141	$ 3,767,124	$ 42,111,017	-47.0%	-5.0%	$ (1,772,086)	$ (2,105,551)	$ (3,877,636)	-8.5%
West Phoenix Common									
341.00 Structures and Improvements	$ 13,554,927	$ 925,341	$ 12,629,586	-41.1%	-5.0%	$ (380,315)	$ (631,479)	$ (1,011,794)	-7.5%
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	$ 13,554,927	$ 925,341	$ 12,629,586	-41.1%	-5.0%	$ (380,315)	$ (631,479)	$ (1,011,794)	-7.5%
Yucca									
341.00 Structures and Improvements	$ 6,386,403	$ 130,684	$ 6,255,719	-48.3%	-5.0%	$ (63,120)	$ (312,786)	$ (375,906)	-5.9%
342.00 Fuel Holders, Products and Accessories	5,481,557	51,470	5,430,087	-17.4%	-5.0%	(8,974)	(271,504)	(280,479)	-5.1%
343.00 Prime Movers	79,372,997	596,117	78,776,880	-158.8%	-5.0%	(946,501)	(3,938,844)	(4,885,345)	-6.2%
344.00 Generators and Devices	10,689,323	517,473	10,171,850	-25.1%	-5.0%	(129,886)	(508,593)	(638,478)	-6.0%
345.00 Accessory Electric Equipment	4,855,252	300,570	4,554,682	-51.8%	-5.0%	(155,814)	(227,734)	(383,548)	-7.9%
346.00 Miscellaneous Power Plant Equipment	2,141,552		2,141,552		-5.0%		(107,078)	(107,078)	-5.0%
Total Yucca	$ 108,927,084	$ 1,596,314	$ 107,330,770	-81.7%	-5.0%	$ (1,304,296)	$ (5,366,539)	$ (6,670,835)	-6.1%
Yucca CT Units 1-4									
341.00 Structures and Improvements	$ 5,315,974	$ 130,684	$ 5,185,290	-48.3%	-5.0%	$ (63,120)	$ (259,265)	$ (322,385)	-6.1%
342.00 Fuel Holders, Products and Accessories	3,977,780	42,920	3,934,860	-18.2%	-5.0%	(7,811)	(196,743)	(204,554)	-5.1%
343.00 Prime Movers	11,624,121	546,976	11,077,145	-172.8%	-5.0%	(945,175)	(553,857)	(1,499,032)	-12.9%
344.00 Generators and Devices	10,576,125	517,473	10,058,652	-25.1%	-5.0%	(129,886)	(502,933)	(632,818)	-6.0%
345.00 Accessory Electric Equipment	3,890,494	153,425	3,737,069	-86.5%	-5.0%	(132,713)	(186,853)	(319,566)	-8.2%
346.00 Miscellaneous Power Plant Equipment	1,328,508		1,328,508		-5.0%		(66,425)	(66,425)	-5.0%
Total Yucca CT Units 1-4	$ 36,713,002	$ 1,391,478	$ 35,321,524	-91.9%	-5.0%	$ (1,278,705)	$ (1,766,076)	$ (3,044,781)	-8.3%

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
Yucca CT Units 5-6									
341.00 Structures and Improvements	$ 1,070,429	$ -	$ 1,070,429		-5.0%	$ -	$ (53,521)	$ (53,521)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,503,777	8,550	1,495,227	-13.6%	-5.0%	(1,163)	(74,761)	(75,924)	-5.0%
343.00 Prime Movers	67,748,876	49,141	67,699,735	-2.7%	-5.0%	(1,327)	(3,384,987)	(3,386,314)	-5.0%
344.00 Generators and Devices	113,198		113,198		-5.0%		(5,660)	(5,660)	-5.0%
345.00 Accessory Electric Equipment	964,758	147,145	817,613	-15.7%	-5.0%	(23,102)	(40,881)	(63,982)	-6.6%
346.00 Miscellaneous Power Plant Equipment	813,044		813,044		-5.0%		(40,652)	(40,652)	-5.0%
Total Yucca CT Units 5-6	$ 72,214,082	$ 204,836	$ 72,009,246	-12.5%	-5.0%	$ (25,591)	$ (3,600,462)	$ (3,626,054)	-5.0%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/15 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	$ 77,737,991	$ 1,837,861	$ 75,900,130	-5.0%	-7.4%	$ (91,893)	$ (5,639,072)	$ (5,730,965)	-7.4%
312.00 Boiler Plant Equipment	378,495,272	8,848,775	369,646,497	-20.0%	-7.4%	(1,769,755)	(27,414,984)	(29,184,739)	-7.7%
314.00 Turbogenerator Units	86,113,816	2,020,168	84,093,648	-15.0%	-7.5%	(303,025)	(6,320,929)	(6,623,954)	-7.7%
315.00 Accessory Electric Equipment	52,313,534	1,261,278	51,052,256	-10.0%	-7.4%	(126,128)	(3,763,290)	(3,889,417)	-7.4%
316.00 Miscellaneous Power Plant Equipment	23,835,993	556,996	23,278,997	-15.0%	-7.5%	(83,549)	(1,734,433)	(1,817,982)	-7.6%
Total Cholla	$ 618,496,606	$ 14,525,078	$ 603,971,528	-16.3%	-7.4%	$ (2,374,351)	$ (44,872,707)	$ (47,247,057)	-7.6%
Cholla Unit 1									
311.00 Structures and Improvements	$ 4,743,207	$ 113,585	$ 4,629,622	-5.0%	-8.5%	$ (5,679)	$ (391,946)	$ (397,625)	-8.4%
312.00 Boiler Plant Equipment	80,244,501	1,879,808	78,364,693	-20.0%	-8.5%	(375,962)	(6,634,392)	(7,010,354)	-8.7%
314.00 Turbogenerator Units	27,503,716	641,686	26,862,030	-15.0%	-8.5%	(96,253)	(2,274,152)	(2,370,405)	-8.6%
315.00 Accessory Electric Equipment	9,492,908	226,618	9,266,290	-10.0%	-8.5%	(22,662)	(784,489)	(807,150)	-8.5%
316.00 Miscellaneous Power Plant Equipment	2,926,476	69,502	2,856,974	-15.0%	-8.5%	(10,425)	(241,873)	(252,298)	-8.6%
Total Cholla Unit 1	$ 124,910,808	$ 2,931,200	$ 121,979,608	-17.4%	-8.5%	$ (510,981)	$ (10,326,852)	$ (10,837,833)	-8.7%
Cholla Unit 3									
311.00 Structures and Improvements	$ 13,288,725	$ 315,920	$ 12,972,805	-5.0%	-7.1%	$ (15,796)	$ (915,836)	$ (931,632)	-7.0%
312.00 Boiler Plant Equipment	238,165,292	5,562,910	232,602,382	-20.0%	-7.1%	(1,112,582)	(16,420,941)	(17,533,523)	-7.4%
314.00 Turbogenerator Units	56,834,120	1,337,260	55,496,860	-15.0%	-7.1%	(200,589)	(3,917,891)	(4,118,480)	-7.2%
315.00 Accessory Electric Equipment	34,832,937	846,289	33,986,648	-10.0%	-7.1%	(84,629)	(2,399,342)	(2,483,971)	-7.1%
316.00 Miscellaneous Power Plant Equipment	6,842,283	161,333	6,680,950	-15.0%	-7.1%	(24,200)	(471,652)	(495,852)	-7.2%
Total Cholla Unit 3	$ 349,963,357	$ 8,223,712	$ 341,739,645	-17.5%	-7.1%	$ (1,437,796)	$ (24,125,663)	$ (25,563,459)	-7.3%
Cholla Common									
311.00 Structures and Improvements	$ 59,706,059	$ 1,408,356	$ 58,297,703	-5.0%	-7.4%	$ (70,418)	$ (4,331,290)	$ (4,401,708)	-7.4%
312.00 Boiler Plant Equipment	60,085,479	1,406,057	58,679,422	-20.0%	-7.4%	(281,211)	(4,359,650)	(4,640,861)	-7.7%
314.00 Turbogenerator Units	1,775,980	41,222	1,734,758	-15.0%	-7.4%	(6,183)	(128,886)	(135,069)	-7.6%
315.00 Accessory Electric Equipment	7,987,689	188,371	7,799,318	-10.0%	-7.4%	(18,837)	(579,459)	(598,296)	-7.5%
316.00 Miscellaneous Power Plant Equipment	14,067,234	326,160	13,741,074	-15.0%	-7.4%	(48,924)	(1,020,908)	(1,069,832)	-7.6%
Total Cholla Common	$ 143,622,441	$ 3,370,166	$ 140,252,275	-12.6%	-7.4%	$ (425,574)	$ (10,420,192)	$ (10,845,766)	-7.6%
Four Corners									
311.00 Structures and Improvements	$ 54,567,232	$ 3,158,404	$ 51,408,828	-5.0%	-17.9%	$ (157,920)	$ (9,221,942)	$ (9,379,862)	-17.2%
312.00 Boiler Plant Equipment	581,513,168	34,140,201	547,372,967	-20.0%	-20.0%	(6,828,040)	(109,736,745)	(116,564,785)	-20.0%
314.00 Turbogenerator Units	83,827,121	4,936,522	78,890,599	-15.0%	-20.2%	(740,478)	(15,959,640)	(16,700,119)	-19.9%
315.00 Accessory Electric Equipment	47,577,191	2,737,069	44,840,122	-10.0%	-18.3%	(273,707)	(8,193,347)	(8,467,054)	-17.8%
316.00 Miscellaneous Power Plant Equipment	44,955,256	2,586,711	42,368,545	-15.0%	-18.1%	(388,007)	(7,650,132)	(8,038,138)	-17.9%
Total Four Corners	$ 812,439,968	$ 47,558,907	$ 764,881,061	-17.6%	-19.7%	$ (8,388,152)	$ (150,761,805)	$ (159,149,958)	-19.6%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/15 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 Units 4-5									
311.00 Structures and Improvements	$ 38,507,966	$ 2,252,541	$ 36,255,425	-5.0%	-20.6%	$ (112,627)	$ (7,468,538)	$ (7,581,165)	-19.7%
312.00 Boiler Plant Equipment	546,025,397	32,110,875	513,914,522	-20.0%	-20.6%	(6,422,175)	(105,865,259)	(112,287,434)	-20.6%
314.00 Turbogenerator Units	80,391,368	4,730,995	75,660,373	-15.0%	-20.6%	(709,649)	(15,585,870)	(16,295,519)	-20.3%
315.00 Accessory Electric Equipment	35,325,258	2,043,982	33,281,276	-10.0%	-20.6%	(204,398)	(6,855,869)	(7,060,268)	-20.0%
316.00 Miscellaneous Power Plant Equipment	32,289,311	1,857,023	30,432,288	-15.0%	-20.6%	(278,553)	(6,268,984)	(6,547,538)	-20.3%
Total Four Corners Units 4-5	$ 732,539,300	$ 42,995,416	$ 689,543,884	-18.0%	-20.6%	$ (7,727,403)	$ (142,044,521)	$ (149,771,924)	-20.4%
Four Corners Common									
311.00 Structures and Improvements	$ 16,059,266	$ 905,862	$ 15,153,404	-5.0%	-11.6%	$ (45,293)	$ (1,753,404)	$ (1,798,697)	-11.2%
312.00 Boiler Plant Equipment	35,487,771	2,029,326	33,458,445	-20.0%	-11.6%	(405,865)	(3,871,486)	(4,277,351)	-12.1%
314.00 Turbogenerator Units	3,435,753	205,527	3,230,226	-15.0%	-11.6%	(30,829)	(373,770)	(404,599)	-11.8%
315.00 Accessory Electric Equipment	12,251,933	693,087	11,558,846	-10.0%	-11.6%	(69,309)	(1,337,477)	(1,406,786)	-11.5%
316.00 Miscellaneous Power Plant Equipment	12,665,945	729,689	11,936,256	-15.0%	-11.6%	(109,453)	(1,381,147)	(1,490,601)	-11.8%
Total Four Corners Common	$ 79,900,668	$ 4,563,491	$ 75,337,177	-14.5%	-11.6%	$ (660,749)	$ (8,717,285)	$ (9,378,034)	-11.7%
Navajo Units 1-3									
311.00 Structures and Improvements	$ 32,849,766	$ 872,401	$ 31,977,365	-5.0%	-5.4%	$ (43,620)	$ (1,727,131)	$ (1,770,751)	-5.4%
312.00 Boiler Plant Equipment	171,354,162	4,567,014	166,787,148	-20.0%	-5.4%	(913,403)	(9,008,351)	(9,921,753)	-5.8%
314.00 Turbogenerator Units	25,206,593	688,309	24,518,284	-15.0%	-5.4%	(103,246)	(1,324,258)	(1,427,505)	-5.7%
315.00 Accessory Electric Equipment	22,361,468	606,620	21,754,848	-10.0%	-5.4%	(60,662)	(1,175,002)	(1,235,664)	-5.5%
316.00 Miscellaneous Power Plant Equipment	19,203,553	504,601	18,698,952	-15.0%	-5.4%	(75,690)	(1,009,950)	(1,085,640)	-5.7%
Total Navajo Units 1-3	$ 270,975,542	$ 7,238,946	$ 263,736,596	-16.5%	-5.4%	$ (1,196,622)	$ (14,244,693)	$ (15,441,314)	-5.7%
Ocotillo Units 1-2									
311.00 Structures and Improvements	$ 4,804,518	$ 25,614	$ 4,778,904	-5.0%	-22.0%	$ (1,281)	$ (1,051,772)	$ (1,053,053)	-21.9%
312.00 Boiler Plant Equipment	25,219,018	139,658	25,079,360	-20.0%	-22.0%	(27,932)	(5,519,628)	(5,547,560)	-22.0%
314.00 Turbogenerator Units	17,146,984	94,768	17,052,216	-15.0%	-22.0%	(14,215)	(3,752,962)	(3,767,177)	-22.0%
315.00 Accessory Electric Equipment	4,894,907	26,144	4,868,763	-10.0%	-22.0%	(2,614)	(1,071,549)	(1,074,163)	-21.9%
316.00 Miscellaneous Power Plant Equipment	7,062,830	36,503	7,026,327	-15.0%	-22.0%	(5,475)	(1,546,400)	(1,551,875)	-22.0%
Total Ocotillo Units 1-2	$ 59,128,257	$ 322,687	$ 58,805,570	-16.0%	-22.0%	$ (51,517)	$ (12,942,311)	$ (12,993,829)	-22.0%
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$ 800,303,960	$ 63,911,914	$ 736,392,046	-5.0%		$ (3,195,596)	$ -	$ (3,195,596)	-0.4%
322.00 Reactor Plant Equipment	1,177,440,897	91,722,234	1,085,718,663	-15.0%		(13,758,335)		(13,758,335)	-1.2%
323.00 Turbogenerator Units	378,902,614	29,565,313	349,337,301	-5.0%		(1,478,266)		(1,478,266)	-0.4%
324.00 Accessory Electric Equipment	286,941,496	22,598,413	264,343,083	-5.0%		(1,129,921)		(1,129,921)	-0.4%
325.00 Miscellaneous Power Plant Equipment	190,865,034	15,118,970	175,746,064	-5.0%		(755,949)		(755,949)	-0.4%
Total Palo Verde	$ 2,834,454,001	$ 222,916,845	$ 2,611,537,156	-9.1%		$ (20,318,066)	$ -	$ (20,318,066)	-0.7%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/15 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 1									
321.00 Structures and Improvements	$ 160,238,922	$ 12,067,694	$ 148,171,228	-5.0%		$ (603,385)	$ -	$ (603,385)	-0.4%
322.00 Reactor Plant Equipment	464,794,795	34,622,691	430,172,104	-15.0%		(5,193,404)		(5,193,404)	-1.1%
323.00 Turbogenerator Units	133,635,855	9,929,429	123,706,426	-5.0%		(496,471)		(496,471)	-0.4%
324.00 Accessory Electric Equipment	117,924,193	8,880,278	109,043,915	-5.0%		(444,014)		(444,014)	-0.4%
325.00 Miscellaneous Power Plant Equipment	31,243,002	2,346,607	28,896,395	-5.0%		(117,330)		(117,330)	-0.4%
Total Palo Verde Unit 1	$ 907,836,767	$ 67,846,699	$ 839,990,068	-10.1%		$ (6,854,604)	$ -	$ (6,854,604)	-0.8%
Palo Verde Unit 2									
321.00 Structures and Improvements	$ 92,055,736	$ 7,183,297	$ 84,872,439	-5.0%		$ (359,165)	$ -	$ (359,165)	-0.4%
322.00 Reactor Plant Equipment	249,302,485	19,157,384	230,145,101	-15.0%		(2,873,608)		(2,873,608)	-1.2%
323.00 Turbogenerator Units	87,999,272	6,748,834	81,250,438	-5.0%		(337,442)		(337,442)	-0.4%
324.00 Accessory Electric Equipment	47,992,891	3,732,862	44,260,029	-5.0%		(186,643)		(186,643)	-0.4%
325.00 Miscellaneous Power Plant Equipment	27,285,762	2,108,306	25,177,456	-5.0%		(105,415)		(105,415)	-0.4%
Total Palo Verde Unit 2	$ 504,636,146	$ 38,930,683	$ 465,705,463	-9.9%		$ (3,862,273)	$ -	$ (3,862,273)	-0.8%
Palo Verde Unit 3									
321.00 Structures and Improvements	$ 165,218,693	$ 13,711,678	$ 151,507,015	-5.0%		$ (685,584)	$ -	$ (685,584)	-0.4%
322.00 Reactor Plant Equipment	427,193,012	34,989,149	392,203,863	-15.0%		(5,248,372)		(5,248,372)	-1.2%
323.00 Turbogenerator Units	152,558,297	12,514,699	140,043,598	-5.0%		(625,735)		(625,735)	-0.4%
324.00 Accessory Electric Equipment	94,317,583	7,809,700	86,507,883	-5.0%		(390,485)		(390,485)	-0.4%
325.00 Miscellaneous Power Plant Equipment	28,965,542	2,392,660	26,572,882	-5.0%		(119,633)		(119,633)	-0.4%
Total Palo Verde Unit 3	$ 868,253,127	$ 71,417,885	$ 796,835,242	-9.9%		$ (7,069,809)	$ -	$ (7,069,809)	-0.8%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$ 210,244,404	$ 16,972,621	$ 193,271,783	-5.0%		$ (848,631)	$ -	$ (848,631)	-0.4%
322.00 Reactor Plant Equipment	561,290	43,929	517,361	-15.0%		(6,589)		(6,589)	-1.2%
323.00 Turbogenerator Units	217,756	18,029	199,727	-5.0%		(901)		(901)	-0.4%
324.00 Accessory Electric Equipment									#DIV/0!
325.00 Miscellaneous Power Plant Equipment	165,219	13,277	151,942	-5.0%		(664)		(664)	-0.4%
Total Palo Verde Water Reclamation	$ 211,188,669	$ 17,047,855	$ 194,140,814	-5.0%		$ (856,786)	$ -	$ (856,786)	-0.4%
Palo Verde Common									
321.00 Structures and Improvements	$ 172,546,205	$ 13,976,625	$ 158,569,580	-5.0%		$ (698,831)	$ -	$ (698,831)	-0.4%
322.00 Reactor Plant Equipment	35,589,315	2,909,081	32,680,234	-15.0%		(436,362)		(436,362)	-1.2%
323.00 Turbogenerator Units	4,491,434	354,322	4,137,112	-5.0%		(17,716)		(17,716)	-0.4%
324.00 Accessory Electric Equipment	26,706,829	2,175,574	24,531,255	-5.0%		(108,779)		(108,779)	-0.4%
325.00 Miscellaneous Power Plant Equipment	103,205,509	8,258,120	94,947,389	-5.0%		(412,906)		(412,906)	-0.4%
Total Palo Verde Common	$ 342,539,292	$ 27,673,722	$ 314,865,570	-6.1%		$ (1,674,594)	$ -	$ (1,674,594)	-0.5%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/15 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
Solar Units									
341.00 Structures and Improvements	$ 32,510,020	$ 2,134,908	$ 30,375,112	-5.0%	-7.8%	$ (106,745)	$ (2,377,445)	$ (2,484,191)	-7.6%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	587,836,565	38,301,436	549,535,129	-5.0%	-7.4%	(1,915,072)	(40,473,766)	(42,388,837)	-7.2%
345.00 Accessory Electric Equipment	105,145,520	6,832,297	98,313,223	-5.0%	-6.9%	(341,615)	(6,757,997)	(7,099,612)	-6.8%
346.00 Miscellaneous Power Plant Equipment	1,557,654	94,438	1,463,216	-5.0%	-9.1%	(4,722)	(133,766)	(138,488)	-8.9%
Total Solar Units	$ 727,049,759	$ 47,363,079	$ 679,686,680	-5.0%	-7.3%	$ (2,368,154)	$ (49,742,974)	$ (52,111,128)	-7.2%
Chino Valley									
341.05 Structures and Improvements	$ 527,889	$ 34,616	$ 493,273	-5.0%	-7.6%	$ (1,731)	$ (37,272)	$ (39,003)	-7.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	77,719,075	5,096,346	72,622,729	-5.0%	-7.6%	(254,817)	(5,487,382)	(5,742,199)	-7.4%
345.05 Accessory Electric Equipment	6,511,775	427,003	6,084,772	-5.0%	-7.6%	(21,350)	(459,766)	(481,116)	-7.4%
346.05 Miscellaneous Power Plant Equipment	216,504	14,197	202,307	-5.0%	-7.6%	(710)	(15,286)	(15,996)	-7.4%
Total Chino Valley	$ 84,975,243	$ 5,572,161	$ 79,403,082	-5.0%	-7.6%	$ (278,608)	$ (5,999,706)	$ (6,278,314)	-7.4%
Cotton Center									
341.05 Structures and Improvements	$ 1,813,500	$ 114,634	$ 1,698,866	-5.0%	-6.7%	$ (5,732)	$ (113,720)	$ (119,451)	-6.6%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	61,593,054	3,893,378	57,699,676	-5.0%	-6.7%	(194,669)	(3,862,335)	(4,057,003)	-6.6%
345.05 Accessory Electric Equipment	15,418,050	974,595	14,443,455	-5.0%	-6.7%	(48,730)	(966,824)	(1,015,554)	-6.6%
346.05 Miscellaneous Power Plant Equipment	262,641	16,602	246,039	-5.0%	-6.7%	(830)	(16,470)	(17,300)	-6.6%
Total Cotton Center	$ 79,087,245	$ 4,999,208	$ 74,088,037	-5.0%	-6.7%	$ (249,960)	$ (4,959,348)	$ (5,209,309)	-6.6%
Desert Star									
341.05 Structures and Improvements	$ 1,572,235	$ 86,581	$ 1,485,654	-5.0%	-11.9%	$ (4,329)	$ (177,248)	$ (181,577)	-11.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	25,365,040	1,396,827	23,968,213	-5.0%	-11.9%	(69,841)	(2,859,567)	(2,929,408)	-11.5%
345.05 Accessory Electric Equipment	3,579,659	197,128	3,382,531	-5.0%	-11.9%	(9,856)	(403,558)	(413,415)	-11.5%
346.05 Miscellaneous Power Plant Equipment	293,963	16,188	277,775	-5.0%	-11.9%	(809)	(33,140)	(33,950)	-11.5%
Total Desert Star	$ 30,810,897	$ 1,696,725	$ 29,114,172	-5.0%	-11.9%	$ (84,836)	$ (3,473,514)	$ (3,558,350)	-11.5%
Foothills Units 1-2									
341.05 Structures and Improvements	$ 10,906,684	$ 740,833	$ 10,165,851	-5.0%	-8.8%	$ (37,042)	$ (896,004)	$ (933,045)	-8.6%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	105,443,248	7,162,200	98,281,048	-5.0%	-8.8%	(358,110)	(8,662,353)	(9,020,463)	-8.6%
345.05 Accessory Electric Equipment	20,815,540	1,413,889	19,401,651	-5.0%	-8.8%	(70,694)	(1,710,034)	(1,780,729)	-8.6%
346.05 Miscellaneous Power Plant Equipment	57,708	3,920	53,788	-5.0%	-8.8%	(196)	(4,741)	(4,937)	-8.6%
Total Foothills Units 1-2	$ 137,223,180	$ 9,320,843	$ 127,902,337	-5.0%	-8.8%	$ (466,042)	$ (11,273,132)	$ (11,739,174)	-8.6%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/15 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
Gila Bend									
341.05 Structures and Improvements	$ 5,018,097	$ 352,590	$ 4,665,507	-5.0%	-10.7%	$ (17,629)	$ (500,606)	$ (518,235)	-10.3%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	89,246,612	6,270,795	82,975,817	-5.0%	-10.7%	(313,540)	(8,903,253)	(9,216,793)	-10.3%
345.05 Accessory Electric Equipment	11,096,944	779,712	10,317,232	-5.0%	-10.7%	(38,986)	(1,107,032)	(1,146,018)	-10.3%
346.05 Miscellaneous Power Plant Equipment	21,142	1,486	19,656	-5.0%	-10.7%	(74)	(2,109)	(2,183)	-10.3%
Total Gila Bend	$ 105,382,795	$ 7,404,582	$ 97,978,213	-5.0%	-10.7%	$ (370,229)	$ (10,513,001)	$ (10,883,230)	-10.3%
Hyder Units 1-2									
341.05 Structures and Improvements	$ 6,915,232	$ 453,315	$ 6,461,917	-5.0%	-4.4%	$ (22,666)	$ (284,224)	$ (306,890)	-4.4%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	93,250,197	6,114,435	87,135,762	-5.0%	-4.4%	(305,722)	(3,832,624)	(4,138,346)	-4.4%
345.05 Accessory Electric Equipment	22,556,482	1,479,659	21,076,823	-5.0%	-4.4%	(73,983)	(927,054)	(1,001,037)	-4.4%
346.05 Miscellaneous Power Plant Equipment	206,389	13,560	192,829	-5.0%	-4.4%	(678)	(8,482)	(9,159)	-4.4%
Total Hyder Units 1-2	$ 122,928,300	$ 8,060,969	$ 114,867,331	-5.0%	-4.4%	$ (403,048)	$ (5,052,384)	$ (5,455,432)	-4.4%
Legacy Units									
341.00 Structures and Improvements	$ 325,971	$ 18,141	$ 307,830	-5.0%		$ (907)	$ -	$ (907)	-0.3%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	10,113,649	540,485	9,573,164	-5.0%		(27,024)		(27,024)	-0.3%
345.00 Accessory Electric Equipment	3,606,980	190,421	3,416,559	-5.0%		(9,521)		(9,521)	-0.3%
346.00 Miscellaneous Power Plant Equipment									
Total Legacy Units	$ 14,046,600	$ 749,047	$ 13,297,553	-5.0%		$ (37,452)	$ -	$ (37,452)	-0.3%
Luke AFB									
341.05 Structures and Improvements	$ 1,566,281	$ 86,253	$ 1,480,028	-5.0%	-12.2%	$ (4,313)	$ (180,481)	$ (184,794)	-11.8%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	24,574,551	1,353,295	23,221,256	-5.0%	-12.2%	(67,665)	(2,831,699)	(2,899,363)	-11.8%
345.05 Accessory Electric Equipment	1,330,175	73,251	1,256,924	-5.0%	-12.2%	(3,663)	(153,275)	(156,937)	-11.8%
346.05 Miscellaneous Power Plant Equipment	377,821	20,806	357,015	-5.0%	-12.2%	(1,040)	(43,536)	(44,576)	-11.8%
Total Luke AFB	$ 27,848,828	$ 1,533,607	$ 26,315,221	-5.0%	-12.2%	$ (76,680)	$ (3,208,990)	$ (3,285,670)	-11.8%
Roof Tops									
341.05 Structures and Improvements	$ 1,582,181	$ 103,700	$ 1,478,481	-5.0%		$ (5,185)	$ -	$ (5,185)	-0.3%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	51,531,113	3,376,319	48,154,794	-5.0%		(168,816)		(168,816)	-0.3%
345.05 Accessory Electric Equipment	7,714,968	505,552	7,209,416	-5.0%		(25,278)		(25,278)	-0.3%
346.05 Miscellaneous Power Plant Equipment									
Total Roof Tops	$ 60,828,262	$ 3,985,571	$ 56,842,691	-5.0%		$ (199,279)	$ -	$ (199,279)	-0.3%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/15 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
Paloma									
341.05 Structures and Improvements	$ 2,281,950	$ 144,245	$ 2,137,705	-5.0%	-8.8%	$ (7,212)	$ (187,891)	$ (195,103)	-8.5%
342.05 Fuel Holders, Products and Accessories									
343.05 Prime Movers									
344.05 Generators and Devices	49,000,026	3,097,356	45,902,670	-5.0%	-8.8%	(154,868)	(4,034,553)	(4,189,421)	-8.5%
345.05 Accessory Electric Equipment	12,514,947	791,086	11,723,861	-5.0%	-8.8%	(39,554)	(1,030,453)	(1,070,007)	-8.5%
346.05 Miscellaneous Power Plant Equipment	121,486	7,679	113,807	-5.0%	-8.8%	(384)	(10,003)	(10,387)	-8.5%
Total Paloma	$ 63,918,409	$ 4,040,366	$ 59,878,043	-5.0%	-8.8%	$ (202,018)	$ (5,262,900)	$ (5,464,918)	-8.5%

ARIZONA PUBLIC SERVICE COMPANY
Dismantlement Costs
Steam Production

Statement G

Unit	Owned MW Capacity	Cost per kW	Estimated Cost	Final Retirements	Distributed Cost	Year of Study	Inflation Rate	Year Spent	Trended Cost	Accrual Rate
A	B	C	D	E		F	G	H	I	J=I/E
Cholla										
1	116	95	$ 11,033,863	$ 121,979,608	$ 8,471,615	2015	2.00%	2025	$ 10,326,852	8.5%
3	271	95	25,777,386	341,739,645	19,791,447	2015	2.00%	2025	24,125,663	7.1%
C				140,252,275	8,548,187	2015	2.00%	2025	10,420,192	7.4%
	387	95	$ 36,811,249	$ 603,971,528	$ 36,811,249				$ 44,872,707	7.4%
	Allocated to Common:		8,548,187							
	Allocated to Units:		$ 28,263,062							
Four Corners										
4-5	970	93	$ 90,078,373	$ 689,543,884		2015	2.00%	2038	$ 142,044,521	20.6%
C			5,528,118	75,337,177		2015	2.00%	2038	8,717,285	11.6%
	970	99	$ 95,606,491	$ 764,881,061					$ 150,761,805	19.7%
Navajo										
1-3	315	36	$ 11,456,480	$ 263,736,596		2015	2.00%	2026	$ 14,244,693	5.4%
C										
	315	36	$ 11,456,480	$ 263,736,596					$ 14,244,693	5.4%
Ocotillo										
1-2	220	53	$ 11,722,250	$ 58,805,570		2013	2.00%	2018	$ 12,942,311	22.0%
C										
	220	53	$ 11,722,250	$ 58,805,570					$ 12,942,311	22.0%
Solar Sites										
Chino Valley	19	185	$ 3,515,000	$ 79,403,082		2015	2.00%	2042	$ 5,999,706	7.6%
Cotton Center	17	185	3,145,000	74,088,037		2015	2.00%	2038	4,959,348	6.7%
Desart Star	11	185	2,035,000	29,114,172		2015	2.00%	2042	3,473,514	11.9%
Foothills	35	185	6,475,000	127,902,337		2015	2.00%	2043	11,273,132	8.8%
Gila Bend	32	185	5,920,000	97,978,213		2015	2.00%	2044	10,513,001	10.7%
Hyder	16	185	2,960,000	114,867,331		2015	2.00%	2042	5,052,384	4.4%
Legacy				13,297,553		2015	2.00%	2037		
Luke AFB	11	185	2,035,000	26,315,221		2015	2.00%	2038	3,208,990	12.2%
Roof Tops				56,842,691		2015	2.00%	2042		
Paloma	17	185	3,145,000	59,878,043		2015	2.00%	2041	5,262,900	8.8%
	158	185	$ 29,230,000	$ 679,686,680					$ 49,742,974	7.3%

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, 2015) 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									24.94	12.23	-8.0	-10.6
312.00 Boiler Plant Equipment									28.65	13.72	-13.5	-14.0
314.00 Turbogenerator Units									27.93	12.19	-11.9	-13.4
315.00 Accessory Electric Equipment									28.45	13.09	-10.9	-11.5
316.00 Miscellaneous Power Plant Equipment									24.00	12.52	-12.9	-13.2
Total Steam Production Plant									27.86	13.25	-12.5	-13.4
NUCLEAR PRODUCTION												
321.00 Structures and Improvements									47.39	29.51	-0.7	
322.00 Reactor Plant Equipment									47.14	28.71	-2.4	
323.00 Turbogenerator Units									45.88	28.77	-1.0	
324.00 Accessory Electric Equipment									51.72	28.76	-0.6	
325.00 Miscellaneous Power Plant Equipment									42.52	29.60	-1.3	
Total Nuclear Production Plant									47.12	29.02	-1.5	-0.7
OTHER PRODUCTION												
341.00 Structures and Improvements									27.90	21.10	-6.5	
342.00 Fuel Holders, Products and Accessories									27.90	16.95	-5.2	
343.00 Prime Movers									29.71	20.40	-6.7	
344.00 Generators and Devices									27.07	22.15	1.5	
345.00 Accessory Electric Equipment									27.25	21.54	-6.4	
346.00 Miscellaneous Power Plant Equipment									24.73	18.60	-5.0	
Total Other Production Plant									27.80	21.42	-1.9	-5.8
TRANSMISSION PLANT												
352.02 Structures and Improvements	50.00	R4	50.62	16.79			50.00	R4	51.64	12.17		
353.00 Station Equipment	45.00	S0.5	45.96	34.11	-4.70	-5.0	53.00	R1.5	53.86	41.27	-4.5	-5.0
354.00 Towers and Fixtures	60.00	R3	60.26	37.13			60.00	R3	60.47	32.86		
355.00 Poles and Fixtures	55.00	R1.5	55.15	48.05	-20.00	-20.0	55.00	R1.5	55.37	44.16	-20.0	-20.0
356.00 Overhead Conductors and Devices	60.00	R3	59.74	47.35	-18.7	-20.0	60.00	R3	59.50	42.77	-18.7	-20.0
Total Transmission Plant									54.01	41.21	-4.8	-5.3

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2015)					
	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	59.91	49.60	-4.7	-5.0	60.00	R3	59.90	48.10	-5.1	-5.0
362.00 Station Equipment	43.00	L0.5	43.06	36.12	9.5	10.0	43.00	L0.5	43.08	35.03	-3.8	-5.0
363.00 Storage Battery Equipment	15.00	SQ					10.00	S3	10.00	6.51		
364.01 Poles, Towers and Fixtures - Wood	40.00	L0	39.92	30.83	-1.0	-5.0	45.00	L0	44.55	34.73	-20.1	-25.0
364.02 Poles, Towers and Fixtures - Steel	38.00	SC	38.18	35.13	-10.0	-10.0	50.00	R0.5	50.04	44.99	-10.0	-10.0
365.00 Overhead Conductors and Devices	48.00	L0	47.78	40.17	4.3	5.0	50.00	SC	49.88	42.18	-22.3	-25.0
366.00 Underground Conduit	60.00	L1	59.96	50.32	-4.9	-5.0	60.00	L1	59.99	47.99	-10.4	-10.0
367.00 Underground Conductors and Devices	35.00	L1	34.90	27.33	-3.8	-5.0	40.00	L1	39.80	30.52	-9.0	-10.0
368.00 Line Transformers	55.00	L1	55.12	44.08	-4.3	-5.0	55.00	L1	55.07	43.00	-3.7	-5.0
369.00 Services	40.00	L1	40.65	29.77	-4.9	-5.0	45.00	L1	45.73	33.10	-46.4	-50.0
370.01 Meters - Electronic	26.00	R1.5					20.00	SC	17.52	15.30	0.5	
370.03 Meters - AMI	26.00	R1.5	26.00	25.47			20.00	SC	20.20	17.79	0.4	
371.00 Installations on Customers' Premises	40.00	L0	40.15	33.33	-14.5	-15.0	45.00	L0	44.99	36.69	-14.8	-15.0
373.00 Street Lighting and Signal Systems	55.00	L0.5	54.60	44.94	-8.4	-10.0	55.00	L0.5	54.49	42.84	-4.7	-5.0
Total Distribution Plant									43.51	34.54	-11.4	-12.8
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	45.00	L1	44.91	34.13	-5.6	-5.0	40.00	L1	39.90	32.65	-6.6	-5.0
391.CM Office Furn. and Equip. - Computer	8.00	L3	8.04	4.96	-0.1		8.00	L3	7.95	4.77	-0.2	
397.00 Communication Equipment	18.00	S1.5	18.11	10.76			21.00	L2	21.02	14.54	-0.1	
Total Depreciable									15.90	11.19	-1.7	-1.5
Amortizable												
391.FE Office Furn. and Equip. - Furniture	20.00	SQ	20.00	14.16			20.00	SQ	20.00	10.99		
393.00 Stores Equipment	20.00	SQ	20.00	17.41			20.00	SQ	20.00	14.20		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	11.90			20.00	SQ	20.00	11.54		
395.00 Laboratory Equipment	20.00	SQ	20.00	7.32			20.00	SQ	20.00	9.74		
398.00 Miscellaneous Equipment	24.00	SQ	24.00	19.16			24.00	SQ	24.00	18.64		
Total Amortizable									20.52	12.17		
Total General Plant									16.50	11.32	-1.4	-1.3
TOTAL UTILITY									34.95	24.58	-7.1	-8.3

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2015)					
	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 (by Unit)												
Cholla												
311.00 Structures and Improvements	2028	200-SC	29.03	17.10	-4.8	-5.0	2025	200-SC	23.80	9.38		
312.00 Boiler Plant Equipment	2028	200-SC	24.33	17.11	-6.2	-5.7	2025	200-SC	19.88	9.38	-8.3	-8.4
314.00 Turbogenerator Units	2028	200-SC	22.21	17.11	-5.2	-5.4	2025	200-SC	18.39	9.38	-11.7	-8.7
315.00 Accessory Electric Equipment	2028	200-SC	28.61	17.11	-5.2	-5.2	2025	200-SC	22.99	9.38	-9.3	-8.6
316.00 Miscellaneous Power Plant Equipment	2028	200-SC	30.40	17.10	-5.4	-5.4	2025	200-SC	25.29	9.38	-9.0	-8.5
Total Cholla									19.95	9.38	-8.6	-8.6
Cholla Unit 1											-10.8	-8.6
311.00 Structures and Improvements	2035	200-SC	48.83	23.70	-4.8	-4.9	2025	200-SC	20.30	9.38		
312.00 Boiler Plant Equipment	2035	200-SC	29.93	23.74	-7.5	-5.8	2025	200-SC	18.70	9.38	-6.2	-7.0
314.00 Turbogenerator Units	2035	200-SC	33.81	23.73	-5.0	-5.5	2025	200-SC	22.42	9.38	-7.6	-7.4
315.00 Accessory Electric Equipment	2035	200-SC	49.50	23.69	-5.3	-5.2	2025	200-SC	30.24	9.38	-3.9	-7.2
316.00 Miscellaneous Power Plant Equipment	2035	200-SC	42.28	23.71	-6.0	-5.5	2025	200-SC	18.97	9.38	-7.1	-7.1
Total Cholla Unit 1									20.07	9.38	-7.2	-7.2
Cholla Unit 3											-6.8	-7.3
311.00 Structures and Improvements	2035	200-SC	34.99	23.73	-4.7	-5.3	2025	200-SC	20.45	9.38		
312.00 Boiler Plant Equipment	2035	200-SC	30.71	23.73	-7.8	-6.2	2025	200-SC	19.92	9.38	-6.8	-7.4
314.00 Turbogenerator Units	2035	200-SC	38.99	23.72	-4.6	-5.9	2025	200-SC	14.13	9.39	-8.9	-7.7
315.00 Accessory Electric Equipment	2035	200-SC	34.82	23.73	-6.3	-5.6	2025	200-SC	19.82	9.38	-7.1	-7.6
316.00 Miscellaneous Power Plant Equipment	2035	200-SC	32.42	23.73	-7.1	-5.9	2025	200-SC	16.49	9.39	-5.2	-7.5
Total Cholla Common									19.63	9.38	-7.3	-7.6
											-7.6	-7.6

ARIZONA PUBLIC SERVICE COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2015)					
	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												
311.00 Structures and Improvements									34.07	21.85	-9.4	-17.2
312.00 Boiler Plant Equipment									41.39	21.83	-18.7	-20.1
314.00 Turbogenerator Units									40.45	21.83	-19.1	-20.0
315.00 Accessory Electric Equipment									32.06	21.85	-16.3	-17.8
316.00 Miscellaneous Power Plant Equipment									35.59	21.84	-17.5	-17.9
Total Four Corners									39.68	21.83	-17.5	-19.6
Four Corners Units 4-5												
311.00 Structures and Improvements	2038	200-SC	44.16	26.51	-65.9	-66.0	2038	200-SC	38.42	21.84	-18.6	-19.7
312.00 Boiler Plant Equipment	2038	200-SC	44.95	26.50	-65.9	-67.1	2038	200-SC	42.42	21.83	-19.1	-20.6
314.00 Turbogenerator Units	2038	200-SC	38.32	26.52	-62.0	-66.8	2038	200-SC	40.60	21.83	-19.7	-20.3
315.00 Accessory Electric Equipment	2038	200-SC	44.51	26.51	-64.5	-66.4	2038	200-SC	34.93	21.84	-19.6	-20.0
316.00 Miscellaneous Power Plant Equipment	2038	200-SC	41.35	26.51	-66.2	-66.7	2038	200-SC	35.89	21.84	-20.3	-20.3
Total Four Corners Units 4-5									41.23	21.83	-19.2	-20.5
Four Corners Common												
311.00 Structures and Improvements	2038	200-SC	47.11	26.50	-21.7	-22.4	2038	200-SC	26.79	21.86	-3.1	-11.2
312.00 Boiler Plant Equipment	2038	200-SC	50.51	26.49	-23.3	-23.5	2038	200-SC	30.09	21.85	-12.8	-12.1
314.00 Turbogenerator Units	2038	200-SC	66.67	26.43	-15.9	-23.1	2038	200-SC	37.20	21.84	-8.9	-11.8
315.00 Accessory Electric Equipment	2038	200-SC	43.49	26.51	-21.7	-22.8	2038	200-SC	25.92	21.86	-8.9	-11.5
316.00 Miscellaneous Power Plant Equipment	2038	200-SC	41.46	26.51	-23.1	-23.2	2038	200-SC	34.86	21.84	-11.0	-11.8
Total Four Corners Common									29.51	21.85	-7.6	-11.8
Navajo Units 1-3												
311.00 Structures and Improvements	2026	200-SC	32.06	15.19	-7.0	-7.1	2026	200-SC	27.65	10.36	-5.3	-5.4
312.00 Boiler Plant Equipment	2026	200-SC	31.18	15.19	-8.2	-7.7	2026	200-SC	29.84	10.35	-5.5	-5.8
314.00 Turbogenerator Units	2026	200-SC	40.93	15.18	-7.5	-7.5	2026	200-SC	39.58	10.35	-5.6	-5.7
315.00 Accessory Electric Equipment	2026	200-SC	37.34	15.18	-7.3	-7.3	2026	200-SC	34.70	10.35	-5.5	-5.5
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	28.11	15.19	-7.8	-7.5	2026	200-SC	24.78	10.36	-7.1	-5.7
Total Navajo Units 1-3									30.15	10.35	-5.6	-5.7

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, 2015) 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	22.13	9.38	-17.8	-18.9	2018	200-SC	19.21	2.49	-20.7	-21.9
312.00 Boiler Plant Equipment	2020	200-SC	34.34	9.38	-19.2	-19.2	2018	200-SC	32.08	2.49	-22.5	-22.0
314.00 Turbogenerator Units	2020	200-SC	23.10	9.38	-18.7	-19.1	2018	200-SC	23.28	2.49	-24.1	-22.0
315.00 Accessory Electric Equipment	2020	200-SC	24.21	9.38	-18.5	-19.0	2018	200-SC	13.14	2.49	-21.6	-21.9
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	18.29	9.38	-18.9	-19.1	2018	200-SC	11.92	2.49	-19.6	-22.0
Total Ocotillo Units 1-2									21.60	2.49	-22.3	-22.0
NUCLEAR PRODUCTION (by Unit)												
Palo Verde												
321.00 Structures and Improvements									47.39	29.51	-0.7	-0.4
322.00 Reactor Plant Equipment									47.14	28.71	-2.4	-1.2
323.00 Turbogenerator Units									45.88	28.77	-1.0	-0.4
324.00 Accessory Electric Equipment									51.72	28.76	-0.6	-0.4
325.00 Miscellaneous Power Plant Equipment									42.52	29.60	-1.3	-0.4
Total Palo Verde									47.12	29.02	-1.5	-0.7
Palo Verde Unit 1												
321.00 Structures and Improvements	2044	200-SC	53.54	32.01	-0.4	-0.4	2044	200-SC	52.70	27.41	-0.5	-0.4
322.00 Reactor Plant Equipment	2044	200-SC	48.33	32.03	-2.1	-1.3	2044	200-SC	47.42	27.43	-1.3	-1.1
323.00 Turbogenerator Units	2044	200-SC	48.84	32.03	-0.7	-0.4	2044	200-SC	45.43	27.43	-1.4	-0.4
324.00 Accessory Electric Equipment	2044	200-SC	53.77	32.01	-0.4	-0.4	2044	200-SC	52.59	27.41	-0.5	-0.4
325.00 Miscellaneous Power Plant Equipment	2044	200-SC	50.74	32.02	-0.9	-0.4	2044	200-SC	49.87	27.41	-1.3	-0.4
Total Palo Verde Unit 1									48.67	27.42	-1.1	-0.8
Palo Verde Unit 2												
321.00 Structures and Improvements	2045	200-SC	54.10	32.92	-0.5	-0.5	2045	200-SC	54.04	28.33	-0.4	-0.4
322.00 Reactor Plant Equipment	2045	200-SC	48.65	32.94	-3.1	-1.3	2045	200-SC	46.16	28.35	-2.3	-1.2
323.00 Turbogenerator Units	2045	200-SC	50.48	32.93	-0.7	-0.4	2045	200-SC	44.59	28.36	-1.1	-0.4
324.00 Accessory Electric Equipment	2045	200-SC	53.24	32.92	-0.6	-0.5	2045	200-SC	52.50	28.34	-0.6	-0.4
325.00 Miscellaneous Power Plant Equipment	2045	200-SC	49.81	32.94	-0.7	-0.4	2045	200-SC	49.51	28.34	-1.1	-0.4
Total Palo Verde Unit 2									47.86	28.35	-1.5	-0.8

ARIZONA PUBLIC SERVICE COMPANY
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Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2015)					
	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
Palo Verde Unit 3												
321.00 Structures and Improvements	2047	200-SC	54.39	34.74	-0.5	-0.5	2047	200-SC	53.93	30.17	-0.4	-0.4
322.00 Reactor Plant Equipment	2047	200-SC	48.75	34.77	-2.2	-1.4	2047	200-SC	47.58	30.20	-3.1	-1.2
323.00 Turbogenerator Units	2047	200-SC	49.91	34.76	-0.8	-0.5	2047	200-SC	47.49	30.19	-0.6	-0.4
324.00 Accessory Electric Equipment	2047	200-SC	53.96	34.74	-0.6	-0.5	2047	200-SC	52.54	30.18	-0.7	-0.4
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	51.86	34.75	-0.9	-0.5	2047	200-SC	50.59	30.18	-1.4	-0.4
Total Palo Verde Unit 3									49.27	30.19	-1.8	-0.8
Palo Verde Water Reclamation												
321.00 Structures and Improvements	2047	200-SC	47.75	34.77	-0.8	-0.5	2047	200-SC	41.80	30.22	-1.1	-0.4
322.00 Reactor Plant Equipment	2047	200-SC	43.41	34.79	-1.4	-1.4	2047	200-SC	33.03	30.25	-1.2	-1.2
323.00 Turbogenerator Units	2047	200-SC	51.70	34.75	-0.7	-0.5	2047	200-SC	51.49	30.18	-6.4	-0.4
324.00 Accessory Electric Equipment												
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	52.00	34.75	-1.9	-0.5	2047	200-SC	40.07	30.22	-0.3	-0.4
Total Palo Verde Water Reclamation									41.78	30.22	-1.1	-0.4
Palo Verde Common												
321.00 Structures and Improvements	2047	200-SC	51.01	34.75	-0.8	-0.5	2047	200-SC	42.59	30.21	-0.8	-0.4
322.00 Reactor Plant Equipment	2047	200-SC	52.35	34.75	-2.8	-1.4	2047	200-SC	45.74	30.20	-10.2	-1.2
323.00 Turbogenerator Units	2047	200-SC	40.77	34.80	-1.2	-0.5	2047	200-SC	35.40	30.24	-4.3	-0.4
324.00 Accessory Electric Equipment	2047	200-SC	52.49	34.75	-0.6	-0.5	2047	200-SC	44.78	30.21	-0.6	-0.4
325.00 Miscellaneous Power Plant Equipment	2047	200-SC	46.42	34.77	-1.9	-0.5	2047	200-SC	37.74	30.23	-1.4	-0.4
Total Palo Verde Common									41.33	30.22	-2.0	-0.5
OTHER PRODUCTION (by Unit)												
Douglas CT												
341.00 Structures and Improvements	2020	200-SC	15.76	9.39	5.0	5.0	2030	200-SC	22.02	14.23	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2020	200-SC	32.80	9.38	4.0	5.0	2030	200-SC	42.08	14.22	-6.4	-5.0
343.00 Prime Movers	2020	200-SC	46.39	9.38	5.0	5.0	2030	200-SC	17.14	14.24	-50.6	-5.0
344.00 Generators and Devices	2020	200-SC	46.97	9.38	5.0	5.0	2030	200-SC	26.54	14.23	-5.0	-5.0
345.00 Accessory Electric Equipment	2020	200-SC	42.30	9.38	4.5	5.0	2030	200-SC	39.59	14.22	-5.9	-5.0
346.00 Miscellaneous Power Plant Equipment	2020	200-SC	34.57	9.38	5.0	5.0	2030	200-SC	42.04	14.22	-4.1	-5.0
Total Douglas CT									19.70	14.24	-37.9	-5.0

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ADAM LEBRECHT,

a witness herein, having been first duly sworn by the Certified Court Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. SCOTT:

Q. Okay. Mr. Lebrecht, I have handed you what I have asked to be marked as S-10 and S-11.

A. Yes.

Q. First of all, for the record, could you please state your name and business address.

A. My name is Adam Lebrecht. Last name is spelled L-E-B-R-E-C-H-T. My business address is 1200 West Washington Street, Phoenix, Arizona, 85007.

Q. And by whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission. And I currently have the title of Executive Consultant I.

Q. And with respect to the S-10 and S-11, could you please identify those for the record?

A. S-10 is a copy of the testimony which I wrote regarding this matter. And S-11 is a copy of the errata which I wrote regarding this matter.

ARIZONA PUBLIC SERVICE COMPANY
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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2015) 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 CT Unit 3												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2037	200-SC	33.56	25.60	5.0	5.0	2037	200-SC	25.14	20.92	-5.0	-5.0
344.00 Generators and Devices	2037	200-SC	33.56	25.60	5.0	5.0	2037	200-SC	33.69	20.90	-5.1	-5.0
345.00 Accessory Electric Equipment	2037	200-SC	33.56	25.60	5.0	5.0	2037	200-SC	33.70	20.90	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment												
Total Saguaro CT Unit 3									32.96	20.90	-5.1	-5.0
Solar Units												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories											-7.9	
343.00 Prime Movers												
344.00 Generators and Devices												
345.00 Accessory Electric Equipment											-7.6	
346.00 Miscellaneous Power Plant Equipment											-7.2	
Total Solar Units									28.12	25.39	-7.6	-7.6
Chino Valley												
341.05 Structures and Improvements	30.00	SQ					2042	200-SC	28.89	25.61	-7.4	-7.4
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2042	200-SC	28.89	25.61	-7.4	-7.4
345.05 Accessory Electric Equipment	30.00	SQ					2042	200-SC	28.89	25.61	-7.4	-7.4
346.05 Miscellaneous Power Plant Equipment	30	SQ					2042	200-SC	28.89	25.61	-7.4	-7.4
Total Chino Valley									28.89	25.61	-7.4	-7.4
Cotton Center												
341.05 Structures and Improvements	30.00	SQ					2041	200-SC	28.90	24.68	-6.6	-6.6
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2041	200-SC	28.90	24.68	-6.6	-6.6
345.05 Accessory Electric Equipment	30.00	SQ					2041	200-SC	28.90	24.68	-6.6	-6.6
346.05 Miscellaneous Power Plant Equipment	30	SQ					2041	200-SC	28.90	24.68	-6.6	-6.6
Total Cotton Center									28.90	24.68	-6.6	-6.6

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2015) 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
Desert Star												
341.05 Structures and Improvements	30.00	SQ					2038	200-SC	22.34	21.87	-11.5	-11.5
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2038	200-SC	22.34	21.87	-11.5	-11.5
345.05 Accessory Electric Equipment	30.00	SQ					2038	200-SC	22.34	21.87	-11.5	-11.5
346.05 Miscellaneous Power Plant Equipment							2038	200-SC	22.34	21.87	-11.5	-11.5
Total Desert Star									22.34	21.87	-11.5	-11.5
Foothills Units 1-2												
341.05 Structures and Improvements	30.00	SQ					2043	200-SC	28.88	26.55	-8.6	-8.6
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2043	200-SC	28.88	26.55	-8.6	-8.6
345.05 Accessory Electric Equipment	30.00	SQ					2043	200-SC	28.88	26.55	-8.6	-8.6
346.05 Miscellaneous Power Plant Equipment							2043	200-SC	28.88	26.55	-8.6	-8.6
Total Foothills Units 1-2									28.88	26.55	-8.6	-8.6
Gila Bend												
341.05 Structures and Improvements	30.00	SQ					2044	200-SC	28.88	27.48	-10.3	-10.3
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2044	200-SC	28.88	27.48	-10.3	-10.3
345.05 Accessory Electric Equipment	30.00	SQ					2044	200-SC	28.88	27.48	-10.3	-10.3
346.05 Miscellaneous Power Plant Equipment							2044	200-SC	28.88	27.48	-10.3	-10.3
Total Gila Bend									28.88	27.48	-10.3	-10.3
Hyder Units 1-2												
341.05 Structures and Improvements	30.00	SQ					2042	200-SC	28.74	25.62	-4.4	-4.4
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2042	200-SC	28.84	25.61	-4.4	-4.4
345.05 Accessory Electric Equipment	30.00	SQ					2042	200-SC	29.00	25.61	-4.4	-4.4
346.05 Miscellaneous Power Plant Equipment							2042	200-SC	29.58	25.61	-4.4	-4.4
Total Hyder Units 1-2									28.86	25.61	-4.4	-4.4

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Account Description	Current Parameters						Proposed Parameters (at December 31, 2015)					
	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
Legacy Units												
341.00 Structures and Improvements	12.00	S3	16.26	2.25	4.8	5.0	2037	200-SC	41.95	20.89	-3.9	-5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												
344.00 Generators and Devices	12.00	S3	12.62	4.22	11.7	5.0	2037	200-SC	25.92	20.91	-3.3	-5.0
345.00 Accessory Electric Equipment	12.00	S3	12.11	8.61	5.0	5.0	2037	200-SC	22.73	20.92	-5.2	-5.0
346.00 Miscellaneous Power Plant Equipment												
Total Legacy Units									25.23	20.91	-3.6	-5.0
Luke AFB												
341.05 Structures and Improvements	12.00	S3	16.26	2.25	4.8	5.0	2038	200-SC	22.34	21.87	-11.8	-11.8
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	12.00	S3	12.62	4.22	11.7	5.0	2038	200-SC	22.34	21.87	-11.8	-11.8
345.05 Accessory Electric Equipment	12.00	S3	12.11	8.61	5.0	5.0	2038	200-SC	22.34	21.87	-11.8	-11.8
346.05 Miscellaneous Power Plant Equipment							2038	200-SC	22.34	21.87	-11.8	-11.8
Total Luke AFB									22.34	21.87	-11.8	-11.8
Roof Tops												
341.05 Structures and Improvements	30.00	SQ					2042	200-SC	28.71	25.62	-5.0	-5.0
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2042	200-SC	28.58	25.62	-5.0	-5.0
345.05 Accessory Electric Equipment	30.00	SQ					2042	200-SC	28.62	25.62	-5.0	-5.0
346.05 Miscellaneous Power Plant Equipment												
Total Roof Tops									28.59	25.62	-5.0	-5.0
Paloma												
341.05 Structures and Improvements	30.00	SQ					2041	200-SC	28.90	24.68	-8.5	-8.5
342.05 Fuel Holders, Products and Accessories												
343.05 Prime Movers												
344.05 Generators and Devices	30.00	SQ					2041	200-SC	28.90	24.68	-8.5	-8.5
345.05 Accessory Electric Equipment	30.00	SQ					2041	200-SC	28.90	24.68	-8.5	-8.5
346.05 Miscellaneous Power Plant Equipment							2041	200-SC	28.90	24.68	-8.5	-8.5
Total Paloma									28.90	24.68	-8.5	-8.5

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2015) 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
Sundance												
341.00 Structures and Improvements	2037	200-SC	30.66	25.61	5.0	5.0	2037	200-SC	29.70	20.91	-6.8	-5.0
342.00 Fuel Holders, Products and Accessories	2037	200-SC	30.69	25.61	5.0	5.0	2037	200-SC	29.93	20.91	-5.0	-5.0
343.00 Prime Movers	2037	200-SC	30.75	25.61	5.0	5.0	2037	200-SC	30.53	20.91	-5.0	-5.0
344.00 Generators and Devices	2037	200-SC	29.27	25.61	5.0	5.0	2037	200-SC	21.85	20.92	-5.0	-5.0
345.00 Accessory Electric Equipment	2037	200-SC	30.69	25.61	5.0	5.0	2037	200-SC	30.16	20.91	-5.2	-5.0
346.00 Miscellaneous Power Plant Equipment	2037	200-SC	29.31	25.61	5.0	5.0	2037	200-SC	27.86	20.91	-5.0	-5.0
Total Sun Dance									29.94	20.91	-5.1	-5.0
West Phoenix												
341.00 Structures and Improvements									28.82	19.82	-6.3	
342.00 Fuel Holders, Products and Accessories									26.78	14.84	-5.1	
343.00 Prime Movers									29.88	19.81	-4.8	
344.00 Generators and Devices									26.99	18.56	1.5	
345.00 Accessory Electric Equipment									22.77	16.06	-6.3	
346.00 Miscellaneous Power Plant Equipment									22.88	16.94	-5.2	
Total West Phoenix									27.37	18.50	-1.7	-5.0
West Phoenix CC Units 1-3												
341.00 Structures and Improvements	2028	200-SC	20.32	17.11	4.7	5.0	2030	200-SC	25.02	14.23	-4.9	-5.0
342.00 Fuel Holders, Products and Accessories	2028	200-SC	25.88	17.11	4.6	5.0	2030	200-SC	25.61	14.23	-5.2	-5.0
343.00 Prime Movers												
344.00 Generators and Devices	2028	200-SC	25.48	17.11	17.3	5.0	2030	200-SC	25.17	14.23	-3.4	-5.0
345.00 Accessory Electric Equipment	2028	200-SC	26.01	17.11	3.6	5.0	2030	200-SC	19.28	14.23	-6.9	-5.0
346.00 Miscellaneous Power Plant Equipment	2028	200-SC	24.83	17.11	4.3	5.0	2030	200-SC	20.85	14.23	-4.8	-5.0
Total West Phoenix CC Units 1-3									23.89	14.23	-4.3	-5.0
West Phoenix CC Unit 4												
341.00 Structures and Improvements	2036	200-SC	32.78	24.67	5.0	5.0	2036	200-SC	32.59	19.96	-5.1	-5.0
342.00 Fuel Holders, Products and Accessories	2036	200-SC	33.58	24.67	5.0	5.0	2036	200-SC	33.73	19.96	-5.0	-5.0
343.00 Prime Movers	2036	200-SC	33.58	24.67	5.0	5.0	2036	200-SC	33.65	19.96	0.6	-5.0
344.00 Generators and Devices	2036	200-SC	32.59	24.67	9.6	5.0	2036	200-SC	27.51	19.96	-4.8	-5.0
345.00 Accessory Electric Equipment	2036	200-SC	28.02	24.68	5.0	5.0	2036	200-SC	25.84	19.97	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment	2036	200-SC	26.86	24.68	4.7	5.0	2036	200-SC	22.59	19.97	-4.9	-5.0
Total West Phoenix CC Unit 4									31.42	19.96	-1.5	-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
West Phoenix CC Unit 5												
341.00 Structures and Improvements	2038	200-SC	33.50	26.54	5.0	5.0	2038	200-SC	32.33	21.85	-5.3	-5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2038	200-SC	32.59	26.54	2.9	5.0	2038	200-SC	31.65	21.85	-6.1	-5.0
344.00 Generators and Devices	2038	200-SC	32.94	26.54	6.2	5.0	2038	200-SC	28.72	21.86	5.9	-5.0
345.00 Accessory Electric Equipment	2038	200-SC	33.56	26.54	5.0	5.0	2038	200-SC	31.69	21.85	-5.3	-5.0
346.00 Miscellaneous Power Plant Equipment	2038	200-SC	29.15	26.55	5.0	5.0	2038	200-SC	25.22	21.86	-5.4	-5.0
Total West Phoenix CC Unit 5									29.82	21.86	0.7	-5.0
West Phoenix CT Units 1-2												
341.00 Structures and Improvements	2020	200-SC	19.08	9.38	5.0	5.0	2030	200-SC	16.66	14.24	-7.7	-5.0
342.00 Fuel Holders, Products and Accessories	2020	200-SC	36.73	9.38	5.0	5.0	2030	200-SC	31.39	14.22	-5.0	-5.0
343.00 Prime Movers	2020	200-SC	32.96	9.38	4.6	5.0	2030	200-SC	20.27	14.23	-10.0	-5.0
344.00 Generators and Devices	2020	200-SC	24.86	9.38	6.9	5.0	2030	200-SC	21.33	14.23	-6.3	-5.0
345.00 Accessory Electric Equipment	2020	200-SC	33.43	9.38	4.7	5.0	2030	200-SC	41.82	14.22	-5.1	-5.0
346.00 Miscellaneous Power Plant Equipment	2020	200-SC	20.80	9.38	4.9	5.0	2030	200-SC	29.86	14.23	-7.8	-5.0
Total West Phoenix CT Units 1-2									21.05	14.23	-8.5	-5.0
West Phoenix Common												
341.00 Structures and Improvements	2031	200-SC	29.46	19.96	4.7	5.0	2038	200-SC	32.02	21.85	-7.5	-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									32.02	21.85	-7.5	-5.0
Yucca												
341.00 Structures and Improvements									20.37	15.64	-5.9	
342.00 Fuel Holders, Products and Accessories									42.26	18.50	-5.1	
343.00 Prime Movers									32.99	24.64	-6.2	
344.00 Generators and Devices									26.23	14.34	-6.0	
345.00 Accessory Electric Equipment									29.63	16.46	-7.9	
346.00 Miscellaneous Power Plant Equipment									30.81	19.56	-5.0	
Total Yucca									31.25	21.97	-6.1	-5.0

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Account Description	Current Parameters						Proposed Parameters (at December 31, 2015)					
	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	2043	200-SC	36.51	31.16	4.4	5.0	2030	200-SC	19.06	14.23	-6.1	-5.0
342.00 Fuel Holders, Products and Accessories	2043	200-SC	61.23	31.06	4.9	5.0	2030	200-SC	46.94	14.21	-5.1	-5.0
343.00 Prime Movers	2043	200-SC	65.30	31.04	5.0	5.0	2030	200-SC	30.01	14.23	-12.9	-5.0
344.00 Generators and Devices	2043	200-SC	45.07	31.13	9.0	5.0	2030	200-SC	26.18	14.23	-6.0	-5.0
345.00 Accessory Electric Equipment	2043	200-SC	51.04	31.10	4.8	5.0	2030	200-SC	29.68	14.23	-8.2	-5.0
346.00 Miscellaneous Power Plant Equipment	2043	200-SC	46.77	31.12	5.0	5.0	2030	200-SC	33.71	14.22	-5.0	-5.0
Total Yucca CT Units 1-4									27.71	14.23	-8.3	-5.0
Yucca CT Units 5-6												
341.00 Structures and Improvements	2043	200-SC	33.48	31.17	5.0	5.0	2043	200-SC	30.49	26.54	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2043	200-SC	33.48	31.17	5.0	5.0	2043	200-SC	33.48	26.54	-5.0	-5.0
343.00 Prime Movers	2043	200-SC	33.48	31.17	5.0	5.0	2043	200-SC	33.54	26.54	-5.0	-5.0
344.00 Generators and Devices	2043	200-SC	33.48	31.17	5.0	5.0	2043	200-SC	32.00	26.54	-5.0	-5.0
345.00 Accessory Electric Equipment	2043	200-SC	33.48	31.17	5.0	5.0	2043	200-SC	29.39	26.55	-6.6	-5.0
346.00 Miscellaneous Power Plant Equipment							2043	200-SC	27.02	26.55	-5.0	-5.0
Total Yucca CT Units 5-6									33.34	26.54	-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 367.00 – UG Conductors and Devices. 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 3. 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: 367.00 UG Conductors and Devices

Dispersion: 40 - L1
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2015 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
2015	0.5	91,359,584	40.00	39.53	0.9882	1.0000	90,284,635	2,283,973
2014	1.5	65,956,784	40.00	38.60	0.9650	1.0000	63,646,093	1,648,846
2013	2.5	45,289,616	40.00	37.69	0.9421	1.0000	42,668,762	1,132,127
2012	3.5	52,667,171	40.00	36.80	0.9199	1.0000	48,445,928	1,316,538
2011	4.5	48,027,742	40.01	35.93	0.8981	1.0000	43,132,417	1,200,488
2010	5.5	54,141,429	39.99	35.08	0.8773	1.0000	47,498,016	1,353,823
2009	6.5	52,324,833	40.02	34.27	0.8563	1.0000	44,803,684	1,307,547
2008	7.5	91,168,473	39.98	33.47	0.8374	1.0000	76,340,889	2,280,634
2007	8.5	117,968,836	39.99	32.71	0.8180	1.0000	96,504,072	2,950,299
2006	9.5	112,039,137	39.92	31.98	0.8009	1.0000	89,734,834	2,806,390
2005	10.5	86,507,732	40.00	31.27	0.7818	1.0000	67,633,119	2,162,861
2004	11.5	64,161,451	39.95	30.60	0.7658	1.0000	49,132,981	1,605,902
2003	12.5	56,481,107	40.03	29.95	0.7482	1.0000	42,258,662	1,410,968
2002	13.5	57,225,087	39.98	29.33	0.7338	1.0000	41,992,383	1,431,500
2001	14.5	69,442,379	40.09	28.75	0.7171	1.0000	49,799,838	1,732,281
2000	15.5	59,803,506	39.93	28.19	0.7060	1.0000	42,221,256	1,497,744
1999	16.5	53,110,336	40.01	27.66	0.6913	1.0000	36,713,984	1,327,395
1998	17.5	64,216,421	40.38	27.15	0.6725	1.0000	43,183,703	1,590,368
1997	18.5	42,513,091	40.34	26.67	0.6612	1.0000	28,109,962	1,053,931
1996	19.5	41,758,299	40.23	26.21	0.6516	1.0000	27,207,896	1,037,991
1995	20.5	30,953,517	38.37	25.77	0.6716	1.0000	20,788,738	806,642
1994	21.5	26,193,832	40.20	25.35	0.6305	1.0000	16,516,069	651,548
1993	22.5	29,027,921	40.36	24.94	0.6179	1.0000	17,935,635	719,143
1992	23.5	37,313,721	40.32	24.54	0.6087	1.0000	22,711,780	925,411
1991	24.5	22,660,981	40.14	24.15	0.6017	1.0000	13,635,939	564,592
1990	25.5	37,571,415	39.54	23.77	0.6010	1.0000	22,581,910	950,145
1989	26.5	27,832,508	38.81	23.39	0.6027	1.0000	16,774,059	717,232
1988	27.5	17,182,891	36.48	23.01	0.6309	1.0000	10,840,774	471,075
1987	28.5	11,730,661	35.65	22.64	0.6352	1.0000	7,451,747	329,090
1986	29.5	7,564,173	34.92	22.28	0.6380	1.0000	4,825,990	216,616
1985	30.5	12,323,550	36.72	21.92	0.5970	1.0000	7,356,545	335,613
1984	31.5	7,982,701	36.59	21.57	0.5894	1.0000	4,704,741	218,164
1983	32.5	4,470,318	37.33	21.22	0.5683	1.0000	2,540,477	119,747
1982	33.5	4,393,975	37.08	20.87	0.5629	1.0000	2,473,195	118,503
1981	34.5	6,976,922	37.19	20.53	0.5520	1.0000	3,851,383	187,600
1980	35.5	4,350,962	36.43	20.19	0.5543	1.0000	2,411,775	119,434
1979	36.5	2,285,065	34.72	19.86	0.5720	1.0000	1,307,001	65,805

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant
Account: 367.00 UG Conductors and Devices

Dispersion: 40 - L1
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2015 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
1978	37.5	2,795,801	36.10	19.53	0.5411	1.0000	1,512,839	77,446
1977	38.5	1,791,160	35.82	19.21	0.5364	1.0000	960,724	50,009
1976	39.5	1,477,640	37.12	18.89	0.5090	1.0000	752,117	39,812
1975	40.5	2,160,022	36.45	18.58	0.5097	1.0000	1,100,976	59,267
1974	41.5	1,107,952	35.56	18.27	0.5137	1.0000	569,166	31,161
1973	42.5	1,139,154	37.18	17.96	0.4830	1.0000	550,200	30,638
1972	43.5	1,213,620	34.90	17.65	0.5058	1.0000	613,891	34,772
1971	44.5	640,087	31.90	17.35	0.5440	1.0000	348,200	20,064
1970	45.5	3,559,841	42.99	17.06	0.3968	1.0000	1,412,522	82,804
1969	46.5	926,575	39.60	16.77	0.4234	1.0000	392,324	23,401
1968	47.5	1,923,248	44.69	16.48	0.3687	1.0000	709,098	43,037
1967	48.5	2,779,657	48.49	16.19	0.3339	1.0000	928,129	57,325
1966	49.5	777,402	45.48	15.91	0.3498	1.0000	271,938	17,094
1965	50.5	1,379,371	47.19	15.63	0.3312	1.0000	456,862	29,231
1964	51.5	1,286,584	44.08	15.35	0.3483	1.0000	448,167	29,190
1963	52.5	301,588	42.92	15.08	0.3514	1.0000	105,970	7,027
1962	53.5	1,121	30.20	14.81	0.4904	1.0000	550	37
1961	54.5	2,502,019	46.94	14.54	0.3098	1.0000	775,214	53,300
1960	55.5	47,899	39.78	14.28	0.3590	1.0000	17,197	1,204
1958	57.5	39,261	43.41	13.76	0.3170	1.0000	12,446	904
1956	59.5	1,552,939	51.05	13.25	0.2596	1.0000	403,174	30,418
Total	13.0	$1,646,381,070	39.80	30.52	0.7667	1.0000	$1,262,362,572	$41,366,104

Schedule B
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ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2015	Derived Additions	1971 Opening Balance	Experience to 12/31/2015 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2015	0.5	91,359,584		91,359,584	1.0000	0.5000
2014	1.5	65,979,642		65,956,784	0.9997	1.4998
2013	2.5	45,438,007		45,289,616	0.9967	2.4983
2012	3.5	52,989,093		52,667,171	0.9939	3.4923
2011	4.5	48,431,203		48,027,742	0.9917	4.4853
2010	5.5	54,891,190		54,141,429	0.9863	5.4565
2009	6.5	52,776,797		52,324,833	0.9914	6.4643
2008	7.5	93,137,353		91,168,473	0.9789	7.3980
2007	8.5	120,914,282		117,968,836	0.9756	8.3781
2006	9.5	116,078,372		112,039,137	0.9652	9.2779
2005	10.5	88,986,954		86,507,732	0.9721	10.3059
2004	11.5	66,598,425		64,161,451	0.9634	11.2071
2003	12.5	58,501,475		56,481,107	0.9655	12.2177
2002	13.5	60,105,727		57,225,087	0.9521	13.0859
2001	14.5	72,627,404		69,442,379	0.9561	14.1077
2000	15.5	64,165,335		59,803,506	0.9320	14.8462
1999	16.5	57,265,024		53,110,336	0.9274	15.8105
1998	17.5	67,935,430		64,216,421	0.9453	17.0451
1997	18.5	45,960,570		42,513,091	0.9250	17.8555
1996	19.5	46,166,607		41,758,299	0.9045	18.5822
1995	20.5	39,198,296		30,953,517	0.7897	17.5426
1994	21.5	30,532,870		26,193,832	0.8579	20.1710
1993	22.5	32,818,292		29,027,921	0.8845	21.1142
1992	23.5	44,555,099		37,313,721	0.8375	21.8334
1991	24.5	28,788,635		22,660,981	0.7872	22.3931
1990	25.5	52,677,451		37,571,415	0.7132	22.5244
1989	26.5	44,455,312		27,832,508	0.6261	22.4937
1988	27.5	40,865,800		17,182,891	0.4205	20.8524
1987	28.5	30,924,071		11,730,661	0.3793	20.6919
1986	29.5	21,795,900		7,564,173	0.3470	20.6170
1985	30.5	24,808,329		12,323,550	0.4968	23.0497
1984	31.5	17,735,429		7,982,701	0.4501	23.5351
1983	32.5	8,745,998		4,470,318	0.5111	24.8723
1982	33.5	9,391,181		4,393,975	0.4679	25.1983
1981	34.5	13,919,669		6,976,922	0.5012	25.8700
1980	35.5	10,300,233		4,350,962	0.4224	25.6521
1979	36.5	6,639,570		2,285,065	0.3442	24.4721
1978	37.5	6,975,826		2,795,801	0.4008	26.3549

Schedule B
Page 2 of 2

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2015	Derived Additions	1971 Opening Balance	Experience to 12/31/2015 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1977	38.5	4,440,551		1,791,160	0.4034	26.5614
1976	39.5	3,277,478		1,477,640	0.4508	28.3339
1975	40.5	5,492,574		2,160,022	0.3933	28.1206
1974	41.5	2,968,554		1,107,952	0.3732	27.6706
1973	42.5	2,820,657		1,139,154	0.4039	29.7194
1972	43.5	3,877,951		1,213,620	0.3130	27.8477
1971	44.5	2,578,631		640,087	0.2482	25.2400
1970	45.5		7,023,065	3,559,841	0.5069	36.7048
1969	46.5		1,968,869	926,575	0.4706	33.6710
1968	47.5		3,241,505	1,923,248	0.5933	39.1090
1967	48.5		3,838,902	2,779,657	0.7241	43.2417
1966	49.5		1,378,728	777,402	0.5639	40.5470
1965	50.5		2,643,892	1,379,371	0.5217	42.5610
1964	51.5		3,507,482	1,286,584	0.3668	39.7381
1963	52.5		1,017,190	301,588	0.2965	38.8569
1962	53.5		128,232	1,121	0.0087	26.4000
1961	54.5		6,995,617	2,502,019	0.3577	43.3927
1960	55.5		264,023	47,899	0.1814	36.4654
1959	56.5		93,968		0.0000	30.4671
1958	57.5		190,948	39,261	0.2056	40.5403
1957	58.5		67,204		0.0000	28.9379
1956	59.5		4,023,015	1,552,939	0.3860	48.5772
1955	60.5		122,718		0.0000	33.2093
1954	61.5		19,062		0.0000	31.2236
1953	62.5		15,400		0.0000	34.1003
1952	63.5		14,699		0.0000	33.4659
1951	64.5		4,289		0.0000	35.6181
1950	65.5		10,233		0.0000	44.0000
1946	69.5		8,447		0.0000	48.0000
1940	75.5		4,926		0.0000	42.7389
Total	13.0	$1,860,892,830	$36,582,414	$1,646,381,070	0.8677	

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	11,234,859	5,227,485			16,462,344
1972	16,462,344	5,626,788	167,216		21,921,916
1973	21,921,916	5,899,426	110,107		27,711,235
1974	27,711,235	6,605,495	72,619		34,244,111
1975	34,244,111	4,188,877	143,093		38,289,895
1976	38,289,895	4,904,543	119,194	196	43,075,440
1977	43,075,440	7,682,950	62,687	135	50,695,839
1978	50,695,839	6,255,514	144,347	223	56,807,229
1979	56,807,229	12,165,882	180,100	338	68,793,348
1980	68,793,348	11,925,816	261,221	6,573	80,464,517
1981	80,464,517	13,706,676	311,535	(182)	93,859,475
1982	93,859,475	12,677,752	280,423		106,256,805
1983	106,256,805	12,220,047	167,539	27	118,309,340
1984	118,309,340	24,564,892	620,234	(711,901)	141,542,097
1985	141,542,097	28,119,927	588,413	100,773	169,174,384
1986	169,174,384	33,086,796	776,947	(819,083)	200,665,150
1987	200,665,150	40,442,295	1,411,693	11,977	239,707,730
1988	239,707,730	44,562,290	1,298,863	(102,165)	282,868,992
1989	282,868,992	39,930,190	1,822,189	1,230,377	322,207,369
1990	322,207,369	48,232,643	2,081,398	(242,515)	368,116,099
1991	368,116,099	26,258,331	6,505,011	(35,194)	387,834,225
1992	387,834,225	43,961,641	7,676,820	(25,026,623)	399,092,424
1993	399,092,424	32,825,279	12,346,537	(323,901)	419,247,265
1994	419,247,265	30,533,944	6,133,313	385,837	444,033,733
1995	444,033,733	39,423,523	5,497,824		477,959,432
1996	477,959,432	46,015,566	2,560,192		521,414,806
1997	521,414,806	45,962,909	8,905,235	(37,625)	558,434,855
1998	558,434,855	67,536,428	21,756,216		604,215,067
1999	604,215,067	57,369,075	9,569,466		652,014,675
2000	652,014,675	63,360,845	10,611,085		704,764,435
2001	704,764,435	51,081,906	10,079,147		745,767,195
2002	745,767,195	69,400,154	13,144,993		802,022,355
2003	802,022,355	60,001,037	12,088,891		849,934,501
2004	849,934,501	74,271,162	15,315,290		908,890,373
2005	908,890,373	91,985,491	7,426,563	379,484	993,828,785
2006	993,828,785	123,918,259	8,664,638	429	1,109,082,836
2007	1,109,082,836	134,150,439	10,281,509	1,872,293	1,234,824,060
2008	1,234,824,060	94,814,104	9,083,916	(95,633)	1,320,458,614
2009	1,320,458,614	62,492,252	11,733,105	202,017	1,371,419,778
2010	1,371,419,778	58,927,725	7,660,141	21,140	1,422,708,502

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2011	1,422,708,502	43,524,346	9,210,495	(44,497)	1,456,977,856
2012	1,456,977,856	47,222,515	9,583,537	36,067	1,494,652,901
2013	1,494,652,901	53,730,829	6,521,014	115,062	1,541,977,778
2014	1,541,977,778	54,477,481	8,392,283	(984,094)	1,587,078,882
2015	1,587,078,882	69,029,324	9,727,135		1,646,381,070

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	11,081,927	5,227,485			16,309,412
1972	16,309,412	6,221,813	167,216		22,364,009
1973	22,364,009	6,947,551	109,802		29,201,758
1974	29,201,758	5,440,303	71,744		34,570,317
1975	34,570,317	3,856,115	143,398		38,283,034
1976	38,283,034	4,856,897	108,092	196	43,032,035
1977	43,032,035	5,547,742	73,789	135	48,506,123
1978	48,506,123	9,535,737	144,905	223	57,897,178
1979	57,897,178	11,431,460	180,100	338	69,148,876
1980	69,148,876	12,365,001	261,538	6,573	81,258,911
1981	81,258,911	13,176,167	311,535	(182)	94,123,362
1982	94,123,362	12,706,417	280,423		106,549,356
1983	106,549,356	13,043,237	165,751	27	119,426,869
1984	119,426,869	21,961,759	617,304	(711,901)	140,059,423
1985	140,059,423	24,635,568	591,343	100,773	164,204,421
1986	164,204,421	33,744,143	773,965	(819,083)	196,355,516
1987	196,355,516	32,889,905	1,408,643	11,977	227,848,755
1988	227,848,755	43,251,756	1,217,615	(102,165)	269,780,732
1989	269,780,732	49,842,853	1,833,911	1,230,377	319,020,051
1990	319,020,051	46,937,808	2,081,042	(242,515)	363,634,302
1991	363,634,302	36,843,350	6,580,659	(35,194)	393,861,799
1992	393,861,799	38,618,248	7,675,544	(25,026,623)	399,777,881
1993	399,777,881	32,821,128	12,345,547	(323,901)	419,929,561
1994	419,929,561	30,543,844	6,132,492	385,837	444,726,750
1995	444,726,750	39,205,414	5,497,343		478,434,821
1996	478,434,821	46,165,701	2,559,267		522,041,255
1997	522,041,255	45,963,007	8,902,760	(37,625)	559,063,877
1998	559,063,877	67,627,089	21,754,729		604,936,237
1999	604,936,237	57,268,388	9,560,988		652,643,637
2000	652,643,637	64,094,317	10,610,781		706,127,173
2001	706,127,173	72,356,008	10,078,436		768,404,745
2002	768,404,745	59,854,232	13,144,764		815,114,212
2003	815,114,212	57,994,724	12,111,789		860,997,147
2004	860,997,147	66,443,756	15,353,546		912,087,356
2005	912,087,356	88,711,500	7,750,593	379,484	993,427,747
2006	993,427,747	115,778,603	8,299,685	429	1,100,907,095
2007	1,100,907,095	120,859,815	10,281,509	1,871,806	1,213,357,206
2008	1,213,357,206	93,119,595	9,083,916	(95,633)	1,297,297,252
2009	1,297,297,252	52,776,797	11,733,105	202,017	1,338,542,961
2010	1,338,542,961	54,761,885	7,660,141	21,140	1,385,665,846

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2011	1,385,665,846	48,440,401	9,210,495	(44,497)	1,424,851,254
2012	1,424,851,254	53,809,516	9,583,537	36,067	1,469,113,301
2013	1,469,113,301	45,438,007	6,521,014	115,062	1,508,145,356
2014	1,508,145,356	65,979,642	8,392,283	(984,094)	1,564,748,621
2015	1,564,748,621	91,359,584	9,727,135		1,646,381,070

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ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2015
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling 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
1971-1975	66.0	51.3	L0.5	2.57	47.6	L1	2.83	36.7	R2	4.43
1972-1976	67.4	55.1	L0.5	2.60	52.3	L1	2.68	41.0	R1.5	3.26
1973-1977	82.2	75.6	L0.5	2.10	145.1	SC *	1.42	49.5	R2	2.42
1974-1978	81.4	73.2	L0.5	1.94	141.4	SC *	1.13	51.5	R2	2.10
1975-1979	71.5	59.3	L1	1.61	53.4	L1.5	2.30	113.1	O3 *	1.83
1976-1980	66.2	55.5	L1	1.97	45.3	S0.5	4.31	138.6	SC *	2.03
1977-1981	50.2	48.2	L1 *	2.58	37.8	S1	5.90	104.9	O4 *	2.95
1978-1982	44.7	46.3	L1.5 *	2.81	36.1	S1	7.05	103.7	O4 *	3.16
1979-1983	48.1	49.3	L1.5 *	2.62	38.1	S1	7.43	118.0	SC *	3.47
1980-1984	27.2	45.7	L1.5 *	7.23	33.8	S1.5	6.44	63.2	O4 *	3.14
1981-1985	23.0	45.6	L1.5 *	8.16	33.5	S1.5	6.97	44.6	L1.5 *	4.28
1982-1986	21.1	46.2	L1.5 *	8.71	34.0	S1.5	6.53	34.7	S1.5	5.46
1983-1987	13.3	45.1	L1 *	11.96	32.6	S1.5	5.11	32.5	S1.5	5.19
1984-1988	13.1	44.7	L1	10.48	33.2	S1.5	5.16	32.8	S1.5	5.75
1985-1989	16.8	44.1	L1	7.51	34.9	S1	4.21	34.0	R2	5.53
1986-1990	5.1	41.4	L1	9.31	33.4	S1	2.78	32.5	R2	4.23
1987-1991	4.6	43.8	L0	10.67	34.8	R1	3.32	31.1	R2	7.23
1988-1992	0.4	34.7	L0.5	13.06	92.3	O4 *	20.15	103.2	O4 *	22.85
1989-1993	0.8	27.3	L0.5	6.54	79.8	O4 *	16.22	78.3	O4 *	15.75
1990-1994	0.0	27.3	L0.5	8.31	76.0	O4 *	16.34	72.8	O4 *	15.27
1991-1995	0.0	27.8	L0.5	9.71	74.0	O4 *	15.84	69.5	O4 *	14.26
1992-1996	0.0	30.3	L0.5	12.57	79.4	O4 *	16.72	73.8	O4 *	14.84
1993-1997	0.0	29.6	L1	8.88	54.7	O4 *	10.33	64.8	O4 *	12.11
1994-1998	0.0	25.7	L1.5 *	4.11	26.0	S0.5	3.25	26.7	R1.5	3.40
1995-1999	0.0	26.0	L1.5 *	4.65	26.0	S0.5	3.37	26.6	R1.5	2.57
1996-2000	5.5	26.2	L1.5 *	5.40	26.0	S0.5	4.32	26.4	R1	3.03
1997-2001	5.8	25.9	L1.5 *	5.13	25.6	S0.5	4.59	25.8	S0	3.66
1998-2002	10.9	26.5	L1 *	4.22	26.4	L1	4.29	26.4	L1	4.26
1999-2003	46.1	33.3	L0.5	10.40	95.4	O4 *	3.85	90.8	O4 *	5.34
2000-2004	34.3	32.2	L0.5	9.15	86.6	O4 *	3.36	81.1	O4 *	4.94
2001-2005	25.2	34.2	L0.5	8.17	89.1	O4 *	3.80	85.5	O4 *	5.08
2002-2006	42.4	36.6	L1	8.27	94.0	O4 *	3.14	91.4	O4 *	4.72
2003-2007	44.1	39.6	L1	7.08	94.2	O4 *	3.09	95.4	O4 *	4.65
2004-2008	46.3	41.8	L1	6.85	93.9	O4 *	3.14	99.5	O4 *	4.43
2005-2009	5.1	45.1	L1	7.39	94.9	O4 *	6.17	105.2	O4 *	7.27
2006-2010	20.1	46.5	L1	6.26	85.1	O4 *	4.61	105.6	O4 *	5.82
2007-2011	48.2	46.7	L1	6.94	85.4	O4 *	4.19	104.7	O4 *	5.15
2008-2012	0.0	47.9	L1 *	7.57	86.3	O4 *	6.55	106.2	O4 *	7.50

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2015
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
2009-2013	53.9	50.1	L1.5 *	6.11	88.9	O4 *	3.73	109.8	O4 *	4.13
2010-2014	55.2	53.0	L1.5 *	5.51	81.1	O3 *	3.85	113.5	O3 *	3.53
2011-2015	57.1	52.3	L1.5 *	7.35	85.2	O4 *	5.10	111.5	O3 *	5.35

ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2015
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking 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
1971-2015	36.7	40.6	L1	5.59	62.1	O4 *	3.12	87.8	O4 *	1.22
1973-2015	36.7	40.6	L1	5.59	62.2	O4 *	3.12	87.8	O4 *	1.22
1975-2015	36.7	40.6	L1	5.59	62.2	O4 *	3.12	87.8	O4 *	1.22
1977-2015	36.7	40.6	L1	5.59	62.3	O4 *	3.12	87.8	O4 *	1.22
1979-2015	36.7	40.5	L1	5.59	62.3	O4 *	3.11	87.8	O4 *	1.22
1981-2015	36.7	40.5	L1	5.59	62.4	O4 *	3.10	87.7	O4 *	1.22
1983-2015	36.7	40.5	L1	5.58	62.5	O4 *	3.09	87.7	O4 *	1.22
1985-2015	36.7	40.5	L1	5.57	62.8	O4 *	3.07	87.7	O4 *	1.22
1987-2015	36.6	40.5	L1	5.57	63.2	O4 *	3.05	87.6	O4 *	1.21
1989-2015	36.6	40.5	L1	5.58	64.0	O4 *	3.01	87.6	O4 *	1.21
1991-2015	36.6	40.5	L1	5.56	64.5	O4 *	2.98	87.6	O4 *	1.22
1993-2015	36.8	40.7	L1	5.61	64.7	O4 *	3.03	88.0	O4 *	1.22
1995-2015	36.9	41.6	L1	5.22	57.1	O3 *	3.38	88.4	O4 *	1.16
1997-2015	36.4	41.6	L1	5.03	53.4	O3 *	3.48	87.2	O4 *	1.14
1999-2015	50.1	45.4	L1	8.41	101.4	O4 *	3.06	106.0	O4 *	3.26
2001-2015	50.4	46.2	L1	8.10	98.0	O4 *	3.50	105.7	O4 *	3.59
2003-2015	50.9	47.6	L1	7.41	91.3	O4 *	3.94	106.2	O4 *	3.75
2005-2015	52.7	49.9	L1 *	6.73	82.6	O4 *	4.27	109.1	O4 *	3.85
2007-2015	53.1	50.1	L1.5 *	6.85	81.1	O4 *	4.51	108.5	O4 *	4.19
2009-2015	53.2	50.9	L1.5 *	6.50	79.3	O3 *	4.42	108.9	O4 *	4.03
2011-2015	57.1	52.3	L1.5 *	7.35	85.2	O4 *	5.10	111.5	O3 *	5.35
2013-2015	55.9	53.7	L1.5 *	6.37	72.6	O3 *	4.94	112.4	O3 *	4.68
2015-2015	49.5	49.7	L1.5 *	6.61	55.9	L1 *	5.57	100.1	O4 *	5.21

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ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None

Placement Band: 1940-2015

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing 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
1971-1972	66.4	44.2	L0.5	3.54	32.0	S1	8.19	29.7	R2	9.75
1971-1974	71.2	55.2	L0.5	3.05	43.0	S0.5	4.53	36.8	R2	5.74
1971-1976	68.2	57.6	L0.5	2.48	55.7	L1	2.49	40.6	R2	3.15
1971-1978	67.7	69.5	L0.5	3.33	54.7	S0.5	2.45	73.1	O3 *	2.59
1971-1980	53.1	56.3	L1	4.85	44.0	S0.5	1.75	115.6	O3 *	3.18
1971-1982	37.5	50.3	L1	7.51	37.7	S1	1.69	79.8	O4 *	2.61
1971-1984	25.5	48.8	L1 *	9.21	35.4	S1.5	3.22	42.1	L2 *	1.88
1971-1986	16.7	47.7	L1 *	11.03	34.9	S1.5	2.86	35.2	S1.5	2.56
1971-1988	10.0	46.9	L1	13.11	34.5	S1.5	2.08	34.3	S1.5	2.19
1971-1990	2.5	43.4	L1 *	13.58	33.8	S1	1.90	33.5	S1.5	1.51
1971-1992	0.9	38.1	L0.5	13.77	39.1	L0.5	14.40	107.6	O4 *	21.74
1971-1994	0.0	31.5	L1	8.22	87.7	O4 *	17.74	92.4	O4 *	19.17
1971-1996	0.0	33.7	L1	10.00	96.0	O4 *	18.98	94.3	O4 *	18.51
1971-1998	0.0	27.4	L1.5 *	4.19	26.9	S0.5	3.50	27.2	S0.5	3.11
1971-2000	0.0	28.3	L1 *	3.79	27.9	L1.5	3.40	27.8	S0	2.91
1971-2002	0.0	29.0	L1	4.15	29.2	L1	4.30	31.1	L1 *	4.54
1971-2004	0.0	29.5	L1	3.47	31.6	L0.5 *	3.50	53.8	O4 *	5.19
1971-2006	0.0	31.6	L1	4.19	36.9	L0.5 *	3.15	62.1	O4 *	3.82
1971-2008	0.0	33.4	L1	4.49	43.8	O3 *	3.35	69.8	O4 *	4.16
1971-2010	7.8	35.2	L1	4.32	48.5	O3 *	2.89	74.8	O4 *	3.47
1971-2012	0.0	37.2	L1	5.44	56.3	O4 *	4.04	80.6	O4 *	4.52
1971-2014	36.1	39.7	L1	5.44	62.8	O4 *	2.87	86.7	O4 *	1.36
1971-2015	36.7	40.6	L1	5.59	62.1	O4 *	3.12	87.8	O4 *	1.22

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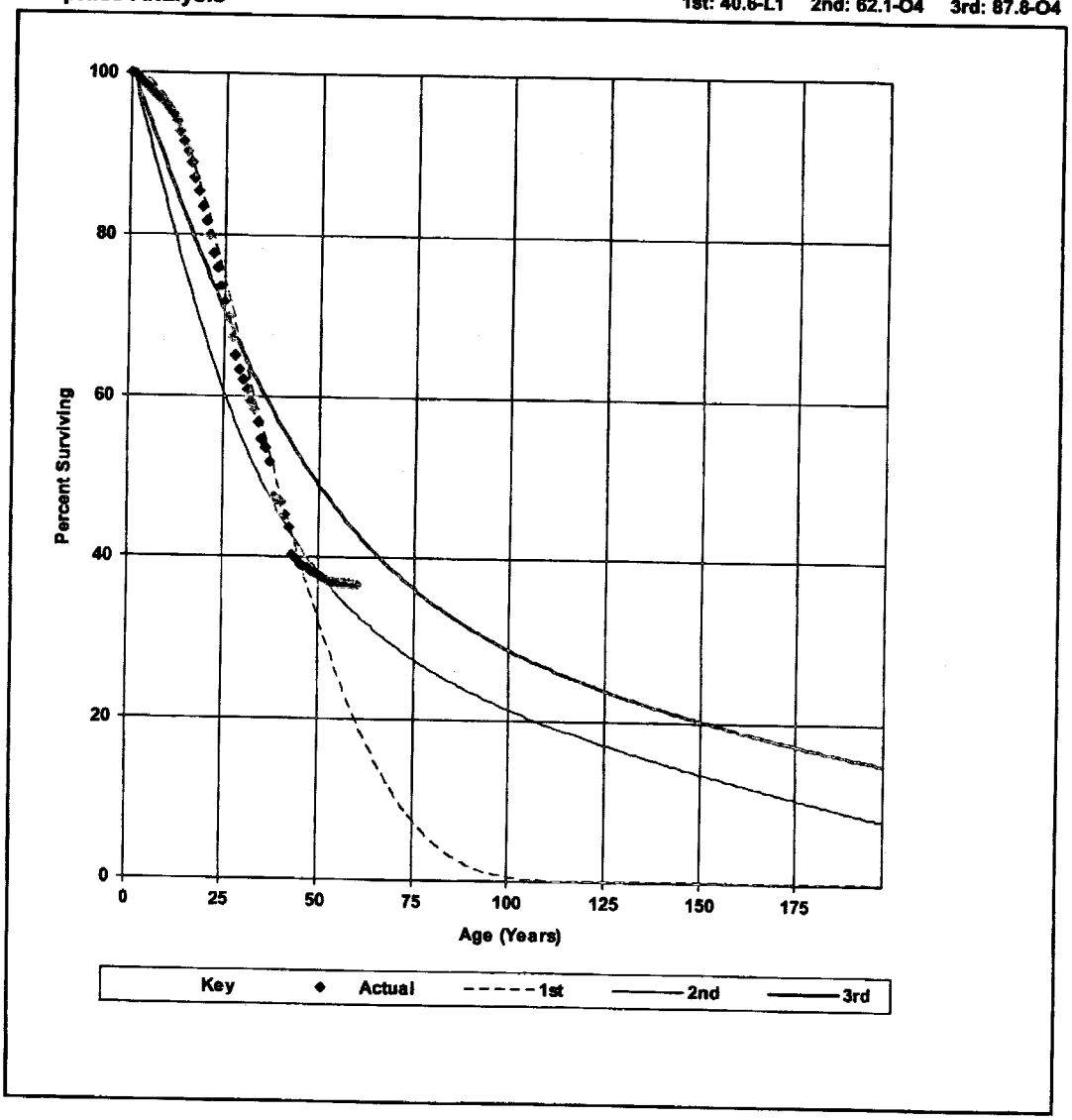
ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2015 Observation Band: 1971-2015
Hazard Function: Proportion Retired
Weighting: Exposures
1st: 40.6-L1 2nd: 62.1-O4 3rd: 87.8-O4

Graphics Analysis



Schedule E
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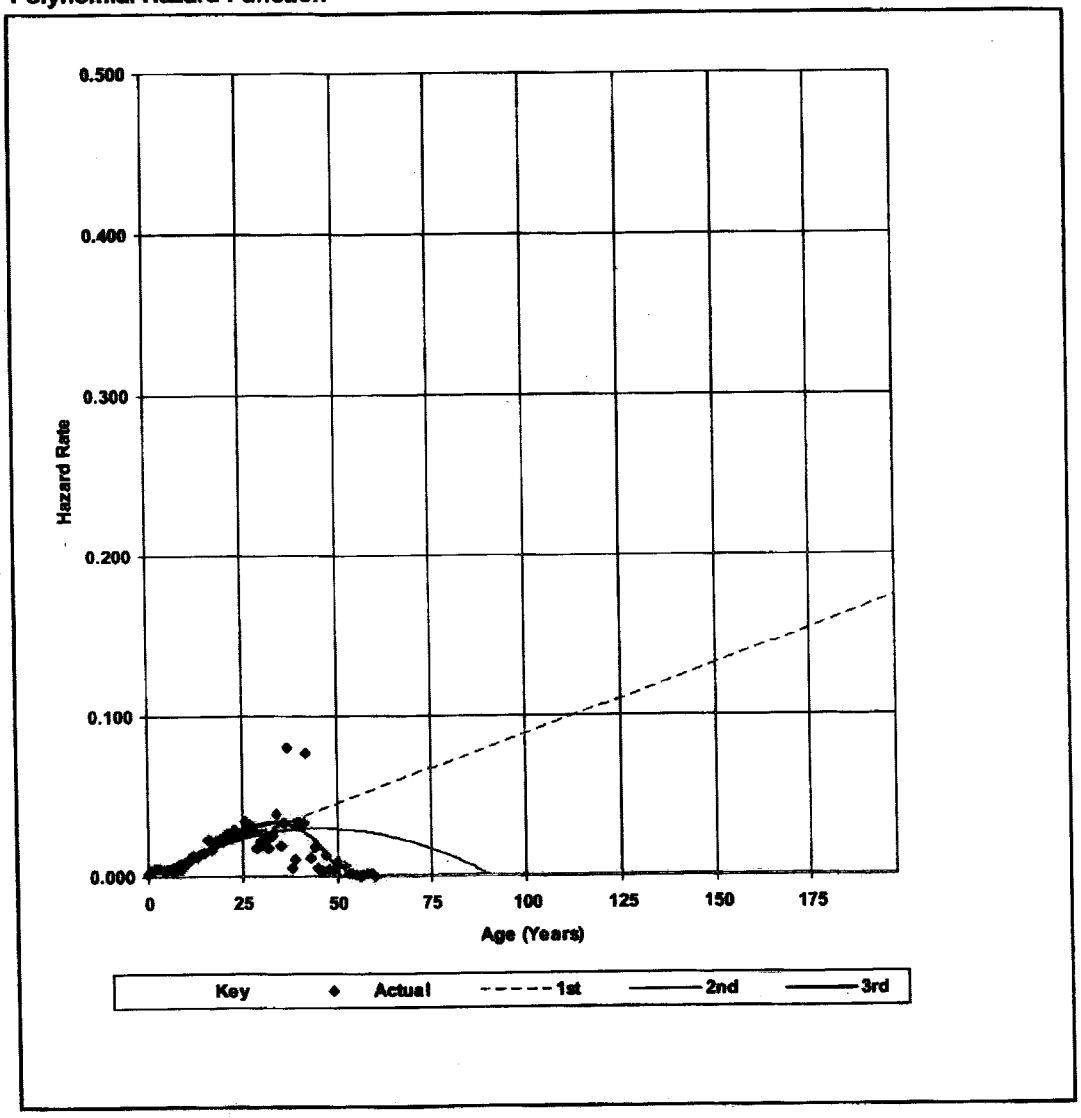
ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2015 Observation Band: 1971-2015
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Function 1st: 40.6-L1 2nd: 62.1-O4 3rd: 87.8-O4



Schedule E
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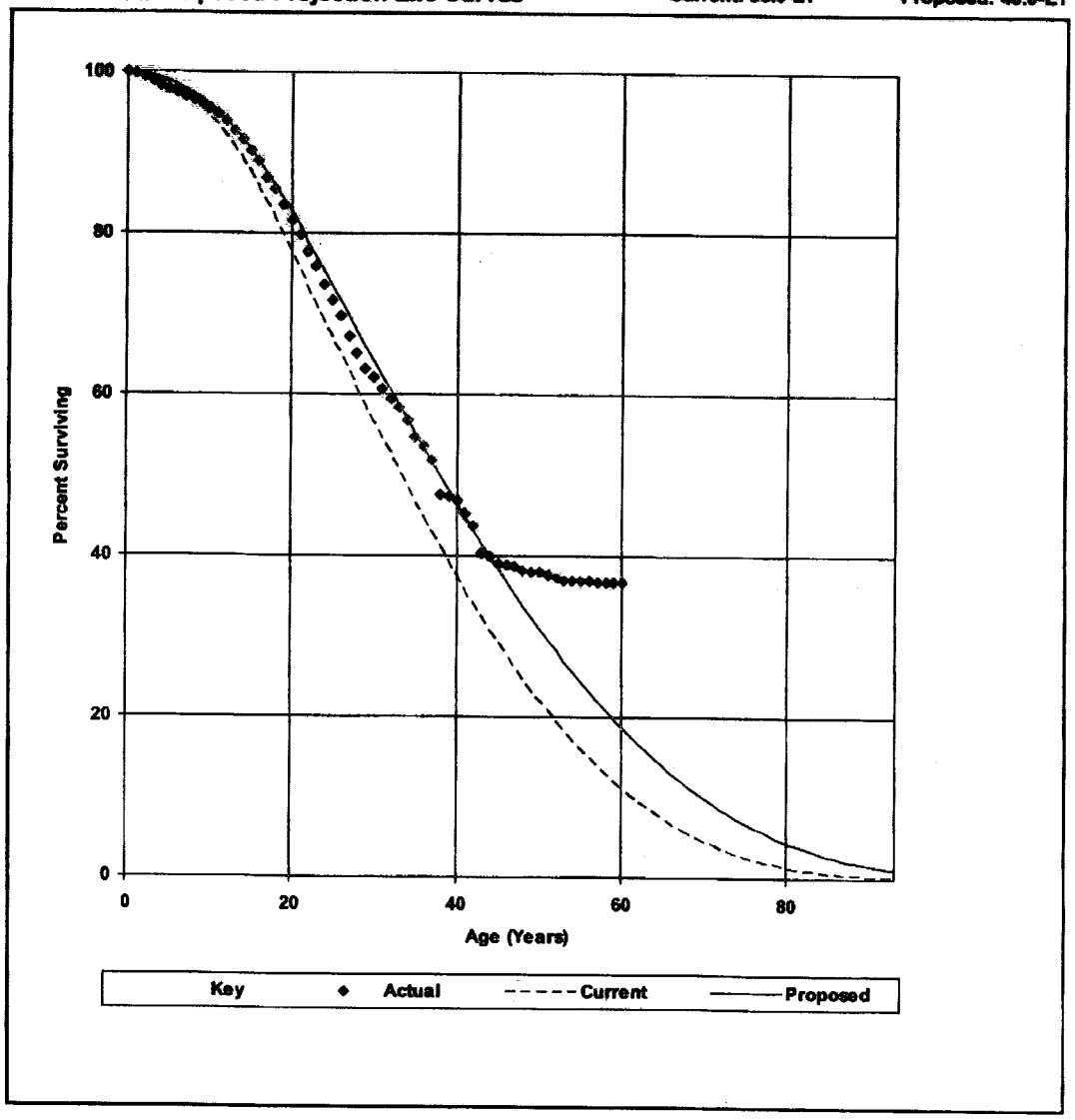
ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2015
Observation Band: 1971-2015

Current and Proposed Projection Life Curves Current: 35.0-L1 Proposed: 40.0-L1



ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

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
1993	12,346,537	2,524,434	20.4		1,610,244	13.0		914,190	7.4	
1994	6,133,313	1,148,835	18.7		909,409	14.8		239,426	3.9	
1995	5,497,824	1,113,693	20.3		616,784	11.2		496,909	9.0	
1996	2,560,192	265,961	10.4		270,617	10.6		(4,655)	-0.2	
1997	8,905,235	1,174,025	13.2	17.6	597,293	6.7	11.3	576,731	6.5	6.3
1998	21,756,216		0.0	8.3	4,596	0.0	5.3	(4,596)	0.0	2.9
1999	9,569,466		0.0	5.3	13,462	0.1	3.1	(13,462)	-0.1	2.2
2000	10,611,085	2,917,118	27.5	8.2	851,477	8.0	3.3	2,065,640	19.5	4.9
2001	10,079,147	1,973,691	19.6	10.0	1,993,829	19.8	5.7	(20,138)	-0.2	4.3
2002	13,144,993	1,533,592	11.7	9.9	2,379,742	18.1	8.0	(846,150)	-6.4	1.8
2003	12,088,891	1,208,607	10.0	13.8	2,121,011	17.5	13.3	(912,404)	-7.5	0.5
2004	15,315,290	1,306,856	8.5	14.6	1,971,252	12.9	15.2	(664,396)	-4.3	-0.6
2005	7,426,563	1,536,983	20.7	13.0	3,342,225	45.0	20.3	(1,805,242)	-24.3	-7.3
2006	8,664,638	4,972,381	57.4	18.6	2,695,724	31.1	22.1	2,276,657	26.3	-3.4
2007	10,281,509	3,672,708	35.7	23.6	3,782,266	36.8	25.9	(109,557)	-1.1	-2.3
2008	9,083,916	3,764,197	41.4	30.0	4,689,426	51.6	32.5	(925,229)	-10.2	-2.4
2009	11,733,105	2,169,201	18.5	34.2	3,391,321	28.9	37.9	(1,222,120)	-10.4	-3.8
2010	7,660,141	12,570,515	164.1	57.2	4,986,596	65.1	41.2	7,583,919	99.0	16.0
2011	9,210,495	1,131,945	12.3	48.6	2,767,426	30.0	40.9	(1,635,481)	-17.8	7.7
2012	9,583,537	1,495,667	15.6	44.7	3,097,894	32.3	40.1	(1,602,227)	-16.7	4.7
2013	6,521,014	296,727	4.6	39.5	2,926,160	44.9	38.4	(2,629,433)	-40.3	1.1
2014	8,392,283	1,491,999	17.8	41.1	4,304,042	51.3	43.7	(2,812,043)	-33.5	-2.6
2015	9,727,135	1,295,380	13.3	13.2	4,942,304	50.8	41.5	(3,646,925)	-37.5	-28.4
Total	226,292,524	49,564,515	21.9		54,265,101	24.0		(4,700,586)	-2.1	

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ARIZONA PUBLIC SERVICE COMPANY
Distribution Plant
Account: 367.00 UG Conductors and Devices

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
1993	12,345,547	2,524,434	20.4		1,610,244	13.0		914,190	7.4	
1994	6,132,492	1,148,835	18.7		909,409	14.8		239,426	3.9	
1995	5,497,343	1,113,693	20.3		616,784	11.2		496,909	9.0	
1996	2,559,267	265,961	10.4		270,617	10.6		(4,655)	-0.2	
1997	8,902,760	1,174,025	13.2	17.6	597,293	6.7	11.3	576,731	6.5	6.3
1998	21,754,729		0.0	8.3	4,596	0.0	5.3	(4,596)	0.0	2.9
1999	9,560,988		0.0	5.3	13,462	0.1	3.1	(13,462)	-0.1	2.2
2000	10,610,781	2,917,118	27.5	8.2	851,477	8.0	3.3	2,065,640	19.5	4.9
2001	10,078,436	1,973,691	19.6	10.0	1,993,829	19.8	5.7	(20,138)	-0.2	4.3
2002	13,144,764	1,533,592	11.7	9.9	2,379,742	18.1	8.0	(846,150)	-6.4	1.8
2003	12,111,789	1,208,607	10.0	13.8	2,121,011	17.5	13.3	(912,404)	-7.5	0.5
2004	15,353,546	1,306,856	8.5	14.6	1,971,252	12.8	15.2	(664,396)	-4.3	-0.6
2005	7,750,593	1,536,983	19.8	12.9	3,342,225	43.1	20.2	(1,805,242)	-23.3	-7.3
2006	8,299,685	4,972,381	59.9	18.6	2,695,724	32.5	22.1	2,276,657	27.4	-3.4
2007	10,281,509	3,672,708	35.7	23.6	3,782,266	36.8	25.9	(109,557)	-1.1	-2.3
2008	9,083,916	3,764,197	41.4	30.0	4,689,426	51.6	32.5	(925,229)	-10.2	-2.4
2009	11,733,105	2,169,201	18.5	34.2	3,391,321	28.9	38.0	(1,222,120)	-10.4	-3.8
2010	7,660,141	12,570,515	164.1	57.7	4,986,596	65.1	41.5	7,583,919	99.0	16.2
2011	9,210,495	1,131,945	12.3	48.6	2,767,426	30.0	40.9	(1,635,481)	-17.8	7.7
2012	9,583,537	1,495,667	15.6	44.7	3,097,894	32.3	40.1	(1,602,227)	-16.7	4.7
2013	6,521,014	296,727	4.6	39.5	2,926,160	44.9	38.4	(2,629,433)	-40.3	1.1
2014	8,392,283	1,491,999	17.8	41.1	4,304,042	51.3	43.7	(2,812,043)	-33.5	-2.6
2015	9,727,135	1,295,380	13.3	13.2	4,942,304	50.8	41.5	(3,646,925)	-37.5	-28.4
Total	226,295,855	49,564,515	21.9		54,265,101	24.0		(4,700,586)	-2.1	