0000170846

Arizona Public Service Company

Rate Application

E-01345A-16-0036

Part 1 of 3 0000170846

To see Part 2 of 3 see 0000170847

To see Part 3 of 3 see 0000170848

ORIGINAL

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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
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COMMISSIONERS

DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-16-0036 **APPLICATION**

With the strong foundation established in Arizona Public Service Company's last rate case and disciplined cost management, APS has been able to defer filing a rate case for five years. APS now requests an increase in base rate revenue of $165.9 million, or 5.74%, net of existing adjustor mechanisms, as described below. APS submits this Application under Arizona Revised Statute §40-250 and Arizona Administrative Code R14-2-103. APS requests that the increase be effective on July 1, 2017.

The increase reflects investments that APS has made on behalf of its customers over the past five years. It also includes significant plant additions up to the proposed rate-effective date. Dramatic changes are occurring in the electric utility industry, from environmental regulations to low natural gas prices to the opportunities afforded by distributed technologies. Although the industry is in flux, APS remains committed to providing its customers safe and reliable electricity that meets customers' evolving needs. APS is building a bridge to the future—a future of clean, sustainable energy. To do this, APS must build, operate, and maintain a flexible grid that enables customer choices. The requested increase reflects, at least in part, the substantial efforts APS has made towards this goal of a clean, sustainable energy future.

Bridging Arizona to a clean, sustainable energy future also requires changing an antiquated method of how customers are charged for electricity. In addition to a revenue increase, APS requests that the Commission modernize APS's residential and small commercial rate design to encourage new distributed technologies and begin addressing the inequitable reallocation of revenue requirements caused by the current volumetric rate design and net energy metering (NEM).

APS's request also includes, among other items, (i) a cost deferral and step increase for the costs associated with installing selective catalytic reduction (SCR) technology at the Four Corners Power Plant; (ii) a cost deferral for its Ocotillo Modernization Project (OMP); (iii) changes to its non-residential rates, including several new rate options for larger general service and lighting customers and not renewing the Experimental AG-1 program; and, (iv) changes to the depreciation rates currently applied to APS's utility plant.

APS's complete request is described in and supported by the testimony, exhibits, and schedules submitted with this Application. The Company intends to call the following witnesses as part of its direct case, who will address the indicated topics:

Daniel Froetscher	Overview of Company, Impact to Arizona, and Industry Challenges
Barbara Lockwood	Overview of the Rate Case
John Lucas	Fossil Generation
John Cadogan	Nuclear Generation
Jacob Tetlow	Distribution and Grid Facilities
Stacy Derstine	Customer Service, Customer Outreach on Rate Design Changes, and Customer Information System
James Wilde	Resource Planning
Scott Bordenkircher	Technology, Renewables, and Advanced Power Grid
Peter Ewen	Base Fuel Cost and the Power Supply Adjustor; Weather Normalization and Bond Rating
Dr. Bente Villadsen	Cost of Equity and Fair Value Rate of Return
Leland Snook	Cost of Service, Deferral Proposals and Step Increase, Fair Value Rate Base and Rate of Return, LFCR, EIS, and TCA Changes, Extra High Load Factor Rate, AG-1, Economic Development Schedule, SFR Schedules A and G
Dr. Ahmad Faruqui	Overview of National Residential Rate Design
Charles Miessner	Residential and C&I Rate Design, Service Schedules
Elizabeth Blankenship	Accounting, rate base and income statement pro formas, Cholla 2, adjustor transfers
Dr. Ronald White	Depreciation

As with prior rate cases, APS includes subject matter witnesses from the four major operational business units—fossil, nuclear, customer service, and transmission and

distribution—to discuss business operations and the support necessary to help the Company safely and reliably operate its system. These subject matter witnesses should provide all parties with important context that will facilitate assessing the Company's operations and the associated capital expenditure needs. For convenience, APS includes as Attachment A an executive summary of APS's proposal, including a summary of each witness's direct testimony.

I. SUMMARY OF RATE REQUEST

APS's current rates, which became effective on July 1, 2012 following Decision No. 73183 (May 24, 2012), were based on a test year ending December 31, 2010. Since that time, APS engaged in a rigorous cost management effort that successfully permitted APS to refrain from seeking new rates for five years. At the same time, APS continued to provide the high quality electric service its customers have come to know and expect.

But the needs of APS customers are evolving. To prepare for and enable these changing customer needs, APS has made (and will continue to make) significant investments in the electrical grid and its generation resources. These investments are needed to create a flexible platform that will be the bridge to Arizona's energy future. After five years of making investments, APS now seeks an increase to its rates based on the adjusted sales and expenses for the Company's jurisdictional electric operations that occurred during the twelve months ending December 31, 2015 (Test Year). The details of this rate request are contained in the Direct Testimony of APS's witnesses and are summarized below.

A. Base Rate Request

APS proposes to increase net base rate revenues by $165.9 million, which would increase the amount of net revenue APS currently collects from customers by 5.74%. APS also seeks to transfer to base rates $267.6 million that is currently collected in adjustor mechanisms. Because this amount is already reflected in customers' bills, however, transferring these dollars into base rates is revenue neutral and therefore not

included in the $165.9 million figure cited above. Including the transferred adjustor mechanism revenue, the gross base rate revenue requirement increase is $433.4 million, or 15%.

The total revenue requirement increase of $433.4 million includes (i) a non-fuel gross base rate increase of $227.6 million; (ii) $267.6 million that is being transferred from adjustor mechanisms; and (iii) a decrease in base fuel costs of ($61.7 million). The non-fuel increase includes the investments APS has made over the last five years since its last rate case. It also includes a pro forma adjustment that incorporates 18 months of post-Test Year plant. The post-Test Year plant adjustment is structured in the same manner as similar adjustments made in connection with APS's two preceding rate cases, and will only capture plant that is actually in service by the time new rates become effective on July 1, 2017. The post-Test Year investments in this pro forma adjustment are critical for APS to meet the evolving needs of its customers, and include the following major projects:

- A modernized Customer Information System. APS is upgrading its 17-year old customer billing platform to improve operating efficiencies and enable advanced billing structures that promote new technologies;
- Solar Partners Program. A program evaluated in Decision No. 74878 that involves studying how rooftop solar can be strategically targeted on the grid for maximum benefit while serving low-income customers;
- Advanced Distribution Monitoring and Management System (ADMS). An operating platform that will lay the foundation for a flexible distribution grid that more easily integrates distributed technologies. ADMS will allow for remote monitoring, diagnosis and operation of field devices, and improve efficiency, reliability, power quality, and safety.
- Energy Imbalance. APS is joining the western Energy Imbalance Market (EIM). The proliferation of intermittent resources, such as solar and wind, make energy imbalance increasingly prevalent. Joining the EIM will improve the efficiency of generation dispatch and permit many more opportunities for APS to buy and sell energy for the economic benefit of its customers.

This Application also presents an updated depreciation study that reflects the Company's depreciation expense using 2014-2015 data. This update demonstrates that APS's depreciation expense has increased by $81.4 million. This increase is due to: (1) the need to accurately reflect the useful lives of APS's property; (2) the investments the Company has made in its property since 2011; and, (3) changes in estimated retirement costs. APS witness Dr. Ronald White authors the updated depreciation study.

APS has chosen to propose a return of just 1% on the difference between APS's "fair value" rate base and the original cost of that rate base (also referred to as the fair value increment). Although both this increment and the requested 1% return have been calculated in a very conservative manner, they are nonetheless consistent with past findings of the Commission in APS's last two rate cases. APS also proposes its actual capital structure and embedded cost of debt at the end of the Test Year—55.8% equity and 44.2% long-term debt, and 5.13%, respectively—be adopted by the Commission. As discussed by APS witness Dr. Bente Villadsen, APS proposes a return on equity of 10.5%, which appropriately reflects market risks and would permit APS to effectively compete for the capital APS will need to continue investing in Arizona's energy future. Combined with the embedded 5.13% cost of debt, APS's weighted cost of capital is 8.13%. The inclusion of a 1% return on the fair value increment of the Company's fair value rate base produces a requested return on that rate base of 5.84%.

B. SCR's, OMP and Property Taxes

1. SCRs and Ocotillo Modernization Project

To comply with federal environmental laws, APS must install SCRs at the Four Corners Generating Station. As it did when acquiring Four Corners from SCE, APS requests a cost deferral order. The deferral would span from when the SCRs are installed to when they are incorporated in rates, and use the same procedure as authorized in the 2012 Settlement (Decision No. 73183). APS also requests a step rate increase in connection with the SCR project using the same procedure implemented in Decision No.

74876 (December 23, 2014). APS estimates that this step increase will necessitate an additional 2% across-the-board increase in rates beginning in 2019, or approximately $3 per month for the typical APS residential customer.

In addition, APS seeks a deferral for the costs associated with building the OMP. The OMP will supply fast-ramping natural gas generation in APS's load pocket, and is critical for APS to effectively integrate the increasing amount of renewable generation on its system. 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. APS does not seek a step increase for the OMP costs.

Both the two requested deferral orders and the SCR-related step increase are necessary to preserve APS's opportunity to earn a reasonable return until its next rate case. Just as APS was able to forestall this rate case for five years, APS hopes to delay filing its next rate case as much as possible, and certainly after the rates requested in this case are fully implemented. Absent these deferral and step increase mechanisms, the sheer magnitude of the SCR and OMP projects would necessitate an immediate filing of a new rate case before the ink dried on the Order resolving this Docket.

2. Property Taxes

APS experienced a significant increase in property tax rates in Arizona in the years after its last rate case and into the current proposed test period. APS anticipates changes to tax rates, and thus asks to defer the jurisdictional component of all increases or decreases in Arizona property taxes: (i) above the levels reflected in rates in this proceeding; and (ii) attributable to increases or decreases in tax rates as contrasted to changes in assessed tax value. These cost increases are wholly outside the Company's ability to control or mitigate. Without a deferral mechanism similar to that used in Decision No. 73183, anticipated tax increases would undermine the Company's ability to earn a reasonable rate of return. Moreover, the deferral would ensure that customers

only pay the exact amount of property taxes that APS pays, no more and no less. As in Decision No. 73183, this proposed property tax deferral would be without return until included in rates in the Company's next general rate case.

C. Changes to Adjustors

1. Power Supply Adjustor

APS requests that the PSA be modified to include chemical costs, the cost of water to supply generation plants, and contracts with third party suppliers of electric storage. Environmental chemicals and water are as important inputs to the production of power as fuel itself, and their costs vary directly with power plant output. And a contract with a third party owner of electric storage for the output of that storage is directly analogous to a small PPA with any other source of electric power.

2. Lost Fixed Cost Recovery

APS believes that a full revenue-per-customer decoupling mechanism benefits both customers and the company with consistency and stability. But APS heard concerns from some stakeholders about pairing a decoupling mechanism with modernized rate design at this time. Responding to those concerns, APS instead seeks to revise its LFCR mechanism to improve the recovery of lost fixed costs associated with energy efficiency and distributed generation. Although intended to relieve APS of the financial impact of Commission policies regarding energy efficiency and distributed generation, APS's LFCR has only permitted APS to collect approximately 40% of the lost fixed costs caused by these policies. APS proposes changes to the LFCR that would better account for actual lost fixed costs, and move APS to a position of financial neutrality regarding EE and DG. The Company proposes the following five primary changes: (i) increasing the year over year cap to 2%; (ii) updating the costs eligible for recovery to include 100% of the generation, customer, transmission,[1] and distribution costs currently

[1] 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.

collected through energy charges, and 50% of the generation, transmission, and distribution costs currently collected through demand charges; (iii) removing the LFCR opt-out rate option; (iv) applying the adjustment to customers' bills as a per kWh charge for customers under a two-part rate, and a per kW charge for customers taking service under a three-part rate (rather than on a percentage basis); and (v) providing that the LFCR rate filed on January 15th becomes effective on the first billing cycle in March each year, unless the Commission takes specific action on the LFCR compliance filing. The revised LFCR Plan of Administration is provided in the Standard Filing Requirement Book under "Plans of Administration." Customers exempt from the present LFCR mechanism will continue to be exempt. And the sales associated with customers who are exempt from the LFCR will continue to be excluded from the derivation of the annual adjustments.[2]

3. Transmission Cost Adjustor

APS seeks no structural change to its TCA, but proposes adding a balancing account feature similar to all of APS's other rate adjustment mechanisms. Although the current TCA adopts the true-up feature of APS's formula transmission rate, that feature does not include a means to reconcile differences in billing determinants from those used to calculate the annual charge. This leaves customers at risk for over-recoveries and APS at risk for under-recoveries—risks that neither party can control or eliminate without a balancing account.

4. Environmental Improvement Surcharge

The EIS is currently capped at a per kWh amount that translates into roughly $5 million per year. In anticipation of needing to comply with upcoming environmental regulation, APS asks to double that cap and make it a year-over-year amount, which

[2] APS continues to believe that decoupling is a reasonable and appropriate rate mechanism to address lost fixed cost recovery. It is commonly used by utilities and can be implemented in a way that maximizes customer protections. But during APS's stakeholder process, stakeholders expressed concern about decoupling paired with modernized residential rate design. Accordingly, APS decided not to propose full revenue decoupling while also proposing universal three-part rates.

would allow an increase each year of up to $10 million for the capital carrying costs and O&M associated with qualifying environmental projects.

D. Rate Design Proposals

1. Residential

Rate design modernization and reform, especially for residential customers, is a critical part of the Company's Application. The time has come to modernize rate design. Current residential rate design sends inaccurate price signals to new technologies, making it more difficult for those new technologies to be viable options for customers. Current residential rate design also creates inequitable cost shifts between customers.

In this rate case alone, the proposed rate increase on residential customers is 1.25% higher solely because of the cost shift caused by rooftop solar under current rate design. And the total cost shift from solar residential and commercial customers to non-solar residential and commercial customers combined already totals $42.7 million annually. Rooftop solar systems typically last for 20 years or more. Assuming grandfathering, rooftop solar subsidies over this 20 year life continue to grow at the rate of $740,000 per day. By the time this case is resolved in mid-2017, the total 20-year subsidy will exceed $1 billion. Moreover, these numbers do not take into account the over $800 million in cash incentives paid and committed to residential and commercial customers over the last decade, among other subsidies. This is unsustainable, and cannot continue if Arizona's energy future is to include the full range of distributed technology opportunities. Meaningful action to address the cost shift must be taken to address current inequities and to send appropriate price signals for customer adoption of current and yet-to-be-invented technologies.

To take that first meaningful step, APS proposes adding a third billing element, called demand, to all residential customers except the very smallest. Although this third element would be added, customer rates would not correspondingly increase because the

energy charge would be reduced significantly. APS also proposes making the basic service charge more cost based.

As discussed by APS witness Charles Miessner, this will not be a one-size-fits-all approach. APS proposes several new rates and billing options. They are tailored to various customer groups, from high to low use customers, and from solar to non-solar customers. The rate options include a non-timed, non-demand rate for the Company's smallest non-solar customers. APS also proposes to change other 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 demand rates.

APS also proposes to modify its present NEM program for all but "grandfathered" residential rooftop solar customers. Power generated and concurrently consumed on-site would still be credited at the fully-bundled retail energy rate. But APS proposes that "exported" generation be (i) measured on an instantaneous basis; and (ii) credited through the PSA at an avoided cost rate to ensure that all other customers only pay an amount for exported energy that equals the costs saved due to the exported energy.

APS proposes to "grandfather" (i) currently interconnected rooftop solar systems; and (ii) those systems for which APS has received a complete interconnection application through July 1, 2017 and that are installed within 180 days. APS proposes that these grandfathered customers retain their current rate plans and net metering arrangements for 20 years after the system was first interconnected to the APS system. The grandfathering provisions would apply to property on which the system is located and may transfer with the property to a new customer within the applicable time period.

In addition to making three-part rates the primary form of residential rate, APS proposes to change the on-peak period to 3 p.m. to 8 p.m. (from 12 p.m. to 7 p.m.). This

new peak period better matches the Company's changing load profile. Basic service charges would also be brought closer to cost, but still accommodate smaller users.[3]

APS witness Stacy Derstine describes APS's extensive plan for transitioning the Company's over 1.1 million residential customers to these new rate plans. This will involve both education and advice about these plans so that customers have the information they need to take advantage of their new opportunities to save on their monthly bills. The transition plan also takes into consideration the time needed to train APS service personnel about the new rates and install and test the software required to implement the proposed rates.

APS acknowledges that it is proposing significant changes in residential rate design. But there are no other options. The cost shift described above is large and growing larger. APS has the technology to measure demand and over 30 years of experience with residential demand charges. Some have claimed that demand rates put customers at significant risk. But this is simply not true. APS has 120,000 residential customers on a demand rate, and they have thrived.

Demand offers a third way for customers to save money on their electric bill, and it shows. In a study on this issue, actual data show that 90% of customers sampled saved money after transitioning to a demand rate.[4] Successfully bridging to a sustained future of clean energy requires a rate structure that isn't built on subsidies, but instead incentivizes the most efficient technologies. For the benefit of all customers, and to unlock the promise of future technologies, we must transition to demand rates.

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[3] Each of APS's four residential rate offerings will have basic service charges and/or demand charges set to reduce the impact of this rate design on low-use customers while still making significant progress in reducing the subsidy within the residential class.

[4] APS's study on this issue included all of its customers who were on a non-demand rate for all of 2012, switched to a demand rate in 2013, and stayed on that demand rate for all of 2014. The total sample size was 977 customers.

2. Commercial

APS's requested changes to its menu of general service rate offerings are listed below:

- Increase the rates to reflect the requested increase in revenue requirements for the class;
- Increase the basic service charges;
- Modify rate E-32 XS (extra-small) by including a modest demand charge;
- Modify water pumping Rate Schedule E-221 to make it more cost-justified;
- Modify the on-peak hours for the smaller E-32 time of use rates;
- Reduce the cost of service gaps for rate E-20 , and reduce the difference between this rates and the alternative E-32 rate options;
- Cancel rate rider E-54;
- Let the AG-1 experimental rate rider for buy-through power lapse by its own terms;
- Add new lighting options for LED lights and to encourage more APS lighting customers to own and operate their own lighting equipment;
- Add a new optional aggregation discount for large customers with multiple sites;
- Add a new rate for large customers with extra high load factors; and
- Add a new service schedule to support economic development.

These changes and additions will make APS's general service rates even more aligned with the Company's cost of service. They will also make APS's non-residential rates more competitive with those charged by other electric utilities so that APS can attract businesses to locate and expand in its service area.

E. Elimination of Antiquated, Unneeded or Redundant Regulatory Requirements

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 to the direct testimony of Barbara Lockwood for a more detailed description and justification on the requested waivers and eliminations.

II. STATEMENTS IN SUPPORT OF APPLICATION AND RELIEF REQUESTED

In support of this Application, APS states as follows:

1. The Company is a corporation duly organized, existing, and in good standing under the laws of the State of Arizona. Its principal place of business is 400 North Fifth Street, Phoenix, Arizona, 85004.
2. The Company is a public service corporation, engaged in the generation, transmission, and distribution of electricity for sale in Arizona. In conducting such business, the Company operates an interconnected and integrated electric system.
3. All communications and correspondence concerning this Application, as well as discovery and pleadings with respect thereto, should be served upon:

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4. This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of the public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate scheduled designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearings, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery, and other prehearing and post-hearing matters.
5. Accompanying this Application are all the relevant Standard Filing Requirements (SFR) and rate design schedules described in A.A.C. R14-2-103[5] and the direct testimony and attachments of the witnesses identified above.
6. The Company respectfully requests that this Commission set a date for the hearing on this Application such that new rates for the Company will become effective by July 1, 2017. At the hearing conducted pursuant to this rate request, APS alleges and will establish, among other items, that:
   a. APS's current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;
   b. The requested increase produces the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, preserve the Company's financial

[5] This Application does not include SFR Schedule E-6 because that schedule applies only to a "combination utility" within the meaning of A.A.C. R14-2-103(A)(3)(q), and APS is not a "combination utility."

integrity, and permit the Company to attract new capital investment on reasonable terms;

c. The Company requires additional permanent base revenue of at least a net $165.9 million, based on annualized test period sales, calculated as described in this Application, in order to continue to provide, both now and in the future, adequate and reliable electric service to its customers as required by law;

d. The EIS should be amended, as described herein;

e. The PSA should be modified, as described herein and in the Direct Testimony of APS witness Peter Ewen;

f. The LFCR and TCA should be modified, as described herein and in the Direct Testimony of APS witnesses Barbara D. Lockwood and Leland Snook;

g. The portion of transmission costs now recovered through the TCA should be transferred for recovery through the Base Transmission Charge, presently part of the Company's unbundled base rates;

h. An additional approximately $10 million in demand-side management costs should be included in and recovered through APS base rates;

i. The portion of renewable-generation related capital investment now being recovered through the RES should be transferred for recovery through base rates;

j. APS's new rate and service offerings for both residential and general service customers are in the public interest and should be approved;

k. Modifications to existing rate and service schedules as proposed by the Company are in the public interest and should be approved;

l. The requested accounting orders for the SCRs at Four Corners and the OMP are in the public interest and should be approved;

m. The step increase for the SCRs using the same procedures as approved in Decision No. 73183 should be authorized, after notice and hearing, effective January 1, 2019;

n. The depreciation rates and Palo Verde decommissioning contributions proposed in the Direct Testimonies of APS witnesses Dr. Ronald White and Elizabeth Blankenship should be approved; and

o. All other proposals supported by the testimony and the accompanying exhibits are in the public interest and should be approved.

7. In addition to setting a hearing date, APS asks that the Commission issue a procedural order setting forth the prescribed notice for the Application, establishing procedures for intervention, and providing for appropriate discovery.

RESPECTFULLY SUBMITTED this 1st day of June 2016.

By:_____
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Thomas L. Mumaw
Attorneys for Arizona Public Service Company

ORIGINAL and fifteen (15) copies
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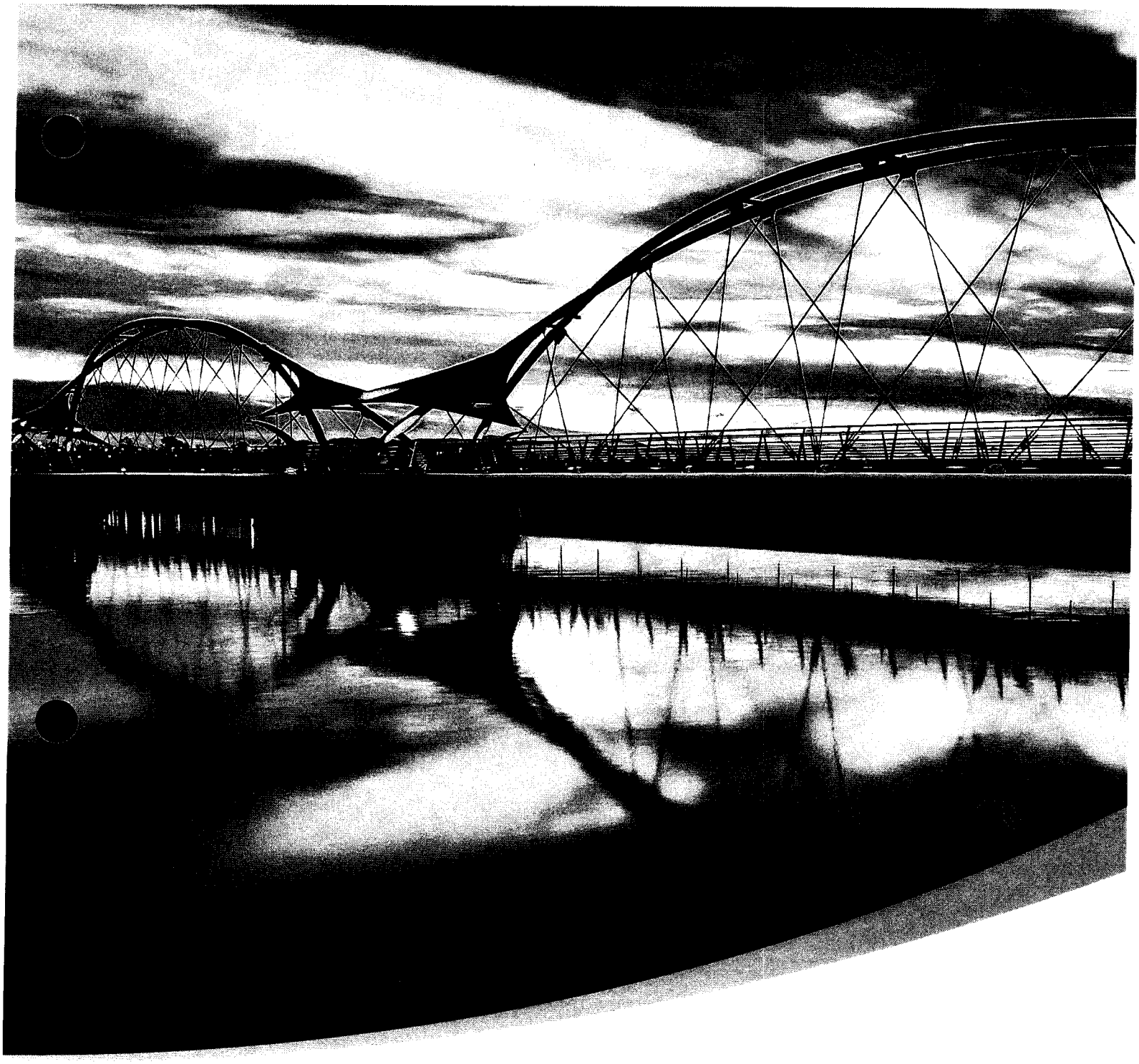
Attachment 1



BRIDGE TO THE FUTURE

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[illegible] Rate Review Points

Financial

5.74% average customer bill increase (see below)

8.13% weighted average cost of capital (includes a 10.5% return on equity)

1% return on fair value increment

$6.8 billion ACC adjusted rate base, including 18 months of post-Test Year plant

Base fuel rate of 2.9882 ¢/kWh

Rate Design (see appendix)

3 p.m. – 8 p.m. Monday through Friday on-peak hours, excluding holidays

Three-part (demand) rates for most residential and small commercial customers

Grandfather existing solar customers

Economic development rate

Extra-high load factor rate

Adjustors

PSA: Include environmental chemical costs, cost of water to supply our generation plants, and contracts with third-party suppliers of electrical storage (batteries)

LFCR: Update to improve the recovery of lost fixed costs associated with energy efficiency and distributed generation

EIS: Increase cap to $10 million year over year

TCA: Add balancing account

Other

Ocotillo Modernization Project: Cost deferral from date of commercial operation in 2018 and 2019 to the effective date of rates in next rate case

SCR installation at Four Corners: Cost deferral from the time of installation to incorporation of the SCR costs in rates using a step increase requested to be effective by January 1, 2019

Arizona Property tax deferral for any changes in the Arizona property tax rate until the next rate case

AMI opt-out: fee $70 one-time set-up fee; $15 per month meter-reading fee

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%**

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Introduction

In 2016, APS celebrated 130 years of providing its customers safe, reliable and low-cost electricity. Our proud commitment to quality and service has helped power Arizona through more than a century of change and we look forward to the opportunities and growth for the state and our customers that lie ahead.

The 2016 rate review is the first rate review in five years. Much has changed in the world and in energy since 2011. From the development of low-cost natural gas through fracking to the explosive growth of rooftop solar, little, in fact, remains unchanged. To adapt to this changing landscape, APS has made and continues to make strategic investments that make our operations more efficient and enable customer choice.

Building on the foundation established in previous rate reviews, the investments and proposals discussed in this rate review provide a clear and compelling vision of the future. In many respects, this case serves as a transition from the challenges of the present to the opportunities of the future—it is a bridge to the future for APS and its customers.

The pace of change is accelerating in many aspects of our lives and the generation and delivery of energy is certainly no exception. Customers are increasingly utilizing new technologies to better control their use of energy. Sending the right price signals will help customers make informed decisions about the types of technology that will lower costs for everyone.

New rate designs are necessary to ensure that the price a customer pays more accurately reflects the way that customer uses the electric grid. A modernized pricing structure will allow APS to continue investing in our communities and updating infrastructure to maintain reliability, support emerging technologies, and create a cleaner energy for our customers and Arizona.

That is why APS's 2016 Rate Case is so important to the company and our customers. Our proposals in this case are based on four core values—the pursuit of clean energy, customer choice, innovation, and sustainability. This includes continuing our transition to clean generation sources, modernizing our energy infrastructure, and utilizing innovative technologies like solar, energy storage, and smart thermostats. Building on these values connects today's accomplishments with tomorrow needs; it builds a bridge to the future.

Framing the Issue

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.

The total cost shift to non-solar customers already totals **$42.7 million** 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 incentive committed or already paid to rooftop solar customers.

Daniel Froetscher

APS Senior Vice President, Transmission, Distribution and Customer Service

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Mr. Froetscher's direct testimony introduces APS, and the role the Company plays in Arizona's communities. He describes the core principles driving APS, and the context behind this rate Application. His 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 the future of clean, sustainable energy in Arizona.

Direct Testimony Key Points

- Mr. Froestcher's direct testimony begins by describing the large number of significant changes occurring within the electric industry. Despite pressures imposed by these myriad changes, APS remains optimistic and committed to its core principles of safe, reliable, and affordable electricity for its customers while focusing on a sustainable energy future.
- 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 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 a 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 transformation continues.
- 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.
- Each component of this rate Application feeds into and is critical to achieving three overarching outcomes:
  1. APS needs to be financially healthy and stable to continue supplying reliable power at reasonable prices. 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.
  2. APS requires a reasonable return on its invested capital to continue investing in the grid that makes clean energy a reality. A reasonable return can send a positive message to investors that Arizona is a good state in which to invest capital.
  3. The design of APS's rates must be modernized to achieve a sustainable path forward for all types of clean energy and developing technologies. The current structure of cross subsidies does not promote the cost-effective development of distributed technologies, and raises serious questions about equity among customers.
- APS's vision for the future of energy in Arizona is rooted in four areas: clean energy, sustainability, innovation, and technological options 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.

- 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 upgrading physical facilities, refining operational practices, and modernizing regulatory policies. Specifically, sustainable clean energy requires:
  - A flexible grid that can react to changing and often unpredictable conditions.
  - An infrastructure that readily integrates the unpredictable deployment and operating characteristics of distributed technologies.
  - A focus on cost-based pricing to encourage, rather than discourage, new 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.

With this Application, APS is asking the Commission to support its vision of a sustainable environment for clean energy, new technologies, and customer options. This support entails approval of new rates that permit healthy and stable financial strength, a reasonable return on investments made for the benefit of APS customers, and modernized regulatory policies and rate structures that incentivize all forms of technology and produce equitable results for APS's entire customer base.

Barbara D. Lockwood

APS Vice President of Regulation

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

In her direct testimony Ms. Lockwood discusses the challenges and opportunities that APS experienced in the five years since its last general rate case, as well as the environment APS and the Commission will face in the next five years and beyond.

She also provides an overview of the Company's rate request, including the initial steps of rate modernization, and shows how this is essential for APS to meet its long-term goal of providing a sustainable energy future for its customers and the state as a whole.

Direct Testimony Key Points

- APS is requesting a net increase of $165.9 million in base rates, or 5.74% on average. Ms. Lockwood terms the request a "net increase" because APS is seeking to "zero out" or significantly reduce several current rate adjuster mechanisms and surcharges by folding these costs, already born by APS customers, into base rates. The average annual bill impact for a typical APS residential customer would be $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 selective catalytic reduction (SCR) equipment for Four Corners.
- Residential rates are proposed to increase more than the overall average increase due in large part to absorbing "grandfathered" Net Energy Metering (NEM) customers and the resultant $27.3 million in cost shift to other residential customers since the Company's last rate case.
- APS is also requesting a 10.5% return on equity as supported by witness Dr. Bente Villadsen, resulting in an 8.13% weighted average cost of capital when combined with APS's embedded cost of debt of 5.13% at the end of the test year. APS's proposed 5.84% return on fair value rate base includes a 1% return on the Fair Value Increment of such rate base.
- The first SCR at Four Corners will be placed in service in late 2017 and the second in early 2018. APS's share of this investment is approximately $400 million of direct construction costs. APS is requesting a cost deferral order from the time of installation to incorporation of the SCR costs in rates and a step increase in rates. 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 Ocotillo Modernization Project (OMP) in this proceeding. Rather, the Company asks for an accounting order running from the date of commercial operation of the OMP in 2018 and 2019 to the effective date of rates in APS's next 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 in recovering unrecovered fixed costs attributable to rooftop solar and energy efficiency. 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.

- APS is also requesting a modest expansion of the environmental improvement surcharge (EIS) from the current effective cap of $5 million to an annual year-over-year cap of $10 million. Improvements to the power supply adjustor (PSA) and the transmission cost adjustor (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 gradual modernization of its residential and extra small commercial rate plans. These new rate proposals will make substantial progress on the recovery of fixed costs and meeting system demand, as well as address the specific subsidization of rooftop solar customers who, based on the cost of service study sponsored by witness Snook, are currently only paying approximately 38% of the cost to provide them service.
- APS will expand its limited income support from $35.6 million during the Test Year to approximately $48 million and provide an alternative metering program for residential customers opposed to AMI meters.
- APS proposes to eliminate the alternative generation, or AG-1, option for large commercial and industrial customers. At the same time, APS wants to offer new rate options for these types of customers, including a high load factor rate, an aggregation rate and an economic development Rate Rider. Other general service rates will have very few changes because the Company believes they are already properly structured and reflect the cost of service.

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 significant 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.

John R. Lucas

APS General Manager of Generation Engineering and Projects

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

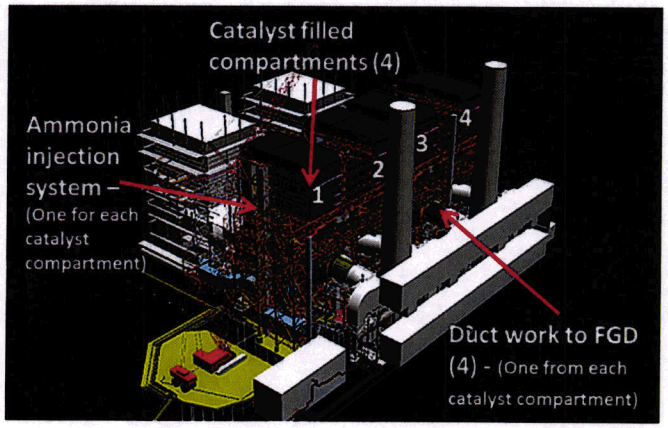
Direct Testimony Overview

Mr. Lucas's direct 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, he discusses:

- The Selective Catalytic Reduction (SCR) project at Four Corners;
- Projects completed in the 2015 Test Year and planned through June 30, 2017; and,
- Fossil Generation's contribution to the Company's post-Test Year Plant Adjustment, which adds $160.6 million to gross utility plant in service.

Direct Testimony Key Points

- APS has been focused on actions needed to comply with the standards for the Clean Air Act:
  - Mercury and Air Toxics Standards for Utilities
  - Regional Haze Regulations
  - Reasonably Available Control Technology
  - New Source Performance Standards and New Source Review
- In alignment with the EPA's Federal Implementation Plan and the Consent Decree issued June 24, 2015 for Four Corners Power Plant Units 4 and 5, APS must install SCR technology to reduce the NOx emissions and replace sections of the Flue Gas Desulfurization (FGD) systems to meet SO2 emissions removal standards.



- APS began the SCR project in early 2014. Its share of the SCR project is estimated at $400 million, and an estimated $35 million is to upgrade the condition of the FGD. The SCR must be operational at Four Corners for one of the units by March 31, 2018 and for the remaining unit by July 31, 2018.
- Project expenditures in 2015 that ensure compliance with environmental regulations totaled $41 million.
- Two of the main environmental projects being completed in the post-Test Year Plant period include:
  - 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.
  - Installation of an 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.

John J. Cadogan

APS Vice President of Nuclear Engineering

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Mr. Cadogan's direct testimony begins with a description of Palo Verde Nuclear Generating Station, including a discussion of some of the unique aspects of nuclear power and, in particular, Palo Verde's Water Reclamation Facility that supplies cooling tower makeup water to the station. Next he describes Palo Verde's budgeting and cost management practices for both capital and Operations and Management (O&M), followed by a general summary of those capital projects will be placed in service during the post-Test Year period January 1, 2016, through June 30, 2017. Finally, he briefly summarizes the impact that rigorous cost oversight and management have had on Palo Verde non-fuel O&M costs.

Direct Testimony Key Points

- APS is seeking $278.6 million in rate base additions for Palo Verde through the end of the 2015 Test Year. Each of these additions will enhance the reliability, safety or efficiency of Palo Verde's operations.
- Palo Verde expects to add approximately $124 million of plant by June 30, 2017. These additions contribute to the Company's overall proposed post-Test Year Plant adjustment.

  As with the $278.6 million referenced above, the following five projects, which total $50 million, will enhance the reliability, safety or efficiency of Palo Verde's operations:

  1. Improving administrative procedures governing Palo Verde.
  2. Adding a seventh clarifier train to the Water Reclamation Facility to allow for extended outages to repair and refurbish the six original clarifier trains.
  3. Repairing concrete in the Unit 1 ultimate heat sink or spray pond.
  4. Replacing the originally installed Unit 3 main generator excitation system.
  5. Refurbishing Water Reclamation Facility clarifiers.
- 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%.
- O&M costs during the Test Year compare favorably to the five-year average from 2010 to 2014. Rigorous cost controls and management oversight have kept the increase over the five-year average to below 2%.

Jacob Tetlow

APS General Manager, Transmission and Distribution Operations and Maintenance

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Mr. Tetlow's direct testimony describes the Company's ongoing commitment to operate and maintain the Transmission and Distribution (T&D) system in a cost-effective and sustainable manner. He further explains that the infrastructure replacement and upgrade projects that incorporate the latest available technologies will strengthen APS's ability to reliably serve its customers. Lastly, he outlines the Company's planned capital expenditures within the T&D organization that are included in the 18-month post-Test Year plant pro forma.

Direct Testimony Key Points

- Project Illuminate is a major initiative 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 Advanced Distribution Management System (ADMS) that will allow for automation of distribution field devices and significantly enhanced visibility into APS's system.
- APS is proposing that approximately $470 million in Total Company capital expenditures be included in the Company's post-Test Year plant pro forma adjustment for distribution, information technology, and facilities projects.
- Of the $470 million in capital expenditures, $46.5 million is directly related to installation of ADMS system components. During the post-Test Year period, APS will install supervisory control and data acquisition (SCADA) devices, communications facilities, and Distribution Management System and Outage Management System software applications associated with ADMS.
- The majority of the distribution system capital expenditures, some $164.7 million, will be necessary to meet expected growth in the Company's service territory. 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.
- The proposed information technology and facilities capital expenditures for projects that will be in service through June 30, 2017, total $200 million.
- Beyond ADMS system components, 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.

Stacy L. Derstine

APS Vice President of Customer Service and Chief Customer Officer

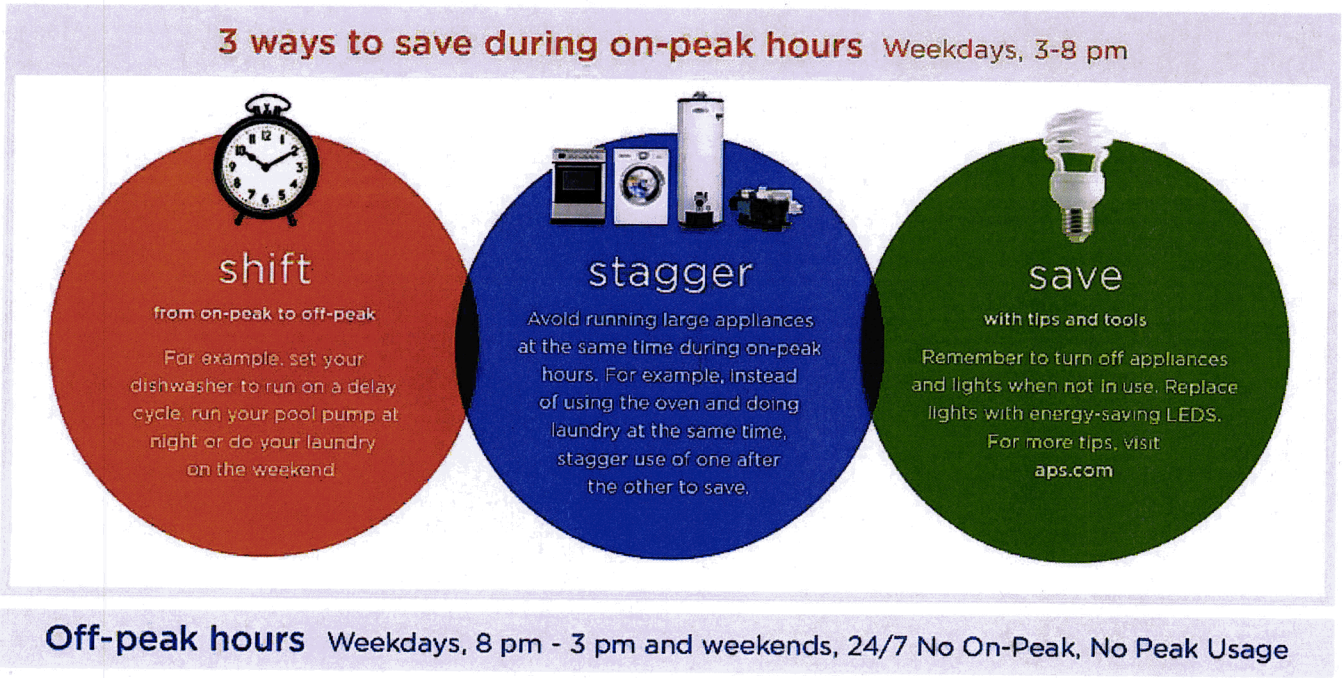
Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Ms. Derstine's direct testimony discusses the key Customer Service initiatives during the Test Year and post-Test Year period through June 30, 2017, including the Company's deployment of the new customer information and billing system (New CIS), technology upgrades and enhancements that make it more convenient and efficient for customers to do business with APS, and changes to the limited income program. Also, she will discuss the Company's current and future plans to inform and educate customers about three-part rates and its plan regarding the transition of customers to three-part rates.

Direct Testimony Key Points

- APS has upgraded the notification features of aps.com. Customers can now log on to aps.com and elect to receive notifications regarding outages, kW and kWh usage amounts and bill amounts and via text, phone or email. The notifications are customizable and customers can elect what alerts they want to receive, as well as how and when they want to receive them.
- APS is working on the deployment of short, customized videos that can be sent to customers via email periodically or after a triggering event. The videos could also be used to explain bill and payment options and educate customers regarding energy efficiency, renewable energy and three-part rates.



- 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 to manage their energy, which helps them manage their energy costs. To help customers save money on a demand rate APS's message is simple: "Shift, Stagger and Save." (see sample message on previous page)
- Most customers already understand that it often makes sense to "shift" to off-peak times when they do their laundry, run their dishwasher or run their pool pump. 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 running the dishwasher or doing laundry. (see sample scenarios below)
- 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 in their trucks, so they can share this information with customers who happen to ask them.
- APS is also conducting community outreach with stakeholders and community leaders to discuss its rate case as well as the proposed demand rates. 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 the community. This outreach began prior to filing this rate case and will continue before any customer transitions to a new rate.
- APS needs a New CIS system that can meet the changing technology needs of its customers and the business.
- The New CIS will also allow for a tailored customer experience. This includes customized communications, customized website visits and overall enablement giving the customer a more relevant and better experience. What's more, the New CIS will improve operational efficiencies and allow APS to implement more advanced billing structures that promote energy technologies customers want.

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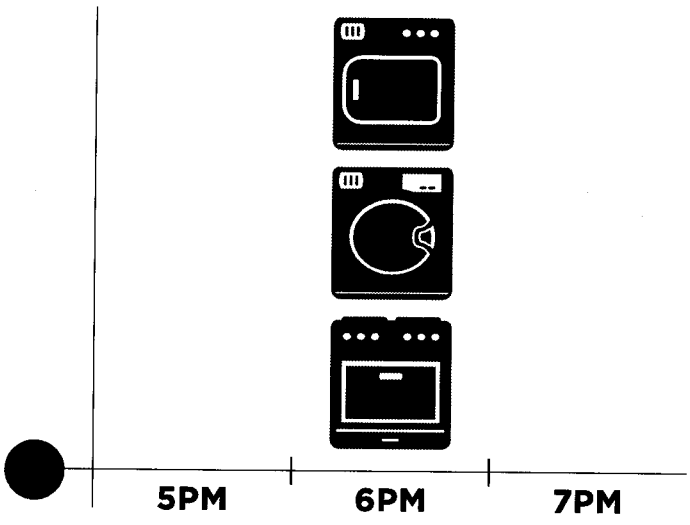

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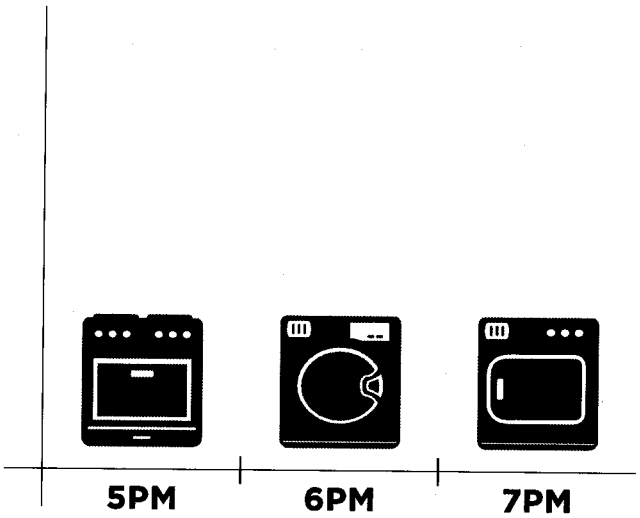


- The New CIS system is expected to have a total cost of approximately $120 million.
- APS will implement an education plan regarding changes to its service plans and will work with customers to refine its messaging. This targeted campaign will include bill inserts, website content, emails and direct mail.
- APS will develop communications that are simple and easy to understand and 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 plans to transition its customers to the new proposed rate plans in phases. APS will move customers to the new plans based upon their billing cycle. No 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.
- APS will move all residential customers to the plan that is best for them, provided they are eligible for that plan. Any time after the new rate plans first go into effect, a customer may voluntarily select one of the new plans. They do not need to wait to be migrated.

James C. Wilde

APS Director of Resource Planning

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

In his direct testimony, Mr. Wilde discusses the changing nature of customer demand patterns and a general shift from electric resources that provide energy year-round, to resources that are highly dispatchable for meeting customers' peak summer-time demands. He outlines 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 demand.

Mr. Wilde also illustrates the need to update customer price signals through demand-based rates and updated time-of-use (TOU) rates. He then discusses APS's Coal Strategy and demonstrates the customer benefits of retiring Cholla Unit 2.

Direct Testimony Key Points

- The Ocotillo Modernization Project (OMP) and customer-sited microgrid resources provide the flexible dispatch characteristics APS's system needs today and will increasingly need in the future.
- APS expects to need more than 3,500 MW of new resources by 2022.
- APS is 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 options to customers if they choose to manage their demand in response to APS's proposed three-part rates.
- Because APS must build or procure sufficient resources to meet summer-time peak demand, a rate structure that coincides with high use periods would be appropriate. By aligning customer price signals with high use periods, APS could defer building or procuring resources in the future since customers would be incentivized to reduce peak demand.
- By participating in the EIM, APS will have more opportunities to take advantage of beneficial pricing opportunities on behalf of customers. The EIM enables APS to transact power in five-minute increments, which provides utilities not only opportunities to purchase power at low prices, but also opportunities to sell power at higher prices. The anticipated annual benefit to APS customers is expected to be in the range of $7 million to $18.1 million per year.
- The closure of Cholla Unit 2 delivered important economic and environmental benefits for APS customers. Cholla Unit 2 required significant and expensive upgrades to comply with the federal Mercury and Air Toxics Standards and the Regional Haze Rule. Unlike the Four Corners generating plant, Cholla has much smaller units and as a result it was not cost effective to implement the environmental upgrades.

Scott Bordenkircher

APS Director of Transmission and Distribution Technology Innovation and Integration

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Mr. Bordenkircher's 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.

His testimony discusses the Transmission and Distribution Operations Vision Plan and the benefits of the included advanced grid technologies. He further describes key customer programs including the Solar Partner Program and the Solar Innovation Study, Red Rock Solar, and the newly launched microgrid program. Lastly, Mr. Bordenkircher identifies projects planned through June 30, 2017, and discusses Technology Innovation and Integration's contribution to the company's post-Test Year plant adjustment.

Direct Testimony Key Points

- APS developed a Transmission and Distribution Operations Vision Plan (Ops Vision Plan) in 2013 to address APS's advanced grid technology needs on a five-year rolling basis. These technologies permit APS to receive near real-time operational data and more accurate information about its facilities, infrastructure and customer power quality. APS's advanced-grid technologies include:
  - **Fire mitigation technologies.** These include Downed Conductor Detectors (DCD), a combination of sensors and automation technology that provides real-time alerts to distribution operators when a power line has fallen to the ground.
  - **Supervisory capacitor bank controls.** Capacitor banks improve the overall efficiency of the utility system and ensure power quality for customer end-use equipment.
  - **Integrated Volt-VAR Control.** IVVC is an automated system of capacitors and voltage regulators that can autonomously control voltage levels along a distribution feeder.
  - **Distribution substation health monitoring.** Adding real-time monitoring and analysis devices to APS's substations allows APS to better predict equipment failures and make necessary adjustments, prolonging the life of the equipment.
  - **Network backbone.** Launched in 2013, this program implements long-distance, high-bandwidth, secure data communications between APS's operations centers and field installations. 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.
- APS has implemented Advanced Data Analytics programs to more accurately predict rooftop solar production, monitor and trend power quality, provide outage intelligence, and perform predictive and preventative asset health analysis.
- The Solar Partner Program enables APS to gain a greater understanding of how increased penetration of various customer-

sited technologies affects the grid. Consistent with Decision No. 74878, APS has installed approximately 10 MW of rooftop solar on approximately 1,600 homes at targeted locations. SPP is exploring how to optimize the grid and increase reliability for the long-term benefit of all customers.

- APS's Solar Innovation Study is a 75-customer home energy management and rate research and development field program designed to examine the integration of customer-sided advanced technologies—including rooftop solar, advanced inverters, home energy management systems—with demand-based rates.
- Advanced Metering Infrastructure (AMI) has resulted in a significant increase in efficiencies, reductions in O&M costs and vehicle emissions, as well as an increased opportunity for customers 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 and situational awareness, and makes AMI a foundational platform for many future advanced grid programs.
- Microgrids increase the reliability of the distribution grid; especially in the local area. APS will have two microgrids in service by the third quarter of 2016, a 25 MW partnership with Marine Corps Air Station Yuma and a 62.5 MW partnership with Aligned Data Center in Phoenix.
- Red Rock Solar is a 40-megawatt single-axis tracking, grid-scale solar facility. APS will own, operate, and maintain the plant, and over the 20 year term of the agreement, ASU and PayPal will purchase the Renewable Energy Credits and equivalent energy to what Red Rock Solar is producing.
- APS is proposing that approximately $239 million in Total Company capital expenditures be included in the Company's post-Test Year plant pro forma adjustment for renewables, microgrid and technology projects. These projects contribute $101 million to the Company's proposed Total Company rate base.

Peter M. Ewen

APS Director of Financial Planning and Forecasts

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Mr. Ewen's direct testimony covers three main areas: APS's financial projections, the system average cost of fuel for generation and purchased power, and modifications to the Power Supply Adjuster (PSA). Specifically, he discusses the benefits resulting from the regulatory framework established for APS by the 2012 Settlement Agreement and explains why, because of the Settlement's financial design, APS is seeking a rate increase now.

Additionally, he sponsors the Company's Base Fuel and Purchased Power pro forma, which sets forth the base rate level of fuel and purchased power expenses. 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. The testimony explains the reasons for this decrease.

Mr. Ewen also discusses a few modifications to the PSA Plan of Administration (POA). Specifically, he explains why the inclusion of environmental chemical costs and generation-related water costs in the PSA are appropriate, and also explains 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.

Direct Testimony Key Points

- 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. For the last four years, the Company has been able to earn close to its authorized return on equity (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, APS'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.
- 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 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.
- 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.
- 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 2.99¢/kWh, which reflects normalized levels of plant performance, expected 2017 fuel and purchased power prices, and a credit for anticipated off-system sales margins.
- APS is proposing to include in the PSA environmental chemical costs that directly correlate to the use of fuel. Chemicals, such as lime, ammonia, and sulfur are used to scrub the emissions from a coal plant and are dependent upon the amount of fuel burned. As production from the power plants varies, so too does the amount of chemicals used. The Company therefore proposes that annual changes in the chemical cost expense associated with power plant emission controls be recovered through the PSA.
- APS uses water to produce steam power at several of its generating plants, and this water consumption and the chemicals and chemical 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 recovered through the PSA.
- 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. The Company proposes that the PSA POA be modified to allow such costs, if incurred, to be recovered in the PSA.

Dr. Bente Villadsen

Principal, The Brattle Group

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Dr. Villadsen determined and presents the Company's cost of equity and recommends the specific return on equity that should be included in its rates. Her testimony also offers an opinion on the fair value of APS's rate base and an appropriate fair value rate of return.

Direct Testimony Key Points

- 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, Dr. Villadsen's 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.
- To determine APS's cost of equity Dr. Villadsen selects 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. She calculates 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, she then considers specific risks of APS to derive a range of cost of equity estimates for the Company. Dr. Villadsen concludes that a range of reasonable return on equity (ROE) estimates are as indicated as follows:

	Reasonable Range for Proxy Group
CAPM-based Methods	10.0% – 10.5%
DCF-based Methods	9.9% – 10.8%
Risk Premium Method	10.3%

- Dr. Villadsen concludes that APS should be in the upper half of the range because of, among other factors, the Company's significant portfolio of nuclear generation. She notes that APS has been unable to achieve its allowed ROE since 2002 and currently faces substantial business uncertainty in connection with unresolved economic and regulatory issues surrounding distributed generation. Therefore, she recommend that an ROE of 10.5% is appropriate for setting rates in this case.
- Dr. Villadsen finds that the ACC jurisdiction fair value rate base for APS is $9.976 billion using the Commission's traditional weighting of original cost and reconstruction cost new. She then checks the reasonableness of that figure using the market value of comparable benchmark transactions. These transactions indicate that the APS figure was reasonable, although toward the bottom of the range.
- Dr. Villadsen proposes a rate of return on the fair value rate base of 8.13%. She also concludes that a standalone return on the Fair Value Increment of 6.04% is appropriate, which would produce a Fair Value Rate of Return of 7.46%. APS's proposal of 5.84% is far below this appropriate level, and thus conservative.

Leland R. Snook

APS Director of Rates and Rate Strategy

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Mr. Snook's direct testimony supports the Company's request in this rate case for a net increase in base rate revenue. His testimony also describes why the Commission should approve APS's request for Accounting Deferral Orders regarding the Ocotillo Modernization Project (OMP) and the installation of Selective Catalytic Reduction (SCR) emissions control technology at the Four Corners Power Plant.

Mr. Snook outlines the Company's Cost of Service Study (COSS) that is used to support rate designs in the Company's Application, as well as the jurisdictional allocation of costs. Additionally, he discusses APS's proposed modifications to its existing Lost Fixed Cost Recovery (LFCR), Environmental Improvement Surcharge (EIS) and Transmission Cost Adjustor (TCA) mechanisms.

He also reviews the Company's fair value increment and a new Extra-High Load Factor (XHLF) rate for extra-large customers. His testimony concludes with APS's economic development service schedule and a determination that the AG-1 buy-through rate program should not be renewed.

Direct Testimony Key Points

- APS is requesting a net increase in base rate revenue requirements of $433,434,000. This amount includes transferring $267,551,000 of revenue currently collected in various adjustors to base rates. These adjustor transfers are revenue neutral and do not change the amount collected.
- If proposed rates are effective on July 1, 2017, this requested revenue will allow APS to earn a rate of return of 5.84% on a fair-value rate base of $9,976,023,000. The additional revenue, excluding the "fair value increment," results in an 8.13% rate of return on an adjusted Original Cost Rate Base of $6,771,151,000.
- The components of the base rate increase inclusive of adjustor transfers are as follows:

Overview of Rate Increase ($ in thousands)

Total base rate increase (inclusive of adjustor transfers)	$433,434	15.00%
Less: Transfer to base rates of various adjustors	$267,551	9.26%
Net customer bill impact	$165,883	5.74%

- APS requests an Accounting Deferral Order from the Commission to defer for possible subsequent recovery the costs associated with constructing the OMP. APS also requests a deferral and step rate increase for its SCR project.
- Mr. Snook describes the COSS that is used to support APS's rate designs as well as the jurisdictional allocation of costs. The COSS shows:
  - Why it is appropriate to place residential customers taking service under APS's Net Metering Rate Rider into a separate sub-class of customers;
  - That 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; and

- After accounting for APS's proposed rebalancing of the residential cost of service up to historical levels of 92%, 57% of the increase in residential rates is directly related to the cost shift resulting from residential rooftop solar that has occurred since APS's last rate case. (see chart below)

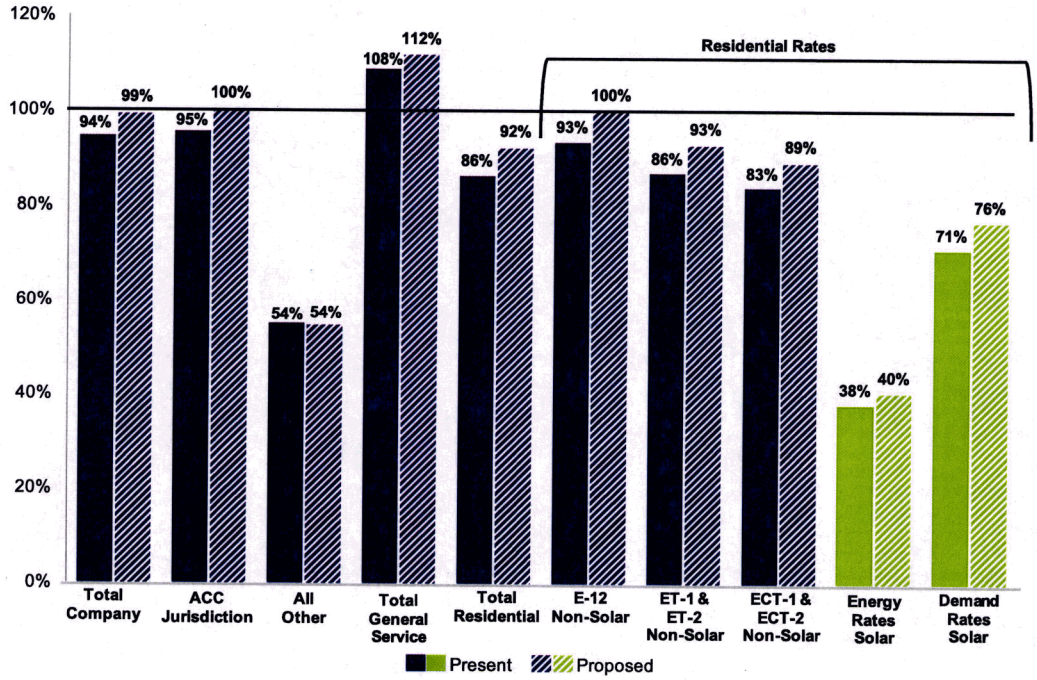
- APS proposes modifications to three of its existing adjustor mechanisms:
  - **LFCR** – Improve the LFCR's ability to collect lost fixed costs, and adjust the LFCR compliance filing process.
  - **EIS** – Provide flexibility to recover environmental costs by creating a $10 million year-over-year cap to account for increasing costs.
  - **TCA** – Add a balancing account for the amounts collected through the adjustor to be consistent with all of APS's other adjustor mechanisms.

- APS's proposed XHLF general service rate to customers with at least 5 MW of load and a monthly average load factor of 92% or more. Transmission service options would be available to customers with a minimum size of 15,000 kW.

- 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. 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.

- 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 new customers with at least 2 MW or increasing loads of at least 1 MW and a load factor of 55% or more. The program will be capped at 100 MW or 50 new customers, whichever is less (on a MW basis).

APS Customer Classes % of Cost to Serve
2015 Test Year



Dr. Ahmad Faruqui

Principal, The Brattle Group

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

The purpose of Dr. Faruqui's direct testimony is to comment on the merits of APS's proposal to make demand charges a universal rate feature of the residential rate.

An overriding principle of electric rate design is that of cost causation: revenue collection should match cost generation.

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.

With a three-part rate design, customers more efficiently use the electric grid in a way that also reduces the cost shift. In addition, demand rates 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.

Direct Testimony Key Points

- Each of APS's proposed three-part rates more closely match demand, fixed, and variable costs with demand, fixed, and variable charges so that all customers will pay their fair share.
- 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.
- APS has the most highly subscribed residential three-part rate in the U.S., with over 120,000 customers on its Combined Advantage tariff. This represents more than 10% of its residential customer base and more than 20% of its residential energy sales. When new rate designs are introduced on a voluntary basis, they rarely achieve enrollment levels in excess of 10%. 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 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.
- The introduction of a cost-based demand charge is a significant and necessary improvement over two-part rate offerings. APS has shown that residential customers can respond to demand charges.
- The introduction of a three-part rate will not change APS's revenues.

Charles A. Miessner
APS Manager of Rates

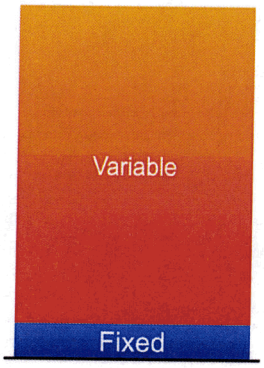
Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

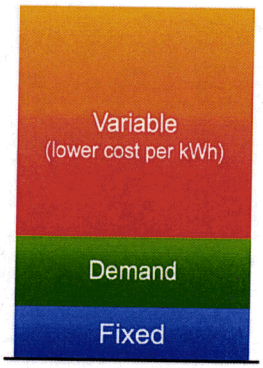
Mr. Miessner's direct testimony explains why there is a compelling need to restructure rates for residential and small-business customers, and he provides the specific proposals for new rates. In addition, Mr. Miessner's testimony describes how the proposed revenue is allocated to individual rate classes.

Direct Testimony Key Points

- Mr. Miessner explains that the higher requested increase for the residential class is caused in part by the cost shift from the solar net metering program, where subsidized bill savings for solar customers create higher rates for other residential customers. While this was true in the last rate case, the volume of installations since the last case has made this a critical issue.
- The new portfolio of residential rates proposed by APS includes the following:
  1. **R-1** — a time of use (TOU) rate with a small demand charge of $6.60/kW during the on-peak hours and a basic service charge of approximately $24 per month.
  2. **R-2** — a TOU rate with a modest demand charge of $8.40/kW during on-peak hours and lower basic service charge of approximately $14.50 per month.
  3. **R-3** — a TOU rate with lower kWh charges and seasonally differentiated demand charges of $16.40/kW in the summer and $11.50/kW in the winter, and a basic service charge of approximately $24 per month. This rate is very similar to APS's current demand rate.
  4. **Extra Small** — a two-part rate for extra-small customers with no demand charge and an $18 per month basic service charge.
- The three primary rate options proposed for residential customers will have lower kWh charges, a higher basic service charge, and a demand charge component. The TOU on-peak hours will be revised to 3 p.m. to 8 p.m. weekdays to better reflect the highest system load hours. The demand will be measured on the highest average use over an on-peak hour.



2 ways to save
- Using less energy
- Using power at off-peak times



3 ways to save
- Stagger use of major appliances
- Shift usage to off-peak times
- Save on overall energy use

- APS also proposes to modify its present NEM (Net Energy Metering) program for all but "grandfathered" residential rooftop solar customers. Power generated and concurrently consumed on site would still be credited at the fully-bundled retail energy rate. But APS proposes that "exported" generation be (i) measured on an instantaneous basis; and

(ii) paid through the PSA at an avoided cost rate to ensure that all other customers only pay an amount for exported energy that equals the costs saved due to the exported energy.

- APS proposes to "grandfather" solar systems for which APS has received a complete interconnection application by July 1, 2017 that are installed within 180 days. APS proposes that these grandfathered customers retain their current rate plans and net metering arrangements for 20 years after the system was first interconnected to the APS system.
- APS proposes to simplify the discount structure for the limited-income bill discount program and provide for increased program participation.
- Mr. Miessner also describes some of the proposed rate changes for business customers, which include:

1. Improving the time-of-use rate options to work better with the operating schedules of many businesses by updating the time-of-use on-peak hours to 3 p.m. to 8 p.m. weekdays; and
2. Adding a demand charge component for extra-small business customers.

- The adoption of future technologies depends on effective prices that reflect cost. When rates reflect cost, technologies that reduce utility cost will also provide customers the opportunity to obtain bill savings that don't involve the cost shift occurring under the current rate design.
- 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 more than 120,000 customers on the rate. When customers switch to that rate, they typically reduce both their demand and energy consumption.
- Mr. Miessner concludes 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.

Elizabeth A. Blankenship
APS Director of Accounting Operations

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

Ms. Blankenship's direct testimony addresses the historical accounting information and pro forma adjustments required by the Standard Filing Requirements (SFR) of the Arizona Corporation Commission in support of the Company's rate case filing. She sponsors historical information for the 12-month period ending December 31, 2015, which was used as the Test Year in this proceeding and any prior years presented on the SFR Schedules.

She presents testimony concerning the capital structure of the Company and provides APS's actual overall cost of capital. This will include information on the cost of equity and debt capital, as provided by Dr. Bente Villadsen, APS's cost of capital and return on equity (ROE) witness.

Direct Testimony Key Points

- Ms. Blankenship's direct 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 and other government agencies for the relevant years.
- In large part, her direct testimony supports the testimony of other APS witnesses. The direct testimony of APS witness Peter 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 direct testimony addresses the Company's requested ROE and overall cost of capital.
- Ms. Blankenship sponsors more than 40 rate base and income statement pro forma adjustments. 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 include normalizations, annualization and out-of-period adjustments. All of the pro forma adjustments discussed in her testimony reflect Total Company amounts prior to any jurisdictional allocation.
- Ms. Blankenship's direct testimony also discusses APS's request for continuation of the property tax deferral. The 2012 Settlement approved a property tax deferral that helped to alleviate risk of changes to property tax rates within Arizona. APS proposes to defer for future recovery 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.

Dr. Ronald E. White

President, Foster Associates Consultants, LLC

Direct Testimony Submitted June 1, 2016
Docket No. E-01345A-16-0036

Direct Testimony Overview

The purpose of Dr. White's direct testimony is to sponsor and describe the 2016 depreciation rate study conducted by Foster Associates at the request of APS.

Depreciation rates currently used by APS were approved by the Arizona Corporation Commission pursuant to a Settlement Agreement in Docket No. E-01345A-11-0224. (Decision No. 73183, dated May 24, 2012).

Direct Testimony Key Points

- 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.
- 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.
- 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.
- Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.99%. Depreciation expense is currently accrued at rates that composite to 2.45%. The recommended change in the composite depreciation rate is, therefore, an increase of 0.54 percentage points.

Change on-peak time-of-use period from noon – 7 p.m. to 3 p.m. – 8 p.m. Monday through Friday, excluding holidays.

Reduce the difference in the on- and off-peak energy prices and lower all energy charges.

Offer four rate plan options:

	Basic Service Charge (per month)	**Demand Charge** ($/kW)**	**Summer Energy Charge** (On/Off Peak $/kWh)	**Winter Energy Charge** (On/Off Peak $/kWh)
Extra Small*	$18	None	$0.10324	$0.10324
R-1	$24	$6.60/kW	$0.1516/ $0.08070	$0.12730/ $0.08070
R-2	$14.50	$8.40/kW	$0.1516/ $0.0808	$0.12730/ $0.0808
R-3	$24	$16.40/kW summer $11.50/kW winter	$0.0909/ $0.05475	$0.06670/ $0.05475

*Extra Small option is available for customers using less than 600kWh per month on average. Partial requirements customers are not eligible for this rate.

**Demand charge calculated as the average over one hour during the on-peak window only.

Offer a flat bill option where the customer pays the same amount every month regardless of how much energy they use or when they use it.

New rooftop solar customers are eligible for the R-3 customer rate only.

Existing solar customers will be grandfathered on their existing rate plans for 20 years from the date of interconnection.

Modify net metering with a retail rate credit for solar customers offsetting their own load, and an export rate that credits all energy delivered to the grid.

The total cost shift from solar customers to non-solar customers already totals **$42.7 million annually**.

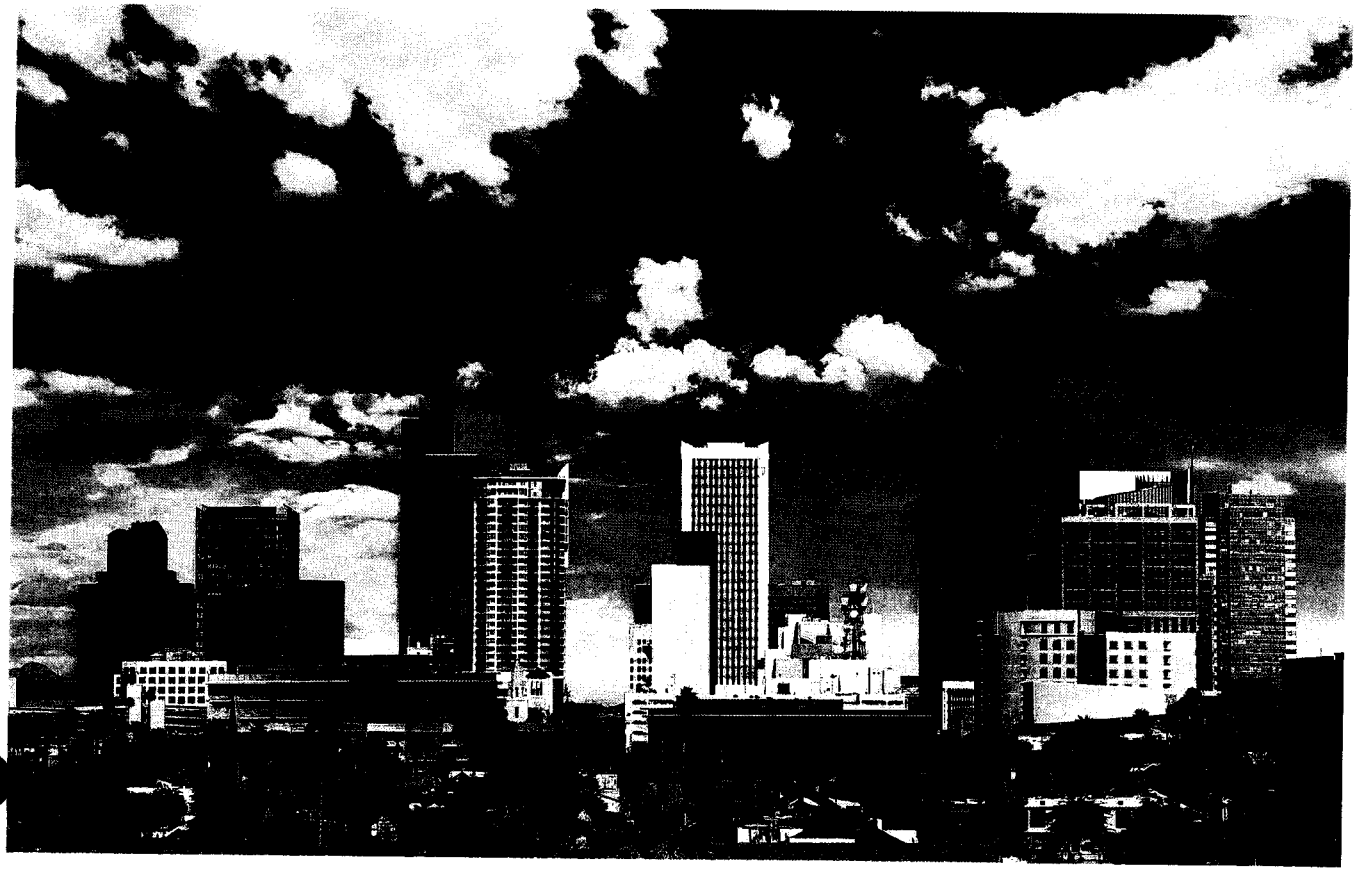
The rooftop solar subsidy continues to grow by **$740,000 per day**.

By the time this case is resolved in mid-2017, the 20 year subsidy will total **over $1 billion**.

If the cost shift issue is deferred until APS's next case, the total annual cost shift will have ballooned to **$102.9 million per year**.

Commercial and Industrial Rate Design

- Change time-of-use period for small, medium and large general service customers to 3 p.m. – 8 p.m. Monday through Friday.
- Allow the current AG-1 program to expire.
- Transition extra small business customers to a three-part rate with a $35.28 basic service charge, $6.90/kW demand charge, a summer energy charge of $0.11129/kWh and a winter energy charge of $0.07147/kWh for secondary service.
- Offer an aggregation rider that allows large (E-32L) customers with at least 5 MW total load to qualify for a reduced rate.
- Offer an extra-high load factor rate schedule for customers with at least 5 MW of load and monthly average load factor of 92% or more. Transmission service options available for customers with 15 MW or more.
- Offer an economic development rate for new loads of at least 2 MW or increasing loads of at least 1 MW and a load factor of 55% or more. Set a six-year limit with a program cap of 100 MW or 50 new customers, whichever is less (on MW basis).



Customer Education and Transition Plan

Customer Education

- Customer education material will describe the new rate plans and provide information to help customers manage their demand. APS will use multiple channels and touch points to communicate with customers, including:
  - Bill inserts
  - Website content
  - Videos
  - Printed material
  - Peak usage brochures
  - Email
  - Direct mail
- The education plan will also include community outreach events, stakeholder briefings and open houses to discuss demand rates and peak usage with community leaders and customers.
- Information related to demand will be available on aps.com and azenergyfuture.com.
- Printed materials will be available in APS offices, and with APS field personnel.

Tools and Technology

- APS.com will feature:
  - Customer demand and energy usage information (also available on the APS mobile app)
  - A summary of the new rate plans and a link to the tariffs
  - Hints and tips for managing demand
- APS has requested approval of a new smart thermostat program that will allow customers to receive an incentive for purchasing a qualifying smart thermostat of their choice.

Transition Plan

- Customers will be transitioned to new rates in phases.

  Once new rate plans are available, customers may choose any plan for which they are eligible.

  If customers do not choose a rate plan, APS will move each customer to the most beneficial rate plan for that customer based on past usage.

  Transition communication to customers will explain:
  - New rates
  - Timing of the change
  - Tips on how to "Shift, Stagger and Save"

A1

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

Line No.	Description	Electric Original Cost	Electric RCND	Electric Fair Value	Line No.
1.	Adjusted Rate Base	$ 6,771,151 (a)	$ 13,180,895 (a)	$ 9,976,023	1.
2.	Adjusted Operating Income	314,303 (b)	314,303 (b)	314,303 (b)	2.
3.	Current Rate of Return	4.64%	2.38%	3.15%	3.
4.	Required Operating Income	550,495	550,495	550,495	4.
5.	Required Rate of Return on OCRB	8.13% *	4.18% *	5.52% *	5.
6.	Adjusted Operating Income Deficiency on OCRB	236,192	236,192	236,192	6.
7.	Gross Revenue Conversion Factor	1.6155 (c)	1.6155 (c)	1.6155 (c)	7.
8.	Increase in Base Revenue Requirements Based on OCRB	$ 381,568 **	$ 381,568 **	$ 381,568 **	8.
9.	After Tax Return on Fair Value Increment			51,866	9.
10.	Requested Increase in Base Revenue Requirements			$ 433,434	10.
11.	Required Rate of Return with Fair Value Increment			5.84%	11.

	Customer Classification	Projected Revenue Increase Due to Base Rates	Base Rate % Increase	Bill Impact % Increase	
12.	Residential	$ 286,895	19.30%	7.96%	12.
13.	General Service	138,650	10.32%	3.29%	13.
14.	Irrigation and Water Pumping	4,892	17.02%	5.74%	14.
15.	Outdoor Lighting	2,130	10.10%	5.46%	15.
16.	Dusk-to-Dawn	867	10.11%	6.46%	16.
17.	Total	$ 433,434	15.00%	5.74%	17.
18.	Total Sales to Ultimate Retail Customers	$ 2,888,903 (d)			18.

Notes:

* The Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.

** Does not include the fair value increment reflected on Line 9.

Supporting Schedules:
(a) B-1
(b) C-1, page 2 of 2
(c) C-3
(d) H-1

Recap Schedules:
N/A

A2

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY RESULTS OF OPERATIONS
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	Prior Years: Year Ended 12/31/2013 (a) (A)	Prior Years: Year Ended 12/31/2014 (a) (B)	Test Year: Actual 12/31/2015 (a) (C)	Test Year: Adjusted 12/31/2015 (b) (D)	Projected Years: Present Rates 12/31/2016 (c) (E)	Projected Years: Present Rates 12/31/2017 (c) (F)	Projected Years: Present Rates 12/31/2018 (c) (G)	Projected Years: Proposed Rates 12/31/2017 (c) (H)	Projected Years: Proposed Rates 12/31/2018 (c) (I)	Line No.
1.	Gross Revenues	$ 3,451,251	$ 3,488,946	$ 3,492,357	$ 3,103,089	$ 3,459,020	$ 3,493,821	$ 3,562,292	$ 3,621,913	$ 3,797,016	1.
2.	Revenue Deductions & Operating Expenses	2,868,197	2,925,306	2,899,866	2,710,945	2,867,206	2,863,797	2,921,611	2,954,534	3,085,406	2.
3.	Operating Income	583,054	563,640	592,491	392,144	591,814	630,024	640,681	667,379	711,610	3.
4.	Other Income and (Deductions)	20,797	36,358	33,332	33,332	35,359	37,612	38,603	37,472	38,597	4.
5.	Interest Expense	178,882	178,779	175,549	175,549	189,834	213,782	244,913	210,340	231,340	5.
6.	Net Income	$ 424,969	$ 421,219	$ 450,274	$ 249,927	$ 437,339	$ 453,854	$ 434,371	$ 494,511	$ 518,867	6.
7.	Earned Per Average Common Share *	$ 5.96	$ 5.91	$ 6.32	$ 3.51	N/A	N/A	N/A	N/A	N/A	7.
8.	Dividends Per Common Share *	$ 3.44	$ 3.73	$ 3.80	$ 3.80	N/A	N/A	N/A	N/A	N/A	8.
9.	Payout Ratio *	57.6%	63.1%	60.1%	108.2%	N/A	N/A	N/A	N/A	N/A	9.
10.	Return on Average Invested Capital	8.1%	7.7%	7.6%	5.2%	7.3%	7.2%	6.9%	7.7%	7.7%	10.
11.	Return on Year End Capital	7.9%	7.4%	7.5%	5.1%	7.0%	7.0%	6.8%	7.4%	7.6%	11.
12.	Return on Average Common Equity	10.1%	9.5%	9.8%	5.4%	9.2%	9.2%	8.5%	10.0%	10.0%	12.
13.	Return on Year End Common Equity	9.9%	9.4%	9.6%	5.3%	9.1%	9.0%	8.4%	9.7%	9.8%	13.
14.	Times Bond Interest Earned-Before Income Taxes	4.5	4.5	4.8	3.3	4.5	4.2	3.7	4.5	4.4	14.
15.	Times Total Interest & Preferred Dividends Earned-After Income Taxes	3.2	3.2	3.5	2.4	3.3	3.1	2.7	3.3	3.2	15.

Notes

* Optional for projected years. Lines 7 and 8 are calculated using the common stock shares of Arizona Public Service Company, as indicated by the SFRs. APS's common stock shares have remained constant at 71.3 million, even though Pinnacle West has increased its equity investment in APS, and all APS shares are wholly owned by Pinnacle West Capital Corp. Pinnacle West's common stock is publicly held and the PNW share count is more indicative of the increasing equity investment needed to support APS's investment to serve its customers. APS's earnings per share of Pinnacle West diluted common stock outstanding was $3.84, $3.79, $4.04 and $2.24 for 2013, 2014, Test Year ended 12/31/2015, and adjusted Test Year ended 12/31/2015, respectively. APS's dividends per share of Pinnacle West diluted common stock outstanding was $2.21, $2.39, $2.42 and $2.42 for 2013, 2014, Test Year ended 12/31/2015, and adjusted Test Year ended 12/31/2015, respectively.

Supporting Schedules:
(a) E-2
(b) C-1
(c) F-1

Recap Schedules:
N/A

A3

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF CAPITAL STRUCTURE
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	Prior Years (a) Year Ended 12/31/2013 (A)	Prior Years (a) Year Ended 12/31/2014 (B)	Actual Test Year (a) Ended 12/31/2015 (C)	Projected Years (b) Present Rates Year Ended 12/31/2016 (D)	Projected Years (b) Present Rates Year Ended 12/31/2017 (E)	Projected Years (b) Present Rates Year Ended 12/31/2018 (F)	Projected Years (b) Proposed Rates Year Ended 12/31/2017 (G)	Projected Years (b) Proposed Rates Year Ended 12/31/2018 (H)	Line No.
1.	Short-Term Debt *	$ 153,125	$ 147,400	$ -	$ -	$ -	$ -	$ -	$ -	1.
2.	Long-Term Debt (with Cur Maturities) **	3,176,705	3,280,705	3,728,555	4,093,125	4,488,125	4,800,150	4,393,125	4,535,150	2.
3.	TOTAL DEBT	3,329,830	3,428,105	3,728,555	4,093,125	4,488,125	4,800,150	4,393,125	4,535,150	3.
4.	Preferred Stock	-	-	-	-	-	-	-	-	4.
5.	Common Equity	4,308,884	4,478,243	4,679,254	4,863,072	5,094,453	5,240,889	5,135,130	5,366,159	5.
6.	Total Capital	$ 7,638,714	$ 7,906,348	$ 8,407,809	$ 8,956,197	$ 9,582,578	$ 10,041,039	$ 9,528,255	$ 9,901,309	6.
	Capitalization Ratios:									
7.	Short-Term Debt	2.00%	1.86%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.
8.	Long-Term Debt	41.59%	41.49%	44.35%	45.70%	46.84%	47.81%	46.11%	45.80%	8.
9.	TOTAL DEBT	43.59%	43.36%	44.35%	45.70%	46.84%	47.81%	46.11%	45.80%	9.
10.	Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.
11.	Common Equity	56.41%	56.64%	55.65%	54.30%	53.16%	52.19%	53.89%	54.20%	11.
		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
12.	Weighted Cost of Short-Term Debt	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	12.
13.	Weighted Cost of Long-Term Debt	2.44%	2.26%	2.27%	2.32%	2.47%	2.68%	2.42%	2.53%	13.
14.	Weighted Cost of Senior Capital	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	14.

Notes

* Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions. For the unadjusted Test Year ending 12/31/2015 there was no short-term debt.

** Debt balances exclude unamortized discounts/premiums/debt issuance cost and Palo Verde capital lease obligation.

Supporting Schedules:
(a) E-1
(b) D-1

Recap Schedules:
N/A

A4

ARIZONA PUBLIC SERVICE COMPANY
CONSTRUCTION EXPENDITURES, NET PLANT PLACED IN SERVICE AND GROSS UTILITY PLANT IN SERVICE
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Year	Construction Expenditures (a)* (A)	Net Plant Placed In Service (B)	Gross Utility Plant in Service (b) (C)	Line No.
1.	Year Ended 2013	$ 982,785	$ 620,542	$ 15,481,565	1.
2.	Year Ended 2014	878,603	359,383	15,840,948	2.
3.	Year Ended 2015	1,053,972	739,502	16,580,450	3.
4.	Projected Year - Year Ended 12/31/2016	1,201,097	841,300	17,421,750	4.
5.	Projected Year - Year Ended 12/31/2017	1,280,569	924,681	18,346,431	5.
6.	Projected Year - Year Ended 12/31/2018	1,119,480	1,336,230	19,682,661	6.

Notes:
* Includes nuclear fuel and all construction expenditures reflected on accrual basis.

Supporting Schedules:
(a) F-3
(b) E-5

Recap Schedules:
N/A

A5

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY CHANGES IN FINANCIAL POSITION
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	Prior Years (a) Year Ended 12/31/2013 (A)	Prior Years (a) Year Ended 12/31/2014 (B)	Actual Test Year (a) Ended 12/31/2015 (C)	Projected Years (b) Present Rates Year Ended 12/31/2016 (D)	Projected Years (b) Present Rates Year Ended 12/31/2017 (E)	Projected Years (b) Present Rates Year Ended 12/31/2018 (F)	Projected Years (b) Proposed Rates Year Ended 12/31/2017 (G)	Projected Years (b) Proposed Rates Year Ended 12/31/2018 (H)	Line No.
	Sources / use of Funds:									
1.	Operations	$ 1,150,628	$ 1,078,236	$ 1,051,608	$ 1,069,995	$ 1,155,557	$ 1,123,561	$ 1,250,523	$ 1,294,390	1.
2.	Outside Financing	(140,993)	(155,328)	25,965	85,646	200,789	23,851	105,822	(146,978)	2.
3.	Total Funds Provided	1,009,635	922,908	1,077,573	1,155,640	1,356,345	1,147,413	1,356,345	1,147,413	3.
	Application of Funds:									
4.	Capital Expenditures *	975,232	889,759	1,025,507	1,157,815	1,332,393	1,124,000	1,332,393	1,124,000	4.
5.	Other	34,177	32,359	34,525	19,881	23,952	23,413	23,952	23,413	5.
6.	Total Funds Applied	$ 1,009,409	$ 922,118	$ 1,060,032	$ 1,177,696	$ 1,356,345	$ 1,147,413	$ 1,356,345	$ 1,147,413	6.

Notes:
* Capital expenditures are shown net of contributions in aid of construction and are reflected on a cash basis.

Supporting Schedules:
(a) E-3
(b) F-2

Recap Schedules:
N/A

B1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	Original Cost						Line No.
		Total Company			ACC			
		Unadjusted Test Year (a) (A)	Pro Forma (a) (B)	Adjusted Test Year (a) (C)	Unadjusted Test Year (a) (D)	Pro Forma (a) (E)	Adjusted Test Year (a) (F)	
1.	Gross utility plant in service	$ 16,835,977	$ 1,100,143	$ 17,936,120	$ 14,362,768	$ 1,074,192	$ 15,436,960	1.
2.	Less: Accumulated depreciation & amortization	6,402,411	727,533	7,129,944	5,632,319	712,193	6,344,512	2.
3.	Net utility plant in service	10,433,566	372,610	10,806,176	8,730,449	361,999	9,092,448	3.
	Deductions:							
4.	Deferred income taxes	2,873,411	111,056	2,984,467	2,359,729	111,891	2,471,620	4.
5.	Investment tax credits (c)	187,080	-	187,080	186,047	-	186,047	5.
6.	Customer advances for construction (c)	115,609	-	115,609	94,903	-	94,903	6.
7.	Customer deposits	72,622	-	72,622	72,622	-	72,622	7.
8.	Pension liabilities	426,442	-	426,442	394,050	-	394,050	8.
9.	Liability for asset retirements (c)	443,576	-	443,576	441,181	-	441,181	9.
10.	Other deferred credits	42,847	-	42,847	41,426	-	41,426	10.
11.	Coal mine reclamation (c)	201,984	-	201,984	200,611	-	200,611	11.
12.	Unrecognized tax benefits (c)	35,251	-	35,251	29,523	-	29,523	12.
13.	Regulatory liabilities	787,438	-	787,438	756,476	-	756,476	13.
14.	Total deductions	5,186,260	111,056	5,297,316	4,576,568	111,891	4,688,459	14.
	Additions:							
15.	Regulatory assets	1,098,378	59,488	1,157,866	1,006,675	59,486	1,066,161	15.
16.	Other deferred debits	121,338	-	121,338	113,265	-	113,265	16.
17.	Decommissioning trust accounts (c)	735,196	-	735,196	731,226	-	731,226	17.
18	OPEB assets (c)	182,625	-	182,625	168,753	-	168,753	18
19.	Allowance for working capital (d)	324,803	(18,888)	305,915	305,210	(17,453)	287,757	19.
20.	Total additions	2,462,340	40,600	2,502,940	2,325,129	42,033	2,367,162	20.
21.	Total rate base	$ 7,709,646	$ 302,154	$ 8,011,800	$ 6,479,010	$ 292,141	$ 6,771,151 (e)	21.

Supporting Schedules:
(a) B-2
(b) B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) A-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE AYSE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	RCND Total Company Unadjusted Test Year (b) (A)	Total Company Pro Forma (b) (B)	Total Company Adjusted Test Year (b) (C)	ACC Unadjusted Test Year (b) (D)	ACC Pro Forma (b) (E)	ACC Adjusted Test Year (b) (F)	Line No.
1.	Gross utility plant in service	$ 34,956,729	$ 1,100,143	$ 36,056,872	$ 29,821,577	$ 1,074,192	$ 30,895,769	1.
2.	Less: Accumulated depreciation & amortization	13,659,172	727,533	14,386,705	12,016,225	712,193	12,728,418	2.
3.	Net utility plant in service	21,297,557	372,610	21,670,167	17,805,352	361,999	18,167,351	3.
	Deductions:							
4.	Deferred income taxes	6,118,741	111,056	6,229,797	5,024,888	111,891	5,136,779	4.
5.	Investment tax credits (c)	187,080	-	187,080	186,047	-	186,047	5.
6.	Customer advances for construction (c)	115,609	-	115,609	94,903	-	94,903	6.
7.	Customer deposits	72,622	-	72,622	72,622	-	72,622	7.
8.	Pension liabilities	426,442	-	426,442	394,050	-	394,050	8.
9.	Liability for asset retirements (c)	443,576	-	443,576	441,181	-	441,181	9.
10.	Other deferred credits	42,847	-	42,847	41,426	-	41,426	10.
11.	Coal mine reclamation (c)	201,984	-	201,984	200,611	-	200,611	11.
12.	Unrecognized tax benefits (c)	35,251	-	35,251	29,523	-	29,523	12.
13.	Regulatory liabilities	787,438	-	787,438	756,476	-	756,476	13.
14.	Total deductions	8,431,590	111,056	8,542,646	7,241,727	111,891	7,353,618	14.
	Additions:							
15.	Regulatory assets	1,098,378	59,488	1,157,866	1,006,675	59,486	1,066,161	15.
16.	Other deferred debits	121,338	-	121,338	113,265	-	113,265	16.
17.	Decommissioning trust accounts (c)	735,196	-	735,196	731,226	-	731,226	17.
18	OPEB assets (c)	182,625	-	182,625	168,753	-	168,753	18
19.	Allowance for working capital (d)	324,803	(18,888)	305,915	305,210	(17,453)	287,757	19.
20.	Total additions	2,462,340	40,600	2,502,940	2,325,129	42,033	2,367,162	20.
21.	Total rate base	$ 15,328,307	$ 302,154	$ 15,630,461	$ 12,888,754	$ 292,141	$ 13,180,895 (e)	21.

Supporting Schedules:
(a) B-2
(b) B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) A-1

B2

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(1) Actual at End of Test Year 12/31/2015 (a) (b) Total Co. (A)	(b) ACC (B)	(2) Fossil Generation Post-Test Year Plant Additions Total Co. (C)	ACC (D)	(3) Nuclear Generation Post-Test Year Plant Additions Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 16,835,977	$ 14,362,768	$ 160,635	$ 159,768	$ 123,961	$ 123,291
2.	Less: Accumulated Depreciation & Amort.	6,402,411	5,632,319	218,381	217,202	74,294	73,893
3	Net Utility Plant in Service	10,433,566	8,730,449	(57,746)	(57,434)	49,667	49,398
4.	Less: Total Deductions	5,186,260	4,576,568	(19,967)	(19,859)	1,583	1,574
5.	Total Additions	2,462,340	2,325,129	-	-	-	-
6.	Total Rate Base	$ 7,709,646	$ 6,479,010	$ (37,779)	$ (37,575)	$ 48,084	$ 47,824

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

LUCAS / BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

CADOGAN / BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1.

(2) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Fossil Generation with an estimated in service date prior to 6/30/2017.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Nuclear Generation with an estimated in service date prior to 6/30/2017.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(4) Distribution and IT/Facilities Post-Test Year Plant Additions		(5) Customer Service Post-Test Year Plant Additions		(6) Renewables & Modern Grid Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 470,386	$ 455,104	$ 120,485	$ 111,333	$ 238,509	$ 238,454
2.	Less: Accumulated Depreciation & Amort.	383,258	369,941	6,050	5,590	50,830	50,818
3	Net Utility Plant in Service	87,128	85,163	114,435	105,743	187,679	187,636
4.	Less: Total Deductions	11,672	12,907	6,426	5,938	93,391	93,369
5.	Total Additions	-	-	-	-	7,024	7,022
6.	Total Rate Base	$ 75,456	$ 72,256	$ 108,009	$ 99,805	$ 101,312	$ 101,289

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

TETLOW / BLANKENSHIP
1. Jurisdictional
2. Distribution facilities functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries

DERSTINE / BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries.

BORDENKIRCHER / BLANKENSHIP
1. Jurisdictional
2. Renewables functionalized on Demand Production [Retail DEMPROD1], Grid functionalized on Distribution.

(4) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Distribution and IT/Facilities with an estimated in service date prior to 6/30/2017.

(5) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Customer Service with an estimated in service date prior to 6/30/2017.

(6) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Renewables & Modern Grid with an estimated in service date prior to 6/30/2017.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(7) Include AG-1 Deferral		(8) Include West Phoenix Unit 4 Regulatory Disallowance		(9) Include Property Tax Deferral	
		Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
1.	Gross Utility Plant in Service	$ -	$ -	$ (13,833)	$ (13,758)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	(5,280)	(5,251)	-	-
3	Net Utility Plant in Service	-	-	(8,553)	(8,507)	-	-
4.	Less: Total Deductions	5,309	5,309	(2,038)	(2,027)	14,680	14,680
5.	Total Additions	13,935	13,935	-	-	38,529	38,529
6.	Total Rate Base	$ 8,626	$ 8,626	$ (6,515)	$ (6,480)	$ 23,849	$ 23,849
	PRO FORMA WITNESS:	MIESSNER		BLANKENSHIP		BLANKENSHIP	
	FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]	1. General Service ACC Specific 2. Revenues and expenses are class specific.		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)		1. ACC Specific 2. Functionalized on P T & D	

(7) 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.

(8) Adjustment to Test Year rate base to reflect depreciation of regulatory disallowance of West Phoenix Unit 4 per Decisions Nos. 67744 and 69663.

(9) Adjustment to Test Year rate base to include the estimated property tax deferral amount from 1/1/2016 to 6/30/2017 per Decision No. 73183.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(10) Adjust Cash Working Capital for Cost of Service		(11) Total Original Cost Rate Base Pro Forma Adjustments		(12) Adjusted at End of Test Year 12/31/2015	
		Total Co. (S)	ACC (T)	(b) Total Co. (U)	(b) ACC (V)	(b) Total Co. (W)	(b) ACC (X)
1.	Gross Utility Plant in Service	$ -	$ -	$ 1,100,143	$ 1,074,192	$ 17,936,120	$ 15,436,960
2.	Less: Accumulated Depreciation & Amort.	-	-	727,533	712,193	7,129,944	6,344,512
3	Net Utility Plant in Service	-	-	372,610	361,999	10,806,176	9,092,448
4.	Less: Total Deductions	-	-	111,056	111,891	5,297,316	4,688,459
5.	Total Additions	(18,888)	(17,453)	40,600	42,033	2,502,940	2,367,162
6.	Total Rate Base	$ (18,888)	$ (17,453)	$ 302,154	$ 292,141	$ 8,011,800	$ 6,771,151

PRO FORMA WITNESS: BLANKENSHIP

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

1. Jurisdictional
2. Functionalized on Wages & Salaries

(10) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) B-1

B3

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(1) Actual at End of Test Year 12/31/2015 (a) (b) Total Co. (A)	(a) (b) ACC (B)	(2) Fossil Generation Post-Test Year Plant Additions Total Co. (C)	ACC (D)	(3) Nuclear Generation Post-Test Year Plant Additions Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 34,956,729	$ 29,821,577	$ 160,635	$ 159,768	$ 123,961	$ 123,291
2.	Less: Accumulated Depreciation & Amort.	13,659,172	12,016,225	218,381	217,202	74,294	73,893
3	Net Utility Plant in Service	21,297,557	17,805,352	(57,746)	(57,434)	49,667	49,398
4.	Less: Total Deductions	8,431,590	7,241,727	(19,967)	(19,859)	1,583	1,574
5.	Total Additions	2,462,340	2,325,129	-	-	-	-
6.	Total Rate Base	$ 15,328,307	$ 12,888,754	$ (37,779)	$ (37,575)	$ 48,084	$ 47,824

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

LUCAS / BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

CADOGAN / BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1.

(2) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Fossil Generation with an estimated in service date prior to 6/30/2017.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Nuclear Generation with an estimated in service date prior to 6/30/2017.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(4) Distribution and IT/Facilities Post-Test Year Plant Additions		(5) Customer Service Post-Test Year Plant Additions		(6) Renewables, Microgrid & Technology Innovation Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 470,386	$ 455,104	$ 120,485	$ 111,333	$ 238,509	$ 238,454
2.	Less: Accumulated Depreciation & Amort.	383,258	369,941	6,050	5,590	50,830	50,818
3	Net Utility Plant in Service	87,128	85,163	114,435	105,743	187,679	187,636
4.	Less: Total Deductions	11,672	12,907	6,426	5,938	93,391	93,369
5.	Total Additions	-	-	-	-	7,024	7,022
6.	Total Rate Base	$ 75,456	$ 72,256	$ 108,009	$ 99,805	$ 101,312	$ 101,289

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

TETLOW / BLANKENSHIP
1. Jurisdictional
2. Distribution facilities functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries

DERSTINE / BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries.

BORDENKIRCHER / BLANKENSHIP
1. Jurisdictional
2. Renewables functionalized on Demand Production [Retail DEMPROD1], Grid functionalized on Distribution.

(4) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Distribution and IT/Facilities with an estimated in service date prior to 6/30/2017.

(5) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Customer Service with an estimated in service date prior to 6/30/2017.

(6) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for Renewables, Microgrid & Technology Innovation with an estimated in service date prior to 6/30/2017.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(7) Include AG-1 Deferral Total Co. (M)	(7) Include AG-1 Deferral ACC (N)	(8) Include West Phoenix Unit 4 Regulatory Disallowance Total Co. (O)	(8) Include West Phoenix Unit 4 Regulatory Disallowance ACC (P)	(9) Include Property Tax Deferral Total Co. (Q)	(9) Include Property Tax Deferral ACC (R)
1.	Gross Utility Plant in Service	$ -	$ -	$ (13,833)	$ (13,758)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	(5,280)	(5,251)	-	-
3	Net Utility Plant in Service	-	-	(8,553)	(8,507)	-	-
4.	Less: Total Deductions	5,309	5,309	(2,038)	(2,027)	14,680	14,680
5.	Total Additions	13,935	13,935	-	-	38,529	38,529
6.	Total Rate Base	$ 8,626	$ 8,626	$ (6,515)	$ (6,480)	$ 23,849	$ 23,849

PRO FORMA WITNESS:	MIESSNER	BLANKENSHIP	BLANKENSHIP
FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]	1. General Service ACC Specific 2. Revenues and expenses are class specific.	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. ACC Specific 2. Functionalized on P T & D

(7) 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.

(8) Adjustment to Test Year rate base to reflect depreciation of regulatory disallowance of West Phoenix Unit 4 per Decisions Nos. 67744 and 69663.

(9) Adjustment to Test Year rate base to include the estimated property tax deferral amount from 1/1/2016 to 6/30/2017 per Decision No. 73183.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(10) Adjust Cash Working Capital for Cost of Service: Total Co. (S)	(10) Adjust Cash Working Capital for Cost of Service: ACC (T)	(11) Total RCND Rate Base Pro Forma Adjustments: (b) Total Co. (U)	(11) Total RCND Rate Base Pro Forma Adjustments: (b) ACC (V)	(12) Adjusted at End of Test Year 12/31/2015: (b) Total Co. (W)	(12) Adjusted at End of Test Year 12/31/2015: (b) ACC (X)
1.	Gross Utility Plant in Service	$ -	$ -	$ 1,100,143	$ 1,074,192	$ 36,056,872	$ 30,895,769
2.	Less: Accumulated Depreciation & Amort.	-	-	727,533	712,193	14,386,705	12,728,418
3	Net Utility Plant in Service	-	-	372,610	361,999	21,670,167	18,167,351
4.	Less: Total Deductions	-	-	111,056	111,891	8,542,646	7,353,618
5.	Total Additions	(18,888)	(17,453)	40,600	42,033	2,502,940	2,367,162
6.	Total Rate Base	$ (18,888)	$ (17,453)	$ 302,154	$ 292,141	$ 15,630,461	$ 13,180,895

PRO FORMA WITNESS:

BLANKENSHIP

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

1. Jurisdictional
2. Functionalized on Wages & Salaries

(10) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) B-1

B4

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN (A)	CONDITION PERCENT (B)	RCND (C)	Line No.
1.	INTANGIBLES	301	Organization	$ -	0%	$ -	1.
2.		302	Franchises and consents	3,341	56.70%	1,895	2.
3.		303	Miscellaneous intangible plant	522,876	20.90%	109,283	3.
4.			SUBTOTAL	526,217		111,178	4.
5.	PRODUCTION	310	Land and Land Rights	5,794	98.89%	5,729	5.
6.		310	Limit Term Land Rights	-	98.78%	-	6.
7.		311	Structures and improvements	487,993	49.28%	240,483	7.
8.		312	Boiler plant equipment	3,161,771	36.31%	1,148,039	8.
9.		314	Turbogenerator units	789,516	34.34%	271,120	9.
10.		315	Accessory electric equipment	846,377	40.44%	342,275	10.
11.		316	Miscellaneous power plant equip.	196,349	41.10%	80,699	11.
12.		317	ARO for Steam Production	42,687	72.51%	30,951	12.
13.		320	Land and land rights	4,418	0.00%	-	13.
14.		321	Structures and improvements	1,492,216	48.01%	716,413	14.
15.		322	Reactor plant equipment	2,494,738	44.85%	1,118,890	15.
16.		323	Turbogenerator units	783,842	49.11%	384,945	16.
17.		324	Accessory electric equipment	1,133,537	36.45%	413,174	17.
18.		325	Misc power plant equip	362,772	59.49%	215,813	18.
19.		326	ARO for Nuclear Production	(53,660)	127.92%	(68,641)	19.
20.		330	Limit Term Land Rights	-	0.00%	-	20.
21.		331	Structures and improvements	-	0.00%	-	21.
22.		332	Reservoirs, dams, and waterways	-	0.00%	-	22.
23.		333	Water wheels, turbines and generators	-	0.00%	-	23.
24.		334	Accessory electric equipment	-	0.00%	-	24.
25.		335	Miscellaneous power plant equip.	-	0.00%	-	25.
26.		336	Roads, railroads and bridges	-	0.00%	-	26.
27.		337	ARO for Hydraulic Production	-	0.00%	-	27.
28.		340	Land and land rights	15,767	100.00%	15,767	28.
29.		341	Structures and improvements	178,185	73.29%	130,592	29.
30.		342	Fuel holders, products, and accessories	100,653	58.95%	59,335	30.
31.		343	Prime movers	1,448,634	67.07%	971,599	31.
32.		344	Generators	2,079,650	81.17%	1,688,052	32.
33.		345	Accessory electric equipment	378,039	77.89%	294,454	33.
34.		346	Miscellaneous power plant equip.	40,582	80.99%	32,867	34.
35.			SUBTOTAL	15,989,858		8,092,556	35.
36.	TRANSMISSION	350	Land and land rights	158,033	49.33%	77,958	36.
37.		350	Limit Term Land Rights	-	0.00%	-	37.
38.		352	Structures and improvements	194,812	4.51%	8,786	38.
39.		353	Station equipment	2,330,751	77.39%	1,803,768	39.
40.		354	Towers and fixtures	474,903	59.22%	281,238	40.
41.		355	Poles and fixtures	774,976	75.80%	587,432	41.
42.		356	Overhead conductors and devices	1,190,643	69.25%	824,521	42.
43.		357	Underground conduit	57,570	64.19%	36,956	43.
44.		358	Underground conductors and devices	141,283	75.51%	106,686	44.
45.			SUBTOTAL	5,322,972		3,727,344	45.
46.	DISTRIBUTION	360	Land and land rights	62,585	93.95%	58,802	46.
47.		360	Limit Term Land Rights	-	0.00%	-	47.
48.		361	Structures and improvements	140,782	76.96%	108,346	48.
49.		362	Station equipment	957,315	79.98%	765,661	49.
50.		363	Storage Battery Equipment	2,145	88.33%	1,894	50.
51.		364	Poles, towers, and fixtures	1,026,811	74.34%	763,287	51.
52.		365	Overhead conductors and devices	851,780	83.66%	712,599	52.
53.		366	Underground conduit	1,145,674	74.91%	858,224	53.
54.		367	Underground conductors and devices	3,713,925	64.25%	2,386,197	54.
55.		368	Line transformers	2,642,618	71.44%	1,887,886	55.
56.		369	Services	683,489	57.55%	393,348	56.
57.		370	Meters	400,722	98.93%	396,438	57.
58.		371	Installations on customers' premises	104,025	68.34%	71,091	58.
59.		373	Street lighting and signal systems	190,014	68.96%	131,033	59.
60.			SUBTOTAL	11,921,884		8,534,806	60.

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN (A)	CONDITION PERCENT (B)	RCND (C)	Line No.
61.	GENERAL	389	Land and land rights	14,600	99.43%	14,516	61.
62.		390	Structures and improvements	359,354	82.95%	298,084	62.
63.		390	Structures and improvements - Lease	-	0.00%	-	63.
64.		391	Office furniture and equipment	305,162	66.78%	203,787	64.
65.		391	Capitalized Lease-Computer Equipment		66.78%	-	65.
66.		392	Transportation equipment	53,170	31.13%	16,554	66.
67.		392	Capitalized Lease-Transportation Equip.	-	0.00%	-	67.
68.		393	Stores equipment	405	66.11%	268	68.
69.		394	Tools, shop and garage equipment	52,945	51.78%	27,415	69.
70.		395	Laboratory equipment	1,994	49.53%	987	70.
71.		396	Power operated equipment	22,885	27.35%	6,260	71.
72.		397	Communication equipment	362,766	68.14%	247,189	72.
73.		398	Miscellaneous equipment	22,517	73.78%	16,613	73.
74.			SUBTOTAL	1,195,798		831,674	74.
75.		TOTAL PLANT (a)		$ 34,956,729		$ 21,297,557	75.

Supporting Schedules:
RCND Study

Recap Schedules:
(a) B-3

B4a

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF RCND RATE BASE ELEMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	Total Company (B + C) (A)	ACC (B)	All Other (C)	Line No.
1.	A. ORIGINAL COST:				1.
2.	Gross Utility Plant in Service	$ 16,835,977	$ 14,362,768	$ 2,473,209	2.
3.	Accumulated Depreciation & Amortization	6,402,411	5,632,319	770,092	3.
4.	Net Utility Plant in Service	10,433,566	8,730,449	1,703,117	4.
5.	B. RCND:				5.
6.	Reproduction Cost New (a)	34,956,729	29,821,577	5,135,152	6.
7.	Accumulated Depreciation (a)	13,659,172	12,016,225	1,642,947	7.
8.	Total RCND Plant in Service at 12/31/2015 from B-4 (a)	21,297,557	17,805,352	3,492,205	8.
9.	Deductions:				9.
10.	Deferred Taxes	6,118,741	5,024,888	1,093,852	10.
11.	Investment Tax Credits	187,080	186,047	1,033	11.
12.	Total Deferred Taxes and ITC	6,305,821	5,210,935	1,094,885	12.
13.	Customer Advances for Construction	115,609	94,903	20,706	13.
14.	Customer Deposits	72,622	72,622	-	14.
15.	Pension Liability	426,442	394,050	32,392	15.
16.	Liability for Asset Retirement	443,576	441,181	2,395	16.
17.	Other Deferred Credits	42,847	41,426	1,421	17.
18.	Coal Mine Reclamation	201,984	200,611	1,373	18.
19.	Unrecognized Tax Benefits	35,251	29,523	5,728	19.
20.	Regulatory Liabilities	787,438	756,476	30,962	20.
21.	Total Deductions (a)	8,431,590	7,241,727	1,189,862	21.
22.	Additions:				22.
23.	Regulatory Assets	1,098,378	1,006,675	91,703	23.
24.	Deferred Debit Income Tax Receivable	121,338	113,265	8,073	24.
25.	Miscellaneous Deferred Debits	735,196	731,226	3,970	25.
26.	Depreciation Fund - Decommissioning	182,625	168,753	13,872	26.
27.	Allowance for Working Capital	324,803	305,210	19,593	27.
28.	Total Additions (a)	2,462,340	2,325,129	137,211	28.
29.	Total RCND Rate Base Before Proforma Adj. (a)	15,328,307	12,888,754	2,439,554	29.
30.	Proforma Adjustments	302,154	292,141	10,013	30.
31.	Total RCND Rate Base	$ 15,630,461	$ 13,180,895	$ 2,449,567	31.

Supporting Schedules:
For Lines 2-3 Col. (A): See Schedule B-1, Column (A) page 1 of 2.
For Lines 2-3 Col. (B): See Schedule B-1, Column (D) page 1 of 2.
For Line 6-28 Col. (A): See Schedule B-4, Column (A) page 2 of 2.
For Line 6-28 Col. (B): See Schedule B-4, Column (D) page 2 of 2.

Recap Schedules:
(a) B-3

B5

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF WORKING CAPITAL
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	Amount	Line No.
1.	Working Capital - Operations (a)	$ (113,623)	1.
2.	Materials and Supplies (b)	234,234	2.
3.	Fuel - Coal and Oil (b)	45,697	3.
4.	Fuel - Nuclear, Net (b)	123,139	4.
5.	Prepayments (b)	32,489	5.
6.	Special Deposits & Working Funds (b)	2,868	6.
7.	Total Allowance for Working Capital (c)	$ 324,803	7.

Supporting Schedules:
(a) Lead-Lag Study
(b) E-1

Recap Schedule
(c) B-1

C1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	Total Company: Actual For The Test Year Ended 12/31/2015 (a) (A)	Proforma Adjustments (b) (B)	Test Year Results After Proforma Adjustments (c) (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,909,648	$ 23,340	$ 2,932,988	1.
2.	Revenues from Surcharges	408,660	(408,660)	-	2.
3.	Other Electric Revenues	174,049	(3,948)	170,101	3.
4.	Total	3,492,357	(389,268)	3,103,089	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,101,298	(102,374)	998,924	5.
6.	Operations and maintenance excluding fuel expenses	892,796	(129,678)	763,118	6.
7.	Depreciation and amortization	474,131	134,734	608,865	7.
8.	Income taxes	260,143	(133,796)	126,347	8.
9.	Other taxes	171,499	42,192	213,691	9.
10.	Total	2,899,866	(188,922)	2,710,945	10.
11.	Operating income	592,491	(200,346)	392,144	11.
	Other income (deductions):				
12.	Income taxes	14,302	-	14,302	12.
13.	Allowance for equity funds used during construction	35,215	-	35,215	13.
14.	Other income	2,834	-	2,834	14.
15.	Other expense	(19,019)	-	(19,019)	15.
16.	Total	33,332	-	33,332	16.
17.	Income before interest deductions	625,823	(200,346)	425,476	17.
	Interest deductions:				
18.	Interest on long-term debt	179,563	-	179,563	18.
19.	Interest on short-term borrowings	7,376	-	7,376	19.
20.	Debt discount, premium and expense	4,793	-	4,793	20.
21.	Allowance for borrowed funds used during construction	(16,183)	-	(16,183)	21.
22.	Total	175,549	-	175,549	22.
23.	Net income	$ 450,274	$ (200,346)	$ 249,927	23.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

ARIZONA PUBLIC SERVICE COMPANY
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	ACC Jurisdiction: Actual For The Test Year Ended 12/31/2015 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (b) (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,865,563	$ 23,340	$ 2,888,903	1.
2.	Revenues from Surcharges	408,240	(408,240)	-	2.
3.	Other Electric Revenues	162,496	(3,946)	158,550	3.
4.	Total	3,436,299	(388,846)	3,047,453	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,094,373	(102,311)	992,062	5.
6.	Operations and maintenance excluding fuel expenses	1,046,362	(128,334)	918,028	6.
7.	Depreciation and amortization	420,408	130,023	550,431	7.
8.	Income taxes	226,096	(129,936)	96,160	8.
9.	Other taxes	139,384	37,085	176,469	9.
10.	Total	2,926,623	(193,473)	2,733,150	10.
11.	Operating income	509,676	(195,373)	314,303	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	509,676	(195,373)	314,303	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 509,676	$ (195,373)	$ 314,303	23.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

C2

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(1) Fossil Generation Post-Test Year Plant Additions Total Co. (A)	(1) ACC (B)	(2) Nuclear Generation Post-Test Year Plant Additions Total Co. (C)	(2) ACC (D)	(3) Distribution and IT/Facilities Post-Test Year Plant Additions Total Co. (E)	(3) ACC (F)
	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	6,876	6,839	2,008	1,997	24,244	22,903
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	1,118	1,112	866	861	9,420	9,120
14.	Total Other Operating Expense	7,994	7,951	2,874	2,858	33,664	32,023
15.	Operating Income Before Income Tax	(7,994)	(7,951)	(2,874)	(2,858)	(33,664)	(32,023)
16.	Interest Expense	(858)	(853)	1,092	1,086	1,713	1,640
17.	Taxable Income	(7,136)	(7,098)	(3,966)	(3,944)	(35,377)	(33,663)
18.	Current Income Tax Rate - 38.10%	(2,719)	(2,704)	(1,511)	(1,503)	(13,479)	(12,826)
19.	Operating Income (line 15 minus line 18)	$ (5,275)	$ (5,247)	$ (1,363)	$ (1,355)	$ (20,185)	$ (19,197)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

LUCAS / BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

CADOGAN / BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

TETLOW / BLANKENSHIP
1. Jurisdictional
2. Distribution facilities functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries

(1) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 2.

(2) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Nuclear Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

(3) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Distribution and IT/Facilities Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(4) Customer Service Post-Test Year Plant Additions Total Co. (G)	(4) ACC (H)	(5) Renewables, Microgrid & Technology Innovation Post-Test Year Plant Additions Total Co. (I)	(5) ACC (J)	(6) Base Fuel and Purchased Power Total Co. (K)	(6) ACC (L)
	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	-	-	-	-	(41,625)	(41,625)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	2,511	2,511	41,625	41,625
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	12,048	11,133	8,915	8,914	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	2,353	2,174	2,295	2,295	-	-
14.	Total Other Operating Expense	14,401	13,307	11,210	11,209	-	-
15.	Operating Income Before Income Tax	(14,401)	(13,307)	(8,699)	(8,698)	41,625	41,625
16.	Interest Expense	2,452	2,266	2,300	2,300	-	-
17.	Taxable Income	(16,853)	(15,573)	(10,999)	(10,998)	41,625	41,625
18.	Current Income Tax Rate - 38.10%	(6,421)	(5,933)	(4,191)	(4,190)	15,859	15,859
19.	Operating Income (line 15 minus line 18)	$ (7,980)	$ (7,374)	$ (4,508)	$ (4,508)	$ 25,766	$ 25,766

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

DERSTINE / BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries.

BORDENKIRCHER / SNOOK / BLANKENSHIP
1. Jurisdictional
2. Renewables functionalized on Demand Production [Retail DEMPROD1], Grid functionalized on Distribution.

EWEN
1. ACC Specific
2. Assigned to Production - Energy (Retail Only ENERGY2)

(4) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Customer Service Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 5.

(5) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Renewables, Microgrid & Technology Innovation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 6.

(6) Adjustment to Test Year operations to include 2017 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(7) Test Year PSA Revenue and Deferred Fuel Amortization		(8) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals		(9) Normalize Weather Conditions	
		Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ 10,514	$ 10,514
2.	Revenues from Surcharges	(1,554)	(1,555)	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(1,554)	(1,555)	-	-	10,514	10,514
5.	Electric Fuel and Purchased Power Costs	(1,579)	(1,580)	(14,899)	(14,899)	3,647	3,647
6.	Oper Rev Less Fuel & Purch Pwr Costs	25	25	14,899	14,899	6,867	6,867
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	(25)	(25)	-	-	-	-
9.	Subtotal	(25)	(25)	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(25)	(25)	-	-	-	-
15.	Operating Income Before Income Tax	50	50	14,899	14,899	6,867	6,867
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	50	50	14,899	14,899	6,867	6,867
18.	Current Income Tax Rate - 38.10%	19	19	5,677	5,677	2,616	2,616
19.	Operating Income (line 15 minus line 18)	$ 31	$ 31	$ 9,222	$ 9,222	$ 4,251	$ 4,251

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

EWEN
1. Jurisdictional
2. Revenues and Expenses are class specific.

EWEN
1. ACC Specific
2. Assigned to Production - Energy (Retail Only ENERGY2_XAG1)

MIESSNER
1. ACC Specific
2. Revenues and Expenses are class specific.

(7) 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.

(8) Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and mark-to-market accruals.

(9) Adjustment to Test Year operating revenues to reflect normal weather conditions for the ten years ended 12/31/2015.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(10) Annualize Customer Levels Total Co. (S)	(10) Annualize Customer Levels ACC (T)	(11) Limited Income Discount (E-3/E-4) Total Co. (U)	(11) Limited Income Discount (E-3/E-4) ACC (V)	(12) Service Schedule Adjustments Total Co. (W)	(12) Service Schedule Adjustments ACC (X)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ 10,326	$ 10,326	$ (11,900)	$ (11,900)	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(3,934)	(3,932)
4.	Total Electric Operating Revenues	10,326	10,326	(11,900)	(11,900)	(3,934)	(3,932)
5.	Electric Fuel and Purchased Power Costs	3,626	3,626	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	6,700	6,700	(11,900)	(11,900)	(3,934)	(3,932)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	764	764	-	-
9.	Subtotal	-	-	764	764	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	764	764	-	-
15.	Operating Income Before Income Tax	6,700	6,700	(12,664)	(12,664)	(3,934)	(3,932)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	6,700	6,700	(12,664)	(12,664)	(3,934)	(3,932)
18.	Current Income Tax Rate - 38.10%	2,553	2,553	(4,825)	(4,825)	(1,499)	(1,498)
19.	Operating Income (line 15 minus line 18)	$ 4,147	$ 4,147	$ (7,839)	$ (7,839)	$ (2,435)	$ (2,434)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

MIESSNER
1. ACC Specific
2. Revenues and Expenses are class specific.

MIESSNER
1. ACC Specific
2. Revenues are class specific and Expenses are Assigned to System Benefits. (Retail ERGSYSBEN)

MIESSNER
1. ACC Specific
2. Functionalized on PT&D Distribution Only

(10) Adjustment to Test Year operating revenues to reflect the annualization of customer levels at 12/31/2015.

(11) Adjustment to Test Year operating revenues to reflect the increase in limited income customer discounts from the Test Year through 6/30/2017.

(12) Adjustment to Test Year operating other revenues to reflect changes in service schedule charges.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(13) AG-1 Adjustment Total Co. (Y)	(13) AG-1 Adjustment ACC (Z)	(14) Include Amortization of AG-1 Deferral Total Co. (AA)	(14) Include Amortization of AG-1 Deferral ACC (AB)	(15) Remove Amortization of Pension/OPEB Deferral Total Co. (AC)	(15) Remove Amortization of Pension/OPEB Deferral ACC (AD)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ 11,889	$ 11,889	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	11,889	11,889	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	194	194	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	11,695	11,695	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	(4,238)	(4,238)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	(4,238)	(4,238)
10.	Depreciation and Amortization	-	-	2,787	2,787	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	2,787	2,787	(4,238)	(4,238)
15.	Operating Income Before Income Tax	11,695	11,695	(2,787)	(2,787)	4,238	4,238
16.	Interest Expense	-	-	196	196	-	-
17.	Taxable Income	11,695	11,695	(2,983)	(2,983)	4,238	4,238
18.	Current Income Tax Rate - 38.10%	4,456	4,456	(1,136)	(1,136)	1,615	1,615
19.	Operating Income (line 15 minus line 18)	$ 7,239	$ 7,239	$ (1,651)	$ (1,651)	$ 2,623	$ 2,623

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

MIESSNER
1. ACC Specific
2. Revenues and expenses are class specific.

MIESSNER
1. ACC Specific
2. Revenues are class specific.
3. Expenses are assigned to Production Energy (GEN. SERV. SPECIFIC).

BLANKENSHIP
1. ACC Specific
2. Functionalized on Wages & Salaries

(13) Adjustment to Test Year retail revenue to adjust for AG-1 customers unrecovered revenues.

(14) 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 5 year period. Pro forma adjusted as shown on Schedule B-2, page 3, column 7.

(15) Adjustment to Test Year operations to remove 6 months of amortization of the Pension/OPEB deferral authorized in Decision No. 71448.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(16) Amonix, Star Center Patent Rights and Sale of Kyrene to Knox Amortization Total Co. (AE)	ACC (AF)	(17) Office Closure and Paystation Fee Socialization Total Co. (AG)	ACC (AH)	(18) Remove Test Year Regulatory Assessment Total Co. (AI)	ACC (AJ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	(7,545)	(7,545)
3.	Other Electric Revenues	-	-	(14)	(14)	-	-
4.	Total Electric Operating Revenues	-	-	(14)	(14)	(7,545)	(7,545)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(14)	(14)	(7,545)	(7,545)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(4,038)	(4,038)	(1,033)	(1,033)	(7,545)	(7,545)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(4,038)	(4,038)	(1,033)	(1,033)	(7,545)	(7,545)
10.	Depreciation and Amortization	-	-	(27)	(27)	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	(18)	(18)	-	-
14.	Total Other Operating Expense	(4,038)	(4,038)	(1,078)	(1,078)	(7,545)	(7,545)
15.	Operating Income Before Income Tax	4,038	4,038	1,064	1,064	-	-
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	4,038	4,038	1,064	1,064	-	-
18.	Current Income Tax Rate - 38.10%	1,538	1,538	405	405	-	-
19.	Operating Income (line 15 minus line 18)	$ 2,500	$ 2,500	$ 659	$ 659	$ -	$ -
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1)		1. ACC Specific 2. Assigned to Customer Accounts (CUSTNUM_A)		1. ACC Specific 2. Revenues are class specific and expenses are functionalized on Distribution of W&S	

(16) 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.

(17) Adjustment to Test Year operations for reduced expenses related to closure of Customer Service offices and for the increase cost of paystation fees.

(18) Adjustment to Test Year operations to remove the Regulatory Assessment surcharges from operating revenues and expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(19) Remove and Transfer Test Year Transmission Cost Adjustor (TCA) Total Co. (AK)	(19) ACC (AL)	(20) Remove and Transfer Test Year Lost Fixed Cost Recovery Mechanism (LFCR) Total Co. (AM)	(20) ACC (AN)	(21) Remove and Transfer Test Year Environmental Improvement Surcharge (EIS) Total Co. (AO)	(21) ACC (AP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(128,782)	(128,603)	(45,988)	(45,988)	(2,461)	(2,456)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(128,782)	(128,603)	(45,988)	(45,988)	(2,461)	(2,456)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(128,782)	(128,603)	(45,988)	(45,988)	(2,461)	(2,456)
	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)	(128,603)	(45,988)	(45,988)	(2,461)	(2,456)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(128,782)	(128,603)	(45,988)	(45,988)	(2,461)	(2,456)
18.	Current Income Tax Rate - 38.10%	(49,066)	(48,998)	(17,521)	(17,521)	(938)	(936)
19.	Operating Income (line 15 minus line 18)	$ (79,716)	$ (79,605)	$ (28,467)	$ (28,467)	$ (1,523)	$ (1,520)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Revenues are class specific

BLANKENSHIP
1. ACC Specific
2. Revenues are class specific

BLANKENSHIP
1. Jurisdictional
2. Revenues are class specific

(19) Adjustment to Test Year operations to remove the Transmission Cost Adjustor from operating revenues and transfer it to base rates.

(20) Adjustment to Test Year operations to remove the LFCR mechanism from operating revenues and transfer it to base rates.

(21) Adjustment to Test Year operations to remove the EIS from operating revenues and transfer it to base rates.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(22) Remove and Transfer a Portion of Test Year Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense		(23) Remove and Transfer a Portion of Test Year Renewable Energy Adjustment Clause (REAC)		(24) Remove and Transfer Test Year Rate Rider Four Corners Revenue	
		Total Co. (AQ)	ACC (AR)	Total Co. (AS)	ACC (AT)	Total Co. (AU)	ACC (AV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(51,369)	(51,262)	(113,286)	(113,243)	(57,675)	(57,588)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(51,369)	(51,262)	(113,286)	(113,243)	(57,675)	(57,588)
5.	Electric Fuel and Purchased Power Costs	-	-	(44,870)	(44,853)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(51,369)	(51,262)	(68,416)	(68,390)	(57,675)	(57,588)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(41,369)	(41,283)	(30,859)	(30,847)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(41,369)	(41,283)	(30,859)	(30,847)	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(41,369)	(41,283)	(30,859)	(30,847)	-	-
15.	Operating Income Before Income Tax	(10,000)	(9,979)	(37,557)	(37,543)	(57,675)	(57,588)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(10,000)	(9,979)	(37,557)	(37,543)	(57,675)	(57,588)
18.	Current Income Tax Rate - 38.10%	(3,810)	(3,802)	(14,309)	(14,304)	(21,974)	(21,941)
19.	Operating Income (line 15 minus line 18)	$ (6,190)	$ (6,177)	$ (23,248)	$ (23,239)	$ (35,701)	$ (35,647)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Revenues and Expenses are class specific.

BLANKENSHIP
1. Jurisdictional
2. Revenues and Expenses are class specific.

BLANKENSHIP
1. Jurisdictional
2. Revenues are class specific.

(22) Adjustment to Test Year operations to remove the DSMAC from operating revenues and transfer a portion of it to base rates.

(23) 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.

(24) Adjustment to Test Year operations to remove the Four Corners Rate Rider from operating revenues and transfer a portion to base rates.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(25) Four Corners Deferral True Up Total Co. (AW)	(25) Four Corners Deferral True Up ACC (AX)	(26) Remove Cholla 2 Non-Fuel / Non-Payroll Costs Total Co. (AY)	(26) Remove Cholla 2 Non-Fuel / Non-Payroll Costs ACC (AZ)	(27) Adjust Cholla Unit 2 Regulatory Asset Amortization Total Co. (BA)	(27) Adjust Cholla Unit 2 Regulatory Asset Amortization ACC (BB)
	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)	(5,625)	-	-
8.	Maintenance	-	-	(2,219)	(2,207)	-	-
9.	Subtotal	-	-	(7,875)	(7,832)	-	-
10.	Depreciation and Amortization	1,388	1,388	(7,144)	(7,105)	7,890	7,847
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	(2,336)	(2,323)	-	-
14.	Total Other Operating Expense	1,388	1,388	(17,355)	(17,260)	7,890	7,847
15.	Operating Income Before Income Tax	(1,388)	(1,388)	17,355	17,260	(7,890)	(7,847)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(1,388)	(1,388)	17,355	17,260	(7,890)	(7,847)
18.	Current Income Tax Rate - 38.10%	(529)	(529)	6,612	6,576	(3,006)	(2,990)
19.	Operating Income (line 15 minus line 18)	$ (859)	$ (859)	$ 10,743	$ 10,684	$ (4,884)	$ (4,857)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. ACC Specific
2. Assigned to Production - Demand (Retail DEMPROD1)

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

(25) Adjustment to Test Year operations to include the true-up of the Four Corners deferral balance.

(26) Adjustment to Test Year operations to remove Cholla Unit 2 costs due to the shut down of the unit in October of 2015.

(27) 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.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(28) Include West Phoenix Unit 4 Regulatory Disallowance Total Co. (BC)	(28) ACC (BD)	(29) Include Interest Expense on Customer Deposits Total Co. (BE)	(29) ACC (BF)	(30) Adjust Depreciation Expense - 2016 Depreciation Rate Study Total Co. (BG)	(30) ACC (BH)
	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	443	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	443	443	-	-
10.	Depreciation and Amortization	(329)	(327)	-	-	75,989	73,519
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(329)	(327)	443	443	75,989	73,519
15.	Operating Income Before Income Tax	329	327	(443)	(443)	(75,989)	(73,519)
16.	Interest Expense	(148)	(148)	-	-	-	-
17.	Taxable Income	477	475	(443)	(443)	(75,989)	(73,519)
18.	Current Income Tax Rate - 38.10%	182	181	(169)	(169)	(28,952)	(28,011)
19.	Operating Income (line 15 minus line 18)	$ 147	$ 146	$ (274)	$ (274)	$ (47,037)	$ (45,508)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

BLANKENSHIP
1. ACC Specific
2. Assigned to Customer Accounts (CUSTDEP)

BLANKENSHIP
1. Jurisdictional
2. Specific assigned to PT&D, General and Intangible functionalized on Wages & Salaries

(28) 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 ACC Decision Nos. 67744 and 69663. Pro forma adjusted as shown on Schedule B-2, page 3, column 8.

(29) Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits using January 2016 interest rates.

(30) Adjustment to Test Year operations to reflect depreciation expense based on the 2016 Depreciation Rate Study.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(31) Decommissioning and Spent Fuel Costs Total Co. (BI)	(31) ACC (BJ)	(32) Annualize Payroll Expense Total Co. (BK)	(32) ACC (BL)	(33) Normalize Employee Benefits Total Co. (BM)	(33) ACC (BN)
	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)	(956)	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	962	956	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	4,236	3,914	8,400	7,762
8.	Maintenance	-	-	1,092	1,009	-	-
9.	Subtotal	-	-	5,328	4,923	8,400	7,762
10.	Depreciation and Amortization	(13,383)	(13,292)	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(13,383)	(13,292)	5,328	4,923	8,400	7,762
15.	Operating Income Before Income Tax	14,345	14,248	(5,328)	(4,923)	(8,400)	(7,762)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	14,345	14,248	(5,328)	(4,923)	(8,400)	(7,762)
18.	Current Income Tax Rate - 38.10%	5,465	5,428	(2,030)	(1,876)	(3,200)	(2,957)
19.	Operating Income (line 15 minus line 18)	$ 8,880	$ 8,820	$ (3,298)	$ (3,047)	$ (5,200)	$ (4,805)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries	

(31) Adjustment to Test Year operations to reflect updated decommissioning funding levels for Palo Verde and updated ISFSI expense.

(32) 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.

(33) Adjustment to Test Year operations to reflect the current December 2015 actuarial valuation of retirement program expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(34) Remove Supplemental Excess Benefit Retirement Plan Expense (SERP) Total Co. (BO)	ACC (BP)	(35) Remove Stock Compensation Total Co. (BQ)	ACC (BR)	(36) Normalize Cash Incentive Total Co. (BS)	ACC (BT)
	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)	(7,215)	(15,753)	(14,556)	(2,029)	(1,875)
8.	Maintenance	-	-	-	-	(50)	(47)
9.	Subtotal	(7,808)	(7,215)	(15,753)	(14,556)	(2,079)	(1,922)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	(928)	(858)
14.	Total Other Operating Expense	(7,808)	(7,215)	(15,753)	(14,556)	(3,007)	(2,780)
15.	Operating Income Before Income Tax	7,808	7,215	15,753	14,556	3,007	2,780
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	7,808	7,215	15,753	14,556	3,007	2,780
18.	Current Income Tax Rate - 38.10%	2,975	2,749	6,002	5,546	1,146	1,059
19.	Operating Income (line 15 minus line 18)	$ 4,833	$ 4,466	$ 9,751	$ 9,010	$ 1,861	$ 1,721

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries

BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries

BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries

(34) Adjustment to Test Year operations to remove Supplemental Excess Benefit Retirement Plan Expense ("SERP").

(35) Adjustment to Test Year operations to remove stock compensation expense.

(36) Adjustment to Test Year operations to normalize the cash incentive program over a 3 year period.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(37) Normalize Income Tax Expense/Interest Synchronization Total Co. (BU)	(37) ACC (BV)	(38) Annualize Property Tax Expense Total Co. (BW)	(38) ACC (BX)	(39) Amortize Property Tax Deferral Total Co. (BY)	(39) ACC (BZ)
	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	8,898
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	28,494	23,864	-	-
14.	Total Other Operating Expense	-	-	28,494	23,864	8,898	8,898
15.	Operating Income Before Income Tax	-	-	(28,494)	(23,864)	(8,898)	(8,898)
16.	Interest Expense	10,169	9,099	-	-	541	541
17.	Taxable Income	(10,169)	(9,099)	(28,494)	(23,864)	(9,439)	(9,439)
18.	Current Income Tax Rate - 38.10%	(3,874)	(3,467)	(10,856)	(9,092)	(3,596)	(3,596)
19.	Operating Income (line 15 minus line 18)	$ 3,874	$ 3,467	$ (17,638)	$ (14,772)	$ (5,302)	$ (5,302)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Calculated as the weighted average of "Other Tax Items"

BLANKENSHIP
1. Jurisdictional
2. Functionalized on P T & D

BLANKENSHIP
1. ACC Specific
2. Functionalized on P T & D

(37) 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.

(38) Adjustment to Test Year operations to annualize property taxes calculated using the anticipated 2016 tax assessment ratio and tax rate.

(39) 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.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(40) Annualize Four Corners Power Plant Coal Reclamation Costs		(41) Annualize Navajo Power Plant Coal Reclamation Costs		(42) Adjust Cash Working Capital for Cost of Service Pro Formas	
		Total Co. (CA)	ACC (CB)	Total Co. (CC)	ACC (CD)	Total Co. (CE)	ACC (CF)
	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	(6,559)	(6,514)	653	649	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	6,559	6,514	(653)	(649)	-	-
	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	6,559	6,514	(653)	(649)	-	-
16.	Interest Expense	-	-	-	-	(429)	(396)
17.	Taxable Income	6,559	6,514	(653)	(649)	429	396
18.	Current Income Tax Rate - 38.10%	2,499	2,482	(249)	(247)	163	151
19.	Operating Income (line 15 minus line 18)	$ 4,060	$ 4,032	$ (404)	$ (402)	$ (163)	$ (151)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Assigned to System Benefits (ERGSYSBEN)

BLANKENSHIP
1. Jurisdictional
2. Assigned to System Benefits (ERGSYSBEN)

BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries

(40) Adjustment to Test Year operations to reflect most recent Four Corners Power Plant coal reclamation study.

(41) Adjustment to Test Year operations to reflect the most recent Navajo Power Plant coal reclamation study.

(42) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment. Pro forma adjusted as shown on Schedule B-2, page 4, column 10.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(43) Transfer Palo Verde Unit 2 Lease Reduction to Base Rates		(44) Normalize Nuclear Maintenance Expense		(45) Normalize Fossil Maintenance Expense	
		Total Co. (CG)	ACC (CH)	Total Co. (CI)	ACC (CJ)	Total Co. (CK)	ACC (CL)
	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)	(21,375)	-	-	-	-
8.	Maintenance	-	-	248	246	1,285	1,276
9.	Subtotal	(21,491)	(21,375)	248	246	1,285	1,276
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	4,574	4,549	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(16,917)	(16,826)	248	246	1,285	1,276
15.	Operating Income Before Income Tax	16,917	16,826	(248)	(246)	(1,285)	(1,276)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	16,917	16,826	(248)	(246)	(1,285)	(1,276)
18.	Current Income Tax Rate - 38.10%	6,445	6,411	(94)	(94)	(490)	(486)
19.	Operating Income (line 15 minus line 18)	$ 10,472	$ 10,415	$ (154)	$ (152)	$ (795)	$ (790)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production Demand (DEMPROD1)

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Energy (ENERGY1)

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Energy (ENERGY1)

(43) Adjustment to the Test Year operation to include the net expense associated with the reduced Palo Verde Unit 2 lease amount.

(44) Adjustment to Test Year operations to reflect normalization of nuclear production maintenance expense.

(45) Adjustment to Test Year operations to reflect normalization of fossil production maintenance expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	(46) Annualize Solar Partner Program Expense Total Co. (CM)	(46) ACC (CN)	(47) Remove Out of Period and Miscellaneous Items Total Co. (CO)	(47) ACC (CP)	(48) Total Income Statement Adjustments (a) Total Co. (CQ)	(48) (a) ACC (CR)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ 23,340	$ 23,340
2.	Revenues from Surcharges		-	-	-	(408,660)	(408,240)
3.	Other Electric Revenues		-	-	-	(3,948)	(3,946)
4.	Total Electric Operating Revenues	-	-	-	-	(389,268)	(388,846)
5.	Electric Fuel and Purchased Power Costs		-	-	-	(102,374)	(102,311)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(286,894)	(286,535)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	528	528	-	-	(128,212)	(126,983)
8.	Maintenance		-	-	-	1,095	1,016
9.	Subtotal	528	528	-	-	(127,117)	(125,967)
10.	Depreciation and Amortization		-	-	-	130,160	125,474
11.	Amortization of Gain		-	-	-	4,574	4,549
12.	Administrative and General		-	(1,633)	(1,509)	(2,561)	(2,367)
13.	Other Taxes		-	-	-	42,192	37,085
14.	Total Other Operating Expense	528	528	(1,633)	(1,509)	47,248	38,774
15.	Operating Income Before Income Tax	(528)	(528)	1,633	1,509	(334,142)	(325,309)
16.	Interest Expense		-	-	-	17,028	15,731
17.	Taxable Income	(528)	(528)	1,633	1,509	(351,170)	(341,040)
18.	Current Income Tax Rate - 38.10%	(201)	(201)	622	575	(133,796)	(129,936)
19.	Operating Income (line 15 minus line 18)	$ (327)	$ (327)	$ 1,011	$ 934	$ (200,346)	$ (195,373)

PRO FORMA WITNESS:

FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. ACC Specific
2. Assigned to Customer Accounts (CUSTNUM_A)

BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries

(46) Adjustment to Test Year operations to annualize solar partner program expense as authorized in Decision No. 74878.

(47) Adjustment to Test Year operations to remove out of period and miscellaneous items from the Test Year period including consulting fees, miscellaneous advertising, other general expenses, etc.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

C3

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR
TEST YEAR ENDED 12/31/2015

Line No.	Description	2015 Test Year Percentage of Incremental Gross Revenues	Adjusted Test Year Rate Percentage of Incremental Gross Revenues	Line No.
1.	Federal Income Taxes	35.00%	35.00%	1.
2.	State Income Taxes Net of Federal Tax Benefit	3.87%	3.10%	2.
3.	Total Tax Percentage	38.87%	38.10%	3.
4.	Operating Income % = 100% - Tax Percentage	61.13%	61.90%	4.
5.	1/Operating Income % = Gross Revenue Conversion Factor (a)	1.6359	1.6155	5.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-1

D1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
SUMMARY COST OF CAPITAL
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Invested Capital	Adjusted *** End of Test Year 12/31/2015 Amount	%	Cost Rate	Composite Cost	Projected - Present Rates End Of 12/31/2016 Amount (e)	% (e)	Cost Rate	Composite Cost (e)	Projected - Present Rates End Of 12/31/2017 Amount (e)	% (e)	Cost Rate	Composite Cost (e)	Line No.
1.	Long-Term Debt * (a)	$3,728,555	44.20%	5.13%	2.27%	$4,093,125	45.70%	5.08%	2.32%	$4,488,125	46.84%	5.27%	2.47%	1.
2.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	2.
3.	Common Equity (c)	4,706,351	55.80%	10.50%	5.86%	4,863,072	54.30%	10.50%	5.70%	5,094,453	53.16%	10.50%	5.58%	3.
4.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	4.
5.	Total	$ 8,434,906	100.00%		8.13%	$ 8,956,197	100.00%		8.02%	$ 9,582,578	100.00%		8.05%	5.

		Projected - Present Rates End Of 12/31/2018 Amount (e)	% (e)	Cost Rate	Composite Cost (e)	Projected - Proposed Rates End Of 12/31/2017 Amount (e)	% (e)	Cost Rate	Composite Cost (e)	Projected - Proposed Rates End Of 12/31/2018 Amount (e)	% (e)	Cost Rate	Composite Cost (e)	
6.	Long-Term Debt * (a)	$4,800,150	47.81%	5.60%	2.68%	$4,393,125	46.11%	5.25%	2.42%	$4,535,150	45.80%	5.52%	2.53%	6.
7.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	7.
8.	Common Equity (c)	5,240,889	52.19%	10.50%	5.48%	5,135,130	53.89%	10.50%	5.66%	5,366,159	54.20%	10.50%	5.69%	8.
9.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	9.
10.	Total	$ 10,041,039	100.00%		8.16%	$ 9,528,255	100.00%		8.08%	$ 9,901,309	100.00%		8.22%	10.

Notes:
* Debt balances exclude unamortized discounts/premiums/debt issuance cost and Palo Verde capital lease obligation.
** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions.
*** See Schedule D-1, page 2 of 2 for pro forma adjustments to Test Year actual period ended 12/31/2015.

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4
(d) E-1

Recap Schedules:
(e) A-3

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
SUMMARY COST OF CAPITAL
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		End of Test Year 12/31/2015 - Unadjusted				Proformas to Test Year Ended 12/31/2015				End of Test Year 12/31/2015 - Adjusted				
Line No.	Invested Capital	Amount (e)	% (e)	Cost Rate	Composite Cost (e)	Pension OCI to Zero	Adjusted Derivative OCI to Zero	Combined Total Adj. Amount	Cost Rate Adj.	Amount	%	Cost Rate	Composite Cost	Line No.
1.	Long-Term Debt * (a)	$3,728,555	44.35%	5.13%	2.27%	-	-	-	-	$3,728,555	44.20%	5.13%	2.27%	1.
2.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	-	-	-	-	0.00%	0.00%	0.00%	2.
3.	Common Equity (c)	4,679,254	55.65%	10.50%	5.84%	19,942	7,155	27,097	0.00%	4,706,351	55.80%	10.50%	5.86%	3.
4.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	-	-	-	-	0.00%	0.00%	0.00%	4.
5.	Total	$8,407,809	100.00%		8.11%					$8,434,906	100.00%		8.13%	5.

Notes:
* Debt balances exclude unamortized discounts/premiums/debt issuance cost and Palo Verde capital lease obligation.
** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions. For the unadjusted Test Year ending 12/31/2015 there was no short-term debt.

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4
(d) E-1

Recap Schedules:
(e) A-3

D2

ARIZONA PUBLIC SERVICE COMPANY
COST OF LONG-TERM AND SHORT-TERM DEBT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description of Debt	Test Year End of Year 12/31/2015		Projected - Present Rates End of Year 12/31/2016		Projected - Present Rates End of Year 12/31/2017		Projected - Present Rates End of Year 12/31/2018		Projected - Proposed Rates End of Year 12/31/2017		Projected - Proposed Rates End of Year 12/31/2018		Line No.
		Outstanding	Annual Interest *	Outstanding	Annual Interest *	Outstanding	Annual Interest *	Outstanding	Annual Interest *	Outstanding	Annual Interest *	Outstanding	Annual Interest *	
	Long-Term:													
1.	Pollution Control Indebtedness	$ 303,555	$ 10,740	$ 183,125	$ 6,597	$ 183,125	$ 6,871	$ 115,150	$ 5,539	$ 183,125	$ 6,871	$ 115,150	$ 5,539	1.
2.	Capitalized Lease obligation	-	-	-	-	-	-	-	-	-	-	-	-	2.
3.	Other Long-Term Debt - Unsecured Notes	3,425,000	179,263	3,910,000	199,998	4,305,000	228,368	4,685,000	261,926	4,210,000	222,297	4,420,000	243,394	3.
4.	Other	-	1,399	-	1,440	-	1,440	-	1,440	-	1,440	-	1,440	4.
5.	Total Long-Term (a) (b) **	$ 3,728,555	$ 191,402	$ 4,093,125	$ 208,035	$ 4,488,125	$ 236,679	$ 4,800,150	$ 268,905	$ 4,393,125	$ 230,608	$ 4,535,150	$ 250,373	5.
6.	Cost Rate (a)	5.13%		5.08%		5.27%		5.60%		5.25%		5.52%		6.
	Short-term:													
7.	Commercial Paper	-	-	-	-	-	-	-	-	-	-	-	-	7.
8.	Total Short-Term (a) ***	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	8.
9.	Cost Rate (a)	0%		0%		0%		0%		0%		0%		9.

Notes:
* Including amortization of discount, premium and expense.
** Excludes unamortized discount/premium and debt cost of ($33,584) and Palo Verde capital lease obligation $193,313.
*** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions. For the unadjusted Test Year ending 12/31/2015, actual short-term debt was zero.

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

D3

ARIZONA PUBLIC SERVICE COMPANY
COST OF PREFERRED STOCK
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description of Issue	End of Test Year 12/31/2015			Projected - Present Rates End of Year 12/31/2016			Projected - Present Rates End of Year 12/31/2017			Projected - Present Rates End of Year 12/31/2018			Projected - Projected Rates End of Year 12/31/2017			Projected - Projected Rates End of Year 12/31/2018			Line No.
		Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	
1.	No Outstanding Issues	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.
2.	Total (a) (b)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.
3.	Cost Rate (a)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

D4

ARIZONA PUBLIC SERVICE COMPANY
COST OF COMMON EQUITY
TEST YEAR ENDED 12/31/2015

For purposes of this filing, the Company is proposing a return on common equity of 10.50%.

Supporting Schedules
N/A

Recap Schedules
D-1

E1

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE BALANCE SHEETS
TEST YEAR ENDED 12/31/2015 AND PRIOR YEARS
(Dollars in Thousands)

Line No.	Description	Test Year Ended 12/31/2015 (A)	Prior Year Ended 12/31/2014 (B)	Prior Year Ended 12/31/2013 (C)	Line No.
	UTILITY PLANT:				
1.	Plant in service and held for future use	$16,412,037	$ 15,754,621	$ 15,196,598	1.
2.	Accumulated depreciation and amortization	(5,857,507)	(5,685,406)	(5,627,800)	2.
3.	Net	10,554,530	10,069,215	9,568,798	3.
4.	Construction work in progress (a)	812,845	682,807	581,369	4.
5.	Palo Verde sale leaseback, net of accumulated depreciation	-	-	-	5.
6.	Intangible assets, net of accumulated amortization	123,820	119,600	157,534	6.
7.	Nuclear fuel, net of accumulated amortization (a)	123,139	125,201	124,557	7.
8.	Total property, plant and equipment (a)	11,614,334	10,996,823	10,432,258	8.
	INVESTMENTS AND OTHER ASSETS:				
9.	Nuclear decommissioning trust	735,196	713,866	642,007	9.
10.	Assets from risk management activities	12,106	17,620	23,815	10.
11.	Other assets	34,455	33,362	33,709	11.
12.	Total investments and other assets	781,757	764,848	699,531	12.
	CURRENT ASSETS:				
13.	Cash and cash equivalents	22,056	4,515	3,725	13.
14.	Customer and other receivables	274,428	297,712	299,055	14.
15.	Accrued unbilled revenues	96,240	100,533	96,796	15.
16.	Allowance for doubtful accounts	(3,125)	(3,094)	(3,203)	16.
17.	Materials and supplies (at average cost)	234,234	218,889	221,682	17.
18.	Fossil fuel (at average cost)	45,697	37,097	38,028	18.
19.	Income tax receivable	-	-	135,179	19.
20.	Assets from risk management activities	15,905	13,785	17,169	20.
21.	Deferred fuel and purchased power regulatory asset	-	6,926	20,755	21.
22.	Other regulatory assets	149,555	129,808	76,388	22.
23.	Deferred income taxes	-	55,253	-	23.
24.	Other current assets	35,765	38,693	39,153	24.
25.	Total current assets	870,755	900,117	944,727	25.
	DEFERRED DEBITS:				
26.	Regulatory assets	1,196,003	1,019,647	670,633	26.
27.	Assets for other postretirement benefits	182,625	149,260	-	27.
28.	Other	127,923	128,026	114,865	28.
29.	Total deferred debits	1,506,551	1,296,933	785,498	29.
30.		$14,773,397	$ 13,958,721	$ 12,862,014	30.

Supporting Schedules:
(a) E-5

Recap Schedules:
N/A - See Next Page

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE BALANCE SHEETS
TEST YEAR ENDED 12/31/2015 AND PRIOR YEARS
(Dollars in Thousands)

Line No.	Description	Test Year Ended 12/31/2015 (A)	Prior Year Ended 12/31/2014 (B)	Prior Year Ended 12/31/2013 (C)	Line No.
	CAPITALIZATION:				
1.	Common stock	$ 178,162	$ 178,162	$ 178,162	1.
2.	Additional paid-in capital	2,379,696	2,379,696	2,379,696	2.
3.	Retained earnings	2,148,493	1,968,718	1,804,398	3.
	Accumulated other comprehensive (loss):				
4.	Pension and other postretirement benefits	(19,942)	(37,948)	(30,313)	4.
5.	Derivative instruments	(7,155)	(10,385)	(23,059)	5.
6.	Total shareholder equity (b)	4,679,254	4,478,243	4,308,884	6.
7.	Noncontrolling interests	-	-	-	7.
8.	Total equity	4,679,254	4,478,243	4,308,884	8.
9.	Long-term debt less current maturities	3,523,600	3,096,383	2,636,184	9.
11.	Total capitalization	8,202,854	7,574,626	6,945,068	11.
	CURRENT LIABILITIES:				
12.	Short-term borrowings	-	147,400	153,125	12.
13.	Current maturities of long-term debt	364,684	370,150	514,975	13.
14.	Accounts payable	291,574	289,930	281,237	14.
15.	Accrued taxes	144,488	131,110	122,460	15.
16.	Accrued interest	56,003	52,358	48,132	16.
17.	Common dividends payable	69,400	65,800	62,500	17.
18.	Customer deposits	73,073	72,307	76,101	18.
19.	Deferred income taxes	-	-	2,033	19.
20.	Liabilities from risk management activities	77,716	59,676	31,892	20.
21.	Liabilities for asset retirements	28,573	32,462	32,896	21.
22.	Deferred fuel and purchased power regulatory liabilities	9,688	-	-	22.
23.	Other regulatory liabilities	136,078	130,549	99,273	23.
24.	Other current liabilities	180,535	167,302	130,774	24.
25.	Total current liabilities	1,431,812	1,519,044	1,555,398	25.
	DEFERRED CREDITS AND OTHER:				
26.	Deferred income taxes	2,764,489	2,571,365	2,347,724	26.
27.	Regulatory liabilities	727,582	760,440	469,998	27.
28.	Liability for asset retirements	415,003	358,288	313,833	28.
29.	Liabilities for pension and other postretirement benefits	459,065	424,508	476,017	29.
30.	Liabilities from risk management activities	89,973	50,602	70,315	30.
31.	Customer advances	115,609	123,052	114,480	31.
32.	Coal mine reclamation	201,984	198,292	207,453	32.
33.	Deferred investment tax credit	187,080	178,607	152,361	33.
34.	Unrecognized tax benefits	35,251	45,740	42,209	34.
35.	Other	142,696	154,157	167,158	35.
36.	Total deferred credits and other	5,138,732	4,865,051	4,361,548	36.
37.	TOTAL	$14,773,397	$13,958,721	$12,862,014	37.

Supporting Schedules:
N/A - See previous page

Recap Schedules:
(b) A-3

E2

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE INCOME STATEMENTS
TEST YEAR ENDED 12/31/2015 AND PRIOR YEARS
(Dollars in Thousands, except per share amounts)

Line No.	Description	Test Year 12 months Ended 12/31/2015 (b) (A)	Prior Year Ended 12/31/2014 (B)	Prior Year Ended 12/31/2013 (C)	Line No.
1.	ELECTRIC OPERATING REVENUES (a)	$ 3,492,357	$ 3,488,946	$ 3,451,251	1.
	OPERATING EXPENSES				
2.	Fuel and purchased power	1,101,298	1,179,829	1,095,709	2.
3.	Operations and maintenance	892,796	922,103	937,485	3.
4.	Depreciation and amortization	474,131	406,755	414,762	4.
5.	Income taxes	260,143	245,036	256,864	5.
6.	Taxes other than income taxes	171,499	171,583	163,377	6.
7.	Total (a)	2,899,866	2,925,306	2,868,197	7.
8.	OPERATING INCOME (a)	592,491	563,640	583,054	8.
	OTHER INCOME (DEDUCTIONS)				
9.	Income taxes	14,302	7,676	11,769	9.
10.	Allowance for equity funds used during construction	35,215	30,790	25,581	10.
11.	Other income	2,834	11,295	3,896	11.
12.	Other expense	(19,019)	(13,403)	(20,449)	12.
13.	Total (a)	33,332	36,358	20,797	13.
14.	Income Before Interest Deductions	625,823	599,998	603,851	14.
	INTEREST EXPENSE				
15.	Interest on long-term debt	179,563	183,272	183,092	15.
16.	Interest on short-term borrowings	7,376	6,796	6,605	16.
17.	Debt discount, premium and expense	4,793	4,168	4,046	17.
18.	Allowance for borrowed funds used during construction	(16,183)	(15,457)	(14,861)	18.
19.	Total (a)	175,549	178,779	178,882	19.
20.	NET INCOME (a)	450,274	421,219	424,969	20.
21.	Less: Net income attributable to noncontrolling interests	-	-	-	21.
22.	NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 450,274	$ 421,219	$ 424,969	22.
23.	Average Common Shares Outstanding	71,264,947	71,264,947	71,264,947	23.
24.	Earnings Per Share of Average Common (a) Stock Outstanding (line 22/line 23)	$ 6.32	$ 5.91	$ 5.96	24.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-2
(b) C-1

E3

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE STATEMENTS OF CHANGES IN FINANCIAL POSITION
TEST YEAR ENDED 12/31/2015 AND PRIOR YEARS
(Dollars in Thousands)

Line No.	Description	Test Year Ended 12/31/2015 (a) (A)	Prior Year Ended 12/31/2014 (a) (B)	Prior Year Ended 12/31/2013 (a) (C)	Line No.
	Cash Flows from Operating Activities:				
1.	Net income	$ 450,274	$ 421,219	$ 424,969	1.
	Items Not Requiring Cash:				
2.	Depreciation and amortization including nuclear fuel	551,373	485,884	491,376	2.
3.	Deferred fuel and purchased power	14,997	(26,927)	21,678	3.
4.	Deferred fuel and purchased power amortization	1,617	40,757	31,190	4.
5.	Allowance for equity funds used during construction	(35,215)	(30,790)	(25,581)	5.
6.	Deferred income taxes	223,069	155,401	278,101	6.
7.	Deferred investment tax credit	8,473	26,246	52,542	7.
8.	Change in derivative instruments fair value	(381)	339	534	8.
	Changes in current assets and liabilities:				
9.	Customer and other receivables	(21,040)	(52,466)	(46,552)	9.
10.	Accrued unbilled revenues	4,293	(3,737)	(1,951)	10.
11.	Materials, supplies and fossil fuel	(23,945)	3,724	(11,878)	11.
12.	Income tax receivable	-	135,179	(134,590)	12.
13.	Other current assets	4,498	3,766	(17,112)	13.
14.	Accounts payable	(34,891)	(2,355)	47,870	14.
15.	Accrued taxes	13,378	8,650	5,760	15.
16.	Other current liabilities	(3,718)	33,970	(9,005)	16.
17.	Change in margin and collateral accounts — assets	(324)	(343)	993	17.
18.	Change in margin and collateral accounts — liabilities	22,776	(24,975)	12,355	18.
19.	Change in long-term regulatory liabilities	(20,535)	59,618	64,473	19.
20.	Change in long-term income tax receivable	-	-	137,665	20.
21.	Change in unrecognized tax benefits	(10,328)	2,778	(91,244)	21.
22.	Change in other long-term assets	(10,134)	(72,060)	(55,996)	22.
23.	Change in other long-term liabilities	(82,628)	(85,642)	(24,969)	23.
24.	Net cash flow provided by operating activities	1,051,608	1,078,236	1,150,628	24.
	Cash Flows from Investing Activities:				
25.	Capital expenditures	(1,072,053)	(910,084)	(1,016,322)	25.
26.	Contributions in aid of construction	46,546	20,325	41,090	26.
27.	Allowance for borrowed funds used during construction	(16,183)	(15,457)	(14,861)	27.
28.	Proceeds from nuclear decommissioning trust sales	478,813	356,195	446,025	28.
29.	Investment in nuclear decommissioning trust	(496,062)	(373,444)	(463,274)	29.
30.	Other	(1,093)	347	(2,067)	30.
31.	Net cash flow used for investing activities	(1,060,032)	(922,118)	(1,009,409)	31.
	Cash Flows from Financing Activities:				
32.	Issuance of long-term debt	842,415	606,126	136,307	32.
33.	Repayment of long-term debt	(402,150)	(502,129)	(96,150)	33.
34.	Short-term borrowings and payments — net	(147,400)	(5,725)	60,950	34.
35.	Dividends paid on common stock	(266,900)	(253,600)	(242,100)	35.
36.	Noncontrolling interests	-	-	-	36.
37.	Net cash flow provided by (used for) financing activities	25,965	(155,328)	(140,993)	37.
38.	Net increase in cash and cash equivalents	17,541	790	226	38.
39.	CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	4,515	3,725	3,499	39.
40.	Cash and cash equivalents at end of period	$ 22,056	$ 4,515	$ 3,725	40.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-5

E4

ARIZONA PUBLIC SERVICE COMPANY
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
TEST YEAR ENDED 12/31/2015 AND PRIOR YEARS
(Dollars in Thousands)

Line No.	Description	Common Shares	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total	Line No.
1.	Balance at December 31, 2012	71,264,947	$ 178,162	$ 2,379,696	$ 1,624,237	$ (89,095)	$ 4,093,000	1.
2.	Net income				424,969		424,969	2.
3.	Other comprehensive income					35,723	35,723	3.
4.	Dividends on common stock				(244,800)		(244,800)	4.
5.	Other				(8)		(8)	5.
6.	Balance, December 31, 2013	71,264,947	$ 178,162	$ 2,379,696	$ 1,804,398	$ (53,372)	$ 4,308,884	6.
7.	Net income				421,219		421,219	7.
8.	Other comprehensive income					5,039	5,039	8.
9.	Dividends on common stock				(256,900)		(256,900)	9.
10.	Other				1		1	10.
11.	Balance, December 31, 2014	71,264,947	$ 178,162	$ 2,379,696	$ 1,968,718	$ (48,333)	$ 4,478,243	11.
12.	Net income				450,274		450,274	12.
13.	Other comprehensive income					21,236	21,236	13.
14.	Dividends on common stock				(270,500)		(270,500)	14.
15.	Other				1		1	15.
16.	Balance, December 31, 2015	71,264,947	$ 178,162	$ 2,379,696	$ 2,148,493	$ (27,097)	$ 4,679,254	16.

Supporting Schedules:
N/A

Recap Schedules:
N/A

E5

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY DETAIL OF UTILITY PLANT
TEST YEAR ENDED 12/31/2015 & PRIOR YEAR ENDED 12/31/2014
(Dollars in Thousands)

Line No.	Account Number	Account Description	Prior Year Ended Bal. 12/31/2014 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2015 (C)	Line No.
		Gross Plant Includible in Rate Base: (a)				
1.	101	Plant in Service	$ 15,840,948	$ 739,502	$ 16,580,450	1.
2.	101.1	Property Under Capital Lease	214,810	(21,497)	193,313	2.
3.	108	Less: Accum. Depreciation-Plant in Service	5,520,859	157,546	5,678,405	3.
4.	111	Accum. Amortization-Plant in Service	652,498	60,182	712,680	4.
5.		Net Plant Includible in Rate Base	9,882,401	521,774	10,382,678	5.
6.	120.2-120.5	Nuclear fuel, net of amortization (b)	125,201	(2,062)	123,139	6.
7.	107	Construction Work in Progress	591,741	121,546	713,287	7.
8.	120.1	Nuclear Fuel in Process	91,066	8,492	99,558	8.
9.		Total Construction Work in Progress (b)	682,807	130,038	812,845	9.
10.	105	Plant Held for Future Use	51,341	131	51,472	10.
11.	108	Less: Accum Depreciation Related to Plant Held for Future Use	-	-	-	11.
12.		Net Plant held for Future Use	51,341	131	51,472	12.
13.	114	Electric Plant Acquisition Adjustment	255,526	-	255,526	13.
14.	115	Less: Accum Depreciation Related to Plant Held for Future Use	453	10,873	11,326	14.
15.		Net Electric Plant Acquisition Adjustment	255,073	(10,873)	244,200	15.
16.		Utility Plant - Net (b)	$ 10,996,823	$ 617,511	$ 11,614,334	16.

Supporting Schedules:
N/A

Recap Schedule:
(a) A-4
(b) E-1

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2015 & PRIOR YEAR ENDED 12/31/2014
(Dollars in Thousands)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2014 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2015 (C)	Line No.
		Intangible Plant:				
1.	301	Organization	$ -	$ -	$ -	1.
2.	302	Franchises and Consents	3,493	24	3,517	2.
3.	303	Miscellaneous Intangible Plant	648,479	39,534	688,013	3.
4.		Total Intangible Plant	$ 651,972	$ 39,558	$ 691,530	4.
		Production Plant:				
		Steam Production Plant:				
5.	310	Land and Land Rights	$ 5,794	$ -	$ 5,794	5.
6.	311	Structures and Improvements	159,820	10,139	169,959	6.
7.	312	Boiler Plant Equipment	1,176,686	(20,105)	1,156,581	7.
8.	314	Turbogenerator Units	211,795	500	212,295	8.
9.	315	Accessory Electric Equipment	123,412	3,735	127,147	9.
10.	316	Miscellaneous Power Plant Equip	94,240	818	95,058	10.
11.	317	Asset Retirement Costs for Steam Production	4,877	37,810	42,687	11.
12.		Total Steam Production Plant	$ 1,776,624	$ 32,897	$ 1,809,521	12.
		Nuclear Production Plant:				
13.	320	Land and Land Rights	$ 4,418	$ -	$ 4,418	13.
14.	321	Structures and Improvements	789,134	27,652	816,786	14.
15.	322	Reactor Plant Equipment	1,257,375	(17,378)	1,239,997	15.
16.	323	Turbogenerator Units	382,539	17,692	400,231	16.
17.	324	Accessory Electric Equipment	282,963	6,928	289,891	17.
18.	325	Miscellaneous Power Plant Equip	166,807	27,630	194,437	18.
19.	326	Asset Retirement Costs for Nuclear Production	(53,660)	-	(53,660)	19.
20.		Total Nuclear Production Plant	$ 2,829,576	$ 62,524	$ 2,892,100	20.

Supporting Schedules:
N/A

Recap Schedule:
N/A

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2015 & PRIOR YEAR ENDED 12/31/2014
(Dollars in Thousands)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2014 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2015 (C)	Line No.
		Hydraulic Production Plant:				
1.	330	Land and Land Rights	$ -	$ -	$ -	1.
2.	331	Structures and Improvements	-	-	-	2.
3.	332	Reservoirs, Dams and Waterways	-	-	-	3.
4.	333	Water Wheels, Turbines and Generators	-	-	-	4.
5.	334	Accessory Electric Equipment	-	-	-	5.
6.	335	Miscellaneous Power Plant Equip	-	-	-	6.
7.	336	Roads, Railroads and Bridges	-	-	-	7.
8.	337	Asset Retirement Costs for Hydraulic Production	-	-	-	8.
9.		Total Hydraulic Production Plant	$ -	$ -	$ -	9.
		Other Production Plant:				
10.	340	Land and Land Rights	$ 15,723	$ 44	$ 15,767	10.
11.	341	Structures and Improvements	107,546	7,715	115,261	11.
12.	342	Fuel Holders, Producers and Accessories	54,832	389	55,221	12.
13.	343	Prime Movers	667,232	(14,569)	652,663	13.
14.	344	Generators	1,229,504	65,754	1,295,258	14.
15.	345	Accessory Electric Equipment	190,761	18,636	209,397	15.
16.	346	Miscellaneous Power Plant Equip	25,354	1,991	27,345	16.
17.	347	Asset Retirement Costs for Other Production	6,052	2,804	8,856	17.
18.		Total Other Production Plant	$ 2,297,004	$ 82,764	$ 2,379,768	18.
19.		Total Production Plant	$ 6,903,204	$ 178,185	$ 7,081,389	19.

Supporting Schedules:
N/A

Recap Schedule:
N/A

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2015 & PRIOR YEAR ENDED 12/31/2014
(Dollars in Thousands)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2014 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2015 (C)	Line No.
		Transmission Plant				
1.	350	Land and Land Rights	$ 153,275	$ (806)	$ 152,469	1.
2.	352	Structures and Improvements	91,127	24,094	115,221	2.
3.	353	Station Equipment	978,521	62,060	1,040,581	3.
4.	354	Towers and Fixtures	105,328	46,093	151,421	4.
5.	355	Poles and Fixtures	459,350	19,835	479,185	5.
6.	356	Overhead Conductors and Devices	358,515	95,569	454,084	6.
7.	357	Underground Conduit	20,947	370	21,317	7.
8.	358	Underground Conductors and Devices	34,518	88	34,606	8.
9.		Total Transmission Plant	$ 2,201,581	$ 247,303	$ 2,448,884	9.
		Distribution Plant:				
10.	360	Land and Land Rights	$ 59,259	$ 3,274	$ 62,533	10.
11.	361	Structures and Improvements	80,065	2,401	82,466	11.
12.	362	Station Equipment	466,810	27,961	494,771	12.
13.	363	Storage Battery Equipment	2,124	-	2,124	13.
14.	364	Poles, Towers, and Fixtures	569,328	23,780	593,108	14.
15.	365	Overhead Conductors and Devices	322,337	32,781	355,118	15.
16.	366	Underground Conduit	668,639	16,875	685,514	16.
17.	367	Underground Conductors and Devices	1,587,079	59,302	1,646,381	17.
18.	368	Line Transformers	812,217	21,238	833,455	18.
19.	369	Services	361,473	14,172	375,645	19.
20.	370	Meters	290,729	634	291,363	20.
21.	371	Installations on Customers' Premises	42,799	756	43,555	21.
22.	373	Street Lighting and Signal Systems	73,537	1,065	74,602	22.
23.		Total Distribution Plant	$ 5,336,396	$ 204,239	$ 5,540,635	23.

Supporting Schedules:
N/A

Recap Schedule:
N/A

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2015 & PRIOR YEAR ENDED 12/31/2014
(Dollars in Thousands)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2014 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2015 (C)	Line No.
		General Plant				
1.	389	Land and Land Rights	$ 14,645	$ (45)	$ 14,600	1.
2.	390	Structures and Improvements	201,572	14,550	216,122	2.
3.	391	Office Furniture and Equipment	185,272	42,937	228,209	3.
4.	392	Transportation Equipment	41,894	(1,051)	40,843	4.
5.	393	Stores Equipment	237	6	243	5.
6.	394	Tools, Shop and Garage Equipment	36,166	975	37,141	6.
7.	395	Laboratory Equipment	811	-	811	7.
8.	396	Power Operated Equipment	10,681	(530)	10,151	8.
9.	397	Communication Equipment	231,172	21,274	252,446	9.
10.	398	Miscellaneous Equipment	25,345	(7,899)	17,446	10.
11.		Total General Plant	$ 747,795	$ 70,217	$ 818,012	11.
12.		Total Net Plant Includible in Rate Base (a)	$ 15,840,948	$ 739,502	$ 16,580,450	12.

Supporting Schedules:
N/A

Recap Schedule:
(a) E-5, page 1 of 5

E6

SCHEDULE E-6 DOES NOT APPLY

E7

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC OPERATING STATISTICS
TEST YEAR ENDED 12/31/2015 AND PRIOR YEARS

Line No.	Description	Test Year Ended 12/31/2015 (A)	Prior Year Ended 12/31/2014 (B)	Prior Year Ended 12/31/2013 (C)	Line No.
1.	**Billed kWh Sales (thousands)**				1.
2.	Residential	13,142,277	12,820,394	13,284,499	2.
3.	Commercial	12,372,493	12,353,597	12,492,483	3.
4.	Industrial	2,272,163	2,238,137	2,193,073	4.
5.	Irrigation	10,875	11,492	11,471	5.
6.	Public Street and Highway Lighting	148,213	142,665	142,741	6.
7.	Other Sales to Public Authorities	2,822	2,729	2,866	7.
8.	Total Sales to Ultimate Consumers	27,948,843	27,569,014	28,127,133	8.
9.	Sales for Resale - Requirements Customers	150,328	625,309	600,170	9.
10.	Sales for Resale - Other Customers	5,528,035	4,741,546	3,399,770	10.
11.	Total Sales for Resale	5,678,363	5,366,855	3,999,940	11.
12.	**Total kWh Sales**	33,627,206	32,935,869	32,127,073	12.
13.	**Average Number of Customers**				13.
14.	Residential	1,046,989	1,033,728	1,019,292	14.
15.	Commercial	125,579	124,460	123,319	15.
16.	Industrial	3,444	3,429	3,402	16.
17.	Irrigation	300	299	299	17.
18.	Public Street and Highway Lighting	1,028	1,007	991	18.
19.	Other Sales to Public Authorities	154	156	159	19.
20.	Total Retail Consumers	1,177,494	1,163,079	1,147,462	20.
21.	Sales for Resale - Requirements Customers	13	14	14	21.
22.	**Total Customers**	1,177,507	1,163,093	1,147,476	22.
23.	**Average Billed kWh Use (Annual)**				23.
24.	Residential	12,552	12,402	13,033	24.
25.	Commercial	98,524	99,258	101,302	25.
26.	Industrial	659,745	652,708	644,642	26.
27.	Irrigation	36,250	38,435	38,365	27.
28.	Public Street and Highway Lighting	144,176	141,673	144,037	28.
29.	Other Sales to Public Authorities	18,325	17,494	18,025	29.
30.	Sales for Resale - Requirements Customers	11,563,692	44,664,929	42,869,286	30.
31.	**Average Annual Revenue per Residential Customer**				31.
32.	Annual Revenue per Customer	1,625.86	1,583.74	1,638.25	32.
33.	Revenue per kWh (Cents)	12.95	12.77	12.57	33.
34.	**Direct Production Expense per kWh Sold (Cents)**	4.56	4.92	4.74	34.
35.	**Direct Transmission Expense per kWh Sold (Cents)**	0.25	0.24	0.22	35.

Supporting Schedules:
N/A

Recap Schedules:
N/A

Note: Information included above only includes billed amounts.

E8

ARIZONA PUBLIC SERVICE COMPANY
TAXES CHARGED TO OPERATIONS
TEST YEAR ENDED 12/31/2015 AND PRIOR YEARS
(Dollars in Thousands)

Line No.	Description	Test Year Ended 12/31/2015 (A)	Prior Year Ended 12/31/2014 (B)	Prior Year Ended 12/31/2013 (C)	Line No.
	Federal Taxes:				
1.	Income	$ 20,832	$ 38,069	$ (1,013)	1.
2.	F.I.C.A.*	26,229	26,581	25,449	2.
3.	Deferred Income Taxes	207,267	174,617	219,408	3.
4.	Total	254,328	239,267	243,843	4.
	State Taxes:				
5.	Ad Valorem	171,597	172,435	164,306	5.
6.	Sales and Use**	(98)	(851)	(928)	6.
7.	Income	8,799	15,399	12,961	7.
8.	Deferred Income Taxes	23,245	16,950	25,508	8.
9.	Total	203,543	203,932	201,846	9.
10.	Total Taxes	$ 457,871	$ 443,200	$ 445,690	10.

Notes:
* Includes payroll related taxes charged to others. These taxes are included in operations and maintenance on C-1, E-2 and F-1.
** Includes local taxes.

Supporting Schedules:
N/A

Recap Schedules:
N/A

E9

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO FINANCIAL STATEMENTS
TEST YEAR ENDED 12/31/2015

See the attached Arizona Public Service Company Form 10-K filed with the Securities and Exchange Commission for the period ended December 31, 2015. The notes to the financial statements are contained on pages 92 through 156 of the document.

Supporting Schedules:
N/A

Recap Schedules:
N/A

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number	Registrants; State of Incorporation; Addresses; and Telephone Number	IRS Employer Identification No.
1-8962	**PINNACLE WEST CAPITAL CORPORATION** (An Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	**ARIZONA PUBLIC SERVICE COMPANY** (An Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0011170

Securities registered pursuant to Section 12(b) of the Act:

	Title Of Each Class	Name Of Each Exchange On Which Registered
PINNACLE WEST CAPITAL CORPORATION	Common Stock, No Par Value	New York Stock Exchange
ARIZONA PUBLIC SERVICE COMPANY	None	None

Securities registered pursuant to Section 12(g) of the Act:
ARIZONA PUBLIC SERVICE COMPANY Common Stock, Par Value $2.50 per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act

PINNACLE WEST CAPITAL CORPORATION	Yes ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

PINNACLE WEST CAPITAL CORPORATION	Yes ☐ No ☒
ARIZONA PUBLIC SERVICE COMPANY	Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PINNACLE WEST CAPITAL CORPORATION	Yes ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PINNACLE WEST CAPITAL CORPORATION	Yes ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or in any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

PINNACLE WEST CAPITAL CORPORATION

Large accelerated filer ☒ Accelerated filer ☐

Non-accelerated filer ☐ Smaller reporting company ☐

(Do not check if a smaller reporting company)

ARIZONA PUBLIC SERVICE COMPANY

Large accelerated filer ☐ Accelerated filer ☐

Non-accelerated filer ☒ Smaller reporting company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of each registrant's most recently completed second fiscal quarter:

PINNACLE WEST CAPITAL CORPORATION	$6,271,269,171 as of June 30, 2015
ARIZONA PUBLIC SERVICE COMPANY	$0 as of June 30, 2015

The number of shares outstanding of each registrant's common stock as of February 12, 2016

PINNACLE WEST CAPITAL CORPORATION	111,004,916 shares
ARIZONA PUBLIC SERVICE COMPANY	Common Stock, $2.50 par value, 71,264,947 shares. Pinnacle West Capital Corporation is the sole holder of Arizona Public Service Company's Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Pinnacle West Capital Corporation's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 18, 2016 are incorporated by reference into Part III hereof.

Arizona Public Service Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

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This combined Form 10-K is separately filed by Pinnacle West and APS. Each registrant is filing on its own behalf all of the information contained in this Form 10-K that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is filing any information that does not relate to such registrant, and therefore makes no representation as to any such information. The information required with respect to each company is set forth within the applicable items. Item 8 of this report includes Consolidated Financial Statements of Pinnacle West and Consolidated Financial Statements of APS. Item 8 also includes Combined Notes to Consolidated Financial Statements.

GLOSSARY OF NAMES AND TECHNICAL TERMS

ac	Alternating Current
ACC	Arizona Corporation Commission
ADEQ	Arizona Department of Environmental Quality
AFUDC	Allowance for Funds Used During Construction
ANPP	Arizona Nuclear Power Project, also known as Palo Verde
APS	Arizona Public Service Company, a subsidiary of the Company
ARO	Asset retirement obligations
BART	Best available retrofit technology
Base Fuel Rate	The portion of APS's retail base rates attributable to fuel and purchased power costs
BCE	Bright Canyon Energy Corporation, a subsidiary of the Company
BHP Billiton	BHP Billiton New Mexico Coal, Inc.
BNCC	BHP Navajo Coal Company
CAISO	California Independent System Operator
CCR	Coal combustion residuals
Cholla	Cholla Power Plant
dc	Direct Current
distributed energy systems	Small-scale renewable energy technologies that are located on customers' properties, such as rooftop solar systems
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOJ	United States Department of Justice
DSM	Demand side management
DSMAC	Demand side management adjustment charge
EES	Energy Efficiency Standard
El Dorado	El Dorado Investment Company, a subsidiary of the Company
El Paso	El Paso Electric Company
EPA	United States Environmental Protection Agency
FERC	United States Federal Energy Regulatory Commission
Four Corners	Four Corners Power Plant
GWh	Gigawatt-hour, one billion watts per hour
kV	Kilovolt, one thousand volts
kWh	Kilowatt-hour, one thousand watts per hour
LFCR	Lost Fixed Cost Recovery Mechanism
MMBtu	One million British Thermal Units
MW	Megawatt, one million watts
MWh	Megawatt-hour, one million watts per hour
Native Load	Retail and wholesale sales supplied under traditional cost-based rate regulation
Navajo Plant	Navajo Generating Station
NERC	North American Electric Reliability Corporation
NRC	United States Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company, LLC
OCI	Other comprehensive income
OSM	Office of Surface Mining Reclamation and Enforcement
Palo Verde	Palo Verde Nuclear Generating Station or PVNGS
Pinnacle West	Pinnacle West Capital Corporation (any use of the words "Company," "we," and "our" refer to Pinnacle West)
PSA	Power supply adjustor approved by the ACC to provide for recovery or refund of variations in actual fuel and purchased power costs compared with the Base Fuel Rate
RES	Arizona Renewable Energy Standard and Tariff
Salt River Project or SRP	Salt River Project Agricultural Improvement and Power District
SCE	Southern California Edison Company
SIB	System Improvement Benefits
TCA	Transmission cost adjustor
VIE	Variable interest entity

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Item 1A and in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations," these factors include, but are not limited to:

- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation or regulation, including those relating to environmental requirements, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, including in real estate markets;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and ACC orders.

These and other factors are discussed in the Risk Factors described in Item 1A of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

PART I

ITEM 1. BUSINESS

Pinnacle West

Pinnacle West is a holding company that conducts business through its subsidiaries. We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the State of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona.

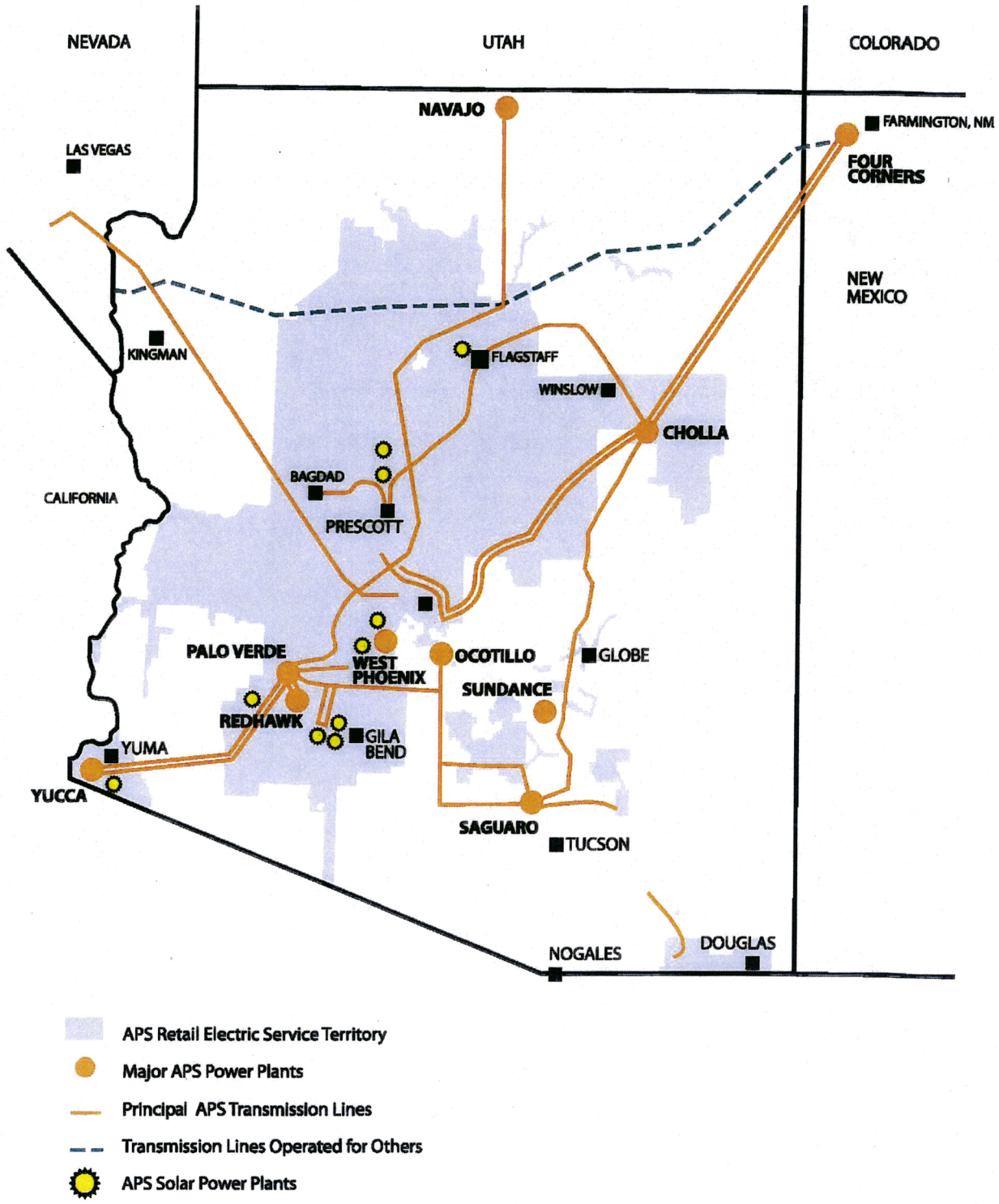
Pinnacle West's other subsidiaries are El Dorado and BCE. Additional information related to these subsidiaries is provided later in this report.

Our reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities, and includes electricity generation, transmission and distribution.

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

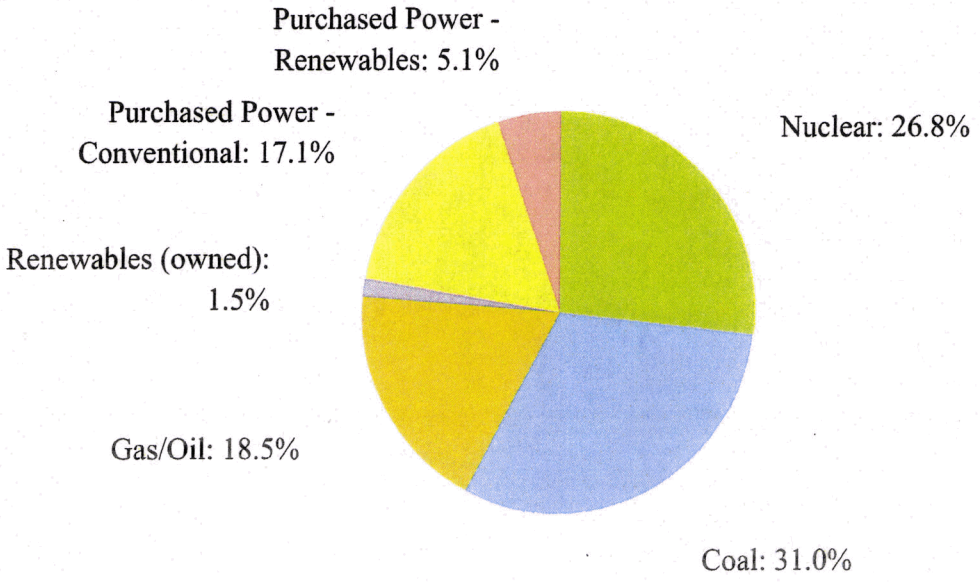
APS currently provides electric service to approximately 1.2 million customers. We own or lease 6,186 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2015, no single purchaser or user of energy accounted for more than 1.3% of our electric revenues.

The following map shows APS's retail service territory, including the locations of its generating facilities and principal transmission lines.



Energy Sources and Resource Planning

To serve its customers, APS obtains power through its various generation stations and through purchased power agreements. Resource planning is an important function necessary to meet Arizona's future energy needs. APS's sources of energy by type used to supply energy to Native Load customers during 2015 were as follows:



Generation Facilities

APS has ownership interests in or leases the coal, nuclear, gas, oil and solar generating facilities described below. For additional information regarding these facilities, see Item 2.

Coal-Fueled Generating Facilities

Four Corners — Four Corners was originally a 5-unit coal-fired power plant, which is located in the northwestern corner of New Mexico. APS operates the plant and owns 100% of Four Corners Units 1, 2 and 3 and 63% of Four Corners Units 4 and 5 following the acquisition of SCE's interest in Units 4 and 5 described below. As of December 30, 2013, APS retired Units 1, 2 and 3. APS has a total entitlement from Four Corners of 970 MW.

On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for SCE's interest was approximately $182 million. In connection with APS's most recent retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners

transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustment was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed in Note 3, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton will be retained by NTEC under contract as the mine manager and operator until July 2016. Also occurring concurrently with the closing, the Four Corners' co-owners executed a long-term agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031 (the "2016 Coal Supply Agreement"). El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. The cash purchase price, which will be subject to certain adjustments at closing, is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016.

When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. On December 29, 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

EPA, in its final regional haze rule for Four Corners, required the Four Corners' owners to elect one of two emissions alternatives to apply to the plant. On December 30, 2013, APS, on behalf of the co-owners, notified EPA that they chose the alternative BART compliance strategy requiring the permanent closure of Units 1, 2 and 3 by January 1, 2014 and installation and operation of SCR controls on Units 4 and 5 by July 31, 2018. On December 30, 2013, APS retired Units 1, 2 and 3.

The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process and culminated in the issuance by the DOI of a record of decision on July 17, 2015. The record of decision provided the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015.

On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with the environmental review described above were not in accordance with applicable law. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

In 2012, several environmental groups filed a lawsuit in federal district court against OSM challenging OSM's 2012 approval of a permit revision which allowed for the expansion of mining operations into a new area of the mine that serves Four Corners ("Area IV North"). In April 2015, the court issued an order invalidating the permit revision, thereby prohibiting mining in Area IV North until OSM takes action to cure the defect in its permitting process identified by the court. On December 29, 2015, OSM took action to cure the defect in its permitting process by issuing a revised environmental assessment and finding of no new significant impact, and reissued the permit. This action is subject to possible judicial review.

Cholla — Cholla was originally a 4-unit coal-fired power plant, which is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4, and APS operates that unit for PacifiCorp. On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 10 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long term than the benefits that would have resulted from adding the emissions control equipment. APS closed Unit 2 on October 1, 2015. Following the closure of Unit 2, APS has a total entitlement from Cholla of 387 MW.

APS purchases all of Cholla's coal requirements from a coal supplier that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. The Cholla coal contract runs through 2024. In addition, APS has a long-term coal transportation contract that runs through 2017. See "Current and Future Resources - Future Resources and Resource Plan" below for a discussion of future plans for Cholla.

Navajo Generating Station — The Navajo Plant is a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operates the plant and APS owns a 14% interest in Navajo Units 1, 2 and 3. APS has a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant's coal requirements are purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Plant is under contract with its coal supplier through 2019, with extension rights through 2026. The Navajo Plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. The current lease expires in 2019. See "Environmental Matters - EPA Environmental Regulation - Regional Haze Rules - Navajo Plant" below for a discussion of potential future plans for the Navajo Plant.

These coal-fueled plants face uncertainties, including those related to existing and potential legislation and regulation, that could significantly impact their economics and operations. See "Environmental Matters" below and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview and Capital Expenditures" in Item 7 for developments impacting these coal-fueled facilities. See Note 10 for information regarding APS's coal mine reclamation obligations.

Nuclear

Palo Verde Nuclear Generating Station — Palo Verde is a 3-unit nuclear power plant located approximately 50 miles west of Phoenix, Arizona. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and approximately 17% of Unit 2. In addition, APS leases approximately 12.1% of Unit 2, resulting in a 29.1% combined ownership and leasehold interest in that unit. APS has a total entitlement from Palo Verde of 1,146 MW.

Palo Verde Leases — In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. The leaseback was originally scheduled to expire at the end of 2015 and contained options to renew the leases or to purchase the leased property for fair market value at the end of the lease terms. On July 7, 2014, APS exercised the fixed rate lease renewal options. The length of the renewal options resulted in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. 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. See Note 18 for additional information regarding the Palo Verde Unit 2 sale leaseback transactions.

Palo Verde Operating Licenses — Operation of each of the three Palo Verde Units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986 and Unit 3 in November 1987, and issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2 and 3 to June 2045, April 2046 and November 2047, respectively.

Palo Verde Fuel Cycle — The Palo Verde participants are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The fuel cycle for Palo Verde is comprised of the following stages:

- mining and milling of uranium ore to produce uranium concentrates;
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride;
- fabrication of fuel assemblies;
- utilization of fuel assemblies in reactors; and
- storage and disposal of spent nuclear fuel.

The Palo Verde participants have contracted for 100% of Palo Verde's requirements for uranium concentrates and conversion services through 2018 and 45% of its requirements in 2019-2025. The participants have also contracted for 100% of Palo Verde's enrichment services through 2020 and 20% of its enrichment services for 2021-2026; and all of Palo Verde's fuel assembly fabrication services through 2022.

Spent Nuclear Fuel and Waste Disposal — The Nuclear Waste Policy Act of 1982 ("NWPA") required the DOE to accept, transport, and dispose of spent nuclear fuel and high level waste generated by the nation's nuclear power plants by 1998. The DOE's obligations are reflected in a contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (the "Standard Contract") with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. APS is directly and indirectly involved in several legal proceedings related to DOE's failure to meet its statutory and contractual obligations regarding acceptance of spent nuclear fuel and high level waste.

APS Lawsuit for Breach of Standard Contract — In December 2003, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a lawsuit against DOE in the U.S. Court of Federal Claims for damages incurred due to DOE's breach of the Standard Contract. The Court of Federal Claims ruled in favor of APS and the Palo Verde participants in October 2010 and awarded $30.2 million in damages to APS and the Palo Verde participants for costs incurred through December 2006.

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE. This lawsuit sought to recover damages incurred due to DOE's failure to accept Palo Verde's spent nuclear fuel for the period beginning January 1, 2007 through June 30, 2011. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified

costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million.

APS's first claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2011 through June 30, 2014, was for $42.0 million (APS's share of this amount was $12.2 million), and payment was received on June 1, 2015. APS's second claim made pursuant to the terms of the August 18, 2014, settlement agreement, which was for the period July 1, 2014 through June 30, 2015, and was for $12.0 million (APS's share of this amount is $3.6 million), was submitted to the DOE on November 2, 2015. The second claim is presently being reviewed by DOE.

Amounts recovered in the lawsuit and settlement were recorded as adjustments to regulatory liability and had no impact on current income.

The One-Mill Fee — In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged DOE's 2010 determination of the adequacy of the one tenth of a cent per kWh fee (the "one-mill fee") paid by the nation's commercial nuclear power plant owners pursuant to their individual obligations under the Standard Contract. This fee is recovered by APS in its retail rates. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") held that DOE failed to conduct a sufficient fee analysis in making the 2010 determination. The D.C. Circuit remanded the 2010 determination to the Secretary of the DOE ("Secretary") with instructions to conduct a new fee adequacy determination within six months. In February 2013, upon completion of DOE's revised one-mill fee adequacy determination, the D.C. Circuit reopened the proceedings. On November 19, 2013, the D.C. Circuit found that the DOE did not conduct a legally adequate fee assessment and ordered the Secretary to notify Congress of his intent to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators, as he is required to do pursuant to the NWPA and the D.C. Circuit's order. On January 3, 2014, the Secretary notified Congress of his intention to suspend collection of the one-mill fee, subject to Congress' disapproval. On May 16, 2014, the DOE notified all commercial nuclear power plant operators who are party to a Standard Contract that it reduced the one-mill fee to zero, thus effectively terminating the one-mill fee.

DOE's Construction Authorization Application for Yucca Mountain — The DOE had planned to meet its NWPA and Standard Contract disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In June 2008, the DOE submitted its Yucca Mountain construction authorization application to the NRC, but in March 2010, the DOE filed a motion to dismiss with prejudice the Yucca Mountain construction authorization application. Several interested parties have also intervened in the NRC proceeding. Additionally, a number of interested parties filed a variety of lawsuits in different jurisdictions around the country challenging the DOE's authority to withdraw the Yucca Mountain construction authorization application and NRC's cessation of its review of the Yucca Mountain construction authorization application. The cases have been consolidated into one matter at the D.C. Circuit. In August 2013, the D.C. Circuit ordered the NRC to resume its review of the application with available appropriated funds.

On October 16, 2014, the NRC issued Volume 3 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume addresses repository safety after permanent closure, and its issuance is a key milestone in the Yucca Mountain licensing process. Volume 3 contains the staff's finding that the DOE's repository design meets the requirements that apply after the repository is permanently closed, including but not limited to the post-closure performance objectives in NRC's regulations.

On December 18, 2014, the NRC issued Volume 4 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume covers administrative and programmatic requirements for the repository. It documents the staff's evaluation of whether the DOE's

research and development and performance confirmation programs, as well as other administrative controls and systems, meet applicable NRC requirements. Volume 4 contains the staff's finding that most administrative and programmatic requirements in NRC regulations are met, except for certain requirements relating to ownership of land and water rights.

Publication of Volumes 3 and 4 does not signal whether or when the NRC might authorize construction of the repository.

Waste Confidence — On June 8, 2012, the D.C. Circuit issued its decision on a challenge by several states and environmental groups of the NRC's rulemaking regarding temporary storage and permanent disposal of high level nuclear waste and spent nuclear fuel. The petitioners had challenged the NRC's 2010 update to the agency's Waste Confidence Decision and temporary storage rule ("Waste Confidence Decision").

The D.C. Circuit found that the agency's 2010 Waste Confidence Decision update constituted a major federal action, which, consistent with the National Environmental Policy Act ("NEPA"), requires either an environmental impact statement or a finding of no significant impact from the agency's actions. The D.C. Circuit found that the NRC's evaluation of the environmental risks from spent nuclear fuel was deficient, and therefore remanded the 2010 Waste Confidence Decision update for further action consistent with NEPA.

On September 6, 2012, the NRC Commissioners issued a directive to the NRC staff to proceed directly with development of a generic environmental impact statement to support an updated Waste Confidence Decision. The NRC Commissioners also directed the staff to establish a schedule to publish a final rule and environmental impact study within 24 months of September 6, 2012.

In September 2013, the NRC issued its draft Generic Environmental Impact Statement ("GEIS") to support an updated Waste Confidence Decision. On August 26, 2014, the NRC approved a final rule on the environmental effects of continued storage of spent nuclear fuel. The continued storage rule adopted the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations. As a result, those generic impacts do not need to be re-analyzed in the environmental reviews for individual licenses. Although Palo Verde had not been involved in any licensing actions affected by the D.C. Circuit's June 8, 2012, decision, the NRC lifted its suspension on final licensing actions on all nuclear power plant licenses and renewals that went into effect when the D.C. Circuit issued its June 2012 decision. The August 26th final rule has been subject to continuing legal challenges before the NRC and the Court of Appeals.

Palo Verde has sufficient capacity at its on-site independent spent fuel storage installation ("ISFSI") to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, Palo Verde has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in November 2047. If uncertainties regarding the United States government's obligation to accept and store spent fuel are not favorably resolved, APS will evaluate alternative storage solutions that may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the period of extended operation.

Nuclear Decommissioning Costs — APS currently relies on an external sinking fund mechanism to meet the NRC financial assurance requirements for decommissioning its interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in APS's ACC jurisdictional rates. Decommissioning costs are recoverable through a non-bypassable system benefits charge (paid by all retail customers taking service from the APS system). Based on current nuclear decommissioning trust asset balances, site specific decommissioning cost studies, anticipated future contributions to the decommissioning trusts, and return projections on the asset portfolios over the expected remaining operating

life of the facility, we are on track to meet the current site specific decommissioning costs for Palo Verde at the time the units are expected to be decommissioned. See Note 19 for additional information about APS's nuclear decommissioning trusts.

Palo Verde Liability and Insurance Matters — See "Palo Verde Nuclear Generating Station — Nuclear Insurance" in Note 10 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

Impact of Earthquake and Tsunami in Japan on Nuclear Energy Industry — On March 11, 2011, an earthquake measuring 9.0 on the Richter Scale occurred off the coast of Japan causing a series of seven tsunamis. As a result, the Fukushima Daiichi Nuclear Power Station experienced severe damage.

Following the earthquake and tsunamis, the NRC established a task force to conduct a systematic and methodical review of NRC processes and regulations to determine whether the agency should make additional improvements to its regulatory system. On March 12, 2012, the NRC issued the first regulatory requirements based on the recommendations of the Near Term Task Force. With respect to Palo Verde, the NRC issued two orders requiring safety enhancements regarding: (1) mitigation strategies to respond to extreme natural events resulting in the loss of power at the plant; and (2) enhancement of spent fuel pool instrumentation.

The NRC has issued a number of guidance documents regarding implementation of these requirements. Palo Verde has met the NRC's imposed deadlines for installation of equipment to address these requirements, but has minor additional work to perform in 2016. Palo Verde has spent approximately $125 million on capital enhancements as of December 31, 2015 (APS's share is 29.1%).

Natural Gas and Oil Fueled Generating Facilities

APS has six natural gas power plants located throughout Arizona, consisting of Redhawk, located near Palo Verde; Ocotillo, located in Tempe (discussed below); Sundance, located in Coolidge; West Phoenix, located in southwest Phoenix; Saguaro, located north of Tucson; and Yucca, located near Yuma. Several of the units at Yucca run on either gas or oil. APS has one oil-only power plant, Douglas, located in the town of Douglas, Arizona. APS owns and operates each of these plants with the exception of one oil-only combustion turbine unit and one oil and gas steam unit at Yucca that are operated by APS and owned by the Imperial Irrigation District. APS has a total entitlement from these plants of 3,179 MW. Gas for these plants is financially hedged up to three years in advance of purchasing and the gas is generally purchased one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2024. Fuel oil is acquired under short-term purchases delivered primarily to West Phoenix, where it is distributed to APS's other oil power plants by truck.

Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. APS completed a competitive solicitation process in which the Ocotillo project was evaluated against other alternatives. Consistent with the independent monitor's report, the Ocotillo project was selected as the best alternative. APS must finalize the permitting process before construction begins.

Solar Facilities

To date, APS has begun operation of 170 MW of utility scale solar through its AZ Sun Program, discussed below. These facilities are owned by APS and are located in multiple locations throughout Arizona.

Additionally, APS owns and operates more than forty small solar systems around the state. Together they have the capacity to produce approximately 4 MW of renewable energy. This fleet of solar systems includes a 3 MW facility located at the Prescott Airport and 1 MW of small solar in various locations across Arizona. APS has also developed solar photovoltaic distributed energy systems installed as part of the Community Power Project in Flagstaff, Arizona. The Community Power Project, approved by the ACC on April 1, 2010, is a pilot program through which APS owns, operates and receives energy from approximately 1 MW of solar photovoltaic distributed energy systems located within a certain test area in Flagstaff, Arizona. Additionally, APS owns 12 MW of solar photovoltaic systems installed across Arizona through the ACC-approved Schools and Government Program.

In December 2014, the ACC voted that it had no objection to APS implementing a 10 MWdc (approximately 8.5 MWac) residential rooftop program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. Under this program, APS will own, operate and maintain approximately 1,500 residential systems. The program will target specific distribution feeders in an effort to maximize potential system benefits, while employing multiple "use cases" that will lead to a better understanding of the byproducts stemming from the multitude of complex technical interactions occurring as distributed energy resources are employed on the APS grid.

Purchased Power Contracts

In addition to its own available generating capacity, APS purchases electricity under various arrangements, including long-term contracts and purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements. A portion of APS's purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. (See Note 16.) APS continually assesses its need for additional capacity resources to assure system reliability.

Purchased Power Capacity — APS's purchased power capacity under long-term contracts as of December 31, 2015 is summarized in the table below. All capacity values are based on net capacity unless otherwise noted.

Type	Dates Available	Capacity (MW)
Purchase Agreement (a)	Year-round through June 14, 2020	60
Exchange Agreement (b)	May 15 to September 15 annually through 2020	480
Tolling Agreement	Year-round through May 2017	514
Tolling Agreement	Summer seasons through October 2019	560
Day-Ahead Call Option Agreement	Summer seasons through summer 2016	150
Demand Response Agreement (c)	Summer seasons through 2024	25
Renewable Energy (d)	Various	629

(a) Up to 60 MW of capacity is available; however, the amount of electricity available to APS under this agreement is based in large part on customer demand and is adjusted annually.

(b) This is a seasonal capacity exchange agreement under which APS receives electricity during the summer peak season (from May 15 to September 15) and APS returns a like amount of electricity during the winter season (from October 15 to February 15).

(c) The capacity under this agreement may be increased in 5 MW increments in each of 2015 and 2016 and 10 MW increments in years 2017 through 2024, up to a maximum of 50 MW.

(d) Renewable energy purchased power agreements are described in detail below under "Current and Future Resources — Renewable Energy Standard — Renewable Energy Portfolio."

Current and Future Resources

Current Demand and Reserve Margin

Electric power demand is generally seasonal. In Arizona, demand for power peaks during the hot summer months. APS's 2015 peak one-hour demand on its electric system was recorded on August 15, 2015 at 7,031 MW, compared to the 2014 peak of 7,007 MW recorded on July 23, 2014. APS's reserve margin at the time of the 2015 peak demand, calculated using system load serving capacity, was 28%. Excluding certain contractual rights to call on additional capacity on short notice, which APS may use in the event of unusual weather or unplanned outages, the 2015 reserve margin was 21%. APS anticipates the reserve margin for 2016 will be approximately 24%. Due to expiring purchase contracts and anticipated load growth, APS anticipates additional resources will be needed by 2017 in order to maintain its 15% planning reserve criteria.

Future Resources and Resource Plan

On May 8, 2015, the ACC acknowledged APS's 2014 resource plan. Under the ACC's resource planning rule, APS's next resource plan would be due on April 1, 2016. On September 16, 2015, however, the ACC issued an order extending the timeframe for all utilities, including APS, to file their next resource plans. The new schedule is designed to allow utilities additional time to consider the impacts of the Clean Power Plan and improve the resource planning process by allowing more time for input and review by the ACC and applicable stakeholders. Under the revised schedule, APS will file a preliminary resource plan on March 1, 2016 and a final resource plan on April 3, 2017. The revised schedule provides that the ACC will complete its review by February 1, 2018.

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and plans to seek recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its next retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($122 million as of December 31, 2015), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

Renewable Energy Standard

In 2006, the ACC adopted the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement is 6% of retail electric sales in 2016 and increases annually until it reaches 15% in 2025. In APS's 2009 retail rate case settlement agreement (the "2009 Settlement Agreement"), APS committed to have 1,700 GWh of new renewable resources in service by year-end 2015 in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2015.

A component of the RES is focused on stimulating development of distributed energy systems. Accordingly, under the RES, an increasing percentage of that requirement must be supplied from distributed energy resources. This distributed energy requirement is 30% of the overall RES requirement of 6% in 2016. The following table summarizes the RES requirement standard (not including the additional commitment required by the 2009 Settlement Agreement) and its timing:

	2016	2020	2025
RES as a % of retail electric sales	6%	10%	15%
Percent of RES to be supplied from distributed energy resources	30%	30%	30%

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

Renewable Energy Portfolio. To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1,328 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1,278 MW are currently in operation and 50 MW are under contract for development or are under construction. Renewable resources in operation include 189 MW of facilities owned by APS, 629 MW of long-term purchased power agreements, and an estimated 427 MW of customer-sited, third-party owned distributed energy resources.

APS's strategy to achieve its RES requirements includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS. In September 2015, APS completed construction of its 170 MW AZ Sun Program. APS has invested approximately $675 million in its AZ Sun Program. See Note 3 for additional details about the AZ Sun Program.

The following table summarizes APS's renewable energy sources currently in operation and under development. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid.

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity In Operation (MW AC)	Net Capacity Planned/ Under Development (MW AC)
APS Owned					
Solar:					
AZ Sun Program:					
Paloma	**Gila Bend, AZ**	**2011**		**17**	
Cotton Center	**Gila Bend, AZ**	**2011**		**17**	
Hyder Phase 1	**Hyder, AZ**	**2011**		**11**	
Hyder Phase 2	**Hyder, AZ**	**2012**		**5**	
Chino Valley	**Chino Valley, AZ**	**2012**		**19**	
Hyder II	**Hyder, AZ**	**2013**		**14**	
Foothills	**Yuma, AZ**	**2013**		**35**	
Gila Bend	**Gila Bend, AZ**	**2014**		**32**	
Luke AFB	**Glendale, AZ**	**2015**		**10**	
Desert Star	**Buckeye, AZ**	**2015**		**10**	
Subtotal AZ Sun Program				**170**	
Multiple Facilities	**AZ**	**Various**		**4**	
Distributed Energy:					
APS Owned (a)	**AZ**	**Various**		**15**	**9** (c)
Total APS Owned				**189**	**9**
Purchased Power Agreements					
Solar:					
Solana	**Gila Bend, AZ**	**2013**	**30**	**250**	
RE Ajo	**Ajo, AZ**	**2011**	**25**	**5**	
Sun E AZ 1	**Prescott, AZ**	**2011**	**30**	**10**	
Saddle Mountain	**Tonopah, AZ**	**2012**	**30**	**15**	
Badger	**Tonopah, AZ**	**2013**	**30**	**15**	
Gillespie	**Maricopa County, AZ**	**2013**	**30**	**15**	
Wind:					
Aragonne Mesa	**Santa Rosa, NM**	**2006**	**20**	**90**	
High Lonesome	**Mountainair, NM**	**2009**	**30**	**100**	
Perrin Ranch Wind	**Williams, AZ**	**2012**	**25**	**99**	
Geothermal:					
Salton Sea	**Imperial County, CA**	**2006**	**23**	**10**	
Biomass:					
Snowflake	**Snowflake, AZ**	**2008**	**15**	**14**	
Biogas:					
Glendale Landfill	**Glendale, AZ**	**2010**	**20**	**3**	
NW Regional Landfill	**Surprise, AZ**	**2012**	**20**	**3**	
Total Purchased Power Agreements				**629**	—
Distributed Energy					
Solar (b)					
Third-party Owned	**AZ**	**Various**		**427**	**41**
Agreement 1	**Bagdad, AZ**	**2011**	**25**	**15**	
Agreement 2	**AZ**	**2011-2012**	**20-21**	**18**	
Total Distributed Energy				**460**	**41**
Total Renewable Portfolio				**1,278**	**50**

(a) Includes Flagstaff Community Power Project, APS School and Government Program and APS Solar Partner Program.

(b) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in DC and is converted to AC for reporting purposes.

(c) This amount represents the Solar Partner Program consisting of approximately 1,500 APS-owned rooftop solar systems. We are in the process of installing these systems and expect all to be installed and operational by mid-2016, at which time the 9 MW will be considered "in operation" for purposes of this table.

Demand Side Management

In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated its Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard ("EES") of 22% cumulative annual energy savings by 2020. This standard was adopted and became effective on January 1, 2011. This standard will likely impact Arizona's future energy resource needs. (See Note 3 for energy efficiency and other demand side management obligations).

Government Awards

Through various DOE initiatives, the Federal government made a number of programs available for utilities to develop renewable resources, improve reliability and create jobs. In 2015, APS completed its work on a $3 million financial award for a high penetration photovoltaic generation study related to the Community Power Project in Flagstaff, Arizona.

Competitive Environment and Regulatory Oversight

Retail

The ACC regulates APS's retail electric rates and its issuance of securities. The ACC must also approve any significant transfer or encumbrance of APS's property used to provide retail electric service and approve or receive prior notification of certain transactions between Pinnacle West, APS and their respective affiliates.

APS is subject to varying degrees of competition from other investor-owned electric and gas utilities in Arizona (such as Southwest Gas Corporation), as well as cooperatives, municipalities, electrical districts and similar types of governmental or non-profit organizations. In addition, some customers, particularly industrial and large commercial customers, may own and operate generation facilities to meet some or all of their own energy requirements. This practice is becoming more popular with customers installing or having installed products such as rooftop solar panels to meet or supplement their energy needs.

On April 14, 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not "public service corporations" under the Arizona Constitution, and are therefore not regulated by the ACC. APS cannot predict when, and the extent to which, additional electric service providers will enter or re-enter APS's service territory.

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. As a result, as of January 1, 2001, all of APS's retail customers were eligible to choose alternate energy suppliers. Although some very limited retail competition existed in APS's service territory in 1999 and 2000, there are

currently no active retail competitors offering unbundled energy or other utility services to APS's customers. In 2000, the Arizona Superior Court found that the rules were in part unconstitutional and in other respects unlawful, the latter finding being primarily on procedural grounds, and invalidated all ACC orders authorizing competitive electric services providers to operate in Arizona. In 2004, the Arizona Court of Appeals invalidated some, but not all of the rules and upheld the invalidation of the orders authorizing competitive electric service providers. In 2005, the Arizona Supreme Court declined to review the Court of Appeals' decision.

In 2008, the ACC directed the ACC staff to investigate whether such retail competition was in the public interest and what legal impediments remain to competition in light of the Court of Appeals' decision referenced above. The ACC staff's report on the results of its investigation was issued on August 12, 2010. The report stated that additional analysis, discussion and study of all aspects of the issue are required in order to perform a proper evaluation. While the report did not make any specific recommendations other than to conduct more workshops, the report did state that the current retail electric competition rules are incomplete and in need of modification.

On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations was whether various aspects of a deregulated market, including setting utility rates on a "market" basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. The ACC opened a docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. A series of workshops in this docket were held in 2014 and another in February of 2015. No further workshops are scheduled and no actions were taken as a result of these workshops.

On January 28, 2016, an ACC Commissioner, Robert L. Burns, sent APS a Notice of Investigation pursuant to an Arizona statute that authorizes a Commissioner and his agents to inspect the accounts, books, papers and documents of any public service corporation, and examine under oath any officer, agent or employee of such corporation in relation to the business and affairs of the corporation. The Notice states that Commissioner Burns intends to investigate whether APS has used funds recoverable from ratepayers for political contributions, lobbying, or charitable donations purposes; whether APS's corporate affiliates have made contributions or donations under APS' brand name; and the degree to which APS and Pinnacle West are "intertwined" in terms of organization, management and operations. APS intends to cooperate with this investigation to the full extent that the matter is lawfully authorized, but cannot predict its timing or outcome.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS's transmission rates.) During 2015, approximately 5.2% of APS's electric operating revenues resulted from such sales and services. APS's wholesale activity primarily consists of managing fuel and purchased power supplies to serve retail customer energy requirements. APS also sells, in the wholesale market, its generation output that is not needed for APS's Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. Additionally, subject to specified parameters, APS hedges both electricity and fuels. The majority of these activities are undertaken to mitigate risk in APS's portfolio.

Environmental Matters

Climate Change

Legislative Initiatives. There have been no recent attempts by Congress to pass legislation that would regulate greenhouse gas ("GHG") emissions, and it is unclear whether the 114th Congress will consider a climate change bill. In the event climate change legislation ultimately passes, the actual economic and operational impact of such legislation on APS depends on a variety of factors, none of which can be fully known until a law is enacted and the specifics of the resulting program are established. These factors include the terms of the legislation with regard to allowed GHG emissions; the cost to reduce emissions; in the event a cap-and-trade program is established, whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned (and, if so, the cost of those allowances in the marketplace) and whether offsets and other measures to moderate the costs of compliance will be available; and, in the event of a carbon tax, the amount of the tax per pound of carbon dioxide ("CO_2") equivalent emitted.

In addition to federal legislative initiatives, state-specific initiatives may also impact our business. While Arizona has no pending legislation and no proposed agency rule regulating GHGs in Arizona, the California legislature enacted AB 32 and SB 1368 in 2006 to address GHG emissions. In October 2011, the California Air Resources Board approved final regulations that established a state-wide cap on GHG emissions beginning on January 1, 2013 and established a GHG allowance trading program under that cap. The first phase of the program, which applies to, among other entities, importers of electricity, commenced on January 1, 2013. Under the program, entities selling electricity into California, including APS, must hold carbon allowances to cover GHG emissions associated with electricity sales into California from outside the state. APS is authorized to recover the cost of these carbon allowances through the PSA.

Regulatory Initiatives. In 2009, EPA determined that GHG emissions endanger public health and welfare. As a result of this "endangerment finding," EPA determined that the Clean Air Act required new regulatory requirements for new and modified major GHG emitting sources, including power plants. APS will generally be required to consider the impact of GHG emissions as part of its traditional New Source Review ("NSR") analysis for new major sources and major modifications to existing plants.

On June 2, 2014, EPA issued two proposed rules to regulate GHG emissions from modified and reconstructed electric generating units ("EGUs") pursuant to Section 111(b) of the Clean Air Act and existing fossil fuel-fired power plants pursuant to Clean Air Act Section 111(d). On August 3, 2015, EPA finalized each of these carbon pollution standards for existing, new, modified, and reconstructed EGUs.

EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

With respect to existing power plants, EPA's recently finalized "Clean Power Plan" imposes state-specific goals or targets to achieve reductions in CO_2 emission rates from existing EGUs measured from a 2012 baseline. In a significant change from the proposed rule, EPA's final performance standards apply directly to specific units based upon their fuel-type and configuration (i.e., coal- or oil-fired steam plants versus combined cycle natural gas plants). As such, each state's goal is an emissions performance standard that reflects the fuel mix employed by the EGUs in operation in those states. The final rule provides guidelines to states to help develop their plans for meeting the interim (2022-2029) and final (2030 and beyond) emission performance standards, with three distinct compliance periods within that timeframe. States were originally required to submit their plans to EPA by September 2016, with an optional two-year extension provided to

states establishing a need for additional time; however, it is expected that this timing will be impacted by the court-imposed stay described below.

ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, is presently working to develop a compliance plan for submittal to EPA. In addition to these on-going state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such delay.

With respect to our Arizona generating units, we are currently evaluating the range of compliance options available to ADEQ, including whether Arizona deploys a rate- or mass-based compliance plan. Based on the fuel-mix and location of our Arizona EGUs, and the significant investments we have made in renewable generation and demand-side energy efficiency, if ADEQ selects a rate-based compliance plan, we believe that we will be able to comply with the Clean Power Plan for our Arizona generating units in a manner that will not have material financial or operational impacts to the Company. On the other hand, if ADEQ selects a mass-based approach to compliance with the Clean Power Plan, our annual cost of compliance could be material. These costs could include costs to acquire mass-based compliance allowances.

As to our facilities on the Navajo Nation, EPA has yet to determine whether or to what extent EGUs on the Navajo Nation will be required to comply with the Clean Power Plan. EPA has proposed to determine that it is necessary or appropriate to impose a federal plan on the Navajo Nation for compliance with the Clean Power Plan. In response, we filed comments with EPA advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. If EPA reaches a determination that is consistent with our preferred approach for the Navajo Nation, we believe the Clean Power Plan will not have material financial or operational impacts on our operations within the Navajo Nation.

Alternatively, if EPA determines that a federal plan is necessary or appropriate for the Navajo Nation, and depending on our need for future operations at our EGUs located there, we may be unable to comply with the federal plan unless we acquire mass-based allowances or emission rate credits within established carbon trading markets, or curtail our operations. Subject to the uncertainties set forth below, and assuming that EPA establishes a federal plan for the Navajo Nation that requires carbon allowances or credits to be surrendered for plan compliance, it is possible we will be required to purchase some quantity of credits or allowances, the cost of which could be material.

Because ADEQ has not issued its plan for Arizona, and because we do not know whether EPA will decide to impose a plan or, if so, what that plan will require, there are a number of uncertainties associated with our potential cost exposure. These uncertainties include: whether judicial review will result in the Clean Power Plan being vacated in whole or in part or, if not, the extent of any resulting compliance deadline delays; whether any plan will be imposed for EGUs on the Navajo Nation; the future existence and liquidity of allowance or credit compliance trading markets; the applicability of existing contractual obligations with current and former owners of our participant-owned coal-fired EGUs; the type of federal or state compliance plan (either rate- or mass-based); whether or not the trading of allowances or credits will be authorized mechanisms for compliance with any final EPA or ADEQ plan; and how units that have been closed will be treated for allowance or credit allocation purposes.

In the event that the incurrence of compliance costs is not economically viable or prudent for our operations in Arizona or on the Navajo Nation, or if we do not have the option of acquiring allowances to account for the emissions from our operations, we may explore other options, including reduced levels of output, as an alternative to purchasing allowances. Given these uncertainties, our analysis of the available compliance options remains on-going, and additional information or considerations may arise that change our expectations.

Company Response to Climate Change Initiatives. We have undertaken a number of initiatives that address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency. (See "Energy Sources and Resource Planning - Current and Future Resources" above for details of these plans and initiatives.) APS currently has a diverse portfolio of renewable resources, including solar, wind, geothermal, biogas, and biomass, and we expect the percentage of renewable energy in our resource portfolio to increase over the coming years.

APS prepares an inventory of GHG emissions from its operations. This inventory is reported to EPA under the EPA GHG Reporting Program and is voluntarily communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on our website (*www.pinnaclewest.com*). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle West's website, including the Corporate Responsibility Report, is not incorporated by reference into or otherwise a part of this report.

EPA Environmental Regulation

Regional Haze Rules. In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal land, EPA) to determine what pollution control technologies constitute the BART for certain older major stationary sources, including fossil-fired power plants. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis.

The Four Corners and Navajo Plant participants' obligations to comply with EPA's final BART determinations (and Cholla's obligations to comply with ADEQ's and EPA's determinations), coupled with the financial impact of potential future climate change legislation, other environmental regulations, and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to continue their participation in these plants.

Cholla. In 2007, ADEQ required APS to perform a BART analysis for Cholla pursuant to the Clean Air Visibility Rule. APS completed the BART analysis for Cholla and submitted its BART recommendations to ADEQ in early 2008. The recommendations include the installation of certain pollution control equipment that APS believes constitutes BART. ADEQ reviewed APS's recommendations and submitted its proposed BART State Implementation Plan ("SIP") for Cholla and other sources in Arizona in early 2011.

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA approved ADEQ's BART emissions limits for sulfur dioxide ("SO_2") and emissions of particulate matter ("PM"), but added a SO_2 removal efficiency requirement of 95%. In addition, EPA disapproved ADEQ's BART determinations for oxides of nitrogen ("NO_x") and promulgated a Federal Implementation Plan ("FIP") establishing a new, more stringent "bubbled" NO_x emission rate applicable to the two BART-eligible Cholla units owned by APS and the other BART-eligible unit owned by PacifiCorp.

APS believes that EPA's final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was

closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 (which occurred on October 1, 2015) and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015. On October 16, 2015, ADEQ issued the Cholla permit, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. APS is unable to predict when or whether APS's proposal may ultimately be approved by the EPA.

Four Corners. On August 6, 2012, EPA issued its final BART determination for Four Corners, which requires APS to install and operate SCR control technology on Units 4 and 5 by July 31, 2018. (APS retired Four Corners Units 1-3 on December 30, 2013.) APS estimates that its 63% share of the cost of these controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016. In December 2015, NTEC notified APS of its intention to exercise its option to acquire the 7% interest from APS. The cost of the controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

Navajo Plant. On January 18, 2013, EPA issued a proposed BART rule for the Navajo Plant, which would require installation of SCR technology in order to achieve a new, more stringent plant-wide NO_x emission limit. In addition, EPA proposed a "better than BART" alternative and solicited comment on other options that could set longer time frames for installing pollution controls if the Navajo Plant can achieve additional emission reductions. On July 26, 2013, a group of stakeholders, including SRP, the operating agent for the Navajo Plant, submitted to EPA two suggested alternatives to BART, which would achieve greater NO_x emission reductions and result in greater reasonable progress toward the national visibility goal than EPA's proposed BART determination. On July 28, 2014, EPA issued a final Navajo Plant BART rule approving the alternative stakeholder plan. Depending on which alternate operating scenario the Navajo Plant participants ultimately select, the required NO_x emission reductions could be achieved by either closing one of the three 750 MW units at the plant or curtailing energy production across all three units, such that the emission reductions are commensurate with the closure of approximately one of the Navajo Plant units. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe, and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this petition.

Mercury and other Hazardous Air Pollutants. In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excluding costs related to Cholla Unit 2, which was closed

on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in *Michigan vs. EPA* reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of coal combustion residuals ("CCR"), such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

Because the Subtitle D rule is self-implementing, the CCR standards apply directly to the regulated facility, and facilities are directly responsible for ensuring that their operations comply with the rule's requirements. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million, and its share of incremental costs for Cholla is approximately $85 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million.

Effluent Limitation Guidelines. On September 30, 2015, EPA finalized revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired EGUs. EPA's final regulation targets metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero discharge" from fly ash and bottom ash handling, and impoundment for coal ash disposal leachate. Compliance with these limitations will be required in connection with National Pollution Discharge Elimination System ("NPDES") discharge permit renewals, which occur in five-year intervals, that arise between 2018 and 2023. Until a draft NPDES permit for Four Corners is proposed during that timeframe, we are uncertain what will be required to control these discharges in compliance with the finalized effluent limitations at that facility. Cholla and the Navajo Plant do not require NPDES permitting.

Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone national ambient air quality standards ("NAAQS") at a level of 70 parts per billion ("ppb"). With ozone standards becoming more stringent, our fossil generation units will come under

increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA is expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. Depending on when EPA approves attainment designations for the Arizona and Navajo Nation jurisdictions in which our fossil generation units are located, revisions to SIPs and FIPs, respectively, implementing required controls to achieve the new 70 ppb standard are expected to be in place between 2020 and 2021. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

Clean Air Act Citizen Lawsuit. On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners participants alleging violations of the NSR provisions of the Clean Air Act. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the Clean Air Act's New Source Performance Standards ("NSPS") program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

The settlement requires installation of pollution control technology and implementation of other measures to reduce sulfur dioxide and nitrogen oxide emissions from the two Four Corners units, although installation of much of this equipment was already planned in order to comply with EPA's Regional Haze Rule requirements. The settlement also requires the Four Corners co-owners to pay a civil penalty of $1.5 million and spend $6.7 million for certain environmental mitigation projects to benefit the Navajo Nation. APS is responsible for 15 percent of these costs based on its ownership interest in the units at the time of the alleged violations, which does not result in a material impact on our financial position, results of operations or cash flows.

Superfund-Related Matters. The Comprehensive Environmental Response Compensation and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("PRPs"). PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study work plan. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these

facilities may have contributed to groundwater contamination in this area. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Manufactured Gas Plant Sites. Certain properties which APS now owns or which were previously owned by it or its corporate predecessors were at one time sites of, or sites associated with, manufactured gas plants. APS is taking action to voluntarily remediate these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations or cash flows.

Navajo Nation Environmental Issues

Four Corners and the Navajo Plant are located on the Navajo Reservation and are held under easements granted by the federal government, as well as leases from the Navajo Nation. See "Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities" above for additional information regarding these plants.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Navajo Acts"). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water, and pesticide activities, including those activities that occur at Four Corners and the Navajo Plant. On October 17, 1995, the Four Corners participants and the Navajo Plant participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, challenging the applicability of the Navajo Acts as to Four Corners and the Navajo Plant. The Court has stayed these proceedings pursuant to a request by the parties, and the parties are seeking to negotiate a settlement.

In April 2000, the Navajo Nation Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. APS believes the Navajo Nation exceeded its authority when it adopted the operating permit regulations. On July 12, 2000, the Four Corners participants and the Navajo Plant participants each filed a petition with the Navajo Supreme Court for review of these regulations. Those proceedings have been stayed, pending the settlement negotiations mentioned above. APS cannot currently predict the outcome of this matter.

On May 18, 2005, APS, SRP, as the operating agent for the Navajo Plant, and the Navajo Nation executed a Voluntary Compliance Agreement to resolve their disputes regarding the Navajo Nation Air Pollution Prevention and Control Act. As a result of this agreement, APS sought, and the courts granted, dismissal of the pending litigation in the Navajo Nation Supreme Court and the Navajo Nation District Court, to the extent the claims relate to the Clean Air Act. The agreement does not address or resolve any dispute relating to other Navajo Acts. APS cannot currently predict the outcome of this matter.

Water Supply

Assured supplies of water are important for APS's generating plants. At the present time, APS has adequate water to meet its needs. However, the Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future operations of the plant. The effect of the drought cannot be fully assessed at this time, and APS cannot predict the ultimate outcome, if any, of the drought or whether the drought will adversely affect the amount of power available, or the price thereof, from Four Corners.

Conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions, which, in addition to future supply conditions, have the potential to impact APS's operations.

San Juan River Adjudication. Both groundwater and surface water in areas important to APS's operations have been the subject of inquiries, claims, and legal proceedings, which will require a number of years to resolve. APS is one of a number of parties in a proceeding, filed March 13, 1975, before the Eleventh Judicial District Court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss. In addition, APS is a party to a water contract that allows the company to secure water for Four Corners in the event of a water shortage and is a party to a shortage sharing agreement, which provides for the apportionment of water supplies to Four Corners in the event of a water shortage in the San Juan River Basin.

Gila River Adjudication. A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Arizona Superior Court. Palo Verde is located within the geographic area subject to the summons. APS's rights and the rights of the other Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. As operating agent of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Several of APS's other power plants are also located within the geographic area subject to the summons. APS's claims dispute the court's jurisdiction over APS's groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court's criteria for resolving groundwater claims. Litigation on both of these issues has continued in the trial court. In December 2005, APS and other parties filed a petition with the Arizona Supreme Court requesting interlocutory review of a September 2005 trial court order regarding procedures for determining whether groundwater pumping is affecting surface water rights. The Arizona Supreme Court denied the petition in May 2007, and the trial court is now proceeding with implementation of its 2005 order. No trial date concerning APS's water rights claims has been set in this matter.

Little Colorado River Adjudication. APS has filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court, which was originally filed on September 5, 1985. APS's groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and, therefore, is potentially at issue in the case. APS's claims dispute the court's jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. Other claims have been identified as ready for litigation in motions filed with the court. No trial date concerning APS's water rights claims has been set in this matter.

Although the above matters remain subject to further evaluation, APS does not expect that the described litigation will have a material adverse impact on its financial position, results of operations, or cash flows.

BUSINESS OF OTHER SUBSIDIARIES

Bright Canyon Energy

On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE will focus on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon continues to pursue transmission development opportunities in the western United States consistent with its strategy.

El Dorado

El Dorado owns minority interests in several energy-related investments and Arizona community-based ventures. El Dorado's short-term goal is to prudently realize the value of its existing investments. As of December 31, 2015, El Dorado had total assets of approximately $9 million. El Dorado is not expected to contribute in any material way to our future financial performance, nor will it require any material amounts of capital over the next three years.

OTHER INFORMATION

Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. BCE is incorporated in Delaware. Additional information for each of these companies is provided below:

	Principal Executive Office Address	Year of Incorporation	Approximate Number of Employees at December 31, 2015
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	93
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,309
BCE	400 North Fifth Street Phoenix, AZ 85004	2014	5
El Dorado	400 North Fifth Street Phoenix, AZ 85004	1983	—
Total			6,407

The APS number includes employees at jointly-owned generating facilities (approximately 2,830 employees) for which APS serves as the generating facility manager. Approximately 1,673 APS employees are union employees, represented by the International Brotherhood of Electrical Workers ("IBEW") or the United Security Professionals of America ("USPA"). APS concluded negotiations with IBEW representatives over the new collective bargaining agreement in April 2015, and the new agreement is in place until March 31, 2018. The contract provides an average wage increase of 2.0% for the first year, 2.25% for the second year and 3.0% for the third year. The Company concluded negotiations with the USPA over the terms of a new collective bargaining agreement in May of 2014, and the new agreement is in place until May 31, 2017.

WHERE TO FIND MORE INFORMATION

We use our website (*www.pinnaclewest.com)* as a channel of distribution for material Company information. The following filings are available free of charge on our website as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission ("SEC"): Annual Reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports. Our board and committee charters, Code of Ethics for Financial Executives, Code of Ethics and Business Practices and other corporate governance information is also available on the Pinnacle West website. Pinnacle West will post any amendments to the Code of Ethics for Financial Executives and Code of Ethics and Business Practices, and any waivers that are required to be disclosed by the rules of either the SEC or the New York Stock Exchange, on its website. The information on Pinnacle West's website is not incorporated by reference into this report.

You can request a copy of these documents, excluding exhibits, by contacting Pinnacle West at the following address: Pinnacle West Capital Corporation, Office of the Corporate Secretary, Mail Station 8602, P.O. Box 53999, Phoenix, Arizona 85072-3999 (telephone 602-250-4400).

ITEM 1A. RISK FACTORS

In addition to the factors affecting specific business operations identified in the description of these operations contained elsewhere in this report, set forth below are risks and uncertainties that could affect our financial results. Unless otherwise indicated or the context otherwise requires, the following risks and uncertainties apply to Pinnacle West and its subsidiaries, including APS.

REGULATORY RISKS

Our financial condition depends upon APS's ability to recover costs in a timely manner from customers through regulated rates and otherwise execute its business strategy.

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies that significantly influence its business, liquidity, results of operations and its ability to fully recover costs from utility customers in a timely manner. The ACC regulates APS's retail electric rates and FERC regulates rates for wholesale power sales and transmission services. The profitability of APS is affected by the rates it may charge and the timeliness of recovering costs incurred through its rates. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings and ancillary matters which may come before the ACC and FERC, including in some cases how court challenges to these regulatory decisions are resolved. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify otherwise final orders under certain circumstances.

APS is currently pursuing certain activities, such as microgrid investments and construction of renewable facilities intended for specific customers. To date, APS has not received regulatory assurance of cost recovery for such investments. As APS engages in these activities, we will have to demonstrate to regulators that these investments are both prudent and useful in providing electric service to customers.

The ACC must also approve APS's issuance of securities and any significant transfer or encumbrance of APS property used to provide retail electric service, and must approve or receive prior notification of certain transactions between us, APS and our respective affiliates. Decisions made by the ACC or FERC could have a material adverse impact on our financial condition, results of operations or cash flows.

In a recent appellate challenge to an ACC rate decision regarding a water company (referred to in Note 3 as "SIB"), the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors or surcharges outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

APS's ability to conduct its business operations and avoid fines and penalties depends upon compliance with federal, state or local statutes, regulations and ACC requirements, and obtaining and maintaining certain regulatory permits, approvals and certificates.

APS must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of agencies that regulate APS's business, including FERC, NRC, EPA, the ACC, and state and local governmental agencies. These agencies regulate many aspects of APS's utility operations, including safety and performance, emissions, siting and construction of facilities, customer service and the rates that APS can charge retail and wholesale customers. Failure to comply can subject APS to, among other things, fines and penalties. For example, under the Energy Policy Act of 2005, FERC can impose penalties (up to one million dollars per day per violation) for failure to comply with mandatory electric reliability standards. APS is also required to have numerous permits, approvals and certificates from these agencies. APS believes the necessary permits, approvals and certificates have been obtained for its existing operations and that APS's business is conducted in accordance with applicable laws in all material respects. However, changes in regulations or the imposition of new or revised laws or regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies.

On January 28, 2016, an ACC Commissioner, Robert L. Burns, sent APS a Notice of Investigation pursuant to an Arizona statute that authorizes a Commissioner and his agents to inspect the accounts, books, papers and documents of any public service corporation, and examine under oath any officer, agent or employee of such corporation in relation to the business and affairs of the corporation. The Notice states that Commissioner Burns intends to investigate whether APS has used funds recoverable from ratepayers for political contributions, lobbying, or charitable donations purposes; whether APS's corporate affiliates have made contributions or donations under APS' brand name; and the degree to which APS and Pinnacle West are "intertwined" in terms of organization, management and operations. APS intends to cooperate with this investigation to the full extent that the matter is lawfully authorized, but cannot predict its timing or outcome.

The operation of APS's nuclear power plant exposes it to substantial regulatory oversight and potentially significant liabilities and capital expenditures.

The NRC has broad authority under federal law to impose safety-related, security-related and other licensing requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generation facilities, including Palo Verde. As a result of the March 2011 earthquake and tsunamis that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan, various industry organizations analyzed information from the Japan incident and develop action plans for U.S. nuclear power plants. Additionally, the NRC performed its own independent review of the events at Fukushima Daiichi, including a review of the agency's processes and regulations in order to determine whether the agency

should promulgate additional regulations and possibly make more fundamental changes to the NRC's system of regulation. As a result of the Fukushima event, the NRC has directed nuclear power plants to implement the first tier recommendations of the NRC's Near Term Task Force. In response to these recommendations, Palo Verde expects to spend approximately $0.5 million for capital enhancements to the plant over the next year in addition to the approximate $125 million that has already been spent on capital enhancements as of December 31, 2015 (APS's share is 29.1%). We cannot predict whether these amounts will increase or whether additional financial and/or operational requirements on Palo Verde and APS may be imposed.

In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increased inspection regime that could ultimately result in the shut-down of a unit or civil penalties, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect APS's financial condition, results of operations and cash flows.

APS is subject to numerous environmental laws and regulations, and changes in, or liabilities under, existing or new laws or regulations may increase APS's cost of operations or impact its business plans.

APS is, or may become, subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, discharges of wastewater and streams originating from fly ash and bottom ash handling facilities, solid waste, hazardous waste, and coal combustion products, which consist of bottom ash, fly ash, and air pollution control wastes. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require APS to obtain and comply with a wide variety of environmental licenses, permits, and other approvals. If there is a delay or failure to obtain any required environmental regulatory approval, or if APS fails to obtain, maintain, or comply with any such approval, operations at affected facilities could be suspended or subject to additional expenses. In addition, failure to comply with applicable environmental laws and regulations could result in civil liability as a result of government enforcement actions or private claims or criminal penalties. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. APS cannot predict the outcome (financial or operational) of any related litigation that may arise.

Environmental Clean Up. APS has been named as a PRP for a Superfund site in Phoenix, Arizona, and it could be named a PRP in the future for other environmental clean-up at sites identified by a regulatory body. APS cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs.

Regional Haze. APS has received final rulemakings imposing new requirements on Four Corners, Cholla and the Navajo Plant. Pursuant to these rules, EPA and ADEQ will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants. The financial impact of installing and operating the required pollution control equipment could jeopardize the economic viability of these plants or the ability of individual participants to continue their participation in these plants.

Coal Ash. In December 2014, EPA issued final regulations governing the handling and disposal of CCR, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners and in a dry landfill storage area at the Navajo Plant. To the extent the rule requires the closure or modification of these CCR units or the construction of new CCR units beyond what we currently anticipate, APS would incur significant additional costs for CCR disposal.

Ozone National Ambient Air Quality Standards. In 2015, EPA finalized revisions to the national ambient air quality standards for nitrogen oxides, which set new, more stringent standards intended to protect human health and human welfare. Depending on the stringency of the final standards and the implementation requirements, APS may be required to invest in new pollution control technologies and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas.

APS cannot assure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to it. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs incurred by APS are not fully recoverable from APS's customers, could have a material adverse effect on its financial condition, results of operations or cash flows. Due to current or potential future regulations or legislation coupled with trends in natural gas and coal prices, the economics of continuing to own certain resources, particularly coal facilities, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

APS faces physical and operational risks related to climate effects, and potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG emissions.

Concern over climate change has led to significant legislative and regulatory efforts to limit CO2, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions.

Financial Risks - Greenhouse Gas Regulation and the Clean Power Plan. In 2015, EPA finalized a rule to limit carbon dioxide emissions from existing power plants. The implementation of this rule within the jurisdictions where APS operates could result in a shift in in-state generation from coal to natural gas and renewable generation. Such a substantial change in APS's generation portfolio could require additional capital investments and increased operating costs, and thus have a significant financial impact on the Company. See Note 10 for additional risks and uncertainties resulting from the Clean Power Plan.

Physical and Operational Risks. Weather extremes such as drought and high temperature variations are common occurrences in the Southwest's desert area, and these are risks that APS considers in the normal course of business in the engineering and construction of its electric system. Large increases in ambient temperatures could require evaluation of certain materials used within its system and represent a greater challenge.

Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on APS's business and its results of operations.

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on APS due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Although some very limited retail competition existed in APS's service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS's customers. On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a "market" basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority

before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition.

One of these options would be a continuation or expansion of APS's existing AG (Alternative Generation) - 1 program, which essentially allows up to 200 MW of cumulative load to be served via a buy-through arrangement with competitive suppliers of generation. On November 25, 2015, the ACC issued an order approving a request by several AG-1 customers and suppliers to extend the term of the program from July 1, 2016 to the conclusion of APS's next general rate case. The order also authorized APS to defer for future recovery unmitigated unrecovered costs attributable to the program at 90% of the first $10 million per year and at 100% of amounts above $10 million per year.

In 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not "public service corporations" under the Arizona Constitution, and are therefore not regulated by the ACC. The use of such products by customers within our territory results in some level of competition. APS cannot predict when, and the extent to which, additional service providers will enter APS's service territory, increasing the level of competition in the market.

Proposals to enable or support retail electric competition are made from time to time in legislative or other forums in Arizona. We cannot predict future regulatory or legislative action that might result in increased competition.

OPERATIONAL RISKS

APS's results of operations can be adversely affected by various factors impacting demand for electricity.

Weather Conditions. Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, APS's overall operating results fluctuate substantially on a seasonal basis. In addition, APS has historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish APS's financial condition, results of operations and cash flows.

Higher temperatures may decrease the snowpack, which might result in lowered soil moisture and an increased threat of forest fires. Forest fires could threaten APS's communities and electric transmission lines and facilities. Any damage caused as a result of forest fires could negatively impact APS's financial condition, results of operations or cash flows.

Effects of Energy Conservation Measures and Distributed Energy. The ACC has enacted rules regarding energy efficiency that mandate a 22% annual energy savings requirement by 2020. This will likely increase participation by APS customers in energy efficiency and conservation programs and other demand-side management efforts, which in turn will impact the demand for electricity. The rules also include a requirement for the ACC to review and address financial disincentives, recovery of fixed costs and the recovery of net lost income/revenue that would result from lower sales due to increased energy efficiency requirements. To that end, the settlement agreement in APS's most recent retail rate case (the "2012 Settlement Agreement") includes a mechanism, the LFCR, to address these matters.

APS must also meet certain distributed energy requirements. A portion of APS's total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small

scale renewable technologies located on customers' properties). The distributed energy requirement was 25% of the overall RES requirement of 3% in 2011 and increased to 30% of the applicable RES requirement for 2012 and subsequent years. Customer participation in distributed energy programs would result in lower demand, since customers would be meeting some or all of their own energy needs. Reduced demand due to these energy efficiency and distributed energy requirements, unless substantially offset through ratemaking mechanisms, could have a material adverse impact on APS's financial condition, results of operations and cash flows.

Customer and Sales Growth. For the three years 2013 through 2015, APS's retail customer growth averaged 1.3% per year. We currently expect annual customer growth to average in the range of 2.0-3.0% for 2016 through 2018 based on our assessment of modestly improving economic conditions in Arizona. For the three years 2013 through 2015 APS experienced annual increases in retail electricity sales averaging 0.1%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average in the range of 0.5-1.5% during 2016 through 2018, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. Actual customer and sales growth may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. Additionally, recovery of a substantial portion of our fixed costs of providing service is based upon the volumetric amount of our sales. If our customer growth rate does not continue to improve as projected, or if it declines, or if the Arizona economy fails to improve, we may be unable to reach our estimated demand level and sales projections, which could have a negative impact on our financial condition, results of operations and cash flows.

The operation of power generation facilities and transmission systems involves risks that could result in reduced output or unscheduled outages, which could materially affect APS's results of operations.

The operation of power generation, transmission and distribution facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption, and performance below expected levels of output or efficiency. Unscheduled outages, including extensions of scheduled outages due to mechanical failures or other complications, occur from time to time and are an inherent risk of APS's business. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the larger transmission power grid, and the operation or failure of our facilities could adversely affect the operations of others. If APS's facilities operate below expectations, especially during its peak seasons, it may lose revenue or incur additional expenses, including increased purchased power expenses. Concerns over physical security of these assets is also increasing, which may require us to incur additional capital and operating costs to address. Damage to certain of our facilities due to vandalism or other deliberate acts could lead to outages or other adverse effects.

The inability to successfully develop or acquire generation resources to meet reliability requirements, new or evolving standards or regulations could adversely impact our business.

Potential changes in regulatory standards, impacts of new and existing laws and regulations, including environmental laws and regulations, and the need to obtain certain regulatory approvals create uncertainty surrounding our generation portfolio. The current abundance of low, stably priced natural gas, together with environmental and other concerns surrounding coal-fired generation resources, create strategic questions related to the appropriate generation portfolio and fuel diversification mix. In addition, APS is required by the ACC to meet certain energy resource portfolio requirements such as the EES and the RES. The development of any generation facility is subject to many risks, including risks related to financing, siting, permitting, technology, the construction of sufficient transmission capacity to support these facilities and stresses to generation and transmission resources from intermittent generation characteristics of renewable resources.

APS's inability to adequately develop or acquire the necessary generation resources could have a material adverse impact on our business and results of operations.

The lack of access to sufficient supplies of water could have a material adverse impact on APS's business and results of operations.

Assured supplies of water are important for APS's generating plants. Water in the southwestern United States is limited, and various parties have made conflicting claims regarding the right to access and use such limited supply of water. Both groundwater and surface water in areas important to APS's generating plants have been and are the subject of inquiries, claims and legal proceedings. In addition, the region in which APS's power plants are located is prone to drought conditions, which could potentially affect the plants' water supplies. APS's inability to access sufficient supplies of water could have a material adverse impact on our business and results of operations.

We are subject to cybersecurity risks and risks of unauthorized access to our systems.

In the regular course of our business, we handle a range of sensitive security, customer and business systems information. A security breach of our information systems such as theft or the inappropriate release of certain types of information, including confidential customer, employee, financial or system operating information, could have a material adverse impact on our financial condition, results of operations or cash flows. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, our technology systems are vulnerable to disability, failures or unauthorized access. Our generation, transmission and distribution facilities, information technology systems and other infrastructure facilities and systems and physical assets could be targets of such unauthorized access. Failures or breaches of our systems could impact the reliability of our generation, transmission and distribution systems and also subject us to financial harm. If our technology systems were to fail or be breached and if we are unable to recover in a timely way, we may not be able to fulfill critical business functions and sensitive confidential data could be compromised, which could have a material adverse impact on our financial condition, results of operations or cash flows.

We are subject to laws and rules issued by multiple government agencies concerning safeguarding and maintaining the confidentiality of our security, customer and business information. One of these agencies, NERC, has issued comprehensive regulations and standards surrounding the security of our operating systems, and is continually in the process of developing updated and additional requirements with which the utility industry must comply. The increasing promulgation of NERC rules and standards will increase our compliance costs and our exposure to the potential risk of violations of the standards.

We have experienced, and expect to continue to experience, these types of threats and attempted intrusions. The implementation of additional security measures could increase costs and have a material adverse impact on our financial results. We have obtained cyber insurance to provide coverage for a portion of the losses and damages that may result from a security breach of our information technology systems, but such insurance may not cover the total loss or damage caused by a breach. These types of events could also require significant management attention and resources, and could adversely affect Pinnacle West's and APS's reputation with customers and the public.

The ownership and operation of power generation and transmission facilities on Indian lands could result in uncertainty related to continued leases, easements and rights-of-way, which could have a significant impact on our business.

Certain APS power plants and portions of the transmission lines that carry power from these plants are located on Indian lands pursuant to leases, easements or other rights-of-way that are effective for specified periods. APS is unable to predict the final outcome of pending and future approvals by applicable governing bodies with respect to renewals of these leases, easements and rights-of-way.

There are inherent risks in the ownership and operation of nuclear facilities, such as environmental, health, fuel supply, spent fuel disposal, regulatory and financial risks and the risk of terrorist attack.

APS has an ownership interest in and operates, on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the United States. Palo Verde constitutes approximately 19% of our owned and leased generation capacity. Palo Verde is subject to environmental, health and financial risks, such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. In addition, APS may be required under federal law to pay up to $111 million (but not more than $16.6 million per year) of liabilities arising out of a nuclear incident occurring not only at Palo Verde, but at any other nuclear power plant in the United States. Although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

APS's operations include managing market risks related to commodity prices. APS is exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas and coal to the extent that unhedged positions exist. We have established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time and financial losses that negatively impact our results of operations.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") contains measures aimed at increasing the transparency and stability of the over-the counter, or OTC, derivative markets and preventing excessive speculation. The Dodd-Frank Act could restrict, among other things, trading positions in the energy futures markets, require different collateral or settlement positions, or increase regulatory reporting over derivative positions. Based on the provisions included in the Dodd-Frank Act and the implementation of regulations, these changes could, among other things, impact our ability to hedge commodity price and interest rate risk or increase the costs associated with our hedging programs.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of all counterparties. Despite the fact that the majority of APS's trading counterparties are rated as investment grade by the rating agencies, there is still a possibility that one or more of these companies could default, which could result in a material adverse impact on our earnings for a given period.

Changes in technology could create challenges for APS's existing business.

Alternative energy technologies that produce power or reduce power consumption or emissions are being developed and commercialized, including renewable technologies such as photovoltaic (solar) cells, customer-sited generation, energy storage (batteries), and efficiency technologies. Advances in technology and equipment/appliance efficiency could reduce the demand for supply from conventional generation, which could adversely affect APS's business.

APS continues to pursue and implement advanced grid technologies, including transmission and distribution system technologies and digital meters enabling two-way communications between the utility and its customers. Many of the products and processes resulting from these and other alternative technologies have not yet been widely used or tested on a long-term basis, and their use on large-scale systems is not as established or mature as APS's existing technologies and equipment. Widespread installation and acceptance of new technologies could enable the entry of new market participants, such as technology companies, into the interface between APS and its customers and could have other unpredictable effects on APS's business.

Deployment of renewable energy technologies is expected to continue across the western states and result in a larger portion of the overall energy production coming from these sources. These trends, which have benefited from historical and continuing government subsidies for certain technologies, have the potential to put downward pressure on wholesale power prices throughout the western states which could make APS's existing generating facilities less economical and impact their operational patterns and long-term viability.

We are subject to employee workforce factors that could adversely affect our business and financial condition.

Like most companies in the electric utility industry, our workforce is maturing, with approximately 36% of employees eligible to retire by the end of 2018. Although we have undertaken efforts to recruit and train new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability of qualified personnel, the need to negotiate collective bargaining agreements with union employees and potential work stoppages. These or other employee workforce factors could negatively impact our business, financial condition or results of operations.

FINANCIAL RISKS

Financial market disruptions or new rules or regulations may increase our financing costs or limit our access to various financial markets, which may adversely affect our liquidity and our ability to implement our financial strategy.

Pinnacle West and APS rely on access to credit markets as a significant source of liquidity and the capital markets for capital requirements not satisfied by cash flow from our operations. We believe that we will maintain sufficient access to these financial markets. However, certain market disruptions or rules or regulations may cause our cost of borrowing to increase generally, and/or otherwise adversely affect our ability to access these financial markets.

In addition, the credit commitments of our lenders under our bank facilities may not be satisfied or continued beyond current commitment periods for a variety of reasons, including new rules and regulations, periods of financial distress or liquidity issues affecting our lenders or financial markets, which could materially adversely affect the adequacy of our liquidity sources and the cost of maintaining these sources.

Changes in economic conditions, monetary policy, financial regulation or other factors could result in higher interest rates, which would increase interest expense on our existing variable rate debt and new debt we expect to issue in the future, and thus reduce funds available to us for our current plans.

Additionally, an increase in our leverage, whether as a result of these factors or otherwise, could adversely affect us by:

- causing a downgrade of our credit ratings;
- increasing the cost of future debt financing and refinancing;
- increasing our vulnerability to adverse economic and industry conditions; and
- requiring us to dedicate an increased portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future investment in our business or other purposes.

A downgrade of our credit ratings could materially and adversely affect our business, financial condition and results of operations.

Our current ratings are set forth in "Liquidity and Capital Resources — Credit Ratings" in Item 7. We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade or withdrawal could adversely affect the market price of Pinnacle West's and APS's securities, limit our access to capital and increase our borrowing costs, which would diminish our financial results. We would be required to pay a higher interest rate for future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under our existing credit facilities depend on our credit ratings. A downgrade could also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could severely limit access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

Investment performance, changing interest rates and other economic factors could decrease the value of our benefit plan assets and nuclear decommissioning trust funds and increase the valuation of our related obligations, resulting in significant additional funding requirements. We are subject to risks related to the provision of employee healthcare benefits and healthcare reform legislation. Any inability to fully recover these costs in our utility rates would negatively impact our financial condition.

We have significant pension plan and other postretirement benefits plan obligations to our employees and retirees, and legal obligations to fund nuclear decommissioning trusts for Palo Verde. We hold and invest substantial assets in these trusts that are designed to provide funds to pay for certain of these obligations as they arise. Declines in market values of the fixed income and equity securities held in these trusts may increase our funding requirements into the related trusts. Additionally, the valuation of liabilities related to our pension plan and other postretirement benefit plans are impacted by a discount rate, which is the interest rate used to discount future pension and other postretirement benefit obligations. Declining interest rates decrease the discount rate, increase the valuation of the plan liabilities and may result in increases in pension and other

postretirement benefit costs, cash contributions, regulatory assets, and charges to OCI. Changes in demographics, including increased number of retirements or changes in life expectancy and changes in other actuarial assumptions, may also result in similar impacts. The minimum contributions required under these plans are impacted by federal legislation. Increasing liabilities or otherwise increasing funding requirements under these plans, resulting from adverse changes in legislation or otherwise, could result in significant cash funding obligations that could have a material impact on our financial position, results of operations or cash flows.

We recover most of the pension costs and other postretirement benefit costs and all of the nuclear decommissioning costs in our regulated rates. Any inability to fully recover these costs in a timely manner would have a material negative impact on our financial condition, results of operations or cash flows.

Employee healthcare costs in recent years have continued to rise. Most of the Patient Protection and Affordable Care Act provisions have been implemented; however, costs and other effects of the legislation, which may include the cost of compliance and potentially increased costs of providing for medical insurance for our employees, cannot be determined with certainty at this time.

Our cash flow depends on the performance of APS.

We derive essentially all of our revenues and earnings from our wholly owned subsidiary, APS. Accordingly, our cash flow and our ability to pay dividends on our common stock is dependent upon the earnings and cash flows of APS and its distributions to us. APS is a separate and distinct legal entity and has no obligation to make distributions to us.

APS's financing agreements may restrict its ability to pay dividends, make distributions or otherwise transfer funds to us. In addition, an ACC financing order requires APS to maintain a common equity ratio of at least 40% and does not allow APS to pay common dividends if the payment would reduce its common equity below that threshold. The common equity ratio, as defined in the ACC order, is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt.

Pinnacle West's ability to meet its debt service obligations could be adversely affected because its debt securities are structurally subordinated to the debt securities and other obligations of its subsidiaries.

Because Pinnacle West is structured as a holding company, all existing and future debt and other liabilities of our subsidiaries will be effectively senior in right of payment to our debt securities. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations. Our ability to have the benefit of their cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors have been satisfied.

The market price of our common stock may be volatile.

The market price of our common stock could be subject to significant fluctuations in response to factors such as the following, some of which are beyond our control:

- variations in our quarterly operating results;
- operating results that vary from the expectations of management, securities analysts and investors;

- changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;
- developments generally affecting industries in which we operate;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- announcements by third parties of significant claims or proceedings against us;
- favorable or adverse regulatory or legislative developments;
- our dividend policy;
- future sales by the Company of equity or equity-linked securities; and
- general domestic and international economic conditions.

In addition, the stock market in general has experienced volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

Certain provisions of our articles of incorporation and bylaws and of Arizona law make it difficult for shareholders to change the composition of our board and may discourage takeover attempts.

These provisions, which could preclude our shareholders from receiving a change of control premium, include the following:

- restrictions on our ability to engage in a wide range of "business combination" transactions with an "interested shareholder" (generally, any person who owns 10% or more of our outstanding voting power or any of our affiliates or associates) or any affiliate or associate of an interested shareholder, unless specific conditions are met;
- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;
- the ability of the Board of Directors to increase the size of the Board of Directors and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise; and
- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval.

While these provisions have the effect of encouraging persons seeking to acquire control of us to negotiate with our Board of Directors, they could enable the Board of Directors to hinder or frustrate a transaction that some, or a majority, of our shareholders might believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Neither Pinnacle West nor APS has received written comments regarding its periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of its 2015 fiscal year and that remain unresolved.

ITEM 2. PROPERTIES

Generation Facilities

APS's portfolio of owned and leased generating facilities is provided in the table below:

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) See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Nuclear" in Item 1 for details regarding leased interests in Palo Verde. 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.

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 with respect to matters having a possible impact on the operation of certain of APS's generating facilities.

See "Business of Arizona Public Service Company" in Item 1 for a map detailing the location of APS's major power plants and principal transmission lines.

Transmission and Distribution Facilities

Current Facilities. APS's transmission facilities consist of approximately 6,070 pole miles of overhead lines and approximately 49 miles of underground lines, 5,847 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,077 miles of overhead lines and approximately 18,071 miles of underground primary cable, all of which are located in Arizona. APS distribution facilities reflect an actual net gain of 169 miles in 2015. APS shares ownership of some of its transmission facilities with other companies. The following table shows APS's jointly-owned interests in those transmission facilities recorded on the Consolidated Balance Sheets at December 31, 2015:

	Percent Owned (Weighted-Average)
Morgan — Pinnacle Peak System	64.6%
Palo Verde — Estrella 500kV System	50.0%
Round Valley System	50.0%
ANPP 500kV System	33.4%
Navajo Southern System	22.7%
Four Corners Switchyards	49.8%
Palo Verde — Yuma 500kV System	19.3%
Phoenix — Mead System	17.1%
Palo Verde — Morgan System	87.7%
Hassayampa — North Gila System	80.0%
Cholla 500 Switchyard	85.7%
Saguaro 500 Switchyard	75.0%

Expansion. Each year APS prepares and files with the ACC a ten-year transmission plan. In APS's 2015 plan, APS projects it will develop 275 miles of new lines over the next ten years. One significant project currently under development is a new 500kV path that will span from the Palo Verde hub around the western and northern edges of the Phoenix metropolitan area and terminate at a bulk substation in the northeast part of Phoenix. The Palo Verde to Morgan System includes Palo Verde-Delaney-Sun Valley-Morgan. The project consists of four phases. The first phase, Morgan to Pinnacle Peak 500kV, is currently in-service. The second

and third phases, Delaney to Palo Verde 500kV and Delaney to Sun Valley 500kV, are under construction and are expected to be energized by May 2016. The fourth phase, Morgan to Sun Valley 500kV, has been permitted and is in final design and development. In total, the projects consist of over 100 miles of new 500kV lines, with many of those miles constructed with the capability to string a 230kV line as a second circuit.

APS continues to work with regulators to identify transmission projects necessary to support renewable energy facilities. Two such projects, which are included in APS's 2015 transmission plan, are the Delaney to Palo Verde line and the North Gila to Hassayampa line, both of which are intended to support the transmission of renewable energy to Phoenix and California. The North Gila to Hassayampa line went into service in May 2015.

Physical Security Standards. On July 14, 2015, FERC approved version 2 of the proposed Physical Security Reliability Standard CIP-014 (CIP-014-2). As a result, CIP-014-2, the Physical Security Reliability Standard that requires transmission owners and operators to protect those critical transmission stations and substations and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack, could result in widespread instability, uncontrolled separation or cascading within an interconnection, became effective on October 2, 2015, triggering a series of staggered, but interdependent obligations for APS. As required by the Physical Security Reliability Standard, APS determined its critical transmission stations and substations and associated primary control centers that will be required to comply with the standard by October 2, 2015. However, as contemplated under CIP-014-2, this verification has triggered additional requirements and obligations within the Physical Security Reliability Standard that are not yet due to be completed. These remaining obligations, which consist of a risk evaluation and development and verification of a physical security plan, are due to be completed by the end the third quarter of 2016. Until APS has completed all required activities under the Physical Security Reliability Standard, we cannot predict the extent of any financial or operational impacts on APS.

NERC Critical Infrastructure Protection Requirements. In 2014, APS initiated a comprehensive project to ensure compliance with Version 5 of NERC's Critical Infrastructure Protection Requirements (CIP V.5) which will become effective April 1, 2016. APS will be incurring incremental capital expenditures through 2017 associated with the CIP V.5 compliance implementation project estimated to be approximately $52 million.

Plant and Transmission Line Leases and Rights-of-Way on Indian Lands

The Navajo Plant and Four Corners are located on land held under leases from the Navajo Nation and also under rights-of-way from the federal government. The right-of-way and lease for the Navajo Plant expire in 2019 and the right-of-way and lease for Four Corners were scheduled to expire in 2016. In March, 2011, the Navajo Nation Council signed a resolution approving a 25-year extension to the existing Four Corners lease term and providing Navajo Nation consent to renewal of the related rights-of-way. The effectiveness of the lease amendment also required the approval of the DOI, as did the related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015. The record of decision provides the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015.

Certain portions of the transmission lines that carry power from several of our power plants are located on Indian lands pursuant to rights-of-way that are effective for specified periods. Some of these rights-of-way have expired and our renewal applications have not yet been acted upon by the appropriate Indian tribes or federal agencies. Other rights expire at various times in the future and renewal action by the applicable tribe or federal agencies will be required at that time. In recent negotiations, certain of the affected Indian tribes have

required payments substantially in excess of amounts that we have paid in the past for such rights-of-way. The ultimate cost of renewal of certain of the rights-of-way for our transmission lines is therefore uncertain.

ITEM 3. LEGAL PROCEEDINGS

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 with regard to pending or threatened litigation and other disputes.

See Note 3 for ACC and FERC-related matters.

See Note 10 for information regarding environmental matters, Superfund–related matters, matters related to a September 2011 power outage and a New Mexico tax matter.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF PINNACLE WEST

Pinnacle West's executive officers are elected no less often than annually and may be removed by the Board of Directors at any time. The executive officers, their ages at February 19, 2016, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Donald E. Brandt	61	Chairman of the Board and Chief Executive Officer of Pinnacle West; Chairman of the Board of APS	2009-Present
		President of APS	2013-Present
		President of Pinnacle West	2008-Present
		Chief Executive Officer of APS	2008-Present
Robert S. Bement	60	Senior Vice President, Site Operations, PVNGS, of APS	2011-Present
Denise R. Danner	60	Vice President, Controller and Chief Accounting Officer of Pinnacle West; Chief Accounting Officer of APS	2010-Present
		Vice President and Controller of APS	2009-Present
Patrick Dinkel	52	Vice President, Transmission and Distribution Operations of APS	2014-Present
		Vice President, Resource Management of APS	2012-2014
		Vice President, Power Marketing, Resource Planning and Acquisition of APS	2011-2012
		Vice President, Power Marketing and Resource Planning of APS	2010-2011
Randall K. Edington	62	Executive Vice President and Chief Nuclear Officer, PVNGS, of APS	2007-Present
David P. Falck	62	Executive Vice President and General Counsel of Pinnacle West and APS	2009-Present
		Secretary of Pinnacle West and APS	2009-2012
Daniel T. Froetscher	54	Senior Vice President, Transmission, Distribution & Customers of APS	2014-Present
		Vice President, Energy Delivery of APS	2008-2014
Barbara M. Gomez	61	Vice President, Human Resources of APS	2014-Present
		Vice President, Chief Procurement Officer of APS	2013-2014
		Vice President, Supply Chain Management of APS	2010-2013
Jeffrey B. Guldner	50	Senior Vice President, Public Policy of APS	2014-Present
		Senior Vice President, Customers and Regulation of APS	2012-2014
		Vice President, Rates and Regulation of APS	2007-2012
James R. Hatfield	58	Executive Vice President of Pinnacle West and APS	2012-Present
		Chief Financial Officer of Pinnacle West and APS	2008-Present
		Senior Vice President of Pinnacle West and APS	2008-2012
John S. Hatfield	50	Vice President, Communications of APS	2010-Present
Tammy D. McLeod	54	Vice President, Resource Management of APS	2014-Present
		Vice President and Chief Customer Officer of APS	2007-2014
Lee R. Nickloy	49	Vice President and Treasurer of Pinnacle West and APS	2010-Present
Mark A. Schiavoni	60	Executive Vice President and Chief Operating Officer of APS	2014-Present
		Executive Vice President, Operations of APS	2012-2014
		Senior Vice President, Fossil Operations of APS	2009-2012

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Pinnacle West's common stock is publicly held and is traded on the New York Stock Exchange. At the close of business on February 12, 2016, Pinnacle West's common stock was held of record by approximately 20,570 shareholders.

QUARTERLY STOCK PRICES AND DIVIDENDS PAID PER SHARE
STOCK SYMBOL: PNW

2015	High	Low	Close	Dividends Per Share
1st Quarter	$ 73.31	$ 61.53	$ 63.75	$ 0.595
2nd Quarter	64.95	56.01	56.89	0.595
3rd Quarter	65.23	56.77	64.14	0.595
4th Quarter	67.02	60.70	64.48	0.625

2014	High	Low	Close	Dividends Per Share
1st Quarter	$ 55.99	$ 51.15	$ 54.66	$ 0.5675
2nd Quarter	58.06	53.71	57.84	0.5675
3rd Quarter	57.95	52.13	54.64	0.5675
4th Quarter	71.11	54.59	68.31	0.595

APS's common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. As a result, there is no established public trading market for APS's common stock.

The chart below sets forth the dividends paid on APS's common stock for each of the four quarters for 2015 and 2014.

Common Stock Dividends
(Dollars in Thousands)

Quarter	2015	2014
1st Quarter	$ 65,800	$ 62,500
2nd Quarter	65,900	62,600
3rd Quarter	65,900	62,700
4th Quarter	69,300	65,800

The sole holder of APS's common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. As of December 31, 2015, APS did not have any outstanding preferred stock.

Issuer Purchases of Equity Securities

The following table contains information about our purchases of our common stock during the fourth quarter of 2015.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 – October 31, 2015	61,471	$ 65.74	—	—
November 1 – November 30, 2015	—	—	—	—
December 1 – December 31, 2015	—	—	—	—
Total	61,471	$ 65.74	—	—

(1) Represents shares of common stock withheld by Pinnacle West to satisfy tax withholding obligations upon the vesting of performance shares.

ITEM 6. SELECTED FINANCIAL DATA

PINNACLE WEST CAPITAL CORPORATION – CONSOLIDATED

The selected data presented below as of and for the years ended December 31, 2015, 2014, 2013, 2012 and 2011 are derived from the Consolidated Financial Statements. The data should be read in connection with the Consolidated Financial Statements including the related notes included in Item 8 of this Form 10-K.

	2015	2014	2013	2012	2011
	(dollars in thousands, except per share amounts)				
OPERATING RESULTS					
Operating revenues	$ 3,495,443	$ 3,491,632	$ 3,454,628	$ 3,301,804	$ 3,241,379
Income from continuing operations	$ 456,190	$ 423,696	$ 439,966	$ 418,993	$ 355,634
Income (loss) from discontinued operations – net of income taxes	—	—	—	(5,829)	11,306
Net income	456,190	423,696	439,966	413,164	366,940
Less: Net income attributable to noncontrolling interests	18,933	26,101	33,892	31,622	27,467
Net income attributable to common shareholders	$ 437,257	$ 397,595	$ 406,074	$ 381,542	$ 339,473
COMMON STOCK DATA					
Book value per share – year-end	$ 41.30	$ 39.50	$ 38.07	$ 36.20	$ 34.98
Earnings per weighted-average common share outstanding:					
Continuing operations attributable to common shareholders – basic	$ 3.94	$ 3.59	$ 3.69	$ 3.54	$ 3.01
Net income attributable to common shareholders – basic	$ 3.94	$ 3.59	$ 3.69	$ 3.48	$ 3.11
Continuing operations attributable to common shareholders – diluted	$ 3.92	$ 3.58	$ 3.66	$ 3.50	$ 2.99
Net income attributable to common shareholders – diluted	$ 3.92	$ 3.58	$ 3.66	$ 3.45	$ 3.09
Dividends declared per share	$ 2.44	$ 2.33	$ 2.23	$ 2.67	$ 2.10
Weighted-average common shares outstanding – basic	111,025,944	110,626,101	109,984,160	109,510,296	109,052,840
Weighted-average common shares outstanding – diluted	111,552,130	111,178,141	110,805,943	110,527,311	109,864,243
BALANCE SHEET DATA (a)					
Total assets	$ 15,028,258	$ 14,288,890	$ 13,486,826	$ 13,357,123	$ 13,089,837
Liabilities and equity:					
Current liabilities	$ 1,442,317	$ 1,559,143	$ 1,618,644	$ 1,083,542	$ 1,342,705
Long-term debt less current maturities	3,462,391	3,006,573	2,774,605	3,176,596	2,997,873
Deferred credits and other	5,404,093	5,204,072	4,753,117	4,994,696	4,818,673
Total liabilities	10,308,801	9,769,788	9,146,366	9,254,834	9,159,251
Total equity	4,719,457	4,519,102	4,340,460	4,102,289	3,930,586
Total liabilities and equity	$ 15,028,258	$ 14,288,890	$ 13,486,826	$ 13,357,123	$ 13,089,837

(a) During the fourth quarter of 2015, we adopted the new accounting standard related to balance sheet presentation of debt issuance costs. See further discussion in Note 2.

SELECTED FINANCIAL DATA

ARIZONA PUBLIC SERVICE COMPANY – CONSOLIDATED

	2015	2014	2013	2012	2011
			(dollars in thousands)		
OPERATING RESULTS					
Electric operating revenues	$ 3,492,357	$ 3,488,946	$ 3,451,251	$ 3,293,489	$ 3,237,241
Fuel and purchased power costs	1,101,298	1,179,829	1,095,709	994,790	1,009,464
Other operating expenses	1,779,075	1,716,325	1,733,677	1,693,170	1,673,394
Operating income	611,984	592,792	621,865	605,529	554,383
Other income	33,332	36,358	20,797	16,358	24,974
Interest expense — net of allowance for borrowed funds	176,109	181,830	183,801	194,777	215,584
Net income	469,207	447,320	458,861	427,110	363,773
Less: Net income attributable to noncontrolling interests	18,933	26,101	33,892	31,613	27,524
Net income attributable to common shareholder	$ 450,274	$ 421,219	$ 424,969	$ 395,497	$ 336,249
BALANCE SHEET DATA (a)					
Total assets	$ 14,982,182	$ 14,190,362	$ 13,359,517	$ 13,220,050	$ 13,011,056
Liabilities and equity:					
Total equity	$ 4,814,794	$ 4,629,852	$ 4,454,874	$ 4,222,483	$ 4,051,406
Long-term debt less current maturities	3,337,391	2,881,573	2,649,604	3,051,596	2,872,872
Total capitalization	8,152,185	7,511,425	7,104,478	7,274,079	6,924,278
Current liabilities	1,424,708	1,532,464	1,580,847	1,043,087	1,322,714
Deferred credits and other	5,405,289	5,146,473	4,674,192	4,902,884	4,764,064
Total liabilities and equity	$ 14,982,182	$ 14,190,362	$ 13,359,517	$ 13,220,050	$ 13,011,056

(a) During the fourth quarter of 2015, we adopted the new accounting standard related to balance sheet presentation of debt issuance costs. See further discussion in Note 2.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West's Consolidated Financial Statements and APS's Consolidated Financial Statements and the related Notes that appear in Item 8 of this report. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see "Forward-Looking Statements" at the front of this report and "Risk Factors" in Item 1A.

OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS currently accounts for essentially all of our revenues and earnings.

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. APS operates and is a joint owner of Palo Verde. The March 2011 earthquake and tsunamis in Japan and the resulting accident at Japan's Fukushima Daiichi nuclear power station had a significant impact on nuclear power operators worldwide. In the aftermath of the accident, the NRC conducted an independent assessment to consider actions to address lessons learned from the Fukushima events. The independent assessment, named the "Near Term Task Force," recommended a number of proposed enhancements to U.S. commercial nuclear power plant equipment and emergency plans. The NRC has directed nuclear power plants to begin implementing some of the Near Term Task Force's recommendations. To implement these recommendations, Palo Verde expects to spend approximately $0.5 million for capital enhancements to the plant through 2016 in addition to the approximate $125 million that has already been spent on capital enhancements as of December 31, 2015 (APS's share is 29.1%).

Coal and Related Environmental Matters and Transactions. APS is a joint owner of three coal-fired power plants and acts as operating agent for two of the plants. APS is focused on the impacts on its coal fleet that may result from increased regulation and potential legislation concerning GHG emissions. On June 2, 2014, EPA proposed a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"), and EPA finalized its proposal on August 3, 2015.

EPA's nationwide CO_2 emissions reduction goal is 32% below 2005 emission levels. As finalized for the state of Arizona and the Navajo Nation, compliance with the Clean Power Plan could involve a shift in generation from coal to natural gas and renewable generation. Until implementation plans for these jurisdictions are finalized, we are unable to determine the actual impacts to APS. APS continually analyzes its long-range capital management plans to assess the potential effects of these changes, understanding that any resulting regulation and legislation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to continue participation in such plants.

Cholla

On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 10 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long term than the benefits that would have resulted from adding emissions control equipment. APS closed Unit 2 on October 1, 2015.

Four Corners

Asset Purchase Agreement and Coal Supply Matters. On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. In connection with APS's most recent retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustments was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed below, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton will be retained by NTEC under contract as the mine manager and operator until July 2016. Also occurring concurrently with the closing, the Four Corners' co-owners executed the 2016 Coal Supply Agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. The cash purchase price, which will be subject to certain adjustments at closing, is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016.

When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. On December 29, 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

Lease Extension. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record

of decision on July 17, 2015. The record of decision provided the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015. On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with the environmental review described above were not in accordance with applicable law. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. APS completed a competitive solicitation process in which the Ocotillo project was evaluated against other alternatives. Consistent with the independent monitor's report, the Ocotillo project was selected as the best alternative. APS must finalize the permitting process before construction can begin.

Transmission and Delivery. APS is working closely with regulators to identify and plan for transmission needs that continue to support system reliability, access to markets and renewable energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section below includes new APS transmission projects through 2018, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand advanced grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better monitor their energy use and needs, minimize system outage durations, as well as the number of customers that experience outages, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions, including remote meter reading and remote connects and disconnects.

Renewable Energy. The ACC approved the RES in 2006. The renewable energy requirement is 6% of retail electric sales in 2016 and increases annually until it reaches 15% in 2025. In the 2009 Settlement Agreement, APS agreed to exceed the RES standards, committing to use APS's best efforts to obtain 1,700 GWh of new renewable resources to be in service by year-end 2015, in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2015. A component of the RES targets development of distributed energy systems.

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

On July 1, 2014, APS filed its 2015 RES implementation plan and proposed a RES budget of approximately $154 million. On December 31, 2014, the ACC issued a decision approving the 2015 RES implementation plan with minor modifications, including reducing the requested budget to approximately $152 million.

On July 1, 2015, APS filed its 2016 RES implementation plan and proposed a RES budget of approximately $148 million. On January 12, 2016, the ACC approved APS's plan and requested budget.

APS has developed owned solar resources through the ACC-approved AZ Sun Program. APS has invested approximately $675 million in its AZ Sun Program. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the project to the electric grid.

In accordance with the ACC's decision on the 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 MW of APS-owned utility scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of utility scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

Demand Side Management. In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated an Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard of 22% cumulative annual energy savings by 2020. The 22% figure represents the cumulative reduction in future energy usage through 2020 attributable to energy efficiency initiatives. This standard became effective on January 1, 2011.

On June 1, 2012, APS filed its 2013 DSM Plan. In 2013, the standards required APS to achieve cumulative energy savings equal to 5% of its 2012 retail energy sales. Later in 2012, APS filed a supplement to its plan that included a proposed budget for 2013 of $87.6 million.

On March 11, 2014, the ACC issued an order approving APS's 2013 DSM Plan. The ACC approved a budget of $68.9 million for each of 2013 and 2014. The ACC also approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also approved that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standard, however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its Lost Fixed Cost Recovery mechanism.

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. The DSM Plan also proposed a reduction in the DSMAC of approximately 12%.

Electric Energy Efficiency. On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Utility Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. A formal rulemaking has not been initiated and there has been no additional action on the draft to date.

Rate Matters. APS needs timely recovery through rates of its capital and operating expenditures to maintain its financial health. APS's retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by FERC. On June 1, 2011, APS filed a rate case with the ACC. APS and other parties to the retail rate case subsequently entered into the 2012 Settlement Agreement detailing the terms upon which the parties have agreed to settle the rate case. See Note 3 for details regarding the 2012 Settlement Agreement terms and for information on APS's FERC rates.

On January 29, 2016, APS filed a NOI informing the ACC that APS intends to submit a rate case application in June 2016 using an adjusted test year ending December 31, 2015. The NOI provides an overview of the key issues APS expects to address in its formal request such as rate design changes (residential, commercial and industrial), a decoupling mechanism, permission to defer for potential future recovery costs associated with the Company's Ocotillo Modernization Project, permission to defer for potential future recovery costs associated with environmental standards compliance, inclusion of post-test year plant and modifications to certain adjustor mechanisms, among other items. In its rate application, APS will request that its proposed pricing changes take effect in July 2017. APS is still developing the exact amount of the request.

APS has several recovery mechanisms in place that provide more timely recovery to APS of its fuel and transmission costs, and costs associated with the promotion and implementation of its demand side management and renewable energy efforts and customer programs. These mechanisms are described more fully in Note 3.

As part of APS's acquisition of SCE's interest in Units 4 and 5 of Four Corners, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

Net Metering. On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing has been scheduled to commence in April 2016. APS cannot predict the outcome of this proceeding.

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS has also requested intervention in the upcoming Tucson Electric Power Company rate case. The outcomes of these proceedings will not directly impact our financial position.

Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB"). In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

Financial Strength and Flexibility. Pinnacle West and APS currently have ample borrowing capacity under their respective credit facilities, and may readily access these facilities ensuring adequate liquidity for each company. Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Other Subsidiaries.

Bright Canyon Energy. On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE will focus on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon

continues to pursue transmission development opportunities in the western United States consistent with its strategy.

El Dorado. The operations of El Dorado are not expected to have any material impact on our financial results, or to require any material amounts of capital, over the next three years.

Key Financial Drivers

In addition to the continuing impact of the matters described above, many factors influence our financial results and our future financial outlook, including those listed below. We closely monitor these factors to plan for the Company's current needs, and to adjust our expectations, financial budgets and forecasts appropriately.

Electric Operating Revenues. For the years 2013 through 2015, retail electric revenues comprised approximately 93% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Customer and Sales Growth. Retail customers in APS's service territory increased 1.2% for the year ended December 31, 2015 compared with the prior year. For the three years 2013 through 2015, APS's customer growth averaged 1.3% per year. We currently expect annual customer growth to average in the range of 2.0-3.0% for 2016 through 2018 based on our assessment of modestly improving economic conditions in Arizona. Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.7% for the year ended December 31, 2015 compared with the prior year, reflecting the effects of improving economic conditions and customer growth, partially offset by customer conservation and energy efficiency and distributed renewable generation initiatives. For the three years 2013 through 2015, APS experienced annual increases in retail electricity sales averaging 0.1%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average in the range of 0.5-1.5% during 2016 through 2018, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy could further impact these estimates.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. Based on past experience, a reasonable range of variation in our kWh sales projections attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of up to $10 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historically, extreme weather variations have resulted in annual variations in net income in excess of $20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to $10 million.

Fuel and Purchased Power Costs. Fuel and purchased power costs included on our Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market

prices, new generating plants being placed in service in our market areas, changes in our generation resource allocation, our hedging program for managing such costs and PSA deferrals and the related amortization.

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, outages, renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors. On September 30, 2014, Pinnacle West announced plan design changes to the group life and medical postretirement benefit plan, which reduced net periodic benefit costs. See Note 7.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and changes in depreciation and amortization rates. See "Capital Expenditures" below for information regarding the planned additions to our facilities. See Note 3 regarding deferral of certain costs pursuant to an ACC order.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 11.0% of the assessed value for 2015, 10.7% for 2014 and 10.5% for 2013. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units, transmission and distribution facilities. (See Note 3 for property tax deferrals contained in the 2012 Settlement Agreement.)

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 6). The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. An allowance for borrowed funds used during construction offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed in commercial operation.

RESULTS OF OPERATIONS

Pinnacle West's only reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results – 2015 compared with 2014.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2015 was $437 million, compared with $398 million for the prior year. The results reflect an increase of approximately $34 million for the regulated electricity segment primarily due to the Four Corners-related rate change, lower operations and maintenance expenses, and higher retail sales due to customer growth and changes in customer usage patterns and related pricing, partially offset by higher depreciation and amortization. The all other segment's income was higher by $5 million primarily related to El Dorado's investment losses in 2014.

The following table presents net income attributable to common shareholders by business segment compared with the prior year:

	Year Ended December 31,		
	2015	2014	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,391	$ 2,309	$ 82
Operations and maintenance	(868)	(908)	40
Depreciation and amortization	(494)	(417)	(77)
Taxes other than income taxes	(172)	(172)	—
All other income and expenses, net	19	28	(9)
Interest charges, net of allowance for borrowed funds used during construction	(179)	(185)	6
Income taxes	(239)	(224)	(15)
Less income related to noncontrolling interests (Note 18)	(19)	(26)	7
Regulated electricity segment income	439	405	34
All other	(2)	(7)	5
Net Income Attributable to Common Shareholders	$ 437	$ 398	$ 39

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $82 million higher for the year ended December 31, 2015 compared with the prior year. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Four Corners-related rate change	$ 56	$ —	$ 56
Higher retail sales due to customer growth and changes in customer usage patterns and related pricing	25	6	19
Lost fixed cost recovery	12	—	12
Effects of weather	16	6	10
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(69)	(68)	(1)
Changes in long-term wholesale contracted sales	(40)	(25)	(15)
Miscellaneous items, net	3	2	1
Total	$ 3	$ (79)	$ 82

Operations and maintenance. Operations and maintenance expenses decreased $40 million for the year ended December 31, 2015 compared with the prior year primarily because of:

- A decrease of $21 million for employee benefit costs;

- A decrease of $14 million in fossil generation costs primarily related to lower planned outage costs;
- A decrease of $13 million for costs related to corporate support;
- A decrease of $8 million related to costs for demand-side management, renewable energy and similar regulatory programs, which is partially offset in operating revenues and purchased power;
- An increase of $9 million related to higher nuclear generation costs;
- An increase of $6 million in customer service costs including costs related to a new customer information system; and
- An increase of $1 million related to other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $77 million higher for the year ended December 31, 2015 compared with the prior year primarily related to:

- An increase of $34 million related to the absence of 2014 Four Corners cost deferrals and the related 2015 amortization;
- An increase of $16 million related to the Four Corners acquisition adjustment;
- An increase of $20 million due to increased plant in service;
- An increase of $10 million related to the regulatory treatment of the Palo Verde sale leaseback, which is offset in noncontrolling interests; and
- A decrease of $3 million due to other miscellaneous factors.

All other income and expenses, net. All other income and expenses, net, were $9 million lower for the year ended December 31, 2015 compared with the prior year primarily due to the return on the Four Corners acquisition in 2014.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, decreased $6 million for the year ended December 31, 2015 compared with the prior year, primarily because of lower interest rates on our debt in the current year.

Income taxes. Income taxes were $15 million higher for the year ended December 31, 2015 compared with the prior year primarily due to the effects of higher pretax income in the current year.

Operating Results – 2014 compared with 2013.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2014 was $398 million, compared with $406 million for the prior year. The results reflect a decrease of approximately $4 million for the regulated electricity segment primarily due to higher fossil generation costs, lower retail sales due to the effects of weather, higher property taxes, and lower retail transmission revenues. These

negative factors were partially offset by lower operations and maintenance expenses related to lower employee benefit costs, higher other income, and increased revenues for lost fixed cost recovery. All other segment's income was lower by $4 million primarily related to El Dorado's investment losses.

The following table presents net income attributable to common shareholders by business segment compared with the prior year:

	Year Ended December 31,		
	2014	2013	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,309	$ 2,356	$ (47)
Operations and maintenance	(908)	(925)	17
Depreciation and amortization	(417)	(416)	(1)
Taxes other than income taxes	(172)	(164)	(8)
All other income and expenses, net	28	11	17
Interest charges, net of allowance for borrowed funds used during construction	(185)	(187)	2
Income taxes	(224)	(232)	8
Less income related to noncontrolling interests (Note 18)	(26)	(34)	8
Regulated electricity segment income	405	409	(4)
All other	(7)	(3)	(4)
Net Income Attributable to Common Shareholders	$ 398	$ 406	$ (8)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $47 million lower for the year ended December 31, 2014 compared with the prior year. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Effects of weather	$ (45)	$ (16)	$ (29)
Lower demand side management regulatory surcharges, offset by renewable energy regulatory surcharges and purchased power	—	20	(20)
Lower retail transmission revenues	(7)	—	(7)
Lower retail sales due to changes in customer usage patterns and related pricing, partially offset by customer growth	(4)	—	(4)
Higher net fuel and purchased power costs, including related deferrals and higher off-system sales margins	78	79	(1)
Lost fixed cost recovery	12	—	12
Miscellaneous items, net	3	1	2
Total	$ 37	$ 84	$ (47)

Operations and maintenance. Operations and maintenance expenses decreased $17 million for the year ended December 31, 2014 compared with the prior year primarily because of:

- A decrease of $33 million related to costs for demand-side management, renewable energy and similar regulatory programs, which were partially offset in operating revenues and purchased power;
- A decrease of $20 million related to lower employee benefit costs;
- An increase of $33 million in generation costs, primarily related to an increased ownership share in Four Corners, a portion of which is deferred in depreciation and amortization, and higher fossil maintenance costs; and
- An increase of $3 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $1 million higher for the year ended December 31, 2014 compared with the prior year primarily related to higher plant balances of approximately $23 million, partially offset by higher Four Corners cost deferrals in the current year of approximately $22 million.

Taxes other than income taxes. Taxes other than income taxes were $8 million higher for the year ended December 31, 2014 compared with the prior year primarily due to higher property tax rates and higher plant balances.

All other income and expenses, net. All other income and expenses, net, were $17 million higher for the year ended December 31, 2014 compared with the prior year due to the debt return on the Four Corners acquisition, an increase in the allowance for equity funds used during construction due to higher balances, and other non-operating income.

Income taxes. Income taxes were $8 million lower for the year ended December 31, 2014 compared with the prior year primarily due to the effects of lower pretax income in the current year.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Pinnacle West's primary cash needs are for dividends to our shareholders and principal and interest payments on our indebtedness. The level of our common stock dividends and future dividend growth will be dependent on declaration by our Board of Directors and based on a number of factors, including our financial condition, payout ratio, free cash flow and other factors.

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2015, APS's common equity ratio, as defined, was 55%. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.6 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

APS's capital requirements consist primarily of capital expenditures and maturities of long-term debt. APS funds its capital requirements with cash from operations and, to the extent necessary, external debt financing and equity infusions from Pinnacle West.

Many of APS's current capital expenditure projects qualify for bonus depreciation. On December 18, 2015, President Obama signed into law the Consolidated Appropriations Act, 2016 (H.R. 2029) which combined the tax and government funding bills (The Protecting Americans from Tax Hikes Act and Omnibus Bill) containing an extension of bonus depreciation through 2019. Enactment of this legislation is expected to generate approximately $375-$425 million of cash tax benefits over the next three years, which is expected to be fully realized by APS and Pinnacle West Consolidated during this time frame. The cash generated by the extension of bonus depreciation is an acceleration of the tax benefits that APS would have otherwise received over 20 years. At Pinnacle West Consolidated, the extension of bonus depreciation will, in turn, delay until 2019 full cash realization of approximately $82 million of currently unrealized Investment Tax Credits, which are recorded as a deferred tax asset on the Consolidated Balance Sheet as of December 31, 2015.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the years ended December 31, 2015, 2014 and 2013 (dollars in millions):

Pinnacle West Consolidated

	2015	2014	2013
Net cash flow provided by operating activities	$ 1,094	$ 1,100	$ 1,153
Net cash flow used for investing activities	(1,066)	(923)	(1,009)
Net cash flow provided by (used for) financing activities	4	(179)	(161)
Net increase (decrease) in cash and cash equivalents	$ 32	$ (2)	$ (17)

Arizona Public Service Company

	2015	2014	2013
Net cash flow provided by operating activities	$ 1,100	$ 1,124	$ 1,194
Net cash flow used for investing activities	(1,060)	(922)	(1,009)
Net cash flow used for financing activities	(22)	(201)	(185)
Net increase in cash and cash equivalents	$ 18	$ 1	$ —

Operating Cash Flows

2015 Compared with 2014. Pinnacle West's consolidated net cash provided by operating activities was $1,094 million in 2015 compared to $1,100 million in 2014, a decrease of $6 million in net cash provided. The decrease is primarily related to a $135 million income tax refund received in the first quarter of 2014, which is partially offset by a $48 million change in cash collateral posted, and other changes in working capital including increased cash receipts for the Four Corners-related rate change of $56 million.

2014 Compared with 2013. Pinnacle West's consolidated net cash provided by operating activities was $1,100 million in 2014 compared to $1,153 million in 2013, a decrease of $53 million in net cash provided. The decrease is primarily related to $99 million in higher fuel and purchased power costs, a $39 million increase in cash collateral posted, $34 million of higher pension contributions in 2014, and other changes in working capital. The decrease is partially offset by a $121 million increase in income tax refunds net of payments (primarily related to a $135 million income tax refund received in the first quarter of 2014). APS's

operating cash flows included income tax refunds of approximately $86 million in 2014 compared with payments of $8 million in 2013.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 116% funded as of January 1, 2015 and is estimated to be approximately 116% funded as of January 1, 2016. Under GAAP, the qualified pension plan was 89% funded as of January 1, 2015 and is estimated to be approximately 88% funded as of January 1, 2016. See Note 7 for additional details. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $100 million in 2015, $175 million in 2014, and $141 million in 2013. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2016-2018 period. With regard to our contributions to our other postretirement benefit plans, we made a contribution of approximately $1 million in 2015, $1 million in 2014, and $14 million in 2013. We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans.

Investing Cash Flows

2015 Compared with 2014. Pinnacle West's consolidated net cash used for investing activities was $1,066 million in 2015, compared to $923 million in 2014, an increase of $143 million in net cash used primarily related to increased capital expenditures.

2014 Compared with 2013. Pinnacle West's consolidated net cash used for investing activities was $923 million in 2014, compared to $1,009 million in 2013, a decrease of $86 million in net cash used. The decrease in net cash used for investing activities is primarily related to APS's purchase of SCE's interest in Units 4 and 5 of Four Corners of approximately $209 million in 2013, partially offset by an increase of approximately $123 million in other capital expenditures.

Capital Expenditures. The following table summarizes the estimated capital expenditures for the next three years:

Capital Expenditures
(dollars in millions)

	Estimated for the Year Ended December 31,		
	2016	**2017**	**2018**
APS			
Generation:			
Nuclear Fuel	$ 81	$ 78	$ 81
Renewables	110	1	1
Environmental	235	199	130
New Gas Generation	77	237	112
Other Generation	134	133	222
Distribution	357	345	376
Transmission	123	210	120
Other (a)	88	82	82
Total APS	$ 1,205	$ 1,285	$ 1,124

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. The estimated renewables capital expenditures include a planned utility-scale solar facility, which is subject to regulatory approval. We have not included estimated costs for Cholla's compliance with MATS or EPA's regional haze rule since we have challenged the regional haze rule judicially and we have proposed a compromise strategy to EPA, which, if approved, would allow us to avoid expenditures related to environmental control equipment. The portion of estimated costs for 2016 through 2018 for installation of pollution control equipment needed to ensure Four Corners' compliance with EPA's regional haze rules have been included in the table above. Costs related to the Navajo Plant's compliance with the regional haze rules are not included in the table above, as they are expected to be incurred post-2018. The portion of estimated costs for 2016 through 2018 for incremental costs to comply with the CCR rule for Four Corners and Cholla have also been included in the table above.

On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. On December 29, 2015, NTEC notified APS of its intent to exercise its option to purchase the 7% interest. The table above does not include capital expenditures related to El Paso's 7% interest in Four Corners Units 4 and 5 of $27 million in 2016 and $20 million in 2017. We are monitoring the status of other environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

Distribution and transmission capital expenditures are comprised of infrastructure additions and upgrades, capital replacements, and new customer construction. Examples of the types of projects included in the forecast include power lines, substations, and line extensions to new residential and commercial developments.

Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Financing Cash Flows and Liquidity

2015 Compared with 2014. Pinnacle West's consolidated net cash provided by financing activities was $4 million in 2015, compared to $179 million net cash used in 2014, an increase of $183 million in net cash provided. The increase in net cash provided by financing activities is primarily due to $237 million lower repayments of long-term debt and $111 million higher issuances of long-term debt (see below), partially offset by a $142 million net change in short-term borrowings.

2014 Compared with 2013. Pinnacle West's consolidated net cash used for financing activities was $179 million in 2014, compared to $161 million in 2013, an increase of $18 million in net cash used. The increase in net cash used for financing activities is primarily due to $530 million in higher repayments of long-term debt, a $67 million net reduction in funds received through short-term borrowings, and $11 million in higher dividend payments, partially offset by $595 million in higher issuances of long-term debt (see below).

Significant Financing Activities. On December 16, 2015, the Pinnacle West Board of Directors declared a quarterly dividend of $0.625 per share of common stock, payable on March 1, 2016, to shareholders of record on February 1, 2015. During 2015, Pinnacle West increased its indicated annual dividend from $2.38 per share to $2.50 per share. For the year ended December 31, 2015, Pinnacle West's total dividends paid per share of common stock were $2.41 per share, which resulted in dividend payments of $260 million.

On January 12, 2015, APS issued $250 million of 2.20% unsecured senior notes that mature on January 15, 2020. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On May 19, 2015, APS issued $300 million of 3.15% unsecured senior notes that mature on May 15, 2025. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper borrowings and drawings under our revolving credit facilities, incurred in connection with the payment at maturity of our $300 million aggregate principal amount of 4.65% notes due May 15, 2015.

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On June 26, 2015, APS entered into a $50 million term loan facility that matures June 26, 2018. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On November 6, 2015, APS issued $250 million of 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance via redemption and cancellation at par our indebtedness related to the principal amounts of the Navajo County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A and 2009 Series C both due June 1, 2034, and repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla

Project), 2009 Series A. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On November 17, 2015, APS canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series B, purchased in connection with the mandatory tender provision on May 30, 2014.

On December 8, 2015, APS redeemed at par and canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series C.

Available Credit Facilities. Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs.

At December 31, 2015, Pinnacle West had a $200 million revolving credit facility that matures in May 2019. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

On September 2, 2015, APS replaced its $500 million revolving credit facility that would have matured in April 2018, with a new $500 million facility that matures in September 2020.

At December 31, 2015, APS had two credit facilities totaling $1 billion, including the $500 million credit facility that matures in September 2020 and a $500 million credit facility that matures in May 2019. APS may increase the amount of each facility up to a maximum of $700 million each, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2015, APS had no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 10 for a discussion of APS's separate outstanding letters of credit.

Other Financing Matters. See Note 3 for information regarding the PSA approved by the ACC.

See Note 16 for information related to the change in our margin and collateral accounts.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2015, the ratio was approximately 47% for Pinnacle West and 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements and term loan facilities contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

See Note 6 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 12, 2016 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	A3	A-	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	A2	A-	A-
Senior unsecured	A2	A-	A
Commercial paper	P-1	A-2	F2
Outlook	Stable	Stable	Stable

Off-Balance Sheet Arrangements

See Note 18 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2015 (dollars in millions):

	2016	2017-2018	2019-2020	Thereafter	Total
Long-term debt payments, including interest: (a)					
APS	$ 542	$ 414	$ 1,011	$ 4,422	$ 6,389
Pinnacle West	2	127	—	—	129
Total long-term debt payments, including interest	544	541	1,011	4,422	6,518
Fuel and purchased power commitments (b)	643	1,174	1,064	7,559	10,440
Renewable energy credits (c)	42	80	80	432	634
Purchase obligations (d)	233	512	37	213	995
Coal reclamation	15	34	39	262	350
Nuclear decommissioning funding requirements	2	4	4	62	72
Noncontrolling interests (e)	23	46	46	226	341
Operating lease payments	9	16	11	61	97
Total contractual commitments	$ 1,511	$ 2,407	$ 2,292	$ 13,237	$ 19,447

(a) The long-term debt matures at various dates through 2045 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2015 (see Note 6).

(b) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation (see Notes 3 and 10). These amounts include commitments incurred assuming an additional 7% in the 2016 Coal Supply Agreement.

(c) Contracts to purchase renewable energy credits in compliance with the RES (see Note 3).

(d) These contractual obligations include commitments for capital expenditures and other obligations.

(e) Payments to the noncontrolling interests relate to the Palo Verde Sale Leaseback (see Note 18).

This table excludes $34 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. Estimated minimum required pension contributions are zero for 2016, 2017 and 2018 (see Note 7).

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"), management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of the uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers. Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $1,364 million of regulatory assets and $1,140 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2015.

Included in the balance of regulatory assets at December 31, 2015 is a regulatory asset of $619 million for pension benefits. This regulatory asset represents the future recovery of these costs through retail rates as these amounts are charged to earnings. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future earnings.

See Notes 1 and 3 for more information.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, the mortality assumptions, and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2015 reported pension liability on the Consolidated Balance Sheets and our 2015 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Pension Liability**	**Impact on Pension Expense**
Discount rate:		
Increase 1%	$ (329)	$ (11)
Decrease 1%	399	16
Expected long-term rate of return on plan assets:		
Increase 1%	—	(13)
Decrease 1%	—	13

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2015 other postretirement benefit obligation and our 2015 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Other Postretirement Benefit Obligation**	**Impact on Other Postretirement Benefit Expense**
Discount rate:		
Increase 1%	$ (84)	$ (3)
Decrease 1%	107	6
Healthcare cost trend rate (b):		
Increase 1%	100	9
Decrease 1%	(80)	(6)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	—	(4)
Decrease 1%	—	4

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.
(b) This assumes a 1% change in the initial and ultimate healthcare cost trend rate.

See Note 7 for further details about our pension and other postretirement benefit plans.

Fair Value Measurements

We account for derivative instruments, investments held in our nuclear decommissioning trust fund, certain cash equivalents, and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We use inputs, or assumptions that market participants would use, to determine fair market value. We utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The significance of a particular input determines how the instrument is classified in a fair value hierarchy. The determination of fair value sometimes requires subjective and complex judgment. Our assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within a fair value hierarchy. Actual results could differ from our estimates of fair value. See Note 1 for a discussion on accounting policies and Note 13 for fair value measurement disclosures.

OTHER ACCOUNTING MATTERS

During the fourth quarter of 2015, we early adopted two new accounting standards related to balance sheet presentation of debt issuance costs, and balance sheet presentation of deferred income taxes. The adoption of these standards did not impact our results of operations or cash flows.

During the first quarter of 2016, we will be adopting new consolidation accounting guidance. We do not expect the adoption of this guidance to have a material impact on our financial statements.

We are currently evaluating the impacts of adopting new revenue recognition guidance and financial instrument recognition and measurement guidance. These two new accounting standards will be effective for us on January 1, 2018.

See Note 2 for additional information related to accounting matters.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by our nuclear decommissioning trust fund and benefit plan assets.

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 13 and Note 19) and benefit plan assets. The nuclear decommissioning trust fund and benefit plan assets also have risks associated with the changing market value of their equity and other non-fixed income investments. Nuclear decommissioning and benefit plan costs are recovered in regulated electricity prices.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2015 and 2014. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2015 and 2014 (dollars in millions):

Pinnacle West – Consolidated

	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2015	Interest Rates	Amount	Interest Rates	Amount
2016	0.01%	$ 44	6.15%	$ 314
2017	1.17%	125	—	—
2018	1.02%	50	1.75%	32
2019	—	—	8.75%	500
2020	—	—	2.20%	250
Years thereafter	0.23%	49	4.64%	2,490
Total		$ 268		$ 3,586
Fair value		$ 268		$ 3,839

2014	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2015	0.40%	$ 147	0.03%	$ 32	4.32%	$ 352
2016	—	—	0.04%	44	6.15%	314
2017	—	—	0.82%	157	—	—
2018	—	—	—	—	1.75%	32
2019	—	—	—	—	8.75%	500
Years thereafter	—	—	0.27%	49	4.90%	1,940
Total		$ 147		$ 282		$ 3,138
Fair value		$ 147		$ 282		$ 3,558

The tables below present contractual balances of APS's long-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2015 and 2014. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2015 and 2014 (dollars in millions):

APS — Consolidated

2015	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2016	0.01%	$ 44	6.15%	$ 314
2017	—	—	—	—
2018	1.02%	50	1.75%	32
2019	—	—	8.75%	500
2020	—	—	2.20%	250
Years thereafter	0.23%	49	4.64%	2,490
Total		$ 143		$ 3,586
Fair value		$ 143		$ 3,839

2014	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2015	0.40%	$ 147	0.03%	$ 32	4.32%	$ 352
2016	—	—	0.04%	44	6.15%	314
2017	—	—	0.03%	32	—	—
2018	—	—	—	—	1.75%	32
2019	—	—	—	—	8.75%	500
Years thereafter	—	—	0.27%	49	4.90%	1,940
Total		$ 147		$ 157		$ 3,138
Fair value		$ 147		$ 157		$ 3,558

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity and natural gas. Our risk management committee, consisting of officers and key management personnel, oversees company-wide energy risk management activities to ensure compliance with our stated energy risk management policies. We manage risks associated with these market fluctuations by utilizing various commodity instruments that may qualify as derivatives, including futures, forwards, options and swaps. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities.

The following table shows the net pretax changes in mark-to-market of our derivative positions in 2015 and 2014 (dollars in millions):

	2015	2014
Mark-to-market of net positions at beginning of year	$ (115)	$ (73)
Increase in regulatory asset	(44)	(64)
Recognized in OCI:		
Change in mark-to-market losses for future deliveries	(1)	—
Mark-to-market losses realized during the period	6	22
Change in valuation techniques	—	—
Mark-to-market of net positions at end of year	$ (154)	$ (115)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2015 by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, "Derivative Accounting" and "Fair Value Measurements", for more discussion of our valuation methods.

Source of Fair Value	2016	2017	2018	2019	2020	Total fair value
Observable prices provided by other external sources	$ (65)	$ (40)	$ (16)	$ —	$ —	$ (121)
Prices based on unobservable inputs	(11)	(7)	(7)	(6)	(2)	(33)
Total by maturity	$ (76)	$ (47)	$ (23)	$ (6)	$ (2)	$ (154)

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West's Consolidated Balance Sheets at December 31, 2015 and 2014 (dollars in millions):

	December 31, 2015 Gain (Loss)		December 31, 2014 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) or OCI (a)				
Electricity	$ 2	$ (2)	$ 3	$ (3)
Natural gas	35	(35)	29	(29)
Total	$ 37	$ (37)	$ 32	$ (32)

(a) These contracts are economic hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged. To the extent the amounts are eligible for inclusion in the PSA, the amounts are recorded as either a regulatory asset or liability.

Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 16 for a discussion of our credit valuation adjustment policy.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Market and Credit Risks" in Item 7 above for a discussion of quantitative and qualitative disclosures about market risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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See Note 12 for the selected quarterly financial data (unaudited) required to be presented in this Item.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (PINNACLE WEST CAPITAL CORPORATION)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for Pinnacle West. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's consolidated financial statements.

February 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become

inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 19, 2016

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(dollars and shares in thousands, except per share amounts)

	Year Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$ 3,495,443	$ 3,491,632	$ 3,454,628
OPERATING EXPENSES			
Fuel and purchased power	1,101,298	1,179,829	1,095,709
Operations and maintenance	868,377	908,025	924,727
Depreciation and amortization	494,422	417,358	415,708
Taxes other than income taxes	171,812	172,295	164,167
Other expenses	4,932	2,883	7,994
Total	2,640,841	2,680,390	2,608,305
OPERATING INCOME	854,602	811,242	846,323
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	35,215	30,790	25,581
Other income (Note 17)	621	9,608	1,704
Other expense (Note 17)	(17,823)	(21,746)	(16,024)
Total	18,013	18,652	11,261
INTEREST EXPENSE			
Interest charges	194,964	200,950	201,888
Allowance for borrowed funds used during construction (Note 1)	(16,259)	(15,457)	(14,861)
Total	178,705	185,493	187,027
INCOME BEFORE INCOME TAXES	693,910	644,401	670,557
INCOME TAXES (Note 4)	237,720	220,705	230,591
NET INCOME	456,190	423,696	439,966
Less: Net income attributable to noncontrolling interests (Note 18)	18,933	26,101	33,892
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 437,257	$ 397,595	$ 406,074
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	111,026	110,626	109,984
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	111,552	111,178	110,806
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$ 3.94	$ 3.59	$ 3.69
Net income attributable to common shareholders — diluted	$ 3.92	$ 3.58	$ 3.66

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
NET INCOME	$ 456,190	$ 423,696	$ 439,966
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $(342), $(438), and $140 (Note 16)	(957)	(810)	(213)
Reclassification of net realized loss, net of tax benefit of $1,801, $7,932 and $17,472 (Note 16)	4,187	13,483	26,747
Pension and other postretirement benefits activity, net of tax (expense) benefit of $(13,302), $1,307, and $(6,156) (Note 7)	20,163	(2,761)	9,421
Total other comprehensive income	23,393	9,912	35,955
COMPREHENSIVE INCOME	479,583	433,608	475,921
Less: Comprehensive income attributable to noncontrolling interests	18,933	26,101	33,892
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 460,650	$ 407,507	$ 442,029

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 39,488	$ 7,604
Customer and other receivables	274,691	297,740
Accrued unbilled revenues	96,240	100,533
Allowance for doubtful accounts	(3,125)	(3,094)
Materials and supplies (at average cost)	234,234	218,889
Fossil fuel (at average cost)	45,697	37,097
Deferred income taxes (Note 4)	—	122,232
Income tax receivable (Note 4)	589	3,098
Assets from risk management activities (Note 16)	15,905	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	149,555	129,808
Other current assets	37,242	38,817
Total current assets	890,516	973,435
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 16)	12,106	17,620
Nuclear decommissioning trust (Notes 13 and 19)	735,196	713,866
Other assets	52,518	54,047
Total investments and other assets	799,820	785,533
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	16,222,232	15,543,063
Accumulated depreciation and amortization	(5,594,094)	(5,397,751)
Net	10,628,138	10,145,312
Construction work in progress	816,307	682,807
Palo Verde sale leaseback, net of accumulated depreciation of $233,665 and $229,795 (Note 18)	117,385	121,255
Intangible assets, net of accumulated amortization of $546,038 and $489,538	123,975	119,755
Nuclear fuel, net of accumulated amortization of $146,228 and $143,554	123,139	125,201
Total property, plant and equipment	11,808,944	11,194,330
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	1,214,146	1,054,087
Assets for other postretirement benefits (Note 7)	185,997	152,290
Other	128,835	129,215
Total deferred debits	1,528,978	1,335,592
TOTAL ASSETS	$ 15,028,258	$ 14,288,890

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 297,480	$ 295,211
Accrued taxes (Note 4)	138,600	140,613
Accrued interest	56,305	52,603
Common dividends payable	69,363	65,790
Short-term borrowings (Note 5)	—	147,400
Current maturities of long-term debt (Note 6)	357,580	383,570
Customer deposits	73,073	72,307
Liabilities from risk management activities (Note 16)	77,716	59,676
Liabilities for asset retirements (Note 11)	28,573	32,462
Deferred fuel and purchased power regulatory liability (Note 3)	9,688	—
Other regulatory liabilities (Note 3)	136,078	130,549
Other current liabilities	197,861	178,962
Total current liabilities	1,442,317	1,559,143
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	3,462,391	3,006,573
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,723,425	2,582,636
Regulatory liabilities (Notes 1, 3, 4 and 7)	994,152	1,051,196
Liabilities for asset retirements (Note 11)	415,003	358,288
Liabilities for pension benefits (Note 7)	480,998	453,736
Liabilities from risk management activities (Note 16)	89,973	50,602
Customer advances	115,609	123,052
Coal mine reclamation	201,984	198,292
Deferred investment tax credit	187,080	178,607
Unrecognized tax benefits (Note 4)	9,524	19,377
Other	186,345	188,286
Total deferred credits and other	5,404,093	5,204,072
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 111,095,402 and 110,649,762 issued at respective dates	2,541,668	2,512,970
Treasury stock at cost; 115,030 shares at end of 2015 and 78,400 shares at end of 2014	(5,806)	(3,401)
Total common stock	2,535,862	2,509,569
Retained earnings	2,092,803	1,926,065
Accumulated other comprehensive loss:		
Pension and other postretirement benefits (Note 7)	(37,593)	(57,756)
Derivative instruments (Note 16)	(7,155)	(10,385)
Total accumulated other comprehensive loss	(44,748)	(68,141)
Total shareholders' equity	4,583,917	4,367,493
Noncontrolling interests (Note 18)	135,540	151,609
Total equity	4,719,457	4,519,102
TOTAL LIABILITIES AND EQUITY	$ 15,028,258	$ 14,288,890

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 456,190	$ 423,696	$ 439,966
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	571,664	496,487	492,322
Deferred fuel and purchased power	14,997	(26,927)	21,678
Deferred fuel and purchased power amortization	1,617	40,757	31,190
Allowance for equity funds used during construction	(35,215)	(30,790)	(25,581)
Deferred income taxes	236,819	159,023	249,296
Deferred investment tax credit	8,473	26,246	52,542
Change in derivative instruments fair value	(381)	339	534
Changes in current assets and liabilities:			
Customer and other receivables	(22,219)	(52,672)	(44,991)
Accrued unbilled revenues	4,293	(3,737)	(1,951)
Materials, supplies and fossil fuel	(23,945)	3,724	(11,878)
Income tax receivable	2,509	132,419	(133,094)
Other current assets	3,145	4,384	(17,913)
Accounts payable	(34,266)	(353)	45,414
Accrued taxes	(2,013)	9,615	6,059
Other current liabilities	603	17,892	(7,513)
Change in margin and collateral accounts — assets	(324)	(343)	993
Change in margin and collateral accounts — liabilities	22,776	(24,975)	12,355
Change in long-term income tax receivable	—	—	137,270
Change in unrecognized tax benefits	(10,328)	2,778	(91,425)
Change in long-term regulatory liabilities	(20,535)	59,618	64,473
Change in other long-term assets	2,426	(56,561)	(42,389)
Change in other long-term liabilities	(81,959)	(80,993)	(24,050)
Net cash flow provided by operating activities	1,094,327	1,099,627	1,153,307
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,076,087)	(910,634)	(1,016,322)
Contributions in aid of construction	46,546	20,325	41,090
Allowance for borrowed funds used during construction	(16,259)	(15,457)	(14,861)
Proceeds from nuclear decommissioning trust sales	478,813	356,195	446,025
Investment in nuclear decommissioning trust	(496,062)	(373,444)	(463,274)
Other	(3,184)	347	(2,059)
Net cash flow used for investing activities	(1,066,233)	(922,668)	(1,009,401)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	842,415	731,126	136,307
Repayment of long-term debt	(415,570)	(652,578)	(122,828)
Short-term borrowings and payments — net	(147,400)	(5,725)	60,950
Dividends paid on common stock	(260,027)	(246,671)	(235,244)
Common stock equity issuance - net of purchases	19,373	15,288	17,319
Distributions to noncontrolling interests	(35,002)	(20,482)	(17,385)
Other	1	161	299
Net cash flow provided by (used for) financing activities	3,790	(178,881)	(160,582)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	31,884	(1,922)	(16,676)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	7,604	9,526	26,202
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 39,488	$ 7,604	$ 9,526

The accompanying notes are an integral part of the financial statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands, except per share amounts)

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2012	109,837,957	$2,466,923	(95,192)	$ (4,211)	$ 1,624,102	$ (114,008)	$ 129,483	$ 4,102,289
Net income		—		—	406,074	—	33,892	439,966
Other comprehensive income		—		—	—	35,955	—	35,955
Dividends on common stock ($2.23 per share)		—		—	(244,903)	—	—	(244,903)
Issuance of common stock	442,746	24,635		—	—	—	—	24,635
Purchase of treasury stock (a)		—	(174,290)	(9,727)	—	—	—	(9,727)
Reissuance of treasury stock for stock-based compensation and other		—	170,538	9,630	—	—	—	9,630
Net capital activities by noncontrolling interests		—		—	—	—	(17,385)	(17,385)
Balance, December 31, 2013	110,280,703	2,491,558	(98,944)	(4,308)	1,785,273	(78,053)	145,990	4,340,460
Net income		—		—	397,595	—	26,101	423,696
Other comprehensive income		—		—	—	9,912	—	9,912
Dividends on common stock ($2.33 per share)		—		—	(256,803)	—	—	(256,803)
Issuance of common stock	369,059	21,412		—	—	—	—	21,412
Purchase of treasury stock (a)		—	(139,746)	(7,893)	—	—	—	(7,893)
Reissuance of treasury stock for stock-based compensation and other		—	160,290	8,800	—	—	—	8,800
Net capital activities by noncontrolling interests		—		—	—	—	(20,482)	(20,482)
Balance, December 31, 2014	110,649,762	2,512,970	(78,400)	(3,401)	1,926,065	(68,141)	151,609	4,519,102
Net income		—		—	437,257	—	18,933	456,190
Other comprehensive income		—		—	—	23,393	—	23,393
Dividends on common stock ($2.44 per share)		—		—	(270,519)	—	—	(270,519)
Issuance of common stock	445,640	28,698		—	—	—	—	28,698
Purchase of treasury stock (a)		—	(154,751)	(10,136)	—	—	—	(10,136)
Reissuance of treasury stock for stock-based compensation and other		—	118,121	7,731	—	—	—	7,731
Net capital activities by noncontrolling interests		—		—	—	—	(35,002)	(35,002)
Balance, December 31, 2015	111,095,402	$2,541,668	(115,030)	$ (5,806)	$ 2,092,803	$ (44,748)	$ 135,540	$ 4,719,457

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.

The accompanying notes are an integral part of the financial statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (ARIZONA PUBLIC SERVICE COMPANY)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for APS. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework (2013),* our management concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's financial statements.

February 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Arizona Public Service Company
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiary (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become

inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Arizona Public Service Company and subsidiary as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 19, 2016

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
ELECTRIC OPERATING REVENUES	$ 3,492,357	$ 3,488,946	$ 3,451,251
OPERATING EXPENSES			
Fuel and purchased power	1,101,298	1,179,829	1,095,709
Operations and maintenance	853,135	882,442	897,824
Depreciation and amortization	494,298	417,264	415,612
Income taxes (Note 4)	260,143	245,036	256,864
Taxes other than income taxes	171,499	171,583	163,377
Total	2,880,373	2,896,154	2,829,386
OPERATING INCOME	611,984	592,792	621,865
OTHER INCOME (DEDUCTIONS)			
Income taxes (Note 4)	14,302	7,676	11,769
Allowance for equity funds used during construction (Note 1)	35,215	30,790	25,581
Other income (Note 17)	2,834	11,295	3,896
Other expense (Note 17)	(19,019)	(13,403)	(20,449)
Total	33,332	36,358	20,797
INTEREST EXPENSE			
Interest on long-term debt	180,123	186,323	188,011
Interest on short-term borrowings	7,376	6,796	6,605
Debt discount, premium and expense	4,793	4,168	4,046
Allowance for borrowed funds used during construction (Note 1)	(16,183)	(15,457)	(14,861)
Total	176,109	181,830	183,801
NET INCOME	469,207	447,320	458,861
Less: Net income attributable to noncontrolling interests (Note 18)	18,933	26,101	33,892
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 450,274	$ 421,219	$ 424,969

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
NET INCOME	$ 469,207	$ 447,320	$ 458,861
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $(342), $(438), and $140 (Note 16)	(957)	(809)	(214)
Reclassification of net realized loss, net of tax benefit of $1,801, $7,932, and $17,472 (Note 16)	4,187	13,483	26,747
Pension and other postretirement benefits activity, net of tax (expense) benefit of $(11,776), $4,655, and $(6,003) (Note 7)	18,006	(7,635)	9,190
Total other comprehensive income	21,236	5,039	35,723
COMPREHENSIVE INCOME	490,443	452,359	494,584
Less: Comprehensive income attributable to noncontrolling interests	18,933	26,101	33,892
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 471,510	$ 426,258	$ 460,692

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	December 31, 2014
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	$ 16,218,724	$ 15,539,811
Accumulated depreciation and amortization	(5,590,937)	(5,394,650)
Net	10,627,787	10,145,161
Construction work in progress	812,845	682,807
Palo Verde sale leaseback, net of accumulated depreciation of $233,665 and $229,795 (Note 18)	117,385	121,255
Intangible assets, net of accumulated amortization of $546,038 and $489,538	123,820	119,600
Nuclear fuel, net of accumulated amortization of $146,228 and $143,554	123,139	125,201
Total property, plant and equipment	11,804,976	11,194,024
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 13 and 19)	735,196	713,866
Assets from risk management activities (Note 16)	12,106	17,620
Other assets	34,455	33,362
Total investments and other assets	781,757	764,848
CURRENT ASSETS		
Cash and cash equivalents	22,056	4,515
Customer and other receivables	274,428	297,712
Accrued unbilled revenues	96,240	100,533
Allowance for doubtful accounts	(3,125)	(3,094)
Materials and supplies (at average cost)	234,234	218,889
Fossil fuel (at average cost)	45,697	37,097
Assets from risk management activities (Note 16)	15,905	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	149,555	129,808
Deferred income taxes (Note 4)	—	55,253
Other current assets	35,765	38,693
Total current assets	870,755	900,117
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, and 4)	1,214,146	1,054,087
Assets for other postretirement benefits (Note 7)	182,625	149,260
Other	127,923	128,026
Total deferred debits	1,524,694	1,331,373
TOTAL ASSETS	$ 14,982,182	$ 14,190,362

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,379,696	2,379,696
Retained earnings	2,148,493	1,968,718
Accumulated other comprehensive (loss):		
Pension and other postretirement benefits (Note 7)	(19,942)	(37,948)
Derivative instruments (Note 16)	(7,155)	(10,385)
Total shareholder equity	4,679,254	4,478,243
Noncontrolling interests (Note 18)	135,540	151,609
Total equity	4,814,794	4,629,852
Long-term debt less current maturities (Note 6)	3,337,391	2,881,573
Total capitalization	8,152,185	7,511,425
CURRENT LIABILITIES		
Short-term borrowings (Note 5)	—	147,400
Current maturities of long-term debt (Note 6)	357,580	383,570
Accounts payable	291,574	289,930
Accrued taxes (Note 4)	144,488	131,110
Accrued interest	56,003	52,358
Common dividends payable	69,400	65,800
Customer deposits	73,073	72,307
Liabilities from risk management activities (Note 16)	77,716	59,676
Liabilities for asset retirements (Note 11)	28,573	32,462
Deferred fuel and purchased power regulatory liability (Note 3)	9,688	—
Other regulatory liabilities (Note 3)	136,078	130,549
Other current liabilities	180,535	167,302
Total current liabilities	1,424,708	1,532,464
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,764,489	2,571,365
Regulatory liabilities (Notes 1, 3, and 4)	994,152	1,051,196
Liabilities for asset retirements (Note 11)	415,003	358,288
Liabilities for pension benefits (Note 7)	459,065	424,508
Liabilities from risk management activities (Note 16)	89,973	50,602
Customer advances	115,609	123,052
Coal mine reclamation	201,984	198,292
Deferred investment tax credit	187,080	178,607
Unrecognized tax benefits (Note 4)	35,251	45,740
Other	142,683	144,823
Total deferred credits and other	5,405,289	5,146,473
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$ 14,982,182	$ 14,190,362

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 469,207	$ 447,320	$ 458,861
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	571,540	496,393	492,226
Deferred fuel and purchased power	14,997	(26,927)	21,678
Deferred fuel and purchased power amortization	1,617	40,757	31,190
Allowance for equity funds used during construction	(35,215)	(30,790)	(25,581)
Deferred income taxes	223,069	155,401	278,101
Deferred investment tax credit	8,473	26,246	52,542
Change in derivative instruments fair value	(381)	339	534
Changes in current assets and liabilities:			
Customer and other receivables	(21,040)	(52,466)	(46,552)
Accrued unbilled revenues	4,293	(3,737)	(1,951)
Materials, supplies and fossil fuel	(23,945)	3,724	(11,878)
Income tax receivable	—	135,179	(134,590)
Other current assets	4,498	3,766	(17,112)
Accounts payable	(34,891)	(2,355)	47,870
Accrued taxes	13,378	8,650	5,760
Other current liabilities	(3,718)	33,970	(9,005)
Change in margin and collateral accounts — assets	(324)	(343)	993
Change in margin and collateral accounts — liabilities	22,776	(24,975)	12,355
Change in long-term regulatory liabilities	(20,535)	59,618	64,473
Change in long-term income tax receivable	—	—	137,665
Change in unrecognized tax benefits	(10,328)	2,778	(91,244)
Change in other long-term assets	(813)	(62,739)	(46,675)
Change in other long-term liabilities	(82,628)	(85,642)	(24,969)
Net cash flow provided by operating activities	1,100,030	1,124,167	1,194,691
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,072,053)	(910,084)	(1,016,322)
Contributions in aid of construction	46,546	20,325	41,090
Allowance for borrowed funds used during construction	(16,183)	(15,457)	(14,861)
Proceeds from nuclear decommissioning trust sales	478,813	356,195	446,025
Investment in nuclear decommissioning trust	(496,062)	(373,444)	(463,274)
Other	(1,093)	347	(2,067)
Net cash flow used for investing activities	(1,060,032)	(922,118)	(1,009,409)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	842,415	606,126	136,307
Repayment of long-term debt	(415,570)	(527,578)	(122,828)
Short-term borrowings and payments — net	(147,400)	(5,725)	60,950
Dividends paid on common stock	(266,900)	(253,600)	(242,100)
Noncontrolling interests	(35,002)	(20,482)	(17,385)
Net cash flow used for financing activities	(22,457)	(201,259)	(185,056)
NET INCREASE IN CASH AND CASH EQUIVALENTS	17,541	790	226
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	4,515	3,725	3,499
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 22,056	$ 4,515	$ 3,725
Supplemental disclosure of cash flow information:			
Cash paid (received) during the year for:			
Income taxes, net of refunds	$ 14,831	$ (86,054)	$ 7,524
Interest, net of amounts capitalized	167,670	173,436	180,757
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 83,798	$ 44,712	$ 33,184
Dividends declared but not paid	69,400	65,800	62,500
Liabilities assumed related to acquisition of SCE's Four Corners' interest	—	—	145,609

The accompanying notes are an integral part of the financial statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2012	71,264,947	$ 178,162	$2,379,696	$1,624,237	$ (89,095)	$ 129,483	$ 4,222,483
Net income		—	—	424,969	—	33,892	458,861
Other comprehensive income		—	—	—	35,723	—	35,723
Dividends on common stock		—	—	(244,800)	—	—	(244,800)
Other		—	—	(8)	—	—	(8)
Net capital activities by noncontrolling interests		—	—	—	—	(17,385)	(17,385)
Balance, December 31, 2013	71,264,947	178,162	2,379,696	1,804,398	(53,372)	145,990	4,454,874
Net income		—	—	421,219	—	26,101	447,320
Other comprehensive income		—	—	—	5,039	—	5,039
Dividends on common stock		—	—	(256,900)	—	—	(256,900)
Other		—	—	1	—	—	1
Net capital activities by noncontrolling interests		—	—	—	—	(20,482)	(20,482)
Balance, December 31, 2014	71,264,947	178,162	2,379,696	1,968,718	(48,333)	151,609	4,629,852
Net income		—	—	450,274	—	18,933	469,207
Other comprehensive income		—	—	—	21,236	—	21,236
Dividends on common stock		—	—	(270,500)	—	—	(270,500)
Other		—	—	1	—	—	1
Net capital activities by noncontrolling interests		—	—	—	—	(35,002)	(35,002)
Balance, December 31, 2015	71,264,947	$ 178,162	$2,379,696	$2,148,493	$ (27,097)	$ 135,540	$ 4,814,794

The accompanying notes are an integral part of the financial statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Description of Business and Basis of Presentation

Pinnacle West is a holding company that conducts business through its subsidiaries, APS, El Dorado, and BCE. APS, our wholly-owned subsidiary, is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS accounts for essentially all of our revenues and earnings, and is expected to continue to do so. El Dorado is an investment firm. BCE is a subsidiary that was formed in 2014 that focuses on growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE is currently pursuing transmission opportunities through a joint venture arrangement.

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, El Dorado and BCE. APS's consolidated financial statements include the accounts of APS and certain VIEs relating to the Palo Verde sale leaseback. Intercompany accounts and transactions between the consolidated companies have been eliminated.

We consolidate VIEs for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. In performing our primary beneficiary analysis, we consider all relevant facts and circumstances, including the design and activities of the VIE, the terms of the contracts the VIE has entered into, and which parties participated significantly in the design or redesign of the entity. We continually evaluate our primary beneficiary conclusions to determine if changes have occurred which would impact our primary beneficiary assessments. We have determined that APS is the primary beneficiary of certain VIE lessor trusts relating to the Palo Verde sale leaseback, and therefore APS consolidates these entities (see Note 18).

Our consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments, except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations and cash flows for the periods presented.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the ACC and FERC. The accompanying financial statements reflect the rate-making policies of these commissions. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory environment and recent rate orders applicable to APS or other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

See Note 3 for additional information.

Electric Revenues

We derive electric revenues primarily from sales of electricity to our regulated Native Load customers. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated by applying an average revenue/kWh by customer class to the number of estimated kWhs delivered but not billed. Differences historically between the actual and estimated unbilled revenues are immaterial. We exclude sales taxes and franchise fees on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on Pinnacle West's Consolidated Statements of Income. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called a "book-out" and usually occurs for contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and fuel and purchased power costs.

Some of our cost recovery mechanisms are alternative revenue programs. For alternative revenue programs that meet specified accounting criteria, we recognize revenues when the specific events permitting billing of the additional revenues have been completed.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including accrued utility revenues. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment.

Property, Plant and Equipment

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- allowance for funds used during construction.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Pinnacle West's property, plant and equipment included in the December 31, 2015 and 2014 consolidated balance sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	2015	2014
Generation	$ 7,336,902	$ 7,158,729
Transmission	2,494,744	2,247,309
Distribution	5,543,561	5,339,322
General plant	847,025	797,703
Plant in service and held for future use	16,222,232	15,543,063
Accumulated depreciation and amortization	(5,594,094)	(5,397,751)
Net	10,628,138	10,145,312
Construction work in progress	816,307	682,807
Palo Verde sale leaseback, net of accumulated depreciation	117,385	121,255
Intangible assets, net of accumulated amortization	123,975	119,755
Nuclear fuel, net of accumulated amortization	123,139	125,201
Total property, plant and equipment	$ 11,808,944	$ 11,194,330

Property, plant and equipment balances and classes for APS are not materially different than Pinnacle West.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense, and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 11.

APS records a regulatory liability for the difference between the amount that has been recovered in regulated rates and the amount calculated in accordance with guidance on accounting for asset retirement obligations. APS believes it can recover in regulated rates the costs calculated in accordance with this accounting guidance.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2015 were as follows:

- Fossil plant — 19 years;
- Nuclear plant — 28 years;
- Other generation — 25 years;
- Transmission — 39 years;
- Distribution — 33 years; and
- Other — 7 years.

Pursuant to an ACC order, we deferred operating costs in 2013 and 2014 related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. See Note 3 for further discussion. These costs were deferred and are now being amortized on the depreciation line of the Consolidated Statements of Income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $430 million in 2015, $396 million in 2014, and $400 million in 2013. For the years 2013 through 2015, the depreciation rates ranged from a low of 0.30% to a high of 12.37%. The weighted-average depreciation rate was 2.74% in 2015, 2.77% in 2014, and 3.00% in 2013.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and an allowed return on the equity funds used for construction of regulated utility plant. Both the debt and equity components of AFUDC are non-cash amounts within the Consolidated Statements of Income. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 8.02% for 2015, 8.47% for 2014, and 8.56% for 2013. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

Materials and Supplies

APS values materials, supplies and fossil fuel inventory using a weighted-average cost method. APS materials, supplies and fossil fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered.

Fair Value Measurements

We account for derivative instruments, investments held in our nuclear decommissioning trust, certain cash equivalents and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Due to the short-term nature of net accounts receivable, accounts payable, and short-term borrowings, the carrying values of these instruments approximate fair value. Fair value measurements may also be applied on a nonrecurring basis to other assets and liabilities in certain circumstances such as impairments. We also disclose fair value information for our long-term debt, which is carried at amortized cost (see Note 6).

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market which we can access for the asset or liability in an orderly transaction between willing market participants on the measurement date. Inputs to fair value may include observable and unobservable data. We maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

We determine fair market value using observable inputs such as actively-quoted prices for identical instruments when available. When actively quoted prices are not available for the identical instruments, we use other observable inputs, such as prices for similar instruments, other corroborative market information, or prices provided by other external sources. For options, long-term contracts and other contracts for which observable price data are not available, we use models and other valuation methods, which may incorporate unobservable inputs to determine fair market value.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

See Note 13 for additional information about fair value measurements.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial instruments including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power expenses in our Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

We account for our derivative contracts in accordance with derivatives and hedging guidance, which requires all derivatives not qualifying for a scope exception to be measured at fair value on the balance sheet as either assets or liabilities. Transactions with counterparties that have master netting arrangements are reported net on the balance sheet. See Note 16 for additional information about our derivative instruments.

Loss Contingencies and Environmental Liabilities

Pinnacle West and APS are involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses and environmental liabilities are recorded when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, Pinnacle West and APS record a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan for the employees of Pinnacle West and its subsidiaries. We also sponsor an other postretirement benefit plan for the employees of Pinnacle West and its subsidiaries that provides medical and life insurance benefits to retired employees. Pension and other postretirement benefit expense are determined by actuarial valuations, based on assumptions that are evaluated annually. See Note 7 for additional information on pension and other postretirement benefits.

Nuclear Fuel

APS amortizes nuclear fuel by using the unit-of-production method. The unit-of-production method is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel and charged APS $0.001 per kWh of nuclear generation through May 2014, at which point the DOE suspended the fee. In accordance with a settlement agreement with the DOE in August 2014, we will now accrue a receivable for incurred claims and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

an offsetting regulatory liability through the settlement period ending December of 2016. See Note 10 for information on spent nuclear fuel disposal costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by guidance relating to accounting for income taxes. We file our federal income tax return on a consolidated basis, and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each first-tier subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. The income tax accounts reflect the tax and interest associated with management's estimate of the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement for all known and measurable tax exposures (see Note 4).

Cash and Cash Equivalents

We consider all highly liquid investments with a remaining maturity of three months or less at acquisition to be cash equivalents.

The following table summarizes supplemental Pinnacle West cash flow information for each of the last three years (dollars in thousands):

	Year ended December 31,		
	2015	2014	2013
Cash paid (received) during the period for:			
Income taxes, net of refunds	$ 6,550	$ (102,154)	$ 18,537
Interest, net of amounts capitalized	170,209	177,074	184,010
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 83,798	$ 44,712	$ 33,184
Dividends declared but not paid	69,363	65,790	62,528
Liabilities assumed relating to acquisition of SCE Four Corners' interest (see Note 3)	—	—	145,609

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets, primarily APS's software, on Pinnacle West's Consolidated Balance Sheets. The intangible assets are amortized over their finite useful lives. Amortization expense was $58 million in 2015, $53 million in 2014, and $53 million in 2013. Estimated amortization expense on existing intangible assets over the next five years is $48 million in 2016, $36 million in 2017, $18 million in 2018, $9 million in 2019, and $3 million in 2020. At December 31, 2015, the weighted-average remaining amortization period for intangible assets was 5 years.

Investments

El Dorado accounts for its investments using either the equity method (if significant influence) or the cost method (if less than 20% ownership and no significant influence).

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our investments in the nuclear decommissioning trust fund are accounted for in accordance with guidance on accounting for certain investments in debt and equity securities. See Note 13 and Note 19 for more information on these investments.

Business Segments

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electricity service to Native Load customers) and related activities and includes electricity generation, transmission and distribution. All other segment activities are insignificant.

Preferred Stock

At December 31, 2015, Pinnacle West had 10 million shares of serial preferred stock authorized with no par value, none of which was outstanding, and APS had 15,535,000 shares of various types of preferred stock authorized with $25, $50 and $100 par values, none of which was outstanding.

2. New Accounting Standards

In May 2014, new revenue recognition guidance was issued. This guidance provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. The new revenue standard will be effective for us on January 1, 2018. The guidance may be adopted using a full retrospective application or a simplified transition method that allows entities to record a cumulative effect adjustment in retained earnings at the date of initial application. We are currently evaluating this new guidance and the impacts it may have on our financial statements.

In February 2015, new consolidation accounting guidance was issued that amends many aspects of the guidance relating to the analysis and consolidation of variable interest entities. The new guidance is effective for us, and will be adopted, during the first quarter of 2016; and may be adopted using either a full retrospective or modified retrospective approach. We do not expect the adoption of this guidance to have a material impact on our financial statements.

In January 2016, new guidance was issued relating to the recognition and measurement of financial instruments. The amended guidance will require certain investments in equity securities to be measured at fair value with changes in fair value recognized in net income, and modifies the impairment assessment of certain equity securities. The new guidance is effective for us on January 1, 2018. Certain aspects of the guidance may require a cumulative-effect adjustment and other aspects of the guidance are required to be adopted prospectively. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

During the fourth quarter of 2015 we elected to early adopt the following accounting standard updates:

- Balance sheet presentation of deferred income taxes. See Note 4.
- Balance sheet presentation of debt issuance costs: Adopted on a retrospective basis, the new guidance requires debt issuance costs to be presented on the balance sheets as a direct reduction to the related debt liabilities. Prior to the adoption of this guidance we were required to present debt issuance costs as an asset on the balance sheets. As a result of adopting this guidance, our December 31, 2015 Consolidated Balance Sheet includes $28 million of debt issuance costs as a reduction to our long-term

debt. Our December 31, 2014 Consolidated Balance Sheet presents $25 million of debt issuance costs as a reduction to long-term debt; this amount was previously presented as a component of non-current other deferred debits. The adoption of this guidance did not impact our results of operations or cash flows. Debt issuance costs continue to be amortized as interest expense. See Note 6.

3. Regulatory Matters

Retail Rate Case Filings with the Arizona Corporation Commission

Upcoming Rate Case Filing

On January 29, 2016, APS filed a NOI informing the ACC that APS intends to submit a rate case application in June 2016 using an adjusted test year ending December 31, 2015. The NOI provides an overview of the key issues APS expects to address in its formal request such as rate design changes (residential, commercial and industrial), a decoupling mechanism, permission to defer for potential future recovery costs associated with the Company's Ocotillo Modernization Project, permission to defer for potential future recovery costs associated with environmental standards compliance, inclusion of post-test year plant and modifications to certain adjustor mechanisms, among other items. In its rate application, APS will request that its proposed pricing changes take effect in July 2017. APS is still developing the exact amount of the request.

Prior Rate Case Filing

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. APS requested that the increase become effective July 1, 2012. The request would have increased the average retail customer bill by approximately 6.6%. On January 6, 2012, APS and other parties to the general retail rate case entered into the 2012 Settlement Agreement detailing the terms upon which the parties agreed to settle the rate case. On May 15, 2012, the ACC approved the 2012 Settlement Agreement without material modifications.

Settlement Agreement

The 2012 Settlement Agreement provides for a zero net change in base rates, consisting of: (1) a non-fuel base rate increase of $116.3 million; (2) a fuel-related base rate decrease of $153.1 million (to be implemented by a change in the Base Fuel Rate from $0.03757 to $0.03207 per kWh); and (3) the transfer of cost recovery for certain renewable energy projects from the RES surcharge to base rates in an estimated amount of $36.8 million.

Other key provisions of the 2012 Settlement Agreement include the following:

- An authorized return on common equity of 10.0%;
- A capital structure comprised of 46.1% debt and 53.9% common equity;
- A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;
- Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:

- Deferral of increases in property taxes of 25% in 2012, 50% in 2013 and 75% for 2014 and subsequent years if Arizona property tax rates increase; and
- Deferral of 100% in all years if Arizona property tax rates decrease;

- A procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners (APS made its filing under this provision on December 30, 2013, see "Four Corners" below);
- Implementation of a "Lost Fixed Cost Recovery" rate mechanism to support energy efficiency and distributed renewable generation;
- Modifications to the Environmental Improvement Surcharge to allow for the recovery of carrying costs for capital expenditures associated with government-mandated environmental controls, subject to an existing cents per kWh cap on cost recovery that could produce up to approximately $5 million in revenues annually;
- Modifications to the PSA, including the elimination of the 90/10 sharing provision;
- A limitation on the use of the RES surcharge and the DSMAC to recoup capital expenditures not required under the terms of the 2009 Settlement Agreement;
- Allowing a negative credit that existed in the PSA rate to continue until February 2013, rather than being reset on the anticipated July 1, 2012 rate effective date;
- Modification of the TCA to streamline the process for future transmission-related rate changes; and
- Implementation of various changes to rate schedules, including the adoption of an experimental "buy-through" rate that could allow certain large commercial and industrial customers to select alternative sources of generation to be supplied by APS.

The 2012 Settlement Agreement was approved by the ACC on May 15, 2012, with new rates effective on July 1, 2012. This accomplished a goal set by the parties to the 2009 Settlement Agreement to process subsequent rate cases within twelve months of sufficiency findings from the ACC staff, which generally occurs within 30 days after the filing of a rate case.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget.

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable

energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

In accordance with the ACC's decision on the 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 MW of APS-owned utility scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of utility scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

On July 1, 2014, APS filed its 2015 RES implementation plan and proposed a RES budget of approximately $154 million. On December 31, 2014, the ACC issued a decision approving the 2015 RES implementation plan with minor modifications, including reducing the requested budget to approximately $152 million.

On July 1, 2015, APS filed its 2016 RES implementation plan and proposed a RES budget of approximately $148 million. On January 12, 2016, the ACC approved APS's plan and requested budget.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a DSM Plan for review by and approval of the ACC.

On June 1, 2012, APS filed its 2013 DSM Plan. In 2013, the standards required APS to achieve cumulative energy savings equal to 5% of its 2012 retail energy sales. Later in 2012, APS filed a supplement to its plan that included a proposed budget for 2013 of $87.6 million.

On March 11, 2014, the ACC issued an order approving APS's 2013 DSM Plan. The ACC approved a budget of $68.9 million for each of 2013 and 2014. The ACC also approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also approved that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standard, however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its LFCR mechanism.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. The DSM Plan also proposed a reduction in the DSMAC of approximately 12%.

Electric Energy Efficiency. On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. A formal rulemaking has not been initiated and there has been no additional action on the draft to date.

PSA Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;
- An adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- The PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- The PSA rate includes (a) a "Forward Component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "Historical Component," under which differences between actual fuel and purchased power costs and those recovered through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "Transition Component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and
- The PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Beginning balance	$ 6,926	$ 20,755
Deferred fuel and purchased power costs - current period	(14,997)	26,927
Amounts charged to customers	(1,617)	(40,756)
Ending balance	$ (9,688)	$ 6,926

The PSA rate for the PSA year beginning February 1, 2016 is $0.001678 per kWh, as compared to $0.000887 per kWh for the prior year. This new rate is comprised of a forward component of $0.001975 per kWh and a historical component of $(0.000297) per kWh. On October 15, 2015, APS notified the ACC that it was initiating a PSA transition component of $(0.004936) per kWh for the months of November 2015, December 2015, and January 2016. The PSA transition component is a mid-year adjustment to the PSA rate that may be established when conditions change sufficiently to cause high balances to accrue in the PSA balancing account. The transition component expired on February 1, 2016. Any uncollected (overcollected) deferrals during the PSA year, after accounting for the transition component, will be included in the calculation of the PSA rate for the PSA year beginning February 1, 2017.

Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters. In July 2008, FERC approved an Open Access Transmission Tariff for APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the 2012 Settlement Agreement, however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected. APS reviews the proposed formula rate filing amounts with the ACC staff. Any items or adjustments which are not agreed to by APS and the ACC staff can remain in dispute until settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts.

Effective June 1, 2014, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $5.9 million for the twelve-month period beginning June 1, 2014 in accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2014.

Effective June 1, 2015, APS's annual wholesale transmission rates for all users of its transmission system decreased by approximately $17.6 million for the twelve-month period beginning June 1, 2015 in accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

APS's formula rate protocols have been in effect since 2008. Recent FERC orders suggest that FERC is examining the structure of formula rate protocols and may require companies such as APS to make changes to their protocols in the future.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to distributed generation such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were established in the 2012 Settlement Agreement and amount to approximately 3.1 cents per residential kWh lost and 2.3 cents per non-residential kWh lost. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWh's lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. Distributed generation sales losses are determined from the metered output from the distributed generation units.

APS files for a LFCR adjustment every January. APS filed its 2014 annual LFCR adjustment on January 15, 2014, requesting a LFCR adjustment of $25.3 million, effective March 1, 2014. The ACC approved APS's LFCR adjustment without change on March 11, 2014, which became effective April 1, 2014. APS filed its 2015 annual LFCR adjustment on January 15, 2015, requesting an LFCR adjustment of $38.5 million, which was approved on March 2, 2015, effective for the first billing cycle of March. APS filed its 2016 annual LFCR adjustment on January 15, 2016, requesting an LFCR adjustment of $46.4 million (a $7.9 million annual increase), to be effective for the first billing cycle of March 2016.

Net Metering

On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing has been scheduled to commence in April 2016. APS cannot predict the outcome of this proceeding.

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS has also requested intervention in the upcoming Tucson Electric Power Company rate case. The outcomes of these proceedings will not directly impact our financial position.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB")

In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

Four Corners

On December 30, 2013, APS purchased SCE's 48% ownership interest in each of Units 4 and 5 of Four Corners. The 2012 Settlement Agreement includes a procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of the additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. APS made its filing under this provision on December 30, 2013. On December 23, 2014, the ACC approved rate adjustments resulting in a revenue increase of $57.1 million on an annual basis. This includes the deferral for future recovery of all non-fuel operating costs for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Units 1-3 from the date of closing of the purchase through its inclusion in rates. The 2012 Settlement Agreement also provides for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Units 1-3. The deferral balance related to the acquisition of SCE's interest in Units 4 and 5 and the closure of Units 1-3 was $70 million as of December 31, 2015 and is being amortized in rates over a total of 10 years. On February 23, 2015, the Arizona School Boards Association and the Association of Business Officials filed a notice of appeal in Division 1 of the Arizona Court of Appeals of the ACC decision approving the rate adjustments. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed above, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third-parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cholla

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and plans to seek recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its next retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($122 million as of December 31, 2015), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in thousands):

	Amortization Through	December 31, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Pension	(a)	$ —	$ 619,223	$ —	$ 485,037
Retired power plant costs	2033	9,913	127,518	9,913	136,182
Income taxes - AFUDC equity	2045	5,495	133,712	4,813	118,396
Deferred fuel and purchased power — mark-to-market (Note 16)	2018	71,852	69,697	51,209	46,233
Four Corners cost deferral	2024	6,689	63,582	6,689	70,565
Income taxes — investment tax credit basis adjustment	2045	1,766	48,462	1,716	46,200
Lost fixed cost recovery	2016	45,507	—	37,612	—
Palo Verde VIEs (Note 18)	2046	—	18,143	—	34,440
Deferred compensation	2036	—	34,751	—	34,162
Deferred property taxes	(d)	—	50,453	—	30,283
Loss on reacquired debt	2034	1,515	16,375	1,435	16,410
Tax expense of Medicare subsidy	2024	1,520	12,163	1,528	13,756
Transmission vegetation management	2016	4,543	—	9,086	4,543
Mead-Phoenix transmission line CIAC	2050	332	11,040	332	11,372
Deferred fuel and purchased power (b) (c)	2015	—	—	6,926	—
Coal reclamation	2026	418	6,085	418	6,503
Pension and other postretirement benefits deferral	2015	—	—	4,238	—
Other	Various	5	2,942	819	5
Total regulatory assets (e)		$ 149,555	$ 1,214,146	$ 136,734	$ 1,054,087

(a) This asset represents the future recovery of pension benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future revenues. See Note 7 for further discussion.

(b) See "Cost Recovery Mechanisms" discussion above.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(c) Subject to a carrying charge.
(d) Per the provision of the 2012 Settlement Agreement.
(e) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters."

The detail of regulatory liabilities is as follows (dollars in thousands):

	Amortization Through	December 31, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Asset retirement obligations	2057	$ —	$ 277,554	$ —	$ 295,546
Removal costs	(a)	39,746	240,367	31,033	272,825
Other postretirement benefits	(d)	34,100	179,521	32,317	198,599
Income taxes — deferred investment tax credit	2045	3,604	97,175	3,505	92,727
Income taxes - change in rates	2045	1,113	72,454	371	72,423
Spent nuclear fuel	2047	3,051	67,437	4,396	65,594
Renewable energy standard (b)	2017	43,773	4,365	24,596	22,677
Demand side management (b)	2017	6,079	19,115	31,335	—
Sundance maintenance	2030	—	13,678	—	12,069
Deferred fuel and purchased power (b) (c)	2016	9,688	—	—	—
Deferred gains on utility property	2019	2,062	6,001	2,062	8,001
Four Corners coal reclamation	2031	—	8,920	—	1,200
Other	Various	2,550	7,565	934	9,535
Total regulatory liabilities		$ 145,766	$ 994,152	$ 130,549	$ 1,051,196

(a) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal (see Note 11).
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) See Note 7.

4. Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statement purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using currently enacted income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction, investment tax credit basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to deferred taxes resulting from investment tax credits ("ITC") and the change in income tax rates.

In accordance with regulatory requirements, APS ITCs are deferred and are amortized over the life of the related property with such amortization applied as a credit to reduce current income tax expense in the statement of income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax (see Note 18). As a result, there is no income tax expense associated with the VIEs recorded on the Pinnacle West Consolidated and APS Consolidated Statements of Income.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits, excluding interest and penalties, at the beginning and end of the year that are included in accrued taxes and unrecognized tax benefits (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Total unrecognized tax benefits, January 1	$ 44,775	$ 41,997	$ 133,422	$ 44,775	$ 41,997	$ 133,241
Additions for tax positions of the current year	2,175	4,309	3,516	2,175	4,309	3,516
Additions for tax positions of prior years	—	751	13,158	—	751	13,158
Reductions for tax positions of prior years for:						
Changes in judgment	(10,244)	(2,282)	(108,099)	(10,244)	(2,282)	(107,918)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(2,259)	—	—	(2,259)	—	—
Total unrecognized tax benefits, December 31	$ 34,447	$ 44,775	$ 41,997	$ 34,447	$ 44,775	$ 41,997

During the year ended December 31, 2013, Internal Revenue Service ("IRS") guidance was released which provided clarification regarding an APS tax accounting method change approved by the IRS in the third quarter of 2009. As a result of this guidance, uncertain tax positions decreased $67 million. Additionally, the IRS finalized the examination of tax returns for the years ended December 31, 2008 and 2009, which further reduced uncertain tax positions by approximately $41 million. These reductions in uncertain tax positions, materially offset by an increase in deferred tax liabilities, resulted in a cash refund that was received in the first quarter of 2014.

Included in the balances of unrecognized tax benefits are the following tax positions that, if recognized, would decrease our effective tax rate (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Tax positions, that if recognized, would decrease our effective tax rate	$ 9,523	$ 11,207	$ 9,827	$ 9,523	$ 11,207	$ 9,827

As of the balance sheet date, the tax year ended December 31, 2012 and all subsequent tax years remain subject to examination by the IRS. With a few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 2011.

We reflect interest and penalties, if any, on unrecognized tax benefits in the Pinnacle West Consolidated and APS Consolidated Statements of Income as income tax expense. The amount of interest expense or benefit recognized related to unrecognized tax benefits are as follows (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Unrecognized tax benefit interest expense/ (benefit) recognized	$ (161)	$ 752	$ (3,716)	$ (161)	$ 752	$ (3,716)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Following are the total amount of accrued liabilities for interest recognized related to unrecognized benefits that could reverse and decrease our effective tax rate to the extent matters are settled favorably (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Unrecognized tax benefit interest accrued	$ 804	$ 965	$ 213	$ 804	$ 965	$ 213

Additionally, as of December 31, 2015, we have recognized less than $1 million of interest expense to be paid on the underpayment of income taxes for certain adjustments that we have filed, or will file, with the IRS.

The components of income tax expense are as follows (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2015	2014	2013	2015	2014	2013
Current:						
Federal	$ (12,335)	$ 25,054	$ (81,784)	$ 6,485	$ 40,115	$ (97,531)
State	4,763	10,382	10,537	7,813	15,598	11,983
Total current	(7,572)	35,436	(71,247)	14,298	55,713	(85,548)
Deferred:						
Federal	221,505	167,365	279,973	208,326	165,027	305,389
State	23,787	17,904	21,865	23,217	16,620	25,254
Total deferred	245,292	185,269	301,838	231,543	181,647	330,643
Income tax expense	$ 237,720	$ 220,705	$ 230,591	$ 245,841	$ 237,360	$ 245,095

On the APS Consolidated Statements of Income, federal and state income taxes are allocated between operating income and other income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following chart compares pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2015	2014	2013	2015	2014	2013
Federal income tax expense at 35% statutory rate	$ 242,869	$ 225,540	$ 234,695	$ 250,267	$ 239,638	$ 246,384
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	18,265	18,149	21,387	20,433	21,148	23,970
Credits and favorable adjustments related to prior years resolved in current year	(2,169)	—	(3,356)	(1,892)	—	(3,231)
Medicare Subsidy Part-D	837	830	823	837	830	823
Allowance for equity funds used during construction (see Note 1)	(9,711)	(8,523)	(6,997)	(9,711)	(8,523)	(6,997)
Palo Verde VIE noncontrolling interest (see Note 18)	(6,626)	(9,135)	(11,862)	(6,626)	(9,135)	(11,862)
Investment tax credit amortization	(5,527)	(4,928)	(3,548)	(5,527)	(4,928)	(3,548)
Other	(218)	(1,228)	(551)	(1,940)	(1,670)	(444)
Income tax expense	$ 237,720	$ 220,705	$ 230,591	$ 245,841	$ 237,360	$ 245,095

During the fourth quarter of 2015, we prospectively adopted guidance requiring deferred income tax assets and liabilities to be presented as non-current on the balance sheet and eliminating the requirement to present a current portion. As a result of this guidance all deferred income tax assets and liabilities are presented as net non-current deferred income tax liabilities on the Consolidated Balance Sheet as of December 31, 2015. Prior periods have not been restated.

The following table shows the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2015	2014	2015	2014
Current asset	$ —	$ 122,232	$ —	$ 55,253
Long-term liability	(2,723,425)	(2,582,636)	(2,764,489)	(2,571,365)
Deferred income taxes — net	$ (2,723,425)	$ (2,460,404)	$ (2,764,489)	$ (2,516,112)

On February 17, 2011, Arizona enacted legislation (H.B. 2001) that included a four-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West has revised the tax rate applicable to reversing temporary items in Arizona. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2015, APS has recorded a regulatory liability of $75 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

On April 4, 2013, New Mexico enacted legislation (H.B. 641) that included a five-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West has revised the tax rate applicable to reversing temporary items in New Mexico. In accordance with accounting

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2015, APS has recorded a regulatory liability of $2 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

The components of the net deferred income tax liability were as follows (dollars in thousands):

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2015	2014	2015	2014
DEFERRED TAX ASSETS				
Risk management activities	$ 70,498	$ 57,505	$ 70,498	$ 57,505
Regulatory liabilities:				
Asset retirement obligation and removal costs	216,765	229,772	216,765	229,772
Unamortized investment tax credits	100,779	96,232	100,779	96,232
Other postretirement benefits	83,034	90,496	83,034	90,496
Other	60,707	60,409	60,707	60,409
Pension liabilities	191,028	205,227	181,787	194,541
Renewable energy incentives	60,956	65,169	60,956	65,169
Credit and loss carryforwards	59,557	68,347	—	—
Other	149,033	138,729	176,016	161,379
Total deferred tax assets	992,357	1,011,886	950,542	955,503
DEFERRED TAX LIABILITIES				
Plant-related	(3,116,752)	(2,958,369)	(3,116,752)	(2,958,369)
Risk management activities	(10,626)	(12,171)	(10,626)	(12,171)
Other postretirement assets	(71,737)	(59,170)	(70,986)	(58,495)
Regulatory assets:				
Allowance for equity funds used during construction	(54,110)	(48,286)	(54,110)	(48,286)
Deferred fuel and purchased power	—	(2,498)	—	(2,498)
Deferred fuel and purchased power — mark-to-market	(55,020)	(38,187)	(55,020)	(38,187)
Pension benefits	(240,692)	(191,747)	(240,692)	(191,747)
Retired power plant costs (see Note 3)	(53,420)	(57,255)	(53,420)	(57,255)
Other	(108,441)	(99,123)	(108,441)	(99,123)
Other	(4,984)	(5,484)	(4,984)	(5,484)
Total deferred tax liabilities	(3,715,782)	(3,472,290)	(3,715,031)	(3,471,615)
Deferred income taxes — net	$ (2,723,425)	$ (2,460,404)	$ (2,764,489)	$ (2,516,112)

As of December 31, 2015, the deferred tax assets for credit and loss carryforwards relate primarily to federal general business credits of approximately $82 million, which first begin to expire in 2031, and other federal and state loss carryforwards of $3 million, which first begin to expire in 2019. The credit and loss carryforwards amount above has been reduced by $26 million of unrecognized tax benefits.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Lines of Credit and Short-Term Borrowings

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2015 and 2014 (dollars in thousands):

	December 31, 2015			December 31, 2014		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facility	$ 200,000	$1,000,000	$1,200,000	$ 200,000	$1,000,000	$ 1,200,000
Outstanding Commercial Paper Borrowings	—	—	—	—	(147,400)	(147,400)
Amount of Credit Facility Available	$ 200,000	$1,000,000	$1,200,000	$ 200,000	$ 852,600	$ 1,052,600
Weighted-Average Commitment Fees	0.125%	0.100%		0.175%	0.125%	

Pinnacle West

At December 31, 2015, Pinnacle West had a $200 million revolving credit facility that matures in May 2019. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

APS

On September 2, 2015, APS replaced its $500 million revolving credit facility that would have matured in April 2018, with a new $500 million facility that matures in September 2020.

At December 31, 2015, APS had two credit facilities totaling $1 billion, including the $500 million credit facility that matures in September 2020 and a $500 million credit facility that matures in May 2019. APS may increase the amount of each facility up to a maximum of $700 million each, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2015, APS had no outstanding borrowings or letters of credit under its revolving credit facilities. See "Financial Assurances" in Note 10 for a discussion of APS's other outstanding letters of credit.

Debt Provisions

On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of 7% of APS's capitalization, and $500 million (which is required to be used for costs relating to purchases of natural gas and power). This financing order is set to expire on December 31, 2017. See Note 6 for additional long-term debt provisions.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

6. Long-Term Debt and Liquidity Matters

All of Pinnacle West's and APS's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2015 and 2014 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2015	December 31, 2014
APS				
Pollution control bonds:				
Variable	2029-2038	(b)	$ 92,405	$ 156,405
Fixed	2024-2034	1.75%-5.75%	211,150	249,300
Total pollution control bonds			303,555	405,705
Senior unsecured notes	2016-2045	2.20%-8.75%	3,375,000	2,875,000
Palo Verde sale leaseback lessor notes	2015	8.00%	—	13,420
Term loan	2018	(c)	50,000	—
Unamortized discount			(10,374)	(9,206)
Unamortized premium			4,686	4,866
Unamortized debt issuance cost	(d)		(27,896)	(24,642)
Total APS long-term debt			3,694,971	3,265,143
Less current maturities	(e)		357,580	383,570
Total APS long-term debt less current maturities			3,337,391	2,881,573
Pinnacle West				
Term loan	2017	(f)	125,000	125,000
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 3,462,391	$ 3,006,573

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.

(b) The weighted-average rate for the variable rate pollution control bonds was 0.01%-0.24% at December 31, 2015 and 0.03%-0.27% at December 31, 2014.

(c) The weighted-average interest rate was 1.024% at December 31, 2015.

(d) In the fourth quarter of 2015, we adopted a new accounting standard related to balance sheet presentation of debt issuance costs. See Note 2 for additional details.

(e) Current maturities include $108 million of pollution control bonds expected to be remarketed in 2016 and $250 million in senior unsecured notes that mature in 2016.

(f) The weighted-average interest rate was 1.174% at December 31, 2015 and 1.019% at December 31, 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows principal payments due on Pinnacle West's and APS's total long-term debt (dollars in thousands):

Year	Consolidated Pinnacle West	Consolidated APS
2016	$ 357,580	$ 357,580
2017	125,000	—
2018	82,000	82,000
2019	500,000	500,000
2020	250,000	250,000
Thereafter	2,538,975	2,538,975
Total	$ 3,853,555	$ 3,728,555

Debt Fair Value

Our long-term debt fair value estimates are based on quoted market prices for the same or similar issues, and are classified within Level 2 of the fair value hierarchy. Certain of our debt instruments contain third-party credit enhancements and, in accordance with GAAP, we do not consider the effect of these credit enhancements when determining fair value. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of December 31, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 125,000	$ 125,000	$ 125,000	$ 125,000
APS	3,694,971	3,981,367	3,265,143	3,714,108
Total	$ 3,819,971	$ 4,106,367	$ 3,390,143	$ 3,839,108

Credit Facilities and Debt Issuances

APS

On January 12, 2015, APS issued $250 million of 2.20% unsecured senior notes that mature on January 15, 2020. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On May 19, 2015, APS issued $300 million of 3.15% unsecured senior notes that mature on May 15, 2025. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper borrowings and drawings under our revolving credit facilities, incurred in connection with the payment at maturity of our $300 million aggregate principal amount of 4.65% notes due May 15, 2015.

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On June 26, 2015, APS entered into a $50 million term loan facility that matures June 26, 2018. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On November 6, 2015, APS issued $250 million of 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance via redemption and cancellation at par our indebtedness related to the principal amounts of the Navajo County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A and 2009 Series C both due June 1, 2034, and repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On November 17, 2015, APS canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series B, purchased in connection with the mandatory tender provision on May 30, 2014.

On December 8, 2015, APS redeemed at par and canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series C.

See "Lines of Credit and Short-Term Borrowings" in Note 5 and "Financial Assurances" in Note 10 for discussion of APS's separate outstanding letters of credit.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2015, the ratio was approximately 47% for Pinnacle West and 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2015, APS was in

compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.6 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS's total capitalization remains the same. Since APS was in compliance with this common equity ratio requirement, this restriction does not materially affect Pinnacle West's ability to meet its ongoing capital requirements.

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved an increase in APS's long-term debt authorization from $4.2 billion to $5.1 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs, and authorized APS to enter into derivative financial instruments for the purpose of managing interest rate risk associated with its long- and short-term debt. This financing order is set to expire on December 31, 2017. See Note 5 for additional short-term debt provisions.

7. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan (The Pinnacle West Capital Corporation Retirement Plan) and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. All new employees participate in the account balance plan. Defined benefit plans specify the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. We calculate the benefits based on age, years of service and pay.

Pinnacle West also sponsors an other postretirement benefit plan (Pinnacle West Capital Corporation Group Life and Medical Plan) for the employees of Pinnacle West and its subsidiaries. This plan provides medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plan, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

On September 30, 2014, Pinnacle West announced plan design changes to the other postretirement benefit plan, which required an interim remeasurement of the benefit obligation for the plan. Effective January 1, 2015, those eligible retirees and dependents over age 65 and on Medicare can choose to be enrolled in a Health Reimbursement Arrangement (HRA). The Company will provide a subsidy allowing post-65 retirees to purchase a Medicare supplement plan on a private exchange network. The remeasurement of the benefit obligation included updating the assumptions. The remeasurement reduced net periodic benefit costs in 2014 by $10 million ($5 million of which reduced expense). The remeasurement also resulted in a decrease in Pinnacle West's other postretirement benefit obligation of $316 million, which was offset by the related regulatory asset and accumulated other comprehensive income.

Because of the plan changes, the Company is currently in the process of seeking IRS and regulatory approval to move approximately $100 million of the other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date. See Note 13 for further discussion of how fair values are determined. Due to subjective and complex judgments, which may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and therefore is recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability. In its 2009 retail rate case settlement, APS received approval to defer a portion of pension and other postretirement benefit cost increases incurred in 2011 and 2012. We deferred pension and other postretirement benefit costs of approximately $14 million in 2012 and $11 million in 2011. Pursuant to an ACC regulatory order, we began amortizing the regulatory asset over three years beginning in July 2012. We amortized approximately $5 million in 2015, $8 million in 2014, $8 million in 2013 and $4 million in 2012.

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction, billed to electric plant participants or charged to the regulatory asset or liability) (dollars in thousands):

	Pension			Other Benefits		
	2015	2014	2013	2015	2014	2013
Service cost-benefits earned during the period	$ 59,627	$ 53,080	$ 64,195	$ 16,827	$ 18,139	$ 23,597
Interest cost on benefit obligation	123,983	129,194	112,392	28,102	41,243	41,536
Expected return on plan assets	(179,231)	(158,998)	(146,333)	(36,855)	(46,400)	(45,717)
Amortization of:						
Prior service cost (credit)	594	869	1,097	(37,968)	(9,626)	(179)
Net actuarial loss	31,056	10,963	39,852	4,881	1,175	11,310
Net periodic benefit cost	$ 36,029	$ 35,108	$ 71,203	$ (25,013)	$ 4,531	$ 30,547
Portion of cost charged to expense	$ 20,036	$ 21,985	$ 38,968	$ (10,391)	$ 6,000	$ 18,469

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the plans' changes in the benefit obligations and funded status for the years 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Change in Benefit Obligation				
Benefit obligation at January 1	$ 3,078,648	$ 2,646,530	$ 682,335	$ 890,418
Service cost	59,627	53,080	16,827	18,139
Interest cost	123,983	129,194	28,102	41,243
Benefit payments	(137,115)	(128,550)	(24,988)	(29,054)
Actuarial (gain) loss	(91,340)	378,394	(55,256)	150,188
Plan amendments	—	—	—	(388,599)
Benefit obligation at December 31	3,033,803	3,078,648	647,020	682,335
Change in Plan Assets				
Fair value of plan assets at January 1	2,615,404	2,264,121	834,625	748,339
Actual return on plan assets	(44,690)	292,992	(2,399)	105,223
Employer contributions	100,000	175,000	791	770
Benefit payments	(127,940)	(116,709)	—	(19,707)
Fair value of plan assets at December 31	2,542,774	2,615,404	833,017	834,625
Funded Status at December 31	$ (491,029)	$ (463,244)	$ 185,997	$ 152,290

The following table shows the projected benefit obligation and the accumulated benefit obligation for pension plans with an accumulated obligation in excess of plan assets as of December 31, 2015 and 2014 (dollars in thousands):

	2015	2014
Projected benefit obligation	$ 3,033,803	$ 3,078,648
Accumulated benefit obligation	2,873,467	2,873,741
Fair value of plan assets	2,542,774	2,615,404

The following table shows the amounts recognized on the Consolidated Balance Sheets as of December 31, 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Noncurrent asset	$ —	$ —	$ 185,997	$ 152,290
Current liability	(10,031)	(9,508)	—	—
Noncurrent liability	(480,998)	(453,736)	—	—
Net amount recognized	$ (491,029)	$ (463,244)	$ 185,997	$ 152,290

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the details related to accumulated other comprehensive loss as of December 31, 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Net actuarial loss	$ 679,501	$ 577,976	$ 127,124	$ 148,006
Prior service cost (credit)	609	1,203	(341,301)	(379,269)
APS's portion recorded as a regulatory (asset) liability	(619,223)	(485,037)	213,621	230,916
Income tax expense (benefit)	(23,663)	(36,890)	925	851
Accumulated other comprehensive loss	$ 37,224	$ 57,252	$ 369	$ 504

The following table shows the estimated amounts that will be amortized from accumulated other comprehensive loss and regulatory assets and liabilities into net periodic benefit cost in 2016 (dollars in thousands):

	Pension	Other Benefits
Net actuarial loss	$ 38,923	$ 3,784
Prior service cost (credit)	527	(37,884)
Total amounts estimated to be amortized from accumulated other comprehensive loss (gain) and regulatory assets (liabilities) in 2016	$ 39,450	$ (34,100)

The following table shows the weighted-average assumptions used for both the pension and other benefits to determine benefit obligations and net periodic benefit costs:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,			
	2015	2014	2015	2014		2013
				January - September	October - December	
Discount rate – pension	4.37%	4.02%	4.02%	4.88%	4.88%	4.01%
Discount rate – other benefits	4.52%	4.14%	4.14%	5.10%	4.41%	4.20%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets - pension	N/A	N/A	6.90%	6.90%	6.90%	7.00%
Expected long-term return on plan assets - other benefits	N/A	N/A	4.45%	6.80%	4.25%	7.00%
Initial healthcare cost trend rate (pre-65 participants)	7.00%	7.00%	7.00%	7.50%	7.50%	7.50%
Initial healthcare cost trend rate (post-65 participants)	5.00%	5.00%	5.00%	7.50%	5.00%	7.50%
Ultimate healthcare cost trend rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Number of years to ultimate trend rate (pre-65 participants)	4	4	4	4	4	4
Number of years to ultimate trend rate (post-65 participants)	0	0	0	4	0	4

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. For 2016, we are assuming a 6.90% long-term rate of return for pension assets and 4.74% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In October 2014, the Society of Actuaries' Retirement Plans Experience Committee issued its final reports on its recommended mortality basis ("RP-2014 Mortality Tables Report" and "Mortality Improvement Scale MP-2014 Report"). At December 31, 2014, we updated our mortality assumptions using the recommended basis with modifications to better reflect our plan experience and additional data regarding mortality trends. The updated mortality assumptions resulted in a $67 million increase in Pinnacle West's pension and other postretirement obligations, which was offset by the related regulatory asset, regulatory liability and accumulated other comprehensive income.

In selecting our healthcare trend rates, we consider past performance and forecasts of healthcare costs. A one percentage point change in the assumed initial and ultimate healthcare cost trend rates would have the following effects (dollars in thousands):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 8,834	$ (5,890)
Effect on service and interest cost components of net periodic other postretirement benefit costs	9,069	(6,949)
Effect on the accumulated other postretirement benefit obligation	100,322	(80,332)

Plan Assets

The Board of Directors has delegated oversight of the pension and other postretirement benefit plans' assets to an Investment Management Committee ("Committee"). The Committee has adopted investment policy statements ("IPS") for the pension and the other postretirement benefit plans' assets. The investment strategies for these plans include external management of plan assets, and prohibition of investments in Pinnacle West securities.

The overall strategy of the pension plan's IPS is to achieve an adequate level of trust assets relative to the benefit obligations. To achieve this objective, the plan's investment policy provides for mixes of investments including long-term fixed income assets and return-generating assets. The target allocation between return-generating and long-term fixed income assets is defined in the IPS and is a function of the plan's funded status. The plan's funded status is reviewed on at least a monthly basis.

Long-term fixed income assets, also known as liability-hedging assets, are designed to offset changes in the benefit obligations due to changes in interest rates. Long-term fixed income assets consist primarily of fixed income debt securities issued by the U.S. Treasury, other government agencies, and corporations. Long-term fixed income assets may also include interest rate swaps, U.S. Treasury futures and other instruments.

Return-generating assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-generating assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments include investments in real estate, private equity and various other strategies. The plan may hold investments in return-generating assets by holding securities in partnerships and common and collective trusts.

Based on the IPS, and given the pension plan's funded status at year-end 2015, the long-term fixed income assets had a target allocation of 58% with a permissible range of 55% to 61% and the return-generating assets had a target allocation of 42% with a permissible range of 39% to 45%. The return-generating assets have additional target allocations, as a percent of total plan assets, of 22% equities in U.S. and other developed markets, 6% equities in emerging markets, and 14% in alternative investments. The pension plan IPS does not

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

provide for a specific mix of long-term fixed income assets, but does expect the average credit quality of such assets to be investment grade. As of December 31, 2015, long-term fixed income assets represented 60% of total pension plan assets, and return-generating assets represented 40% of total pension plan assets.

As of December 31, 2015, the asset allocation for other postretirement benefit plan assets is governed by the IPS for those plans, which provides for different asset allocation target mixes depending on the characteristics of the liability. Some of these asset allocation target mixes vary with the plan's funded status. As of December 31, 2015, investment in fixed income assets represented 40% of the other postretirement benefit plan total assets, and non-fixed income assets represented 60% of the other postretirement benefit plan's assets. Fixed income assets are primarily invested in corporate bonds of investment-grade U.S. issuers, and U.S. Treasuries. Non-fixed income assets are primarily invested in large cap U.S. equities in diverse industries, and international equities in both emerging and developed markets.

See Note 13 for a discussion on the fair value hierarchy and how fair value methodologies are applied. The plans invest directly in fixed income and equity securities, in addition to investing indirectly in fixed income securities, equity securities and real estate through the use of mutual funds, partnerships and common and collective trusts. Equity securities held directly by the plans are valued using quoted active market prices from the published exchange on which the equity security trades, and are classified as Level 1. Fixed income securities issued by the U.S. Treasury held directly by the plans are valued using quoted active market prices, and are classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies are primarily valued using quoted inactive market prices, or quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield, maturity and credit quality. These instruments are classified as Level 2.

Mutual funds, partnerships, and common and collective trusts are valued utilizing a net asset value (NAV) concept or its equivalent. Exchange traded mutual funds, are classified as Level 1, as the valuation for these instruments is based on the active market in which the fund trades.

Common and collective trusts, are maintained by banks or investment companies and hold certain investments in accordance with a stated set of objectives (such as tracking the performance of the S&P 500 Index). The trust's shares are offered to a limited group of investors, and are not traded in an active market. The NAV for trusts investing in exchange traded equities is derived from the quoted active market prices of the underlying securities held by the trusts. The NAV for trusts investing in real estate is derived from the appraised values of the trust's underlying real estate assets. As of December 31, 2015, the plans were able to transact in the common and collective trusts at NAV and classifies these investments as Level 2.

Investments in partnerships are also valued using the concept of NAV, which is derived from the value of the partnerships' underlying assets. The plan's partnerships holdings relate to investments in high-yield fixed income instruments and assets of privately held portfolio companies. Certain partnerships also include funding commitments that may require the plan to contribute up to $75 million to these partnerships; as of December 31, 2015, approximately $40 million of these commitments have been funded. Partnerships are classified as Level 2 if the plan is able to transact in the partnership at the NAV, otherwise the partnership is classified as Level 3.

The plans' trustee provides valuation of our plan assets by using pricing services that utilize methodologies described to determine fair market value. We have internal control procedures to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2015, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (b)	Balance at December 31, 2015
Pension Plan:					
Assets:					
Cash and cash equivalents	$ 1,893	$ —	$ —	$ —	$ 1,893
Fixed income securities:					
Corporate	—	1,108,736	—	—	1,108,736
U.S. Treasury	274,778	—	—	—	274,778
Other (a)	—	113,008	—	—	113,008
Equities:					
U.S. companies	233,021	—	—	—	233,021
International companies	14,680	—	—	—	14,680
Common and collective trusts:					
U.S. equities	—	130,097	—	—	130,097
International equities	—	185,892	—	—	185,892
Real estate	—	150,359	—	—	150,359
Partnerships	—	127,840	42,097	—	169,937
Mutual funds - International equities	116,307	—	—	—	116,307
Short-term investments and other	—	29,599	—	14,467	44,066
Total Pension Plan	$ 640,679	$ 1,845,531	$ 42,097	$ 14,467	$ 2,542,774
Other Benefits:					
Assets:					
Cash and cash equivalents	$ 240	$ —	$ —	$ —	$ 240
Fixed income securities:					
Corporate	—	217,026	—	—	217,026
U.S. Treasury	131,435	—	—	—	131,435
Other (a)	—	31,106	—	—	31,106
Equities:					
U.S. companies	253,193	—	—	—	253,193
International companies	12,390	—	—	—	12,390
Common and collective trusts:					
U.S. equities	—	81,516	—	—	81,516
International equities	—	28,539	—	—	28,539
Real estate	—	13,512	—	—	13,512
Mutual funds - International equities	52,568	—	—	—	52,568
Short-term investments and other	5,065	3,331	—	3,096	11,492
Total Other Benefits	$ 454,891	$ 375,030	$ —	$ 3,096	$ 833,017

(a) This category consists primarily of debt securities issued by municipalities.
(b) Represents plan receivables and payables.

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The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2014, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (b)	Balance at December 31, 2014
Pension Plan:					
Assets:					
Cash and cash equivalents	$ 387	$ —	$ —	$ —	$ 387
Fixed Income Securities:					
Corporate	—	1,162,096	—	—	1,162,096
U.S. Treasury	291,817	—	—	—	291,817
Other (a)	—	113,265	—	—	113,265
Equities:					
U.S. Companies	246,387	—	—	—	246,387
International Companies	18,069	—	—	—	18,069
Common and collective trusts:					
U.S. Equities	—	127,336	—	—	127,336
International Equities	—	317,167	—	—	317,167
Real estate	—	129,715	—	—	129,715
Partnerships	—	138,337	27,929	—	166,266
Short-term investments and other	—	26,016	—	16,883	42,899
Total Pension Plan	$ 556,660	$ 2,013,932	$ 27,929	$ 16,883	$ 2,615,404
Other Benefits:					
Assets:					
Cash and cash equivalents	$ 318	$ —	$ —	$ —	$ 318
Fixed Income Securities:					
Corporate	—	187,961	—	—	187,961
U.S. Treasury	130,967	—	—	—	130,967
Other (a)	—	35,291	—	—	35,291
Equities:					
U.S. Companies	265,106	—	—	—	265,106
International Companies	17,813	—	—	—	17,813
Common and collective trusts:					
U.S. Equities	—	88,258	—	—	88,258
International Equities	—	85,746	—	—	85,746
Real Estate	—	11,657	—	—	11,657
Short-term investments and other	—	7,408	—	4,100	11,508
Total Other Benefits	$ 414,204	$ 416,321	$ —	$ 4,100	$ 834,625

(a) This category consists primarily of debt securities issued by municipalities.
(b) Represents plan receivables and payables.

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The following table shows the changes in fair value for assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2015 and 2014 (dollars in thousands):

Partnerships	Pension	
	2015	2014
Beginning balance at January 1	$ 27,929	$ 8,660
Actual return on assets still held at December 31	2,789	927
Purchases	13,187	19,984
Sales	(1,808)	(1,642)
Transfers in and/or out of Level 3	—	—
Ending balance at December 31	$ 42,097	$ 27,929

Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $100 million in 2015, $175 million in 2014, and $141 million in 2013. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2016-2018 period. With regard to contributions to our other postretirement benefit plans, we made a contribution of $1 million in 2015, $1 million in 2014, and $14 million in 2013. We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans. APS funds its share of the contributions. APS's share of the pension plan contribution was $100 million in 2015, $175 million in 2014, and $140 million in 2013. APS's share of the contributions to the other postretirement benefit plan was $1 million in 2015, $1 million in 2014, and $14 million in 2013.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter, are estimated to be as follows (dollars in thousands):

Year	Pension	Other Benefits
2016	$ 152,146	$ 26,468
2017	171,005	28,444
2018	170,534	30,490
2019	180,700	32,438
2020	188,988	33,982
Years 2021-2025	1,023,451	184,335

Electric plant participants contribute to the above amounts in accordance with their respective participation agreements.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and its subsidiaries. In 2015, costs related to APS's employees represented 99% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account, the Company's matching contributions and earnings or losses on their investments. Under this plan, the Company matches a percentage of the participants' contributions in cash which is then invested in the same investment mix as participants elect to invest their own

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

future contributions. Pinnacle West recorded expenses for this plan of approximately $9 million for 2015, $9 million for 2014, and $9 million for 2013.

8. Leases

We lease certain vehicles, land, buildings, equipment and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Consolidated Statements of Income was $17 million in 2015, $18 million in 2014, and $18 million in 2013. APS's lease expense was $14 million in 2015, $15 million in 2014, and $15 million in 2013.

Estimated future minimum lease payments for Pinnacle West's and APS's operating leases, excluding purchased power agreements, are approximately as follows (dollars in thousands):

Year	Pinnacle West Consolidated	APS
2016	$ 9,182	$ 8,797
2017	8,557	8,317
2018	7,045	6,880
2019	6,121	5,961
2020	4,835	4,680
Thereafter	61,251	61,101
Total future lease commitments	$ 96,991	$ 95,736

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 18 for a discussion of VIEs.

9. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. We are responsible for our share of operating costs which are included in the corresponding operating expenses on our consolidated statement of income. We are also responsible for providing our own financing. Our share of operating expenses and utility plant costs related to these facilities is accounted for using proportional consolidation. The following table shows APS's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2015 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1%		$ 1,744,137	$ 1,067,376	$ 22,228
Palo Verde Unit 2 (a)	16.8%		583,633	356,767	4,142
Palo Verde Common	28.0%	(b)	643,201	231,609	64,069
Palo Verde Sale Leaseback		(a)	351,050	233,665	—
Four Corners Generating Station	63.0%		857,555	577,321	77,317
Navajo Generating Station Units 1, 2 and 3	14.0%		274,640	168,132	4,460
Cholla common facilities (c)	63.3%	(b)	158,623	53,777	1,390
Transmission facilities:					
ANPP 500kV System	33.4%	(b)	109,348	36,576	1,594
Navajo Southern System	22.7%	(b)	62,139	19,361	397
Palo Verde — Yuma 500kV System	19.3%	(b)	14,043	5,226	133
Four Corners Switchyards	49.8%	(b)	38,420	9,833	1,687
Phoenix — Mead System	17.1%	(b)	39,089	13,173	151
Palo Verde — Estrella 500kV System	50.0%	(b)	89,832	18,359	1,008
Morgan — Pinnacle Peak System	64.6%	(b)	129,855	11,087	2,592
Round Valley System	50.0%	(b)	703	286	—
Palo Verde — Morgan System	87.7%	(b)	12	—	133,813
Hassayampa - North Gila System	80.0%	(b)	164,854	1,159	—
Cholla 500 Switchyard	85.7%	(b)	547	15	—
Saguaro 500 Switchyard	75.0%	(b)	773	26	—

(a) See Note 18.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.

10. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo

Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of current reported net income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through 2016.

APS's first claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2011 through June 30, 2014, and was for $42.0 million (APS's share of this amount was $12.2 million), was received on June 1, 2015. APS's $12.2 million share was recorded as an adjustment to a regulatory liability and had no impact on the amount of current reported net income. APS's second claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2014 through June 30, 2015, was filed for $12.0 million (APS's share of this amount would be $3.6 million), and has been submitted to, but not yet approved by, the DOE in the fourth quarter of 2015.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to $13.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $375 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of $13.1 billion of liability coverage is provided through a mandatory industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum retrospective premium assessment per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to an annual limit of $19 million per incident, to be periodically adjusted for inflation. Based on APS's ownership interest in the three Palo Verde units, APS's maximum potential retrospective premium assessment per incident for all three units is approximately $111 million, with a maximum annual retrospective premium assessment of approximately $16.6 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of replacement generation or purchased power and business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $23.1 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $61.7 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

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Fuel and Purchased Power Commitments and Purchase Obligations

APS is party to various fuel and purchased power contracts and purchase obligations with terms expiring between 2016 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $876 million in 2016; $949 million in 2017; $737 million in 2018; $603 million in 2019; $498 million in 2020; and $7.8 billion thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various fuel and purchased power contracts mentioned above, some of those contracts for coal supply include take-or-pay provisions. The current coal contracts with take-or-pay provisions have terms expiring through 2031.

The following table summarizes our estimated coal take-or-pay commitments (dollars in thousands):

	Years Ended December 31,					
	2016	2017	2018	2019	2020	Thereafter
Coal take-or-pay commitments (a)	$ 170,714	$ 195,428	$ 189,588	$ 193,818	$ 198,160	$ 2,270,974

(a) Total take-or-pay commitments are approximately $3.2 billion. The total net present value of these commitments is approximately $2.2 billion.

APS may spend more to meet its actual fuel requirements than the minimum purchase obligations in our coal take-or-pay contracts. The following table summarizes actual payments under the coal contracts which include take-or-pay provisions for each of the last three years (dollars in thousands):

	Year Ended December 31,		
	2015	2014	2013
Total payments	$ 211,327	$ 236,773	$ 188,496

Renewable Energy Credits

APS has entered into contracts to purchase renewable energy credits to comply with the RES. APS estimates the contract requirements to be approximately $42 million in 2016; $40 million in 2017; $40 million in 2018; $40 million in 2019; $40 million in 2020; and $432 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for final and contemporaneous coal mine reclamation. We account for contemporaneous reclamation costs as part of the cost of the delivered coal. We utilize site-specific studies of costs expected to be incurred in the future to estimate our final reclamation obligation. These studies utilize various assumptions to estimate the future costs. Based on the most recent reclamation studies, APS recorded an obligation for the coal mine final reclamation of approximately $202 million at December 31, 2015 and $198 million at December 31, 2014. Under our current coal supply agreements, we expect to make payments for the final mine reclamation as follows: $15 million in 2016; $16 million in 2017; $18 million in 2018; $19 million in 2019; $20 million in 2020; and $262 million thereafter. Any amendments to current coal supply agreements may change the timing of the contribution. Portions of

these funds will be held in an escrow account and distributed to certain coal providers under the terms of the applicable coal supply agreements.

Superfund-Related Matters

Superfund establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are PRPs. PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, OU3 in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study work plan. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, RID filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Southwest Power Outage

On September 8, 2011 at approximately 3:30 PM, a 500 kV transmission line running between the Hassayampa and North Gila substations in southwestern Arizona tripped out of service due to a fault that occurred at a switchyard operated by APS. Approximately ten minutes after the transmission line went off-line, generation and transmission resources for the Yuma area were lost, resulting in approximately 69,700 APS customers losing service.

On September 6, 2013, a purported consumer class action complaint was filed in Federal District Court in San Diego, California, naming APS and Pinnacle West as defendants and seeking damages for loss of perishable inventory and sales as a result of interruption of electrical service. APS and Pinnacle West filed a motion to dismiss, which the court granted on December 9, 2013. On January 13, 2014, the plaintiffs appealed the lower court's decision. The appeal is now fully briefed and pending before the United States Court of Appeals for the Ninth Circuit, which heard oral argument on February 9, 2016. A written decision on the case is expected 30-60 days after oral argument. We believe the District Court's decision will be upheld on appeal, but cannot predict the outcome at the appellate court. If the District Court's decision is reversed, the case would be remanded for discovery and trial, and there is insufficient information at this time to reasonably estimate any possible loss or range of loss to APS and Pinnacle West.

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Clean Air Act Citizen Lawsuit

On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners participants alleging violations of the NSR provisions of the Clean Air Act. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the Clean Air Act's NSPS program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

The settlement requires installation of pollution control technology and implementation of other measures to reduce sulfur dioxide and nitrogen oxide emissions from the two Four Corners units, although installation of much of this equipment was already planned in order to comply with EPA's Regional Haze Rule requirements. The settlement also requires the Four Corners co-owners to pay a civil penalty of $1.5 million and spend $6.7 million for certain environmental mitigation projects to benefit the Navajo Nation. APS is responsible for 15 percent of these costs based on its ownership interest in the units at the time of the alleged violations, which does not result in a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, wastewater discharges, solid waste, hazardous waste, and CCRs. These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates, but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing new requirements on Four Corners, Cholla and the Navajo Plant. EPA and ADEQ will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants.

Four Corners. Based on EPA's final standards, APS estimates that its 63% share of the cost of these controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. In December 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The cost of the pollution controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

Navajo Plant. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this review process.

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Cholla. APS believes that EPA's final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015. On October 16, 2015, ADEQ issued the Cholla permit, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. APS is unable to predict when or whether APS's proposal may ultimately be approved by the EPA.

Mercury and Air Toxic Standards ("MATS"). In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in *Michigan vs. EPA* reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

Because the Subtitle D rule is self-implementing, the CCR standards apply directly to the regulated facility, and facilities are directly responsible for ensuring that their operations comply with the rule's

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requirements. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million, and its share of incremental costs for Cholla is approximately $85 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million.

Clean Power Plan. On August 3, 2015, EPA finalized carbon pollution standards for existing, new, modified, and reconstructed EGUs. EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

With respect to existing power plants, EPA's recently finalized "Clean Power Plan" imposes state-specific goals or targets to achieve reductions in CO_2 emission rates from existing EGUs measured from a 2012 baseline. In a significant change from the proposed rule, EPA's final performance standards apply directly to specific units based upon their fuel-type and configuration (i.e., coal- or oil-fired steam plants versus combined cycle natural gas plants). As such, each state's goal is an emissions performance standard that reflects the fuel mix employed by the EGUs in operation in those states. The final rule provides guidelines to states to help develop their plans for meeting the interim (2022-2029) and final (2030 and beyond) emission performance standards, with three distinct compliance periods within that timeframe. States were originally required to submit their plans to EPA by September 2016, with an optional two-year extension provided to states establishing a need for additional time; however, it is expected that this timing will be impacted by the court-imposed stay described below.

ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, is presently working to develop a compliance plan for submittal to EPA. In addition to these on-going state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such delay.

With respect to our Arizona generating units, we are currently evaluating the range of compliance options available to ADEQ, including whether Arizona deploys a rate- or mass-based compliance plan. Based on the fuel-mix and location of our Arizona EGUs, and the significant investments we have made in renewable generation and demand-side energy efficiency, if ADEQ selects a rate-based compliance plan, we believe that we will be able to comply with the Clean Power Plan for our Arizona generating units in a manner that will not have material financial or operational impacts to the Company. On the other hand, if ADEQ selects a mass-based approach to compliance with the Clean Power Plan, our annual cost of compliance could be material. These costs could include costs to acquire mass-based compliance allowances.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As to our facilities on the Navajo Nation, EPA has yet to determine whether or to what extent EGUs on the Navajo Nation will be required to comply with the Clean Power Plan. EPA has proposed to determine that it is necessary or appropriate to impose a federal plan on the Navajo Nation for compliance with the Clean Power Plan. In response, we filed comments with EPA advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. If EPA reaches a determination that is consistent with our preferred approach for the Navajo Nation, we believe the Clean Power Plan will not have material financial or operational impacts on our operations within the Navajo Nation.

Alternatively, if EPA determines that a federal plan is necessary or appropriate for the Navajo Nation, and depending on our need for future operations at our EGUs located there, we may be unable to comply with the federal plan unless we acquire mass-based allowances or emission rate credits within established carbon trading markets, or curtail our operations. Subject to the uncertainties set forth below, and assuming that EPA establishes a federal plan for the Navajo Nation that requires carbon allowances or credits to be surrendered for plan compliance, it is possible we will be required to purchase some quantity of credits or allowances, the cost of which could be material.

Because ADEQ has not issued its plan for Arizona, and because we do not know whether EPA will decide to impose a plan or, if so, what that plan will require, there are a number of uncertainties associated with our potential cost exposure. These uncertainties include: whether judicial review will result in the Clean Power Plan being vacated in whole or in part or, if not, the extent of any resulting compliance deadline delays; whether any plan will be imposed for EGUs on the Navajo Nation; the future existence and liquidity of allowance or credit compliance trading markets; the applicability of existing contractual obligations with current and former owners of our participant-owned coal-fired EGUs; the type of federal or state compliance plan (either rate- or mass-based); whether or not the trading of allowances or credits will be authorized mechanisms for compliance with any final EPA or ADEQ plan; and how units that have been closed will be treated for allowance or credit allocation purposes.

In the event that the incurrence of compliance costs is not economically viable or prudent for our operations in Arizona or on the Navajo Nation, or if we do not have the option of acquiring allowances to account for the emissions from our operations, we may explore other options, including reduced levels of output, as an alternative to purchasing allowances. Given these uncertainties, our analysis of the available compliance options remains on-going, and additional information or considerations may arise that change our expectations.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard, greenhouse gas emissions, and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

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Notice of Intent to Sue Related to Four Corners

On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the DOI's review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

New Mexico Tax Matter

On May 23, 2013, the New Mexico Taxation and Revenue Department ("NMTRD") issued a notice of assessment for coal severance surtax, penalty, and interest totaling approximately $30 million related to coal supplied under the coal supply agreement for Four Corners (the "Assessment"). APS's share of the Assessment is approximately $12 million. For procedural reasons, on behalf of the Four Corners co-owners, including APS, the coal supplier made a partial payment of the Assessment and immediately filed a refund claim with respect to that partial payment in August 2013. The NMTRD denied the refund claim. On December 19, 2013, the coal supplier and APS, on its own behalf and as operating agent for Four Corners, filed a complaint with the New Mexico District Court contesting both the validity of the Assessment and the refund claim denial. On June 30, 2015, the court ruled that the Assessment was not valid and further ruled that APS and the other Four Corners co-owners receive a refund of all of the contested amounts previously paid under the applicable tax statute. The NMTRD filed an appeal of the decision on August 31, 2015. The parties are engaged in settlement discussions and we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support certain debt arrangements, commodity contract collateral obligations, and other transactions. As of December 31, 2015, standby letters of credit totaled $79 million and will expire in 2016. As of December 31, 2015, surety bonds expiring through 2018 totaled $158 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at December 31, 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Asset Retirement Obligations

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets.

The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term and coal ash pond closures. Some of APS's transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such transmission and distribution assets. Additionally, APS has aquifer protection permits for some of its generation sites that require the closure of certain facilities at those sites.

In 2015, a revision to the estimated cash flows for the decommissioning study was completed for the Four Corners coal-fired plant, which resulted in an increase to the ARO in the amount of $24 million. Also in 2015, Four Corners spent $32 million in actual decommissioning costs. In addition, APS recognized an ARO for Cholla as a result of new CCR environmental rules that were published in the Federal Register in the second quarter of 2015. See Note 10 for additional information related to the CCR environmental rules. This resulted in an increase to the ARO in the amount of $39 million, an increase in plant in service of $23 million and a reduction of the regulatory liability of $16 million. Finally, in 2015 there was a revision in estimated cash flows for the Cholla decommissioning, which resulted in a decrease of the ARO in the amount of $3 million.

In 2014, an update to the 2013 decommissioning study was completed for Palo Verde nuclear generation facility to incorporate additional spent fuel related charges resulting in an increase to the ARO in the amount of $20 million. Also in 2014, an updated Four Corners Units 1-3 coal-fired power plant decommissioning study was finalized, which resulted in an increase to the ARO of $24 million. In addition, Four Corners spent $30 million in actual decommissioning costs. Finally, in 2014 APS also recognized an ARO related to a new solar facility on leased property that requires the land to be returned to its original condition upon decommissioning of the plant, which resulted in an increase to the ARO of $6 million.

The following table shows the change in our asset retirement obligations for 2015 and 2014 (dollars in thousands):

	2015	2014
Asset retirement obligations at the beginning of year	$ 390,750	$ 346,729
Changes attributable to:		
Accretion expense	25,163	23,567
Settlements	(32,048)	(29,497)
Estimated cash flow revisions	17,556	43,899
Newly incurred obligation	42,155	6,052
Asset retirement obligations at the end of year	$ 443,576	$ 390,750

As mentioned above, decommissioning activities for Four Corners Units 1-3 began in January 2014. Decommissioning activities for Cholla ash ponds began in January 2015. Thus, $29 million of the total ARO of $444 million at December 31, 2015, is classified as a current liability on the balance sheet. At December 31, 2014, $32 million of the total ARO of $391 million was classified as a current liability on the balance sheet.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 3.

12. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2015 and 2014 is provided in the tables below (dollars in thousands, except per share amounts). Weather conditions cause significant seasonal fluctuations in our revenues; therefore, results for interim periods do not necessarily represent results expected for the year.

	2015 Quarter Ended				2015
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 671,219	$ 890,648	$ 1,199,146	$ 734,430	$ 3,495,443
Operations and maintenance	214,944	210,965	220,449	222,019	868,377
Operating income	67,684	231,973	445,111	109,834	854,602
Income taxes	7,947	67,371	139,555	22,847	237,720
Net income	20,727	127,507	261,978	45,978	456,190
Net income attributable to common shareholders	16,122	122,902	257,116	41,117	437,257
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$ 0.15	$ 1.11	$ 2.32	$ 0.37	$ 3.94
Net income attributable to common shareholders — Diluted	0.14	1.10	2.30	0.37	3.92

	2014 Quarter Ended				2014
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 686,251	$ 906,264	$ 1,172,667	$ 726,450	$ 3,491,632
Operations and maintenance	212,882	211,222	223,418	260,503	908,025
Operating income	75,170	254,113	421,775	60,184	811,242
Income taxes	6,405	74,540	134,753	5,007	220,705
Net income	24,691	141,384	248,086	9,535	423,696
Net income attributable to common shareholders	15,766	132,458	243,961	5,410	397,595
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$ 0.14	$ 1.20	$ 2.20	$ 0.05	$ 3.59
Net income attributable to common shareholders — Diluted	0.14	1.19	2.20	0.05	3.58

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Selected Quarterly Financial Data (Unaudited) - APS

APS's quarterly financial information for 2015 and 2014 is as follows (dollars in thousands):

	2015 Quarter Ended,				2015
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 670,668	$ 889,723	$ 1,198,380	$ 733,586	$ 3,492,357
Operations and maintenance	209,947	208,031	216,011	219,146	853,135
Operating income	61,333	162,704	301,238	86,709	611,984
Net income attributable to common shareholder	19,868	125,362	261,187	43,857	450,274

	2014 Quarter Ended,				2014
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 685,545	$ 905,578	$ 1,172,190	$ 725,633	$ 3,488,946
Operations and maintenance	208,285	208,059	212,430	253,668	882,442
Operating income	69,635	180,394	287,928	54,835	592,792
Net income attributable to common shareholder	19,518	134,916	251,047	15,738	421,219

13. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Unadjusted quoted prices in active markets for identical assets or liabilities that we have the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide information on an ongoing basis. This category includes exchange traded equities, exchange traded derivative instruments, exchange traded mutual funds, cash equivalents, and investments in U.S. Treasury securities.

Level 2 — Utilizes quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active; and model-derived valuations whose inputs are observable (such as yield curves). This category includes non-exchange traded contracts such as forwards, options, swaps and certain investments in fixed income securities. This category also includes certain investments that are valued and redeemable based on NAV, such as common and collective trusts and commingled funds.

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust and plan assets held in our retirement and other benefit plans. See Note 7 for the fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent short-term investments with original maturities of three months or less in exchange traded money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

Option contracts are primarily valued using a Black-Scholes option valuation model, which utilizes both observable and unobservable inputs such as broker quotes, interest rates and price volatilities.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. Our classification of instruments as Level 3 is primarily reflective of the

long-term nature of our energy transactions and the use of option valuation models with significant unobservable inputs.

Our energy risk management committee, consisting of officers and key management personnel, oversees our energy risk management activities to ensure compliance with our stated energy risk management policies. We have a risk control function that is responsible for valuing our derivative commodity instruments in accordance with established policies and procedures. The risk control function reports to the chief financial officer's organization.

Investments Held in our Nuclear Decommissioning Trust

The nuclear decommissioning trust invests in fixed income securities and equity securities. Equity securities are held indirectly through commingled funds. The commingled funds are valued based on the concept of NAV, which is a value primarily derived from the quoted active market prices of the underlying equity securities. We may transact in these commingled funds on a semi-monthly basis at the NAV. We classify these investments as Level 2. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

Cash equivalents reported within Level 1 represent investments held in a short-term investment exchange-traded mutual fund, which invests in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, and commercial paper.

Fixed income securities issued by the U.S. Treasury held directly by the nuclear decommissioning trust are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes. See Note 19 for additional discussion about our nuclear decommissioning trust.

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Fair Value Tables

The following table presents the fair value at December 31, 2015 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other	Balance at December 31, 2015
Assets					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ 22,992	$ 30,364	$ (25,345) (b)	$ 28,011
Nuclear decommissioning trust:					
U.S. commingled equity funds	—	314,957	—	—	314,957
Fixed income securities:					
Cash and cash equivalent funds	12,260	—	—	(335) (c)	11,925
U.S. Treasury	117,245	—	—	—	117,245
Corporate debt	—	96,243	—	—	96,243
Mortgage-backed securities	—	99,065	—	—	99,065
Municipal bonds	—	72,206	—	—	72,206
Other	—	23,555	—	—	23,555
Subtotal nuclear decommissioning trust	129,505	606,026	—	(335)	735,196
Total	$ 129,505	$ 629,018	$ 30,364	$ (25,680)	$ 763,207
Liabilities					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ (144,044)	$ (63,343)	$ 39,698 (b)	$ (167,689)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 16.
(c) Represents nuclear decommissioning trust net pending securities sales and purchases.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2014 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other	Balance at December 31, 2014
Assets					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ 20,769	$ 32,598	$ (21,962) (b)	$ 31,405
Nuclear decommissioning trust:					
U.S. commingled equity funds	—	309,620	—	—	309,620
Fixed income securities:					
U.S. Treasury	118,843	—	—	—	118,843
Cash and cash equivalent funds	—	11,453	—	(7,245) (c)	4,208
Corporate debt	—	109,379	—	—	109,379
Mortgage-backed securities	—	88,465	—	—	88,465
Municipal bonds	—	69,139	—	—	69,139
Other	—	14,212	—	—	14,212
Subtotal nuclear decommissioning trust	118,843	602,268	—	(7,245)	713,866
Total	$ 118,843	$ 623,037	$ 32,598	$ (29,207)	$ 745,271
Liabilities					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ (95,061)	$ (73,984)	$ 58,767 (b)	$ (110,278)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 16.
(c) Represents nuclear decommissioning trust net pending securities sales and purchases.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote and option model inputs. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 3).

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our option contracts classified as Level 3 primarily relate to purchase heat rate options. The significant unobservable inputs at December 31, 2015 for these instruments include electricity prices, and volatilities. The significant unobservable inputs at December 31, 2014 for these instruments include electricity prices, gas prices and volatilities. If electricity prices and electricity price volatilities increase, we would expect the fair value of these options to increase, and if these valuation inputs decrease, we would expect the fair value of these options to decrease. If natural gas prices and natural gas price volatilities increase, we would expect the fair value of these options to decrease, and if these inputs decrease, we would expect the fair value of the options to increase. The commodity prices and volatilities do not always move in corresponding directions. The options' fair values are impacted by the net changes of these various inputs.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at December 31, 2015 and December 31, 2014:

	December 31, 2015 Fair Value (thousands)					
Commodity Contracts	Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Range	Weighted-Average
Electricity:						
Forward Contracts (a)	$ 24,543	$ 54,679	Discounted cash flows	Electricity forward price (per MWh)	$15.92 - $40.73	$ 26.86
Option Contracts (b)	—	5,628	Option model	Electricity forward price (per MWh)	$23.87 - $44.13	$ 33.91
				Electricity price volatilities	40% - 59%	52%
				Natural gas price volatilities	32% - 40%	35%
Natural Gas:						
Forward Contracts (a)	5,821	3,036	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.18 - $3.14	$ 2.61
Total	$ 30,364	$ 63,343				

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Commodity Contracts	December 31, 2014 Fair Value (thousands) Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Range	Weighted-Average
Electricity:						
Forward Contracts (a)	$ 29,471	$ 55,894	Discounted cash flows	Electricity forward price (per MWh)	$19.51 - $56.72	$ 35.27
Option Contracts (b)	—	15,035	Option model	Electricity forward price (per MWh)	$32.14 - $66.09	$ 45.83
				Natural gas forward price (per MMBtu)	$3.18 - $3.29	$ 3.25
				Electricity price volatilities	23% - 63%	41%
				Natural gas price volatilities	23% - 41%	31%
Natural Gas:						
Forward Contracts (a)	3,127	3,055	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.98 - $4.13	$ 3.45
Total	$ 32,598	$ 73,984				

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the years ended December 31, 2015 and 2014 (dollars in thousands):

Commodity Contracts	Year Ended December 31, 2015	2014
Net derivative balance at beginning of period	$ (41,386)	$ (49,165)
Total net gains (losses) realized/unrealized:		
Included in earnings	—	102
Included in OCI	(452)	(239)
Deferred as a regulatory asset or liability	(4,009)	(482)
Settlements	14,809	12,080
Transfers into Level 3 from Level 2	(6,256)	(2,090)
Transfers from Level 3 into Level 2	4,315	(1,592)
Net derivative balance at end of period	$ (32,979)	$ (41,386)
Net unrealized gains included in earnings related to instruments still held at end of period	$ —	$ —

Amounts included in earnings are recorded in either operating revenues or fuel and purchased power depending on the nature of the underlying contract.

Transfers reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

other hierarchy level. Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

Financial Instruments Not Carried at Fair Value

The carrying value of our net accounts receivable, accounts payable and short-term borrowings approximate fair value. Our short-term borrowings are classified within Level 2 of the fair value hierarchy. See Note 6 for our long-term debt fair values.

14. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for continuing operations attributable to common shareholders for the years ended December 31, 2015, 2014 and 2013 (in thousands, except per share amounts):

	2015	2014	2013
Net income attributable to common shareholders	$ 437,257	$ 397,595	$ 406,074
Weighted average common shares outstanding — basic	111,026	110,626	109,984
Net effect of dilutive securities:			
Contingently issuable performance shares and restricted stock units	526	552	822
Weighted average common shares outstanding — diluted	111,552	111,178	110,806
Earnings per average common share attributable to common shareholders — basic	$ 3.94	$ 3.59	$ 3.69
Earnings per average common share attributable to common shareholders — diluted	$ 3.92	$ 3.58	$ 3.66

15. Stock-Based Compensation

Pinnacle West has incentive compensation plans under which stock-based compensation is granted to officers, key-employees, and non-officer members of the Board of Directors. Awards granted under the 2012 Long-Term Incentive Plan ("2012 Plan") may be in the form of stock grants, restricted stock units, stock units, performance shares, restricted stock, dividend equivalents, performance share units, performance cash, incentive and non-qualified stock options, and stock appreciation rights. The 2012 Plan authorizes up to 4.6 million common shares to be available for grant. As of December 31, 2015, 2.8 million common shares were available for issuance under the 2012 Plan. During 2015, 2014, and 2013, the Company has granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. The Company has not granted stock options since 2004 and has no stock options outstanding. Awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"), and no new awards may be granted under the 2007 Plan.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $19 million in 2015, $33 million in 2014, and $25 million in 2013. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $7 million in 2015, $13 million in 2014, and $10 million in 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2015, there were approximately $14 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. These costs are expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $21 million in 2015, $20 million in 2014 and $20 million in 2013.

The following table is a summary of awards granted and the weighted-average fair value for the three years ended 2015, 2014 and 2013.

	Restricted Stock Units, Stock Grants, and Stock Units (a)			Performance Shares (b)		
	2015	2014	2013	2015	2014	2013
Units granted	152,651	179,291	182,240	151,430	166,244	176,332
Weighted-average grant date fair value	$ 64.12	$ 54.89	$ 55.14	$ 64.97	$ 54.86	$ 55.45

(a) Units granted includes awards that will be cash settled of 45,104 in 2015, 49,018 in 2014, and 52,620 in 2013.

(b) Reflects the target payout level.

The following table is a summary of the status of non-vested awards as of December 31, 2015 and changes during the year.

	Restricted Stock Units, Stock Grants, and Stock Units		Performance Shares	
	Shares	Weighted-Average Grant Date Fair Value	Shares (b)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2015	480,933 (a)	$ 51.27	324,230	$ 54.92
Granted	152,651	64.12	151,430	64.97
Change in performance factor	—	—	40,496	54.98
Vested	(198,424)	49.20	(202,480)	54.98
Forfeited	(6,873)	56.78	(7,844)	57.89
Nonvested at December 31, 2015	428,287	56.69	305,832	59.78
Vested Awards Outstanding at December 31, 2015	106,712		202,480	

(a) Includes 127,634 of awards that will be cash settled and 353,299 of awards that will be settled in shares.

(b) Nonvested performance shares are reflected at target payout level. The increase or decrease in the number of shares from the target level to the estimated actual payout level is included in the increase for performance factor amounts in the year the award vests.

Share-based liabilities paid relating to restricted stock unit awards was $10 million, $9 million and $10 million in 2015, 2014 and 2013, respectively. This includes cash used to settle restricted stock units of $3 million, $3 million and $4 million in 2015, 2014 and 2013, respectively. Share-based liabilities paid relating to performance share awards was $16 million, $12 million and $15 million in 2015, 2014 and 2013, respectively.

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Restricted Stock Units, Stock Grants, and Stock Units

Restricted stock units have been granted to officers and key employees. Restricted stock units typically vest and settle in equal annual installments over a 4-year period after the grant date. Vesting is typically dependent upon continuous service during the vesting period; however, awards granted to retirement-eligible employees will vest upon the employee's retirement. Awardees elect to receive payment in either 100% stock, or 50% in cash and 50% in stock. Restricted stock unit awards typically include a dividend equivalent feature. This feature allows each award to accrue dividend rights, equal to the amount of dividends that they would have received had they directly owned stock, equal to the number of vested restricted stock units from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited the employee is not entitled to the dividends on those shares.

In December 2012, a retention award of 50,617 restricted stock units was granted to the Chairman of the Board, President, and Chief Executive Officer of Pinnacle West. This award will vest and will be paid in shares of common stock on December 31, 2016, provided that he remains employed with the Company until the vesting date. The award can be increased up to an additional 33,745 restricted stock units payable in stock if certain performance requirements are met.

Restricted stock unit awards are accounted for as liability awards, with compensation cost initially calculated on the date of grant using the Company's closing stock price, and remeasured at each balance sheet date.

Stock grants are issued to non-officer members of the Board of Directors. They may elect to receive the stock grant, or to defer receipt until a later date and receive stock units in lieu of the stock grant. The members of the Board of Directors who elect to defer may elect to receive payment in either 100% stock, or 50% in cash and 50% in stock. The stock units accrue dividend rights, equal to the amount of dividends the Directors would have received had they directly owned stock equal to the number of vested restricted stock units or stock units from the date of grant to the date of payment plus interest compounded quarterly. The dividends and interest are paid, based on the Director's election, in either stock, or 50% in cash and 50% in stock.

Performance Share Awards

Performance share awards have been granted to officers and key employees. Performance share awards contain two performance element criteria that affect the number of shares received after the end of a three-year performance period if performance criteria conditions are met. The performance share grant criteria is based 50% upon the percentile ranking of Pinnacle West's total shareholder return at the end of the three-year performance period, as compared with the total shareholder return of all relevant companies in a specified utility index and the other 50% is based upon six non-financial separate performance metrics. The exact number of shares issued will vary from 0% to 200% of the target award. Shares received include dividend rights paid in stock equal to the amount of dividends that they would have received had they directly owned stock, equal to the number of vested performance shares from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited or if the performance criteria are not achieved the employee is not entitled to the dividends on those shares.

Performance share awards are accounted for as liability awards, with compensation cost initially calculated on the date of grant using the Company's closing stock price, and remeasured at each balance sheet date. Management evaluates the probability of meeting the performance criteria at each balance sheet date. If

performance criteria are not achieved, no compensation cost is recognized and any previously recognized compensation cost is reversed.

16. Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. While we believe the economic hedges mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power costs in our Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

On June 1, 2012, we elected to discontinue cash flow hedge accounting treatment for the significant majority of our contracts that had previously been designated as cash flow hedges. This discontinuation is due to changes in PSA recovery (see Note 3), which now allows for 100% deferral of the unrealized gains and losses relating to these contracts. For those contracts that were de-designated, all changes in fair value after May 31, 2012 are no longer recorded through OCI, but are deferred through the PSA. The amounts previously recorded in accumulated OCI relating to these instruments will remain in accumulated OCI, and will transfer to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if we determine it is probable that the forecasted transaction will not occur. Cash flow hedge accounting treatment will continue for a limited number of contracts that are not subject to PSA recovery.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheet as an asset or liability and are measured at fair value. See Note 13 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

Hedge effectiveness is the degree to which the derivative instrument contract and the hedged item are correlated and is measured based on the relative changes in fair value of the derivative instrument contract and the hedged item over time. We assess hedge effectiveness both at inception and on a continuing basis. These assessments exclude the time value of certain options. For accounting hedges that are deemed an effective hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of OCI and reclassified into earnings in the same period during which the hedged transaction affects earnings. We recognize in current earnings, subject to the PSA, the gains and losses representing hedge ineffectiveness, and the gains and losses on any hedge components which are excluded from our effectiveness assessment. As cash flow hedge accounting has been discontinued for the significant majority of our contracts, after May 31, 2012, effectiveness testing is no longer being performed for these contracts.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 3). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of December 31, 2015, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Quantity	
Power	2,487	GWh
Gas	182	Billion cubic feet

Gains and Losses from Derivative Instruments

The following table provides information about gains and losses from derivative instruments in designated cash flow accounting hedging relationships during the years ended December 31, 2015, 2014 and 2013 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2015	2014	2013
Loss Recognized in OCI on Derivative Instruments (Effective Portion)	OCI — derivative instruments	$ (615)	$ (372)	$ (353)
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	(5,988)	(21,415)	(44,219)
Gain Recognized in Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Fuel and purchased power (b)	—	—	—

(a) During the years ended December 31, 2015, 2014, and 2013, we had no losses reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.

(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that a net loss of $4 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the years ended December 31, 2015, 2014 and 2013 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2015	2014	2013
Net Gain Recognized in Income	Operating revenues	$ 574	$ 324	$ 289
Net Loss Recognized in Income	Fuel and purchased power (a)	(108,973)	(66,367)	(10,449)
Total		$ (108,399)	$ (66,043)	$ (10,160)

(a) Amounts are before the effect of PSA deferrals.

Derivative Instruments in the Consolidated Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Consolidated Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. Additionally, in the event of a default, our master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The significant majority of our derivative instruments are not currently designated as hedging instruments. The Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014, include gross liabilities of $3 million and $4 million, respectively, of derivative instruments designated as hedging instruments.

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The following tables provide information about the fair value of our risk management activities reported on a gross basis, and the impacts of offsetting as of December 31, 2015 and 2014. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of our Consolidated Balance Sheets.

As of December 31, 2015: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 37,396	$ (22,163)	$ 15,233	$ 672	$ 15,905
Investments and other assets	15,960	(3,854)	12,106	—	12,106
Total assets	53,356	(26,017)	27,339	672	28,011
Current liabilities	(113,560)	40,223	(73,337)	(4,379)	(77,716)
Deferred credits and other	(93,827)	3,854	(89,973)	—	(89,973)
Total liabilities	(207,387)	44,077	(163,310)	(4,379)	(167,689)
Total	$ (154,031)	$ 18,060	$ (135,971)	$ (3,707)	$ (139,678)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $18,060.
(c) Represents cash collateral and cash margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $4,379, and cash margin provided to counterparties of $672.

As of December 31, 2014: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 28,557	$ (15,127)	$ 13,430	$ 355	$ 13,785
Investments and other assets	24,810	(7,190)	17,620	—	17,620
Total assets	53,367	(22,317)	31,050	355	31,405
Current liabilities	(86,055)	33,829	(52,226)	(7,443)	(59,669)
Deferred credits and other	(82,990)	32,388	(50,602)	—	(50,602)
Total liabilities	(169,045)	66,217	(102,828)	(7,443)	(110,271)
Total	$ (115,678)	$ 43,900	$ (71,778)	$ (7,088)	$ (78,866)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $43,900.
(c) Represents cash collateral and margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $7,443, and cash margin provided to counterparties of $355.

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Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management contracts with many counterparties, including one counterparty for which our exposure represents approximately 87% of Pinnacle West's $28 million of risk management assets as of December 31, 2015. This exposure relates to a long-term traditional wholesale contract with a counterparty that has a high credit quality. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

The following table provides information about our derivative instruments that have credit-risk-related contingent features at December 31, 2015 (dollars in thousands):

	December 31, 2015
Aggregate fair value of derivative instruments in a net liability position	$ 207,387
Cash collateral posted	18,060
Additional cash collateral in the event credit-risk related contingent features were fully triggered (a)	112,301

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

We also have energy related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $161 million if our debt credit ratings were to fall below investment grade.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for 2015, 2014 and 2013 (dollars in thousands):

	2015	2014	2013
Other income:			
Interest income	$ 493	$ 1,010	$ 1,629
Debt return on the purchase of Four Corners units 4 & 5	—	8,386	—
Miscellaneous	128	212	75
Total other income	$ 621	$ 9,608	$ 1,704
Other expense:			
Non-operating costs	$ (11,292)	$ (9,657)	$ (8,207)
Investment loss — net	(2,080)	(9,426)	(3,711)
Miscellaneous	(4,451)	(2,663)	(4,106)
Total other expense	$ (17,823)	$ (21,746)	$ (16,024)

Other Income and Other Expense - APS

The following table provides detail of APS's other income and other expense for 2015, 2014 and 2013 (dollars in thousands):

	2015	2014	2013
Other income:			
Interest income	$ 163	$ 689	$ 1,234
Debt return on the purchase of Four Corners units 4 & 5	—	8,386	—
Gain on disposition of property	716	1,197	1,024
Miscellaneous	1,955	1,023	1,638
Total other income	$ 2,834	$ 11,295	$ 3,896
Other expense:			
Non-operating costs (a)	$ (11,648)	$ (10,397)	$ (9,626)
Loss on disposition of property	(2,219)	(615)	(4,992)
Miscellaneous	(5,152)	(2,391)	(5,831)
Total other expense	$ (19,019)	$ (13,403)	$ (20,449)

(a) As defined by FERC, includes non-operating utility income and expense (items excluded from utility rate recovery).

18. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. The original lease was scheduled to end on December 31, 2015; however, the lease agreements include fixed rate renewal options which APS exercised on July 7, 2014. As a result, APS will retain the assets through 2023 under one lease and 2033 under the other two leases. APS will be required to make payments relating to these leases of approximately $23 million annually for the period 2016 through 2023, and about $16 million annually for the period 2024 through

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

The fixed rate renewal periods give APS the ability to utilize the assets for a significant portion of the assets' economic life, and therefore provide APS with the power to direct activities of the VIEs that most significantly impact the VIEs' economic performance. Predominately due to the fixed rate renewal periods, APS has been deemed the primary beneficiary of these VIEs and therefore consolidates the VIEs.

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation and interest expense, resulting in an increase in net income for 2015, 2014 and 2013 of $19 million, $26 million and $34 million, respectively, entirely attributable to the noncontrolling interests. The income attributable to the noncontrolling interests decreased in 2015 and 2014 compared with the prior year because of lower rent income resulting from the lease extensions.

In accordance with the regulatory treatment, higher depreciation expense and a regulatory liability were recorded in consolidation to offset the decrease in the noncontrolling interests' share of net income that resulted from the lease extensions. Accordingly, income attributable to Pinnacle West shareholders was not impacted by the consolidation or the lease extensions. Consolidation of these VIEs also results in changes to our Consolidated Statements of Cash Flows, but does not impact net cash flows.

Our Consolidated Balance Sheets at December 31, 2015 and December 31, 2014 include the following amounts relating to the VIEs (dollars in thousands):

	December 31, 2015	December 31, 2014
Palo Verde sale leaseback property, plant and equipment, net of accumulated depreciation	$ 117,385	$ 121,255
Current maturities of long-term debt	—	13,420
Equity-Noncontrolling interests	135,540	151,609

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. Other than the VIEs' assets reported on our consolidated financial statements, the creditors of the VIEs have no other recourse to the assets of APS or Pinnacle West, except in certain circumstances, such as a default by APS under the lease.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS could be required to make specified payments to the VIEs' noncontrolling equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event were to occur during the lease extension period, APS may be required to pay the noncontrolling equity participants approximately $288 million beginning in 2016, and up to $465 million over the lease extension term.

For regulatory ratemaking purposes, the agreements continue to be treated as operating leases and, as a result, we have recorded a regulatory asset relating to the arrangements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

19. Nuclear Decommissioning Trusts

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. APS classifies investments in decommissioning trust funds as available for sale. As a result, we record the decommissioning trust funds at their fair value on our Consolidated Balance Sheets. See Note 13 for a discussion of how fair value is determined and the classification of the nuclear decommissioning trust investments within the fair value hierarchy. Because of the ability of APS to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, we have deferred realized and unrealized gains and losses (including other-than-temporary impairments on investment securities) in other regulatory liabilities. The following table includes the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trust fund assets at December 31, 2015 and December 31, 2014 (dollars in thousands):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2015			
Equity securities	$ 314,957	$ 157,098	$ (115)
Fixed income securities	420,574	11,955	(2,645)
Net payables (a)	(335)	—	—
Total	$ 735,196	$ 169,053	$ (2,760)

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2014			
Equity securities	$ 309,620	$ 159,274	$ (15)
Fixed income securities	411,491	17,260	(1,073)
Net payables (a)	(7,245)	—	—
Total	$ 713,866	$ 176,534	$ (1,088)

(a) Net payables relate to pending purchases and sales of securities.

The costs of securities sold are determined on the basis of specific identification. The following table sets forth approximate gains and losses and proceeds from the sale of securities by the nuclear decommissioning trust funds (dollars in thousands):

	Year Ended December 31,		
	2015	2014	2013
Realized gains	$ 5,189	$ 4,725	$ 5,459
Realized losses	(6,225)	(4,525)	(6,706)
Proceeds from the sale of securities (a)	478,813	356,195	446,025

(a) Proceeds are reinvested in the trust.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of fixed income securities, summarized by contractual maturities, at December 31, 2015 is as follows (dollars in thousands):

	Fair Value
Less than one year	$ 14,001
1 year – 5 years	117,356
5 years – 10 years	114,769
Greater than 10 years	174,448
Total	$ 420,574

20. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the years ended December 31, 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Balance at beginning of period	$ (68,141)	$ (78,053)
Derivative Instruments		
OCI (loss) before reclassifications	(957)	(810)
Amounts reclassified from accumulated other comprehensive loss (a)	4,187	13,483
Net current period OCI (loss)	3,230	12,673
Pension and Other Postretirement Benefits		
OCI (loss) before reclassifications	16,980	(5,419)
Amounts reclassified from accumulated other comprehensive loss (b)	3,183	2,658
Net current period OCI (loss)	20,163	(2,761)
Balance at end of period	$ (44,748)	$ (68,141)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 16.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 7.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Changes in Accumulated Other Comprehensive Loss - APS

The following table shows the changes in APS's accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the years ended December 31, 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Balance at beginning of period	$ (48,333)	$ (53,372)
Derivative Instruments		
OCI (loss) before reclassifications	(957)	(809)
Amounts reclassified from accumulated other comprehensive loss (a)	4,187	13,483
Net current period OCI (loss)	3,230	12,674
Pension and Other Postretirement Benefits		
OCI (loss) before reclassifications	14,726	(10,415)
Amounts reclassified from accumulated other comprehensive loss (b)	3,280	2,780
Net current period OCI (loss)	18,006	(7,635)
Balance at end of period	$ (27,097)	$ (48,333)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 16.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 7.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
Operating revenues	$ 550	$ 642	$ 799
Operating expenses	12,733	23,507	24,930
Operating loss	(12,183)	(22,865)	(24,131)
Other			
Equity in earnings of subsidiaries	446,508	411,528	420,926
Other expense	(3,302)	(3,276)	(1,999)
Total	443,206	408,252	418,927
Interest expense	2,672	3,663	3,226
Income before income taxes	428,351	381,724	391,570
Income tax benefit	(8,906)	(15,871)	(14,504)
Net income attributable to common shareholders	437,257	397,595	406,074
Other comprehensive income — attributable to common shareholders	23,393	9,912	35,955
Total comprehensive income — attributable to common shareholders	$ 460,650	$ 407,507	$ 442,029

See Combined Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 17,432	$ 3,088
Accounts receivable	93,093	99,958
Current deferred income taxes	—	66,979
Income tax receivable	14,895	7,329
Other current assets	197	124
Total current assets	125,617	177,478
Investments and other assets		
Investments in subsidiaries	4,815,236	4,630,570
Deferred income taxes	41,065	—
Other assets	43,422	43,051
Total investments and other assets	4,899,723	4,673,621
Total Assets	$ 5,025,340	$ 4,851,099
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 5,901	$ 5,250
Accrued taxes	6,904	12,220
Common dividends payable	69,363	65,790
Other current liabilities	33,120	38,992
Total current liabilities	115,288	122,252
Long-term debt less current maturities	125,000	125,000
Deferred credits and other		
Deferred income taxes	—	12,055
Pension liabilities	21,933	29,228
Other	43,662	43,462
Total deferred credits and other	65,595	84,745
Common stock equity		
Common stock	2,535,862	2,509,569
Accumulated other comprehensive loss	(44,748)	(68,141)
Retained earnings	2,092,803	1,926,065
Total Pinnacle West Shareholders' equity	4,583,917	4,367,493
Noncontrolling interests	135,540	151,609
Total Equity	4,719,457	4,519,102
Total Liabilities and Equity	$ 5,025,340	$ 4,851,099

See Combined Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
Cash flows from operating activities			
Net income	$ 437,257	$ 397,595	$ 406,074
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(446,508)	(411,528)	(420,926)
Depreciation and amortization	92	94	95
Deferred income taxes	12,967	4,406	(28,806)
Accounts receivable	11,336	(22,945)	21,671
Accounts payable	637	2,017	(2,449)
Accrued taxes and income tax receivables — net	(12,882)	(1,795)	1,402
Dividends received from subsidiaries	266,900	253,600	242,100
Other	(6,995)	18,432	(15,065)
Net cash flow provided by operating activities	262,804	239,876	204,096
Cash flows from investing activities			
Construction work in progress	(3,462)	—	—
Investments in subsidiaries	(3,491)	(10,236)	(3,400)
Repayments of loans from subsidiaries	157	322	2,149
Advances of loans to subsidiaries	(1,010)	(1,450)	(2,099)
Net cash flow used for investing activities	(7,806)	(11,364)	(3,350)
Cash flows from financing activities			
Issuance of long-term debt	—	125,000	—
Dividends paid on common stock	(260,027)	(246,671)	(235,244)
Repayment of long-term debt	—	(125,000)	—
Common stock equity issuance	19,373	15,288	17,319
Other	—	161	298
Net cash flow used for financing activities	(240,654)	(231,222)	(217,627)
Net increase (decrease) in cash and cash equivalents	14,344	(2,710)	(16,881)
Cash and cash equivalents at beginning of year	3,088	5,798	22,679
Cash and cash equivalents at end of year	$ 17,432	$ 3,088	$ 5,798

See Combined Notes to Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2015	$ 3,094	$ 4,073	$ —	$ 4,042	$ 3,125
2014	3,203	3,942	—	4,051	3,094
2013	3,340	4,923	—	5,060	3,203

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2015	$ 3,094	$ 4,073	$ —	$ 4,042	$ 3,125
2014	3,203	3,942	—	4,051	3,094
2013	3,340	4,923	—	5,060	3,203

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term "disclosure controls and procedures" means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934 (the "Exchange Act") (15 U.S.C. 78a *et seq.*) is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West's management, with the participation of Pinnacle West's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West's disclosure controls and procedures as of December 31, 2015. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of APS's disclosure controls and procedures as of December 31, 2015. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Management's Annual Reports on Internal Control Over Financial Reporting

Reference is made to "Management's Report on Internal Control over Financial Reporting (Pinnacle West Capital Corporation)" on page 74 of this report and "Management's Report on Internal Control over Financial Reporting (Arizona Public Service Company)" on page 83 of this report.

(c) Attestation Reports of the Registered Public Accounting Firm

Reference is made to "Report of Independent Registered Public Accounting Firm" on page 75 of this report and "Report of Independent Registered Public Accounting Firm" on page 84 of this report on the internal control over financial reporting of Pinnacle West and APS, respectively.

(d) Changes In Internal Control Over Financial Reporting

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended December 31, 2015 that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF PINNACLE WEST

Reference is hereby made to "Information About Our Board and Corporate Governance," "Proposal 1 — Election of Directors" and to "Section 16(a) Beneficial Ownership Reporting Compliance" in the Pinnacle West Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 18, 2016 (the "2016 Proxy Statement") and to the "Executive Officers of Pinnacle West" section in Part I of this report.

Pinnacle West has adopted a Code of Ethics for Financial Executives that applies to financial executives including Pinnacle West's Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller, Treasurer, and General Counsel, the President and Chief Operating Officer of APS and other persons designated as financial executives by the Chair of the Audit Committee. The Code of Ethics for Financial Executives is posted on Pinnacle West's website (*www.pinnaclewest.com)*. Pinnacle West intends to satisfy the requirements under Item 5.05 of Form 8-K regarding disclosure of amendments to, or waivers from, provisions of the Code of Ethics for Financial Executives by posting such information on Pinnacle West's website.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to "Directors' Compensation," "Report of the Human Resources Committee," "Executive Compensation," and "Human Resources Committee Interlocks and Insider Participation" in the 2016 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Reference is hereby made to "Ownership of Pinnacle West Stock" in the 2016 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2015 with respect to the 2012 Plan and the 2007 Plan, under which our equity securities are outstanding or currently authorized for issuance.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,611,402	—	2,763,056
Equity compensation plans not approved by security holders	—	—	-
Total	1,611,402	—	2,763,056

(a) This amount includes shares subject to outstanding performance share awards and restricted stock unit awards at the maximum amount of shares issuable under such awards. However, payout of the performance share awards is contingent on the Company reaching certain levels of performance during a three-year performance period. If the performance criteria for these awards are not fully satisfied, the award recipient will receive less than the maximum number of shares available under these grants and may receive nothing from these grants.

(b) The weighted-average exercise price in this column does not take performance share awards or restricted stock unit awards into account, as those awards have no exercise price.

(c) Awards under the 2012 Plan can take the form of options, stock appreciation rights, restricted stock, performance shares, performance share units, performance cash, stock grants, stock units, dividend equivalents, and restricted stock units. Additional shares cannot be awarded under the 2007 Plan. However, if an award under the 2012 Plan is forfeited, terminated or canceled or expires, the shares subject to such award, to the extent of the forfeiture, termination, cancellation or expiration, may be added back to the shares available for issuance under the 2012 Plan.

Equity Compensation Plans Approved By Security Holders

Amounts in column (a) in the table above include shares subject to awards outstanding under two equity compensation plans that were previously approved by our shareholders: (a) the 2007 Plan, which was approved by our shareholders at our 2007 annual meeting of shareholders and under which no new stock awards may be granted; and (b) the 2012 Plan, which was approved by our shareholders at our 2012 annual meeting of shareholders. See Note 15 of the Notes to Consolidated Financial Statements for additional information regarding these plans.

Equity Compensation Plans Not Approved by Security Holders

The Company does not have any equity compensation plans under which shares can be issued that have not been approved by the shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Reference is hereby made to "Information About Our Board and Corporate Governance" and "Related Party Transactions" in the 2016 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pinnacle West

Reference is hereby made to "Accounting and Auditing Matters — Audit Fees and — Pre-Approval Policies" in the 2016 Proxy Statement.

APS

The following fees were paid to APS's independent registered public accountants, Deloitte & Touche LLP, for the last two fiscal years:

Type of Service	2014	2015
Audit Fees (1)	$ 2,062,685	$ 2,014,747
Audit-Related Fees (2)	212,600	233,555
Tax Fees (3)	8,857	—
All Other Fees (4)	—	10,000

(1) The aggregate fees billed for services rendered for the audit of annual financial statements and for review of financial statements included in Reports on Form 10-Q.

(2) The aggregate fees billed for assurance services that are reasonably related to the performance of the audit or review of the financial statements that are not included in Audit Fees reported above, which primarily consist of fees for employee benefit plan audits performed in 2015 and 2014.

(3) The aggregate fees billed primarily related to tax compliance and tax planning.

(4) The aggregate fees billed for advice relating to the development of a statement of work for the Company's system integrator for its new Customer Information System.

Pinnacle West's Audit Committee pre-approves each audit service and non-audit service to be provided by APS's registered public accounting firm. The Audit Committee has delegated to the Chair of the Audit Committee the authority to pre-approve audit and non-audit services to be performed by the independent public accountants if the services are not expected to cost more than $50,000. The Chair must report any pre-approval decisions to the Audit Committee at its next scheduled meeting. All of the services performed by Deloitte & Touche LLP for APS in 2015 were pre-approved by the Audit Committee or the Chair of the Audit Committee consistent with the pre-approval policy.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

See the Index to Financial Statements and Financial Statement Schedule in Part II, Item 8.

Exhibits Filed

The documents listed below are being filed or have previously been filed on behalf of Pinnacle West or APS and are incorporated herein by reference from the documents indicated and made a part hereof. Exhibits not identified as previously filed are filed herewith.

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
3.1	Pinnacle West	Articles of Incorporation, restated as of May 21, 2008	3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8/7/2008
3.2	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of May 19, 2010	3.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form 18 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9/29/1993
3.3.1	APS	Amendment to the Articles of Incorporation of Arizona Public Service Company, amended May 16, 2012	3.1 to Pinnacle West/APS May 22, 2012 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/22/2012
3.4	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K, File No. 1-4473	2/20/2009
4.1	Pinnacle West	Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value	4.1 to Pinnacle West June 28, 2011 Form 8-K Report, File No. 1-8962	6/28/2011
4.2	Pinnacle West APS	Indenture dated as of January 1, 1995 among APS and The Bank of New York Mellon, as Trustee	4.6 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473	1/11/1995
4.2a	Pinnacle West APS	First Supplemental Indenture dated as of January 1, 1995	4.4 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473	1/11/1995
4.3	Pinnacle West APS	Indenture dated as of November 15, 1996 between APS and The Bank of New York, as Trustee	4.5 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333- 15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473	11/22/1996

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.3a	Pinnacle West APS	First Supplemental Indenture dated as of November 15, 1996	4.6 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473	11/22/1996
4.3b	Pinnacle West APS	Second Supplemental Indenture dated as of April 1, 1997	4.10 to APS's Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report, File No. 1-4473	4/9/1997
4.3c	Pinnacle West APS	Third Supplemental Indenture dated as of November 1, 2002	10.2 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5/15/2003
4.4	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Senior Unsecured Debt Securities	4.1 to Pinnacle West's Registration Statement No. 333-52476	12/21/2000
4.5	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Subordinated Unsecured Debt Securities	4.2 to Pinnacle West's Registration Statement No. 333-52476	12/21/2000
4.6	Pinnacle West APS	Indenture dated as of January 15, 1998 between APS and The Bank of New York Mellon Trust Company N.A. (successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank), as Trustee	4.10 to APS's Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report, File No. 1-4473	1/16/1998
4.6a	Pinnacle West APS	Seventh Supplemental Indenture dated as of May 1, 2003	4.1 to APS's Registration Statement No. 333-90824 by means of May 7, 2003 Form 8-K Report, File No. 1-4473	5/9/2003
4.6b	Pinnacle West APS	Eighth Supplemental Indenture dated as of June 15, 2004	4.1 to APS's Registration Statement No. 333-106772 by means of June 24, 2004 Form 8-K Report, File No. 1-4473	6/28/2004
4.6c	Pinnacle West APS	Ninth Supplemental Indenture dated as of August 15, 2005	4.1 to APS's Registration Statements Nos. 333-106772 and 333-121512 by means of August 17, 2005 Form 8-K Report, File No. 1-4473	8/22/2005
4.6d	APS	Tenth Supplemental Indenture dated as of August 1, 2006	4.1 to APS's July 31, 2006 Form 8-K Report, File No. 1-4473	8/3/2006
4.6e	Pinnacle West APS	Eleventh Supplemental Indenture dated as of February 26, 2009	4.6e to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6f	Pinnacle West APS	Twelfth Supplemental Indenture dated as of August 25, 2011	4.6f to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6g	Pinnacle West APS	Thirteenth Supplemental Indenture dated as of January 13, 2012	4.6g to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6h	Pinnacle West APS	Fourteenth Supplemental Indenture dated as of January 10, 2014	4.6h to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
4.6i	Pinnacle West APS	Fifteenth Supplemental Indenture dated as of June 18, 2014	4.6i to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6j	Pinnacle West APS	Sixteenth Supplemental Indenture dated as of January 12, 2015	4.6j to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
4.6k	Pinnacle West APS	Seventeenth Supplemental Indenture dated as of May 19, 2015	4.1 to Pinnacle West/APS May 14, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/19/2015
4.6l	Pinnacle West APS	Eighteenth Supplemental Indenture dated as of November 6, 2015	4.1 to Pinnacle West/APS November 3, 2015 Form 8-K Report, File Nos. 1-8962 and 1-4473	11/6/2015
4.7	Pinnacle West	Second Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of June 23, 2004	4.4 to Pinnacle West's June 23, 2004 Form 8-K Report, File No. 1-8962	8/9/2004
4.7a	Pinnacle West	Third Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of November 25, 2008	4.1 to Pinnacle West's Form S-3 Registration Statement No. 333-155641, File No. 1-8962	11/25/2008
4.8	Pinnacle West	Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to Pinnacle West's 1987 Form 10-K Report, File No. 1-8962	3/30/1988
4.8a	Pinnacle West APS	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS's total assets	4.1 to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
10.1.1	Pinnacle West APS	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS's September 30, 1991 Form 10-Q Report, File No. 1-4473	11/14/1991
10.1.1a	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 1, 1994	10.1 to APS's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1.1b	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 1, 1994	10.2 to APS's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1.1c	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to APS's 1996 Form 10-K Report , File No. 1-4473	3/28/1997
10.1.1d	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.1.1e	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of March 18, 2002	10.2 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.1f	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of March 18, 2002	10.4 to Pinnacle West's March 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.1g	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 19, 2003	10.3 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1.1h	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 19, 2003	10.5 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1.1i	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of May 1, 2007	10.1 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/9/2007
10.1.1j	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of May 1, 2007	10.2 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 104473	5/9/2007
10.1.2	Pinnacle West APS	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to Pinnacle West's 1991 Form 10-K Report, File No. 1-8962	3/26/1992
10.1.2a	Pinnacle West APS	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.1.2b	Pinnacle West APS	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.3 to APS's 1994 Form 10-K Report, File No. 1-4473	3/30/1995
10.1.2c	Pinnacle West APS	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 20, 1996	10.1 to APS's June 30, 1996 Form 10-Q Report, File No. 1-4473	8/9/1996
10.1.2d	Pinnacle West APS	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of December 16, 1996	APS 10.5 to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.1.2e	Pinnacle West APS	Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 30, 2000	10.1 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.2f	Pinnacle West APS	Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of March 18, 2002	10.3 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5/15/2002
10.1.2g	Pinnacle West APS	Amendment No. 7 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of December 19, 2003	10.4 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004
10.1.2h	Pinnacle West APS	Amendment No. 8 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of April 1, 2007	10.1.2h to Pinnacle West's 2007 Form 10-K Report, File No. 1-8962	2/27/2008
10.2.1[b]	Pinnacle West APS	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively	10.4 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.2.1a[b]	Pinnacle West APS	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3A to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
10.2.1b[b]	Pinnacle West APS	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473	11/10/1994
10.2.1c[b]	Pinnacle West APS	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 1997	10.3A to APS's 1996 Form 10-K Report, File No. 1-4473	3/28/1997
10.2.1d[b]	Pinnacle West APS	Sixth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 2001	10.8A to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962	3/14/2001
10.2.2[b]	Pinnacle West APS	Arizona Public Service Company Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to APS's June 30, 1986 Form 10-Q Report, File No. 1-4473	8/13/1986
10.2.2a[b]	Pinnacle West APS	Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993	10.2A to APS's 1993 Form 10-K Report, File No. 1-4473	3/30/1994
10.2.2b[b]	Pinnacle West APS	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of May 1, 1993	10.1 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473	11/10/1994
10.2.2c[b]	Pinnacle West APS	Fourth Amendment to the Arizona Public Service Company Directors Deferred Compensation Plan, effective as of January 1, 1999	10.8A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.2.3[b]	Pinnacle West APS	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996	10.14A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.3a[b]	Pinnacle West APS	First Amendment dated December 7, 1999 to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans	10.15A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.4[b]	Pinnacle West APS	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10A to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.2.4a[b]	Pinnacle West APS	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.7A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.4b[b]	Pinnacle West APS	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3/30/2000
10.2.4c[b]	Pinnacle West APS	Third Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective as of January 1, 2002	10.3 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5/15/2003
10.2.4d[b]	Pinnacle West APS	Fourth Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective January 1, 2003	10.64 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.2.5[b]	Pinnacle West APS	Deferred Compensation Plan of 2005 for Employees of Pinnacle West Capital Corporation and Affiliates (as amended and restated effective January 1, 2016)		
10.3.1[b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplement Excess Benefit Retirement Plan, amended and restated as of January 1, 2003	10.7A to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3/15/2004

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.3.1a[b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 18, 2003	10.48b to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.3.2[b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005 (as amended and restated effective January 1, 2016)		
10.4.1[b]	APS	Letter Agreement dated December 20, 2006 between APS and Randall K. Edington	10.78 to Pinnacle West/APS 2006 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/28/2007
10.4.2[b]	APS	Letter Agreement dated July 22, 2008 between APS and Randall K. Edington	10.3 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-4473	8/7/2008
10.4.3[b]	Pinnacle West APS	Letter Agreement dated June 17, 2008 between Pinnacle West/APS and James R. Hatfield	10.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/7/2008
10.4.4[b]	APS	Supplemental Agreement dated December 26, 2008 between APS and Randall K. Edington	10.4.10 to Pinnacle West/APS 2008 Form 10-K Report, File No. 1-4473	2/20/2009
10.4.5[b]	APS	Description of 2010 Palo Verde Specific Compensation Opportunity for Randall K. Edington	10.4.13 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2010
10.4.6[b]	Pinnacle West	Letter Agreement dated May 21, 2009, between Pinnacle West and David P. Falck	10.4 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File No. 1-8962	5/6/2010
10.4.7[b]	APS	Supplemental Agreement dated June 19, 2012 between APS and Randall K. Edington	10.1 to Pinnacle West/APS June 30, 2012 Form 10-Q Report File Nos. 1-8962 and 1-4473	8/2/2012
10.4.8[b]	APS	Description of 2016 Palo Verde Specific Compensation Opportunity for Randall K. Edington	Pinnacle West/APS December 15, 2015 Form 8-K Report, File No. 1-4473	12/21/2015
10.4.9[b]	APS	Supplemental Agreement dated December 14, 2014 between APS and Randall K. Edington	10.4.9 to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
10.5.1[bd]	Pinnacle West APS	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.77 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.5.1a[bd]	Pinnacle West APS	Form of Amended and Restated Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.4 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11/6/2007
10.5.2[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.3 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11/6/2007

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.5.3[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.3 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/19/2010
10.5.4[bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.4 to Pinnacle West/APS 2012 Form 10-K, File Nos. 1-8962 and 1-4473	2/22/2013
10.6.1[b]	Pinnacle West	Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	Appendix B to the Proxy Statement for Pinnacle West's 2007 Annual Meeting of Shareholders, File No. 1-8962	4/20/2007
10.6.1a[b]	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS April 18, 2007 Form 8-K Report, File No. 1-8962	4/20/2007
10.6.1b[bd]	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.3 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/5/2009
10.6.1c[bd]	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6.1d[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8/3/2010
10.6.1e[bd]	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.4 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6.1f[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.5 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6.1g[bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan (Supplemental 2010 Award)	10.6 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File No. 1-8962	4/29/2011
10.6.2[b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.1 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File No. 1-8962	11/6/2007
10.6.3[b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.2 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8/7/2008
10.6.4[bd]	Pinnacle West APS	Summary of 2016 CEO Variable Incentive Plan and Officer Variable Incentive Plan		
10.6.5	Pinnacle West	Description of Restricted Stock Unit Grant to Donald E. Brandt	Pinnacle West/APS December 24, 2012 Form 8-K Report, File No. 1-8962	12/26/2012

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
10.6.6[b]	Pinnacle West APS	Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	Appendix A to the Proxy Statement for Pinnacle West's 2012 Annual Meeting of Shareholders, File No. 1-8962	3/29/2012
10.6.6a[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.1 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6.6b[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.2 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6.6c[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8c to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6.6d[bd]	Pinnacle West	Form of Restricted Stock Unit Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan	10.6.8d to Pinnacle West/APS 2013 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/21/2014
10.6.6e[bd]	Pinnacle West	Form of Performance Share Award Agreement under the Pinnacle West Capital Corporation 2012 Long-Term Incentive Plan		
10.6.6f[bd]	Pinnacle West	Master Amendment to Performance Share Agreements	10.3 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.6.6g[bd]	Pinnacle West	Master Amendment to Restricted Stock Unit Agreements	10.4 to Pinnacle West/APS March 31, 2012 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/3/2012
10.7.1	Pinnacle West APS	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7.1a	Pinnacle West APS	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7.1b	Pinnacle West APS	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985	10.36 to Pinnacle West's Registration Statement on Form 8-B Report, File No. 1-8962	7/25/1985
10.7.1c	Pinnacle West APS	Amendment and Supplement No. 2 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.1 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473	4/29/2011
10.7.1d	Pinnacle West APS	Amendment and Supplement No. 3 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.2 to Pinnacle West/APS March 31, 2011 Form 10-Q Report, File Nos. 1-8962 and 1-4473	4/29/2011
10.7.2	Pinnacle West APS	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.7.2a	Pinnacle West APS	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Site dated April 25, 1985	10.37 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985
10.7.3	Pinnacle West APS	Application and Grant of APS rights-of-way and easements, Four Corners Site	5.05 to APS's Form S-7 Registration Statement, File No. 2-59644	9/1/1977
10.7.3a	Pinnacle West APS	Application and Amendment No. 1 to Grant of APS rights-of-way and easements, Four Corners Site dated April 25, 1985	10.38 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7/25/1985
10.7.4a	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement Amendment No. 6	10.7 to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962	3/14/2001
10.7.4b	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement Amendment No. 7, dated December 30, 2013, among APS, El Paso Electric Company, Public Service Company of New Mexico, SRP, SCE, and Tucson Electric Power Company	10.3 to Pinnacle West/APS March 31, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2014
10.8.1	Pinnacle West APS	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS's Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8.2	Pinnacle West APS	Application of Grant of rights-of-way and easements, Navajo Plant	5(h) to APS Form S-7 Registration Statement, File No. 2-36505	3/23/1970
10.8.3	Pinnacle West APS	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to APS's Form S-7 Registration Statement, File No. 2-394442	3/16/1971
10.8.4	Pinnacle West APS	Navajo Project Co-Tenancy Agreement dated as of March 23, 1976, and Supplement No. 1 thereto dated as of October 18, 1976, Amendment No. 1 dated as of July 5, 1988, and Amendment No. 2 dated as of June 14, 1996; Amendment No. 3 dated as of February 11, 1997; Amendment No. 4 dated as of January 21, 1997; Amendment No. 5 dated as of January 23, 1998; Amendment No. 6 dated as of July 31, 1998	10.107 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.8.5	Pinnacle West APS	Navajo Project Participation Agreement dated as of September 30, 1969, and Amendment and Supplement No. 1 dated as of January 16, 1970, and Coordinating Committee Agreement No. 1 dated as of September 30, 1971	10.108 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/13/2006
10.9.1	Pinnacle West APS	ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10. 1 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989

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10.9.1a	Pinnacle West APS	Amendment No. 13, dated as of April 22, 1991, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to APS's March 31, 1991 Form 10-Q Report, File No. 1-4473	5/15/1991
10.9.1b	Pinnacle West APS	Amendment No. 14 to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	99.1 to Pinnacle West's June 30, 2000 Form 10-Q Report, File No. 1-8962	8/14/2000
10.9.1c	Pinnacle West APS	Amendment No. 15, dated November 29, 2010, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.9.1c to Pinnacle West/APS 2010 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/18/2011
10.9.1d	Pinnacle West APS	Amendment No. 16, dated April 28, 2014, to ANPP Participation Agreement, dated August 23, 1973, among APS, SRP, SCE, Public Service Company of New Mexico, El Paso, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.2 to Pinnacle West/APS March 31, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/2/2014
10.10.1	Pinnacle West APS	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473	8/8/1991
10.10.2	Pinnacle West APS	Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991	10.2 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473	8/8/1991
10.10.2a	Pinnacle West APS	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.10.3	Pinnacle West APS	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit:	Date Filed
10.10.4	Pinnacle West APS	Contract among PacifiCorp, APS and DOE Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.10.5	Pinnacle West APS	Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994	10.6 to APS's 1995 Form 10-K Report, File No. 1-4473	3/29/1996
10.11.1	Pinnacle West APS	Five-Year Credit Agreement dated as of May 9, 2014, among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.3 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/31/2014
10.11.2	Pinnacle West	Term Loan Agreement dated as of December 31, 2014 among Pinnacle West, as Borrower, JPMorgan Chase Bank, N.A., as Agent, U.S. Bank Association, as Syndication Agent, TD Bank, N.A., The Bank of Nova Scotia and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and such institutions compromising the lenders party thereto	10.11.2 to Pinnacle West/APS 2014 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/20/2015
10.11.3	Pinnacle West	Five-Year Credit Agreement, dated as of May 9, 2014, among Pinnacle West, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.4 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/31/2014
10.11.4	Pinnacle West APS	Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated as of April 16, 2010	10.2 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010
10.11.4a	Pinnacle West APS	Amendment No. 1 to the Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated December 22, 2011	10.11.5a to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2012
10.11.5	Pinnacle West APS	Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated as of April 16, 2010	10.3 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010
10.11.5a	Pinnacle West APS	Amendment No. 1 to the Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated December 22, 2011	10.11.6a to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2012
10.11.6	APS	Five-Year Credit Agreement dated as of September 2, 2015 among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto	10.1 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	10/30/2015

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.11.7	APS	Term Loan Agreement dated as of June 26, 2015 among APS, as Borrower, Toronto Dominion (Texas) LLC, as Agent, Citibank, N.A., as Syndication Agent, and such institutions compromising the lenders party thereto	10.1 to Pinnacle West/APS June 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/30/2015
10.12.1[c]	Pinnacle West APS	Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
10.12.1a[c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
10.12.1b[c]	Pinnacle West APS	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1988 Form 10-K Report, File No. 1-4473	3/8/1989
10.12.1c[c]	Pinnacle West APS	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.12.1d[c]	Pinnacle West APS	Amendment No. 4, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Emerson Finance LLC, as Lessor, and APS, as Lessee	10.2 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	10/30/2015

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.12.1e[e]	Pinnacle West APS	Amendment No. 3, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Security Pacific Capital Leasing Corporation, as Lessor, and APS, as Lessee	10.3 to Pinnacle West/APS September 30, 2015 Form 10-Q Report, File Nos. 1-8962 and 1-4473	10/30/2015
10.12.2	Pinnacle West APS	Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.1 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1/20/1987
10.12.2a	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8/24/1987
10.12.2b	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
10.12.2c	Pinnacle West APS	Amendment No. 3, dated July 10, 2014, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to the First National Bank of Boston, as Lessor, and APS, as Lessee	10.2 to Pinnacle West/APS June 30, 2014 Form 10-Q Report, File Nos. 1-8962 and 1-4473	7/31/2014
10.13.1	Pinnacle West APS	Agreement between Pinnacle West Energy Corporation and APS for Transportation and Treatment of Effluent by and between Pinnacle West Energy Corporation and APS dated as of the 10th day of April, 2001	10.102 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13.2	Pinnacle West APS	Agreement for the Transfer and Use of Wastewater and Effluent by and between APS, SRP and PWE dated June 1, 2001	10.103 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
10.13.3	Pinnacle West APS	Agreement for the Sale and Purchase of Wastewater Effluent dated November 13, 2000, by and between the City of Tolleson, Arizona, APS and SRP	10.104 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13.4	Pinnacle West APS	Operating Agreement for the Co-Ownership of Wastewater Effluent dated November 16, 2000 by and between APS and SRP	10.105 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3/16/2005
10.13.5	Pinnacle West APS	Municipal Effluent Purchase and Sale Agreement dated April 29, 2010, by and between City of Phoenix, City of Mesa, City of Tempe, City of Scottsdale, City of Glendale, APS and SRP	10.1 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5/6/2010
10.14.1	Pinnacle West APS	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement, File No. 2-96386	3/13/1985
10.15.1	Pinnacle West APS	Territorial Agreement between APS and SRP	10.1 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15.2	Pinnacle West APS	Power Coordination Agreement between APS and SRP	10.2 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15.3	Pinnacle West APS	Memorandum of Agreement between APS and SRP	10.3 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5/15/1998
10.15.3a	Pinnacle West APS	Addendum to Memorandum of Agreement between APS and SRP dated as of May 19, 1998	10.2 to APS's May 19, 1998 Form 8-K Report, File No. 1-4473	6/26/1998
10.16	Pinnacle West APS	Purchase and Sale Agreement dated November 8, 2010 by and between SCE and APS	10.1 to Pinnacle West/APS November 8, 2010 Form 8-K Report, File Nos. 1-8962 and 1-4473	11/8/2010
10.17	Pinnacle West APS	Proposed Settlement Agreement dated January 6, 2012 by and among APS and certain parties to its retail rate case (approved by ACC Order No. 73183)	10.17 to Pinnacle West/APS 2011 Form 10-K Report, File Nos. 1-8962 and 1-4473	2/24/2012
12.1	Pinnacle West	Ratio of Earnings to Fixed Charges		
12.2	APS	Ratio of Earnings to Fixed Charges		
12.3	Pinnacle West	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements		
21.1	Pinnacle West	Subsidiaries of Pinnacle West		
23.1	Pinnacle West	Consent of Deloitte & Touche LLP		
23.2	APS	Consent of Deloitte & Touche LLP		
31.1	Pinnacle West	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
31.2	Pinnacle West	Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		
31.3	APS	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		
31.4	APS	Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14 (a) of the Securities Exchange Act, as amended		
32.1[c]	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
32.2[c]	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
99.1	Pinnacle West APS	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.2 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.1a	Pinnacle West APS	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.2[c]	Pinnacle West APS	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.2a[c]	Pinnacle West APS	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.2b[c]	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.3[c]	Pinnacle West APS	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.3a[c]	Pinnacle West APS	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986
99.3b[c]	Pinnacle West APS	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.4c	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to APS's Form 18 Registration Statement, File No. 33-9480	10/24/1986
99.4a[c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12/4/1986

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: a	Date Filed
99.4b[c]	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.5	Pinnacle West APS	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11/9/1992
99.5a	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8/10/1987
99.5b	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Owner Participant named therein	28.5 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.6	Pinnacle West APS	Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to APS's November 18, 1986 Form 10-K Report, File No. 1-4473	1/20/1987
99.6a	Pinnacle West APS	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8/24/1987

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit: [a]	Date Filed
99.6b	Pinnacle West APS	Supplemental Indenture No. 2 to Trust Indenture Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.5 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.7	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1/20/1987
99.7a	Pinnacle West APS	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.8[c]	Pinnacle West APS	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3/30/1993
99.9	Pinnacle West APS	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8/10/1987
99.10	Pinnacle West APS	ACC Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules	10.2 to APS's September 30, 1999 Form 10-Q Report, File No. 1-4473	11/15/1999
99.11	Pinnacle West	Purchase Agreement by and among Pinnacle West Energy Corporation and GenWest, L.L.C. and Nevada Power Company, dated June 21, 2005	99.5 to Pinnacle West/APS June 30, 2005 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/9/2005
101.INS	Pinnacle West APS	XBRL Instance Document		
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document		
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document		
101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document		
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document		
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document		

[a]Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[b]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 15(b) of Form 10-K.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

[e]Furnished herewith as an Exhibit.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Date: February 19, 2016

/s/ Donald E. Brandt
(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Pinnacle West Capital Corporation, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Donald E. Brandt (Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 19, 2016
/s/ James R. Hatfield (James R. Hatfield, Executive Vice President and Chief Financial Officer)	Principal Financial Officer	February 19, 2016
/s/ Denise R. Danner (Denise R. Danner, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 19, 2016

/s/ Denis A. Cortese (Denis A. Cortese, M.D.)	Director	February 19, 2016
/s/ Richard P. Fox (Richard P. Fox)	Director	February 19, 2016
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 19, 2016
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr., Ph.D.)	Director	February 19, 2016
/s/ Dale E. Klein (Dale E. Klein, Ph.D.)	Director	February 19, 2016
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 19, 2016
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 19, 2016
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 19, 2016
/s/ David P. Wagener (David P. Wagener)	Director	February 19, 2016

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: February 19, 2016

/s/ Donald E. Brandt
(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Arizona Public Service Company, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Donald E. Brandt (Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 19, 2016
/s/ James R. Hatfield (James R. Hatfield, Executive Vice President and Chief Financial Officer)	Principal Financial Officer	February 19, 2016
/s/ Denise R. Danner (Denise R. Danner, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 19, 2016

/s/ Denis A. Cortese (Denis A. Cortese, M.D.)	Director	February 19, 2016
/s/ Richard P. Fox (Richard P. Fox)	Director	February 19, 2016
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 19, 2016
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr., Ph.D.)	Director	February 19, 2016
/s/ Dale E. Klein (Dale E. Klein, Ph.D.)	Director	February 19, 2016
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 19, 2016
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	February 19, 2016
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 19, 2016
/s/ David P. Wagener (David P. Wagener)	Director	February 19, 2016

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ARIZONA PUBLIC SERVICE COMPANY
PROJECTED INCOME STATEMENTS
PRESENT RATES AND WITH PROPOSED RATE INCREASE
TEST YEAR ENDED 12/31/2015 AND PROJECTED YEARS
(Dollars in Thousands)

Line No.	Description	Test Year (a)	Projected Years (b)								Line No.
						Includes Ocotillo Deferral and SCR Deferral Impacts		Removes Ocotillo Deferral and SCR Deferral Impacts			
		Actual Year Ended 12/31/2015 (A)	Present Rates Year Ended 12/31/2016 (B)	Present Rates Year Ended 12/31/2017 (C)	Present Rates Year Ended 12/31/2018 (D)	Proposed Rates Year Ended 12/31/2017 (E)	Proposed Rates Year Ended 12/31/2018 (F)	Proposed Rates Year Ended 12/31/2017 (G)	Proposed Rates Year Ended 12/31/2018 (H)		
1.	Electric operating revenues	$ 3,492,357	$ 3,459,020	$ 3,493,821	$ 3,562,292	$ 3,621,913	$ 3,797,016	$ 3,621,909	$ 3,796,921	1.
2.	Fuel and purchased power	1,101,298	1,033,688	999,589	1,011,176	999,589	1,011,177	999,589	1,011,177	2.
3.	Operating revenues less fuel and purchased power	2,391,059	2,425,332	2,494,232	2,551,116	2,622,324	2,785,839	2,622,320	2,785,744	3.
	Other Operating Expenses:									
4.	Operations and maintenance excluding fuel and purchased power *	892,796	938,487	950,306	970,117	950,306	970,117	950,306	970,117	4.
5.	Depreciations and Amortization	474,131	475,329	484,332	511,645	533,701	591,683	535,021	623,064	5.
6.	Income taxes	260,143	248,802	253,929	242,701	279,172	294,990	278,666	282,958	6.
7.	Other taxes	171,499	170,900	175,641	185,972	191,766	217,439	191,766	217,439	7.
8.	Operating income	592,491	591,814	630,024	640,681	667,379	711,610	666,561	692,166	8.
	Other Income (Deductions):									
9.	Income taxes	14,302	10,236	14,000	12,512	14,086	12,515	14,086	12,515	9.
10.	Allowance for equity funds used during construction	35,215	36,400	44,691	43,440	44,691	43,440	44,691	43,440	10.
11.	Other income	2,834	5,923	2,745	3,014	2,519	3,006	2,519	3,005	11.
12.	Other expenses	(19,019)	(17,200)	(23,824)	(20,363)	(23,824)	(20,364)	(23,824)	(20,364)	12.
13.	Total	33,332	35,359	37,612	38,603	37,472	38,597	37,472	38,596	13.
14.	Income Before Interest Deductions	625,823	627,173	667,636	679,284	704,851	750,207	704,033	730,762	14.
	Interest Deductions									
15.	Interest on long-term debt	179,563	198,110	224,537	254,519	221,097	241,440	221,097	241,440	15.
16.	Interest on short-term borrowings	7,376	4,588	5,874	6,121	5,928	5,756	5,928	5,756	16.
17.	Debt discount, premium and expense	4,793	4,836	5,142	5,505	5,086	5,376	5,086	5,376	17.
18.	Allowance for borrowed funds used during construction	(16,183)	(17,700)	(21,771)	(21,232)	(21,771)	(21,232)	(21,771)	(21,232)	18.
19.	Total	175,549	189,834	213,782	244,913	210,340	231,340	210,340	231,340	19.
20.	Net Income	$ 450,274	$ 437,339	$ 453,854	$ 434,371	$ 494,511	$ 518,867	$ 493,693	$ 499,422	20.
21.	Earnings per Share of Average Common Stock Outstanding **	$ 6.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	21.
22.	% Return on Average Common Equity	9.8%	9.2%	9.2%	8.5%	10.0%	10.0%	10.0%	9.6%	22.
23.	Average Common Equity	4,578,749	4,746,996	4,930,429	5,119,338	4,950,768	5,202,312	4,950,355	5,191,750	23.
24.	% Return on Year End Common Equity	9.6%	9.1%	9.0%	8.4%	9.7%	9.8%	9.7%	9.4%	24.
25.	End of Period Common Equity	4,679,254	4,814,739	5,046,120	5,192,556	5,086,797	5,317,826	5,085,972	5,297,529	25.

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs.
** Optional for projected years. Line 22 is calculated using the common stock shares of Arizona Public Service Company. APS's common stock shares have remained constant at 71.3 million, even though Pinnacle West has increased its equity investment in APS, and are wholly owned by Pinnacle West Capital Corporation. Pinnacle West's common stock is publicly held and the PNW share count is more indicative of the increasing equity investment needed to support APS's investment to serve its customers. APS's earnings per share of Pinnacle West diluted common stock outstanding was $3.92 for the Test Year ended 12/31/15.

Supporting Schedules:
(a) E-2

Recap Schedules:
(b) A-2

F2

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED CHANGES IN FINANCIAL POSITION
PRESENT RATES AND WITH PROPOSED RATE INCREASE
TEST YEAR ENDED 12/31/2015 AND PROJECTED YEARS
(Dollars in Thousands)

Line No.	Description	Test Year (a) Actual Year Ended 12/31/2015 (A)	Projected Years (b) Present Rates Year Ended 12/31/2016 (B)	Present Rates Year Ended 12/31/2017 (C)	Present Rates Year Ended 12/31/2018 (D)	Includes Ocotillo Deferral and SCR Deferral Impacts: Proposed Rates Year Ended 12/31/2017 (E)	Proposed Rates Year Ended 12/31/2018 (F)	Removes Ocotillo Deferral and SCR Deferral Impacts: Proposed Rates Year Ended 12/31/2017 (G)	Proposed Rates Year Ended 12/31/2018 (H)	Line No.
	Cash Flows from Operations									
1.	Net Income	$ 450,274	$ 437,339	$ 453,854	$ 434,371	$ 494,511	$ 518,867	$ 493,693	$ 499,422	1.
	Items Not Requiring Cash:									
2.	Depreciation and amortization including nuclear fuel	551,373	550,289	561,104	592,404	610,473	672,442	611,793	703,823	2.
3.	Allowance for equity funds used during construction	(35,215)	(36,400)	(44,691)	(43,440)	(44,691)	(43,440)	(44,691)	(43,440)	3.
4.	Deferred income taxes	223,069	265,478	210,259	221,925	206,753	220,023	206,249	208,027	4.
5.	Changes in mark-to-market valuations	(381)	-	-	-	-	-	-	-	5.
6.	Deferred fuel and purchased power	14,997	(51,485)	(28,362)	(20,579)	(28,362)	(20,579)	(28,362)	(20,579)	6.
7.	Deferred fuel and purchased power amortization	1,617	36,858	18,845	19,685	18,845	19,685	18,845	19,685	7.
8.	Other	(154,125)	(132,085)	(15,453)	(80,804)	(7,007)	(72,607)	(7,006)	(72,616)	8.
9.	Net cash provided	1,051,608	1,069,995	1,155,557	1,123,561	1,250,523	1,294,390	1,250,521	1,294,322	9.
	Cash Flow from Investing Activities:									
10.	Capital expenditures (c) *	(1,072,053)	(1,157,815)	(1,332,393)	(1,124,000)	(1,332,393)	(1,124,000)	(1,332,393)	(1,124,000)	10.
11.	Contributions in aid of construction (c)	46,546	-	-	-	-	-	-	-	11.
12.	Allowance for borrowed funds used during construction	(16,183)	(17,700)	(21,771)	(21,232)	(21,771)	(21,232)	(21,771)	(21,232)	12.
13.	Proceeds from nuclear decommissioning trust sales	478,813	-	-	-	-	-	-	-	13.
14.	Investment in nuclear decommissioning trust	(496,062)	(2,181)	(2,181)	(2,181)	(2,181)	(2,181)	(2,181)	(2,181)	14.
15.	Other	(1,093)	-	-	-	-	-	-	-	15.
16.	Net cash used	(1,060,032)	(1,177,696)	(1,356,345)	(1,147,413)	(1,356,345)	(1,147,413)	(1,356,345)	(1,147,413)	16.
	Cash Flows from Financing:									
17.	Issuance of long-term debt	842,415	735,000	425,000	500,000	330,000	330,000	330,000	330,000	17.
18.	Short-term borrowings and payments-net	(147,400)	3,851	28,263	(237)	28,275	(1,161)	28,285	(1,065)	18.
19.	Equity infusion	-	-	75,000	25,000	75,000	25,000	75,000	25,000	19.
20.	Dividends paid on common stock	(266,900)	(282,776)	(297,474)	(312,936)	(297,453)	(312,842)	(297,460)	(312,870)	20.
21.	Repayment and reacquisition of long-term debt	(402,150)	(370,430)	(30,000)	(187,975)	(30,000)	(187,975)	(30,000)	(187,975)	21.
22.	Net cash provided	25,965	85,646	200,789	23,851	105,822	(146,978)	105,825	(146,910)	22.
23.	Net increase (decrease) in cash and cash equivalents	17,541	(22,056)	-	-	-	-	-	-	23.
24.	Cash and cash equivalents at beginning of period	4,515	22,056	-	-	-	-	-	-	24.
25.	Cash and cash equivalents at end of period	$ 22,056	$ -	$ -	$ -	$ -	$ -	$ -	$ -	25.

Notes:
* In years 2016, 2017, and 2018 capital expenditures and CIAC are combined. Capital expenditures are reflected on cash basis.

Supporting Schedules:
(a) E-3
(c) F-3

Recap Schedules:
(b) A-5

F3

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED CAPITAL EXPENDITURES
TEST YEAR ENDED 12/31/2015 AND PROJECTED YEARS
(Dollars in Thousands)

Line No.	Description	Year to Date Year Ended 12/31/2015 (A)	Projected Years Year Ended 12/31/2016 (B)	Year Ended 12/31/2017 (C)	Year Ended 12/31/2018 (D)	Line No.
	Electric:					
1.	Production Plant:	$ 431,241	$ 637,594	$ 647,172	$ 546,525	1.
2.	Transmission:	201,262	123,165	210,131	119,705	2.
3.	Distribution:	339,768	355,626	343,829	374,148	3.
4.	General:	81,701	84,712	79,437	79,102	4.
5.	Total Construction Expenditures (a) *	1,053,972	1,201,097	1,280,569	1,119,480	5.
6.	Property Taxes Capitalized	2,942	4,158	4,431	4,520	6.
7.	Capital Expenditures (b)	1,056,914	1,205,255	1,285,000	1,124,000	7.
8.	Allowance for Equity Funds Used During Construction	35,215	36,400	44,691	43,440	8.
9.	Allowance for Borrowed Funds Used During Construction	16,183	17,700	21,771	21,232	9.
10.	Total Capital Expenditures with AFUDC	$ 1,108,312	$ 1,259,355	$ 1,351,462	$ 1,188,672	10.

Notes:
* Construction expenditures are reflected on accrual basis.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-4
(b) F-2

F4

ARIZONA PUBLIC SERVICE COMPANY
ASSUMPTIONS USED IN DEVELOPING PROJECTIONED
PERIODS ENDING DECEMBER 2016, 2017 & 2018

Line No.	Item		Line No.
	A.	Customer Growth:	
1.		Retail customer growth for the period 2016-2018 is forecast to grow at an annual average rate of 2.0%.	1.
	B.	Growth in Retail Energy and Retail Peak Demand	
2.		Retail energy sales, assuming normal weather, for the period 2016 to 2018 are forecasted to grow at an annual average rate	2.
3.		of 0.7%. Retail Own Load summer peak demand for the same period is projected to grow at an annual average rate of -0.2%,	3.
4.		assuming normal weather. Sales and peak growth reflects the impact of the company's EE and DG programs.	4.
	C.	Wholesale and Economy Interchange Sales	
5.		Firm wholesale sales and peak demand for requirement-to-serve customers are forecasted per existing contracts. The	5.
6.		Company sells energy on an economy interchange basis on a short-term basis from time to time. Such sales are made	6.
7.		at prices above the Company's variable costs to generate energy and revenues are credited against PSA-related fuel costs.	7.
	D.	Regulatory	
8.		The proposed rates case assumes rates are effective on July 1, 2017 and January 1, 2019 for Four Corners SCR equipment.	8.
9.		The Commission allows APS to adopt increases to the TCA rate charged to retail customers once approved by the FERC.	9.
	E.	Base Fuel Charge and PSA Revenues	
10.		Base Fuel Charge reflects 3.2071 cents / kWh in 2016 to 2018 consistent with Decision No. 73183. Forecast further assumes	10.
11.		PSA Annual Adjustor mechanisms are in effect and a new Forward Adjustor is set each year reflecting that year's anticipated	11.
12.		fuel and purchased power costs in excess of the Base Fuel Cost. The Forward Adjustor is reset annually with the first billing	12.
13.		cycle in February. Starting February 1, 2016 the new PSA surcharge included in the forecast is 0.1678 cents/kWh .	13.
	F.	Fuel	
14.		Fuel costs are based on projected sales, forward contract and market fuel prices and projected operating availability factors	14.
15.		of power plants. Fuel costs reflect use of the PSA cost deferral and annual adjustor recovery mechanism approved in	15.
16.		Decision No. 73183 in present rates case.	16.
	G.	Operations & Maintenance Expenses	
17.		Growth in Operational O&M expense is managed to the expected rate of inflation of approximately 2.5%. Growth rate excludes	17.
18.		RES and DSM program costs.	18.
	H.	Construction Expenditures	
19.		The level of expenditures is primarily driven by customer, sales, and load growth, maintaining reliability, and legal and regulatory	19.
20.		requirements, including environmental requirements. Contributions in aid of construction (CIAC) are normally used to reduce	20.
21.		capital expenditures. See SFR Schedule F-3 for expenditure table.	21.
	I.	Capital Structure Changes	
22.		Capital Structure and Financing are shown on Schedules A-3, D-1, D-2, D-3 and F-2.	22.
	J.	Financing	
23.		Forecasted Interest Rates are as follows:	23.
24.		Variable Rate Pollution Control Bonds - 0.88% in 2016, 1.55% in 2017, 2.25% in 2018	24.
25.		Commercial Paper - 0.95% in 2016, 1.70% in 2017, 2.20% in 2018	25.
26.		New Long-Term Unsecured Debt - 5.50% in 2016, 6.25% in 2017, 7.25% in 2018	26.
27.		Pinnacle West may infuse $75 million and $25 million in equity into APS in 2017 and 2018, respectively.	27.

G1

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE SUMMARY - *PRESENT RATES*
RATES OF RETURN BY CUSTOMER CLASSIFICATION
ADJUSTED TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Base Rates	$ 2,932,988	$ 2,888,903 (a)	$ 44,085	$ 1,486,578 (a)	$ 1,343,926 (a)	$ 28,739 (a)	$ 21,082 (a)	$ 8,578 (a)
1.b.	Revenues from Surcharges								
1.c.	Other Electric Revenues	170,101	158,550	11,551	80,069	75,578	1,803	891	209
2.	Expenses	2,584,597	2,636,990 (b)	(52,393)	1,470,747 (b)	1,117,059 (b)	28,057 (b)	15,826 (b)	5,301 (b)
3.	Operating Income Before Income Taxes	518,492	410,463	108,029	95,900	302,445	2,485	6,147	3,486
4.	Income Taxes	126,348	96,160	30,188	(1,104)	94,119	384	1,704	1,058
5.	Net Operating Income	$ 392,144	$ 314,303	$ 77,841	$ 97,005	$ 208,326	$ 2,102	$ 4,443	$ 2,428
6.	Rate Base	$ 8,011,800	$ 6,771,151 (c)	1,240,649	4,288,515 (c)	2,317,692 (c)	63,173 (c)	71,613 (c)	30,159 (c)
7.	Rate of Return	4.89%	4.64%	6.27%	2.26%	8.99%	3.33%	6.20%	8.05%

Note: Amounts may not add tie to rounding

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

Recap Schedules:
N/A

G2

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE SUMMARY - *PROPOSED RATES*
RATES OF RETURN BY CUSTOMER CLASSIFICATION
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

		Total Company	Total ACC Jurisdiction	All Other	Total ACC Jurisdiction				
					Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Base Rates	$ 3,314,556	$ 3,270,471	44,085	1,740,388	1,465,069	33,151	22,655	9,208
1.b.	Revenues from Surcharges				80,069	75,578	1,803	891	209
1.c.	Other Electric Revenues	170,101	158,550	11,551					
2.	Expenses	2,584,597	2,636,990 (b)	(52,393)	1,470,747 (b)	1,117,059 (b)	28,057 (b)	15,826 (b)	5,301 (b)
3.	Operating Income Before Income Taxes	900,060	792,031	108,029	349,710	423,588	6,897	7,720	4,116
4.	Income Taxes	271,725	241,536	30,188	153,789	81,871	2,252	2,553	1,072
5.	Net Operating Income	$ 628,335	$ 550,495	$ 77,841	$ 195,922	$ 341,717	$ 4,646	$ 5,167	$ 3,044
6.	Rate Base	$ 8,011,800	$ 6,771,151 (c)	1,240,649	4,288,515 (c)	2,317,692 (c)	63,173 (c)	71,613 (c)	30,159 (c)
7.	Rate of Return	7.84%	8.13%	6.27%	4.57%	14.74%	7.35%	7.22%	10.09%

Schedule H-1 Base Revenue Reconciliation

		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
8.	Revenues from Present Rates	$ 2,932,988	$ 2,888,903	$ 44,085	$ 1,486,578	$ 1,343,926	$ 28,739	$ 21,082	$ 8,578
9.	Revenue Increase from Proposed Rates (excluding Fair Value)*	381,568	381,568	-	253,810	121,143	4,412	1,573	630
10.	Revenue Increase from Fair Value	51,866	51,866	-	33,085	17,507	480	557	237
11.	Subtotal of Revenue Increase	433,434	433,434	-	286,895	138,650	4,892	2,130	867
12.	Total Proposed Base Revenues	$ 3,366,422	$ 3,322,337 (a)	$ 44,085	$ 1,773,473 (a)	$ 1,482,576 (a)	$ 33,631 (a)	$ 23,212 (a)	$ 9,445

Notes:
* Proposed Rates allocated based on Total Proposed Increase - Column (c) Schedule H-1.

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

Recap Schedules:
N/A

G3

ARIZONA PUBLIC SERVICE COMPANY
RATE BASE ALLOCATIONS TO CLASSES OF SERVICE
TOTAL RATE BASE
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

Line No.	Class of Service	Production - Demand (A)	Transmission Substation (B)	Transmission Lines (C)	Distribution Substation (D)	Distribution OH Primary (E)	Distribution OH Secondary (F)	Distribution UG Lines (G)	Distribution Line TXFs (H)	Total Demand (I)	Total Demand % (J)	Total Energy (K)	Total Energy % (L)
1.	Residential	$ 1,929,225	$ -	$ -	$ 229,926	$ 257,003	$ 140,589	$ 858,058	$ 320,532	$ 3,735,333	62.90%	$ 61,093	45.33%
2.	General Service	1,266,176	-	-	137,322	153,494	-	424,852	131,285	2,113,129	35.58%	71,406	52.98%
3.	Water Pumping	32,372	-	-	3,701	4,137	-	11,452	5,472	57,134	0.96%	1,499	1.11%
4.	Street Lighting	16,125	-	-	1,864	2,084	676	6,473	1,541	28,764	0.48%	682	0.51%
5.	Dusk to Dawn	2,450	-	-	283	316	103	983	234	4,370	0.07%	104	0.08%
6.	Total	$ 3,246,348 (b)(c)	$ -	$ -	$ 373,097 (b)(c)	$ 417,035 (b)(c)	$ 141,368 (b)(c)	$ 1,301,818 (b)(c)	$ 459,064 (b)(c)	$ 5,938,729	100.00%	$ 134,784 (b)(c)	100.00%

	Class of Service	Cust. Advances & Deposits (A)	Distribution OH Services (B)	Distribution UG Services (C)	Distribution Meters (D)	Customer Accounts (E)	Dusk to Dawn (F)	Street Lighting (G)	Customer Service & Info (H)	Sales (I)	Total Customer (J)	Total Customer % (K)
7.	Residential	$ (88,428)	$ 47,579	$ 111,593	$ 210,758	$ 85,994	$ -	$ -	$ 6,310	$ 21,248	$ 395,054	79.45%
8.	General Service	(77,381)	6,790	43,471	46,812	10,415	-	-	764	2,573	33,443	6.73%
9.	Water Pumping	(845)	150	1,084	1,614	118	-	-	9	29	2,158	0.43%
10.	Street Lighting	(660)	-	-	-	94	-	41,622	7	23	41,085	8.26%
11.	Dusk to Dawn	(210)	-	-	-	669	24,846	-	49	165	25,520	5.13%
12.	Total	$ (167,525) (b)(c)	$ 54,519 (b)(c)	$ 156,147 (b)(c)	$ 259,184 (b)(c)	$ 97,289 (b)(c)	$ 24,846 (b)(c)	$ 41,622 (b)(c)	$ 7,139 (b)(c)	$ 24,039 (b)(c)	$ 497,261	100.00%

	Class of Service	Total System Benefits (A)	Total System Benefits % (B)	TOTAL ACC JURIS. (a) (C)	TOTAL ACC JURIS. % (D)
13.	Residential	$ 97,035	48.43%	$ 4,288,515	63.34%
14.	General Service	99,713	49.76%	2,317,692	34.23%
15.	Water Pumping	2,381	1.19%	63,173	0.93%
16.	Street Lighting	1,083	0.54%	71,613	1.06%
17.	Dusk to Dawn	165	0.08%	30,159	0.45%
18.		$ 200,377 (b)(c)	100.00%	$ 6,771,151	100.00%

Supporting Schedules:
(b) G-5
(c) G-7

Recap Schedules:
(a) G-1 & G-2

G4

ARIZONA PUBLIC SERVICE COMPANY
EXPENSE ALLOCATION TO CLASSES OF SERVICE
OPERATING EXPENSES EXCLUDING INCOME TAXES
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	$ 424,980	$ -	$ 157,012	$ 26,513	$ 39,700	$ 21,490	$ 84,656	$ 29,233	$ 783,585	61.32%	$ 528,424	46.70%
2.	General Service	285,596	-	93,550	15,941	24,146	-	41,916	11,998	473,146	37.03%	584,787	51.68%
3.	Water Pumping	7,323	-	3,922	430	651	-	1,130	499	13,954	1.09%	12,656	1.12%
4.	Street Lighting	3,604	-	1,100	216	328	107	639	141	6,134	0.48%	4,974	0.44%
5.	Dusk to Dawn	564	-	172	33	50	16	97	21	954	0.07%	758	0.07%
6.	Total	$ 722,067 (a)(b)	$ - (a)(b)	$ 255,757 (a)(b)	$ 43,133 (a)(b)	$ 64,874 (a)(b)	$ 21,613 (a)(b)	$ 128,437 (a)(b)	$ 41,891 (a)(b)	$ 1,277,773	100.00%	$ 1,131,600 (a)(b)	100.00%

	Class of Service	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
7.	Residential	$ 7,327	$ 11,077	$ 55,966	$ 73,472	$ -	$ -	$ 2,121	$ 16,684	$ 166,647	80.90%
8.	General Service	1,046	4,315	12,431	8,898	-	-	1,926	2,021	30,636	14.87%
9.	Water Pumping	23	108	429	101	-	-	83	23	765	0.37%
10.	Street Lighting	-	-	-	80	-	4,289	22	18	4,409	2.14%
11.	Dusk to Dawn	-	-	-	572	2,835	-	6	130	3,542	1.72%
12.	Total	$ 8,396 (a)(b)	$ 15,500 (a)(b)	$ 68,825 (a)(b)	$ 83,122 (a)(b)	$ 2,835 (a)(b)	$ 4,289 (a)(b)	$ 4,158 (a)(b)	$ 18,876 (a)(b)	$ 206,000	100.00%

	Class of Service	Total System Benefits	Total System Benefits %	Limited Income Discount	Limited Income Discount %	TOTAL ACC JURIS.	TOTAL ACC JURIS. %
		(A)	(B)	(C)	(D)	(E)	(F)
13.	Residential	27,724	48.43%	(35,634)	100.00%	1,470,747	55.77%
14.	General Service	28,490	49.76%	-	0.00%	1,117,059	42.36%
15.	Water Pumping	680	1.19%	-	0.00%	28,057	1.06%
16.	Street Lighting	309	0.54%	-	0.00%	15,826	0.60%
17.	Dusk to Dawn	47	0.08%	-	0.00%	5,301	0.20%
18.	Total	57,251 (a)(b)	100.00%	-35,634 (a)(b)	100.00%	2,636,990 (c)	100.00%

Supporting Schedules:
(a) G-6
(b) G-7

Recap Schedules:
(c) G-1 & G-2

G-5

ARIZONA PUBLIC SERVICE COMPANY
DISTRIBUTION OF RATE BASE BY FUNCTION
TOTAL RATE BASE
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	$ 3,246,348	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,246,348	54.66%
2.	Transmission Substation	-	-	-	-	-	-	-	-	-	0.00%
3.	Transmission Lines	-	-	-	-	-	-	-	-	-	0.00%
4.	Distribution Substation	-	-	-	373,097	-	-	-	-	373,097	6.28%
5.	Distribution OH Primary	-	-	-	-	417,035	-	-	-	417,035	7.02%
6.	Distribution OH Secondary	-	-	-	-	-	141,368	-	-	141,368	2.38%
7.	Distribution UG Lines	-	-	-	-	-	-	1,301,818	-	1,301,818	21.92%
8.	Distribution Line TXFs	-	-	-	-	-	-	-	459,064	459,064	7.73%
9.	Total	$ 3,246,348	$ -	$ -	$ 373,097	$ 417,035	$ 141,368	$ 1,301,818	$ 459,064	$ 5,938,729	100.00%

	Plant Classification	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
10.	Cust. Advances & Deposit	$ (167,525)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (167,525)	-33.69%
11.	Distribution OH Services	-	54,519	-	-	-	-	-	-	-	54,519	10.96%
12.	Distribution UG Services	-	-	156,147	-	-	-	-	-	-	156,147	31.40%
13.	Distribution Meters	-	-	-	259,184	-	-	-	-	-	259,184	52.12%
14.	Customer Accounts	-	-	-	-	97,289	-	-	-	-	97,289	19.56%
15.	Dusk to Dawn	-	-	-	-	-	24,846	-	-	-	24,846	5.00%
16.	Street Lighting	-	-	-	-	-	-	41,622	-	-	41,622	8.37%
17.	Customer Service & Info	-	-	-	-	-	-	-	7,139	-	7,139	1.44%
18.	Sales	-	-	-	-	-	-	-	-	24,039	24,039	4.83%
19.	Total	$ (167,525)	$ 54,519	$ 156,147	$ 259,184	$ 97,289	$ 24,846	$ 41,622	$ 7,139	$ 24,039	$ 497,261	100.00%

	Plant Classification	Total Energy	Total Energy %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS.
		(A)	(B)	(C)	(D)	(E)
20.	Production - Energy	$ 134,784	100.00%	$ -	-	$ -
21.	System Benefits	-	-	200,377	100.00%	-
22.	TOTAL ACC	-	-	-	-	6,771,151 (a)

Supporting Schedules:
N/A

Recap Schedules:
(a) G-3

G6

ARIZONA PUBLIC SERVICE COMPANY
DISTRIBUTION OF EXPENSES BY FUNCTION
OPERATING EXPENSES EXCLUDING INCOME TAXES
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	$ 722,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 722,067	56.51%
2.	Transmission Substation	-	-	-	-	-	-	-	-	-	0.00%
3.	Transmission Lines	-	-	255,757	-	-	-	-	-	255,757	20.02%
4.	Distribution Substation	-	-	-	43,133	-	-	-	-	43,133	3.38%
5.	Distribution OH Primary	-	-	-	-	64,874	-	-	-	64,874	5.08%
6.	Distribution OH Secondary	-	-	-	-	-	21,613	-	-	21,613	1.69%
7.	Distribution UG Lines	-	-	-	-	-	-	128,437	-	128,437	10.05%
8.	Distribution Line TXFs	-	-	-	-	-	-	-	41,891	41,891	3.28%
9.	Total	$ 722,067	$ -	$ 255,757	$ 43,133	$ 64,874	$ 21,613	$ 128,437	$ 41,891	$ 1,277,773	100.00%

	Plant Classification	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
10.	Distribution OH Services	$ 8,396	$ -	$ -	$ -	$ -	$ -	$ -	$ -	8,396	4.08%
11.	Distribution UG Services	-	15,500	-	-	-	-	-	-	15,500	7.52%
12.	Distribution Meters	-	-	68,825	-	-	-	-	-	68,825	33.41%
13.	Customer Accounts	-	-	-	83,122	-	-	-	-	83,122	40.35%
14.	Dusk to Dawn	-	-	-	-	2,835	-	-	-	2,835	1.38%
15.	Street Lighting	-	-	-	-	-	4,289	-	-	4,289	2.08%
16.	Customer Service & Info	-	-	-	-	-	-	4,158	-	4,158	2.02%
17.	Sales	-	-	-	-	-	-	-	18,876	18,876	9.16%
18.	Total	$ 8,396	$ 15,500	$ 68,825	$ 83,122	$ 2,835	$ 4,289	$ 4,158	$ 18,876	$ 206,000	100.00%

	Plant Classification	Total Production - Energy	Total Energy %	Limited Income Discount	Limited Income Discount %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
19.	Production - Energy	$ 1,131,600	100.00%	$ -	$ -	$ -	-	$ -
20.	Limited Income Discount	-	-	-35,634	100.00%	-	-	-
21.	System Benefits	-	-	-	-	57,251	100.00%	-
22.	TOTAL ACC	-	-	-	-	-	-	2,636,990

Supporting Schedules:
N/A

Recap Schedules:
(a) G-4

G7

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RETAIL: RESIDENTIAL	GENERAL SERVICE	E-221 (Water Pumping)	Street Lighting	Dusk to Dawn
		A	B	C	D	E	F	G	H	I
	CUSTOMER COUNT ALLOCATORS									
1	CUST371 Dusk to Dawn Customer Class Specific (%)	100	100	-	100	-	-	-	-	100
	CUST371 Dusk to Dawn	100.00%	100.00%	-	100.00%	-	-	-	-	100.00%
2	CUST373 Street Lighting Customer Class Specific (%)	100	100	-	100	-	-	-	100	-
	CUST373 Street Lighting	100.00%	100.00%	-	100.00%	-	-	-	100.00%	-
3	CUST910 Number of Customer Accounts	1,198,428	1,198,428	-	1,198,428	1,059,292	128,290	1,450	1,153	8,243
	CUST910 Customer Service and Information	100.00%	100.00%	-	100.00%	88.39%	10.70%	0.12%	0.10%	0.69%
4	CUST916 Number of Customer Accounts	1,199,961	1,198,428	1,533	1,198,428	1,059,292	128,290	1,450	1,153	8,243
	CUST916 Sales Expense	100.00%	99.87%	0.13%	99.87%	88.28%	10.69%	0.12%	0.10%	0.69%
5	CUSTNUM Number of Customer Accounts	1,199,961	1,198,428	1,533	1,198,428	1,059,292	128,290	1,450	1,153	8,243
	CUSTNUM Customer Accounts	100.00%	99.87%	0.13%	99.87%	88.28%	10.69%	0.12%	0.10%	0.69%
6	CUSTNUM_A Number of Customer Accounts ACC	1,198,428	1,198,428	-	1,198,428	1,059,292	128,290	1,450	1,153	8,243
	CUSTNUM_A Customer Accounts ACC	100.00%	100.00%	-	100.00%	88.39%	10.70%	0.12%	0.10%	0.69%
	CUSTOMER COST ALLOCATORS									
7	CUST370 Costs for Distribution Meters ($)	$196,395,680	$195,047,312	$1,348,368	$195,047,312	$158,604,677	$35,227,831	$1,214,805	-	-
	CUST370 Distribution Meters	100.00%	99.31%	0.69%	99.31%	80.76%	17.94%	0.62%	-	-
8	CUSTOH1 Weighted Customer Costs for Distribution Services ($)	$103,448,982	$103,448,982	-	$103,448,982	$90,280,256	$12,883,536	$285,190	-	-
	CUSTOH1 Distribution OH Services	100.00%	100.00%	-	100.00%	87.27%	12.45%	0.28%	-	-
9	CUSTUG1 Weighted Customer Costs for Distribution Services ($)	$609,462,925	$609,462,925	-	$609,462,925	$435,561,435	$169,672,086	$4,229,404	-	-
	CUSTUG1 Distribution UG Services	100.00%	100.00%	-	100.00%	71.47%	27.84%	0.69%	-	-
	DISTRIBUTION DEMAND ALLOCATORS									
10	DEMDIST1 NCP Demand @ Substation Level w/losses (KW)	7,397,196	7,397,196	-	7,397,196	4,558,623	2,722,612	73,386	36,962	5,613
	DEMDIST1 Distribution Substation	100.00%	100.00%	-	100.00%	61.63%	36.81%	0.99%	0.50%	0.08%
11	DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)	7,209,743	7,209,743	-	7,209,743	4,443,103	2,653,618	71,526	36,025	5,471
	DEMDIST2 Distribution OH Primary Lines	100.00%	100.00%	-	100.00%	61.63%	36.81%	0.99%	0.50%	0.08%
12	DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,298,743	7,298,743	-	7,298,743	7,258,543	-	-	34,900	5,300
	DEMDIST3 Distribution OH Secondary Lines	100.00%	100.00%	-	100.00%	99.45%	-	-	0.48%	0.07%
13	DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)	7,209,743	7,209,743	-	7,209,743	4,443,103	2,653,618	71,526	36,025	5,471
	DEMDIST4 Distribution UG Primary Lines	100.00%	100.00%	-	100.00%	61.63%	36.81%	0.99%	0.50%	0.08%
14	DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,298,743	7,298,743	-	7,298,743	7,258,543	-	-	34,900	5,300
	DEMDIST5 Distribution UG Secondary Lines	100.00%	100.00%	-	100.00%	99.45%	-	-	0.48%	0.07%
15	DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	9,921,087	9,921,087	-	9,921,087	7,396,455	2,357,400	126,268	35,563	5,401
	DEMDIST6 Distribution OH Line Transformers	100.00%	100.00%	-	100.00%	74.55%	23.76%	1.27%	0.36%	0.05%
16	DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	10,774,189	10,774,189	-	10,774,189	7,396,455	3,210,502	126,268	35,563	5,401
	DEMDIST7 Distribution UG Line Transformers	100.00%	100.00%	-	100.00%	68.65%	29.80%	1.17%	0.33%	0.05%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	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
		A	B	C	D	E	F	G	H	I
	PRODUCTION DEMAND ALLOCATORS									
17	DEMPROD1 Average & Excess @ Generation (All Other 4CP) (%)	1.00	0.99	0.01	0.99	0.59	0.39	0.01	0.00	0.00
	DEMPROD1 Production Demand	**100.00%**	**99.46%**	**0.54%**	**99.46%**	**59.11%**	**38.79%**	**0.99%**	**0.49%**	**0.08%**
18	DEMPROD6 Specific Assignment	100	-	100	-	-	-	-	-	-
	DEMPROD6 Ancillary Service - Scheduling & Dispatch	**100.00%**	-	**100.00%**	-	-	-	-	-	-
	TRANSMISSION DEMAND ALLOCATORS									
19	DEMTRAN1 Specific Assignment	100	-	100	-	-	-	-	-	-
	DEMTRAN1 Transmission Substation	**100.00%**	-	**100.00%**	-	-	-	-	-	-
20	DEMTRAN3 Specific Assignment	100	-	100	-	-	-	-	-	-
	DEMTRAN3 Transmission Lines	**100.00%**	-	**100.00%**	-	-	-	-	-	-
21	DEMTRAN4 4CP @ Generation (KW)	6,357,311	6,322,719	34,592	6,322,719	3,803,121	2,478,188	41,410	-	-
	DEMTRAN4 Transmission	100.00%	99.46%	0.54%	99.46%	59.82%	38.98%	0.65%	-	-
	ENERGY ALLOCATORS									
22	ENERGY1 Customer Class Energy @ Generation including AG-1 (MWH)	30,309,517	30,103,466	206,051	30,103,466	14,577,927	14,980,348	357,752	162,630	24,809
	ENERGY1 Production - Energy	**100.00%**	**99.32%**	**0.68%**	**99.32%**	**48.10%**	**49.42%**	**1.18%**	**0.54%**	**0.08%**
23	ENERGY1_GS General Service Energy @ Generation including AG-1 (MWH)	14,980,348	14,980,348	-	14,980,348	-	14,980,348	-	-	-
	ENERGY1_GS General Service Energy	**100.00%**	**100.00%**	-	**100.00%**	-	**100.00%**	-	-	-
24	ENERGY2 Weighted Hourly Energy Allocator @ Generation including AG-1 (%)	100.00%	99.32%	0.68%	99.32%	48.46%	49.20%	1.15%	0.44%	0.07%
	ENERGY2 Production - Energy (Fuel and Purchased Power)	100.00%	99.32%	0.68%	99.32%	48.46%	49.20%	1.15%	0.44%	0.07%
25	ENERGY2_XAG1 Weighted Hourly Energy Allocator @ Generation excluding AG-1 (%)	100.00%	99.29%	0.71%	99.29%	50.23%	47.34%	1.19%	0.45%	0.07%
	ENERGY2_XAG1 Production - Energy (Fuel and Purchased Power)	**100.00%**	**99.29%**	**0.71%**	**99.29%**	**50.23%**	**47.34%**	**1.19%**	**0.45%**	**0.07%**
26	ERGSYSBEN Customer Class Energy @ Generation (MWH)	30,309,517	30,103,466	206,051	30,103,466	14,577,927	14,980,348	357,752	162,630	24,809
	ERGSYSBEN System Benefits - Energy Related	**100.00%**	**99.32%**	**0.68%**	**99.32%**	**48.10%**	**49.42%**	**1.18%**	**0.54%**	**0.08%**
	ACC SPECIFIC ALLOCATORS									
27	Retail DEMPROD1 Average & Excess @ Generation (%)	99.46%	99.46%	-	99.46%	59.11%	38.79%	0.99%	0.49%	0.08%
	Retail DEMPROD1 Production Demand	**100.00%**	**100.00%**	-	**100.00%**	**59.43%**	**39.00%**	**1.00%**	**0.50%**	**0.08%**
28	Retail DEMTRAN4 4CP @ Generation	6,322,719	6,322,719	-	6,322,719	3,803,121	2,478,188	41,410	-	-
	Retail DEMTRAN4 4CP- Transmission	**100.00%**	**100.00%**	-	**100.00%**	**60.15%**	**39.19%**	**0.65%**	-	-
29	Retail ENERGY1 Customer Class Energy @ Generation (MWH)	30,103,466	30,103,466	-	30,103,466	14,577,927	14,980,348	357,752	162,630	24,809
	Retail ENERGY1 Production - Energy	**100.00%**	**100.00%**	-	**100.00%**	**48.43%**	**49.76%**	**1.19%**	**0.54%**	**0.08%**
30	Retail ENERGY2 Customer Class Energy @ Generation including AG-1 (%)	99.32%	99.32%	-	99.32%	48.46%	49.20%	1.15%	0.44%	0.07%
	Retail ENERGY2 Production - Energy	**100.00%**	**100.00%**	-	**100.00%**	**48.79%**	**49.54%**	**1.16%**	**0.44%**	**0.07%**
31	Retail ENERGY2_XAG1 Customer Class Energy @ Generation excluding AG-1 (%)	99.29%	99.29%	-	99.29%	50.23%	47.34%	1.19%	0.45%	0.07%
	Retail ENERGY2_XAG1 Production - Energy	100.00%	100.00%	-	100.00%	50.59%	47.68%	1.20%	0.46%	0.07%
32	Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)	30,103,466	30,103,466	-	30,103,466	14,577,927	14,980,348	357,752	162,630	24,809
	Retail ERGSYSBEN System Benefits - Energy Related	**100.00%**	**100.00%**	-	**100.00%**	**48.43%**	**49.76%**	**1.19%**	**0.54%**	**0.08%**

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RETAIL: RESIDENTIAL	GENERAL SERVICE	E-221 (Water Pumping)	Street Lighting	Dusk to Dawn
		A	B	C	D	E	F	G	H	I
	ACC SPECIFIC ALLOCATORS FOR SOLAR CREDITS									
33	Retail DEMPROD1_XSOL Average & Excess @ Generation (All Other 4CP)	96.80%	96.80%	-	96.80%	56.44%	38.79%	0.99%	0.49%	0.08%
	Retail DEMPROD1_XSOL Production Demand (excld Solar)	100.00%	100.00%	-	100.00%	58.31%	40.08%	1.02%	0.51%	0.08%
34	Retail DEMDIST1_XSOL NCP Demand @ Substation Level w/losses (KW)	7,190,435	7,190,435	-	7,190,435	4,351,862	2,722,612	73,386	36,962	5,613
	Retail DEMDIST1_XSOL Distribution Substation (excld Solar)	100.00%	100.00%	-	100.00%	60.52%	37.86%	1.02%	0.51%	0.08%
35	Retail DEMDIST2_XSOL Demand @ Primary Line Level w/losses (KW)	7,008,221	7,008,221	-	7,008,221	4,241,581	2,653,618	71,526	36,025	5,471
	Retail DEMDIST2_XSOL Distribution Primary (excld Solar)	100.00%	100.00%	-	100.00%	60.52%	37.86%	1.02%	0.51%	0.08%
36	Retail DEMDIST3_XSOL Demand @ Secondary Line Level w/losses (KW)	7,005,689	7,005,689	-	7,005,689	6,965,489	-	-	34,900	5,300
	Retail DEMDIST3_XSOL Distribution Secondary (excld Solar)	100.00%	100.00%	-	100.00%	99.43%	-	-	0.50%	0.08%
37	Retail DEMTRAN_XSOL 4CP Demand @ Generation	6,143,454	6,143,454	-	6,143,454	3,623,856	2,478,188	41,410	-	-
	Retail DEMTRAN_XSOL Transmission (excld Solar)	100.00%	100.00%	-	100.00%	58.99%	40.34%	0.67%	-	-
38	Retail ENERGY2_XAG1_XSOL Customer Class Energy @ Generation excluding AG-1 MWH	97.19%	97.19%	-	97.19%	48.13%	47.34%	1.19%	0.45%	0.07%
	Retail ENERGY2_XAG1_XSOL Production - Energy (excld Solar)	100.00%	100.00%	-	100.00%	49.52%	48.71%	1.23%	0.47%	0.07%
	REVENUE ALLOCATORS									
39	CUSTADV Customer Advances	$93,997,866	$93,997,866	-	$93,997,866	$49,312,204	$44,411,864	$129,237	$144,561	-
	CUSTADV Customer Advances	100.00%	100.00%	-	100.00%	52.46%	47.25%	0.14%	0.15%	-
40	CUSTDEP Customer Deposits	(72,621,690)	(72,621,690)	-	(72,621,690)	(38,578,117)	(32,616,324)	(706,920)	(511,132)	(209,197)
	CUSTDEP Customer Deposits	100.00%	100.00%	-	100.00%	53.12%	44.91%	0.97%	0.70%	0.29%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	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
		J	K	L	M	N	O	P	Q	R	S	T
	CUSTOMER COUNT ALLOCATORS											
1	CUST371 Dusk to Dawn Customer Class Specific (%)	-	-	-	-	-	-	-	-	-	-	-
	CUST371 Dusk to Dawn	-	-	-	-	-	-	-	-	-	-	-
2	CUST373 Street Lighting Customer Class Specific (%)	-	-	-	-	-	-	-	-	-	-	-
	CUST373 Street Lighting	-	-	-	-	-	-	-	-	-	-	-
3	CUST910 Number of Customer Accounts	128,290	405	379	73	55	122	122,044	4,231	911	28	42
	CUST910 Customer Service and Information	10.70%	0.03%	0.03%	0.01%	0.00%	0.01%	10.18%	0.35%	0.08%	0.00%	0.00%
4	CUST916 Number of Customer Accounts	128,290	405	379	73	55	122	122,044	4,231	911	28	42
	CUST916 Sales Expense	10.69%	0.03%	0.03%	0.01%	0.00%	0.01%	10.17%	0.35%	0.08%	0.00%	0.00%
5	CUSTNUM Number of Customer Accounts	128,290	405	379	73	55	122	122,044	4,231	911	28	42
	CUSTNUM Customer Accounts	10.69%	0.03%	0.03%	0.01%	0.00%	0.01%	10.17%	0.35%	0.08%	0.00%	0.00%
6	CUSTNUM_A Number of Customer Accounts ACC	128,290	405	379	73	55	122	122,044	4,231	911	28	42
	CUSTNUM_A Customer Accounts ACC	10.70%	0.03%	0.03%	0.01%	0.00%	0.01%	10.18%	0.35%	0.08%	0.00%	0.00%
	CUSTOMER COST ALLOCATORS											
7	CUST370 Costs for Distribution Meters ($)	$35,227,831	$338,840	$140,277	$241,529	$134,402	$118,225	$28,175,007	$3,743,714	$1,689,850	$264,876	$381,111
	CUST370 Distribution Meters	17.94%	0.17%	0.07%	0.12%	0.07%	0.06%	14.35%	1.91%	0.86%	0.13%	0.19%
8	CUSTOH1 Weighted Customer Costs for Distribution Services ($)	$12,883,536	$39,875	$36,716	$10,270	-	$23,700	$11,972,705	$800,270	-	-	-
	CUSTOH1 Distribution OH Services	12.45%	0.04%	0.04%	0.01%	-	0.02%	11.57%	0.77%	-	-	-
9	CUSTUG1 Weighted Customer Costs for Distribution Services ($)	$169,672,086	$481,080	$451,013	$213,606	$557,190	$357,305	$145,047,203	$12,342,558	$9,295,560	$367,133	$559,440
	CUSTUG1 Distribution UG Services	27.84%	0.08%	0.07%	0.04%	0.09%	0.06%	23.80%	2.03%	1.53%	0.06%	0.09%
	DISTRIBUTION DEMAND ALLOCATORS											
10	DEMDIST1 NCP Demand @ Substation Level w/losses (KW)	2,722,612	23,862	6,761	12,510	39,820	38,634	1,005,398	670,757	579,390	125,140	220,340
	DEMDIST1 Distribution Substation	36.81%	0.32%	0.09%	0.17%	0.54%	0.52%	13.59%	9.07%	7.83%	1.69%	2.98%
11	DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)	2,653,618	23,257	6,590	12,193	38,811	37,655	979,920	653,759	564,707	121,969	214,757
	DEMDIST2 Distribution OH Primary Lines	36.81%	0.32%	0.09%	0.17%	0.54%	0.52%	13.59%	9.07%	7.83%	1.69%	2.98%
12	DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	-	-	-	-	-	-	-	-	-	-	-
	DEMDIST3 Distribution OH Secondary Lines	-	-	-	-	-	-	-	-	-	-	-
13	DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)	2,653,618	23,257	6,590	12,193	38,811	37,655	979,920	653,759	564,707	121,969	214,757
	DEMDIST4 Distribution UG Primary Lines	36.81%	0.32%	0.09%	0.17%	0.54%	0.52%	13.59%	9.07%	7.83%	1.69%	2.98%
14	DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	-	-	-	-	-	-	-	-	-	-	-
	DEMDIST5 Distribution UG Secondary Lines	-	-	-	-	-	-	-	-	-	-	-
15	DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	2,357,400	28,087	10,240	14,906	-	47,432	1,432,249	824,486	-	-	-
	DEMDIST6 Distribution OH Line Transformers	23.76%	0.28%	0.10%	0.15%	-	0.48%	14.44%	8.31%	-	-	-
16	DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	3,210,502	28,087	10,240	14,906	45,952	47,432	1,432,249	824,486	590,849	45,971	170,330
	DEMDIST7 Distribution UG Line Transformers	29.80%	0.26%	0.10%	0.14%	0.43%	0.44%	13.29%	7.65%	5.48%	0.43%	1.58%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	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
		J	K	L	M	N	O	P	Q	R	S	T
	PRODUCTION DEMAND ALLOCATORS											
17	DEMPROD1 Average & Excess @ Generation (All Other 4CP) (%)	0.39	0.00	0.00	0.00	0.01	0.00	0.13	0.09	0.08	0.02	0.05
	DEMPROD1 Production Demand	38.79%	0.30%	0.09%	0.17%	0.57%	0.50%	13.41%	9.12%	8.08%	1.99%	4.55%
18	DEMPROD6 Specific Assignment	-	-	-	-	-	-	-	-	-	-	-
	DEMPROD6 Ancillary Service - Scheduling & Dispatch	-	-	-	-	-	-	-	-	-	-	-
	TRANSMISSION DEMAND ALLOCATORS											
19	DEMTRAN1 Specific Assignment	-	-	-	-	-	-	-	-	-	-	-
	DEMTRAN1 Transmission Substation	-	-	-	-	-	-	-	-	-	-	-
20	DEMTRAN3 Specific Assignment	-	-	-	-	-	-	-	-	-	-	-
	DEMTRAN3 Transmission Lines	-	-	-	-	-	-	-	-	-	-	-
21	DEMTRAN4 4CP @ Generation (KW)	2,478,188	9,997	5,831	11,112	32,865	15,156	892,681	570,789	523,514	128,718	287,525
	DEMTRAN4 Transmission	38.98%	0.16%	0.09%	0.17%	0.52%	0.24%	14.04%	8.98%	8.23%	2.02%	4.52%
	ENERGY ALLOCATORS											
22	ENERGY1 Customer Class Energy @ Generation including AG-1 (MWH)	14,980,348	41,247	39,294	76,760	261,223	111,875	4,364,826	3,437,226	3,494,441	860,277	2,293,179
	ENERGY1 Production - Energy	49.42%	0.14%	0.13%	0.25%	0.86%	0.37%	14.40%	11.34%	11.53%	2.84%	7.57%
23	ENERGY1_GS General Service Energy @ Generation including AG-1 (MWH)	14,980,348	41,247	39,294	76,760	261,223	111,875	4,364,826	3,437,226	3,494,441	860,277	2,293,179
	ENERGY1_GS General Service Energy	100.00%	0.28%	0.26%	0.51%	1.74%	0.75%	29.14%	22.94%	23.33%	5.74%	15.31%
24	ENERGY2 Weighted Hourly Energy Allocator @ Generation including AG-1 (%)	49.20%	0.14%	0.13%	0.25%	0.84%	0.36%	14.54%	11.38%	11.42%	2.80%	7.35%
	ENERGY2 Production - Energy (Fuel and Purchased Power)	49.20%	0.14%	0.13%	0.25%	0.84%	0.36%	14.54%	11.38%	11.42%	2.80%	7.35%
25	ENERGY2_XAG1 Weighted Hourly Energy Allocator @ Generation excluding AG-1 (%)	47.34%	0.14%	0.13%	0.26%	0.87%	0.37%	15.07%	11.64%	10.34%	2.47%	6.04%
	ENERGY2_XAG1 Production - Energy (Fuel and Purchased Power)	47.34%	0.14%	0.13%	0.26%	0.87%	0.37%	15.07%	11.64%	10.34%	2.47%	6.04%
26	ERGSYSBEN Customer Class Energy @ Generation (MWH)	14,980,348	41,247	39,294	76,760	261,223	111,875	4,364,826	3,437,226	3,494,441	860,277	2,293,179
	ERGSYSBEN System Benefits - Energy Related	49.42%	0.14%	0.13%	0.25%	0.86%	0.37%	14.40%	11.34%	11.53%	2.84%	7.57%
	ACC SPECIFIC ALLOCATORS											
27	Retail DEMPROD1 Average & Excess @ Generation (%)	38.79%	0.30%	0.09%	0.17%	0.57%	0.50%	13.41%	9.12%	8.08%	1.99%	4.55%
	Retail DEMPROD1 Production Demand	39.00%	0.30%	0.09%	0.18%	0.57%	0.50%	13.48%	9.17%	8.13%	2.00%	4.57%
28	Retail DEMTRAN4 4CP @ Generation	2,478,188	9,997	5,831	11,112	32,865	15,156	892,681	570,789	523,514	128,718	287,525
	Retail DEMTRAN4 4CP- Transmission	39.19%	0.16%	0.09%	0.18%	0.52%	0.24%	14.12%	9.03%	8.28%	2.04%	4.55%
29	Retail ENERGY1 Customer Class Energy @ Generation (MWH)	14,980,348	41,247	39,294	76,760	261,223	111,875	4,364,826	3,437,226	3,494,441	860,277	2,293,179
	Retail ENERGY1 Production - Energy	49.76%	0.14%	0.13%	0.25%	0.87%	0.37%	14.50%	11.42%	11.61%	2.86%	7.62%
30	Retail ENERGY2 Customer Class Energy @ Generation including AG-1 (%)	49.20%	0.14%	0.13%	0.25%	0.84%	0.36%	14.54%	11.38%	11.42%	2.80%	7.35%
	Retail ENERGY2 Production - Energy	49.54%	0.14%	0.13%	0.25%	0.84%	0.36%	14.64%	11.46%	11.50%	2.82%	7.41%
31	Retail ENERGY2_XAG1 Customer Class Energy @ Generation excluding AG-1 (%)	47.34%	0.14%	0.13%	0.26%	0.87%	0.37%	15.07%	11.64%	10.34%	2.47%	6.04%
	Retail ENERGY2_XAG1 Production - Energy	47.68%	0.15%	0.13%	0.26%	0.87%	0.38%	15.18%	11.72%	10.41%	2.49%	6.08%
32	Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)	14,980,348	41,247	39,294	76,760	261,223	111,875	4,364,826	3,437,226	3,494,441	860,277	2,293,179
	Retail ERGSYSBEN System Benefits - Energy Related	49.76%	0.14%	0.13%	0.25%	0.87%	0.37%	14.50%	11.42%	11.61%	2.86%	7.62%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	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
		J	K	L	M	N	O	P	Q	R	S	T
	ACC SPECIFIC ALLOCATORS FOR SOLAR CREDITS											
33	Retail DEMPROD1_XSOL Average & Excess @ Generation (All Other 4CP)	38.79%	0.30%	0.09%	0.17%	0.57%	0.50%	13.41%	9.12%	8.08%	1.99%	4.55%
	Retail DEMPROD1_XSOL Production Demand (excld Solar)	40.08%	0.31%	0.10%	0.18%	0.59%	0.51%	13.86%	9.43%	8.35%	2.06%	4.70%
34	Retail DEMDIST1_XSOL NCP Demand @ Substation Level w/losses (KW)	2,722,612	23,862	8,761	12,510	39,820	38,634	1,005,398	670,757	579,390	125,140	220,340
	Retail DEMDIST1_XSOL Distribution Substation (excld Solar)	37.86%	0.33%	0.09%	0.17%	0.55%	0.54%	13.98%	9.33%	8.06%	1.74%	3.06%
35	Retail DEMDIST2_XSOL Demand @ Primary Line Level w/losses (KW)	2,653,618	23,257	8,590	12,193	38,811	37,655	979,920	653,759	564,707	121,969	214,757
	Retail DEMDIST2_XSOL Distribution Primary (excld Solar)	37.86%	0.33%	0.09%	0.17%	0.55%	0.54%	13.98%	9.33%	8.06%	1.74%	3.06%
36	Retail DEMDIST3_XSOL Demand @ Secondary Line Level w/losses (KW)	-	-	-	-	-	-	-	-	-	-	-
	Retail DEMDIST3_XSOL Distribution Secondary (excld Solar)	-	-	-	-	-	-	-	-	-	-	-
37	Retail DEMTRAN_XSOL 4CP Demand @ Generation	2,478,188	9,997	5,831	11,112	32,865	15,156	892,681	570,789	523,514	128,718	287,525
	Retail DEMTRAN_XSOL Transmission (excld Solar)	40.34%	0.16%	0.09%	0.18%	0.53%	0.25%	14.53%	9.29%	8.52%	2.10%	4.68%
38	Retail ENERGY2_XAG1_XSOL Customer Class Energy @ Generation excluding AG-1 MWH	47.34%	0.14%	0.13%	0.26%	0.87%	0.37%	15.07%	11.64%	10.34%	2.47%	6.04%
	Retail ENERGY2_XAG1_XSOL Production - Energy (excld Solar)	48.71%	0.15%	0.13%	0.27%	0.89%	0.39%	15.51%	11.97%	10.64%	2.54%	6.22%
	REVENUE ALLOCATORS											
39	CUSTADV Customer Advances	$44,411,864	$138,570	$138,776	$227,038	$692,698	$370,558	$17,049,428	$10,389,684	$9,014,683	$1,893,476	$4,496,952
	CUSTADV Customer Advances	47.25%	0.15%	0.15%	0.24%	0.74%	0.39%	18.14%	11.05%	9.59%	2.01%	4.78%
40	CUSTDEP Customer Deposits	(32,616,324)	(101,767)	(101,918)	(166,738)	(508,722)	(272,140)	(12,521,197)	(7,630,243)	(6,620,434)	(1,390,579)	(3,302,587)
	CUSTDEP Customer Deposits	44.91%	0.14%	0.14%	0.23%	0.70%	0.37%	17.24%	10.51%	9.12%	1.91%	4.55%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	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
		U	V	W	X	Y	Z
	CUSTOMER COUNT ALLOCATORS						
1	CUST371 Dusk to Dawn Customer Class Specific (%)	-	-	-	-	-	-
	CUST371 Dusk to Dawn	-	-	-	-	-	-
2	CUST373 Street Lighting Customer Class Specific (%)	-	-	-	-	-	-
	CUST373 Street Lighting	-	-	-	-	-	-
3	CUST910 Number of Customer Accounts	1,059,292	35,988	1,311	473,340	429,763	118,890
	CUST910 Customer Service and Information	88.39%	3.00%	0.11%	39.50%	35.86%	9.92%
4	CUST916 Number of Customer Accounts	1,059,292	35,988	1,311	473,340	429,763	118,890
	CUST916 Sales Expense	88.28%	3.00%	0.11%	39.45%	35.81%	9.91%
5	CUSTNUM Number of Customer Accounts	1,059,292	35,988	1,311	473,340	429,763	118,890
	CUSTNUM Customer Accounts	88.28%	3.00%	0.11%	39.45%	35.81%	9.91%
6	CUSTNUM_A Number of Customer Accounts ACC	1,059,292	35,988	1,311	473,340	429,763	118,890
	CUSTNUM_A Customer Accounts ACC	88.39%	3.00%	0.11%	39.50%	35.86%	9.92%
	CUSTOMER COST ALLOCATORS						
7	CUST370 Costs for Distribution Meters ($)	$158,604,677	$20,368,161	$741,988	$63,680,560	$57,817,950	$15,996,018
	CUST370 Distribution Meters	80.76%	10.37%	0.38%	32.42%	29.44%	8.14%
8	CUSTOH1 Weighted Customer Costs for Distribution Services ($)	$90,280,256	$3,067,008	$111,590	$40,341,424	$36,627,469	$10,132,765
	CUSTOH1 Distribution OH Services	87.27%	2.96%	0.11%	39.00%	35.41%	9.79%
9	CUSTUG1 Weighted Customer Costs for Distribution Services ($)	$435,561,435	$14,797,830	$539,288	$194,628,585	$176,710,553	$48,885,180
	CUSTUG1 Distribution UG Services	71.47%	2.43%	0.09%	31.93%	28.99%	8.02%
	DISTRIBUTION DEMAND ALLOCATORS						
10	DEMDIST1 NCP Demand @ Substation Level w/losses (KW)	4,558,623	196,171	10,590	1,132,215	2,289,599	930,048
	DEMDIST1 Distribution Substation	61.63%	2.65%	0.14%	15.31%	30.95%	12.57%
11	DEMDIST2 NCP Demand @ Primary Line Level w/losses (KW)	4,443,103	191,200	10,322	1,103,523	2,231,578	906,480
	DEMDIST2 Distribution OH Primary Lines	61.63%	2.65%	0.14%	15.31%	30.95%	12.57%
12	DEMDIST3 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,258,543	278,692	14,362	2,248,365	3,446,627	1,270,497
	DEMDIST3 Distribution OH Secondary Lines	99.45%	3.82%	0.20%	30.80%	47.22%	17.41%
13	DEMDIST4 NCP Demand @ Primary Line Level w/losses (KW)	4,443,103	191,200	10,322	1,103,523	2,231,578	906,480
	DEMDIST4 Distribution UG Primary Lines	61.63%	2.65%	0.14%	15.31%	30.95%	12.57%
14	DEMDIST5 Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,258,543	278,692	14,362	2,248,365	3,446,627	1,270,497
	DEMDIST5 Distribution UG Secondary Lines	99.45%	3.82%	0.20%	30.80%	47.22%	17.41%
15	DEMDIST6 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,396,455	283,987	14,635	2,291,084	3,512,113	1,294,636
	DEMDIST6 Distribution OH Line Transformers	74.55%	2.86%	0.15%	23.09%	35.40%	13.05%
16	DEMDIST7 Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,396,455	283,987	14,635	2,291,084	3,512,113	1,294,636
	DEMDIST7 Distribution UG Line Transformers	68.65%	2.64%	0.14%	21.26%	32.60%	12.02%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	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
		U	V	W	X	Y	Z
	PRODUCTION DEMAND ALLOCATORS						
17	DEMPROD1 Average & Excess @ Generation (All Other 4CP) (%)	0.59	0.03	0.00	0.15	0.30	0.12
	DEMPROD1 Production Demand	59.11%	2.53%	0.14%	14.80%	29.57%	12.07%
18	DEMPROD6 Specific Assignment	-	-	-	-	-	-
	DEMPROD6 Ancillary Service - Scheduling & Dispatch	-	-	-	-	-	-
	TRANSMISSION DEMAND ALLOCATORS						
19	DEMTRAN1 Specific Assignment	-	-	-	-	-	-
	DEMTRAN1 Transmission Substation	-	-	-	-	-	-
20	DEMTRAN3 Specific Assignment	-	-	-	-	-	-
	DEMTRAN3 Transmission Lines	-	-	-	-	-	-
21	DEMTRAN4 4CP @ Generation (KW)	3,803,121	169,931	9,334	963,249	1,889,750	770,857
	DEMTRAN4 Transmission	59.82%	2.67%	0.15%	15.15%	29.73%	12.13%
	ENERGY ALLOCATORS						
22	ENERGY1 Customer Class Energy @ Generation including AG-1 (MWH)	14,577,927	572,007	35,231	3,978,203	6,970,899	3,021,587
	ENERGY1 Production - Energy	48.10%	1.89%	0.12%	13.13%	23.00%	9.97%
23	ENERGY1_GS General Service Energy @ Generation including AG-1 (MWH)	-	-	-	-	-	-
	ENERGY1_GS General Service Energy	-	-	-	-	-	-
24	ENERGY2 Weighted Hourly Energy Allocator @ Generation including AG-1 (%)	48.46%	1.91%	0.12%	13.21%	23.24%	9.98%
	ENERGY2 Production - Energy (Fuel and Purchased Power)	48.46%	1.91%	0.12%	13.21%	23.24%	9.98%
25	ENERGY2_XAG1 Weighted Hourly Energy Allocator @ Generation excluding AG-1 (%)	50.23%	1.98%	0.12%	13.69%	24.09%	10.35%
	ENERGY2_XAG1 Production - Energy (Fuel and Purchased Power)	50.23%	1.98%	0.12%	13.69%	24.09%	10.35%
26	ERGSYSBEN Customer Class Energy @ Generation (MWH)	14,577,927	572,007	35,231	3,978,203	6,970,899	3,021,587
	ERGSYSBEN System Benefits - Energy Related	48.10%	1.89%	0.12%	13.13%	23.00%	9.97%
	ACC SPECIFIC ALLOCATORS						
27	Retail DEMPROD1 Average & Excess @ Generation (%)	59.11%	2.53%	0.14%	14.80%	29.57%	12.07%
	Retail DEMPROD1 Production Demand	59.43%	2.54%	0.14%	14.88%	29.73%	12.14%
28	Retail DEMTRAN4 4CP @ Generation	3,803,121	169,931	9,334	963,249	1,889,750	770,857
	Retail DEMTRAN4 4CP- Transmission	60.15%	2.69%	0.15%	15.23%	29.89%	12.19%
29	Retail ENERGY1 Customer Class Energy @ Generation (MWH)	14,577,927	572,007	35,231	3,978,203	6,970,899	3,021,587
	Retail ENERGY1 Production - Energy	48.43%	1.90%	0.12%	13.22%	23.16%	10.04%
30	Retail ENERGY2 Customer Class Energy @ Generation including AG-1 (%)	48.46%	1.91%	0.12%	13.21%	23.24%	9.98%
	Retail ENERGY2 Production - Energy	48.79%	1.93%	0.12%	13.30%	23.40%	10.05%
31	Retail ENERGY2_XAG1 Customer Class Energy @ Generation excluding AG-1 (%)	50.23%	1.98%	0.12%	13.69%	24.09%	10.35%
	Retail ENERGY2_XAG1 Production - Energy	50.59%	2.00%	0.12%	13.79%	24.26%	10.42%
32	Retail ERGSYSBEN Customer Class Energy @ Generation (MWH)	14,577,927	572,007	35,231	3,978,203	6,970,899	3,021,587
	Retail ERGSYSBEN System Benefits - Energy Related	48.43%	1.90%	0.12%	13.22%	23.16%	10.04%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2015

Line #	ALLOCATION FACTORS	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
		U	V	W	X	Y	Z
	ACC SPECIFIC ALLOCATORS FOR SOLAR CREDITS						
33	Retail DEMPROD1_XSOL Average & Excess @ Generation (All Other 4CP)	56.44%	-	-	14.80%	29.57%	12.07%
	Retail DEMPROD1_XSOL Production Demand (excld Solar)	58.31%	-	-	15.29%	30.55%	12.47%
34	Retail DEMDIST1_XSOL NCP Demand @ Substation Level w/losses (KW)	4,351,862	-	-	1,132,215	2,289,599	930,048
	Retail DEMDIST1_XSOL Distribution Substation (excld Solar)	60.52%	-	-	15.75%	31.84%	12.93%
35	Retail DEMDIST2_XSOL Demand @ Primary Line Level w/losses (KW)	4,241,581	-	-	1,103,523	2,231,578	906,480
	Retail DEMDIST2_XSOL Distribution Primary (excld Solar)	60.52%	-	-	15.75%	31.84%	12.93%
36	Retail DEMDIST3_XSOL Demand @ Secondary Line Level w/losses (KW)	6,965,489	-	-	2,248,365	3,446,627	1,270,497
	Retail DEMDIST3_XSOL Distribution Secondary (excld Solar)	99.43%	-	-	32.09%	49.20%	18.14%
37	Retail DEMTRAN_XSOL 4CP Demand @ Generation	3,623,856	-	-	963,249	1,889,750	770,857
	Retail DEMTRAN_XSOL Transmission (excld Solar)	58.99%	-	-	15.68%	30.76%	12.55%
38	Retail ENERGY2_XAG1_XSOL Customer Class Energy @ Generation excluding AG-1 MWH	48.13%	-	-	13.69%	24.09%	10.35%
	Retail ENERGY2_XAG1_XSOL Production - Energy (excld Solar)	49.52%	-	-	14.09%	24.79%	10.65%
	REVENUE ALLOCATORS						
39	CUSTADV Customer Advances	$49,312,204	$656,212	$75,364	$15,002,310	$24,145,286	$9,433,032
	CUSTADV Customer Advances	52.46%	0.70%	0.08%	15.96%	25.69%	10.04%
40	CUSTDEP Customer Deposits	(38,578,117)	(513,370)	(58,959)	(11,736,666)	(18,889,435)	(7,379,687)
	CUSTDEP Customer Deposits	53.12%	0.71%	0.08%	16.16%	26.01%	10.16%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

H1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING DECEMBER 31, 2015 ADJUSTED

		Base Revenues in the Test Year (a)		Proposed Increase (b)					
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
Line No.	Customer Classification	Present Rates [1, 2] ($000)	Proposed Rates [2] ($000)	Amount ($000) (B) - (A)	% (C) / (A)	Adjustor Transfers [3] ($000)	Net Change ($000) (C) - (E)	Net Increase [4] % (F) / (A)	Line No.
1.	Residential	$ 1,486,578	$ 1,773,473	$ 286,895	19.30%	$ 168,607	$ 118,288	7.96%	1.
2.	General Service	1,343,926	1,482,576	138,650	10.32%	94,409	44,241	3.29%	2.
3.	Irrigation/Water Pumping	28,739	33,631	4,892	17.02%	3,243	1,649	5.74%	3.
4.	Outdoor Lighting	21,082	23,212	2,130	10.10%	979	1,151	5.46%	4.
5.	Dusk to Dawn Lighting Service	8,578	9,445	867	10.11%	313	554	6.46%	5.
6.	Total Sales to Ultimate Retail Customers	$ 2,888,903	$ 3,322,337	$ 433,434	15.00%	$ 267,551	$ 165,883	5.74%	6.

Notes:
1) Base Revenues under Present Rates reflect adjusted Test Year revenues including applicable pro forma adjustments.
2) Present and Proposed Rates: base revenues include transmission costs based on OATT rates effective during Test Year.
3) Includes revenue from Test Year adjustor rates that are being transferred into base rates
4) Increase in base rates net of transfers of adjustor revenue. Represents the net increase in retail revenue and net impact on customers

Supporting Schedules:
(a) H-2

Recap Schedules:
(b) A-1

H2

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2015, ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer [(C) x 1000] / (B)	(E) Base Revenues under Present Rates[1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue Base Revenues ($000)	(H) Proposed Revenue Change - Base Rates ($000) (G) - (E)	(I) Proposed Revenue Change - Base Rates % (H) / (E)	(J) Net Increase With Adjustor Transfers ($000)	(K) Net Increase With Adjustor Transfers % (J) / (E)	Line No.
1.	Residential											1.
2.	E-12	466,329	3,788,787	8,125	455,125	R-XS	191,242					2.
3.	ET-1	133,692	2,163,526	16,183	238,379	R-2	421,646					3.
4.	ET-2	293,586	4,363,357	14,862	483,402	R-1	421,784					4.
5.	ECT-2	92,478	2,157,056	23,325	213,940	R-3	708,684					5.
6.	ECT-1R	26,272	677,273	25,779	67,575							6.
7.	ET-SP	1,559	22,959	14,727	2,527							7.
8.	ET-EV	218	5,361	24,592	532							8.
9.	Subtotal	1,014,134	13,178,319	12,995	1,461,480	Subtotal	1,743,356	281,876	19.29%	116,156	7.95%	9.
10.	E-12 (with solar)	12,019	39,519	3,288	5,183	E-12 Solar Legacy	6,255	1,072	20.68%	480	9.26%	10.
11.	ET-1 (with solar)	5,584	46,840	8,388	4,526	ET-1 Solar Legacy	5,429	903	19.95%	364	8.04%	11.
12.	ET-2 (with solar)	14,019	132,410	9,445	13,022	ET-2 Solar Legacy	15,600	2,578	19.80%	1,061	8.15%	12.
13.	ECT-2 (with solar)	883	13,161	14,905	1,606	ECT-2 Solar Legacy	1,922	316	19.68%	153	9.53%	13.
14.	ECT-1R (with solar)	351	6,286	17,909	761	ECT-1R Solar Legacy	911	150	19.71%	74	9.72%	14.
15.	Subtotal	32,856	238,216	7,250	25,098	Subtotal	30,117	5,019	20.00%	2,132	8.49%	15.
16.	Total Residential	1,046,990	13,416,535	12,814	1,486,578	Total Residential	1,773,473	286,895	19.30%	118,288	7.96%	16.

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2015, ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer [(C) x 1000] / (B)	(E) Base Revenues under Present Rates[1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue Base Revenues ($000)	(H) Proposed Revenue Change - Base Rates ($000) (G) - (E)	(I) Proposed Revenue Change - Base Rates % (H) / (E)	(J) Net Increase With Adjustor Transfers ($000)	(K) Net Increase With Adjustor Transfers % (J) / (E)	Line No.
17.	General Service											17.
18.	E-20	406	37,652	92,739	4,069	E-20	4,896	828	20.34%	367	9.01%	18.
19.	E-30	4,420	5,082	1,150	1,206	E-30	1,310	105	8.67%	50	4.11%	19.
20.	E-32 XS	100,532	1,489,451	14,816	210,347	E-32 XS	228,463	18,116	8.61%	(82)	-0.04%	20.
21.	E-32 XS Solar Legacy	-	4,359	-	802	E-32 XS Solar Legacy	871	69	8.60%	-	0.00%	21.
22.	E-32 S	16,657	2,586,160	155,260	299,099	E-32 S	324,861	25,762	8.61%	213	0.07%	22.
23.	E-32 M	4,221	3,138,247	743,484	305,191	E-32 M (includes AG-1)	344,902	36,077	11.68%	12,372	4.01%	23.
24.	E-32 M (AG-1)	28	43,488	1,553,143	3,634							24.
25.	E-32 L	786	2,838,787	3,611,688	239,240	E-32 L (includes AG-1)	302,474	30,296	11.13%	16,507	6.06%	25.
26.	E-32 L (AG-1)	116	405,944	3,499,517	32,938							26.
27.	E-32TOU XS	249	5,939	23,851	792	E-32TOU XS	860	68	8.59%	3	0.38%	27.
28.	E-32TOU S	129	30,814	238,868	3,376	E-32TOU S	3,667	291	8.62%	22	0.65%	28.
29.	E-32TOU M	75	71,307	950,760	6,774	E-32TOU M	7,566	792	11.69%	309	4.56%	29.
30.	E-32TOU L	57	240,589	4,220,860	20,381	E-32TOU L (includes AG-1)	23,571	2,363	11.14%	1,266	5.97%	30.
31.	E-32TOU (AG-1)	4	11,695	2,923,750	827							31.
32.	E-34	249	710,025	2,851,506	50,469	(E-34, E-35, XHLF, AG-1)	225,094	22,017	10.84%	12,469	6.14%	32.
33.	E-34 (AG-1)	4	124,018	31,004,500	9,373							33.
34.	E-35	129	1,469,900	11,394,574	97,503							34.
35.	E-35 (AG-1)	4	465,141	116,285,250	28,956							35.
36.	XHLF	3	295,954	98,651,333	16,776							36.
37.	E-36 M	11	8,626	784,182	829	E-36 M	952	123	14.78%	62	7.42%	37.
38.	GS-S M	57	46,667	818,719	5,421	GS-S M	6,257	836	15.41%	348	6.41%	38.
39.	GS-S L	24	60,100	2,504,167	5,924	GS-S L	6,834	910	15.35%	338	5.70%	39.
40.	Subtotal	128,161	14,089,945		1,343,926	Subtotal	1,482,576	138,650	10.32%	44,241	3.29%	40.

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2015, ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer [(C) x 1000] / (B)	(E) Base Revenues under Present Rates[1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue Base Revenues ($000)	(H) Proposed Revenue Change - Base Rates ($000) (G) - (E)	(I) Proposed Revenue Change - Base Rates % (H) / (E)	(J) Net Increase With Adjustor Transfers ($000)	(K) Net Increase With Adjustor Transfers % (J) / (E)	Line No.
41.	Irrigation	75	334,226	4,456,347	28,739	Irrigation	33,631	4,892	17.02%	1,649	5.74%	41.
42.	Outdoor Lighting											42.
43.	E-58	1,465	28,119	19,194	9,169	E-58	10,095	926	10.10%	592	6.46%	43.
44.	E-59	59	99,829	1,692,017	10,166	E-59	11,194	1,028	10.11%	513	5.05%	44.
45.	E-67	63	9,767	155,032	503	E-67	554	51	10.14%	3	0.60%	45.
46.	Contract 12	3	14,190	4,730,000	1,244	Contract 12	1,369	125	10.05%	43	3.46%	46.
47.	Subtotal	1,590	151,905		21,082	Subtotal	23,212	2,130	10.10%	1,151	5.46%	47.
48.	Dusk to Dawn Lighting [3]		23,004		8,578	Dusk to Dawn Lighting [3]	9,445	867	10.11%	554	6.46%	48.
49.	Total Retail	1,176,816	28,015,615	23,806	2,888,903		3,322,337	433,434		165,883	5.74%	49.

1) Base Revenues under Present Rates reflect adjusted test year revenues based on rates established in Decision No. 73183.
2) MWh and sales excludes revenue credits. MWh with revenue credits = 28,182,412
3) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.

Additional Notes
Rider rate schedules are included in the "Parent" rate schedules listed on schedule H-2 as applicable.
Riders include: E-3, E-4, CPP-RES, CMPW-01, E-53, E-54, RSSP, PPR, CPP-GS, Solar-2, Solar-3, GPS-1, GPS-2, GPS-3, EPR-2, EPR-6, EPR-6S, E-56, and SC-S.
Rate Schedule E-36 is not included as proposed price changes are market-related.
Transmission revenues based on OATT charges effective during test year.

Supporting Schedules:
N/A

Recap Schedules:
(a) H-1

H3

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)	(G) Rates	(H) Proposed Rates Block	(I)	(J) Rates	(K)	(L) Change (I) - (F)	Line No.
1	E-3	Residential Energy	Rate	Sum & Win	For Bills 0-400 kWh		65% disc.	per day discount	$	1.12 disc.		disc.	1
2		Support Program			For Bills 401-800 kWh		45% disc.	capped at 80% of base bill				disc.	2
3					For Bills 801-1200 kWh		26% disc.						3
4					For Bills 1201 kWh and above	$	31.75 disc.						4
5	E-4	Medical Care	Rate	Sum & Win	For Bills 0-800 kWh		65% disc.	per day discount	$	1.87 disc.		disc.	5
6		Equipment			For Bills 801-1400 kWh		45% disc.	capped at 80% of base bill				disc.	6
7		Support Program			For Bills 1401-2000 kWh		26% disc.					disc.	7
8					For Bills 2001 kWh and above	$	60.00 disc.					disc.	8
9	R-XS	Residential Service	Rate	Sum & Win									9
10		Annual monthly usage less than						Basic Service Charge	$	0.592 /day			10
11		or equal to 600 kWh						All kWh		0.10324 /kWh			11
12	R-1	Residential Service	Rate	Summer									12
13		Time of Use						Basic Service Charge	$	0.789 /day			13
14								All On-Peak kW		6.600 /kW			14
15								All On-Peak kWh		0.15160 /kWh			15
16				Winter				All Off-Peak kWh		0.08070 /kWh			16
17								Basic Service Charge	$	0.789 /day			17
18								All On-Peak kW		6.600 /kW			18
19								All On-Peak kWh		0.12730 /kWh			19
20								All Off-Peak kWh		0.08070 /kWh			20
21	R-2	Residential Service	Rate	Summer									21
22		Time of Use						Basic Service Charge	$	0.477 /day			22
23								All On-Peak kW		8.400 /kW			23
24								All On-Peak kWh		0.15160 /kWh			24
25				Winter				All Off-Peak kWh		0.08080 /kWh			25
26								Basic Service Charge	$	0.477 /day			26
27								All On-Peak kW		8.400 /kW			27
28								All On-Peak kWh		0.12730 /kWh			28
29								All Off-Peak kWh		0.08080 /kWh			29
30	R-3	Residential Service	Rate	Summer									30
31		Time of Use						Basic Service Charge	$	0.789 /day			31
32								All On-Peak kW		16.400 /kW			32
33								All On-Peak kWh		0.09090 /kWh			33
34				Winter				All Off-Peak kWh		0.05475 /kWh			34
35								Basic Service Charge	$	0.789 /day			35
36								All On-Peak kW		11.500 /kW			36
37								All On-Peak kWh		0.06670 /kWh			37
38								All Off-Peak kWh		0.05475 /kWh			38
39	E-12	Residential Service	Rate	Summer	Basic Service Charge	$	0.285 /day	Basic Service Charge	$	0.341 /day	$	0.056 /day	39
40	Solar Legacy				First 400 kWh		0.09687 /kWh	First 400 kWh		0.11557 /kWh		0.01870 /kWh	40
41					Next 400 kWh		0.13817 /kWh	Next 400 kWh		0.16484 /kWh		0.02667 /kWh	41
42					Next 2200 kWh		0.16167 /kWh	Next 2200 kWh		0.19287 /kWh		0.03120 /kWh	42
43					All additional kWh		0.17257	All additional kWh		0.20587		0.03330 /kWh	43
44				Winter	Basic Service Charge	$	0.285 /day	Basic Service Charge	$	0.341 /day	$	0.056 /day	44
45					All kWh		0.09417 /kWh	All kWh		0.11234 /kWh		0.01817 /kWh	45
46	ET-1	Residential Service	Rate	Summer	Basic Service Charge	$	0.556 /day	Basic Service Charge	$	0.664 /day	$	0.108 /day	46
47	Solar Legacy	Time of Use			All On-Peak kWh		0.17892 /kWh	All On-Peak kWh		0.21345 /kWh		0.03453 /kWh	47
48					All Off-Peak kWh		0.05770 /kWh	All Off-Peak kWh		0.06884 /kWh		0.01114 /kWh	48
49				Winter	Basic Service Charge	$	0.556 /day	Basic Service Charge	$	0.664 /day	$	0.108 /day	49
50					All On-Peak kWh		0.14533 /kWh	All On-Peak kWh		0.17338 /kWh		0.02805 /kWh	50
51					All Off-Peak kWh		0.05561 /kWh	All Off-Peak kWh		0.06634 /kWh		0.01073 /kWh	51

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
62	ET-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556	/day	Basic Service Charge	$ 0.664	/day	$ 0.108	/day	62
63	Solar Legacy	Time of Use			All On-Peak kWh	0.24477	/kWh	All On-Peak kWh	0.29201	/kWh	0.04724	/kWh	63
64					All Off-Peak kWh	0.06118	/kWh	All Off-Peak kWh	0.07299	/kWh	0.01181	/kWh	64
65													65
66				Winter	Basic Service Charge	$ 0.556	/day	Basic Service Charge	$ 0.664	/day	$ 0.108	/day	66
67					All On-Peak kWh	0.19847	/kWh	All On-Peak kWh	0.23677	/kWh	0.03830	/kWh	67
68					All Off-Peak kWh	0.06116	/kWh	All Off-Peak kWh	0.07296	/kWh	0.01180	/kWh	68
69													69
70	ECT-1R	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556	/day	Basic Service Charge	$ 0.664	/day	$ 0.108	/day	70
71	Solar Legacy	Time of Use with			All On-Peak kW	13.550	/kW	All On-Peak kW	16.165	/kW	2.615	/kW	71
72		Demand Charge			All On-Peak kWh	0.07330	/kWh	All On-Peak kWh	0.08745	/kWh	0.01415	/kWh	72
73					All Off-Peak kWh	0.04083	/kWh	All Off-Peak kWh	0.04871	/kWh	0.00788	/kWh	73
74													74
75				Winter	Basic Service Charge	$ 0.556	/day	Basic Service Charge	$ 0.664	/day	$ 0.108	/day	75
76					All On-Peak kW	9.400	/kW	All On-Peak kW	11.214	/kW	1.814	/kW	76
77					All On-Peak kWh	0.05587	/kWh	All On-Peak kWh	0.06665	/kWh	0.01078	/kWh	77
78					All Off-Peak kWh	0.03967	/kWh	All Off-Peak kWh	0.04733	/kWh	0.00766	/kWh	78
79													79
80	ECT-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556	/day	Basic Service Charge	$ 0.664	/day	$ 0.108	/day	80
81	Solar Legacy	Time of Use with			All On-Peak kW	13.500	/kW	All On-Peak kW	16.105	/kW	2.605	/kW	81
82		Demand Charge			All On-Peak kWh	0.08867	/kWh	All On-Peak kWh	0.10578	/kWh	0.01711	/kWh	82
83					All Off-Peak kWh	0.04417	/kWh	All Off-Peak kWh	0.05269	/kWh	0.00852	/kWh	83
84													84
85				Winter	Basic Service Charge	$ 0.556	/day	Basic Service Charge	$ 0.664	/day	$ 0.108	/day	85
86					All On-Peak kW	9.300	/kW	All On-Peak kW	11.095	/kW	1.795	/kW	86
87					All On-Peak kWh	0.05747	/kWh	All On-Peak kWh	0.06856	/kWh	0.01109	/kWh	87
88					All Off-Peak kWh	0.04107	/kWh	All Off-Peak kWh	0.04900	/kWh	0.00793	/kWh	88
89													89
90	ET-SP	Residential Service	Rate	Super Peak Summer	Basic Service Charge	$ 0.556	/day	RATE SCHEDULE ET-SP PROPOSE TO CANCEL					90
91					All Super-Peak kWh	0.46517	/kWh						91
92		Time of Use			All On-Peak kWh	0.24477	/kWh						92
93					All Off-Peak kWh	0.05517	/kWh						93
94													94
95				Summer	Basic Service Charge	$ 0.556	/day						95
96					All On-Peak kWh	0.24477	/kWh						96
97					All Off-Peak kWh	0.05517	/kWh						97
98													98
99				Winter	Basic Service Charge	$ 0.556	/day						99
100					All On-Peak kWh	0.19847	/kWh						100
101					All Off-Peak kWh	0.05517	/kWh						101
102													102
103	ET-EV	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556	/day	RATE SCHEDULE ET-EV PROPOSE TO CANCEL					103
104					All On-Peak kWh	0.24784	/kWh						104
105		Time of Use			All Off-Peak kWh	0.06460	/kWh						105
106					All Super Off-Peak	0.04195	/kWh						106
107													107
108				Winter	Basic Service Charge	$ 0.556	/day						108
109					All On-Peak kWh	0.20165	/kWh						109
110					All Off-Peak kWh	0.06460	/kWh						110
111					All Super Off-Peak	0.04195	/kWh						111
112													112
113	CPP-RES	Residential Service	Rate	Summer	Critical Peak Price	$ 0.25000	/kWh	Critical Peak Price	$ 0.250000	/kWh	$ -	/kWh	113
114		Critical Peak Pricing			Energy Discount	(0.012143)	/kWh	Energy Discount	(0.012143)	/kWh	-	/kWh	114
115													115
116	PTR-RES	Residential Service	Rate	Summer	Energy Discount	$ 0.250000	/kWh	EXPERIMENTAL RATE RIDER PTR-RES PROPOSE TO CANCEL					116
117		Peak Time Rebate											117
118													118
119	E-20	General Service	Rate	Summer	Basic Service Charge	$ 1.065	/day	Basic Service Charge	$ 2.020	/day	$ 0.955	/day	119
120		Time of Use for			All On-Peak kW	2.391	/kW	All On-Peak kW	3.800	/kW	1.409	/kW	120
121		Religious Houses of			Excess Off-Peak kW	1.196	/kW	Excess Off-Peak kW	2.400	/kW	1.20400	/kWh	121
122		Worship			All On-Peak kWh	0.14457	/kWh	All On-Peak kWh	0.16090	/kWh	0.01633	/kWh	122
123					All Off-Peak kWh	0.07014	/kWh	All Off-Peak kWh	0.07821	/kWh	0.00807	/kWh	123
124													124
125	E-20	General Service	Rate	Winter	Basic Service Charge	$ 1.065	/day	Basic Service Charge	$ 2.020	/day	$ 0.9550	/day	125
126	(continued)	Time of Use for			All On-Peak kW	2.156	/kW	All On-Peak kW	3.800	/kW	1.644	/kW	126
127		Religious Houses of			Excess Off-Peak kW	1.078	/kW	Excess Off-Peak kW	2.400	/kW	1.32200	/kWh	127
128		Worship			All On-Peak kWh	0.12719	/kWh	All On-Peak kWh	0.14182	/kWh	0.01463	/kWh	128
129					All Off-Peak kWh	0.06294	/kWh	All Off-Peak kWh	0.07018	/kWh	0.00724	/kWh	129
130													130
131	E-30	Extra Small General	Rate	Summer	Basic Service Charge	$ 0.311	/day	Basic Service Charge	$ 0.405	/day	$ 0.094	/day	131
132		Service Unmetered			All kWh	0.14455	/kWh	All kWh	0.13664	/kWh	(0.00791)	/kWh	132

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

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TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)	(G) Rates	(H) Proposed Rates Block	(I)	(J) Rates	(K)	(L) Change (I) - (F)	Line No.
133	E-30	Extra Small General											133
134	(continued)	Service Unmetered		Winter	Basic Service Charge	$	0.311 /day	Basic Service Charge	$	0.405 /day	$	0.094 /day	134
135					All kWh		0.12984 /kWh	All kWh		0.12915 /kWh		(0.00669) /kWh	135
136													136
137	E-32 XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$	0.672 /day	BSC: Self-Contained Meters	$	1.160 /day	$	0.488 /day	137
138		20 kW or Less			BSC: Instrument-rated Meters		1.324 /day	BSC: Instrument-rated Meters		2.020 /day		0.696 /day	138
139					BSC: Primary Meters		3.415 /day	BSC: Primary Meters		4.947 /day		1.532 /day	139
140					BSC: Transmission Meters		26.163						140
141													141
142					First 5,000 kWh: Secondary	$	0.13537 /kWh	kW Secondary	$	6.900 /kW			142
143					All remaining kWh: Secondary		0.07427 /kWh	kW Primary		4.300 /kW			143
144					First 5,000 kWh: Primary		0.13209 /kWh	kWh secondary		0.10549 /kWh			144
145					All remaining kWh: Primary		0.07100 /kWh	kWh- primary		0.09951 /kWh			145
146													146
147				Winter	BSC: Self-Contained Meters	$	0.672 /day	BSC: Self-Contained Meters	$	1.1600 /day	$	0.488 /day	147
148					BSC: Instrument-rated Meters		1.324 /day	BSC: Instrument-rated Meters		2.0200 /day		0.696 /day	148
149					BSC: Primary Meters		3.415 /day	BSC: Primary Meters		4.9470 /day		1.532 /day	149
150					BSC: Transmission Meters		26.163						150
151													151
152					First 5,000 kWh: Secondary	$	0.11769 /kWh	kW Secondary	$	6.900 /kW			152
153					All remaining kWh: Secondary		0.05658 /kWh	kW Primary		4.300 /kW			153
154					First 5,000 kWh: Primary		0.11438 /kWh	kWh secondary		0.08630 /kWh			154
155					All remaining kWh: Primary		0.05329 /kWh	kWh- primary		0.08050 /kWh			155
156													156
157	E-32 XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$	0.672 /day	BSC: Self-Contained Meters	$	1.160 /day	$	0.488 /day	157
158	Transition	20 kW or Less			BSC: Instrument-rated Meters		1.324 /day	BSC: Instrument-rated Meters		2.020 /day		0.696 /day	158
159					BSC: Primary Meters		3.415 /day	BSC: Primary Meters		4.947 /day		1.532 /day	159
160					BSC: Transmission Meters		26.163						160
161													161
162					First 5,000 kWh: Secondary	$	0.13537 /kWh	First 5,000 kWh: Secondary	$	0.13201 /kWh	$	(0.00336) /kWh	162
163					All remaining kWh: Secondary		0.07427 /kWh	All remaining kWh: Secondary		0.13201 /kWh		0.05774 /kWh	163
164					First 5,000 kWh: Primary		0.13209 /kWh	First 5,000 kWh: Primary		0.12863 /kWh		(0.00346) /kWh	164
165					All remaining kWh: Primary		0.07100 /kWh	All remaining kWh: Primary		0.12863 /kWh		0.05763 /kWh	165
166													166
167				Winter	BSC: Self-Contained Meters	$	0.672 /day	BSC: Self-Contained Meters	$	1.160 /day	$	0.488 /day	167
168					BSC: Instrument-rated Meters		1.324 /day	BSC: Instrument-rated Meters		2.020 /day		0.696 /day	168
169					BSC: Primary Meters		3.415 /day	BSC: Primary Meters		4.947 /day		1.532 /day	169
170					BSC: Transmission Meters		26.163						170
171													171
172					First 5,000 kWh: Secondary	$	0.11769 /kWh	First 5,000 kWh: Secondary	$	0.11508 /kWh	$	(0.00261) /kWh	172
173					All remaining kWh: Secondary		0.05658 /kWh	All remaining kWh: Secondary		0.11508 /kWh		0.05850 /kWh	173
174					First 5,000 kWh: Primary		0.11438 /kWh	First 5,000 kWh: Primary		0.11168 /kWh		(0.00270) /kWh	174
175					All remaining kWh: Primary		0.05329 /kWh	All remaining kWh: Primary		0.11168 /kWh		0.05839 /kWh	175
176													176
177	E-32 XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$	0.672 /day	BSC: Self-Contained Meters	$	0.730 /day	$	0.058 /day	177
178	Solar Legacy	20 kW or Less			BSC: Instrument-rated Meters		1.324 /day	BSC: Instrument-rated Meters		1.438 /day		0.114 /day	178
179					BSC: Primary Meters		3.415 /day	BSC: Primary Meters		3.709 /day		0.294 /day	179
180					BSC: Transmission Meters		26.163						180
181													181
182					First 5,000 kWh: Secondary	$	0.13537 /kWh	First 5,000 kWh: Secondary	$	0.14728 /kWh	$	0.01191 /kWh	182
183					All remaining kWh: Secondary		0.07427 /kWh	All remaining kWh: Secondary		0.08080 /kWh		0.00653 /kWh	183
184					First 5,000 kWh: Primary		0.13209 /kWh	First 5,000 kWh: Primary		0.14372 /kWh		0.01163 /kWh	184
185					All remaining kWh: Primary		0.07100 /kWh	All remaining kWh: Primary		0.07724 /kWh		0.00624 /kWh	185
186													186

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

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TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
187	E-32 XS	General Service	Rate	Winter	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 0.730	/day	$ 0.058	/day	187
188	Solar Legacy	20 kW or Less			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.438	/day	0.114	/day	188
189	(continued)				BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.709	/day	0.294	/day	189
190					BSC: Transmission Meters	26.163							190
191													191
192					First 5,000 kWh: Secondary	$ 0.11769	/kWh	First 5,000 kWh: Secondary	$ 0.12804	/kWh	$ 0.01035	/kWh	192
193					All remaining kWh: Secondary	0.05658	/kWh	All remaining kWh: Secondary	0.06155	/kWh	0.00497	/kWh	193
194					First 5,000 kWh: Primary	0.11438	/kWh	First 5,000 kWh: Primary	0.12445	/kWh	0.01007	/kWh	194
195					All remaining kWh: Primary	0.05329	/kWh	All remaining kWh: Primary	0.05797	/kWh	0.00468	/kWh	195
196													196
197	E-32 S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.488	/day	197
198		21-100 kW			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	198
199					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	199
200					First 100 kW: Secondary	9.828	/kW	First 100 kW: Secondary	11.360	/kW	1.532	/kW	200
201					All remaining kW: Secondary	5.214	/kW	All remaining kW: Secondary	6.608	/kW	1.394	/kW	201
202					First 100 kW: Primary	9.116	/kW	First 100 kW: Primary	10.627	/kW	1.511	/kW	202
203					All remaining kW: Primary	4.502	/kW	All remaining kW: Primary	5.875	/kW	1.373	/kW	203
204					First 200 kWh per kW	0.10337	/kWh	First 200 kWh per kW	0.10816	/kWh	0.00479	/kWh	204
205					All remaining kWh	0.06257	/kWh	All remaining kWh	0.06529	/kWh	0.00272	/kWh	205
206													206
207			Rate	Winter	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 1.16	/day	$ 0.488	/day	207
208					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	208
209					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	209
210					First 100 kW: Secondary	9.828	/kW	First 100 kW: Secondary	11.360	/kW	1.532	/kW	210
211					All remaining kW: Secondary	5.214	/kW	All remaining kW: Secondary	6.608	/kW	1.394	/kW	211
212					First 100 kW: Primary	9.116	/kW	First 100 kW: Primary	10.627	/kW	1.511	/kW	212
213					All remaining kW: Primary	4.502	/kW	All remaining kW: Primary	5.875	/kW	1.373	/kW	213
214					First 200 kWh per kW	0.08718	/kWh	First 200 kWh per kW	0.09116	/kWh	0.00398	/kWh	214
215					All remaining kWh	0.04638	/kWh	All remaining kWh	0.04832	/kWh	0.00194	/kWh	215
216													216
217	E-32 M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.488	/day	217
218		101- 400 kW			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	218
219					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	219
220					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	36.795	/day	10.632	/day	220
221					First 100 kW: Secondary	10.235	/kW	First 100 kW: Secondary	12.279	/kW	2.044	/kW	221
222					All remaining kW: Secondary	5.385	/kW	All remaining kW: Secondary	7.003	/kW	1.618	/kW	222
223					First 100 kW: Primary	9.488	/kW	First 100 kW: Primary	11.366	/kW	1.878	/kW	223
224					All remaining kW: Primary	4.695	/kW	All remaining kW: Primary	6.253	/kW	1.558	/kW	224
225					First 100 kW: Transmission	7.368	/kW	First 100 kW: Transmission	9.160	/kW	1.792	/kW	225
226					All remaining kW: Transmission	2.519	/kW	All remaining kW: Transmission	3.886	/kW	1.367	/kW	226
227					First 200 kWh per kW	0.09884	/kWh	First 200 kWh per kW	0.10704	/kWh	0.00820	/kWh	227
228					All remaining kWh	0.06091	/kWh	All remaining kWh	0.06579	/kWh	0.00488	/kWh	228
229													229
230			Rate	Winter	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.488	/day	230
231					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	231
232					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	232
233					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	36.795	/day	10.632	/day	233
234					First 100 kW: Secondary	10.235	/kW	First 100 kW: Secondary	12.279	/kW	2.044	/kW	234
235					All remaining kW: Secondary	5.385	/kW	All remaining kW: Secondary	7.003	/kW	1.618	/kW	235
236					First 100 kW: Primary	9.488	/kW	First 100 kW: Primary	11.366	/kW	1.878	/kW	236
237					All remaining kW: Primary	4.695	/kW	All remaining kW: Primary	6.253	/kW	1.558	/kW	237
238					First 100 kW: Transmission	7.368	/kW	First 100 kW: Transmission	9.160	/kW	1.792	/kW	238
239					All remaining kW: Transmission	2.519	/kW	All remaining kW: Transmission	3.886	/kW	1.367	/kW	239
240					First 200 kWh per kW	0.08378	/kWh	First 200 kWh per kW	0.09066	/kWh	0.00688	/kWh	240
241					All remaining kWh	0.04586	/kWh	All remaining kWh	0.04940	/kWh	0.00354	/kWh	241
242													242
243	E-32 L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.068	/day	BSC: Self-Contained Meters	$ 3.060	/day	$ 1.992	/day	243
244		401 kW and above			BSC: Instrument-rated Meters	1.627	/day	BSC: Instrument-rated Meters	3.920	/day	2.293	/day	244
245					BSC: Primary Meters	3.419	/day	BSC: Primary Meters	6.847	/day	3.428	/day	245
246					BSC: Transmission Meters	22.915	/day	BSC: Transmission Meters	38.695	/day	15.780	/day	246
247					First 100 kW: Secondary	21.149	/kW	First 100 kW: Secondary	24.012	/kW	2.863	/kW	247
248					All remaining kW: Secondary	14.267	/kW	All remaining kW: Secondary	16.245	/kW	1.978	/kW	248
249					First 100 kW: Primary	19.091	/kW	First 100 kW: Primary	21.689	/kW	2.598	/kW	249

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

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250	E-32 L	General Service	Rate	Summer	All remaining kW: Primary	$ 13.209	/kW	All remaining kW: Primary	$ 15.0510	/kW	$ 1.842	/kW	250
251	(continued)	401 kW and above			First 100 kW: Transmission	14.284	/kW	First 100 kW: Transmission	16.264	/kW	1.980	/kW	251
252					All remaining kW: Transmission	9.105	/kW	All remaining kW: Transmission	10.393	/kW	1.288	/kW	252
253					All kWh	0.05517	/kWh	First 200 kWh per kW	0.06122	/kWh	0.00605	/kWh	253
254													254
255			Rate	Winter	BSC: Self-Contained Meters	$ 1.068	/day	BSC: Self-Contained Meters	$ 3.060	/day	$ 1.992	/day	255
256					BSC: Instrument-rated Meters	1.627	/day	BSC: Instrument-rated Meters	3.920	/day	2.293	/day	256
257					BSC: Primary Meters	3.419	/day	BSC: Primary Meters	6.847	/day	3.428	/day	257
258					BSC: Transmission Meters	22.915	/day	BSC: Transmission Meters	38.695	/day	15.780	/day	258
259					First 100 kW: Secondary	21.149	/kW	First 100 kW: Secondary	24.012	/kW	2.863	/kW	259
260					All remaining kW: Secondary	14.267	/kW	All remaining kW: Secondary	16.245	/kW	1.978	/kW	260
261					First 100 kW: Primary	19.091	/kW	First 100 kW: Primary	21.689	/kW	2.598	/kW	261
262					All remaining kW: Primary	13.209	/kW	All remaining kW: Primary	15.051	/kW	1.842	/kW	262
263					First 100 kW: Transmission	14.284	/kW	First 100 kW: Transmission	16.264	/kW	1.980	/kW	263
264					All remaining kW: Transmission	9.105	/kW	All remaining kW: Transmission	10.393	/kW	1.288	/kW	264
265					All kWh	0.03804	/kWh	First 200 kWh per kW	0.04204	/kWh	0.00400	/kWh	265
266													266
267	E-32TOU XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.450	/day	267
268		Time of Use			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	268
269		20 kW or Less			BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	269
270					First 5,000 On-Peak kWh: Secondary	0.17033	/kWh	kWh - secondary - on	0.14870	/kWh			270
271					All remaining On-Peak kWh: Secondary	0.08564	/kWh	kWh - secondary - off	0.11391	/kWh			271
272					First 5,000 Off-Peak kWh: Secondary	0.12686	/kWh	kWh - primary - on	0.14670	/kWh			272
273					All remaining Off-Peak kWh: Secondary	0.04755	/kWh	kWh - primary - off	0.10770	/kWh			273
274					First 5,000 On-Peak kWh: Primary	0.16698	/kWh	kW - secondary - on	4.546	/kW			274
275					All remaining On-Peak kWh: Primary	0.08150	/kWh	kW - secondary - off	2.599	/kW			275
276					First 5,000 Off-Peak kWh: Primary	0.12350	/kWh	kW - primary - on	3.951	/kW			276
277					All remaining Off-Peak kWh: Primary	0.04420	/kWh	kW - primary - off	1.565	/kW			277
278													278
279				Winter	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.450	/day	279
280					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	280
281					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	281
282					First 5,000 On-Peak kWh: Secondary	0.15310	/kWh	kWh - secondary - on	0.11870	/kWh			282
283					All remaining On-Peak kWh: Secondary	0.06837	/kWh	kWh - secondary - off	0.09091	/kWh			283
284					First 5,000 Off-Peak kWh: Secondary	0.10959	/kWh	kWh - primary - on	0.11670	/kWh			284
285					All remaining Off-Peak kWh: Secondary	0.03496	/kWh	kWh - primary - off	0.08470	/kWh			285
286					First 5,000 On-Peak kWh: Primary	0.14974	/kWh	kW - secondary - on	4.546	/kW			286
287					All remaining On-Peak kWh: Primary	0.06423	/kWh	kW - secondary - off	2.599	/kW			287
288					First 5,000 Off-Peak kWh: Primary	0.10624	/kWh	kW - primary - on	3.951	/kW			288
289					All remaining Off-Peak kWh: Primary	0.03160	/kWh	kW - primary - off	1.565	/kW			289
290													290
291	E-32TOU XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.450	/day	291
292	Transition	Time of Use			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	292
293		20 kW or Less			BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	293
294					First 5,000 On-Peak kWh: Secondary	0.17033	/kWh	kWh - secondary - on	0.18660	/kWh			294
295					All remaining On-Peak kWh: Secondary	0.08564	/kWh	kWh - secondary - off	0.11341	/kWh			295
296					First 5,000 Off-Peak kWh: Secondary	0.12686	/kWh	kWh - primary - on	0.18060	/kWh			296
297					All remaining Off-Peak kWh: Secondary	0.04755	/kWh	kWh - primary - off	0.11041	/kWh			297
298					First 5,000 On-Peak kWh: Primary	0.16698	/kWh	kW - secondary - on	-	/kW			298
299					All remaining On-Peak kWh: Primary	0.08150	/kWh	kW - secondary - off	-	/kW			299
300					First 5,000 Off-Peak kWh: Primary	0.12350	/kWh	kW - primary - on	-	/kW			300
301					All remaining Off-Peak kWh: Primary	0.04420	/kWh	kW - primary - off	-	/kW			301
302													302
303				Winter	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.16	/day	$ 0.450	/day	303
304					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	304
305					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	305
306					First 5,000 On-Peak kWh: Secondary	0.15310	/kWh	kWh - secondary - on	0.15708	/kWh			306
307					All remaining On-Peak kWh: Secondary	0.06837	/kWh	kWh - secondary - off	0.09373	/kWh			307
308					First 5,000 Off-Peak kWh: Secondary	0.10959	/kWh	kWh - primary - on	0.15108	/kWh			308
309					All remaining Off-Peak kWh: Secondary	0.03496	/kWh	kWh - primary - off	0.09073	/kWh			309
310					First 5,000 On-Peak kWh: Primary	0.14974	/kWh	kW - secondary - on	-	/kW			310
311					All remaining On-Peak kWh: Primary	0.06423	/kWh	kW - secondary - off	-	/kW			311
312					First 5,000 Off-Peak kWh: Primary	0.10624	/kWh	kW - primary - on	-	/kW			312
313					All remaining Off-Peak kWh: Primary	0.03160	/kWh	kW - primary - off	-	/kW			313

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
314													314
315	E-32TOU S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.450	/day	315
316		Time of Use			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	316
317		21-100 kW			BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	317
318					First 100 On-Peak kW: Secondary	14.303	/kW	First 100 On-Peak kW: Secondary	17.636	/kW	3.333	/kW	318
319					All remaining On-Peak kW: Secondary	9.713	/kW	All remaining On-Peak kW: Secondary	12.307	/kW	2.594	/kW	319
320					First 100 Off-Peak kW: Secondary	5.484	/kW	First 100 Off-Peak kW: Secondary	6.367	/kW	0.883	/kW	320
321					All remaining Off-Peak kW: Secondary	3.054	/kW	All remaining Off-Peak kW: Secondary	3.545	/kW	0.491	/kW	321
322					First 100 On-Peak kW: Primary	13.845	/kW	First 100 On-Peak kW: Primary	17.104	/kW	3.259	/kW	322
323					All remaining On-Peak kW: Primary	9.645	/kW	All remaining On-Peak kW: Primary	12.228	/kW	2.583	/kW	323
324					First 100 Off-Peak kW: Primary	4.909	/kW	First 100 Off-Peak kW: Primary	5.699	/kW	0.790	/kW	324
325					All remaining Off-Peak kW: Primary	2.975	/kW	All remaining Off-Peak kW: Primary	3.454	/kW	0.479	/kW	325
326					All On-Peak kWh:	0.07367	/kWh	All On-Peak kWh:	0.08376	/kWh	0.01009	/kWh	326
327					All Off-Peak kWh:	0.05873	/kWh	All Off-Peak kWh:	0.06346	/kWh	0.00473	/kWh	327
328													328
329				Winter	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.450	/day	329
330					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	330
331					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	331
332					First 100 On-Peak kW: Secondary	14.303	/kW	First 100 On-Peak kW: Secondary	17.636	/kW	3.333	/kW	332
333					All remaining On-Peak kW: Secondary	9.713	/kW	All remaining On-Peak kW: Secondary	12.307	/kW	2.594	/kW	333
334					First 100 Off-Peak kW: Secondary	5.484	/kW	First 100 Off-Peak kW: Secondary	6.367	/kW	0.883	/kW	334
335					All remaining Off-Peak kW: Secondary	3.054	/kW	All remaining Off-Peak kW: Secondary	3.545	/kW	0.491	/kW	335
336					First 100 On-Peak kW: Primary	13.845	/kW	First 100 On-Peak kW: Primary	17.104	/kW	3.259	/kW	336
337					All remaining On-Peak kW: Primary	9.645	/kW	All remaining On-Peak kW: Primary	12.228	/kW	2.583	/kW	337
338					First 100 Off-Peak kW: Primary	4.909	/kW	First 100 Off-Peak kW: Primary	5.699	/kW	0.790	/kW	338
339					All remaining Off-Peak kW: Primary	2.975	/kW	All remaining Off-Peak kW: Primary	3.454	/kW	0.479	/kW	339
340					All On-Peak kWh:	0.05665	/kWh	All On-Peak kWh:	0.06541	/kWh	0.00876	/kWh	340
341					All Off-Peak kWh:	0.04170	/kWh	All Off-Peak kWh:	0.04799	/kWh	0.00629	/kWh	341
342													342
343	E-32TOU M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.450	/day	343
344		Time of Use			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	344
345		101- 400 kW			BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	345
346					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	36.795	/day	10.632	/day	346
347					First 100 On-Peak kW: Secondary	15.166	/kW	First 100 On-Peak kW: Secondary	18.144	/kW	2.978	/kW	347
348					All remaining On-Peak kW: Secondary	10.013	/kW	All remaining On-Peak kW: Secondary	12.349	/kW	2.336	/kW	348
349					First 100 Residual kW: Secondary	5.897	/kW	First 100 Off-Peak kW: Secondary	6.632	/kW	0.735	/kW	349
350					All remaining Residual kW: Secondary	3.168	/kW	All remaining Off-Peak kW: Secondary	3.563	/kW	0.395	/kW	350
351					First 100 On-Peak kW: Primary	14.651	/kW	First 100 On-Peak kW: Primary	17.565	/kW	2.914	/kW	351
352					All remaining On-Peak kW: Primary	9.936	/kW	All remaining On-Peak kW: Primary	12.262	/kW	2.326	/kW	352
353					First 100 Residual kW: Primary	5.251	/kW	First 100 Off-Peak kW: Primary	5.906	/kW	0.655	/kW	353
354					All remaining Residual kW: Primary	3.079	/kW	All remaining Off-Peak kW: Primary	3.463	/kW	0.384	/kW	354
355					First 100 On-Peak kW: Transmission	13.730	/kW	First 100 On-Peak kW: Transmission	16.529	/kW	2.799	/kW	355
356					All remaining On-Peak kW: Transmission	9.619	/kW	All remaining On-Peak kW: Transmission	11.905	/kW	2.286	/kW	356
357					First 100 Residual kW: Transmission	4.522	/kW	First 100 Off-Peak kW: Transmission	5.086	/kW	0.564	/kW	357
358					All remaining Residual kW: Transmission	2.959	/kW	All remaining Off-Peak kW: Transmission	3.328	/kW	0.369	/kW	358
359					All On-Peak kWh:	0.06566	/kWh	All On-Peak kWh:	0.07326	/kWh	0.00760	/kWh	359
360					All Off-Peak kWh:	0.05432	/kWh	All Off-Peak kWh:	0.06051	/kWh	0.00619	/kWh	360
361													361
362				Winter	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 1.160	/day	$ 0.450	/day	362
363					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	2.020	/day	0.696	/day	363
364					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	4.947	/day	1.532	/day	364
365					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	36.795	/day	10.632	/day	365
366					First 100 On-Peak kW: Secondary	15.166	/kW	First 100 On-Peak kW: Secondary	18.144	/kW	2.978	/kW	366
367					All remaining On-Peak kW: Secondary	10.013	/kW	All remaining On-Peak kW: Secondary	12.349	/kW	2.336	/kW	367
368					First 100 Residual kW: Secondary	5.897	/kW	First 100 Off-Peak kW: Secondary	6.632	/kW	0.735	/kW	368
369					All remaining Residual kW: Secondary	3.168	/kW	All remaining Off-Peak kW: Secondary	3.563	/kW	0.395	/kW	369
370					First 100 On-Peak kW: Primary	14.651	/kW	First 100 On-Peak kW: Primary	17.565	/kW	2.914	/kW	370
371					All remaining On-Peak kW: Primary	9.936	/kW	All remaining On-Peak kW: Primary	12.262	/kW	2.326	/kW	371
372					First 100 Residual kW: Primary	5.251	/kW	First 100 Off-Peak kW: Primary	5.906	/kW	0.655	/kW	372
373					All remaining Residual kW: Primary	3.079	/kW	All remaining Off-Peak kW: Primary	3.463	/kW	0.384	/kW	373
374					First 100 On-Peak kW: Transmission	13.730	/kW	First 100 On-Peak kW: Transmission	16.529	/kW	2.799	/kW	374
375					All remaining On-Peak kW: Transmission	9.619	/kW	All remaining On-Peak kW: Transmission	11.905	/kW	2.286	/kW	375
376					First 100 Residual kW: Transmission	4.522	/kW	First 100 Off-Peak kW: Transmission	5.086	/kW	0.564	/kW	376
377					All remaining Residual kW: Transmission	2.959	/kW	All remaining Off-Peak kW: Transmission	3.328	/kW	0.369	/kW	377
378					All On-Peak kWh:	0.05275	/kWh	All On-Peak kWh:	0.05874	/kWh	0.00599	/kWh	378
379					All Off-Peak kWh:	0.04142	/kWh	All Off-Peak kWh:	0.04600	/kWh	0.00458	/kWh	379

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
380													380
381	E-32TOU L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 3.060	/day	$ 2.350	/day	381
382		Time of Use			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	3.920	/day	2.596	/day	382
383		401 kW and above			BSC: Primary Meters	3.415	/day	BSC: Primary Meters	6.847	/day	3.432	/day	383
384					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	38.695	/day	12.532	/day	384
385					First 100 On-Peak kW: Secondary	14.915	/kW	First 100 On-Peak kW: Secondary	17.694	/kW	2.779	/kW	385
386					All remaining On-Peak kW: Secondary	9.784	/kW	All remaining On-Peak kW: Secondary	11.981	/kW	2.197	/kW	386
387					First 100 Residual kW: Secondary	5.814	/kW	First 100 Off-Peak kW: Secondary	6.467	/kW	0.653	/kW	387
388					All remaining Residual kW: Secondary	3.097	/kW	All remaining Off-Peak kW: Secondary	3.441	/kW	0.344	/kW	388
389					First 100 On-Peak kW: Primary	14.402	/kW	First 100 On-Peak kW: Primary	17.122	/kW	2.720	/kW	389
390					All remaining On-Peak kW: Primary	9.708	/kW	All remaining On-Peak kW: Primary	11.896	/kW	2.188	/kW	390
391					First 100 Residual kW: Primary	5.170	/kW	First 100 Off-Peak kW: Primary	5.750	/kW	0.580	/kW	391
392					All remaining Residual kW: Primary	3.008	/kW	All remaining Off-Peak kW: Primary	3.343	/kW	0.335	/kW	392
393					First 100 On-Peak kW: Transmission	13.486	/kW	First 100 On-Peak kW: Transmission	16.102	/kW	2.616	/kW	393
394					All remaining On-Peak kW: Transmission	8.601	/kW	All remaining On-Peak kW: Transmission	10.664	/kW	2.063	/kW	394
395					First 100 Residual kW: Transmission	4.444	/kW	First 100 Off-Peak kW: Transmission	4.942	/kW	0.498	/kW	395
396					All remaining Residual kW: Transmission	2.888	/kW	All remaining Off-Peak kW: Transmission	3.208	/kW	0.320	/kW	396
397					All On-Peak kWh:	0.06555	/kWh	All On-Peak kWh:	0.07228	/kWh	0.00673	/kWh	397
398					All Off-Peak kWh:	0.05359	/kWh	All Off-Peak kWh:	0.05900	/kWh	0.00541	/kWh	398
399													399
400				Winter	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 3.060	/day	$ 2.350	/day	400
401					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	3.920	/day	2.596	/day	401
402					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	6.847	/day	3.432	/day	402
403					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	38.695	/day	12.532	/day	403
404					First 100 On-Peak kW: Secondary	14.915	/kW	First 100 On-Peak kW: Secondary	17.694	/kW	2.779	/kW	404
405					All remaining On-Peak kW: Secondary	9.784	/kW	All remaining On-Peak kW: Secondary	11.981	/kW	2.197	/kW	405
406					First 100 Residual kW: Secondary	5.814	/kW	First 100 Off-Peak kW: Secondary	6.467	/kW	0.653	/kW	406
407					All remaining Residual kW: Secondary	3.097	/kW	All remaining Off-Peak kW: Secondary	3.441	/kW	0.344	/kW	407
408					First 100 On-Peak kW: Primary	14.402	/kW	First 100 On-Peak kW: Primary	17.122	/kW	2.720	/kW	408
409					All remaining On-Peak kW: Primary	9.708	/kW	All remaining On-Peak kW: Primary	11.896	/kW	2.188	/kW	409
410					First 100 Residual kW: Primary	5.170	/kW	First 100 Off-Peak kW: Primary	5.750	/kW	0.580	/kW	410
411			Rate	Winter	All remaining Residual kW: Primary	3.008	/kW	All remaining Off-Peak kW: Primary	3.343	/kW	0.335	/kW	411
412				(continued)	First 100 On-Peak kW: Transmission	13.486	/kW	First 100 On-Peak kW: Transmission	16.102	/kW	2.616	/kW	412
413					All remaining On-Peak kW: Transmission	8.601	/kW	All remaining On-Peak kW: Transmission	10.664	/kW	2.063	/kW	413
414					First 100 Residual kW: Transmission	4.444	/kW	First 100 Off-Peak kW: Transmission	4.942	/kW	0.498	/kW	414
415					All remaining Residual kW: Transmission	2.888	/kW	All remaining Off-Peak kW: Transmission	3.208	/kW	0.320	/kW	415
416					All On-Peak kWh:	0.05193	/kWh	All On-Peak kWh:	0.05716	/kWh	0.005	/kWh	416
417					All Off-Peak kWh:	0.03997	/kWh	All Off-Peak kWh:	0.04388	/kWh	0.004	/kWh	417
418													418
419	E-34	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 1.135	/day	BSC: Self-Contained Meters	$ 4.262	/day	$ 3.127	/day	419
420		General Service			BSC: Instrument-rated Meters	1.776	/day	BSC: Instrument-rated Meters	5.122	/day	3.346	/day	420
421					BSC: Primary Meters	3.828	/day	BSC: Primary Meters	8.049	/day	4.221	/day	421
422					BSC: Transmission Meters	26.161	/day	BSC: Transmission Meters	39.897	/day	13.736	/day	422
423					All kW: Secondary	19.930	/kW	All kW: Secondary	22.393	/kW	2.463	/kW	423
424					All kW: Primary	18.649	/kW	All kW: Primary	21.041	/kW	2.392	/kW	424
425					All kW: Primary on Military Bases	12.278	/kW	All kW: Primary on Military Bases	14.316	/kW	2.038	/kW	425
426					All kW: Transmission	13.392	/kW	All kW: Transmission	15.492	/kW	2.100	/kW	426
427					All kWh	0.03665	/kWh	All kWh	0.04048	/kWh	0.004	/kWh	427
428													428
429	E-35	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 1.183	/day	BSC: Self-Contained Meters	$ 4.262	/day	$ 3.079	/day	429
430		General Service			BSC: Instrument-rated Meters	1.795	/day	BSC: Instrument-rated Meters	5.122	/day	3.327	/day	430
431		Time Of Use			BSC: Primary Meters	3.881	/day	BSC: Primary Meters	8.049	/day	4.168	/day	431
432					BSC: Transmission Meters	26.574	/day	BSC: Transmission Meters	39.897	/day	13.323	/day	432
433					All On-Peak kW: Secondary	16.768	/kW	All On-Peak kW: Secondary	19.565	/kW	2.797	/kW	433
434					All Excess Off-Peak kW: Secondary	3.064	/kW	All Off-Peak kW: Secondary	3.037	/kW	(0.027)	/kW	434
435					All On-Peak kW: Primary	15.792	/kW	All On-Peak kW: Primary	18.255	/kW	2.463	/kW	435
436					All Excess Off-Peak kW: Primary	2.966	/kW	All Off-Peak kW: Primary	2.906	/kW	(0.060)	/kW	436
437					All On-Peak kW: Primary on Military Bases	10.755	/kW	All On-Peak kW: Primary on Military Bases	11.492	/kW	0.737	/kW	437
438					All Excess Off-Peak kW; Primary on Military	2.462	/kW	All Off-Peak kW: Primary on Military Bases	2.229	/kW	(0.233)	/kW	438
439					All On-Peak kW: Trans.	12.108	/kW	All On-Peak kW: Transmission	13.309	/kW	1.201	/kW	439
440					All Excess Off-Peak kW: Trans.	2.597	/kW	All Off-Peak kW: Transmission	2.410	/kW	(0.187)	/kW	440
441					All On-Peak kWh	0.04076	/kWh	All On-Peak kWh	0.04571	/kWh	0.00495	/kWh	441
442					All Off-Peak kWh	0.03219	/kWh	All Off-Peak kWh	0.03619	/kWh	0.00400	/kWh	442
443													443
444	E-36 XL	Station Use Service	Rate	Sum & Win	Basic Service Charge	$ 6,912.00	/mo	Basic Service Charge	$ 7,436.00	/mo	$ 524.00	/mo	444
445					Metering Charge Company Owned	1.29%		Metering Charge Company Owned	1.29%		-		445
446					Metering Charge Customer Owned	0.35%		Metering Charge Customer Owned	0.35%		-		446
447					All kW: Secondary	5.190	/kW	All kW: Secondary	5.584	/kW	0.39400	/kW	447
448					All kW: Primary	5.008	/kW	All kW: Primary	5.388	/kW	0.38000	/kW	448
449					All kW: Transmission	1.620	/kW	All kW: Transmission	1.743	/kW	0.12300	/kW	449
450					All kWh: Hourly Pricing Proxy plus	0.00057	/kWh	All kWh: Hourly Pricing Proxy plus	0.00061	/kWh	0.00004	/kWh	450

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (I) - (F)	Line No.
451										451
452	E-36 M	Station Use Service Medium	Rate	Sum & win	Billed on applicable E-32 rate except for BSC Charge		Billed on applicable E-32 rate except for BSC Charge			452
453					BSC (E-32 XS): Self-Contained Meters	$ 1.890 /day	BSC (E-32 XS): Self-Contained Meters	$ 3.803 /day	$ 1.91 /day	453
454					BSC (E-32 XS): Instrument-rated Meters	2.520 /day	BSC (E-32 XS): Instrument-rated Meters	4.641 /day	2.12 /day	454
455					BSC (E-32 XS): Primary Meters	10.119 /day	BSC (E-32 XS): Primary Meters	13.076 /day	2.96 /day	455
456					BSC (E-32 L): Self-Contained Meters	1.811 /day	BSC (E-32 L): Self-Contained Meters	3.803 /day	1.99 /day	456
457					BSC (E-32 L): Instrument-rated Meters	2.348 /day	BSC (E-32 L): Instrument-rated Meters	4.641 /day	2.29 /day	457
458					BSC (E-32 L): Primary Meters	9.648 /day	BSC (E-32 L): Primary Meters	13.076 /day	3.43 /day	458
459					BSC (E-32 L): Transmission Meters	29.1440 /day	BSC (E-32 L): Transmission Meters	44.924 /day	15.78 /day	459
460										460
461	E-47	Dusk to Dawn Lighting Service	Rate	Sum & Win	**FIXTURES** (Company Owned)		**FIXTURES** (Company Owned)			461
462					9500 HPS ACORN	$ 27.06 /mo	9500 HPS ACORN	$ 29.79 /mo	$ 2.73 /mo	462
463					16,000 HPS ACORN	30.04 /mo	16,000 HPS ACORN	33.07 /mo	3.03 /mo	463
464					6,000 INDUCTION	17.87 /mo	6,000 INDUCTION	19.67 /mo	1.80 /mo	464
465					9500 HPS ARCHITECTURAL	15.38 /mo	9500 HPS ARCHITECTURAL	16.93 /mo	1.55 /mo	465
466					16,000 HPS ARCHITECTURAL	17.96 /mo	16,000 HPS ARCHITECTURAL	19.77 /mo	1.81 /mo	466
467					30,000 HPS ARCHITECTURAL	21.31 /mo	30,000 HPS ARCHITECTURAL	23.46 /mo	2.15 /mo	467
468					50,000 HPS ARCHITECTURAL	26.29 /mo	50,000 HPS ARCHITECTURAL	28.95 /mo	2.66 /mo	468
469					14,000 MH ARCHITECTURAL	21.51 /mo	14,000 MH ARCHITECTURAL	23.68 /mo	2.17 /mo	469
470					21,000 MH ARCHITECTURAL	24.42 /mo	21,000 MH ARCHITECTURAL	26.89 /mo	2.47 /mo	470
471					36,000 MH ARCHITECTURAL	30.54 /mo	36,000 MH ARCHITECTURAL	33.62 /mo	3.08 /mo	471
472					8,000 LPS ARCHITECTURAL	22.35 /mo	8,000 LPS ARCHITECTURAL	24.61 /mo	2.26 /mo	472
473					13500 LPS ARCHITECTURAL	26.36 /mo	13500 LPS ARCHITECTURAL	29.02 /mo	2.66 /mo	473
474					22,500 LPS ARCHITECTURAL	30.11 /mo	22,500 LPS ARCHITECTURAL	33.15 /mo	3.04 /mo	474
475					33,000 LPS ARCHITECTURAL	36.22 /mo	33,000 LPS ARCHITECTURAL	39.88 /mo	3.66 /mo	475
476					6,2000 INDUCTION ARCHITECTURAL	9.40 /mo	6,2000 INDUCTION ARCHITECTURAL	10.35 /mo	0.95 /mo	476
477					8,400 INDUCTION ARCHITECTURAL	9.93 /mo	8,400 INDUCTION ARCHITECTURAL	10.93 /mo	1.00 /mo	477
478					10,200 INDUCTION ARCHITECTURAL	10.91 /mo	10,200 INDUCTION ARCHITECTURAL	12.01 /mo	1.10 /mo	478
479					13,000 INDUCTION ARCHITECTURAL	12.05 /mo	13,000 INDUCTION ARCHITECTURAL	13.27 /mo	1.22 /mo	479
480					20,500 INDUCTION ARCHITECTURAL	13.72 /mo	20,500 INDUCTION ARCHITECTURAL	15.11 /mo	1.39 /mo	480
481					22,500 INDUCTION ARCHITECTURAL	16.37 /mo	22,500 INDUCTION ARCHITECTURAL	18.02 /mo	1.65 /mo	481
482					5,800 LED ARCHITECTURAL	16.53 /mo	5,800 LED ARCHITECTURAL	18.20 /mo	1.67 /mo	482
483					7,400 LED ARCHITECTURAL	18.96 /mo	7,400 LED ARCHITECTURAL	20.87 /mo	1.91 /mo	483
484					12,300 LED ARCHITECTURAL	23.66 /mo	12,300 LED ARCHITECTURAL	26.05 /mo	2.39 /mo	484
485					5800 HPS COBRA/ROADWAY	8.73 /mo	5800 HPS COBRA/ROADWAY	9.61 /mo	0.88 /mo	485
486					9500 HPS COBRA/ROADWAY	10.28 /mo	9500 HPS COBRA/ROADWAY	11.32 /mo	1.04 /mo	486
487					16,000 HPS COBRA/ROADWAY	12.87 /mo	16,000 HPS COBRA/ROADWAY	14.17 /mo	1.30 /mo	487
488					30,000 HPS COBRA/ROADWAY	15.52 /mo	30,000 HPS COBRA/ROADWAY	17.09 /mo	1.57 /mo	488
489					50,000 HPS COBRA/ROADWAY	21.06 /mo	50,000 HPS COBRA/ROADWAY	23.19 /mo	2.13 /mo	489
490					14,000 MH COBRA/ROADWAY	14.97 /mo	14,000 MH COBRA/ROADWAY	16.48 /mo	1.51 /mo	490
491					21,000 MH COBRA/ROADWAY	17.49 /mo	21,000 MH COBRA/ROADWAY	19.26 /mo	1.77 /mo	491
492					36,000 MH COBRA/ROADWAY	23.03 /mo	36,000 MH COBRA/ROADWAY	25.36 /mo	2.33 /mo	492
493					8,000 FL COBRA/ROADWAY	17.20 /mo	8,000 FL COBRA/ROADWAY	18.94 /mo	1.74 /mo	493
494					6,200 INDUCTION/ROADWAY	9.78 /mo	6,200 INDUCTION/ROADWAY	10.77 /mo	0.99 /mo	494
495					6,400 INDUCTION/ROADWAY	8.33 /mo	6,400 INDUCTION/ROADWAY	9.17 /mo	0.84 /mo	495
496					8,000 INDUCTION/ROADWAY	9.72 /mo	8,000 INDUCTION/ROADWAY	10.70 /mo	0.98 /mo	496
497					8,400 INDUCTION/ROADWAY	9.01 /mo	8,400 INDUCTION/ROADWAY	9.92 /mo	0.91 /mo	497
498					10,200 INDUCTION/ROADWAY	9.69 /mo	10,200 INDUCTION/ROADWAY	10.67 /mo	0.98 /mo	498
499					13,000 INDUCTION/ROADWAY	10.67 /mo	13,000 INDUCTION/ROADWAY	11.75 /mo	1.08 /mo	499
500					15,250 INDUCTION/ROADWAY	12.87 /mo	15,250 INDUCTION/ROADWAY	14.17 /mo	1.30 /mo	500
501					22,500 INDUCTION/ROADWAY	17.22 /mo	22,500 INDUCTION/ROADWAY	18.96 /mo	1.74 /mo	501
502					3,500 INDUCTION/ROADWAY	9.75 /mo	3,500 INDUCTION/ROADWAY	10.73 /mo	0.98 /mo	502
503					6,000 LED/ROADWAY	15.83 /mo	6,000 LED/ROADWAY	17.43 /mo	1.60 /mo	503
504					8,700 LED/ROADWAY	17.80 /mo	8,700 LED/ROADWAY	19.60 /mo	1.80 /mo	504
505					9,600 LED/ROADWAY	18.94 /mo	9,600 LED/ROADWAY	20.85 /mo	1.91 /mo	505
506					11,600 BETA LED/ROADWAY	17.67 /mo	11,600 BETA LED/ROADWAY	19.45 /mo	1.78 /mo	506
507					3,300 LED/ROADWAY	8.36 /mo	3,300 LED/ROADWAY	9.20 /mo	0.84 /mo	507
508					5,300 LED/ROADWAY	9.70 /mo	5,300 LED/ROADWAY	10.68 /mo	0.98 /mo	508
509					8,300 LED/ROADWAY	12.58 /mo	8,300 LED/ROADWAY	13.85 /mo	1.27 /mo	509
510					10,500 LED/ROADWAY	14.00 /mo	10,500 LED/ROADWAY	15.41 /mo	1.41 /mo	510
511					20,000 LED/ROADWAY	24.33 /mo	20,000 LED/ROADWAY	26.79 /mo	2.46 /mo	511
512					9500 HPS DECORATIVE TRANSIT	37.09 /mo	9500 HPS DECORATIVE TRANSIT	40.84 /mo	3.75 /mo	512
513					16,000 HPS DECORATIVE TRANSIT	36.88 /mo	16,000 HPS DECORATIVE TRANSIT	40.60 /mo	3.72 /mo	513
514					30,000 HPS DECORATIVE TRANSIT	42.46 /mo	30,000 HPS DECORATIVE TRANSIT	46.75 /mo	4.29 /mo	514
515					5,300 LED/DECORATIVE TRANSIT	26.40 /mo	5,300 LED/DECORATIVE TRANSIT	29.07 /mo	2.67 /mo	515
516					8,300 LED/DECORATIVE TRANSIT	28.27 /mo	8,300 LED/DECORATIVE TRANSIT	31.13 /mo	2.86 /mo	516
517					10,500 LED/DECORATIVE TRANSIT	30.35 /mo	10,500 LED/DECORATIVE TRANSIT	33.42 /mo	3.07 /mo	517
518					30,000 HPS FLOOD	20.61 /mo	30,000 HPS FLOOD	22.69 /mo	2.08 /mo	518
519					50,000 HPS FLOOD	25.56 /mo	50,000 HPS FLOOD	28.14 /mo	2.58 /mo	519
520					21,000 MH FLOOD	22.00 /mo	21,000 MH FLOOD	24.22 /mo	2.22 /mo	520

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (I) - (F)	Line No.
521	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**FIXTURES** (Customer Owned)		**FIXTURES** (Customer Owned)			521
522	(continued)	Service			36,000 MH FLOOD	$ 26.82 /mo	36,000 MH FLOOD	$ 29.53 /mo	$ 2.71 /mo	522
523					8,000 FL COLONIAL GRAY POST TOP	18.54 /mo	8,000 FL COLONIAL GRAY POST TOP	20.41 /mo	1.87 /mo	523
524					9500 HPS COLONIAL GRAY POST TOP	10.60 /mo	9500 HPS COLONIAL GRAY POST TOP	11.67 /mo	1.07 /mo	524
525					9500 HPS COLONIAL BLACK POST TOP	12.21 /mo	9500 HPS COLONIAL BLACK POST TOP	13.44 /mo	1.23 /mo	525
526					9500 HPS DECORATIVE POST TOP	32.47 /mo	9500 HPS DECORATIVE POST TOP	35.75 /mo	3.28 /mo	526
527					6000 INDUCTION/POST TOP (COPPER SQUARE)	17.52 /mo	6000 INDUCTION/POST TOP (COPPER SQUARE)	19.29 /mo	1.77 /mo	527
528					8,000 INDUCTION/POST TOP (GRAY/BLACK)	13.80 /mo	8,000 INDUCTION/POST TOP (GRAY/BLACK)	15.19 /mo	1.39 /mo	528
529					4,350 LED/POST TOP (GRAY/BLACK)	12.52 /mo	4,350 LED/POST TOP (GRAY/BLACK)	13.78 /mo	1.26 /mo	529
530					4,000 INC FROZEN	9.78 /mo	4,000 INC FROZEN	10.77 /mo	0.99 /mo	530
531					7,000 MV FROZEN	12.67 /mo	7,000 MV FROZEN	13.95 /mo	1.28 /mo	531
532					20,000 MV FROZEN	24.92 /mo	20,000 MV FROZEN	27.44 /mo	2.52 /mo	532
533					BRACKETS FROZEN	1.72 /mo	BRACKETS FROZEN	1.89 /mo	0.17 /mo	533
534					9500 HPS ACORN	9.22 /mo	9500 HPS ACORN	10.15 /mo	0.93 /mo	534
535					16,000 HPS ACORN	11.65 /mo	16,000 HPS ACORN	12.83 /mo	1.18 /mo	535
536					6,000 INDUCTION	2.77 /mo	6,000 INDUCTION	3.05 /mo	0.28 /mo	536
537					9500 HPS ARCHITECTURAL	7.34 /mo	9500 HPS ARCHITECTURAL	8.08 /mo	0.74 /mo	537
538					16,000 HPS ARCHITECTURAL	9.82 /mo	16,000 HPS ARCHITECTURAL	10.81 /mo	0.99 /mo	538
539					30,000 HPS ARCHITECTURAL	12.60 /mo	30,000 HPS ARCHITECTURAL	13.87 /mo	1.27 /mo	539
540					50,000 HPS ARCHITECTURAL	18.13 /mo	50,000 HPS ARCHITECTURAL	19.96 /mo	1.83 /mo	540
541					14,000 MH ARCHITECTURAL	11.79 /mo	14,000 MH ARCHITECTURAL	12.98 /mo	1.19 /mo	541
542					21,000 MH ARCHITECTURAL	14.54 /mo	21,000 MH ARCHITECTURAL	16.01 /mo	1.47 /mo	542
543					36,000 MH ARCHITECTURAL	20.00 /mo	36,000 MH ARCHITECTURAL	22.02 /mo	2.02 /mo	543
544					8,000 LPS ARCHITECTURAL	9.82 /mo	8,000 LPS ARCHITECTURAL	10.81 /mo	0.99 /mo	544
545					13500 LPS ARCHITECTURAL	11.84 /mo	13500 LPS ARCHITECTURAL	13.04 /mo	1.20 /mo	545
546					22,500 LPS ARCHITECTURAL	14.45 /mo	22,500 LPS ARCHITECTURAL	15.91 /mo	1.46 /mo	546
547					33,000 LPS ARCHITECTURAL	17.02 /mo	33,000 LPS ARCHITECTURAL	18.74 /mo	1.72 /mo	547
548					6,2000 INDUCTION ARCHITECTURAL	2.77 /mo	6,2000 INDUCTION ARCHITECTURAL	3.05 /mo	0.28 /mo	548
549					8,400 INDUCTION ARCHITECTURAL	3.15 /mo	8,400 INDUCTION ARCHITECTURAL	3.47 /mo	0.32 /mo	549
550					10,200 INDUCTION ARCHITECTURAL	3.67 /mo	10,200 INDUCTION ARCHITECTURAL	4.04 /mo	0.37 /mo	550
551					13,000 INDUCTION ARCHITECTURAL	4.50 /mo	13,000 INDUCTION ARCHITECTURAL	4.95 /mo	0.45 /mo	551
552					20,500 INDUCTION ARCHITECTURAL	5.79 /mo	20,500 INDUCTION ARCHITECTURAL	6.37 /mo	0.58 /mo	552
553					22,500 INDUCTION ARCHITECTURAL	7.44 /mo	22,500 INDUCTION ARCHITECTURAL	8.19 /mo	0.75 /mo	553
554					5,800 LED ARCHITECTURAL	3.00 /mo	5,800 LED ARCHITECTURAL	3.30 /mo	0.30 /mo	554
555					7,400 LED ARCHITECTURAL	3.90 /mo	7,400 LED ARCHITECTURAL	4.29 /mo	0.39 /mo	555
556					12,300 LED ARCHITECTURAL	5.86 /mo	12,300 LED ARCHITECTURAL	6.45 /mo	0.59 /mo	556
557					5800 HPS COBRA/ROADWAY	5.16 /mo	5800 HPS COBRA/ROADWAY	5.68 /mo	0.52 /mo	557
558					9500 HPS COBRA/ROADWAY	6.32 /mo	9500 HPS COBRA/ROADWAY	6.96 /mo	0.64 /mo	558
559					16,000 HPS COBRA/ROADWAY	8.82 /mo	16,000 HPS COBRA/ROADWAY	9.71 /mo	0.89 /mo	559
560					30,000 HPS COBRA/ROADWAY	11.46 /mo	30,000 HPS COBRA/ROADWAY	12.62 /mo	1.16 /mo	560
561					50,000 HPS COBRA/ROADWAY	16.37 /mo	50,000 HPS COBRA/ROADWAY	18.02 /mo	1.65 /mo	561
562					14,000 MH COBRA/ROADWAY	10.20 /mo	14,000 MH COBRA/ROADWAY	11.23 /mo	1.03 /mo	562
563					21,000 MH COBRA/ROADWAY	12.69 /mo	21,000 MH COBRA/ROADWAY	13.97 /mo	1.28 /mo	563
564					36,000 MH COBRA/ROADWAY	17.63 /mo	36,000 MH COBRA/ROADWAY	19.41 /mo	1.78 /mo	564
565					8,000 FL COBRA/ROADWAY	5.04 /mo	8,000 FL COBRA/ROADWAY	5.55 /mo	0.51 /mo	565
566					6,200 INDUCTION/ROADWAY	2.54 /mo	6,200 INDUCTION/ROADWAY	2.80 /mo	0.26 /mo	566
567					6,400 INDUCTION/ROADWAY	2.77 /mo	6,400 INDUCTION/ROADWAY	3.05 /mo	0.28 /mo	567
568					8,000 INDUCTION/ROADWAY	2.84 /mo	8,000 INDUCTION/ROADWAY	3.13 /mo	0.29 /mo	568
569					8,400 INDUCTION/ROADWAY	3.15 /mo	8,400 INDUCTION/ROADWAY	3.47 /mo	0.32 /mo	569
570					10,200 INDUCTION/ROADWAY	3.67 /mo	10,200 INDUCTION/ROADWAY	4.04 /mo	0.37 /mo	570
571					13,000 INDUCTION/ROADWAY	4.50 /mo	13,000 INDUCTION/ROADWAY	4.95 /mo	0.45 /mo	571
572					15,250 INDUCTION/ROADWAY	5.79 /mo	15,250 INDUCTION/ROADWAY	6.37 /mo	0.58 /mo	572
573					22,500 INDUCTION/ROADWAY	7.06 /mo	22,500 INDUCTION/ROADWAY	7.77 /mo	0.71 /mo	573
574					3,500 INDUCTION/ROADWAY	2.01 /mo	3,500 INDUCTION/ROADWAY	2.21 /mo	0.20 /mo	574
575					6,000 LED/ROADWAY	3.07 /mo	6,000 LED/ROADWAY	3.38 /mo	0.31 /mo	575
576					8,700 LED/ROADWAY	4.27 /mo	8,700 LED/ROADWAY	4.70 /mo	0.43 /mo	576
577					9,600 LED/ROADWAY	4.65 /mo	9,600 LED/ROADWAY	5.12 /mo	0.47 /mo	577
578					11,600 BETA LED/ROADWAY	5.25 /mo	11,600 BETA LED/ROADWAY	5.78 /mo	0.53 /mo	578
579					3,300 LED/ROADWAY	1.71 /mo	3,300 LED/ROADWAY	1.88 /mo	0.17 /mo	579
580					5,300 LED/ROADWAY	2.32 /mo	5,300 LED/ROADWAY	2.55 /mo	0.23 /mo	580
581					8,300 LED/ROADWAY	3.37 /mo	8,300 LED/ROADWAY	3.71 /mo	0.34 /mo	581
582					10,500 LED/ROADWAY	3.97 /mo	10,500 LED/ROADWAY	4.37 /mo	0.40 /mo	582
583					20,000 LED/ROADWAY	7.29 /mo	20,000 LED/ROADWAY	8.03 /mo	0.74 /mo	583
584					9500 HPS DECORATIVE TRANSIT	11.11 /mo	9500 HPS DECORATIVE TRANSIT	12.23 /mo	1.12 /mo	584
585					16,000 HPS DECORATIVE TRANSIT	6.31 /mo	16,000 HPS DECORATIVE TRANSIT	6.95 /mo	0.64 /mo	585
586					30,000 HPS DECORATIVE TRANSIT	16.02 /mo	30,000 HPS DECORATIVE TRANSIT	17.64 /mo	1.62 /mo	586
587					5,300 LED/DECORATIVE TRANSIT	2.54 /mo	5,300 LED/DECORATIVE TRANSIT	2.80 /mo	0.26 /mo	587
588					8,300 LED/DECORATIVE TRANSIT	3.15 /mo	8,300 LED/DECORATIVE TRANSIT	3.47 /mo	0.32 /mo	588
589					10,500 LED/DECORATIVE TRANSIT	4.50 /mo	10,500 LED/DECORATIVE TRANSIT	4.95 /mo	0.45 /mo	589
590					30,000 HPS FLOOD	12.81 /mo	30,000 HPS FLOOD	14.10 /mo	1.29 /mo	590

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)	(G) Rates	(H) Proposed Rates Block	(I)	(J) Rates	(K)	(L) Change (I) - (F)	Line No.
591	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**FIXTURES** (Customer Owned)			**FIXTURES** (Customer Owned)					591
592	(continued)				50,000 HPS FLOOD	$	17.77 /mo	50,000 HPS FLOOD	$	19.56 /mo	$	1.79 /mo	592
593					21,000 MH FLOOD		13.53 /mo	21,000 MH FLOOD		14.90 /mo		1.37 /mo	593
594					36,000 MH FLOOD		18.35 /mo	36,000 MH FLOOD		20.20 /mo		1.85 /mo	594
595					8,000 FL COLONIAL GRAY POST TOP		5.23 /mo	8,000 FL COLONIAL GRAY POST TOP		5.76 /mo		0.53 /mo	595
596					9500 HPS COLONIAL GRAY POST TOP		6.65 /mo	9500 HPS COLONIAL GRAY POST TOP		7.32 /mo		0.67 /mo	596
597					9500 HPS COLONIAL BLACK POST TOP		6.88 /mo	9500 HPS COLONIAL BLACK POST TOP		7.57 /mo		0.69 /mo	597
598					9500 HPS DECORATIVE POST TOP		10.24 /mo	9500 HPS DECORATIVE POST TOP		11.27 /mo		1.03 /mo	598
599					6000 INDUCTION/POST TOP (COPPER SQUARE)		2.77 /mo	6000 INDUCTION/POST TOP (COPPER SQUARE)		3.05 /mo		0.28 /mo	599
600					8,000 INDUCTION/POST TOP (GRAY/BLACK)		2.84 /mo	8,000 INDUCTION/POST TOP (GRAY/BLACK)		3.13 /mo		0.29 /mo	600
601					4,350 LED/POST TOP (GRAY/BLACK)		2.84 /mo	4,350 LED/POST TOP (GRAY/BLACK)		3.13 /mo		0.29 /mo	601
602					4,000 INC FROZEN		5.47 /mo	4,000 INC FROZEN		6.02 /mo		0.55 /mo	602
603					7,000 MV FROZEN		7.27 /mo	7,000 MV FROZEN		8.00 /mo		0.73 /mo	603
604					20,000 MV FROZEN		14.12 /mo	20,000 MV FROZEN		15.55 /mo		1.43 /mo	604
605					BRACKETS FROZEN		- /mo	BRACKETS FROZEN		0.00 /mo		- /mo	605
606													606
607	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**POLES** (Company Owned)			**POLES** (Company Owned)					607
608	(continued)	Service			Anchor Flush, Round, 1X, 12ft	$	12.17 /mo	Anchor Flush, Round, 1X, 12ft	$	13.40 /mo	$	1.23 /mo	608
609					Anchor Flush, Round, 1X, 22ft		13.70 /mo	Anchor Flush, Round, 1X, 22ft		15.08 /mo		1.38 /mo	609
610					Anchor Flush, Round, 1X, 25ft		14.82 /mo	Anchor Flush, Round, 1X, 25ft		16.32 /mo		1.50 /mo	610
611					Anchor Flush, Round, 1X, 30ft		17.03 /mo	Anchor Flush, Round, 1X, 30ft		18.75 /mo		1.72 /mo	611
612					Anchor Flush, Round, 1X, 32ft		17.89 /mo	Anchor Flush, Round, 1X, 32ft		19.70 /mo		1.81 /mo	612
613					Anchor Flush, Round, 2X, 12ft		12.98 /mo	Anchor Flush, Round, 2X, 12ft		14.29 /mo		1.31 /mo	613
614					Anchor Flush, Round, 2X, 22ft		14.91 /mo	Anchor Flush, Round, 2X, 22ft		16.42 /mo		1.51 /mo	614
615					Anchor Flush, Round, 2X, 25ft		15.55 /mo	Anchor Flush, Round, 2X, 25ft		17.12 /mo		1.57 /mo	615
616					Anchor Flush, Round, 2X, 30ft		18.07 /mo	Anchor Flush, Round, 2X, 30ft		19.90 /mo		1.83 /mo	616
617					Anchor Flush, Round, 2X, 32ft		19.28 /mo	Anchor Flush, Round, 2X, 32ft		21.23 /mo		1.95 /mo	617
618					Anchor Flush, Square, 5", 13ft		13.95 /mo	Anchor Flush, Square, 5", 13ft		15.36 /mo		1.41 /mo	618
619					Anchor Flush, Square, 5", 15ft		12.47 /mo	Anchor Flush, Square, 5", 15ft		13.73 /mo		1.26 /mo	619
620					Anchor Flush, Square, 5", 23ft		14.79 /mo	Anchor Flush, Square, 5", 23ft		16.28 /mo		1.49 /mo	620
621					Anchor Flush, Square, 5", 25ft		16.26 /mo	Anchor Flush, Square, 5", 25ft		17.90 /mo		1.64 /mo	621
622					Anchor Flush, Square, 5", 28ft		18.05 /mo	Anchor Flush, Square, 5", 28ft		19.87 /mo		1.82 /mo	622
623					Anchor Flush, Square, 5", 32ft		17.95 /mo	Anchor Flush, Square, 5", 32ft		19.76 /mo		1.81 /mo	623
624					Anchor Flush, Concrete, 12ft		41.58 /mo	Anchor Flush, Concrete, 12ft		45.78 /mo		4.20 /mo	624
625					Anchor Flush, Fiberglass, 12ft		35.21 /mo	Anchor Flush, Fiberglass, 12ft		38.77 /mo		3.56 /mo	625
626					Anchor Flush, Dec Transit Ped, 4", 16ft		34.33 /mo	Anchor Flush, Dec Transit Ped, 4", 16ft		37.80 /mo		3.47 /mo	626
627					Anchor Flush, Dec Transit, 6", 30ft		66.28 /mo	Anchor Flush, Dec Transit, 6", 30ft		72.97 /mo		6.69 /mo	627
628					Anchor Fluch, Hinged Square 15'		13.20 /mo	Anchor Fluch, Hinged Square 15'		14.53 /mo		1.33 /mo	628
629					Anchor Flush, Hinged Round 19'		11.93 /mo	Anchor Flush, Hinged Round 19'		13.13 /mo		1.20 /mo	629
630					Anchor Pedstl, Round, 1X, 12ft		11.71 /mo	Anchor Pedstl, Round, 1X, 12ft		12.89 /mo		1.18 /mo	630
631					Anchor Pedstl, Round, 1X, 22ft		13.24 /mo	Anchor Pedstl, Round, 1X, 22ft		14.58 /mo		1.34 /mo	631
632					Anchor Pedstl, Round, 1X, 25ft		14.35 /mo	Anchor Pedstl, Round, 1X, 25ft		15.80 /mo		1.45 /mo	632
633					Anchor Pedstl, Round, 1X, 30ft		16.58 /mo	Anchor Pedstl, Round, 1X, 30ft		18.25 /mo		1.67 /mo	633
634					Anchor Pedstl, Round, 1X, 32ft		17.41 /mo	Anchor Pedstl, Round, 1X, 32ft		19.17 /mo		1.76 /mo	634
635					Anchor Pedstl, Round, 2X, 12ft		12.51 /mo	Anchor Pedstl, Round, 2X, 12ft		13.77 /mo		1.26 /mo	635
636					Anchor Pedstl, Round, 2X, 22ft		13.97 /mo	Anchor Pedstl, Round, 2X, 22ft		15.38 /mo		1.41 /mo	636
637					Anchor Pedstl, Round, 2X, 25ft		15.08 /mo	Anchor Pedstl, Round, 2X, 25ft		16.60 /mo		1.52 /mo	637
638					Anchor Pedstl, Round, 2X, 30ft		17.61 /mo	Anchor Pedstl, Round, 2X, 30ft		19.39 /mo		1.78 /mo	638
639					Anchor Pedstl, Round, 2X, 32ft		18.81 /mo	Anchor Pedstl, Round, 2X, 32ft		20.71 /mo		1.90 /mo	639
640					Anchor Pedstl, Round, 3 Bolt, 32ft		21.62 /mo	Anchor Pedstl, Round, 3 Bolt, 32ft		23.80 /mo		2.18 /mo	640
641					Anchor Pedstl, Square, 5", 13ft		13.50 /mo	Anchor Pedstl, Square, 5", 13ft		14.86 /mo		1.36 /mo	641
642					Anchor Pedstl, Square, 5", 15ft		13.80 /mo	Anchor Pedstl, Square, 5", 15ft		15.19 /mo		1.39 /mo	642
643					Anchor Pedstl, Square, 5", 23ft		14.32 /mo	Anchor Pedstl, Square, 5", 23ft		15.77 /mo		1.45 /mo	643
644					Anchor Pedstl, Square, 5", 25ft		15.80 /mo	Anchor Pedstl, Square, 5", 25ft		17.40 /mo		1.60 /mo	644
645					Anchor Pedstl, Square, 5", 28ft		17.56 /mo	Anchor Pedstl, Square, 5", 28ft		19.33 /mo		1.77 /mo	645
646					Anchor Pedstl, Square, 5", 32ft		18.23 /mo	Anchor Pedstl, Square, 5", 32ft		20.07 /mo		1.84 /mo	646
647					Direct Bury, Round, 19ft		18.42 /mo	Direct Bury, Round, 19ft		20.28 /mo		1.86 /mo	647
648					Direct Bury, Round, 30ft		14.38 /mo	Direct Bury, Round, 30ft		15.83 /mo		1.45 /mo	648
649					Direct Bury, Round, 38ft		17.55 /mo	Direct Bury, Round, 38ft		19.32 /mo		1.77 /mo	649
650					Direct Bury, Self-Support, 40ft		21.62 /mo	Direct Bury, Self-Support, 40ft		23.80 /mo		2.18 /mo	650
651					Direct Bury, Stepped 25'		49.72 /mo	Direct Bury, Stepped 25'		54.74 /mo		5.02 /mo	651
652					Direct Bury, Steppen 32'		52.36 /mo	Direct Bury, Steppen 32'		57.65 /mo		5.29 /mo	652
653					Direct Bury, Stepped, 49ft		64.99 /mo	Direct Bury, Stepped, 49ft		71.55 /mo		6.56 /mo	653
654					Direct Bury, Square, 4", 34ft		15.87 /mo	Direct Bury, Square, 4", 34ft		17.47 /mo		1.60 /mo	654
655					Direct Bury, Square, 5", 20ft		15.07 /mo	Direct Bury, Square, 5", 20ft		16.59 /mo		1.52 /mo	655
656					Direct Bury, Square, 5" 30ft		15.71 /mo	Direct Bury, Square, 5" 30ft		17.30 /mo		1.59 /mo	656
657					Direct Bury, Square, 5" 38ft		17.05 /mo	Direct Bury, Square, 5" 38ft		18.77 /mo		1.72 /mo	657
658					Direct Bury Square 8" 28 ft		28.45 /mo	Direct Bury Square 8" 28 ft		31.32 /mo		2.87 /mo	658
659					Direct Bury Square 8" 32 ft		29.74 /mo	Direct Bury Square 8" 32 ft		32.74 /mo		3.00 /mo	659
660					Deecorative Transit 41- 6		20.47 /mo	Deecorative Transit 41- 6		22.54 /mo		2.07 /mo	660
661					Deecorative Transit 47		25.50 /mo	Deecorative Transit 47		28.08 /mo		2.58 /mo	661

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)	(G) Rates	(H) Proposed Rates Block	(I)	(J) Rates	(K)	(L) Change (I) - (F)	Line No.
662	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**POLES** (Company Owned)			**POLES** (Company Owned)					662
663	(continued)				Direct Bury, Steel Dist Pole, 35ft (Lighting only)	$	23.54 /mo	Direct Bury, Steel Dist Pole, 35ft (Lighting only)	$	25.92 /mo	$	2.38 /mo	663
664					Post Top, Dec Transit, 16ft		35.07 /mo	Post Top, Dec Transit, 16ft		38.61 /mo		3.54 /mo	664
665					Post Top, Gray Steel/Fiberglass, 23ft		12.16 /mo	Post Top, Gray Steel/Fiberglass, 23ft		13.39 /mo		1.23 /mo	665
666					Post Top, Black Steel, 23ft		13.41 /mo	Post Top, Black Steel, 23ft		14.76 /mo		1.35 /mo	666
667					FROZEN, Wood Poles, 30ft		8.95 /mo	FROZEN, Wood Poles, 30ft		9.85 /mo		0.90 /mo	667
668					FROZEN, Wood Poles, 35ft		8.95 /mo	FROZEN, Wood Poles, 35ft		9.85 /mo		0.90 /mo	668
669					FROZEN, Wood Poles, 40ft		12.73 /mo	FROZEN, Wood Poles, 40ft		14.02 /mo		1.29 /mo	669
670													670
671					Flush, 4ft	$	9.91 /mo	Flush, 4ft	$	10.91 /mo	$	1.00 /mo	671
672					Flush, 6ft		11.82 /mo	Flush, 6ft		13.01 /mo		1.19 /mo	672
673					Pedestal, 8ft		13.54 /mo	Pedestal, 8ft		14.91 /mo		1.37 /mo	673
674					Pedestal, 32' round steel pole, 4ft 6"		9.39 /mo	Pedestal, 32' round steel pole, 4ft 6"		10.34 /mo		0.95 /mo	674
675													675
676					1. 100' OH, UG if conduit by customer	$	3.50 /mo	1. 100' OH, UG if conduit by customer	$	3.85 /mo	$	0.35 /mo	676
677					2. HPS not accessible by bucket		2.80 /mo	2. HPS not accessible by bucket		3.08 /mo		0.28 /mo	677
678					3. MH not accessible by bucket		6.04 /mo	3. MH not accessible by bucket		6.65 /mo		0.61 /mo	678
679							/mo						679
680					Service Charge	$	3.35 /mo	Service Charge	$	3.69 /mo	$	0.34 /mo	680
681					All kWh		0.06 /mo	All kWh		0.07 /mo		0.01 /mo	681
682													682
683	E-54	Seasonal Service	Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU			RATE SCHEDULE E-54 PROPOSE TO CANCEL					683
684			Minimum	Sum & Win	"Floor" Annual Minimum	$	603.49 /yr						684
685													685
686	E-56	Electric Service for	Basic										686
687		Partial Requirements	Service	Sum & Win	Basic Service Charge		per applicable rate	Basic Service Charge		per applicable rate			687
688		Service for CG					schedule			schedule			688
689		installations of 100kw											689
690			Supplemental	Sum & Win	All Supplemental Charges		per applicable rate	All Supplemental Charges		per applicable rate			690
691			Service				schedule			schedule			691
692													692
693			Back-Up	Sum & Win	Back-Up Service with E-32 On-Peak	$	0.1200 /kW-day	Back-Up Service with E-32 On-Peak	$	0.1330 /kW-day	$	0.01300 /kW-day	693
694			Service		Back-Up Service with E-32 Off-Peak		N/A	Back-Up Service with E-32 Off-Peak		N/A			694
695					Back-Up Service with E-34 On-Peak		0.5900 /kW-day	Back-Up Service with E-34 On-Peak		0.6540 /kW-day		0.06400 /kW-day	695
696					Back-Up Service with E-34 Off-Peak		N/A	Back-Up Service with E-34 Off-Peak		N/A			696
697													697
698			Maint.	Sum & Win	Scheduled Maintenance On-Peak		1/2 Back-up Charge	Scheduled Maintenance On-Peak		1/2 Back-up Charge			698
699			Service		Scheduled Maintenance Off-Peak		N/A	Scheduled Maintenance Off-Peak		N/A			699
700													700
701			Excess	Sum & Win	Secondary Service Excess Charge	$	54.802 /kW	Secondary Service Excess Charge	$	54.802 /kW	$	- /kW	701
702					Primary Service Excess Charge		52.019 /kW	Primary Service Excess Charge		52.019 /kW		- /kW	702
703					Transmission Service Excess Charge		38.187 /kW	Transmission Service Excess Charge		38.187 /kW		- /kW	703
704													704
705	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES** (Company Owned)			**FIXTURES** (Company Owned)					705
706					9500 HPS ACORN	$	27.06 /mo	9500 HPS ACORN	$	29.79 /mo	$	2.73 /mo	706
707					16,000 HPS ACORN		30.04 /mo	16,000 HPS ACORN		33.07 /mo		3.03 /mo	707
708					6,000 INDUCTION		17.87 /mo	6,000 INDUCTION		19.67 /mo		1.80 /mo	708
709					9500 HPS ARCHITECTURAL		15.38 /mo	9500 HPS ARCHITECTURAL		16.93 /mo		1.55 /mo	709
710					16,000 HPS ARCHITECTURAL		17.96 /mo	16,000 HPS ARCHITECTURAL		19.77 /mo		1.81 /mo	710
711					30,000 HPS ARCHITECTURAL		21.31 /mo	30,000 HPS ARCHITECTURAL		23.46 /mo		2.15 /mo	711
712					50,000 HPS ARCHITECTURAL		26.29 /mo	50,000 HPS ARCHITECTURAL		28.95 /mo		2.66 /mo	712
713					14,000 MH ARCHITECTURAL		21.51 /mo	14,000 MH ARCHITECTURAL		23.68 /mo		2.17 /mo	713
714					21,000 MH ARCHITECTURAL		24.42 /mo	21,000 MH ARCHITECTURAL		26.89 /mo		2.47 /mo	714
715					36,000 MH ARCHITECTURAL		30.54 /mo	36,000 MH ARCHITECTURAL		33.62 /mo		3.08 /mo	715
716					8,000 LPS ARCHITECTURAL		22.35 /mo	8,000 LPS ARCHITECTURAL		24.61 /mo		2.26 /mo	716
717					13,500 LPS ARCHITECTURAL		26.36 /mo	13,500 LPS ARCHITECTURAL		29.02 /mo		2.66 /mo	717
718					22,500 LPS ARCHITECTURAL		30.11 /mo	22,500 LPS ARCHITECTURAL		33.15 /mo		3.04 /mo	718
719					33,000 LPS ARCHITECTURAL		36.22 /mo	33,000 LPS ARCHITECTURAL		39.88 /mo		3.66 /mo	719
720					6,200 INDUCTION/ARCHITECTURAL		9.40 /mo	6,200 INDUCTION/ARCHITECTURAL		10.35 /mo		0.95 /mo	720
721					8,400 INDUCTION/ARCHITECTURAL		9.93 /mo	8,400 INDUCTION/ARCHITECTURAL		10.93 /mo		1.00 /mo	721
722					10,200 INDUCTION/ARCHITECTURAL		10.91 /mo	10,200 INDUCTION/ARCHITECTURAL		12.01 /mo		1.10 /mo	722
723					13,000 INDUCTION/ARCHITECTURAL		12.05 /mo	13,000 INDUCTION/ARCHITECTURAL		13.27 /mo		1.22 /mo	723
724					20,500 INDUCTION/ARCHITECTURAL		13.72 /mo	20,500 INDUCTION/ARCHITECTURAL		15.11 /mo		1.39 /mo	724
725					22,500 INDUCTION/ARCHITECTURAL		16.37 /mo	22,500 INDUCTION/ARCHITECTURAL		18.02 /mo		1.65 /mo	725
726					5,800 LED/ARCHITECTURAL		16.53 /mo	5,800 LED/ARCHITECTURAL		18.20 /mo		1.67 /mo	726
727					7,400 LED/ARCHITECTURAL		18.96 /mo	7,400 LED/ARCHITECTURAL		20.87 /mo		1.91 /mo	727
728					12,300 LED/ARCHITECTURAL		23.66 /mo	12,300 LED/ARCHITECTURAL		26.05 /mo		2.39 /mo	728
729					9,200 LED/ARCHITECTURAL		23.77 /mo	9,200 LED/ARCHITECTURAL		26.17 /mo		2.40 /mo	729
730					13,620 LED/ARCHITECTURAL		26.45 /mo	13,620 LED/ARCHITECTURAL		29.12 /mo		2.67 /mo	730
731					6,400 LED/ARCHITECTURAL		16.61 /mo	6,400 LED/ARCHITECTURAL		18.29 /mo		1.68 /mo	731
732					5800 HPS COBRA/ROADWAY		8.73 /mo	5800 HPS COBRA/ROADWAY		9.61 /mo		0.88 /mo	732

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
733	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES** (Company Owned)			**FIXTURES** (Company Owned)					733
734	(continued)				9500 HPS COBRA/ROADWAY	$ 10.28	/mo	9500 HPS COBRA/ROADWAY	$ 11.32	/mo	$ 1.04	/mo	734
735					16,000 HPS COBRA/ROADWAY	12.87	/mo	16,000 HPS COBRA/ROADWAY	14.17	/mo	1.30	/mo	735
736					30,000 HPS COBRA/ROADWAY	15.52	/mo	30,000 HPS COBRA/ROADWAY	17.09	/mo	1.57	/mo	736
737					50,000 HPS COBRA/ROADWAY	21.06	/mo	50,000 HPS COBRA/ROADWAY	23.19	/mo	2.13	/mo	737
738					14,000 MH COBRA/ROADWAY	14.97	/mo	14,000 MH COBRA/ROADWAY	16.48	/mo	1.51	/mo	738
739					21,000 MH COBRA/ROADWAY	17.49	/mo	21,000 MH COBRA/ROADWAY	19.26	/mo	1.77	/mo	739
740					36,000 MH COBRA/ROADWAY	23.03	/mo	36,000 MH COBRA/ROADWAY	25.36	/mo	2.33	/mo	740
741					8,000 FL COBRA/ROADWAY	17.20	/mo	8,000 FL COBRA/ROADWAY	18.94	/mo	1.74	/mo	741
742					6,200 INDUCTION/COBRA ROADWAY	9.78	/mo	6,200 INDUCTION/COBRA ROADWAY	10.77	/mo	0.99	/mo	742
743					6,400 INDUCTION/ COBRA ROADWAY	8.33	/mo	6,400 INDUCTION/ COBRA ROADWAY	9.17	/mo	0.84	/mo	743
744					8,000 INDUCTION/COBRA ROADWAY	9.72	/mo	8,000 INDUCTION/COBRA ROADWAY	10.70	/mo	0.98	/mo	744
745					8,400 INDUCTION/COBRA ROADWAY	9.01	/mo	8,400 INDUCTION/COBRA ROADWAY	9.92	/mo	0.91	/mo	745
746					10,200 INDUCTION/COBRA ROADWAY	9.69	/mo	10,200 INDUCTION/COBRA ROADWAY	10.67	/mo	0.98	/mo	746
747					13,000 INDUCTION/ COBRA ROADWAY	10.67	/mo	13,000 INDUCTION/ COBRA ROADWAY	11.75	/mo	1.08	/mo	747
748					15,250 INDUCTION/ COBRA ROADWAY	12.87	/mo	15,250 INDUCTION/ COBRA ROADWAY	14.17	/mo	1.30	/mo	748
749					22,500 INDUCTION/ COBRA ROADWAY	17.22	/mo	22,500 INDUCTION/ COBRA ROADWAY	18.96	/mo	1.74	/mo	749
750					3,500 INDUCTION/ COBRA ROADWAY (G/B)	9.75	/mo	3,500 INDUCTION/ COBRA ROADWAY (G/B)	10.73	/mo	0.98	/mo	750
751					6,000 LED/COBRA ROADWAY	15.83	/mo	6,000 LED/COBRA ROADWAY	17.43	/mo	1.60	/mo	751
752					8,700 LED/ COBRA ROADWAY	17.80	/mo	8,700 LED/ COBRA ROADWAY	19.60	/mo	1.80	/mo	752
753					9,600 LED/ COBRA ROADWAY	18.94	/mo	9,600 LED/ COBRA ROADWAY	20.85	/mo	1.91	/mo	753
754					11,600 LED/ COBRA ROADWAY	17.67	/mo	11,600 LED/ COBRA ROADWAY	19.45	/mo	1.78	/mo	754
755					3,300 LED/ COBRA ROADWAY	8.36	/mo	3,300 LED/ COBRA ROADWAY	9.20	/mo	0.84	/mo	755
756					5,300 LED/ COBRA ROADWAY	9.70	/mo	5,300 LED/ COBRA ROADWAY	10.68	/mo	0.98	/mo	756
757					8,300 LED/ COBRA ROADWAY	12.58	/mo	8,300 LED/ COBRA ROADWAY	13.85	/mo	1.27	/mo	757
758					10,500 LED/ COBRA ROADWAY	14.00	/mo	10,500 LED/ COBRA ROADWAY	15.41	/mo	1.41	/mo	758
759					20,000 LED/ COBRA ROADWAY	24.33	/mo	20,000 LED/ COBRA ROADWAY	26.79	/mo	2.46	/mo	759
760					9500 HPS DECORATIVE TRANSIT	37.09	/mo	9500 HPS DECORATIVE TRANSIT	40.84	/mo	3.75	/mo	760
761					16,000 HPS DECORATIVE TRANSIT	36.88	/mo	16,000 HPS DECORATIVE TRANSIT	40.60	/mo	3.72	/mo	761
762					30,000 HPS DECORATIVE TRANSIT	42.46	/mo	30,000 HPS DECORATIVE TRANSIT	46.75	/mo	4.29	/mo	762
763					5,300 LED/ DECORATIVE TRANSIT	26.40	/mo	5,300 LED/ DECORATIVE TRANSIT	29.07	/mo	2.67	/mo	763
764					8,300 LED/DECORATIVE TRANSIT	28.27	/mo	8,300 LED/DECORATIVE TRANSIT	31.13	/mo	2.86	/mo	764
765					10,500 LED/ DECORATIVE TRANSIT	30.35	/mo	10,500 LED/ DECORATIVE TRANSIT	33.42	/mo	3.07	/mo	765
766					30,000 HPS FLOOD	20.61	/mo	30,000 HPS FLOOD	22.69	/mo	2.08	/mo	766
767					50,000 HPS FLOOD	25.56	/mo	50,000 HPS FLOOD	28.14	/mo	2.58	/mo	767
768					21,000 MH FLOOD	22.00	/mo	21,000 MH FLOOD	24.22	/mo	2.22	/mo	768
769					36,000 MH FLOOD	26.82	/mo	36,000 MH FLOOD	29.53	/mo	2.71	/mo	769
770					8,000 FL COLONIAL GRAY POST TOP	18.54	/mo	8,000 FL COLONIAL GRAY POST TOP	20.41	/mo	1.87	/mo	770
771					9500 HPS COLONIAL GRAY POST TOP	10.60	/mo	9500 HPS COLONIAL GRAY POST TOP	11.67	/mo	1.07	/mo	771
772					9500 HPS COLONIAL BLACK POST TOP	12.21	/mo	9500 HPS COLONIAL BLACK POST TOP	13.44	/mo	1.23	/mo	772
773					9500 HPS DECORATIVE POST TOP	32.47	/mo	9500 HPS DECORATIVE POST TOP	35.75	/mo	3.28	/mo	773
774					6,000 INDUCTION COPPER SQUARE/ POST TOP	17.52	/mo	6,000 INDUCTION COPPER SQUARE/ POST TOP	19.29	/mo	1.77	/mo	774
775					8,000 INDUCTION/ POST TOP (G/B)	13.80	/mo	8,000 INDUCTION/ POST TOP (G/B)	15.19	/mo	1.39	/mo	775
776					4,350 LED/ POST TOP (G/B)	12.52	/mo	4,350 LED/ POST TOP (G/B)	13.78	/mo	1.26	/mo	776
777					4,000 INC FROZEN	9.78	/mo	4,000 INC FROZEN	10.77	/mo	0.99	/mo	777
778					7,000 MV FROZEN	12.67	/mo	7,000 MV FROZEN	13.95	/mo	1.28	/mo	778
779					11,000 MV FROZEN	15.87	/mo	11,000 MV FROZEN	17.47	/mo	1.60	/mo	779
780					20,000 MV FROZEN	24.92	/mo	20,000 MV FROZEN	27.44	/mo	2.52	/mo	780
781					9500 HPS ACORN	9.22	/mo	9500 HPS ACORN	10.15	/mo	0.93	/mo	781
782					16,000 HPS ACORN	11.65	/mo	16,000 HPS ACORN	12.83	/mo	1.18	/mo	782
783					6,000 INDUCTION	4.77	/mo	6,000 INDUCTION	5.25	/mo	0.48	/mo	783
784					9500 HPS ARCHITECTURAL	7.34	/mo	9500 HPS ARCHITECTURAL	8.08	/mo	0.74	/mo	784
785					16,000 HPS ARCHITECTURAL	9.82	/mo	16,000 HPS ARCHITECTURAL	10.81	/mo	0.99	/mo	785
786					30,000 HPS ARCHITECTURAL	12.6	/mo	30,000 HPS ARCHITECTURAL	13.87	/mo	1.27	/mo	786
787					50,000 HPS ARCHITECTURAL	18.13	/mo	50,000 HPS ARCHITECTURAL	19.96	/mo	1.83	/mo	787
788					14,000 MH ARCHITECTURAL	11.79	/mo	14,000 MH ARCHITECTURAL	12.98	/mo	1.19	/mo	788
789					21,000 MH ARCHITECTURAL	14.54	/mo	21,000 MH ARCHITECTURAL	16.01	/mo	1.47	/mo	789
790					36,000 MH ARCHITECTURAL	20	/mo	36,000 MH ARCHITECTURAL	22.02	/mo	2.02	/mo	790
791					8,000 LPS ARCHITECTURAL	9.82	/mo	8,000 LPS ARCHITECTURAL	10.81	/mo	0.99	/mo	791
792					13,500 LPS ARCHITECTURAL	11.84	/mo	13,500 LPS ARCHITECTURAL	13.04	/mo	1.20	/mo	792
793					22,500 LPS ARCHITECTURAL	14.45	/mo	22,500 LPS ARCHITECTURAL	15.91	/mo	1.46	/mo	793
794					33,000 LPS ARCHITECTURAL	17.02	/mo	33,000 LPS ARCHITECTURAL	18.74	/mo	1.72	/mo	794
795					6,200 INDUCTION/ARCHITECTURAL	3.65	/mo	6,200 INDUCTION/ARCHITECTURAL	4.02	/mo	0.37	/mo	795
796					8,400 INDUCTION/ARCHITECTURAL	4.05	/mo	8,400 INDUCTION/ARCHITECTURAL	4.46	/mo	0.41	/mo	796
797					10,200 INDUCTION/ARCHITECTURAL	4.63	/mo	10,200 INDUCTION/ARCHITECTURAL	5.10	/mo	0.47	/mo	797
798					13,000 INDUCTION/ARCHITECTURAL	5.5	/mo	13,000 INDUCTION/ARCHITECTURAL	6.06	/mo	0.56	/mo	798
799					20,500 INDUCTION/ARCHITECTURAL	6.84	/mo	20,500 INDUCTION/ARCHITECTURAL	7.53	/mo	0.69	/mo	799
800					22,500 INDUCTION/ARCHITECTURAL	8.62	/mo	22,500 INDUCTION/ARCHITECTURAL	9.49	/mo	0.87	/mo	800
801					5,800 LED/ARCHITECTURAL	4.79	/mo	5,800 LED/ARCHITECTURAL	5.27	/mo	0.48	/mo	801
802					7,400 LED/ARCHITECTURAL	5.89	/mo	7,400 LED/ARCHITECTURAL	6.48	/mo	0.59	/mo	802
803					12,300 LED/ARCHITECTURAL	8.22	/mo	12,300 LED/ARCHITECTURAL	9.05	/mo	0.83	/mo	803

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)	(G) Rates	(H) Proposed Rates Block	(I)	(J) Rates	(K)	(L) Change (I) - (F)	Line No.
804	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES** (Customer Owned)			**FIXTURES** (Customer Owned)					804
805	(continued)				9,200 LED/ARCHITECTURAL	$	6.78 /mo	9,200 LED/ARCHITECTURAL	$	7.46 /mo	$	0.68 /mo	805
806					13,620 LED/ARCHITECTURAL		8.58 /mo	13,620 LED/ARCHITECTURAL		9.45 /mo		0.87 /mo	806
807					6,400 LED/ARCHITECTURAL		4.73 /mo	6,400 LED/ARCHITECTURAL		5.21 /mo		0.48 /mo	807
808					5800 HPS COBRA/ROADWAY		5.16 /mo	5800 HPS COBRA/ROADWAY		5.68 /mo		0.52 /mo	808
809					9500 HPS COBRA/ROADWAY		6.32 /mo	9500 HPS COBRA/ROADWAY		6.96 /mo		0.64 /mo	809
810					16,000 HPS COBRA/ROADWAY		8.82 /mo	16,000 HPS COBRA/ROADWAY		9.71 /mo		0.89 /mo	810
811					30,000 HPS COBRA/ROADWAY		11.46 /mo	30,000 HPS COBRA/ROADWAY		12.62 /mo		1.16 /mo	811
812					50,000 HPS COBRA/ROADWAY		16.37 /mo	50,000 HPS COBRA/ROADWAY		18.02 /mo		1.65 /mo	812
813					14,000 MH COBRA/ROADWAY		10.2 /mo	14,000 MH COBRA/ROADWAY		11.23 /mo		1.03 /mo	813
814					21,000 MH COBRA/ROADWAY		12.69 /mo	21,000 MH COBRA/ROADWAY		13.97 /mo		1.28 /mo	814
815					36,000 MH COBRA/ROADWAY		17.63 /mo	36,000 MH COBRA/ROADWAY		19.41 /mo		1.78 /mo	815
816					8,000 FL COBRA/ROADWAY		5.04 /mo	8,000 FL COBRA/ROADWAY		5.55 /mo		0.51 /mo	816
817					6,200 INDUCTION/COBRA ROADWAY		3.5 /mo	6,200 INDUCTION/COBRA ROADWAY		3.85 /mo		0.35 /mo	817
818					6,400 INDUCTION/ COBRA ROADWAY		3.51 /mo	6,400 INDUCTION/ COBRA ROADWAY		3.86 /mo		0.35 /mo	818
819					8,000 INDUCTION/COBRA ROADWAY		3.75 /mo	8,000 INDUCTION/COBRA ROADWAY		4.13 /mo		0.38 /mo	819
820					8,400 INDUCTION/COBRA ROADWAY		3.93 /mo	8,400 INDUCTION/COBRA ROADWAY		4.33 /mo		0.40 /mo	820
821					10,200 INDUCTION/COBRA ROADWAY		4.47 /mo	10,200 INDUCTION/COBRA ROADWAY		4.92 /mo		0.45 /mo	821
822					13,000 INDUCTION/ COBRA ROADWAY		5.32 /mo	13,000 INDUCTION/ COBRA ROADWAY		5.86 /mo		0.54 /mo	822
823					15,250 INDUCTION/ COBRA ROADWAY		6.73 /mo	15,250 INDUCTION/ COBRA ROADWAY		7.41 /mo		0.68 /mo	823
824					22,500 INDUCTION/ COBRA ROADWAY		8.41 /mo	22,500 INDUCTION/ COBRA ROADWAY		9.26 /mo		0.85 /mo	824
825					3,500 INDUCTION/ COBRA ROADWAY (G/B)		3.03 /mo	3,500 INDUCTION/ COBRA ROADWAY (G/B)		3.34 /mo		0.31 /mo	825
826					6,000 LED/COBRA ROADWAY		4.76 /mo	6,000 LED/COBRA ROADWAY		5.24 /mo		0.48 /mo	826
827					8,700 LED/ COBRA ROADWAY		6.06 /mo	8,700 LED/ COBRA ROADWAY		6.67 /mo		0.61 /mo	827
828					9,600 LED/ COBRA ROADWAY		6.54 /mo	9,600 LED/ COBRA ROADWAY		7.20 /mo		0.66 /mo	828
829					11,600 LED/ COBRA ROADWAY		6.9 /mo	11,600 LED/ COBRA ROADWAY		7.60 /mo		0.70 /mo	829
830					3,300 LED/ COBRA ROADWAY		2.59 /mo	3,300 LED/ COBRA ROADWAY		2.85 /mo		0.26 /mo	830
831					5,300 LED/ COBRA ROADWAY		3.29 /mo	5,300 LED/ COBRA ROADWAY		3.62 /mo		0.33 /mo	831
832					8,300 LED/ COBRA ROADWAY		4.59 /mo	8,300 LED/ COBRA ROADWAY		5.05 /mo		0.46 /mo	832
833					10,500 LED/ COBRA ROADWAY		5.29 /mo	10,500 LED/ COBRA ROADWAY		5.82 /mo		0.53 /mo	833
834					20,000 LED/ COBRA ROADWAY		9.54 /mo	20,000 LED/ COBRA ROADWAY		10.50 /mo		0.96 /mo	834
835					9500 HPS DECORATIVE TRANSIT		11.11 /mo	9500 HPS DECORATIVE TRANSIT		12.23 /mo		1.12 /mo	835
836					16,000 HPS DECORATIVE TRANSIT		12.41 /mo	16,000 HPS DECORATIVE TRANSIT		13.66 /mo		1.25 /mo	836
837					30,000 HPS DECORATIVE TRANSIT		16.02 /mo	30,000 HPS DECORATIVE TRANSIT		17.64 /mo		1.62 /mo	837
838					5,300 LED/ DECORATIVE TRANSIT		5.69 /mo	5,300 LED/ DECORATIVE TRANSIT		6.26 /mo		0.57 /mo	838
839					8,300 LED/DECORATIVE TRANSIT		6.47 /mo	8,300 LED/DECORATIVE TRANSIT		7.12 /mo		0.65 /mo	839
840					10,500 LED/ DECORATIVE TRANSIT		7.91 /mo	10,500 LED/ DECORATIVE TRANSIT		8.71 /mo		0.80 /mo	840
841					30,000 HPS FLOOD		12.81 /mo	30,000 HPS FLOOD		14.10 /mo		1.29 /mo	841
842					50,000 HPS FLOOD		17.77 /mo	50,000 HPS FLOOD		19.56 /mo		1.79 /mo	842
843					21,000 MH FLOOD		13.53 /mo	21,000 MH FLOOD		14.90 /mo		1.37 /mo	843
844					36,000 MH FLOOD		18.35 /mo	36,000 MH FLOOD		20.20 /mo		1.85 /mo	844
845					8,000 FL COLONIAL GRAY POST TOP		5.23 /mo	8,000 FL COLONIAL GRAY POST TOP		5.76 /mo		0.53 /mo	845
846					9500 HPS COLONIAL GRAY POST TOP		6.65 /mo	9500 HPS COLONIAL GRAY POST TOP		7.32 /mo		0.67 /mo	846
847					9500 HPS COLONIAL BLACK POST TOP		6.88 /mo	9500 HPS COLONIAL BLACK POST TOP		7.57 /mo		0.69 /mo	847
848					9500 HPS DECORATIVE POST TOP		10.24 /mo	9500 HPS DECORATIVE POST TOP		11.27 /mo		1.03 /mo	848
849					6,000 INDUCTION COPPER SQUARE/ POST TOP		4.72 /mo	6,000 INDUCTION COPPER SQUARE/ POST TOP		5.20 /mo		0.48 /mo	849
850					8,000 INDUCTION/ POST TOP (G/B)		4.29 /mo	8,000 INDUCTION/ POST TOP (G/B)		4.72 /mo		0.43 /mo	850
851					4,350 LED/ POST TOP (G/B)		4.12 /mo	4,350 LED/ POST TOP (G/B)		4.54 /mo		0.42 /mo	851
852					4,000 INC FROZEN		5.47 /mo	4,000 INC FROZEN		6.02 /mo		0.55 /mo	852
853					7,000 MV FROZEN		7.27 /mo	7,000 MV FROZEN		8.00 /mo		0.73 /mo	853
854					11,000 MV FROZEN		9.68 /mo	11,000 MV FROZEN		10.66 /mo		0.98 /mo	854
855					20,000 MV FROZEN		14.12 /mo	20,000 MV FROZEN		15.55 /mo		1.43 /mo	855
856													856
857	E-58	Street Lighting Service	Rate	Sum & Win	**Pole** (Company Owned)			**Pole** (Company Owned)					857
858	(continued)				Anchor Flush, Round, 1X, 12ft	$	12.17 /mo	Anchor Flush, Round, 1X, 12ft	$	13.40 /mo	$	1.23 /mo	858
859					Anchor Flush, Round, 1X, 22ft		13.7 /mo	Anchor Flush, Round, 1X, 22ft		15.08 /mo		1.38 /mo	859
860					Anchor Flush, Round, 1X, 25ft		14.82 /mo	Anchor Flush, Round, 1X, 25ft		16.32 /mo		1.50 /mo	860
861					Anchor Flush, Round, 1X, 30ft		17.03 /mo	Anchor Flush, Round, 1X, 30ft		18.75 /mo		1.72 /mo	861
862					Anchor Flush, Round, 1X, 32ft		17.89 /mo	Anchor Flush, Round, 1X, 32ft		19.70 /mo		1.81 /mo	862
863					Anchor Flush, Round, 2X, 12ft		12.98 /mo	Anchor Flush, Round, 2X, 12ft		14.29 /mo		1.31 /mo	863
864					Anchor Flush, Round, 2X, 22ft		14.91 /mo	Anchor Flush, Round, 2X, 22ft		16.42 /mo		1.51 /mo	864
865					Anchor Flush, Round, 2X, 25ft		15.55 /mo	Anchor Flush, Round, 2X, 25ft		17.12 /mo		1.57 /mo	865
866					Anchor Flush, Round, 2X, 30ft		18.07 /mo	Anchor Flush, Round, 2X, 30ft		19.90 /mo		1.83 /mo	866
867					Anchor Flush, Round, 2X, 32ft		19.28 /mo	Anchor Flush, Round, 2X, 32ft		21.23 /mo		1.95 /mo	867
868					Anchor Flush, Square, 5", 13ft		13.95 /mo	Anchor Flush, Square, 5", 13ft		15.36 /mo		1.41 /mo	868
869					Anchor Flush, Square, 5", 15ft		12.47 /mo	Anchor Flush, Square, 5", 15ft		13.73 /mo		1.26 /mo	869
870					Anchor Flush, Square, 5", 23ft		14.79 /mo	Anchor Flush, Square, 5", 23ft		16.28 /mo		1.49 /mo	870
871					Anchor Flush, Square, 5", 25ft		16.26 /mo	Anchor Flush, Square, 5", 25ft		17.90 /mo		1.64 /mo	871
872					Anchor Flush, Square, 5", 28ft		18.05 /mo	Anchor Flush, Square, 5", 28ft		19.87 /mo		1.82 /mo	872
873					Anchor Flush, Square, 5", 32ft		17.95 /mo	Anchor Flush, Square, 5", 32ft		19.76 /mo		1.81 /mo	873
874					Anchor Flush, Concrete, 12ft		41.58 /mo	Anchor Flush, Concrete, 12ft		45.78 /mo		4.20 /mo	874

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (I) - (F)	Line No.
875	E-58	Street Lighting Service	Rate	Sum & Win	**Pole** (Company Owned)		**Pole** (Company Owned)			875
876	(continued)				Anchor Flush, Fiberglass, 12ft	$ 35.21 /mo	Anchor Flush, Fiberglass, 12ft	$ 38.77 /mo	$ 3.56 /mo	876
877					Anchor Flush, Dec Transit Ped, 4", 16ft	34.33 /mo	Anchor Flush, Dec Transit Ped, 4", 16ft	37.80 /mo	3.47 /mo	877
878					Anchor Flush, Dec Transit, 6", 30ft	66.28 /mo	Anchor Flush, Dec Transit, 6", 30ft	72.97 /mo	6.69 /mo	878
879					Hinged Poles Square 15Ft	13.2 /mo	Hinged Poles Square 15Ft	14.53 /mo	1.33 /mo	879
880					Hinged Poles Round 19Ft	11.93 /mo	Hinged Poles Round 19Ft	13.13 /mo	1.20 /mo	880
881					Anchor Pedstl, Round, 1X, 12ft	11.71 /mo	Anchor Pedstl, Round, 1X, 12ft	12.89 /mo	1.18 /mo	881
882					Anchor Pedstl, Round, 1X, 22ft	13.24 /mo	Anchor Pedstl, Round, 1X, 22ft	14.58 /mo	1.34 /mo	882
883					Anchor Pedstl, Round, 1X, 25ft	14.35 /mo	Anchor Pedstl, Round, 1X, 25ft	15.80 /mo	1.45 /mo	883
884					Anchor Pedstl, Round, 1X, 30ft	16.58 /mo	Anchor Pedstl, Round, 1X, 30ft	18.25 /mo	1.67 /mo	884
885					Anchor Pedstl, Round, 1X, 32ft	17.41 /mo	Anchor Pedstl, Round, 1X, 32ft	19.17 /mo	1.76 /mo	885
886					Anchor Pedstl, Round, 2X, 12ft	12.51 /mo	Anchor Pedstl, Round, 2X, 12ft	13.77 /mo	1.26 /mo	886
887					Anchor Pedstl, Round, 2X, 22ft	13.97 /mo	Anchor Pedstl, Round, 2X, 22ft	15.38 /mo	1.41 /mo	887
888					Anchor Pedstl, Round, 2X, 25ft	15.08 /mo	Anchor Pedstl, Round, 2X, 25ft	16.60 /mo	1.52 /mo	888
889					Anchor Pedstl, Round, 2X, 30ft	17.61 /mo	Anchor Pedstl, Round, 2X, 30ft	19.39 /mo	1.78 /mo	889
890					Anchor Pedstl, Round, 2X, 32ft	18.81 /mo	Anchor Pedstl, Round, 2X, 32ft	20.71 /mo	1.90 /mo	890
891					Anchor Pedstl, Round, 3 Bolt, 32ft	21.62 /mo	Anchor Pedstl, Round, 3 Bolt, 32ft	23.80 /mo	2.18 /mo	891
892					Anchor Pedstl, Square, 5", 13ft	13.5 /mo	Anchor Pedstl, Square, 5", 13ft	14.86 /mo	1.36 /mo	892
893					Anchor Pedstl, Square, 5", 15ft	13.8 /mo	Anchor Pedstl, Square, 5", 15ft	15.19 /mo	1.39 /mo	893
894					Anchor Pedstl, Square, 5", 23ft	14.32 /mo	Anchor Pedstl, Square, 5", 23ft	15.77 /mo	1.45 /mo	894
895					Anchor Pedstl, Square, 5", 25ft	15.8 /mo	Anchor Pedstl, Square, 5", 25ft	17.40 /mo	1.60 /mo	895
896					Anchor Pedstl, Square, 5", 28ft	17.56 /mo	Anchor Pedstl, Square, 5", 28ft	19.33 /mo	1.77 /mo	896
897					Anchor Pedstl, Square, 5", 32ft	18.23 /mo	Anchor Pedstl, Square, 5", 32ft	20.07 /mo	1.84 /mo	897
898					Direct Bury, Round, 19ft	18.42 /mo	Direct Bury, Round, 19ft	20.28 /mo	1.86 /mo	898
899					Direct Bury, Round, 30ft	14.38 /mo	Direct Bury, Round, 30ft	15.83 /mo	1.45 /mo	899
900					Direct Bury, Round, 38ft	17.55 /mo	Direct Bury, Round, 38ft	19.32 /mo	1.77 /mo	900
901					Direct Bury, Self-Support, 40ft	21.62 /mo	Direct Bury, Self-Support, 40ft	23.80 /mo	2.18 /mo	901
902					Direct Bury, Stepped 25ft	49.72 /mo	Direct Bury, Stepped 25ft	54.74 /mo	5.02 /mo	902
903					Direct Bury, Stepped 32	52.36 /mo	Direct Bury, Stepped 32	57.65 /mo	5.29 /mo	903
904					Direct Bury, Stepped, 49ft	64.99 /mo	Direct Bury, Stepped, 49ft	71.55 /mo	6.56 /mo	904
905					Direct Bury, Square, 4", 34ft	15.87 /mo	Direct Bury, Square, 4", 34ft	17.47 /mo	1.60 /mo	905
906					Direct Bury, Square, 5", 20ft	15.07 /mo	Direct Bury, Square, 5", 20ft	16.59 /mo	1.52 /mo	906
907					Direct Bury, Square, 5" 30ft	15.71 /mo	Direct Bury, Square, 5" 30ft	17.30 /mo	1.59 /mo	907
908					Direct Bury, Square, 5" 38ft	17.05 /mo	Direct Bury, Square, 5" 38ft	18.77 /mo	1.72 /mo	908
909					Direct Bury, Square, 8" 28ft	28.45 /mo	Direct Bury, Square, 8" 28ft	31.32 /mo	2.87 /mo	909
910					Direct Bury, Square, 8" 32ft	29.74 /mo	Direct Bury, Square, 8" 32ft	32.74 /mo	3.00 /mo	910
911					Direct Bury Deecorative Transit 41- 6	20.47 /mo	Direct Bury Deecorative Transit 41- 6	22.54 /mo	2.07 /mo	911
912					Direct Bury Deecorative Transit 47	25.50 /mo	Direct Bury Deecorative Transit 47	28.08 /mo	2.58 /mo	912
913					Direct Bury, Steel Dist Pole, 35ft	23.54 /mo	Direct Bury, Steel Dist Pole, 35ft	25.92 /mo	2.38 /mo	913
914					Post Top, Dec Transit, 16ft	35.07 /mo	Post Top, Dec Transit, 16ft	38.61 /mo	3.54 /mo	914
915					Post Top, Gray Steel/Fiberglass, 23ft	12.16 /mo	Post Top, Gray Steel/Fiberglass, 23ft	13.39 /mo	1.23 /mo	915
916					Post Top, Black Steel, 23ft	13.41 /mo	Post Top, Black Steel, 23ft	14.76 /mo	1.35 /mo	916
917					Existing distribution pole	1.48 /mo	Existing distribution pole	1.63 /mo	0.15 /mo	917
918					FROZEN, Wood Poles, 30ft	8.95 /mo	FROZEN, Wood Poles, 30ft	9.85 /mo	0.90 /mo	918
919					FROZEN, Wood Poles, 35ft	8.95 /mo	FROZEN, Wood Poles, 35ft	9.85 /mo	0.90 /mo	919
920					Flush, 4ft	9.91 /mo	Flush, 4ft	10.91 /mo	1.00 /mo	920
921					Flush, 6ft	11.82 /mo	Flush, 6ft	13.01 /mo	1.19 /mo	921
922					Pedestal, 8ft	13.54 /mo	Pedestal, 8ft	14.91 /mo	1.37 /mo	922
923					Pedestal, 32' round steel pole, 4ft 6"	9.39 /mo	Pedestal, 32' round steel pole, 4ft 6"	10.34 /mo	0.95 /mo	923
924					Per foot of cable installed under paving	0.16 /mo	Per foot of cable installed under paving	0.17 /mo	0.01 /mo	924
925					Per foot of cable not installed under paving	0.06 /mo	Per foot of cable not installed under paving	0.06 /mo	0.00 /mo	925
926					Anchor Flush, Round, 1X, 12ft	1.68 /mo	Anchor Flush, Round, 1X, 12ft	1.85 /mo	0.17 /mo	926
927					Anchor Flush, Round, 1X, 22ft	1.88 /mo	Anchor Flush, Round, 1X, 22ft	2.07 /mo	0.19 /mo	927
928					Anchor Flush, Round, 1X, 25ft	2.05 /mo	Anchor Flush, Round, 1X, 25ft	2.26 /mo	0.21 /mo	928
929					Anchor Flush, Round, 1X, 30ft	2.34 /mo	Anchor Flush, Round, 1X, 30ft	2.58 /mo	0.24 /mo	929
930					Anchor Flush, Round, 1X, 32ft	2.37 /mo	Anchor Flush, Round, 1X, 32ft	2.61 /mo	0.24 /mo	930
931					Anchor Flush, Round, 2X, 12ft	1.79 /mo	Anchor Flush, Round, 2X, 12ft	1.97 /mo	0.18 /mo	931
932					Anchor Flush, Round, 2X, 22ft	2.06 /mo	Anchor Flush, Round, 2X, 22ft	2.27 /mo	0.21 /mo	932
933					Anchor Flush, Round, 2X, 25ft	2.14 /mo	Anchor Flush, Round, 2X, 25ft	2.36 /mo	0.22 /mo	933
934					Anchor Flush, Round, 2X, 30ft	2.49 /mo	Anchor Flush, Round, 2X, 30ft	2.74 /mo	0.25 /mo	934
935					Anchor Flush, Round, 2X, 32ft	2.66 /mo	Anchor Flush, Round, 2X, 32ft	2.93 /mo	0.27 /mo	935
936					Anchor Flush, Square, 5", 13ft	1.92 /mo	Anchor Flush, Square, 5", 13ft	2.11 /mo	0.19 /mo	936
937					Anchor Flush, Square, 5", 15ft	1.72 /mo	Anchor Flush, Square, 5", 15ft	1.89 /mo	0.17 /mo	937
938					Anchor Flush, Square, 5", 23ft	2.03 /mo	Anchor Flush, Square, 5", 23ft	2.24 /mo	0.21 /mo	938
939					Anchor Flush, Square, 5", 25ft	2.23 /mo	Anchor Flush, Square, 5", 25ft	2.46 /mo	0.23 /mo	939
940					Anchor Flush, Square, 5", 28ft	2.48 /mo	Anchor Flush, Square, 5", 28ft	2.73 /mo	0.25 /mo	940
941					Anchor Flush, Square, 5", 32ft	2.47 /mo	Anchor Flush, Square, 5", 32ft	2.72 /mo	0.25 /mo	941
942					Anchor Flush, Concrete, 12ft	5.73 /mo	Anchor Flush, Concrete, 12ft	6.31 /mo	0.58 /mo	942
943					Anchor Flush, Fiberglass, 12ft	4.85 /mo	Anchor Flush, Fiberglass, 12ft	5.34 /mo	0.49 /mo	943
944					Anchor Flush, Dec Transit Ped, 4", 16ft	4.73 /mo	Anchor Flush, Dec Transit Ped, 4", 16ft	5.21 /mo	0.48 /mo	944
945					Anchor Flush, Dec Transit, 6", 30ft	9.13 /mo	Anchor Flush, Dec Transit, 6", 30ft	10.05 /mo	0.92 /mo	945

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (I) - (F)	Line No.
946	E-58	Street Lighting Service	Rate	Sum & Win	**Pole** (Company Owned)		**Pole** (Company Owned)			946
947	(continued)				Hinged Poles Square 15ft	$ 1.08 /mo	Hinged Poles Square 15ft	$ 1.19 /mo	$ 0.11 /mo	947
948					Hinged Poles Round 19ft	0.97 /mo	Hinged Poles Round 19ft	1.07 /mo	0.10 /mo	948
949					Anchor Pedstl, Round, 1X, 12ft	1.61 /mo	Anchor Pedstl, Round, 1X, 12ft	1.77 /mo	0.16 /mo	949
950					Anchor Pedstl, Round, 1X, 22ft	1.82 /mo	Anchor Pedstl, Round, 1X, 22ft	2.00 /mo	0.18 /mo	950
951					Anchor Pedstl, Round, 1X, 25ft	1.98 /mo	Anchor Pedstl, Round, 1X, 25ft	2.18 /mo	0.20 /mo	951
952					Anchor Pedstl, Round, 1X, 30ft	2.29 /mo	Anchor Pedstl, Round, 1X, 30ft	2.52 /mo	0.23 /mo	952
953					Anchor Pedstl, Round, 1X, 32ft	2.40 /mo	Anchor Pedstl, Round, 1X, 32ft	2.64 /mo	0.24 /mo	953
954					Anchor Pedstl, Round, 2X, 12ft	1.72 /mo	Anchor Pedstl, Round, 2X, 12ft	1.89 /mo	0.17 /mo	954
955					Anchor Pedstl, Round, 2X, 22ft	1.92 /mo	Anchor Pedstl, Round, 2X, 22ft	2.11 /mo	0.19 /mo	955
956					Anchor Pedstl, Round, 2X, 25ft	2.07 /mo	Anchor Pedstl, Round, 2X, 25ft	2.28 /mo	0.21 /mo	956
957					Anchor Pedstl, Round, 2X, 30ft	2.42 /mo	Anchor Pedstl, Round, 2X, 30ft	2.66 /mo	0.24 /mo	957
958					Anchor Pedstl, Round, 2X, 32ft	2.59 /mo	Anchor Pedstl, Round, 2X, 32ft	2.85 /mo	0.26 /mo	958
959					Anchor Pedstl, Round, 3 Bolt, 32ft	2.97 /mo	Anchor Pedstl, Round, 3 Bolt, 32ft	3.27 /mo	0.30 /mo	959
960					Anchor Pedstl, Square, 5", 13ft	1.86 /mo	Anchor Pedstl, Square, 5", 13ft	2.05 /mo	0.19 /mo	960
961					Anchor Pedstl, Square, 5", 15ft	1.89 /mo	Anchor Pedstl, Square, 5", 15ft	2.08 /mo	0.19 /mo	961
962					Anchor Pedstl, Square, 5", 23ft	1.98 /mo	Anchor Pedstl, Square, 5", 23ft	2.18 /mo	0.20 /mo	962
963					Anchor Pedstl, Square, 5", 25ft	2.19 /mo	Anchor Pedstl, Square, 5", 25ft	2.41 /mo	0.22 /mo	963
964					Anchor Pedstl, Square, 5", 28ft	2.42 /mo	Anchor Pedstl, Square, 5", 28ft	2.66 /mo	0.24 /mo	964
965					Anchor Pedstl, Square, 5", 32ft	2.50 /mo	Anchor Pedstl, Square, 5", 32ft	2.75 /mo	0.25 /mo	965
966					Direct Bury, Round, 19ft	2.54 /mo	Direct Bury, Round, 19ft	2.80 /mo	0.26 /mo	966
967					Direct Bury, Round, 30ft	2.66 /mo	Direct Bury, Round, 30ft	2.93 /mo	0.27 /mo	967
968					Direct Bury, Round, 38ft	2.73 /mo	Direct Bury, Round, 38ft	3.01 /mo	0.28 /mo	968
969					Direct Bury, Self-Support, 40ft	3.42 /mo	Direct Bury, Self-Support, 40ft	3.77 /mo	0.35 /mo	969
970					Direct Bury, Stepped 25ft	4.06 /mo	Direct Bury, Stepped 25ft	4.47 /mo	0.41 /mo	970
971					Direct Bury, Stepped 32	4.27 /mo	Direct Bury, Stepped 32	4.70 /mo	0.43 /mo	971
972					Direct Bury, Stepped, 49ft	8.96 /mo	Direct Bury, Stepped, 49ft	9.86 /mo	0.90 /mo	972
973					Direct Bury, Square, 4", 34ft	2.75 /mo	Direct Bury, Square, 4", 34ft	3.03 /mo	0.28 /mo	973
974					Direct Bury, Square, 5", 20ft	2.49 /mo	Direct Bury, Square, 5", 20ft	2.74 /mo	0.25 /mo	974
975					Direct Bury, Square, 5" 30ft	2.59 /mo	Direct Bury, Square, 5" 30ft	2.85 /mo	0.26 /mo	975
976					Direct Bury, Square, 5" 38ft	2.96 /mo	Direct Bury, Square, 5" 38ft	3.26 /mo	0.30 /mo	976
977					Direct Bury, Square, 8" 28ft	2.32 /mo	Direct Bury, Square, 8" 28ft	2.55 /mo	0.23 /mo	977
978					Direct Bury, Square, 8" 32ft	2.43 /mo	Direct Bury, Square, 8" 32ft	2.68 /mo	0.25 /mo	978
979					Direct Bury Deecorative Transit 41- 6	3.01 /mo	Direct Bury Deecorative Transit 41- 6	3.31 /mo	0.30 /mo	979
980					Direct Bury Deecorative Transit 47	3.75 /mo	Direct Bury Deecorative Transit 47	4.13 /mo	0.38 /mo	980
981					Direct Bury, Steel Dist Pole, 35ft	3.10 /mo	Direct Bury, Steel Dist Pole, 35ft	3.41 /mo	0.31 /mo	981
982					Post Top, Dec Transit, 16ft	4.82 /mo	Post Top, Dec Transit, 16ft	5.31 /mo	0.49 /mo	982
983					Post Top, Gray Steel/Fiberglass, 23ft	2.00 /mo	Post Top, Gray Steel/Fiberglass, 23ft	2.20 /mo	0.20 /mo	983
984					Post Top, Black Steel, 23ft	2.21 /mo	Post Top, Black Steel, 23ft	2.43 /mo	0.22 /mo	984
985					Existing distribution pole	0.00 /mo	Existing distribution pole	0.00 /mo	- /mo	985
986					FROZEN, Wood Poles, 30ft	1.55 /mo	FROZEN, Wood Poles, 30ft	1.71 /mo	0.16 /mo	986
987					FROZEN, Wood Poles, 35ft	1.48 /mo	FROZEN, Wood Poles, 35ft	1.63 /mo	0.15 /mo	987
988										988
989					Flush, 4ft	$ 1.36 /mo	Flush, 4ft	$ 1.50 /mo	$ 0.14 /mo	989
990					Flush, 6ft	2.05 /mo	Flush, 6ft	2.26 /mo	0.21 /mo	990
991					Pedestal, 8ft	2.36 /mo	Pedestal, 8ft	2.60 /mo	0.24 /mo	991
992					Pedestal, 32' round steel pole, 4ft 6"	1.63 /mo	Pedestal, 32' round steel pole, 4ft 6"	1.79 /mo	0.16 /mo	992
993										993
994	E-59	Energy Services for Government		Sum & Win	Service Charge	$ 2.79 /mo	Service Charge	$ 3.07 /mo	$ 0.28 /mo	994
995		Owned Streetlighting Systems			Energy Charge	0.06088 /kWh	Energy Charge	0.06705 /kWh	0.00617 /kWh	995
996										996
997	E-67	Municipal Lighting	Rate	Sum & Win	All kWh	$ 0.05193 /kWh	All kWh	$ 0.05714 /kWh	$ 0.00521 /kWh	997
998		Service -- City of Phoenix								998
999										999
1000	E-221	Water Pumping Service	Rate	Sum & Win	BSC: Self-Contained Meters	$ 0.558 /day	BSC: Self-Contained Meters	$ 1.160 /day	$ 0.602 /day	1000
1001					BSC: Instrument-rated Meters	1.21	BSC: Instrument-rated Meters	2.020 /day		1001
1002					BSC: Primary Meters	3.30	BSC: Primary Meters	4.947 /day		1002
1003					All kW	2.357 /kW	All kW	4.870 /kW	2.513 /kW	1003
1004					First 240 kWh	0.11228 /kWh	First 240 kWh	0.11010 /kWh	(0.00218) /kWh	1004
1005					Next 275 kWh per kW	0.07633 /kWh	Next 275 kWh per kW	0.07480 /kWh	(0.00153) /kWh	1005
1006					All additional kWh	0.06270 /kWh	All additional kWh	- /kWh	(0.06270) /kWh	1006
1007										1007
1008			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.558 /day	Minimum Basic Service Charge	$ 1.160 /day	$ 0.602 /day	1008
1009					Minimum Demand Charge	2.357 /kW	Minimum Demand Charge	4.870 /kW	2.513 /kW	1009
1010										1010
1011	E-221-8T	Water Pumping Service	Rate	Sum & Win	BSC: Self-Contained Meters	$ 0.964 /day	BSC: Self-Contained Meters	$ 1.160 /day	$ 0.196 /day	1011
1012					BSC: Instrument-rated Meters	1.62	BSC: Instrument-rated Meters	2.020 /day		1012
1013		Time Of Use			BSC: Primary Meters	3.71	BSC: Primary Meters	4.947 /day		1013
1014					All On-Peak kW	5.608 /kW	All On-Peak kW	6.820 /kW	1.212 /kW	1014
1015					All Off-Peak kW	3.351 /kW	All Off-Peak kW	4.604 /kW	1.253 /kW	1015
1016					All On-Peak kWh	0.09205 /kWh	All On-Peak kWh	0.09023 /kWh	(0.00182) /kWh	1016

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (I) - (F)	Line No.
1017	E-221-8T	Water Pumping Service	Rate	Sum & Win	All Off-Peak kWh	$ 0.04952 /kWh	All Off-Peak kWh	$ 0.048470 /kWh	$ (0.00105) /kWh	1017
1018	(continued)									1018
1019			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.964 /day	Minimum Basic Service Charge	$ 1.160 /day	$ 0.196 /day	1019
1020					Minimum Demand Charge	3.351 /kW	Minimum Demand Charge	4.604 /kW	1.253 /kW	1020
1021										1021
1022	GS-SCHOOLS M	Time of Use for	Rate	Summer	BSC: Self-Contained Meters	$ 0.672 /day	BSC: Self-Contained Meters	$ 1.160 /day	$ 0.488 /day	1022
1023		Elementary and High Schools		Peak	BSC: Instrument-rated Meters	1.324 /kW	BSC: Instrument-rated Meters	2.020 /kW	0.696 /kW	1023
1024		0-400 kW			BSC: Primary Meters	3.415 /kW	BSC: Primary Meters	4.947 /kW	1.532 /kW	1024
1025					BSC: Transmission Meters	26.163 /kW	BSC: Transmission Meters	36.795 /kW	10.632 /kW	1025
1026					First 100 kW: Secondary	9.612 /kW	First 100 kW: Secondary	11.816 /kW	2.204 /kW	1026
1027					All remaining kW: Secondary	5.113 /kW	All remaining kW: Secondary	6.802 /kW	1.689 /kW	1027
1028					First 100 kW: Primary	8.919 /kW	First 100 kW: Primary	11.044 /kW	2.125 /kW	1028
1029					All remaining kW: Primary	4.419 /kW	All remaining kW: Primary	6.028 /kW	1.609 /kW	1029
1030					First 100 kW: Transmission	6.953 /kW	First 100 kW: Transmission	8.853 /kW	1.900 /kW	1030
1031					All remaining kW: Transmission	2.454 /kW	All remaining kW: Transmission	3.839 /kW	1.385 /kW	1031
1032					All On-Peak kWh:	0.17343 /kWh	All On-Peak kWh:	0.19274 /kWh	0.01931 /kWh	1032
1033					All Shoulder-Peak kWh:	0.12847 /kWh	All Shoulder-Peak kWh:	0.14263 /kWh	0.01416 /kWh	1033
1034					All Off-Peak kWh:	0.06487 /kWh	All Off-Peak kWh:	0.07175 /kWh	0.00688 /kWh	1034
1035										1035
1036			Rate	Summer	BSC: Self-Contained Meters	$ 0.672 /day	BSC: Self-Contained Meters	$ 1.160 /day	$ 0.488 /day	1036
1037				Shoulder	BSC: Instrument-rated Meters	1.324 /kW	BSC: Instrument-rated Meters	2.020 /kW	0.696 /kW	1037
1038					BSC: Primary Meters	3.415 /kW	BSC: Primary Meters	4.947 /kW	1.532 /kW	1038
1039					BSC: Transmission Meters	26.163 /kW	BSC: Transmission Meters	36.795 /kW	10.632 /kW	1039
1040					First 100 kW: Secondary	9.612 /kW	First 100 kW: Secondary	11.816 /kW	2.204 /kW	1040
1041					All remaing kW: Secondary	5.113 /kW	All remaining kW: Secondary	6.802 /kW	1.689 /kW	1041
1042					First 100 kW: Primary	8.919 /kW	First 100 kW: Primary	11.044 /kW	2.125 /kW	1042
1043					All remaining kW: Primary	4.419 /kW	All remaining kW: Primary	6.028 /kW	1.609 /kW	1043
1044					First 100 kW: Transmission	6.953 /kW	First 100 kW: Transmission	8.853 /kW	1.900 /kW	1044
1045					All remaining kW: Transmission	2.454 /kW	All remaining kW: Transmission	3.839 /kW	1.385 /kW	1045
1046					All On-Peak kWh:	0.14977 /kWh	All On-Peak kWh:	0.16637 /kWh	0.01660 /kWh	1046
1047					All Shoulder-Peak kWh:	0.11095 /kWh	All Shoulder-Peak kWh:	0.12310 /kWh	0.01215 /kWh	1047
1048					All Off-Peak kWh:	0.05602 /kWh	All Off-Peak kWh:	0.06170 /kWh	0.00568 /kWh	1048
1049										1049
1050			Rate	Winter	BSC: Self-Contained Meters	$ 0.672 /day	BSC: Self-Contained Meters	$ 1.160 /day	$ 0.488 /day	1050
1051					BSC: Instrument-rated Meters	1.324 /kW	BSC: Instrument-rated Meters	2.020 /kW	0.696 /kW	1051
1052					BSC: Primary Meters	3.415 /kW	BSC: Primary Meters	4.947 /kW	1.532 /kW	1052
1053					BSC: Transmission Meters	26.163 /kW	BSC: Transmission Meters	36.795 /kW	10.632 /kW	1053
1054					First 100 kW: Secondary	9.612 /kW	First 100 kW: Secondary	11.816 /kW	2.204 /kW	1054
1055					All remaining kW: Secondary	5.113 /kW	All remaining kW: Secondary	6.802 /kW	1.689 /kW	1055
1056					First 100 kW: Primary	8.919 /kW	First 100 kW: Primary	11.044 /kW	2.125 /kW	1056
1057					All remaining kW: Primary	4.419 /kW	All remaining kW: Primary	6.028 /kW	1.609 /kW	1057
1058					First 100 kW: Transmission	6.953 /kW	First 100 kW: Transmission	8.853 /kW	1.900 /kW	1058
1059					All remaining kW: Transmission	2.454 /kW	All remaining kW: Transmission	3.839 /kW	1.385 /kW	1059
1060					All On-Peak kWh:	0.11607 /kWh	All On-Peak kWh:	0.12881 /kWh	0.01274 /kWh	1060
1061					All Shoulder-Peak kWh:	0.08599 /kWh	All Shoulder-Peak kWh:	0.09528 /kWh	0.00929 /kWh	1061
1062					All Off-Peak kWh:	0.04342 /kWh	All Off-Peak kWh:	0.04784 /kWh	0.00442 /kWh	1062
1063										1063
1064	GS-SCHOOLS L	Time of Use for	Rate	Summer	BSC: Self-Contained Meters	$ 1.068 /day	BSC: Self-Contained Meters	$ 3.060 /day	$ 1.992 /day	1064
1065		Elementary and High Schools		Peak	BSC: Instrument-rated Meters	1.627 /kW	BSC: Instrument-rated Meters	3.920 /kW	2.293 /kW	1065
1066		401 kW and above			BSC: Primary Meters	3.419 /kW	BSC: Primary Meters	6.847 /kW	3.428 /kW	1066
1067					BSC: Transmission Meters	22.915 /kW	BSC: Transmission Meters	38.695 /kW	15.780 /kW	1067
1068					First 100 kW: Secondary	9.311 /kW	First 100 kW: Secondary	11.564 /kW	2.253 /kW	1068
1069					All remaining kW: Secondary	4.954 /kW	All remaining kW: Secondary	6.661 /kW	1.707 /kW	1069
1070					First 100 kW: Primary	8.636 /kW	First 100 kW: Primary	10.804 /kW	2.168 /kW	1070
1071					All remaining kW: Primary	4.282 /kW	All remaining kW: Primary	5.905 /kW	1.623 /kW	1071
1072					First 100 kW: Transmission	6.736 /kW	First 100 kW: Transmission	8.666 /kW	1.930 /kW	1072
1073					All remaining kW: Transmission	2.377 /kW	All remaining kW: Transmission	3.761 /kW	1.384 /kW	1073
1074					All On-Peak kWh:	0.15355 /kWh	All On-Peak kWh:	0.17221 /kWh	0.01866 /kWh	1074
1075					All Shoulder-Peak kWh:	0.11374 /kWh	All Shoulder-Peak kWh:	0.12741 /kWh	0.01367 /kWh	1075
1076					All Off-Peak kWh:	0.06285 /kWh	All Off-Peak kWh:	0.07015 /kWh	0.00730 /kWh	1076
1077										1077
1078			Rate	Summer	BSC: Self-Contained Meters	$ 1.068 /day	BSC: Self-Contained Meters	$ 3.060 /day	$ 1.992 /day	1078
1079				Shoulder	BSC: Instrument-rated Meters	1.627 /kW	BSC: Instrument-rated Meters	3.920 /kW	2.293 /kW	1079
1080					BSC: Primary Meters	3.419 /kW	BSC: Primary Meters	6.847 /kW	3.428 /kW	1080
1081					BSC: Transmission Meters	22.915 /kW	BSC: Transmission Meters	38.695 /kW	15.780 /kW	1081
1082					First 100 kW: Secondary	9.311 /kW	First 100 kW: Secondary	11.564 /kW	2.253 /kW	1082
1083					All remaining kW: Secondary	4.954 /kW	All remaining kW: Secondary	6.661 /kW	1.707 /kW	1083
1084					First 100 kW: Primary	8.636 /kW	First 100 kW: Primary	10.804 /kW	2.168 /kW	1084
1085					All remaining kW: Primary	4.282 /kW	All remaining kW: Primary	5.905 /kW	1.623 /kW	1085
1086					First 100 kW: Transmission	6.736 /kW	First 100 kW: Transmission	8.666 /kW	1.930 /kW	1086
1087					All remaining kW: Transmission	2.377 /kW	All remaining kW: Transmission	3.761 /kW	1.384 /kW	1087

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (I) - (F)	Line No.
1088	GS-SCHOOLS L	Time of Use for	Rate	Summer	All On-Peak kWh:	$ 0.13260 /kWh	All On-Peak kWh:	$ 0.14864 /kWh	$ 0.01604 /kWh	1088
1089	(continued)	Elementary and High Schools		Shoulder	All Shoulder-Peak kWh:	0.09821 /kWh	All Shoulder-Peak kWh:	0.10994 /kWh	0.01173 /kWh	1089
1090		401 kW and above			All Off-Peak kWh:	0.05428 /kWh	All Off-Peak kWh:	0.05317 /kWh	(0.00111) /kWh	1090
1091										1091
1092			Rate	Winter	BSC: Self-Contained Meters	$ 1.068 /day	BSC: Self-Contained Meters	$ 3.060 /day	$ 1.992 /day	1092
1093					BSC: Instrument-rated Meters	1.627 /kW	BSC: Instrument-rated Meters	3.920 /kW	2.293 /kW	1093
1094					BSC: Primary Meters	3.419 /kW	BSC: Primary Meters	6.847 /kW	3.428 /kW	1094
1095					BSC: Transmission Meters	22.915 /kW	BSC: Transmission Meters	38.695 /kW	15.780 /kW	1095
1096					First 100 kW: Secondary	9.311 /kW	First 100 kW: Secondary	11.564 /kW	2.253 /kW	1096
1097					All remaining kW: Secondary	4.954 /kW	All remaining kW: Secondary	6.661 /kW	1.707 /kW	1097
1098					First 100 kW: Primary	8.636 /kW	First 100 kW: Primary	10.804 /kW	2.168 /kW	1098
1099					All remaining kW: Primary	4.282 /kW	All remaining kW: Primary	5.905 /kW	1.623 /kW	1099
1100					First 100 kW: Transmission	6.736 /kW	First 100 kW: Transmission	8.666 /kW	1.930 /kW	1100
1101					All remaining kW: Transmission	2.377 /kW	All remaining kW: Transmission	3.761 /kW	1.384 /kW	1101
1102					All On-Peak kWh:	0.10276 /kWh	All On-Peak kWh:	0.11506 /kWh	0.01230 /kWh	1102
1103					All Shoulder-Peak kWh:	0.07612 /kWh	All Shoulder-Peak kWh:	0.08508 /kWh	0.00896 /kWh	1103
1104					All Off-Peak kWh:	0.04206 /kWh	All Off-Peak kWh:	0.04675 /kWh	0.00469 /kWh	1104
1105										1105
1106	CPP-GS	General Service	Rate	Summer	Critical Peak Price	$ 0.25000 /kWh	NO CHANGE			1106
1107		Critical Peak Pricing								1107
1108										1108
1109					Energy Discount E-32 M	$ (0.01035) /kWh				1109
1110					Energy Discount E-32 L	(0.00953) /kWh				1110
1111					Energy Discount E-32 TOU M	(0.00927) /kWh				1111
1112					Energy Discount E-32 TOU L	(0.00868) /kWh				1112
1113					Energy Discount E-34	(0.00852) /kWh				1113
1114					Energy Discount E-35	(0.00740) /kWh				1114
1115					Energy Discount E-221	(0.00612) /kWh				1115
1116	E-56R	Standard Contract -	Rate	Sum & Win	All kWh	Varies by Customer	All kWh	Varies by Customer		1116
1117		Solar			All kW	Varies by Customer	All kW	Varies by Customer		1117
1118										1118
1119	EPR-2	Purchase Rates for Qualified	9am - 9pm	Summer	Non-Firm On-Peak	$ 0.02959 /kWh	NO CHANGE			1119
1120		Facilities of 100 kW or less	Rate		Non-Firm Off-Peak	0.02892 /kWh				1120
1121					Firm On-Peak	0.03705 /kWh				1121
1122					Firm Off-Peak	0.03031 /kWh				1122
1123										1123
1124				Winter	Non-Firm On-Peak	$ 0.02927 /kWh				1124
1125					Non-Firm Off-Peak	0.02844 /kWh				1125
1126					Firm On-Peak	0.02927 /kWh				1126
1127					Firm Off-Peak	0.02844 /kWh				1127
1128										1128
1129			12pm - 7pm	Summer	Non-Firm On-Peak	$ 0.02989 /kWh				1129
1130			Rate		Non-Firm Off-Peak	0.02897 /kWh				1130
1131					Firm On-Peak	0.04297 /kWh				1131
1132					Firm Off-Peak	0.03009 /kWh				1132
1133										1133
1134				Winter	Non-Firm On-Peak	$ 0.03040 /kWh				1134
1135					Non-Firm Off-Peak	0.02831 /kWh				1135
1136					Firm On-Peak	0.03040 /kWh				1136
1137					Firm Off-Peak	0.02831 /kWh				1137
1138										1138
1139			11am - 9pm	Summer	Non-Firm On-Peak	$ 0.02982 /kWh				1139
1140			Rate		Non-Firm Off-Peak	0.02888 /kWh				1140
1141					Firm On-Peak	0.03876 /kWh				1141
1142					Firm Off-Peak	0.03015 /kWh				1142
1143										1143
1144				Winter	Non-Firm On-Peak	$ 0.02926 /kWh				1144
1145					Non-Firm Off-Peak	0.02852 /kWh				1145
1146					Firm On-Peak	0.02926 /kWh				1146
1147					Firm Off-Peak	0.02852 /kWh				1147
1148										1148
1149	EPR-6	Legacy Net Metering Rate	Rate	Sum & Win	Non-Firm On-Peak	$ 0.02943 /kWh	Energy Credit for Excess Generation	$ 0.02895 /kWh		1149
1150		Renewable Resource Facilities			Non-Firm Off-Peak	0.02868 /kWh				1150
1151					Total Non-Firm	0.02895 /kWh				1151
1152					Firm On-Peak	0.03320 /kWh				1152
1153					Firm Off-Peak	0.02938 /kWh				1153
1154					Total Firm	0.03075 /kWh				1154
1155										1155
1156	EPR-6S	Modified Net Metering Rate	Rate	Summer			Energy Credit for Excess Generation Summer	$ 0.02920 /kWh		1156
1157		Renewable Resource Facilities		Winter			Energy Credit for Excess Generation Winter	0.02867 /kWh		1157
1158										1158

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L) Line No.
1159	CMPW-01	Community Power Flagstaff SANDVIG 04	Rate	Sum & Win	Solar Charge E-12	$ 0.11242	/kWh	RATE SCHEDULE CMPW-01 PROPOSE TO CANCEL				1159
1160					Solar Charge ET-2	0.13480	/kWh					1160
1161					Solar Charge E-32 S, E-32 M, E-32 L	0.09293	/kWh					1161
1162					Solar Charge E-32 TOU S, E-32 TOU M, E-32 TOU L	0.05855	/kWh					1162
1163												1163
1164	SGSP	Schools and Government Solar Program (Rider)	Rate	Sum & Win	Solar Charge E-32 M & E-32 L	$ 0.07665	/kWh	NO CHANGE				1164
1165					Solar Charge E-32 L	0.04660	/kWh					1165
1166					Solar Charge E-32 TOU S, E-32 TOU M, E-32 TOU L	0.05502	/kWh					1166
1167					Solar Charge GS-Schools M and GS-Schools L	0.07571	/kWh					1167
1168					Solar Charge E-34	0.04236	/kWh					1168
1169					Solar Charge E-35	0.04128	/kWh					1169
1170												1170
1171	IRR	Extra Large General Service Interruptible Rate Rider			Capacity and Energy Credit for reducing hourly usage	varies by customer		NO CHANGE				1171
1172												1172
1173												1173
1174	XHLF 1	Extra Large High Load Factor Contract 1	Rate	Sum & Win	All kWh: Secondary	per contract	/kWh	NO CHANGE				1174
1175					All kWh: Primary	per contract	/kWh					1175
1176					All kWh: Transmission	per contract	/kWh					1176
1177					Generation Capacity Credit - growth	per contract	/kWh					1177
1178												1178
1179	XHLF 2	Extra Large High Load Factor Contract 2	Rate	Sum & Win	BSC: Primary	per contract	/kW					1179
1180					All kW: Primary	per contract	/kW					1180
1181					All kWh:	per contract	/kWh					1181
1182					kWh green premium	per contract	/kWh					1182
1183												1183
1184	AG-1	Alternative Generation Extra Large Service	Rate	Sum & Win	Billed on Rate Schedule E-32 M, E-32 L, E-32TOU M, E-32TOUL, E-34 or Rate Schedule E-35			EXPERIMENTAL RATE RIDER AG-1 PROPOSE TO CANCEL				1184
1185					Generation will be scheduled at market price plus uplift.							1185
1186												1186
1187	DSMAC-1[1]	Demand Side Management Adjustment Charge	Adjustment	Sum & Win	all kWh	$ 0.001845	/kWh	TO BE DETERMINED				1187
1188					all kW	0.696	/kW					1188
1189												1189
1190	RCDAC-1[1]	Returning Customer Direct	Adjustment	Sum & Win	Customers over 3MW	varies by customer		NO CHANGE				1190
1191												1191
1192	PSA-1[1]	Power Supply Adjustment	Adjustment	Sum & Win	PSA Adjustor	$ 0.001678	/kWh	TO BE DETERMINED				1192
1193					PSA Historical	(0.000297)	/kWh					1193
1194					PSA Forward	0.001975	/kWh					1194
1195					PSA Transition	-	/kWh					1195
1196												1196
1197	REAC-1[1]	Renewable Energy Standard	Adjustment	Sum & Win	All kWh	$ 0.009355	/kWh	TO BE DETERMINED				1197
1198					Cap for all Residential Services	3.74	/service					1198
1199					Cap for General Services 100 kW or less	138.99	/service					1199
1200					Cap for General Services over 100, under 400 kW	233.88	/service					1200
1201					Cap for General Services over 400, under 3000 kW	467.75	/service					1201
1202					Cap for General Services over 3000 kW	3,040.00	/service					1202
1203												1203
1204	EIS[1]	Environmental	Adjustment	Sum & Win	All kWh	$ 0.00016	/kWh	TO BE DETERMINED				1204
1205												1205
1206	TCA-1[1]	Transmission Cost	Adjustment	Sum & Win	All kW and kWh							1206
1207					Residential - kWh	$ 0.006565	/kWh	TO BE DETERMINED				1207
1208					General service 20 kW or less	0.002954	/kWh					1208
1209					General service over 20 kW, under 3,000 kW	0.947	/kW					1209
1210					XL General service 3,000 kW and over	1.177	/kW					1210
1211												1211
1212	FCA	Four Corners Adjustment	Adjustment	Sum & Win	% of Base Bill	2.03%		ADJUSTMENT SCHEDULE FCA PROPOSE TO CANCEL				1212
1213												1213
1214	LFCR[1]	Lost Fixed Cost Recovery	Adjustment	Sum & Win	% of Total Bill	1.7095%		TO BE DETERMINED				1214
1215												1215
1216	LFCR-DG	Interim Adjustment for New Distributed Generation	Adjustment	Sum & Win	Generators registered with APS	$ 0.70	/kW-DC	ADJUSTMENT SCHEDULE LFCR-DG PROPOSE TO CANCEL				1216
1217					Generators not registered APS	3.00	/kW-DC					1217
1218												1218
1219	GPS-1[1]	Green Power Block Schedule	Adjustment	Sum & Win	100 kWh Block	$ 1.02	/kWh Block	NO CHANGE				1219
1220												1220
1221	GPS-2[1]	Green Power Percent Schedule	Adjustment	Sum & Win	100.0% total monthly kWh	$ 0.01020	/kWh	NO CHANGE				1221
1222					50.0% total monthly kWh	0.00510	/kWh					1222
1223					35.0% total monthly kWh	0.00360	/kWh					1223
1224					10.0% total monthly kWh	0.00100	/kWh					1224
1225												1225
1226	GPS-3[1]	Green Power Block Schedule for Special Events	Adjustment	Sum & Win	100 kWh Block	$ 1.02	/kWh Block	NO CHANGE				1226
1227					Minimum purchase	500.00	/Transaction					1227
1228												1228

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2015

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L) Line No.
1229	SDR	Self Directed Renewable Resources	Adjustement	Sum & Win	Varies per customer			NO CHANGE				1229
1230												1230
1231												1231
1232	SBA-2	Systems Benefits Adjustment	Adjustment	Sum & Win	All kWh	$ (0.000512)	/kWh	ADJUSTMENT SCHEDULE SBA-2 PROPOSE TO CANCEL				1232
1233												1233

Footnote:

1) These adjustor schedules may be modified outside of a rate case in accordance with the adjustor schedules's Plan of Administration. These schedules do not impact the proof of revenue.

NOTES TO SCHEDULE:

1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.

2) Base Rates effective 7/1/2012; Adjustor Rates effective 5/1/2016.

Supporting Schedules:
N/A

Recap Schedules:
N/A

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Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates

Proposed Rate	Current Rate	Customers	Revenue[1] Current Rates	Revenue[1] Proposed Rates	$ Change	%
R-XS	E-12	224,127	$ 121,999,608	$ 147,601,381	$ 25,601,773	21.0%
	ET-1	10,012	$ 7,199,864	$ 8,563,260	$ 1,363,396	18.9%
	ET-2	30,161	$ 22,004,926	$ 22,955,636	$ 950,710	4.3%
	ECT-1R	428	$ 350,298	$ 312,640	$ (37,658)	-10.8%
	ECT-2	1,726	$ 1,432,539	$ 1,308,148	$ (124,391)	-8.7%
R-1	E-12	44,766	$ 76,082,210	$ 91,020,040	$ 14,937,831	19.6%
	ET-1	25,237	$ 47,373,480	$ 59,038,961	$ 11,665,482	24.6%
	ET-2	85,386	$ 152,691,949	$ 192,803,909	$ 40,111,960	26.3%
	ECT-1R	2,963	$ 6,952,088	$ 7,955,773	$ 1,003,686	14.4%
	ECT-2	16,716	$ 36,295,814	$ 43,773,404	$ 7,477,590	20.6%
R-2	E-12	123,222	$ 144,181,915	$ 177,362,428	$ 33,180,514	23.0%
	ET-1	35,224	$ 44,968,301	$ 54,799,131	$ 9,830,830	21.9%
	ET-2	91,574	$ 114,800,498	$ 142,431,382	$ 27,630,884	24.1%
	ECT-1R	2,320	$ 3,270,472	$ 3,729,805	$ 459,333	14.0%
	ECT-2	10,402	$ 14,111,711	$ 16,767,669	$ 2,655,957	18.8%
R-3	E-12	35,628	$ 75,564,138	$ 75,028,450	$ (535,688)	-0.7%
	ET-1	52,958	$ 118,845,388	$ 135,606,180	$ 16,760,792	14.1%
	ET-2	77,704	$ 172,754,979	$ 198,140,883	$ 25,385,904	14.7%
	ECT-1R	17,951	$ 46,847,687	$ 55,175,107	$ 8,327,420	17.8%
	ECT-2	60,030	$ 147,671,354	$ 179,703,587	$ 32,032,233	21.7%
	Total	948,535	$ 1,355,399,219	$ 1,614,077,774	$ 258,678,556	19.1%

1. Includes customers with 12 months of usage data from AMI meters. Excludes customers participating in net metering.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	13.20	22.72	9.52	72.1%
101-200	22.62	32.63	10.00	44.2%
201-300	33.24	43.26	10.02	30.1%
301-400	47.23	56.06	8.84	18.7%
401-500	63.69	69.48	5.79	9.1%
501-600	81.64	83.11	1.47	1.8%

Winter	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	13.45	23.13	9.68	72.0%
101-200	23.99	34.69	10.70	44.6%
201-300	32.85	44.40	11.55	35.2%
301-400	39.81	52.04	12.22	30.7%
401-500	46.12	58.95	12.83	27.8%
501-600	52.43	65.87	13.44	25.6%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	*(A)*	*(B)*	*(C)*	*(D)*
			Change	
kWh block	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	21.93	23.03	1.10	5.0%
101-200	32.43	33.04	0.61	1.9%
201-300	44.25	43.88	(0.37)	-0.8%
301-400	60.49	58.85	(1.64)	-2.7%
401-500	77.44	74.65	(2.80)	-3.6%
501-600	94.75	90.85	(3.89)	-4.1%

Winter	*(A)*	*(B)*	*(C)*	*(D)*
			Change	
kWh block	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	21.59	23.03	1.44	6.7%
101-200	30.82	33.04	2.22	7.2%
201-300	39.38	43.88	4.50	11.4%
301-400	44.24	58.85	14.61	33.0%
401-500	48.16	74.65	26.48	55.0%
501-600	51.66	90.85	39.19	75.9%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
0-100	22.31	23.54	1.23	5.5%
101-200	32.28	33.25	0.96	3.0%
201-300	44.52	44.60	0.08	0.2%
301-400	59.63	58.85	(0.78)	-1.3%
401-500	75.73	74.23	(1.49)	-2.0%
501-600	91.21	89.00	(2.21)	-2.4%

Winter

kWh block	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
0-100	21.94	23.75	1.81	8.3%
101-200	31.42	35.00	3.58	11.4%
201-300	38.76	43.67	4.91	12.7%
301-400	44.08	49.87	5.79	13.1%
401-500	48.23	55.03	6.80	14.1%
501-600	52.97	60.71	7.74	14.6%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	27.62	23.13	(4.49)	-16.2%
101-200	40.82	35.93	(4.89)	-12.0%
201-300	60.15	46.56	(13.59)	-22.6%
301-400	71.99	58.44	(13.55)	-18.8%
401-500	86.62	70.41	(16.21)	-18.7%
501-600	103.55	89.51	(14.04)	-13.6%

Winter	*(A)*	*(B)*	*(C)*	*(D)*
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount ($) *(B) - (A)*	% *(C) / (A)*
0-100	25.98	23.95	(2.03)	-7.8%
101-200	31.18	31.49	0.31	1.0%
201-300	44.14	41.81	(2.32)	-5.3%
301-400	54.61	50.59	(4.02)	-7.4%
401-500	58.01	58.33	0.33	0.6%
501-600	60.62	59.99	(0.63)	-1.0%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
0-100	24.47	22.30	(2.17)	-8.9%
101-200	42.50	33.56	(8.95)	-21.0%
201-300	56.93	45.12	(11.81)	-20.7%
301-400	73.63	58.33	(15.30)	-20.8%
401-500	88.70	73.61	(15.09)	-17.0%
501-600	102.55	89.20	(13.35)	-13.0%

Winter

kWh block	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
0-100	22.58	22.82	0.24	1.1%
101-200	35.73	34.18	(1.56)	-4.4%
201-300	42.34	42.95	0.62	1.5%
301-400	51.52	51.31	(0.21)	-0.4%
401-500	54.27	55.75	1.48	2.7%
501-600	58.48	61.12	2.65	4.5%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	5.7	$ 91.25	128.43	37.19	40.8%
701-800	5.8	$ 110.68	141.58	30.90	27.9%
801-900	6.0	$ 130.77	155.31	24.54	18.8%
901-1000	6.2	$ 151.00	169.17	18.18	12.0%
1001-1100	6.4	$ 172.48	183.15	10.67	6.2%
1101-1200	6.6	$ 192.82	196.72	3.90	2.0%
1201-1300	6.9	$ 212.37	210.24	(2.13)	-1.0%
1301-1400	7.3	$ 231.07	223.73	(7.34)	-3.2%
1401-1500	7.7	$ 250.62	237.84	(12.78)	-5.1%
1501-1600	8.2	$ 269.75	252.00	(17.75)	-6.6%
1601-1700	8.7	$ 289.63	267.22	(22.41)	-7.7%
1701-1800	9.2	$ 310.02	282.30	(27.73)	-8.9%
1801-1900	9.7	$ 325.01	294.36	(30.65)	-9.4%
1901-2000	10.3	$ 349.45	313.13	(36.32)	-10.4%
2001-2100	10.7	$ 359.92	321.13	(38.80)	-10.8%
2101-2200	11.7	$ 406.45	354.24	(52.21)	-12.8%
2201-2300	11.8	$ 406.75	354.03	(52.71)	-13.0%
2301-2400	12.5	$ 438.09	376.59	(61.50)	-14.0%
2401-2500	13.2	$ 458.44	392.47	(65.97)	-14.4%
2501-2600	13.5	$ 490.45	412.57	(77.88)	-15.9%
2601-2700	14.5	$ 507.61	429.63	(77.99)	-15.4%
2701-2800	14.6	$ 516.17	433.61	(82.55)	-16.0%
2801-2900	15.8	$ 533.01	449.95	(83.06)	-15.6%
2901-3000	15.0	$ 554.10	455.94	(98.16)	-17.7%
3001-3100	15.7	$ 534.93	452.38	(82.54)	-15.4%
3101-3200	17.9	$ 583.05	490.48	(92.57)	-15.9%
3201-3300	19.1	$ 636.68	527.77	(108.90)	-17.1%
3301-3400	18.3	$ 599.73	505.41	(94.32)	-15.7%
3401-3500	14.8	$ 577.81	462.83	(114.98)	-19.9%
3501-3600	21.0	$ 751.29	609.03	(142.26)	-18.9%
3601-3700	20.0	$ 636.67	530.28	(106.39)	-16.7%
3701-3800	20.0	$ 675.72	558.08	(117.64)	-17.4%
3801-3900	18.5	$ 672.25	550.58	(121.67)	-18.1%
3901-4000	19.6	$ 836.86	639.63	(197.22)	-23.6%
4001-5000	24.0	$ 897.78	707.48	(190.30)	-21.2%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Winter		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	6.0	$ 65.81	117.40	51.60	78.4%
701-800	5.8	$ 72.21	121.87	49.67	68.8%
801-900	5.7	$ 78.42	127.17	48.74	62.2%
901-1000	5.6	$ 84.73	132.30	47.57	56.1%
1001-1100	5.6	$ 90.76	137.84	47.08	51.9%
1101-1200	5.6	$ 97.26	143.83	46.57	47.9%
1201-1300	5.7	$ 104.42	151.09	46.67	44.7%
1301-1400	6.0	$ 112.04	160.11	48.07	42.9%
1401-1500	6.3	$ 119.58	169.11	49.53	41.4%
1501-1600	6.6	$ 127.49	178.43	50.94	40.0%
1601-1700	6.9	$ 134.64	187.23	52.58	39.1%
1701-1800	7.2	$ 141.80	195.82	54.02	38.1%
1801-1900	7.6	$ 151.78	207.81	56.02	36.9%
1901-2000	7.9	$ 156.40	214.12	57.73	36.9%
2001-2100	8.6	$ 169.86	231.20	61.34	36.1%
2101-2200	8.1	$ 161.95	220.61	58.66	36.2%
2201-2300	8.7	$ 180.69	241.28	60.59	33.5%
2301-2400	9.7	$ 182.67	249.91	67.24	36.8%
2401-2500	9.1	$ 190.11	253.58	63.47	33.4%
2501-2600	9.0	$ 188.89	250.74	61.85	32.7%
2601-2700	9.6	$ 199.62	266.47	66.85	33.5%
2701-2800	11.1	$ 213.93	289.48	75.54	35.3%
2801-2900	10.8	$ 223.82	295.88	72.06	32.2%
2901-3000	11.2	$ 230.98	305.35	74.37	32.2%
3001-3100	11.1	$ 259.70	331.68	71.98	27.7%
3101-3200	14.0	$ 252.36	342.66	90.31	35.8%
3201-3300	13.7	$ 243.60	333.97	90.37	37.1%
3301-3400	14.3	$ 276.09	368.77	92.68	33.6%
3401-3500	15.6	$ 307.07	402.39	95.32	31.0%
3501-3600	11.7	$ 235.31	313.95	78.64	33.4%
3601-3700	14.5	$ 322.51	411.77	89.26	27.7%
3701-3800	11.6	$ 310.46	384.72	74.26	23.9%
3801-3900	18.9	$ 332.97	453.22	120.25	36.1%
3901-4000	13.1	$ 255.18	341.24	86.06	33.7%
4001-5000	14.1	$ 332.02	419.38	87.35	26.3%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	6.3	104.44	142.02	37.58	36.0%
701-800	6.5	121.57	158.31	36.74	30.2%
801-900	6.4	134.51	168.26	33.75	25.1%
901-1000	6.5	153.66	184.87	31.21	20.3%
1001-1100	6.7	168.61	198.71	30.10	17.9%
1101-1200	6.8	182.23	211.65	29.43	16.1%
1201-1300	7.1	197.45	226.94	29.49	14.9%
1301-1400	7.4	209.82	240.34	30.52	14.5%
1401-1500	7.9	222.62	254.95	32.34	14.5%
1501-1600	8.4	236.00	270.52	34.52	14.6%
1601-1700	8.8	248.75	284.31	35.56	14.3%
1701-1800	9.4	261.38	299.42	38.05	14.6%
1801-1900	10.0	273.26	314.78	41.52	15.2%
1901-2000	10.4	286.49	329.27	42.78	14.9%
2001-2100	11.0	298.81	345.41	46.60	15.6%
2101-2200	11.6	312.71	359.20	46.49	14.9%
2201-2300	11.9	311.47	364.43	52.96	17.0%
2301-2400	12.5	330.75	384.83	54.08	16.4%
2401-2500	13.2	355.51	410.18	54.66	15.4%
2501-2600	13.7	357.12	415.26	58.13	16.3%
2601-2700	13.9	368.92	425.54	56.62	15.3%
2701-2800	14.6	392.17	454.46	62.29	15.9%
2801-2900	15.4	396.26	454.56	58.30	14.7%
2901-3000	15.1	403.07	473.31	70.24	17.4%
3001-3100	17.2	417.16	493.66	76.50	18.3%
3101-3200	16.6	457.89	519.41	61.53	13.4%
3201-3300	18.1	457.19	526.75	69.56	15.2%
3301-3400	17.5	476.11	541.38	65.27	13.7%
3401-3500	19.1	456.12	529.72	73.61	16.1%
3501-3600	19.4	487.64	561.36	73.73	15.1%
3601-3700	17.9	475.05	552.93	77.89	16.4%
3701-3800	24.1	572.05	646.65	74.60	13.0%
3801-3900	19.5	483.48	560.17	76.68	15.9%
3901-4000	20.5	487.05	583.54	96.50	19.8%
4001-5000	24.2	555.25	666.13	110.87	20.0%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	5.1	63.45	104.09	40.64	64.1%
701-800	5.0	67.65	107.25	39.60	58.5%
801-900	5.2	74.57	115.41	40.84	54.8%
901-1000	5.0	77.92	117.40	39.48	50.7%
1001-1100	5.0	83.02	122.70	39.68	47.8%
1101-1200	5.0	88.46	128.23	39.77	45.0%
1201-1300	5.0	92.87	133.00	40.13	43.2%
1301-1400	5.2	98.75	140.55	41.80	42.3%
1401-1500	5.6	105.60	150.09	44.49	42.1%
1501-1600	5.9	111.52	158.27	46.74	41.9%
1601-1700	6.2	118.63	167.39	48.76	41.1%
1701-1800	6.5	125.96	176.79	50.83	40.4%
1801-1900	6.8	132.09	185.53	53.44	40.5%
1901-2000	7.1	139.08	194.27	55.19	39.7%
2001-2100	7.4	144.13	201.78	57.65	40.0%
2101-2200	7.7	153.65	212.42	58.77	38.3%
2201-2300	8.0	163.09	226.58	63.49	38.9%
2301-2400	8.4	166.03	232.00	65.97	39.7%
2401-2500	8.6	167.96	233.14	65.18	38.8%
2501-2600	9.2	184.88	254.02	69.13	37.4%
2601-2700	9.6	192.03	265.83	73.80	38.4%
2701-2800	8.7	186.19	251.64	65.45	35.2%
2801-2900	10.6	213.85	290.98	77.12	36.1%
2901-3000	12.1	194.59	289.47	94.88	48.8%
3001-3100	12.1	221.41	310.64	89.23	40.3%
3101-3200	10.6	209.75	289.69	79.94	38.1%
3201-3300	13.6	234.90	331.71	96.81	41.2%
3301-3400	11.0	235.03	312.52	77.49	33.0%
3401-3500	13.7	266.01	361.63	95.62	35.9%
3501-3600	12.8	263.49	354.64	91.15	34.6%
3601-3700	13.3	273.69	365.21	91.52	33.4%
3701-3800	12.4	256.91	333.10	76.18	29.7%
3801-3900	15.0	316.93	421.30	104.36	32.9%
3901-4000	11.9	308.30	404.27	95.96	31.1%
4001-5000	14.4	309.04	408.50	99.46	32%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	5.9	97.81	135.38	37.56	38.4%
701-800	6.0	113.42	149.71	36.30	32.0%
801-900	6.1	130.37	164.27	33.91	26.0%
901-1000	6.4	146.95	180.01	33.06	22.5%
1001-1100	6.6	164.20	195.39	31.19	19.0%
1101-1200	6.8	179.81	210.08	30.28	16.8%
1201-1300	7.0	194.80	224.55	29.75	15.3%
1301-1400	7.4	208.01	238.90	30.89	14.9%
1401-1500	7.9	220.86	254.25	33.38	15.1%
1501-1600	8.3	234.38	268.35	33.97	14.5%
1601-1700	8.8	245.28	282.51	37.24	15.2%
1701-1800	9.3	256.84	296.83	39.99	15.6%
1801-1900	9.8	270.24	313.26	43.03	15.9%
1901-2000	10.3	281.93	327.19	45.27	16.1%
2001-2100	10.8	292.45	341.77	49.32	16.9%
2101-2200	11.3	303.89	357.10	53.21	17.5%
2201-2300	11.9	315.52	372.44	56.92	18.0%
2301-2400	12.5	325.61	388.22	62.60	19.2%
2401-2500	12.8	336.14	397.70	61.56	18.3%
2501-2600	13.8	352.04	422.72	70.68	20.1%
2601-2700	14.0	356.63	429.29	72.66	20.4%
2701-2800	14.5	366.06	437.54	71.48	19.5%
2801-2900	16.0	383.31	469.79	86.48	22.6%
2901-3000	15.8	385.94	464.30	78.36	20.3%
3001-3100	16.6	406.69	483.91	77.23	19.0%
3101-3200	16.7	415.01	489.05	74.04	17.8%
3201-3300	17.7	431.22	503.37	72.15	16.7%
3301-3400	20.6	446.52	542.48	95.96	21.5%
3401-3500	18.2	447.68	543.43	95.75	21.4%
3501-3600	19.5	434.03	539.30	105.27	24.3%
3601-3700	19.6	451.90	534.78	82.88	18.3%
3701-3800	18.4	519.15	584.43	65.29	12.6%
3801-3900	20.1	522.76	617.19	94.43	18.1%
3901-4000	21.8	477.11	603.72	126.61	26.5%
4001-5000	24.2	546.13	666.13	120.00	22.0%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	5.6	65.87	109.89	44.03	66.8%
701-800	5.4	70.48	113.22	42.74	60.6%
801-900	5.4	74.97	117.74	42.77	57.1%
901-1000	5.3	79.72	121.53	41.80	52.4%
1001-1100	5.2	84.35	125.44	41.08	48.7%
1101-1200	5.2	89.15	130.33	41.18	46.2%
1201-1300	5.3	93.81	135.83	42.02	44.8%
1301-1400	5.5	99.94	143.27	43.33	43.4%
1401-1500	5.8	105.87	151.49	45.62	43.1%
1501-1600	6.1	112.84	160.37	47.53	42.1%
1601-1700	6.4	120.03	169.74	49.70	41.4%
1701-1800	6.8	126.65	179.26	52.61	41.5%
1801-1900	7.0	131.74	186.01	54.27	41.2%
1901-2000	7.3	139.27	195.45	56.18	40.3%
2001-2100	7.5	145.03	203.32	58.29	40.2%
2101-2200	7.7	149.88	210.28	60.41	40.3%
2201-2300	8.0	156.04	218.96	62.92	40.3%
2301-2400	8.2	161.51	225.92	64.41	39.9%
2401-2500	8.9	173.78	242.29	68.51	39.4%
2501-2600	9.3	171.49	244.10	72.62	42.3%
2601-2700	9.6	183.42	257.51	74.09	40.4%
2701-2800	9.8	196.65	273.34	76.69	39.0%
2801-2900	10.4	191.73	271.10	79.36	41.4%
2901-3000	10.7	216.96	295.96	79.00	36.4%
3001-3100	12.4	223.94	313.65	89.72	40.1%
3101-3200	11.8	238.85	322.45	83.61	35.0%
3201-3300	12.7	257.22	339.36	82.14	31.9%
3301-3400	14.3	242.57	347.53	104.96	43.3%
3401-3500	11.6	242.67	326.80	84.12	34.7%
3501-3600	15.4	276.47	385.26	108.79	39.3%
3601-3700	12.5	303.77	389.15	85.38	28.1%
3701-3800	14.8	254.62	367.77	113.16	44.4%
3801-3900	12.2	267.81	351.51	83.70	31.3%
3901-4000	15.8	281.78	407.24	125.46	44.5%
4001-5000	17.1	334.34	456.38	122.04	36.5%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	6.9	159.49	146.44	(13.05)	-8.2%
701-800	5.9	147.18	145.66	(1.52)	-1.0%
801-900	6.6	167.82	169.91	2.09	1.2%
901-1000	6.7	180.96	186.64	5.68	3.1%
1001-1100	6.8	188.30	200.20	11.89	6.3%
1101-1200	6.9	197.86	212.35	14.49	7.3%
1201-1300	7.2	208.86	228.44	19.59	9.4%
1301-1400	7.7	222.34	243.72	21.39	9.6%
1401-1500	8.1	235.80	258.07	22.28	9.4%
1501-1600	8.5	249.08	272.34	23.26	9.3%
1601-1700	9.0	260.89	289.38	28.48	10.9%
1701-1800	9.6	277.24	305.70	28.45	10.3%
1801-1900	10.2	290.90	319.20	28.30	9.7%
1901-2000	10.6	301.00	330.24	29.23	9.7%
2001-2100	11.2	318.52	351.79	33.27	10.4%
2101-2200	11.8	333.02	365.62	32.61	9.8%
2201-2300	12.2	343.90	378.57	34.67	10.1%
2301-2400	13.1	367.98	398.19	30.21	8.2%
2401-2500	13.3	370.39	403.56	33.17	9.0%
2501-2600	13.9	384.34	417.36	33.02	8.6%
2601-2700	14.7	419.06	434.50	15.44	3.7%
2701-2800	15.2	430.19	475.34	45.16	10.5%
2801-2900	16.0	441.49	484.70	43.21	9.8%
2901-3000	16.2	457.01	486.35	29.34	6.4%
3001-3100	18.3	482.03	510.19	28.16	5.8%
3101-3200	19.2	512.16	549.94	37.79	7.4%
3201-3300	17.4	481.57	522.80	41.23	8.6%
3301-3400	16.9	499.18	528.16	28.97	5.8%
3401-3500	18.5	515.99	543.08	27.09	5.3%
3501-3600	18.3	513.87	537.42	23.54	4.6%
3601-3700	18.9	529.53	561.08	31.56	6.0%
3701-3800	21.2	570.82	614.34	43.52	7.6%
3801-3900	20.7	552.34	600.30	47.96	8.7%
3901-4000	20.0	573.39	574.81	1.42	0.2%
4001-5000	25.4	681.74	728.62	46.88	6.9%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	4.8	95.36	105.11	9.75	10.2%
701-800	5.3	103.52	119.51	15.99	15.4%
801-900	4.8	95.42	113.00	17.58	18.4%
901-1000	4.7	99.42	116.75	17.33	17.4%
1001-1100	4.8	100.47	121.30	20.83	20.7%
1101-1200	4.7	104.72	126.91	22.19	21.2%
1201-1300	4.8	107.65	131.29	23.63	22.0%
1301-1400	5.0	111.65	138.67	27.03	24.2%
1401-1500	5.3	117.63	146.77	29.14	24.8%
1501-1600	5.6	124.13	155.94	31.80	25.6%
1601-1700	5.7	127.28	161.03	33.75	26.5%
1701-1800	6.0	132.54	167.86	35.32	26.6%
1801-1900	6.3	141.52	179.68	38.15	27.0%
1901-2000	6.8	149.98	192.03	42.06	28.0%
2001-2100	6.8	152.53	193.57	41.04	26.9%
2101-2200	7.2	160.87	204.95	44.09	27.4%
2201-2300	7.8	169.99	217.71	47.72	28.1%
2301-2400	7.8	173.36	223.68	50.31	29.0%
2401-2500	8.3	182.49	237.85	55.36	30.3%
2501-2600	8.5	190.49	244.81	54.32	28.5%
2601-2700	9.3	202.63	258.02	55.39	27.3%
2701-2800	7.9	180.67	231.14	50.47	27.9%
2801-2900	9.1	199.80	256.84	57.03	28.5%
2901-3000	9.7	214.40	273.73	59.33	27.7%
3001-3100	9.5	216.07	282.85	66.78	30.9%
3101-3200	11.3	229.49	284.60	55.12	24.0%
3201-3300	9.8	224.95	302.88	77.93	34.6%
3301-3400	13.0	266.76	331.31	64.55	24.2%
3401-3500	12.6	274.30	344.93	70.62	25.7%
3501-3600	15.6	312.40	384.94	72.54	23.2%
3601-3700	13.2	291.92	370.87	78.95	27.0%
3701-3800	10.6	256.58	336.57	79.99	31.2%
3801-3900	15.2	305.12	392.86	87.74	28.8%
3901-4000	20.1	389.13	456.00	66.87	17.2%
4001-5000	15.0	308.51	393.60	85.09	27.6%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	5.7	124.75	126.56	1.81	1.5%
701-800	6.6	152.58	156.75	4.17	2.7%
801-900	6.6	163.03	169.87	6.84	4.2%
901-1000	6.6	171.25	183.63	12.38	7.2%
1001-1100	6.9	182.80	200.96	18.16	9.9%
1101-1200	7.0	194.04	215.46	21.42	11.0%
1201-1300	7.2	204.70	230.34	25.64	12.5%
1301-1400	7.6	216.96	244.96	28.00	12.9%
1401-1500	8.1	228.99	259.92	30.93	13.5%
1501-1600	8.6	243.70	276.56	32.86	13.5%
1601-1700	9.0	254.12	290.72	36.59	14.4%
1701-1800	9.6	267.55	306.46	38.92	14.5%
1801-1900	10.0	281.47	321.29	39.82	14.1%
1901-2000	10.6	289.60	335.82	46.22	16.0%
2001-2100	11.1	306.02	352.84	46.82	15.3%
2101-2200	11.6	312.29	363.49	51.19	16.4%
2201-2300	12.2	329.11	381.65	52.54	16.0%
2301-2400	12.8	344.40	396.65	52.25	15.2%
2401-2500	13.3	353.55	411.46	57.91	16.4%
2501-2600	13.8	369.59	425.51	55.92	15.1%
2601-2700	14.2	370.56	435.88	65.32	17.6%
2701-2800	14.6	387.80	450.58	62.79	16.2%
2801-2900	15.2	404.21	465.43	61.22	15.1%
2901-3000	15.5	407.81	480.87	73.06	17.9%
3001-3100	16.1	402.84	482.58	79.74	19.8%
3101-3200	17.0	431.54	506.26	74.72	17.3%
3201-3300	17.7	472.69	531.36	58.67	12.4%
3301-3400	18.9	468.07	529.67	61.59	13.2%
3401-3500	17.8	477.51	552.38	74.88	15.7%
3501-3600	18.8	497.01	555.10	58.09	11.7%
3601-3700	18.2	480.73	584.55	103.82	21.6%
3701-3800	21.9	546.26	614.49	68.23	12.5%
3801-3900	21.3	557.36	641.29	83.93	15.1%
3901-4000	20.3	535.92	633.16	97.25	18.1%
4001-5000	24.0	632.60	698.56	65.96	10.4%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-1

(excludes bill reduction from transferring adjustor rates to base rates)

Winter		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	6.3	94.16	119.74	25.58	27.2%
701-800	5.1	87.03	108.69	21.66	24.9%
801-900	4.9	89.05	113.09	24.04	27.0%
901-1000	4.9	91.21	117.52	26.31	28.8%
1001-1100	4.8	91.99	120.18	28.18	30.6%
1101-1200	4.8	94.25	124.65	30.40	32.3%
1201-1300	4.8	97.36	129.01	31.65	32.5%
1301-1400	4.9	101.14	135.29	34.15	33.8%
1401-1500	5.2	107.20	143.79	36.59	34.1%
1501-1600	5.5	111.65	151.04	39.39	35.3%
1601-1700	5.8	117.64	159.33	41.69	35.4%
1701-1800	6.1	122.71	167.75	45.04	36.7%
1801-1900	6.4	128.61	175.86	47.25	36.7%
1901-2000	6.7	133.11	185.05	51.94	39.0%
2001-2100	6.9	138.53	191.48	52.95	38.2%
2101-2200	7.4	146.14	204.59	58.45	40.0%
2201-2300	7.8	152.12	211.60	59.48	39.1%
2301-2400	7.8	157.04	219.76	62.72	39.9%
2401-2500	8.1	161.33	226.45	65.12	40.4%
2501-2600	8.4	169.44	237.22	67.78	40.0%
2601-2700	8.9	176.96	247.84	70.88	40.1%
2701-2800	9.4	188.71	259.49	70.77	37.5%
2801-2900	9.4	188.65	266.68	78.04	41.4%
2901-3000	10.1	191.58	274.16	82.59	43.1%
3001-3100	10.6	206.45	295.75	89.31	43.3%
3101-3200	10.7	210.77	298.89	88.12	41.8%
3201-3300	10.3	212.17	294.94	82.76	39.0%
3301-3400	11.9	238.65	330.28	91.63	38.4%
3401-3500	13.1	237.57	329.49	91.92	38.7%
3501-3600	12.3	254.34	350.29	95.95	37.7%
3601-3700	13.0	247.69	335.69	88.00	35.5%
3701-3800	15.1	273.17	366.59	93.42	34.2%
3801-3900	15.5	252.96	355.45	102.50	40.5%
3901-4000	13.2	251.81	348.71	96.90	38.5%
4001-5000	17.5	313.60	437.29	123.69	39.4%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		*(A)*	*(B)*	*(C)*	*(D)*
		Monthly Bill under	Monthly Bill under	Change	
kWh block	On-Pk kW	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	3.9	$ 101.16	120.09	18.93	18.7%
701-800	4.3	$ 121.10	136.10	15.00	12.4%
801-900	4.7	$ 140.91	151.72	10.81	7.7%
901-1000	5.0	$ 161.26	166.50	5.25	3.3%
1001-1100	5.4	$ 181.32	181.83	0.50	0.3%
1101-1200	5.8	$ 205.77	199.59	(6.18)	-3.0%
1201-1300	6.4	$ 238.30	223.30	(15.00)	-6.3%
1301-1400	7.2	$ 281.61	252.98	(28.63)	-10.2%
1401-1500	7.7	$ 270.77	245.00	(25.77)	-9.5%
1501-1600					

Winter		*(A)*	*(B)*	*(C)*	*(D)*
		Monthly Bill under	Monthly Bill under	Change	
kWh block	On-Pk kW	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	3.3	$ 58.46	88.71	30.25	51.8%
701-800	3.5	$ 64.68	96.19	31.52	48.7%
801-900	3.7	$ 71.27	103.99	32.73	45.9%
901-1000	3.9	$ 77.67	111.63	33.96	43.7%
1001-1100	4.0	$ 84.17	118.47	34.30	40.7%
1101-1200	4.0	$ 87.65	121.64	33.99	38.8%
1201-1300	3.7	$ 86.15	117.36	31.22	36.2%
1301-1400	2.9	$ 79.46	103.33	23.87	30.0%
1401-1500	2.6	$ 99.14	119.04	19.90	20.1%
1501-1600					

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	4.0	111.23	129.73	18.50	16.6%
701-800	4.4	127.12	146.85	19.73	15.5%
801-900	4.8	142.35	163.42	21.07	14.8%
901-1000	5.2	156.34	178.74	22.40	14.3%
1001-1100	5.6	170.08	194.78	24.70	14.5%
1101-1200	6.0	184.28	210.68	26.39	14.3%
1201-1300	6.5	197.39	229.54	32.15	16.3%
1301-1400	7.1	201.43	244.40	42.97	21.3%
1401-1500	7.9	218.75	274.67	55.92	25.6%
1501-1600					

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	2.6	55.73	75.63	19.89	35.7%
701-800	2.8	60.50	82.04	21.54	35.6%
801-900	3.1	65.63	89.83	24.20	36.9%
901-1000	3.4	71.56	98.23	26.66	37.3%
1001-1100	3.6	76.63	105.29	28.66	37.4%
1101-1200	3.7	81.07	110.90	29.83	36.8%
1201-1300	3.5	80.62	110.54	29.92	37.1%
1301-1400	3.0	80.90	110.04	29.15	36.0%
1401-1500	2.3	72.34	96.19	23.85	33.0%
1501-1600					

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	4.2	107.91	129.43	21.52	19.9%
701-800	4.6	124.31	146.63	22.32	18.0%
801-900	4.9	140.16	162.67	22.52	16.1%
901-1000	5.3	155.76	179.34	23.58	15.1%
1001-1100	5.6	170.69	194.93	24.24	14.2%
1101-1200	6.0	185.07	211.55	26.49	14.3%
1201-1300	6.4	196.69	227.94	31.25	15.9%
1301-1400	7.1	198.40	245.31	46.90	23.6%
1401-1500	7.7	196.50	264.29	67.79	34.5%
1501-1600	8.6	267.12	314.28	47.16	17.7%

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	3.1	56.88	81.02	24.13	42.4%
701-800	3.3	61.76	87.43	25.67	41.6%
801-900	3.5	66.55	94.13	27.58	41.4%
901-1000	3.6	71.43	99.79	28.36	39.7%
1001-1100	3.7	76.29	105.40	29.11	38.2%
1101-1200	3.8	79.91	110.30	30.39	38.0%
1201-1300	3.6	81.04	111.11	30.06	37.1%
1301-1400	3.0	80.29	108.18	27.90	34.7%
1401-1500	2.4	76.58	100.81	24.23	31.6%
1501-1600	1.6	54.38	67.85	13.47	24.8%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	4.0	122.70	130.72	8.02	6.5%
701-800	4.3	132.47	145.91	13.44	10.1%
801-900	4.7	143.96	159.49	15.53	10.8%
901-1000	5.2	161.23	179.60	18.37	11.4%
1001-1100	5.5	171.57	192.89	21.32	12.4%
1101-1200	6.1	186.34	212.53	26.19	14.1%
1201-1300	6.7	204.48	233.02	28.54	14.0%
1301-1400	7.3	211.13	244.85	33.72	16.0%
1401-1500					
1501-1600					

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	2.4	64.29	73.86	9.58	14.9%
701-800	2.6	68.93	80.88	11.95	17.3%
801-900	2.9	77.56	90.94	13.38	17.2%
901-1000	3.2	80.96	96.50	15.54	19.2%
1001-1100	3.5	87.27	105.87	18.60	21.3%
1101-1200	3.5	88.85	108.95	20.10	22.6%
1201-1300	3.2	88.37	107.50	19.13	21.6%
1301-1400	3.1	93.59	115.71	22.11	23.6%
1401-1500					
1501-1600					

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	4.0	117.46	129.79	12.33	10.5%
701-800	4.4	132.53	147.05	14.52	11.0%
801-900	4.8	144.59	164.02	19.43	13.4%
901-1000	5.3	159.34	181.83	22.49	14.1%
1001-1100	5.6	172.40	197.36	24.96	14.5%
1101-1200	6.1	185.98	215.75	29.77	16.0%
1201-1300	6.7	196.70	233.14	36.44	18.5%
1301-1400	7.1	198.64	246.21	47.57	24.0%
1401-1500	7.4	170.85	246.86	76.01	44.5%
1501-1600	8.1	166.00	261.25	95.25	57.4%

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	2.5	59.69	74.58	14.89	24.9%
701-800	2.8	63.91	81.80	17.89	28.0%
801-900	3.0	69.12	88.29	19.17	27.7%
901-1000	3.2	73.26	94.55	21.28	29.1%
1001-1100	3.4	76.72	101.24	24.52	32.0%
1101-1200	3.5	80.37	105.63	25.26	31.4%
1201-1300	3.3	78.99	106.67	27.68	35.0%
1301-1400	2.9	76.81	106.28	29.47	38.4%
1401-1500	2.7	74.48	112.84	38.36	51.5%
1501-1600	2.0	80.45	120.59	40.14	49.9%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	1.6	$ 79.16	87.25	8.09	10.2%
701-800	2.2	$ 100.65	106.17	5.52	5.5%
801-900	2.8	$ 123.48	125.45	1.97	1.6%
901-1000	3.4	$ 147.10	144.88	(2.22)	-1.5%
1001-1100	4.0	$ 166.22	162.43	(3.79)	-2.3%
1101-1200	4.5	$ 186.70	178.69	(8.02)	-4.3%
1201-1300	5.0	$ 206.79	194.58	(12.21)	-5.9%
1301-1400	5.4	$ 225.48	208.34	(17.14)	-7.6%
1401-1500	5.8	$ 243.56	221.75	(21.81)	-9.0%
1501-1600	6.2	$ 263.32	235.75	(27.57)	-10.5%
1601-1700	6.6	$ 281.31	249.22	(32.09)	-11.4%
1701-1800	7.0	$ 302.43	263.77	(38.66)	-12.8%
1801-1900	7.4	$ 321.99	277.55	(44.44)	-13.8%
1901-2000	7.7	$ 340.26	289.39	(50.86)	-14.9%
2001-2100	8.0	$ 360.08	301.48	(58.60)	-16.3%
2101-2200	8.5	$ 383.54	318.63	(64.91)	-16.9%
2201-2300	8.7	$ 395.82	326.36	(69.46)	-17.5%
2301-2400	9.1	$ 419.89	341.65	(78.24)	-18.6%
2401-2500	9.5	$ 441.98	356.45	(85.52)	-19.4%
2501-2600	9.7	$ 452.71	363.56	(89.15)	-19.7%
2601-2700	9.8	$ 473.19	372.46	(100.73)	-21.3%
2701-2800	10.4	$ 499.96	392.22	(107.75)	-21.6%
2801-2900	10.5	$ 512.62	398.38	(114.25)	-22.3%
2901-3000	10.8	$ 544.39	414.78	(129.61)	-23.8%
3001-3100	11.2	$ 558.22	426.81	(131.41)	-23.5%
3101-3200	11.7	$ 571.56	439.03	(132.54)	-23.2%
3201-3300	12.1	$ 582.67	449.89	(132.78)	-22.8%
3301-3400	12.2	$ 598.63	457.25	(141.38)	-23.6%
3401-3500	12.7	$ 643.27	481.59	(161.68)	-25.1%
3501-3600	12.9	$ 656.11	489.32	(166.80)	-25.4%
3601-3700	12.9	$ 705.27	506.80	(198.47)	-28.1%
3701-3800	13.6	$ 717.65	522.80	(194.85)	-27.2%
3801-3900	13.7	$ 700.98	518.17	(182.81)	-26.1%
3901-4000	13.9	$ 736.76	534.43	(202.33)	-27.5%
4001-5000	15.2	$ 830.18	588.64	(241.54)	-29.1%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Winter		*(A)*	*(B)*	*(C)*	*(D)*
		Monthly Bill under	Monthly Bill under	Change	
kWh block	On-Pk kW	Current Rates	Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	2.1	$ 74.00	87.01	13.01	17.6%
701-800	2.4	$ 78.71	93.29	14.58	18.5%
801-900	2.7	$ 83.23	99.46	16.24	19.5%
901-1000	3.0	$ 87.46	105.53	18.06	20.7%
1001-1100	3.4	$ 94.72	114.42	19.70	20.8%
1101-1200	3.8	$ 101.12	122.87	21.76	21.5%
1201-1300	4.2	$ 108.28	131.78	23.50	21.7%
1301-1400	4.4	$ 115.81	138.59	22.78	19.7%
1401-1500	4.8	$ 124.10	148.15	24.05	19.4%
1501-1600	5.0	$ 131.25	154.76	23.50	17.9%
1601-1700	5.3	$ 139.63	163.18	23.54	16.9%
1701-1800	5.6	$ 146.51	170.82	24.32	16.6%
1801-1900	5.8	$ 153.76	177.42	23.66	15.4%
1901-2000	6.1	$ 162.14	185.91	23.77	14.7%
2001-2100	6.3	$ 169.77	192.79	23.02	13.6%
2101-2200	6.5	$ 175.42	198.47	23.05	13.1%
2201-2300	6.8	$ 186.72	208.71	21.99	11.8%
2301-2400	7.0	$ 191.62	214.00	22.38	11.7%
2401-2500	7.2	$ 198.59	220.48	21.90	11.0%
2501-2600	7.5	$ 212.05	231.95	19.90	9.4%
2601-2700	7.6	$ 219.30	237.52	18.22	8.3%
2701-2800	7.8	$ 222.88	241.85	18.96	8.5%
2801-2900	8.1	$ 234.84	252.54	17.70	7.5%
2901-3000	8.2	$ 235.12	254.00	18.88	8.0%
3001-3100	8.6	$ 246.61	265.46	18.85	7.6%
3101-3200	8.8	$ 258.29	274.69	16.40	6.4%
3201-3300	9.3	$ 271.00	288.09	17.09	6.3%
3301-3400	9.7	$ 280.51	298.51	18.00	6.4%
3401-3500	9.5	$ 275.33	292.93	17.60	6.4%
3501-3600	9.5	$ 286.54	299.80	13.26	4.6%
3601-3700	9.2	$ 278.54	291.46	12.92	4.6%
3701-3800	10.4	$ 290.87	312.82	21.95	7.5%
3801-3900	11.0	$ 319.41	336.98	17.58	5.5%
3901-4000	10.3	$ 319.41	328.66	9.26	2.9%
4001-5000	11.5	$ 357.36	365.43	8.07	2.3%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	1.6	86.60	93.77	7.17	8.3%
701-800	2.4	103.26	115.29	12.02	11.6%
801-900	3.1	128.63	139.56	10.93	8.5%
901-1000	3.8	145.59	160.39	14.79	10.2%
1001-1100	4.4	162.33	179.25	16.92	10.4%
1101-1200	4.9	177.08	196.06	18.98	10.7%
1201-1300	5.4	189.93	211.73	21.80	11.5%
1301-1400	5.8	203.48	226.49	23.01	11.3%
1401-1500	6.1	215.01	238.64	23.62	11.0%
1501-1600	6.5	227.68	252.80	25.12	11.0%
1601-1700	6.9	240.11	267.05	26.94	11.2%
1701-1800	7.3	252.36	280.92	28.56	11.3%
1801-1900	7.6	264.33	292.86	28.53	10.8%
1901-2000	7.9	276.29	304.91	28.62	10.4%
2001-2100	8.3	289.07	319.26	30.19	10.4%
2101-2200	8.7	302.11	333.31	31.20	10.3%
2201-2300	9.0	313.59	345.23	31.64	10.1%
2301-2400	9.3	326.81	357.70	30.89	9.5%
2401-2500	9.7	338.85	371.08	32.23	9.5%
2501-2600	9.9	349.87	380.99	31.13	8.9%
2601-2700	10.3	363.04	394.97	31.94	8.8%
2701-2800	10.5	371.66	404.07	32.41	8.7%
2801-2900	10.9	388.48	419.29	30.81	7.9%
2901-3000	11.1	401.24	430.45	29.21	7.3%
3001-3100	11.4	414.26	443.17	28.91	7.0%
3101-3200	11.8	423.56	455.38	31.82	7.5%
3201-3300	12.0	434.89	465.21	30.32	7.0%
3301-3400	12.3	448.34	475.63	27.29	6.1%
3401-3500	12.4	454.01	482.53	28.52	6.3%
3501-3600	13.2	473.20	504.48	31.29	6.6%
3601-3700	13.3	487.90	514.34	26.44	5.4%
3701-3800	13.2	499.33	520.53	21.20	4.2%
3801-3900	14.0	522.65	548.02	25.37	4.9%
3901-4000	14.2	529.82	553.68	23.87	4.5%
4001-5000	15.7	584.58	608.58	24.00	4.1%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	1.9	65.20	78.49	13.29	20.4%
701-800	2.1	71.34	84.76	13.42	18.8%
801-900	2.2	72.11	86.01	13.90	19.3%
901-1000	2.6	75.84	93.27	17.43	23.0%
1001-1100	2.9	80.56	99.58	19.02	23.6%
1101-1200	3.3	85.63	107.51	21.88	25.6%
1201-1300	3.6	92.05	115.20	23.15	25.2%
1301-1400	3.9	97.13	122.20	25.06	25.8%
1401-1500	4.2	103.59	130.09	26.50	25.6%
1501-1600	4.4	109.70	136.73	27.03	24.6%
1601-1700	4.7	115.82	144.30	28.48	24.6%
1701-1800	4.9	122.19	151.05	28.86	23.6%
1801-1900	5.2	129.20	159.08	29.87	23.1%
1901-2000	5.4	136.15	166.11	29.95	22.0%
2001-2100	5.7	141.99	173.49	31.50	22.2%
2101-2200	5.9	148.80	180.33	31.53	21.2%
2201-2300	6.2	155.93	188.40	32.47	20.8%
2301-2400	6.4	162.86	195.28	32.43	19.9%
2401-2500	6.6	170.69	202.40	31.71	18.6%
2501-2600	6.9	178.12	211.01	32.89	18.5%
2601-2700	7.1	185.53	217.81	32.29	17.4%
2701-2800	7.3	194.34	225.88	31.54	16.2%
2801-2900	7.6	201.90	233.05	31.15	15.4%
2901-3000	7.7	205.87	237.82	31.95	15.5%
3001-3100	7.8	211.85	243.02	31.17	14.7%
3101-3200	8.1	221.57	252.57	31.00	14.0%
3201-3300	8.2	229.30	258.68	29.37	12.8%
3301-3400	8.7	241.10	271.13	30.03	12.5%
3401-3500	9.0	249.69	281.25	31.56	12.6%
3501-3600	9.2	258.04	286.86	28.81	11.2%
3601-3700	9.2	265.09	291.10	26.01	9.8%
3701-3800	9.3	270.32	295.87	25.55	9.5%
3801-3900	9.4	267.74	295.14	27.40	10.2%
3901-4000	9.6	278.91	305.94	27.03	9.7%
4001-5000	11.2	324.35	351.09	26.74	8.2%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	1.8	90.90	98.01	7.11	7.8%
701-800	2.4	110.05	117.82	7.77	7.1%
801-900	3.1	131.47	140.40	8.93	6.8%
901-1000	3.8	149.09	161.41	12.32	8.3%
1001-1100	4.4	164.51	179.76	15.25	9.3%
1101-1200	4.9	179.32	196.53	17.21	9.6%
1201-1300	5.4	192.65	212.57	19.92	10.3%
1301-1400	5.9	206.12	228.72	22.60	11.0%
1401-1500	6.3	218.48	242.83	24.35	11.1%
1501-1600	6.7	230.53	256.62	26.10	11.3%
1601-1700	7.1	243.44	271.10	27.66	11.4%
1701-1800	7.4	256.53	283.55	27.01	10.5%
1801-1900	7.8	268.34	297.55	29.20	10.9%
1901-2000	8.2	281.13	311.58	30.45	10.8%
2001-2100	8.5	291.53	323.10	31.57	10.8%
2101-2200	8.9	303.95	336.97	33.02	10.9%
2201-2300	9.2	316.56	349.24	32.68	10.3%
2301-2400	9.5	326.96	361.14	34.18	10.5%
2401-2500	9.9	340.66	375.36	34.69	10.2%
2501-2600	10.2	352.78	387.48	34.70	9.8%
2601-2700	10.4	366.79	399.09	32.30	8.8%
2701-2800	10.8	377.32	412.49	35.18	9.3%
2801-2900	11.1	389.55	424.17	34.62	8.9%
2901-3000	11.4	401.97	436.52	34.54	8.6%
3001-3100	11.7	414.15	447.69	33.54	8.1%
3101-3200	12.0	422.90	458.28	35.38	8.4%
3201-3300	12.2	431.59	467.18	35.59	8.2%
3301-3400	12.7	450.37	486.41	36.03	8.0%
3401-3500	12.9	454.17	491.93	37.76	8.3%
3501-3600	13.3	471.42	508.95	37.53	8.0%
3601-3700	13.4	490.27	519.05	28.78	5.9%
3701-3800	13.7	492.16	527.93	35.77	7.3%
3801-3900	14.3	509.72	546.30	36.58	7.2%
3901-4000	14.4	514.19	550.86	36.67	7.1%
4001-5000	15.3	563.63	596.58	32.95	5.8%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Winter		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	1.9	66.89	78.40	11.50	17.2%
701-800	2.1	69.46	82.54	13.08	18.8%
801-900	2.4	72.15	87.48	15.34	21.3%
901-1000	2.7	75.66	93.47	17.81	23.5%
1001-1100	3.1	80.90	101.46	20.56	25.4%
1101-1200	3.5	86.14	109.58	23.43	27.2%
1201-1300	3.8	92.23	116.82	24.60	26.7%
1301-1400	4.1	97.71	124.00	26.28	26.9%
1401-1500	4.4	104.34	131.74	27.40	26.3%
1501-1600	4.7	110.82	139.58	28.76	25.9%
1601-1700	5.0	116.95	147.10	30.15	25.8%
1701-1800	5.3	123.72	154.90	31.18	25.2%
1801-1900	5.5	130.14	161.55	31.41	24.1%
1901-2000	5.8	136.71	169.36	32.65	23.9%
2001-2100	6.0	144.07	176.71	32.64	22.7%
2101-2200	6.3	151.22	184.63	33.41	22.1%
2201-2300	6.5	157.78	191.44	33.66	21.3%
2301-2400	6.8	165.04	199.70	34.67	21.0%
2401-2500	6.9	172.29	205.06	32.77	19.0%
2501-2600	7.2	179.22	213.34	34.12	19.0%
2601-2700	7.3	184.00	217.68	33.68	18.3%
2701-2800	7.5	191.70	225.05	33.35	17.4%
2801-2900	7.8	200.62	233.78	33.15	16.5%
2901-3000	7.9	206.84	239.17	32.33	15.6%
3001-3100	8.2	217.20	248.47	31.27	14.4%
3101-3200	8.6	225.91	258.86	32.95	14.6%
3201-3300	8.7	235.40	266.03	30.63	13.0%
3301-3400	8.9	238.36	270.03	31.66	13.3%
3401-3500	9.2	249.17	281.29	32.12	12.9%
3501-3600	9.5	254.54	287.36	32.81	12.9%
3601-3700	9.4	260.58	289.81	29.23	11.2%
3701-3800	9.8	270.30	300.82	30.52	11.3%
3801-3900	10.2	280.65	310.35	29.70	10.6%
3901-4000	10.2	289.20	318.16	28.96	10.0%
4001-5000	11.0	318.64	345.62	26.97	8.5%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	1.5	82.02	94.13	12.11	14.8%
701-800	2.2	96.02	112.13	16.11	16.8%
801-900	3.0	115.77	136.95	21.18	18.3%
901-1000	3.7	136.32	159.00	22.69	16.6%
1001-1100	4.2	149.59	174.66	25.07	16.8%
1101-1200	4.7	164.38	191.77	27.39	16.7%
1201-1300	5.3	177.92	209.65	31.73	17.8%
1301-1400	5.6	189.48	221.52	32.04	16.9%
1401-1500	5.9	199.90	233.86	33.96	17.0%
1501-1600	6.3	211.85	247.97	36.12	17.1%
1601-1700	6.7	224.67	263.01	38.34	17.1%
1701-1800	7.0	236.00	274.65	38.66	16.4%
1801-1900	7.4	247.06	289.38	42.32	17.1%
1901-2000	7.7	258.02	300.79	42.77	16.6%
2001-2100	8.1	269.51	315.72	46.21	17.1%
2101-2200	8.4	281.57	328.41	46.84	16.6%
2201-2300	8.7	291.82	340.38	48.56	16.6%
2301-2400	9.1	304.46	355.19	50.73	16.7%
2401-2500	9.5	316.15	368.67	52.52	16.6%
2501-2600	9.7	325.83	379.96	54.13	16.6%
2601-2700	10.2	338.23	394.79	56.56	16.7%
2701-2800	10.6	351.71	410.30	58.60	16.7%
2801-2900	10.6	358.23	416.36	58.12	16.2%
2901-3000	11.3	375.70	436.31	60.61	16.1%
3001-3100	11.4	378.88	442.20	63.32	16.7%
3101-3200	11.5	389.05	453.58	64.53	16.6%
3201-3300	12.1	405.96	470.40	64.43	15.9%
3301-3400	12.3	412.58	479.68	67.10	16.3%
3401-3500	12.7	429.96	499.16	69.19	16.1%
3501-3600	13.0	437.78	508.75	70.97	16.2%
3601-3700	13.5	452.45	525.30	72.85	16.1%
3701-3800	13.4	451.22	521.47	70.26	15.6%
3801-3900	13.6	461.31	536.30	74.98	16.3%
3901-4000	14.5	482.15	558.19	76.04	15.8%
4001-5000	15.4	525.69	607.69	82.00	15.6%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Winter

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	1.2	53.70	68.07	14.37	26.7%
701-800	2.1	69.86	83.94	14.08	20.2%
801-900	2.0	70.72	84.14	13.42	19.0%
901-1000	2.4	76.23	90.75	14.52	19.0%
1001-1100	2.8	83.06	99.21	16.15	19.4%
1101-1200	3.1	88.51	105.90	17.39	19.6%
1201-1300	3.4	95.51	113.56	18.05	18.9%
1301-1400	3.6	100.87	120.23	19.36	19.2%
1401-1500	3.9	108.04	128.02	19.98	18.5%
1501-1600	4.2	113.20	135.53	22.32	19.7%
1601-1700	4.4	118.08	141.58	23.50	19.9%
1701-1800	4.7	124.72	149.86	25.14	20.2%
1801-1900	4.9	129.49	155.87	26.38	20.4%
1901-2000	5.2	136.44	164.49	28.05	20.6%
2001-2100	5.3	141.27	169.28	28.01	19.8%
2101-2200	5.5	146.30	175.64	29.33	20.1%
2201-2300	5.8	152.82	183.65	30.83	20.2%
2301-2400	5.9	158.00	188.85	30.84	19.5%
2401-2500	6.3	165.74	198.24	32.50	19.6%
2501-2600	6.5	169.84	204.64	34.80	20.5%
2601-2700	6.8	176.72	213.20	36.48	20.6%
2701-2800	6.9	180.11	217.41	37.31	20.7%
2801-2900	7.1	186.72	225.47	38.76	20.8%
2901-3000	7.5	193.84	233.87	40.04	20.7%
3001-3100	7.7	201.84	242.92	41.08	20.4%
3101-3200	7.7	203.57	245.10	41.53	20.4%
3201-3300	8.1	212.08	255.44	43.35	20.4%
3301-3400	8.3	218.97	262.63	43.66	19.9%
3401-3500	8.3	218.37	263.04	44.68	20.5%
3501-3600	8.6	226.55	273.12	46.57	20.6%
3601-3700	9.0	232.90	280.74	47.83	20.5%
3701-3800	9.5	249.26	299.95	50.69	20.3%
3801-3900	9.3	248.98	298.68	49.70	20.0%
3901-4000	10.0	259.63	312.42	52.79	20.3%
4001-5000	10.6	284.12	340.49	56.36	19.8%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer

kWh block	On-Pk kW	(A) Monthly Bill under Current Rates	(B) Monthly Bill under Proposed Rates	(C) Change Amount ($) (B) - (A)	(D) Change % (C) / (A)
601-700	1.6	76.62	90.26	13.64	17.8%
701-800	2.3	92.62	111.89	19.27	20.8%
801-900	3.2	119.20	142.29	23.09	19.4%
901-1000	3.8	136.64	162.10	25.47	18.6%
1001-1100	4.4	152.52	180.42	27.90	18.3%
1101-1200	4.9	166.79	197.15	30.36	18.2%
1201-1300	5.4	181.06	213.74	32.67	18.0%
1301-1400	5.8	193.32	227.97	34.65	17.9%
1401-1500	6.2	205.71	242.57	36.87	17.9%
1501-1600	6.6	215.77	255.99	40.22	18.6%
1601-1700	7.0	228.07	270.24	42.17	18.5%
1701-1800	7.3	240.46	283.09	42.63	17.7%
1801-1900	7.7	252.76	297.44	44.68	17.7%
1901-2000	8.1	263.31	311.27	47.96	18.2%
2001-2100	8.4	273.82	323.56	49.74	18.2%
2101-2200	8.7	284.46	336.03	51.57	18.1%
2201-2300	9.1	296.85	350.41	53.56	18.0%
2301-2400	9.4	307.05	362.15	55.10	17.9%
2401-2500	9.8	318.17	376.60	58.43	18.4%
2501-2600	10.1	328.01	388.30	60.29	18.4%
2601-2700	10.5	339.05	402.63	63.58	18.8%
2701-2800	10.7	349.07	412.71	63.64	18.2%
2801-2900	11.1	360.84	426.34	65.50	18.2%
2901-3000	11.3	369.83	436.59	66.76	18.1%
3001-3100	11.6	380.15	449.02	68.87	18.1%
3101-3200	12.0	393.03	463.66	70.63	18.0%
3201-3300	12.3	402.70	475.11	72.41	18.0%
3301-3400	12.6	411.86	487.12	75.26	18.3%
3401-3500	12.7	420.00	494.79	74.80	17.8%
3501-3600	13.2	433.36	512.20	78.84	18.2%
3601-3700	13.4	442.01	520.46	78.45	17.7%
3701-3800	13.7	451.67	531.68	80.01	17.7%
3801-3900	13.9	458.48	539.91	81.42	17.8%
3901-4000	14.4	472.96	557.55	84.59	17.9%
4001-5000	15.5	516.18	606.20	90.02	17.4%

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Winter		*(A)*	*(B)*	*(C)*	*(D)*
				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount ($) *(B) - (A)*	% *(C) / (A)*
601-700	1.8	62.98	81.06	18.08	28.7%
701-800	2.2	67.04	87.33	20.29	30.3%
801-900	2.2	65.34	85.15	19.80	30.3%
901-1000	2.5	69.92	90.84	20.92	29.9%
1001-1100	2.8	76.06	97.33	21.27	28.0%
1101-1200	3.2	81.49	105.42	23.94	29.4%
1201-1300	3.5	87.04	112.44	25.40	29.2%
1301-1400	3.8	93.00	120.01	27.00	29.0%
1401-1500	4.0	97.78	126.01	28.24	28.9%
1501-1600	4.3	104.17	134.13	29.95	28.8%
1601-1700	4.6	110.27	141.83	31.55	28.6%
1701-1800	4.9	115.17	149.23	34.06	29.6%
1801-1900	5.1	120.14	155.47	35.33	29.4%
1901-2000	5.4	126.52	163.44	36.93	29.2%
2001-2100	5.6	131.89	170.27	38.37	29.1%
2101-2200	5.9	137.03	178.00	40.97	29.9%
2201-2300	6.1	141.94	184.19	42.26	29.8%
2301-2400	6.3	148.69	191.53	42.84	28.8%
2401-2500	6.6	153.67	198.99	45.33	29.5%
2501-2600	6.8	159.40	206.26	46.86	29.4%
2601-2700	7.0	164.53	212.76	48.23	29.3%
2701-2800	7.2	170.22	219.90	49.68	29.2%
2801-2900	7.5	176.84	228.23	51.38	29.1%
2901-3000	7.6	182.55	234.29	51.75	28.3%
3001-3100	7.8	186.48	240.61	54.13	29.0%
3101-3200	8.0	191.65	246.97	55.32	28.9%
3201-3300	8.2	198.35	254.33	55.98	28.2%
3301-3400	8.5	203.97	262.51	58.54	28.7%
3401-3500	8.6	210.45	269.58	59.13	28.1%
3501-3600	9.0	215.51	276.92	61.41	28.5%
3601-3700	9.2	221.50	285.80	64.30	29.0%
3701-3800	9.6	230.29	295.65	65.35	28.4%
3801-3900	9.7	236.36	303.47	67.11	28.4%
3901-4000	9.9	241.06	309.17	68.11	28.3%
4001-5000	10.9	267.60	342.79	75.19	28.1%

NOTES TO SCHEDULE:

1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (C) - (B)	% (D) / (B)
200	27.92	33.34	5.42	19.4%
250	32.77	39.12	6.35	19.4%
300	37.61	44.90	7.29	19.4%
350	42.45	50.68	8.23	19.4%
400	47.30	56.46	9.16	19.4%
450	54.21	64.70	10.49	19.4%
500	61.12	72.94	11.82	19.3%
550	68.02	81.18	13.16	19.3%
600	74.93	89.43	14.50	19.4%
650	81.84	97.67	15.83	19.3%
700	88.75	105.91	17.16	19.3%
750	95.66	114.15	18.49	19.3%
800	102.57	122.39	19.82	19.3%
850	110.65	132.04	21.39	19.3%
900	118.73	141.68	22.95	19.3%
950	126.82	151.32	24.50	19.3%
1,000	134.90	160.97	26.07	19.3%
1,100	151.07	180.26	29.19	19.3%
1,200	167.23	199.54	32.31	19.3%
1,300	183.40	218.83	35.43	19.3%
1,400	199.57	238.12	38.55	19.3%
1,500	215.74	257.40	41.66	19.3%
1,600	231.90	276.69	44.79	19.3%
1,700	248.07	295.98	47.91	19.3%
1,800	264.24	315.26	51.02	19.3%
1,900	280.40	334.55	54.15	19.3%
2,000	296.57	353.84	57.27	19.3%
2,200	328.90	392.41	63.51	19.3%
2,400	361.24	430.99	69.75	19.3%
2,600	393.57	469.56	75.99	19.3%
2,800	425.91	508.13	82.22	19.3%
3,000	458.24	546.71	88.47	19.3%
4,000	630.81	752.58	121.77	19.3%
5,000	803.38	958.45	155.07	19.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
			(C) - (B)	(D) / (B)
200	27.38	32.70	5.32	19.4%
250	32.09	38.32	6.23	19.4%
300	36.80	43.93	7.13	19.4%
350	41.51	49.55	8.04	19.4%
400	46.22	55.17	8.95	19.4%
450	50.93	60.78	9.85	19.3%
500	55.64	66.40	10.76	19.3%
550	60.34	72.02	11.68	19.4%
600	65.05	77.63	12.58	19.3%
650	69.76	83.25	13.49	19.3%
700	74.47	88.87	14.40	19.3%
750	79.18	94.49	15.31	19.3%
800	83.89	100.10	16.21	19.3%
850	88.59	105.72	17.13	19.3%
900	93.30	111.34	18.04	19.3%
950	98.01	116.95	18.94	19.3%
1,000	102.72	122.57	19.85	19.3%
1,100	112.14	133.80	21.66	19.3%
1,200	121.55	145.04	23.49	19.3%
1,300	130.97	156.27	25.30	19.3%
1,400	140.39	167.51	27.12	19.3%
1,500	149.81	178.74	28.93	19.3%
1,600	159.22	189.97	30.75	19.3%
1,700	168.64	201.21	32.57	19.3%
1,800	178.06	212.44	34.38	19.3%
1,900	187.47	223.68	36.21	19.3%
2,000	196.89	234.91	38.02	19.3%
2,200	215.72	257.38	41.66	19.3%
2,400	234.56	279.85	45.29	19.3%
2,600	253.39	302.31	48.92	19.3%
2,800	272.23	324.78	52.55	19.3%
3,000	291.06	347.25	56.19	19.3%
4,000	385.23	459.59	74.36	19.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
			(C) - (B)	(D) / (B)
200	38.16	45.55	7.39	19.4%
250	43.53	51.95	8.42	19.3%
300	48.90	58.36	9.46	19.3%
350	54.27	64.77	10.50	19.3%
400	59.64	71.17	11.53	19.3%
450	65.01	77.58	12.57	19.3%
500	70.38	83.99	13.61	19.3%
550	75.75	90.39	14.64	19.3%
600	81.12	96.80	15.68	19.3%
650	86.49	103.20	16.71	19.3%
700	91.86	109.61	17.75	19.3%
750	97.23	116.02	18.79	19.3%
800	102.60	122.42	19.82	19.3%
850	107.97	128.83	20.86	19.3%
900	113.34	135.24	21.90	19.3%
950	118.71	141.64	22.93	19.3%
1,000	124.08	148.05	23.97	19.3%
1,100	134.82	160.86	26.04	19.3%
1,200	145.56	173.68	28.12	19.3%
1,300	156.30	186.49	30.19	19.3%
1,400	167.04	199.30	32.26	19.3%
1,500	177.78	212.12	34.34	19.3%
1,600	188.52	224.93	36.41	19.3%
1,700	199.26	237.74	38.48	19.3%
1,800	210.00	250.55	40.55	19.3%
1,900	220.74	263.37	42.63	19.3%
2,000	231.48	276.18	44.70	19.3%
2,200	252.96	301.81	48.85	19.3%
2,400	274.44	327.43	52.99	19.3%
2,600	295.92	353.06	57.14	19.3%
2,800	317.40	378.68	61.28	19.3%
3,000	338.88	404.31	65.43	19.3%

ET-1 Summer Average Energy On-Peak: 41%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (C) - (B)	% (D) / (B)
200	33.76	40.30	6.54	19.4%
250	38.03	45.39	7.36	19.4%
300	42.30	50.48	8.18	19.3%
350	46.57	55.58	9.01	19.3%
400	50.84	60.67	9.83	19.3%
450	55.11	65.76	10.65	19.3%
500	59.38	70.86	11.48	19.3%
550	63.65	75.95	12.30	19.3%
600	67.92	81.05	13.13	19.3%
650	72.19	86.14	13.95	19.3%
700	76.46	91.23	14.77	19.3%
750	80.73	96.33	15.60	19.3%
800	85.00	101.42	16.42	19.3%
850	89.27	106.52	17.25	19.3%
900	93.54	111.61	18.07	19.3%
950	97.81	116.70	18.89	19.3%
1,000	102.08	121.80	19.72	19.3%
1,100	110.62	131.99	21.37	19.3%
1,200	119.16	142.17	23.01	19.3%
1,300	127.70	152.36	24.66	19.3%
1,400	136.24	162.55	26.31	19.3%
1,500	144.78	172.74	27.96	19.3%
1,600	153.32	182.92	29.60	19.3%
1,700	161.85	193.11	31.26	19.3%
1,800	170.39	203.30	32.91	19.3%
1,900	178.93	213.49	34.56	19.3%
2,000	187.47	223.67	36.20	19.3%
2,200	204.55	244.05	39.50	19.3%
2,400	221.63	264.43	42.80	19.3%
2,600	238.71	284.80	46.09	19.3%
2,800	255.79	305.18	49.39	19.3%
3,000	272.87	325.55	52.68	19.3%

ET-1 Winter Average Energy On-Peak: 33%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
			(C) - (B)	(D) / (B)
200	38.24	45.64	7.40	19.4%
250	43.63	52.08	8.45	19.4%
300	49.02	58.51	9.49	19.4%
350	54.41	64.94	10.53	19.4%
400	59.80	71.37	11.57	19.3%
450	65.20	77.80	12.60	19.3%
500	70.59	84.23	13.64	19.3%
550	75.98	90.66	14.68	19.3%
600	81.37	97.09	15.72	19.3%
650	86.76	103.52	16.76	19.3%
700	92.15	109.95	17.80	19.3%
750	97.54	116.39	18.85	19.3%
800	102.93	122.82	19.89	19.3%
850	108.32	129.25	20.93	19.3%
900	113.71	135.68	21.97	19.3%
950	119.10	142.11	23.01	19.3%
1,000	124.49	148.54	24.05	19.3%
1,100	135.27	161.40	26.13	19.3%
1,200	146.05	174.27	28.22	19.3%
1,300	156.84	187.13	30.29	19.3%
1,400	167.62	199.99	32.37	19.3%
1,500	178.40	212.85	34.45	19.3%
1,600	189.18	225.71	36.53	19.3%
1,700	199.96	238.58	38.62	19.3%
1,800	210.74	251.44	40.70	19.3%
1,900	221.52	264.30	42.78	19.3%
2,000	232.30	277.16	44.86	19.3%
2,200	253.87	302.89	49.02	19.3%
2,400	275.43	328.61	53.18	19.3%
2,600	296.99	354.33	57.34	19.3%
2,800	318.55	380.06	61.51	19.3%
3,000	340.12	405.78	65.66	19.3%

ET-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (C) - (B)	% (D) / (B)
200	34.07	40.67	6.60	19.4%
250	38.42	45.86	7.44	19.4%
300	42.77	51.05	8.28	19.4%
350	47.12	56.23	9.11	19.3%
400	51.47	61.42	9.95	19.3%
450	55.82	66.61	10.79	19.3%
500	60.17	71.80	11.63	19.3%
550	64.52	76.99	12.47	19.3%
600	68.86	82.17	13.31	19.3%
650	73.21	87.36	14.15	19.3%
700	77.56	92.55	14.99	19.3%
750	81.91	97.74	15.83	19.3%
800	86.26	102.93	16.67	19.3%
850	90.61	108.11	17.50	19.3%
900	94.96	113.30	18.34	19.3%
950	99.31	118.49	19.18	19.3%
1,000	103.65	123.68	20.03	19.3%
1,100	112.35	134.05	21.70	19.3%
1,200	121.05	144.43	23.38	19.3%
1,300	129.75	154.80	25.05	19.3%
1,400	138.44	165.18	26.74	19.3%
1,500	147.14	175.55	28.41	19.3%
1,600	155.84	185.93	30.09	19.3%
1,700	164.54	196.31	31.77	19.3%
1,800	173.23	206.68	33.45	19.3%
1,900	181.93	217.06	35.13	19.3%
2,000	190.63	227.43	36.80	19.3%
2,200	208.02	248.18	40.16	19.3%
2,400	225.42	268.94	43.52	19.3%
2,600	242.81	289.69	46.88	19.3%
2,800	260.21	310.44	50.23	19.3%
3,000	277.60	331.19	53.59	19.3%

ET-2 Winter Average Energy On-Peak: 19%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
3	20%	438	80.92	96.55	15.63	19.3%
3	30%	657	92.71	110.62	17.91	19.3%
3	40%	876	104.50	124.69	20.19	19.3%
3	50%	1,095	116.30	138.76	22.46	19.3%
3	75%	1,643	145.81	173.97	28.16	19.3%
5	20%	730	123.74	147.64	23.90	19.3%
5	30%	1,095	143.40	171.09	27.69	19.3%
5	40%	1,460	163.05	194.54	31.49	19.3%
5	50%	1,825	182.71	217.99	35.28	19.3%
5	75%	2,738	231.87	276.65	44.78	19.3%
8	20%	1,168	187.98	224.28	36.30	19.3%
8	30%	1,752	219.43	261.80	42.37	19.3%
8	40%	2,336	250.87	299.32	48.45	19.3%
8	50%	2,920	282.32	336.83	54.51	19.3%
8	75%	4,380	360.95	430.63	69.68	19.3%
10	20%	1,460	230.80	275.37	44.57	19.3%
10	30%	2,190	270.11	322.27	52.16	19.3%
10	40%	2,920	309.42	369.16	59.74	19.3%
10	50%	3,650	348.73	416.06	67.33	19.3%
10	75%	5,475	447.01	533.31	86.30	19.3%
12	20%	1,752	273.63	326.46	52.83	19.3%
12	30%	2,628	320.80	382.74	61.94	19.3%
12	40%	3,504	367.97	439.01	71.04	19.3%
12	50%	4,380	415.15	495.29	80.14	19.3%
12	75%	6,570	533.08	635.99	102.91	19.3%
15	20%	2,190	337.86	403.09	65.23	19.3%
15	30%	3,285	396.83	473.44	76.61	19.3%
15	40%	4,380	455.80	543.79	87.99	19.3%
15	50%	5,475	514.76	614.13	99.37	19.3%
15	75%	8,213	662.20	790.04	127.84	19.3%

ECT-1R Summer Average Energy On-Peak: 40%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
3	20%	438	64.60	77.09	12.49	19.3%
3	30%	657	74.46	88.85	14.39	19.3%
3	40%	876	84.31	100.61	16.30	19.3%
3	50%	1,095	94.17	112.37	18.20	19.3%
3	75%	1,643	118.84	141.80	22.96	19.3%
5	20%	730	96.54	115.20	18.66	19.3%
5	30%	1,095	112.97	134.80	21.83	19.3%
5	40%	1,460	129.40	154.40	25.00	19.3%
5	50%	1,825	145.83	174.00	28.17	19.3%
5	75%	2,738	186.93	223.04	36.11	19.3%
8	20%	1,168	144.46	172.36	27.90	19.3%
8	30%	1,752	170.75	203.72	32.97	19.3%
8	40%	2,336	197.04	235.09	38.05	19.3%
8	50%	2,920	223.33	266.45	43.12	19.3%
8	75%	4,380	289.05	344.86	55.81	19.3%
10	20%	1,460	176.40	210.47	34.07	19.3%
10	30%	2,190	209.27	249.68	40.41	19.3%
10	40%	2,920	242.13	288.88	46.75	19.3%
10	50%	3,650	274.99	328.09	53.10	19.3%
10	75%	5,475	357.14	426.10	68.96	19.3%
12	20%	1,752	208.35	248.58	40.23	19.3%
12	30%	2,628	247.78	295.63	47.85	19.3%
12	40%	3,504	287.22	342.67	55.45	19.3%
12	50%	4,380	326.65	389.72	63.07	19.3%
12	75%	6,570	425.24	507.33	82.09	19.3%
15	20%	2,190	256.27	305.75	49.48	19.3%
15	30%	3,285	305.56	364.55	58.99	19.3%
15	40%	4,380	354.85	423.36	68.51	19.3%
15	50%	5,475	404.14	482.17	78.03	19.3%
15	75%	8,213	527.40	629.21	101.81	19.3%

ECT-1R Winter Average Energy On-Peak: 33%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (E) - (D)	Change % (F) / (D)
3	20%	438	81.28	96.99	15.71	19.3%
3	30%	657	93.33	111.36	18.03	19.3%
3	40%	876	105.38	125.74	20.36	19.3%
3	50%	1,095	117.44	140.12	22.68	19.3%
3	75%	1,643	147.59	176.09	28.50	19.3%
5	20%	730	124.35	148.37	24.02	19.3%
5	30%	1,095	144.44	172.33	27.89	19.3%
5	40%	1,460	164.52	196.29	31.77	19.3%
5	50%	1,825	184.61	220.25	35.64	19.3%
5	75%	2,738	234.85	280.18	45.33	19.3%
8	20%	1,168	188.95	225.43	36.48	19.3%
8	30%	1,752	221.09	263.77	42.68	19.3%
8	40%	2,336	253.23	302.10	48.87	19.3%
8	50%	2,920	285.36	340.44	55.08	19.3%
8	75%	4,380	365.70	436.28	70.58	19.3%
10	20%	1,460	232.02	276.81	44.79	19.3%
10	30%	2,190	272.19	324.73	52.54	19.3%
10	40%	2,920	312.36	372.65	60.29	19.3%
10	50%	3,650	352.53	420.57	68.04	19.3%
10	75%	5,475	452.96	540.37	87.41	19.3%
12	20%	1,752	275.09	328.19	53.10	19.3%
12	30%	2,628	323.29	385.69	62.40	19.3%
12	40%	3,504	371.50	443.20	71.70	19.3%
12	50%	4,380	419.70	500.70	81.00	19.3%
12	75%	6,570	540.21	644.46	104.25	19.3%
15	20%	2,190	339.69	405.26	65.57	19.3%
15	30%	3,285	399.95	477.14	77.19	19.3%
15	40%	4,380	460.20	549.02	88.82	19.3%
15	50%	5,475	520.46	620.90	100.44	19.3%
15	75%	8,213	671.12	800.63	129.51	19.3%

ECT-2 Summer Average Energy On-Peak: 24%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
3	20%	438	63.86	76.21	12.35	19.3%
3	30%	657	73.50	87.71	14.21	19.3%
3	40%	876	83.14	99.21	16.07	19.3%
3	50%	1,095	92.78	110.72	17.94	19.3%
3	75%	1,643	116.91	139.50	22.59	19.3%
5	20%	730	95.32	113.74	18.42	19.3%
5	30%	1,095	111.38	132.91	21.53	19.3%
5	40%	1,460	127.45	152.08	24.63	19.3%
5	50%	1,825	143.52	171.25	27.73	19.3%
5	75%	2,738	183.71	219.20	35.49	19.3%
8	20%	1,168	142.50	170.02	27.52	19.3%
8	30%	1,752	168.21	200.70	32.49	19.3%
8	40%	2,336	193.92	231.37	37.45	19.3%
8	50%	2,920	219.62	262.04	42.42	19.3%
8	75%	4,380	283.90	338.72	54.82	19.3%
10	20%	1,460	173.95	207.55	33.60	19.3%
10	30%	2,190	206.09	245.89	39.80	19.3%
10	40%	2,920	238.22	284.23	46.01	19.3%
10	50%	3,650	270.36	322.57	52.21	19.3%
10	75%	5,475	350.70	418.42	67.72	19.3%
12	20%	1,752	205.41	245.08	39.67	19.3%
12	30%	2,628	243.97	291.08	47.11	19.3%
12	40%	3,504	282.53	337.09	54.56	19.3%
12	50%	4,380	321.10	383.10	62.00	19.3%
12	75%	6,570	417.50	498.12	80.62	19.3%
15	20%	2,190	252.59	301.37	48.78	19.3%
15	30%	3,285	300.79	358.88	58.09	19.3%
15	40%	4,380	349.00	416.39	67.39	19.3%
15	50%	5,475	397.20	473.90	76.70	19.3%
15	75%	8,213	517.73	617.70	99.97	19.3%

ECT-2 Winter Average Energy On-Peak: 18%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-20 Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($)	Change %
					(E) - (D)	(F) / (D)
15	20%	2,190	271.95	345.02	73.07	26.9%
15	30%	3,285	374.02	458.73	84.71	22.6%
15	40%	4,380	476.09	572.44	96.35	20.2%
15	50%	5,475	578.16	686.15	107.99	18.7%
15	75%	8,213	833.38	970.47	137.09	16.4%
30	20%	4,380	511.95	629.44	117.49	22.9%
30	30%	6,570	716.09	856.85	140.76	19.7%
30	40%	8,760	920.23	1,084.27	164.04	17.8%
30	50%	10,950	1,124.37	1,311.69	187.32	16.7%
30	75%	16,425	1,634.71	1,880.24	245.53	15.0%
50	20%	7,300	831.96	1,008.66	176.70	21.2%
50	30%	10,950	1,172.19	1,387.69	215.50	18.4%
50	40%	14,600	1,512.41	1,766.72	254.31	16.8%
50	50%	18,250	1,852.64	2,145.75	293.11	15.8%
50	75%	27,375	2,703.21	3,093.33	390.12	14.4%
100	20%	14,600	1,631.96	1,956.72	324.76	19.9%
100	30%	21,900	2,312.42	2,714.78	402.36	17.4%
100	40%	29,200	2,992.88	3,472.84	479.96	16.0%
100	50%	36,500	3,673.34	4,230.90	557.56	15.2%
100	75%	54,750	5,374.48	6,126.05	751.57	14.0%
150	20%	21,900	2,431.97	2,904.78	472.81	19.4%
150	30%	32,850	3,452.66	4,041.87	589.21	17.1%
150	40%	43,800	4,473.34	5,178.96	705.62	15.8%
150	50%	54,750	5,494.03	6,316.05	822.02	15.0%
150	75%	82,125	8,045.74	9,158.78	1,113.04	13.8%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-20 Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (E) - (D)	Change % (F) / (D)
15	20%	2,190	245.75	319.93	74.18	30.2%
15	30%	3,285	336.48	421.10	84.62	25.1%
15	40%	4,380	427.21	522.26	95.05	22.2%
15	50%	5,475	517.93	623.43	105.50	20.4%
15	75%	8,213	744.80	876.39	131.59	17.7%
30	20%	4,380	459.55	579.26	119.71	26.0%
30	30%	6,570	641.00	781.59	140.59	21.9%
30	40%	8,760	822.46	983.92	161.46	19.6%
30	50%	10,950	1,003.92	1,186.25	182.33	18.2%
30	75%	16,425	1,457.56	1,692.08	234.52	16.1%
50	20%	7,300	744.61	925.04	180.43	24.2%
50	30%	10,950	1,047.04	1,262.25	215.21	20.6%
50	40%	14,600	1,349.47	1,599.47	250.00	18.5%
50	50%	18,250	1,651.90	1,936.69	284.79	17.2%
50	75%	27,375	2,407.97	2,779.73	371.76	15.4%
100	20%	14,600	1,457.27	1,789.47	332.20	22.8%
100	30%	21,900	2,062.13	2,463.91	401.78	19.5%
100	40%	29,200	2,666.99	3,138.34	471.35	17.7%
100	50%	36,500	3,271.85	3,812.78	540.93	16.5%
100	75%	54,750	4,784.00	5,498.86	714.86	14.9%
150	20%	21,900	2,169.93	2,653.91	483.98	22.3%
150	30%	32,850	3,077.22	3,665.56	588.34	19.1%
150	40%	43,800	3,984.51	4,677.21	692.70	17.4%
150	50%	54,750	4,891.80	5,688.86	797.06	16.3%
150	75%	82,125	7,160.02	8,218.00	1,057.98	14.8%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-30 Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (C) - (B)	% (D) / (B)
30	13.67	16.25	2.58	18.9%
40	15.11	17.62	2.51	16.6%
50	16.56	18.98	2.42	14.6%
60	18.00	20.35	2.35	13.1%
70	19.45	21.71	2.26	11.6%
80	20.89	23.08	2.19	10.5%
90	22.34	24.45	2.11	9.4%
100	23.79	25.81	2.02	8.5%
125	27.40	29.23	1.83	6.7%
150	31.01	32.65	1.64	5.3%
175	34.63	36.06	1.43	4.1%
200	38.24	39.48	1.24	3.2%
225	41.85	42.89	1.04	2.5%
250	45.47	46.31	0.84	1.8%
275	49.08	49.73	0.65	1.3%
300	52.70	53.14	0.44	0.8%
325	56.31	56.56	0.25	0.4%
350	59.92	59.97	0.05	0.1%
375	63.54	63.39	(0.15)	-0.2%
400	67.15	66.81	(0.34)	-0.5%
425	70.76	70.22	(0.54)	-0.8%
450	74.38	73.64	(0.74)	-1.0%
475	77.99	77.05	(0.94)	-1.2%
500	81.61	80.47	(1.14)	-1.4%
600	96.06	94.13	(1.93)	-2.0%
700	110.52	107.80	(2.72)	-2.5%
800	124.97	121.46	(3.51)	-2.8%
900	139.43	135.13	(4.30)	-3.1%
1,000	153.88	148.79	(5.09)	-3.3%
1,500	226.16	217.11	(9.05)	-4.0%
2,000	298.43	285.43	(13.00)	-4.4%
2,500	370.71	353.75	(16.96)	-4.6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-30 Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
			(C) - (B)	(D) / (B)
30	13.23	15.84	2.61	19.7%
40	14.52	17.08	2.56	17.6%
50	15.82	18.31	2.49	15.7%
60	17.12	19.54	2.42	14.1%
70	18.42	20.77	2.35	12.8%
80	19.72	22.00	2.28	11.6%
90	21.02	23.23	2.21	10.5%
100	22.31	24.47	2.16	9.7%
125	25.56	27.54	1.98	7.7%
150	28.81	30.62	1.81	6.3%
175	32.05	33.70	1.65	5.1%
200	35.30	36.78	1.48	4.2%
225	38.54	39.86	1.32	3.4%
250	41.79	42.94	1.15	2.8%
275	45.04	46.02	0.98	2.2%
300	48.28	49.10	0.82	1.7%
325	51.53	52.17	0.64	1.2%
350	54.77	55.25	0.48	0.9%
375	58.02	58.33	0.31	0.5%
400	61.27	61.41	0.14	0.2%
425	64.51	64.49	(0.02)	0.0%
450	67.76	67.57	(0.19)	-0.3%
475	71.00	70.65	(0.35)	-0.5%
500	74.25	73.73	(0.52)	-0.7%
600	87.23	86.04	(1.19)	-1.4%
700	100.22	98.36	(1.86)	-1.9%
800	113.20	110.67	(2.53)	-2.2%
900	126.19	122.99	(3.20)	-2.5%
1,000	139.17	135.30	(3.87)	-2.8%
1,500	204.09	196.88	(7.21)	-3.5%
2,000	269.01	258.45	(10.56)	-3.9%
2,500	333.93	320.03	(13.90)	-4.2%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
5	15%	548	94.34	127.11	32.77	34.7%
5	30%	1,095	168.39	184.81	16.42	9.8%
5	45%	1,643	242.57	242.61	0.04	0.0%
5	60%	2,190	316.62	300.31	(16.31)	-5.2%
5	75%	2,738	390.80	358.12	(32.68)	-8.4%
10	15%	1,095	168.39	219.31	50.92	30.2%
10	30%	2,190	316.62	334.81	18.19	5.7%
10	45%	3,285	464.85	450.32	(14.53)	-3.1%
10	60%	4,380	613.08	565.82	(47.26)	-7.7%
10	75%	5,475	732.29	681.33	(50.96)	-7.0%
15	15%	1,643	242.57	311.61	69.04	28.5%
15	30%	3,285	464.85	484.82	19.97	4.3%
15	45%	4,928	687.26	658.13	(29.13)	-4.2%
15	60%	6,570	813.61	831.34	17.73	2.2%
15	75%	8,213	935.64	1,004.65	69.01	7.4%
20	15%	2,190	316.62	403.81	87.19	27.5%
20	30%	4,380	613.08	634.82	21.74	3.5%
20	45%	6,570	813.61	865.84	52.23	6.4%
20	60%	8,760	976.27	1,096.85	120.58	12.4%
20	75%	10,950	1,138.92	1,327.86	188.94	16.6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
5	15%	548	84.65	116.59	31.94	37.7%
5	30%	1,095	149.03	163.80	14.77	9.9%
5	45%	1,643	213.52	211.09	(2.43)	-1.1%
5	60%	2,190	277.90	258.30	(19.60)	-7.1%
5	75%	2,738	342.40	305.59	(36.81)	-10.8%
10	15%	1,095	149.03	198.30	49.27	33.1%
10	30%	2,190	277.90	292.80	14.90	5.4%
10	45%	3,285	406.77	387.30	(19.47)	-4.8%
10	60%	4,380	535.64	481.79	(53.85)	-10.1%
10	75%	5,475	635.49	576.29	(59.20)	-9.3%
15	15%	1,643	213.52	280.09	66.57	31.2%
15	30%	3,285	406.77	421.80	15.03	3.7%
15	45%	4,928	600.14	563.59	(36.55)	-6.1%
15	60%	6,570	697.44	705.29	7.85	1.1%
15	75%	8,213	790.40	847.08	56.68	7.2%
20	15%	2,190	277.90	361.80	83.90	30.2%
20	30%	4,380	535.64	550.79	15.15	2.8%
20	45%	6,570	697.44	739.79	42.35	6.1%
20	60%	8,760	821.35	928.79	107.44	13.1%
20	75%	10,950	945.26	1,117.79	172.53	18.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Transition Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
5	15%	548	94.34	107.14	12.80	13.6%
5	30%	1,095	168.39	179.35	10.96	6.5%
5	45%	1,643	242.57	251.69	9.12	3.8%
5	60%	2,190	316.62	323.90	7.28	2.3%
5	75%	2,738	390.80	396.24	5.44	1.4%
10	15%	1,095	168.39	179.35	10.96	6.5%
10	30%	2,190	316.62	323.90	7.28	2.3%
10	45%	3,285	464.85	468.45	3.60	0.8%
10	60%	4,380	613.08	613.00	(0.08)	0.0%
10	75%	5,475	732.29	757.55	25.26	3.4%
15	15%	1,643	242.57	251.69	9.12	3.8%
15	30%	3,285	464.85	468.45	3.60	0.8%
15	45%	4,928	687.26	685.35	(1.91)	-0.3%
15	60%	6,570	813.61	902.11	88.50	10.9%
15	75%	8,213	935.64	1,119.00	183.36	19.6%
20	15%	2,190	316.62	323.90	7.28	2.3%
20	30%	4,380	613.08	613.00	(0.08)	0.0%
20	45%	6,570	813.61	902.11	88.50	10.9%
20	60%	8,760	976.27	1,191.21	214.94	22.0%
20	75%	10,950	1,138.92	1,480.31	341.39	30.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Transition Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
5	15%	548	84.65	97.86	13.21	15.6%
5	30%	1,095	149.03	160.81	11.78	7.9%
5	45%	1,643	213.52	223.88	10.36	4.9%
5	60%	2,190	277.90	286.83	8.93	3.2%
5	75%	2,738	342.40	349.89	7.49	2.2%
10	15%	1,095	149.03	160.81	11.78	7.9%
10	30%	2,190	277.90	286.83	8.93	3.2%
10	45%	3,285	406.77	412.84	6.07	1.5%
10	60%	4,380	535.64	538.85	3.21	0.6%
10	75%	5,475	635.49	664.86	29.37	4.6%
15	15%	1,643	213.52	223.88	10.36	4.9%
15	30%	3,285	406.77	412.84	6.07	1.5%
15	45%	4,928	600.14	601.91	1.77	0.3%
15	60%	6,570	697.44	790.88	93.44	13.4%
15	75%	8,213	790.40	979.95	189.55	24.0%
20	15%	2,190	277.90	286.83	8.93	3.2%
20	30%	4,380	535.64	538.85	3.21	0.6%
20	45%	6,570	697.44	790.88	93.44	13.4%
20	60%	8,760	821.35	1,042.90	221.55	27.0%
20	75%	10,950	945.26	1,294.93	349.67	37.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
5	15%	548	94.34	127.11	32.77	34.7%
5	30%	1,095	168.39	184.81	16.42	9.8%
5	45%	1,643	242.57	242.61	0.04	0.0%
5	60%	2,190	316.62	300.31	(16.31)	-5.2%
5	75%	2,738	390.80	358.12	(32.68)	-8.4%
10	15%	1,095	168.39	219.31	50.92	30.2%
10	30%	2,190	316.62	334.81	18.19	5.7%
10	45%	3,285	464.85	450.32	(14.53)	-3.1%
10	60%	4,380	613.08	565.82	(47.26)	-7.7%
10	75%	5,475	732.29	681.33	(50.96)	-7.0%
15	15%	1,643	242.57	311.61	69.04	28.5%
15	30%	3,285	464.85	484.82	19.97	4.3%
15	45%	4,928	687.26	658.13	(29.13)	-4.2%
15	60%	6,570	813.61	831.34	17.73	2.2%
15	75%	8,213	935.64	1,004.65	69.01	7.4%
20	15%	2,190	316.62	403.81	87.19	27.5%
20	30%	4,380	613.08	634.82	21.74	3.5%
20	45%	6,570	813.61	865.84	52.23	6.4%
20	60%	8,760	976.27	1,096.85	120.58	12.4%
20	75%	10,950	1,138.92	1,327.86	188.94	16.6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
5	15%	548	84.65	116.59	31.94	37.7%
5	30%	1,095	149.03	163.80	14.77	9.9%
5	45%	1,643	213.52	211.09	(2.43)	-1.1%
5	60%	2,190	277.90	258.30	(19.60)	-7.1%
5	75%	2,738	342.40	305.59	(36.81)	-10.8%
10	15%	1,095	149.03	198.30	49.27	33.1%
10	30%	2,190	277.90	292.80	14.90	5.4%
10	45%	3,285	406.77	387.30	(19.47)	-4.8%
10	60%	4,380	535.64	481.79	(53.85)	-10.1%
10	75%	5,475	635.49	576.29	(59.20)	-9.3%
15	15%	1,643	213.52	280.09	66.57	31.2%
15	30%	3,285	406.77	421.80	15.03	3.7%
15	45%	4,928	600.14	563.59	(36.55)	-6.1%
15	60%	6,570	697.44	705.29	7.85	1.1%
15	75%	8,213	790.40	847.08	56.68	7.2%
20	15%	2,190	277.90	361.80	83.90	30.2%
20	30%	4,380	535.64	550.79	15.15	2.8%
20	45%	6,570	697.44	739.79	42.35	6.1%
20	60%	8,760	821.35	928.79	107.44	13.1%
20	75%	10,950	945.26	1,117.79	172.53	18.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 S Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
21	15%	2,300	464.30	522.13	57.83	12.5%
21	30%	4,599	685.67	753.68	68.01	9.9%
21	45%	6,899	829.58	903.85	74.27	9.0%
21	60%	9,198	973.43	1,053.95	80.52	8.3%
21	75%	11,498	1,117.34	1,204.12	86.78	7.8%
40	15%	4,380	866.04	962.94	96.90	11.2%
40	30%	8,760	1,287.79	1,404.10	116.31	9.0%
40	45%	13,140	1,561.85	1,690.07	128.22	8.2%
40	60%	17,520	1,835.91	1,976.04	140.13	7.6%
40	75%	21,900	2,109.96	2,262.01	152.05	7.2%
60	15%	6,570	1,288.98	1,427.01	138.03	10.7%
60	30%	13,140	1,921.61	2,088.75	167.14	8.7%
60	45%	19,710	2,332.69	2,517.71	185.02	7.9%
60	60%	26,280	2,743.78	2,946.66	202.88	7.4%
60	75%	32,850	3,154.86	3,375.62	220.76	7.0%
80	15%	8,760	1,711.92	1,891.08	179.16	10.5%
80	30%	17,520	2,555.43	2,773.40	217.97	8.5%
80	45%	26,280	3,103.54	3,345.34	241.80	7.8%
80	60%	35,040	3,651.65	3,917.28	265.63	7.3%
80	75%	43,800	4,199.77	4,489.22	289.45	6.9%
90	15%	9,855	1,923.39	2,123.12	199.73	10.4%
90	30%	19,710	2,872.33	3,115.73	243.40	8.5%
90	45%	29,565	3,488.96	3,759.16	270.20	7.7%
90	60%	39,420	4,105.59	4,402.59	297.00	7.2%
90	75%	49,275	4,722.22	5,046.02	323.80	6.9%
100	15%	10,950	2,134.86	2,355.15	220.29	10.3%
100	30%	21,900	3,189.24	3,458.05	268.81	8.4%
100	45%	32,850	3,874.38	4,172.98	298.60	7.7%
100	60%	43,800	4,559.53	4,887.90	328.37	7.2%
100	75%	54,750	5,244.67	5,602.83	358.16	6.8%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
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2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 S Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
21	15%	2,300	427.06	483.03	55.97	13.1%
21	30%	4,599	611.21	675.51	64.30	10.5%
21	45%	6,899	717.88	786.65	68.77	9.6%
21	60%	9,198	824.51	897.74	73.23	8.9%
21	75%	11,498	931.19	1,008.87	77.68	8.3%
40	15%	4,380	795.13	888.48	93.35	11.7%
40	30%	8,760	1,145.97	1,255.20	109.23	9.5%
40	45%	13,140	1,349.11	1,466.84	117.73	8.7%
40	60%	17,520	1,552.26	1,678.49	126.23	8.1%
40	75%	21,900	1,755.40	1,890.13	134.73	7.7%
60	15%	6,570	1,182.61	1,315.32	132.71	11.2%
60	30%	13,140	1,708.87	1,865.40	156.53	9.2%
60	45%	19,710	2,013.59	2,182.87	169.28	8.4%
60	60%	26,280	2,318.31	2,500.33	182.02	7.9%
60	75%	32,850	2,623.02	2,817.79	194.77	7.4%
80	15%	8,760	1,570.10	1,742.16	172.06	11.0%
80	30%	17,520	2,271.78	2,475.61	203.83	9.0%
80	45%	26,280	2,678.07	2,898.89	220.82	8.2%
80	60%	35,040	3,084.36	3,322.17	237.81	7.7%
80	75%	43,800	3,490.64	3,745.46	254.82	7.3%
90	15%	9,855	1,763.84	1,955.58	191.74	10.9%
90	30%	19,710	2,553.23	2,780.71	227.48	8.9%
90	45%	29,565	3,010.30	3,256.90	246.60	8.2%
90	60%	39,420	3,467.38	3,733.09	265.71	7.7%
90	75%	49,275	3,924.45	4,209.29	284.84	7.3%
100	15%	10,950	1,957.58	2,169.00	211.42	10.8%
100	30%	21,900	2,834.68	3,085.81	251.13	8.9%
100	45%	32,850	3,342.54	3,614.91	272.37	8.1%
100	60%	43,800	3,850.40	4,144.02	293.62	7.6%
100	75%	54,750	4,358.27	4,673.12	314.85	7.2%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 M Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
101	15%	11,060	2,161.78	2,479.37	317.59	14.7%
101	30%	22,119	3,182.06	3,583.96	401.90	12.6%
101	45%	33,179	3,855.72	4,311.60	455.88	11.8%
101	60%	44,238	4,529.33	5,039.17	509.84	11.3%
101	75%	55,298	5,202.99	5,766.81	563.82	10.8%
150	15%	16,425	2,955.92	3,396.78	440.86	14.9%
150	30%	32,850	4,471.26	5,037.35	566.09	12.7%
150	45%	49,275	5,471.71	6,117.95	646.24	11.8%
150	60%	65,700	6,472.16	7,198.55	726.39	11.2%
150	75%	82,125	7,472.60	8,279.15	806.55	10.8%
200	15%	21,900	3,766.32	4,332.98	566.66	15.0%
200	30%	43,800	5,786.78	6,520.40	733.62	12.7%
200	45%	65,700	7,120.71	7,961.20	840.49	11.8%
200	60%	87,600	8,454.64	9,402.00	947.36	11.2%
200	75%	109,500	9,788.57	10,842.81	1,054.24	10.8%
300	15%	32,850	5,387.11	6,205.36	818.25	15.2%
300	30%	65,700	8,417.81	9,486.50	1,068.69	12.7%
300	45%	98,550	10,418.70	11,647.70	1,229.00	11.8%
300	60%	131,400	12,419.59	13,808.91	1,389.32	11.2%
300	75%	164,250	14,420.49	15,970.11	1,549.62	10.7%
350	15%	38,325	6,197.51	7,141.56	944.05	15.2%
350	30%	76,650	9,733.32	10,969.55	1,236.23	12.7%
350	45%	114,975	12,067.70	13,490.96	1,423.26	11.8%
350	60%	153,300	14,402.07	16,012.36	1,610.29	11.2%
350	75%	191,625	16,736.45	18,533.76	1,797.31	10.7%
400	15%	43,800	7,007.91	8,077.75	1,069.84	15.3%
400	30%	87,600	11,048.84	12,452.60	1,403.76	12.7%
400	45%	131,400	13,716.69	15,334.21	1,617.52	11.8%
400	60%	175,200	16,384.55	18,215.81	1,831.26	11.2%
400	75%	219,000	19,052.41	21,097.41	2,045.00	10.7%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 M Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
101	15%	11,060	1,995.21	2,298.20	302.99	15.2%
101	30%	22,119	2,848.97	3,221.63	372.66	13.1%
101	45%	33,179	3,356.18	3,768.00	411.82	12.3%
101	60%	44,238	3,863.34	4,314.31	450.97	11.7%
101	75%	55,298	4,370.56	4,860.68	490.12	11.2%
150	15%	16,425	2,708.56	3,127.74	419.18	15.5%
150	30%	32,850	3,976.57	4,499.24	522.67	13.1%
150	45%	49,275	4,729.82	5,310.64	580.82	12.3%
150	60%	65,700	5,483.07	6,122.03	638.96	11.7%
150	75%	82,125	6,236.32	6,933.43	697.11	11.2%
200	15%	21,900	3,436.50	3,974.25	537.75	15.6%
200	30%	43,800	5,127.19	5,802.92	675.73	13.2%
200	45%	65,700	6,131.52	6,884.78	753.26	12.3%
200	60%	87,600	7,135.86	7,966.64	830.78	11.6%
200	75%	109,500	8,140.19	9,048.50	908.31	11.2%
300	15%	32,850	4,892.39	5,667.28	774.89	15.8%
300	30%	65,700	7,428.42	8,410.28	981.86	13.2%
300	45%	98,550	8,934.92	10,033.07	1,098.15	12.3%
300	60%	131,400	10,441.42	11,655.86	1,214.44	11.6%
300	75%	164,250	11,947.93	13,278.65	1,330.72	11.1%
350	15%	38,325	5,620.34	6,513.79	893.45	15.9%
350	30%	76,650	8,579.04	9,713.96	1,134.92	13.2%
350	45%	114,975	10,336.62	11,607.22	1,270.60	12.3%
350	60%	153,300	12,094.21	13,500.47	1,406.26	11.6%
350	75%	191,625	13,851.79	15,393.73	1,541.94	11.1%
400	15%	43,800	6,348.28	7,360.31	1,012.03	15.9%
400	30%	87,600	9,729.66	11,017.64	1,287.98	13.2%
400	45%	131,400	11,738.32	13,181.36	1,443.04	12.3%
400	60%	175,200	13,746.99	15,345.08	1,598.09	11.6%
400	75%	219,000	15,755.66	17,508.80	1,753.14	11.1%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 L Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
401	15%	43,910	8,880.59	10,096.72	1,216.13	13.7%
401	30%	87,819	11,303.05	12,784.82	1,481.77	13.1%
401	45%	131,729	13,725.57	15,472.99	1,747.42	12.7%
401	60%	175,638	16,148.03	18,161.10	2,013.07	12.5%
401	75%	219,548	18,570.54	20,849.27	2,278.73	12.3%
600	15%	65,700	12,921.88	14,663.45	1,741.57	13.5%
600	30%	131,400	16,546.55	18,685.61	2,139.06	12.9%
600	45%	197,100	20,171.22	22,707.76	2,536.54	12.6%
600	60%	262,800	23,795.89	26,729.92	2,934.03	12.3%
600	75%	328,500	27,420.56	30,752.07	3,331.51	12.1%
800	15%	87,600	16,983.50	19,253.17	2,269.67	13.4%
800	30%	175,200	21,816.39	24,616.04	2,799.65	12.8%
800	45%	262,800	26,649.29	29,978.92	3,329.63	12.5%
800	60%	350,400	31,482.18	35,341.79	3,859.61	12.3%
800	75%	438,000	36,315.07	40,704.66	4,389.59	12.1%
1,000	15%	109,500	21,045.13	23,842.89	2,797.76	13.3%
1,000	30%	219,000	27,086.24	30,546.48	3,460.24	12.8%
1,000	45%	328,500	33,127.36	37,250.07	4,122.71	12.4%
1,000	60%	438,000	39,168.47	43,953.66	4,785.19	12.2%
1,000	75%	547,500	45,209.59	50,657.25	5,447.66	12.0%
1,500	15%	164,250	31,199.18	35,317.19	4,118.01	13.2%
1,500	30%	328,500	40,260.86	45,372.57	5,111.71	12.7%
1,500	45%	492,750	49,322.53	55,427.96	6,105.43	12.4%
1,500	60%	657,000	58,384.20	65,483.34	7,099.14	12.2%
1,500	75%	821,250	67,445.87	75,538.73	8,092.86	12.0%
3,000	15%	328,500	61,661.36	69,740.07	8,078.71	13.1%
3,000	30%	657,000	79,784.70	89,850.84	10,066.14	12.6%
3,000	45%	985,500	97,908.05	109,961.61	12,053.56	12.3%
3,000	60%	1,314,000	116,031.39	130,072.38	14,040.99	12.1%
3,000	75%	1,642,500	134,154.74	150,183.15	16,028.41	11.9%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 L Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
401	15%	43,910	8,128.41	9,254.52	1,126.11	13.9%
401	30%	87,819	9,798.71	11,100.46	1,301.75	13.3%
401	45%	131,729	11,469.05	12,946.43	1,477.38	12.9%
401	60%	175,638	13,139.35	14,792.37	1,653.02	12.6%
401	75%	219,548	14,809.68	16,638.34	1,828.66	12.3%
600	15%	65,700	11,796.44	13,403.33	1,606.89	13.6%
600	30%	131,400	14,295.67	16,165.36	1,869.69	13.1%
600	45%	197,100	16,794.89	18,927.38	2,132.49	12.7%
600	60%	262,800	19,294.12	21,689.41	2,395.29	12.4%
600	75%	328,500	21,793.35	24,451.44	2,658.09	12.2%
800	15%	87,600	15,482.91	17,573.00	2,090.09	13.5%
800	30%	175,200	18,815.22	21,255.71	2,440.49	13.0%
800	45%	262,800	22,147.52	24,938.41	2,790.89	12.6%
800	60%	350,400	25,479.83	28,621.12	3,141.29	12.3%
800	75%	438,000	28,812.13	32,303.82	3,491.69	12.1%
1,000	15%	109,500	19,169.39	21,742.68	2,573.29	13.4%
1,000	30%	219,000	23,334.77	26,346.06	3,011.29	12.9%
1,000	45%	328,500	27,500.15	30,949.44	3,449.29	12.5%
1,000	60%	438,000	31,665.53	35,552.82	3,887.29	12.3%
1,000	75%	547,500	35,830.91	40,156.20	4,325.29	12.1%
1,500	15%	164,250	28,385.58	32,166.87	3,781.29	13.3%
1,500	30%	328,500	34,633.65	39,071.94	4,438.29	12.8%
1,500	45%	492,750	40,881.72	45,977.01	5,095.29	12.5%
1,500	60%	657,000	47,129.79	52,882.08	5,752.29	12.2%
1,500	75%	821,250	53,377.86	59,787.15	6,409.29	12.0%
3,000	15%	328,500	56,034.15	63,439.44	7,405.29	13.2%
3,000	30%	657,000	68,530.29	77,249.58	8,719.29	12.7%
3,000	45%	985,500	81,026.43	91,059.72	10,033.29	12.4%
3,000	60%	1,314,000	93,522.57	104,869.86	11,347.29	12.1%
3,000	75%	1,642,500	106,018.71	118,680.00	12,661.29	11.9%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
5	7.5	15%	821	138.30	174.26	35.96	26.0%
5	7.5	30%	1,643	255.44	271.61	16.17	6.3%
5	7.5	45%	2,464	372.44	368.84	(3.60)	-1.0%
5	7.5	60%	3,285	489.44	466.07	(23.37)	-4.8%
5	7.5	75%	4,106	606.44	563.31	(43.13)	-7.1%
10	12	15%	1,314	208.56	267.07	58.51	28.1%
10	12	30%	2,628	395.81	422.69	26.88	6.8%
10	12	45%	3,942	583.07	578.31	(4.76)	-0.8%
10	12	60%	5,256	770.33	733.93	(36.40)	-4.7%
10	12	75%	6,570	957.59	889.55	(68.04)	-7.1%
15	20	15%	2,190	333.40	414.34	80.94	24.3%
15	20	30%	4,380	645.49	673.71	28.22	4.4%
15	20	45%	6,570	957.59	933.07	(24.52)	-2.6%
15	20	60%	8,760	1,221.59	1,192.44	(29.15)	-2.4%
15	20	75%	10,950	1,422.52	1,451.81	29.29	2.1%
20	25	15%	2,738	411.49	514.96	103.47	25.1%
20	25	30%	5,475	801.54	839.11	37.57	4.7%
20	25	45%	8,213	1,171.40	1,163.38	(8.02)	-0.7%
20	25	60%	10,950	1,422.52	1,487.53	65.01	4.6%
20	25	75%	13,688	1,673.73	1,811.80	138.07	8.2%

General Service TOU Average Energy On-Peak: 36%
Proposed General Service TOU Average Energy On-Peak: 13%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
5	7.5	15%	821	122.70	154.63	31.93	26.0%
5	7.5	30%	1,643	224.23	232.32	8.09	3.6%
5	7.5	45%	2,464	325.64	309.93	(15.71)	-4.8%
5	7.5	60%	3,285	427.04	387.53	(39.51)	-9.3%
5	7.5	75%	4,106	528.45	465.13	(63.32)	-12.0%
10	12	15%	1,314	183.60	235.65	52.05	28.3%
10	12	30%	2,628	345.89	359.85	13.96	4.0%
10	12	45%	3,942	508.19	484.06	(24.13)	-4.7%
10	12	60%	5,256	670.49	608.26	(62.23)	-9.3%
10	12	75%	6,570	832.78	732.46	(100.32)	-12.0%
15	20	15%	2,190	291.79	361.97	70.18	24.1%
15	20	30%	4,380	562.29	568.98	6.69	1.2%
15	20	45%	6,570	832.78	775.98	(56.80)	-6.8%
15	20	60%	8,760	1,031.87	982.99	(48.88)	-4.7%
15	20	75%	10,950	1,191.22	1,189.99	(1.23)	-0.1%
20	25	15%	2,738	359.48	449.50	90.02	25.0%
20	25	30%	5,475	697.53	708.21	10.68	1.5%
20	25	45%	8,213	992.07	967.01	(25.06)	-2.5%
20	25	60%	10,950	1,191.22	1,225.72	34.50	2.9%
20	25	75%	13,688	1,390.45	1,484.52	94.07	6.8%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 13%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Transition Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
5	7.5	15%	821	138.30	135.72	(2.58)	-1.9%
5	7.5	30%	1,643	255.44	236.77	(18.67)	-7.3%
5	7.5	45%	2,464	372.44	337.69	(34.75)	-9.3%
5	7.5	60%	3,285	489.44	438.61	(50.83)	-10.4%
5	7.5	75%	4,106	606.44	539.53	(66.91)	-11.0%
10	12	15%	1,314	208.56	196.32	(12.24)	-5.9%
10	12	30%	2,628	395.81	357.85	(37.96)	-9.6%
10	12	45%	3,942	583.07	519.37	(63.70)	-10.9%
10	12	60%	5,256	770.33	680.89	(89.44)	-11.6%
10	12	75%	6,570	957.59	842.42	(115.17)	-12.0%
15	20	15%	2,190	333.40	304.01	(29.39)	-8.8%
15	20	30%	4,380	645.49	573.21	(72.28)	-11.2%
15	20	45%	6,570	957.59	842.42	(115.17)	-12.0%
15	20	60%	8,760	1,221.59	1,111.62	(109.97)	-9.0%
15	20	75%	10,950	1,422.52	1,380.83	(41.69)	-2.9%
20	25	15%	2,738	411.49	371.37	(40.12)	-9.7%
20	25	30%	5,475	801.54	707.81	(93.73)	-11.7%
20	25	45%	8,213	1,171.40	1,044.38	(127.02)	-10.8%
20	25	60%	10,950	1,422.52	1,380.83	(41.69)	-2.9%
20	25	75%	13,688	1,673.73	1,717.39	43.66	2.6%

General Service TOU Average Energy On-Peak: 36%
Proposed General Service TOU Average Energy On-Peak: 13%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Transition Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
5	7.5	15%	821	122.70	118.51	(4.19)	-3.4%
5	7.5	30%	1,643	224.23	202.33	(21.90)	-9.8%
5	7.5	45%	2,464	325.64	286.04	(39.60)	-12.2%
5	7.5	60%	3,285	427.04	369.76	(57.28)	-13.4%
5	7.5	75%	4,106	528.45	453.47	(74.98)	-14.2%
10	12	15%	1,314	183.60	168.78	(14.82)	-8.1%
10	12	30%	2,628	345.89	302.77	(43.12)	-12.5%
10	12	45%	3,942	508.19	436.75	(71.44)	-14.1%
10	12	60%	5,256	670.49	570.73	(99.76)	-14.9%
10	12	75%	6,570	832.78	704.71	(128.07)	-15.4%
15	20	15%	2,190	291.79	258.10	(33.69)	-11.5%
15	20	30%	4,380	562.29	481.41	(80.88)	-14.4%
15	20	45%	6,570	832.78	704.71	(128.07)	-15.4%
15	20	60%	8,760	1,031.87	928.02	(103.85)	-10.1%
15	20	75%	10,950	1,191.22	1,151.32	(39.90)	-3.3%
20	25	15%	2,738	359.48	313.98	(45.50)	-12.7%
20	25	30%	5,475	697.53	593.06	(104.47)	-15.0%
20	25	45%	8,213	992.07	872.24	(119.83)	-12.1%
20	25	60%	10,950	1,191.22	1,151.32	(39.90)	-3.3%
20	25	75%	13,688	1,390.45	1,430.50	40.05	2.9%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 13%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU S Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
21	30	15%	3,285	694.82	815.30	120.48	17.3%
21	30	30%	6,570	903.45	1,034.44	130.99	14.5%
21	30	45%	9,855	1,112.08	1,253.57	141.49	12.7%
21	30	60%	13,140	1,320.71	1,472.71	152.00	11.5%
21	30	75%	16,425	1,529.35	1,691.84	162.49	10.6%
40	50	15%	5,475	1,215.34	1,423.82	208.48	17.2%
40	50	30%	10,950	1,563.06	1,789.04	225.98	14.5%
40	50	45%	16,425	1,910.78	2,154.27	243.49	12.7%
40	50	60%	21,900	2,258.51	2,519.50	260.99	11.6%
40	50	75%	27,375	2,606.23	2,884.72	278.49	10.7%
60	70	15%	7,665	1,750.17	2,049.97	299.80	17.1%
60	70	30%	15,330	2,236.98	2,561.28	324.30	14.5%
60	70	45%	22,995	2,723.79	3,072.60	348.81	12.8%
60	70	60%	30,660	3,210.60	3,583.92	373.32	11.6%
60	70	75%	38,325	3,697.41	4,095.23	397.82	10.8%
80	100	15%	10,950	2,409.38	2,812.83	403.45	16.7%
80	100	30%	21,900	3,104.83	3,543.29	438.46	14.1%
80	100	45%	32,850	3,800.27	4,273.74	473.47	12.5%
80	100	60%	43,800	4,495.71	5,004.19	508.48	11.3%
80	100	75%	54,750	5,191.16	5,734.64	543.48	10.5%
90	110	15%	12,045	2,652.50	3,097.69	445.19	16.8%
90	110	30%	24,090	3,417.49	3,901.19	483.70	14.2%
90	110	45%	36,135	4,182.47	4,704.68	522.21	12.5%
90	110	60%	48,180	4,947.46	5,508.18	560.72	11.3%
90	110	75%	60,225	5,712.45	6,311.68	599.23	10.5%
100	120	15%	13,140	2,895.61	3,382.54	486.93	16.8%
100	120	30%	26,280	3,730.14	4,259.09	528.95	14.2%
100	120	45%	39,420	4,564.68	5,135.63	570.95	12.5%
100	120	60%	52,560	5,399.21	6,012.17	612.96	11.4%
100	120	75%	65,700	6,233.74	6,888.72	654.98	10.5%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU S Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
21	30	15%	3,285	638.88	762.97	124.09	19.4%
21	30	30%	6,570	791.58	929.77	138.19	17.5%
21	30	45%	9,855	944.28	1,096.58	152.30	16.1%
21	30	60%	13,140	1,096.98	1,263.38	166.40	15.2%
21	30	75%	16,425	1,249.68	1,430.18	180.50	14.4%
40	50	15%	5,475	1,122.12	1,336.60	214.48	19.1%
40	50	30%	10,950	1,376.62	1,614.60	237.98	17.3%
40	50	45%	16,425	1,631.12	1,892.61	261.49	16.0%
40	50	60%	21,900	1,885.62	2,170.61	284.99	15.1%
40	50	75%	27,375	2,140.12	2,448.62	308.50	14.4%
60	70	15%	7,665	1,619.66	1,927.86	308.20	19.0%
60	70	30%	15,330	1,975.96	2,317.06	341.10	17.3%
60	70	45%	22,995	2,332.26	2,706.27	374.01	16.0%
60	70	60%	30,660	2,688.56	3,095.48	406.92	15.1%
60	70	75%	38,325	3,044.86	3,484.69	439.83	14.4%
80	100	15%	10,950	2,222.94	2,638.39	415.45	18.7%
80	100	30%	21,900	2,731.94	3,194.40	462.46	16.9%
80	100	45%	32,850	3,240.94	3,750.41	509.47	15.7%
80	100	60%	43,800	3,749.94	4,306.42	556.48	14.8%
80	100	75%	54,750	4,258.94	4,862.43	603.49	14.2%
90	110	15%	12,045	2,447.41	2,905.80	458.39	18.7%
90	110	30%	24,090	3,007.31	3,517.41	510.10	17.0%
90	110	45%	36,135	3,567.21	4,129.02	561.81	15.7%
90	110	60%	48,180	4,127.11	4,740.64	613.53	14.9%
90	110	75%	60,225	4,687.01	5,352.25	665.24	14.2%
100	120	15%	13,140	2,671.88	3,173.21	501.33	18.8%
100	120	30%	26,280	3,282.68	3,840.42	557.74	17.0%
100	120	45%	39,420	3,893.48	4,507.64	614.16	15.8%
100	120	60%	52,560	4,504.28	5,174.85	670.57	14.9%
100	120	75%	65,700	5,115.08	5,842.06	726.98	14.2%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU M Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
101	120	15%	13,140	2,980.84	3,443.72	462.88	15.5%
101	120	30%	26,280	3,742.29	4,265.62	523.33	14.0%
101	120	45%	39,420	4,503.73	5,087.53	583.80	13.0%
101	120	60%	52,560	5,265.18	5,909.44	644.26	12.2%
101	120	75%	65,700	6,026.63	6,731.34	704.71	11.7%
150	170	15%	18,615	3,947.15	4,569.43	622.28	15.8%
150	170	30%	37,230	5,025.86	5,733.80	707.94	14.1%
150	170	45%	55,845	6,104.58	6,898.16	793.58	13.0%
150	170	60%	74,460	7,183.30	8,062.53	879.23	12.2%
150	170	75%	93,075	8,262.01	9,226.90	964.89	11.7%
200	220	15%	24,090	4,923.47	5,707.49	784.02	15.9%
200	220	30%	48,180	6,319.45	7,214.32	894.87	14.2%
200	220	45%	72,270	7,715.44	8,721.15	1,005.71	13.0%
200	220	60%	96,360	9,111.43	10,227.98	1,116.55	12.3%
200	220	75%	120,450	10,507.41	11,734.81	1,227.40	11.7%
300	320	15%	35,040	6,876.11	7,983.61	1,107.50	16.1%
300	320	30%	70,080	8,906.63	10,175.36	1,268.73	14.2%
300	320	45%	105,120	10,937.16	12,367.12	1,429.96	13.1%
300	320	60%	140,160	12,967.68	14,558.87	1,591.19	12.3%
300	320	75%	175,200	14,998.21	16,750.62	1,752.41	11.7%
350	370	15%	40,515	7,852.43	9,121.67	1,269.24	16.2%
350	370	30%	81,030	10,200.22	11,655.89	1,455.67	14.3%
350	370	45%	121,545	12,548.02	14,190.10	1,642.08	13.1%
350	370	60%	162,060	14,895.81	16,724.31	1,828.50	12.3%
350	370	75%	202,575	17,243.61	19,258.53	2,014.92	11.7%
400	420	15%	45,990	8,828.75	10,259.73	1,430.98	16.2%
400	420	30%	91,980	11,493.81	13,136.41	1,642.60	14.3%
400	420	45%	137,970	14,158.88	16,013.08	1,854.20	13.1%
400	420	60%	183,960	16,823.94	18,889.76	2,065.82	12.3%
400	420	75%	229,950	19,489.01	21,766.43	2,277.42	11.7%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU M Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
101	120	15%	13,140	2,811.29	3,253.03	441.74	15.7%
101	120	30%	26,280	3,403.19	3,884.26	481.07	14.1%
101	120	45%	39,420	3,995.09	4,515.48	520.39	13.0%
101	120	60%	52,560	4,586.99	5,146.71	559.72	12.2%
101	120	75%	65,700	5,178.89	5,777.93	599.04	11.6%
150	170	15%	18,615	3,706.95	4,299.29	592.34	16.0%
150	170	30%	37,230	4,545.48	5,193.53	648.05	14.3%
150	170	45%	55,845	5,384.00	6,087.76	703.76	13.1%
150	170	60%	74,460	6,222.53	6,982.00	759.47	12.2%
150	170	75%	93,075	7,061.05	7,876.23	815.18	11.5%
200	220	15%	24,090	4,612.63	5,357.91	745.28	16.2%
200	220	30%	48,180	5,697.78	6,515.15	817.37	14.3%
200	220	45%	72,270	6,782.93	7,672.40	889.47	13.1%
200	220	60%	96,360	7,868.07	8,829.64	961.57	12.2%
200	220	75%	120,450	8,953.22	9,986.89	1,033.67	11.5%
300	320	15%	35,040	6,423.98	7,475.13	1,051.15	16.4%
300	320	30%	70,080	8,002.38	9,158.39	1,156.01	14.4%
300	320	45%	105,120	9,580.77	10,841.66	1,260.89	13.2%
300	320	60%	140,160	11,159.17	12,524.92	1,365.75	12.2%
300	320	75%	175,200	12,737.57	14,208.19	1,470.62	11.5%
350	370	15%	40,515	7,329.65	8,533.74	1,204.09	16.4%
350	370	30%	81,030	9,154.67	10,480.01	1,325.34	14.5%
350	370	45%	121,545	10,979.70	12,426.29	1,446.59	13.2%
350	370	60%	162,060	12,804.72	14,372.56	1,567.84	12.2%
350	370	75%	202,575	14,629.74	16,318.84	1,689.10	11.5%
400	420	15%	45,990	8,235.33	9,592.35	1,357.02	16.5%
400	420	30%	91,980	10,306.97	11,801.63	1,494.66	14.5%
400	420	45%	137,970	12,378.62	14,010.92	1,632.30	13.2%
400	420	60%	183,960	14,450.27	16,220.20	1,769.93	12.2%
400	420	75%	229,950	16,521.92	18,429.49	1,907.57	11.5%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU L Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
401	441	15%	48,290	8,886.36	10,265.08	1,378.72	15.5%
401	441	30%	96,579	11,658.98	13,216.73	1,557.75	13.4%
401	441	45%	144,869	14,431.65	16,168.45	1,736.80	12.0%
401	441	60%	193,158	17,204.27	19,120.11	1,915.84	11.1%
401	441	75%	241,448	19,976.95	22,071.82	2,094.87	10.5%
600	640	15%	70,080	12,700.80	14,665.97	1,965.17	15.5%
600	640	30%	140,160	16,724.59	18,949.59	2,225.00	13.3%
600	640	45%	210,240	20,748.39	23,233.22	2,484.83	12.0%
600	640	60%	280,320	24,772.19	27,516.84	2,744.65	11.1%
600	640	75%	350,400	28,795.99	31,800.47	3,004.48	10.4%
800	860	15%	94,170	16,722.12	19,291.68	2,569.56	15.4%
800	860	30%	188,340	22,129.10	25,047.80	2,918.70	13.2%
800	860	45%	282,510	27,536.07	30,803.93	3,267.86	11.9%
800	860	60%	376,680	32,943.05	36,560.05	3,617.00	11.0%
800	860	75%	470,850	38,350.03	42,316.17	3,966.14	10.3%
1,000	1,200	15%	131,400	21,869.54	25,133.50	3,263.96	14.9%
1,000	1,200	30%	262,800	29,414.16	33,165.30	3,751.14	12.8%
1,000	1,200	45%	394,200	36,958.78	41,197.10	4,238.32	11.5%
1,000	1,200	60%	525,600	44,503.40	49,228.89	4,725.49	10.6%
1,000	1,200	75%	657,000	52,048.02	57,260.69	5,212.67	10.0%
1,500	1,700	15%	186,150	31,453.63	36,191.08	4,737.45	15.1%
1,500	1,700	30%	372,300	42,141.84	47,569.46	5,427.62	12.9%
1,500	1,700	45%	558,450	52,830.06	58,947.84	6,117.78	11.6%
1,500	1,700	60%	744,600	63,518.27	70,326.23	6,807.96	10.7%
1,500	1,700	75%	930,750	74,206.48	81,704.61	7,498.13	10.1%
3,000	3,200	15%	350,400	60,205.91	69,363.83	9,157.92	15.2%
3,000	3,200	30%	700,800	80,324.89	90,781.96	10,457.07	13.0%
3,000	3,200	45%	1,051,200	100,443.88	112,200.09	11,756.21	11.7%
3,000	3,200	60%	1,401,600	120,562.87	133,618.22	13,055.35	10.8%
3,000	3,200	75%	1,752,000	140,681.85	155,036.35	14,354.50	10.2%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU L Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
401	441	15%	48,290	8,228.65	9,534.93	1,306.28	15.9%
401	441	30%	96,579	10,343.57	11,756.46	1,412.89	13.7%
401	441	45%	144,869	12,458.54	13,978.03	1,519.49	12.2%
401	441	60%	193,158	14,573.46	16,199.56	1,626.10	11.2%
401	441	75%	241,448	16,688.43	18,421.13	1,732.70	10.4%
600	640	15%	70,080	11,746.31	13,606.36	1,860.05	15.8%
600	640	30%	140,160	14,815.62	16,830.37	2,014.75	13.6%
600	640	45%	210,240	17,884.92	20,054.39	2,169.47	12.1%
600	640	60%	280,320	20,954.23	23,278.41	2,324.18	11.1%
600	640	75%	350,400	24,023.54	26,502.42	2,478.88	10.3%
800	860	15%	94,170	15,439.52	17,867.83	2,428.31	15.7%
800	860	30%	188,340	19,563.90	22,200.10	2,636.20	13.5%
800	860	45%	282,510	23,688.29	26,532.38	2,844.09	12.0%
800	860	60%	376,680	27,812.67	30,864.65	3,051.98	11.0%
800	860	75%	470,850	31,937.05	35,196.92	3,259.87	10.2%
1,000	1,200	15%	131,400	20,079.87	23,146.73	3,066.86	15.3%
1,000	1,200	30%	262,800	25,834.82	29,191.76	3,356.94	13.0%
1,000	1,200	45%	394,200	31,589.78	35,236.79	3,647.01	11.5%
1,000	1,200	60%	525,600	37,344.73	41,281.82	3,937.09	10.5%
1,000	1,200	75%	657,000	43,099.68	47,326.85	4,227.17	9.8%
1,500	1,700	15%	186,150	28,918.27	33,376.49	4,458.22	15.4%
1,500	1,700	30%	372,300	37,071.12	41,940.29	4,869.17	13.1%
1,500	1,700	45%	558,450	45,223.97	50,504.08	5,280.11	11.7%
1,500	1,700	60%	744,600	53,376.82	59,067.87	5,691.05	10.7%
1,500	1,700	75%	930,750	61,529.66	67,631.67	6,102.01	9.9%
3,000	3,200	15%	350,400	55,433.46	64,065.78	8,632.32	15.6%
3,000	3,200	30%	700,800	70,780.00	80,185.86	9,405.86	13.3%
3,000	3,200	45%	1,051,200	86,126.54	96,305.95	10,179.41	11.8%
3,000	3,200	60%	1,401,600	101,473.08	112,426.03	10,952.95	10.8%
3,000	3,200	75%	1,752,000	116,819.61	128,546.11	11,726.50	10.0%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-34

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
3,000	20%	438,000	75,895.98	85,062.90	9,166.92	12.1%
3,000	30%	657,000	83,922.33	93,928.02	10,005.69	11.9%
3,000	40%	876,000	91,948.68	102,793.14	10,844.46	11.8%
3,000	50%	1,095,000	99,975.03	111,658.26	11,683.23	11.7%
3,000	75%	1,642,500	120,040.91	133,821.06	13,780.15	11.5%
3,500	20%	511,000	88,536.43	99,214.44	10,678.01	12.1%
3,500	30%	766,500	97,900.51	109,557.08	11,656.57	11.9%
3,500	40%	1,022,000	107,264.58	119,899.72	12,635.14	11.8%
3,500	50%	1,277,500	116,628.66	130,242.36	13,613.70	11.7%
3,500	75%	1,916,250	140,038.84	156,098.96	16,060.12	11.5%
4,000	20%	584,000	101,176.88	113,365.98	12,189.10	12.0%
4,000	30%	876,000	111,878.68	125,186.14	13,307.46	11.9%
4,000	40%	1,168,000	122,580.48	137,006.30	14,425.82	11.8%
4,000	50%	1,460,000	133,282.28	148,826.46	15,544.18	11.7%
4,000	75%	2,190,000	160,036.78	178,376.86	18,340.08	11.5%
4,500	20%	657,000	113,817.33	127,517.52	13,700.19	12.0%
4,500	30%	985,500	125,856.86	140,815.20	14,958.34	11.9%
4,500	40%	1,314,000	137,896.38	154,112.88	16,216.50	11.8%
4,500	50%	1,642,500	149,935.91	167,410.56	17,474.65	11.7%
4,500	75%	2,463,750	180,034.72	200,654.76	20,620.04	11.5%
5,000	20%	730,000	126,457.78	141,669.06	15,211.28	12.0%
5,000	30%	1,095,000	139,835.03	156,444.26	16,609.23	11.9%
5,000	40%	1,460,000	153,212.28	171,219.46	18,007.18	11.8%
5,000	50%	1,825,000	166,589.53	185,994.66	19,405.13	11.6%
5,000	75%	2,737,500	200,032.66	222,932.66	22,900.00	11.4%
6,000	20%	876,000	151,738.68	169,972.14	18,233.46	12.0%
6,000	30%	1,314,000	167,791.38	187,702.38	19,911.00	11.9%
6,000	40%	1,752,000	183,844.08	205,432.62	21,588.54	11.7%
6,000	50%	2,190,000	199,896.78	223,162.86	23,266.08	11.6%
6,000	75%	3,285,000	240,028.53	267,488.46	27,459.93	11.4%
7,000	20%	1,022,000	177,019.58	198,275.22	21,255.64	12.0%
7,000	30%	1,533,000	195,747.73	218,960.50	23,212.77	11.9%
7,000	50%	2,555,000	233,204.03	260,331.06	27,127.03	11.6%
7,000	75%	3,832,500	280,024.41	312,044.26	32,019.85	11.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-35

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
3,000	4,000	20%	438,000	77,839.17	88,098.81	10,259.64	13.2%
3,000	4,000	30%	657,000	85,451.83	96,649.88	11,198.05	13.1%
3,000	4,000	40%	876,000	93,064.49	105,200.96	12,136.47	13.0%
3,000	4,000	50%	1,095,000	100,677.15	113,752.03	13,074.88	13.0%
3,000	4,000	75%	1,642,500	119,708.79	135,129.72	15,420.93	12.9%
3,500	4,500	20%	511,000	90,292.72	102,250.17	11,957.45	13.2%
3,500	4,500	30%	766,500	99,174.16	112,226.42	13,052.26	13.2%
3,500	4,500	40%	1,022,000	108,055.59	122,202.67	14,147.08	13.1%
3,500	4,500	50%	1,277,500	116,937.03	132,178.93	15,241.90	13.0%
3,500	4,500	75%	1,916,250	139,140.62	157,119.56	17,978.94	12.9%
4,000	5,000	20%	584,000	102,746.27	116,401.52	13,655.25	13.3%
4,000	5,000	30%	876,000	112,896.49	127,802.96	14,906.47	13.2%
4,000	5,000	40%	1,168,000	123,046.70	139,204.39	16,157.69	13.1%
4,000	5,000	50%	1,460,000	133,196.91	150,605.82	17,408.91	13.1%
4,000	5,000	75%	2,190,000	158,572.44	179,109.40	20,536.96	13.0%
4,500	6,000	20%	657,000	116,731.83	132,071.38	15,339.55	13.1%
4,500	6,000	30%	985,500	128,150.82	144,897.99	16,747.17	13.1%
4,500	6,000	40%	1,314,000	139,569.80	157,724.60	18,154.80	13.0%
4,500	6,000	50%	1,642,500	150,988.79	170,551.22	19,562.43	13.0%
4,500	6,000	75%	2,463,750	179,536.26	202,617.74	23,081.48	12.9%
5,000	7,000	20%	730,000	130,717.38	147,741.24	17,023.86	13.0%
5,000	7,000	30%	1,095,000	143,405.15	161,993.03	18,587.88	13.0%
5,000	7,000	40%	1,460,000	156,092.91	176,244.82	20,151.91	12.9%
5,000	7,000	50%	1,825,000	168,780.68	190,496.61	21,715.93	12.9%
5,000	7,000	75%	2,737,500	200,500.09	226,126.09	25,626.00	12.8%
6,000	8,000	20%	876,000	155,624.49	176,043.96	20,419.47	13.1%
6,000	8,000	30%	1,314,000	170,849.80	193,146.10	22,296.30	13.1%
6,000	8,000	40%	1,752,000	186,075.12	210,248.25	24,173.13	13.0%
6,000	8,000	50%	2,190,000	201,300.44	227,350.40	26,049.96	12.9%
6,000	8,000	75%	3,285,000	239,363.74	270,105.77	30,742.03	12.8%
7,000	8,500	20%	1,022,000	178,999.59	202,828.17	23,828.58	13.3%
7,000	8,500	30%	1,533,000	196,762.46	222,780.68	26,018.22	13.2%
7,000	8,500	40%	2,044,000	214,525.33	242,733.18	28,207.85	13.1%
7,000	8,500	50%	2,555,000	232,288.21	262,685.69	30,397.48	13.1%
7,000	8,500	75%	3,832,500	276,695.38	312,566.96	35,871.58	13.0%

E-35 Average Energy On-Peak: 30%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
E-47

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
						Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (F) - (E)	% (G) / (E)
HPS, cobra / roadway	5,800	29	Company	8.73	9.61	0.88	10.1%
		29	Customer	5.16	5.68	0.52	10.1%
HPS, cobra / roadway	9,500	41	Company	10.28	11.32	1.04	10.1%
		41	Customer	6.32	6.96	0.64	10.1%
HPS, architectural	9,500	41	Company	15.38	16.93	1.55	10.1%
		41	Customer	7.34	8.08	0.74	10.1%
HPS, acorn luminaire	9,500	41	Company	27.06	29.79	2.73	10.1%
		41	Customer	9.22	10.15	0.93	10.1%
HPS, cobra / roadway	16,000	69	Company	12.87	14.17	1.30	10.1%
		69	Customer	8.82	9.71	0.89	10.1%
HPS, architectural	16,000	69	Company	17.96	19.77	1.81	10.1%
		69	Customer	9.82	10.81	0.99	10.1%
HPS, acorn luminaire	16,000	69	Company	30.04	33.07	3.03	10.1%
		69	Customer	11.65	12.83	1.18	10.1%
HPS, cobra / roadway	30,000	99	Company	15.52	17.09	1.57	10.1%
		99	Customer	11.46	12.62	1.16	10.1%
HPS, architectural	30,000	99	Company	21.31	23.46	2.15	10.1%
		99	Customer	12.60	13.87	1.27	10.1%
HPS, cobra / roadway	50,000	153	Company	21.06	23.19	2.13	10.1%
		153	Customer	16.37	18.02	1.65	10.1%
HPS, architectural	50,000	153	Company	26.29	28.95	2.66	10.1%
		153	Customer	18.13	19.96	1.83	10.1%
LPS, architectural	8,000	30	Company	22.35	24.61	2.26	10.1%
		30	Customer	9.82	10.81	0.99	10.1%
LPS, architectural	13,500	50	Company	26.36	29.02	2.66	10.1%
LPS, architectural	22,500	72	Company	30.11	33.15	3.04	10.1%
		72	Customer	14.45	15.91	1.46	10.1%
LPS, architectural	33,000	90	Company	36.22	39.88	3.66	10.1%
		90	Customer	17.02	18.74	1.72	10.1%
Type of Pole	Height	Desc.					
Direct Bury	30 FT	Round Steel	Company	14.38	15.83	1.45	10.1%
			Customer	N/A			N/A
Direct Bury	34 FT	Square Steel	Company	15.87	17.47	1.60	10.1%
			Customer	N/A	N/A		N/A

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
E-58

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
						Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (F) - (E)	% (G) / (E)
HPS, cobra / roadway	5,800	29	Company	8.73	9.61	0.88	10.1%
		29	Customer	5.16	5.68	0.52	10.1%
HPS, cobra / roadway	9,500	41	Company	10.28	11.32	1.04	10.1%
		41	Customer	6.32	6.96	0.64	10.1%
HPS, architectural	9,500	41	Company	15.38	16.93	1.55	10.1%
		41	Customer	7.34	8.08	0.74	10.1%
HPS, acorn luminaire	9,500	41	Company	27.06	29.79	2.73	10.1%
		41	Customer	9.22	10.15	0.93	10.1%
HPS, cobra / roadway	16,000	69	Company	12.87	14.17	1.30	10.1%
		69	Customer	8.82	9.71	0.89	10.1%
HPS, architectural	16,000	69	Company	17.96	19.77	1.81	10.1%
		69	Customer	9.82	10.81	0.99	10.1%
HPS, acorn luminaire	16,000	69	Company	30.04	33.07	3.03	10.1%
		69	Customer	11.65	12.83	1.18	10.1%
HPS, cobra / roadway	30,000	99	Company	15.52	17.09	1.57	10.1%
		99	Customer	11.46	12.62	1.16	10.1%
HPS, architectural	30,000	99	Company	21.31	23.46	2.15	10.1%
		99	Customer	12.60	13.87	1.27	10.1%
HPS, cobra / roadway	50,000	153	Company	21.06	23.19	2.13	10.1%
		153	Customer	16.37	18.02	1.65	10.1%
HPS, architectural	50,000	153	Company	26.29	28.95	2.66	10.1%
		153	Customer	18.13	19.96	1.83	10.1%
LPS, architectural	8,000	30	Company	22.35	24.61	2.26	10.1%
		30	Customer	9.82	10.81	0.99	10.1%
LPS, architectural	13,500	50	Company	26.36	29.02	2.66	10.1%
LPS, architectural	22,500	72	Company	30.11	33.15	3.04	10.1%
		72	Customer	14.45	15.91	1.46	10.1%
LPS, architectural	33,000	90	Company	36.22	39.88	3.66	10.1%
		90	Customer	17.02	18.74	1.72	10.1%
Type of Pole	Height	Desc.					
Direct Bury	30 FT	Round	Company	14.38	15.83	1.45	10.1%
		Steel	Customer	2.66	2.93	0.27	10.2%
Direct Bury	34 FT	Square	Company	15.87	17.47	1.60	10.1%
		Steel	Customer	2.75	3.03	0.28	10.2%
Direct Bury	38 FT	Square	Company	17.05	18.77	1.72	10.1%
		Steel	Customer	2.96	3.26	0.30	10.1%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
E-59

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
Lamps	kWh per Lamp	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
50	30	1,500	230.82	254.08	23.26	10.1%
50	60	3,000	322.14	354.65	32.51	10.1%
50	75	3,750	367.80	404.94	37.14	10.1%
50	100	5,000	443.90	488.75	44.85	10.1%
50	150	7,500	596.10	656.38	60.28	10.1%
100	30	3,000	461.64	508.15	46.51	10.1%
100	60	6,000	644.28	709.30	65.02	10.1%
100	75	7,500	735.60	809.88	74.28	10.1%
100	100	10,000	887.80	977.50	89.70	10.1%
100	150	15,000	1,192.20	1,312.75	120.55	10.1%
200	30	6,000	923.28	1,016.30	93.02	10.1%
200	60	12,000	1,288.56	1,418.60	130.04	10.1%
200	75	15,000	1,471.20	1,619.75	148.55	10.1%
200	100	20,000	1,775.60	1,955.00	179.40	10.1%
200	150	30,000	2,384.40	2,625.50	241.10	10.1%
500	30	15,000	2,308.20	2,540.75	232.55	10.1%
500	60	30,000	3,221.40	3,546.50	325.10	10.1%
500	75	37,500	3,678.00	4,049.38	371.38	10.1%
500	100	50,000	4,439.00	4,887.50	448.50	10.1%
500	150	75,000	5,961.00	6,563.75	602.75	10.1%
1,000	30	30,000	4,616.40	5,081.50	465.10	10.1%
1,000	60	60,000	6,442.80	7,093.00	650.20	10.1%
1,000	75	75,000	7,356.00	8,098.75	742.75	10.1%
1,000	100	100,000	8,878.00	9,775.00	897.00	10.1%
1,000	150	150,000	11,922.00	13,127.50	1,205.50	10.1%
2,000	30	60,000	9,232.80	10,163.00	930.20	10.1%
2,000	60	120,000	12,885.60	14,186.00	1,300.40	10.1%
2,000	75	150,000	14,712.00	16,197.50	1,485.50	10.1%
2,000	100	200,000	17,756.00	19,550.00	1,794.00	10.1%
2,000	150	300,000	23,844.00	26,255.00	2,411.00	10.1%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
E-67

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
			Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
			(C) - (B)	(D) / (B)
30	1.56	1.71	0.15	9.6%
40	2.08	2.29	0.21	10.1%
50	2.60	2.86	0.26	10.0%
60	3.12	3.43	0.31	9.9%
70	3.64	4.00	0.36	9.9%
80	4.15	4.57	0.42	10.1%
90	4.67	5.14	0.47	10.1%
100	5.19	5.71	0.52	10.0%
125	6.49	7.14	0.65	10.0%
150	7.79	8.57	0.78	10.0%
175	9.09	10.00	0.91	10.0%
200	10.39	11.43	1.04	10.0%
225	11.68	12.86	1.18	10.1%
250	12.98	14.29	1.31	10.1%
275	14.28	15.71	1.43	10.0%
300	15.58	17.14	1.56	10.0%
325	16.88	18.57	1.69	10.0%
350	18.18	20.00	1.82	10.0%
375	19.47	21.43	1.96	10.1%
400	20.77	22.86	2.09	10.1%
425	22.07	24.28	2.21	10.0%
450	23.37	25.71	2.34	10.0%
475	24.67	27.14	2.47	10.0%
500	25.97	28.57	2.60	10.0%
600	31.16	34.28	3.12	10.0%
700	36.35	40.00	3.65	10.0%
800	41.54	45.71	4.17	10.0%
900	46.74	51.43	4.69	10.0%
1,000	51.93	57.14	5.21	10.0%
1,500	77.90	85.71	7.81	10.0%
2,000	103.86	114.28	10.42	10.0%
2,500	129.83	142.85	13.02	10.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
E-221

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
10	20%	1,460	160.38	201.18	40.80	25.4%
10	35%	2,555	243.96	283.09	39.12	16.0%
10	50%	3,650	318.55	315.62	(2.92)	-0.9%
10	65%	4,745	387.20	315.62	(71.58)	-18.5%
10	80%	5,840	455.86	315.62	(140.24)	-30.8%
30	20%	4,380	430.40	517.00	86.59	20.1%
30	35%	7,665	681.15	762.71	81.57	12.0%
30	50%	10,950	898.36	824.42	(73.94)	-8.2%
30	65%	14,235	1,104.33	824.42	(279.91)	-25.3%
30	80%	17,520	1,310.30	824.42	(485.88)	-37.1%
75	20%	10,950	1,037.96	1,227.58	189.63	18.3%
75	35%	19,163	1,664.85	1,841.91	177.06	10.6%
75	50%	27,375	2,202.95	1,969.22	(233.72)	-10.6%
75	65%	35,588	2,717.90	1,969.22	(748.68)	-27.5%
75	80%	43,800	3,232.79	1,969.22	(1,263.57)	-39.1%
100	20%	14,600	1,375.49	1,622.35	246.87	17.9%
100	35%	25,550	2,211.30	2,441.41	230.11	10.4%
100	50%	36,500	2,927.71	2,605.22	(322.49)	-11.0%
100	65%	47,450	3,614.28	2,605.22	(1,009.06)	-27.9%
100	80%	58,400	4,300.84	2,605.22	(1,695.62)	-39.4%
150	20%	21,900	2,050.55	2,411.89	361.35	17.6%
150	35%	38,325	3,304.27	3,640.48	336.22	10.2%
150	50%	54,750	4,377.25	3,877.22	(500.03)	-11.4%
150	65%	71,175	5,407.10	3,877.22	(1,529.88)	-28.3%
150	80%	87,600	6,436.95	3,877.22	(2,559.72)	-39.8%
200	20%	29,200	2,725.60	3,201.43	475.83	17.5%
200	35%	51,100	4,397.23	4,839.55	442.32	10.1%
200	50%	73,000	5,826.79	5,149.22	(677.57)	-11.6%
200	65%	94,900	7,199.92	5,149.22	(2,050.70)	-28.5%
200	80%	116,800	8,573.05	5,149.22	(3,423.83)	-39.9%
300	20%	43,800	4,075.72	4,780.51	704.79	17.3%
300	35%	76,650	6,583.16	7,237.69	654.53	9.9%
300	50%	109,500	8,725.86	7,693.22	(1,032.64)	-11.8%
300	65%	142,350	10,785.56	7,693.22	(3,092.34)	-28.7%
300	80%	175,200	12,845.25	7,693.22	(5,152.03)	-40.1%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
E-221-8T time-of-use

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount ($) (F) - (E)	Change % (G) / (E)
10	30	20%	1,460	276.46	330.18	53.72	19.4%
10	30	35%	2,555	344.65	396.97	52.32	15.2%
10	30	50%	3,650	412.85	463.76	50.91	12.3%
10	30	65%	4,745	481.04	530.56	49.52	10.3%
10	30	80%	5,840	549.24	597.35	48.11	8.8%
30	90	20%	4,380	771.53	920.93	149.40	19.4%
30	90	35%	7,665	976.12	1,121.31	145.19	14.9%
30	90	50%	10,950	1,180.71	1,321.69	140.98	11.9%
30	90	65%	14,235	1,385.29	1,522.07	136.78	9.9%
30	90	80%	17,520	1,589.88	1,722.44	132.56	8.3%
75	225	20%	10,950	1,885.45	2,250.13	364.68	19.3%
75	225	35%	19,163	2,396.95	2,751.10	354.15	14.8%
75	225	50%	27,375	2,908.38	3,252.02	343.64	11.8%
75	225	65%	35,588	3,419.88	3,753.00	333.12	9.7%
75	225	80%	43,800	3,931.32	4,253.91	322.59	8.2%
100	300	20%	14,600	2,504.29	2,988.57	484.28	19.3%
100	300	35%	25,550	3,186.25	3,656.50	470.25	14.8%
100	300	50%	36,500	3,868.20	4,324.43	456.23	11.8%
100	300	65%	47,450	4,550.16	4,992.36	442.20	9.7%
100	300	80%	58,400	5,232.11	5,660.28	428.17	8.2%
150	450	20%	21,900	3,741.98	4,465.46	723.48	19.3%
150	450	35%	38,325	4,764.91	5,467.35	702.44	14.7%
150	450	50%	54,750	5,787.85	6,469.24	681.39	11.8%
150	450	65%	71,175	6,810.78	7,471.13	660.35	9.7%
150	450	80%	87,600	7,833.71	8,473.02	639.31	8.2%
200	600	20%	29,200	4,979.67	5,942.34	962.67	19.3%
200	600	35%	51,100	6,343.58	7,278.20	934.62	14.7%
200	600	50%	73,000	7,707.49	8,614.05	906.56	11.8%
200	600	65%	94,900	9,071.40	9,949.91	878.51	9.7%
200	600	80%	116,800	10,435.31	11,285.77	850.46	8.1%
300	900	20%	43,800	7,455.04	8,896.11	1,441.07	19.3%
300	900	35%	76,650	9,500.91	10,899.90	1,398.99	14.7%
300	900	50%	109,500	11,546.77	12,903.68	1,356.91	11.8%
300	900	65%	142,350	13,592.64	14,907.47	1,314.83	9.7%
300	900	80%	175,200	15,638.50	16,911.25	1,272.75	8.1%

E-221-8T Average Energy On-Peak: 30%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Summer Shoulder (May, September & October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
101	15%	11,060	1,946.67	2,290.01	343.34	17.6%
101	30%	22,119	2,887.23	3,330.93	443.70	15.4%
101	45%	33,179	3,827.87	4,371.95	544.08	14.2%
101	60%	44,238	4,768.42	5,412.86	644.44	13.5%
101	75%	55,298	5,709.06	6,453.88	744.82	13.0%
150	15%	16,425	2,653.50	3,128.29	474.79	17.9%
150	30%	32,850	4,050.42	4,674.28	623.86	15.4%
150	45%	49,275	5,447.35	6,220.27	772.92	14.2%
150	60%	65,700	6,844.27	7,766.25	921.98	13.5%
150	75%	82,125	8,241.20	9,312.24	1,071.04	13.0%
200	15%	21,900	3,374.79	3,983.72	608.93	18.0%
200	30%	43,800	5,237.36	6,045.04	807.68	15.4%
200	45%	65,700	7,099.92	8,106.35	1,006.43	14.2%
200	60%	87,600	8,962.49	10,167.67	1,205.18	13.4%
200	75%	109,500	10,825.06	12,228.99	1,403.93	13.0%
300	15%	32,850	4,817.37	5,694.58	877.21	18.2%
300	30%	65,700	7,611.22	8,786.55	1,175.33	15.4%
300	45%	98,550	10,405.08	11,878.53	1,473.45	14.2%
300	60%	131,400	13,198.93	14,970.51	1,771.58	13.4%
300	75%	164,250	15,992.78	18,062.49	2,069.71	12.9%
350	15%	38,325	5,538.66	6,550.01	1,011.35	18.3%
350	30%	76,650	8,798.16	10,157.31	1,359.15	15.4%
350	45%	114,975	12,057.65	13,764.62	1,706.97	14.2%
350	60%	153,300	15,317.15	17,371.93	2,054.78	13.4%
350	75%	191,625	18,576.64	20,979.23	2,402.59	12.9%
400	15%	43,800	6,259.96	7,405.44	1,145.48	18.3%
400	30%	87,600	9,985.09	11,528.07	1,542.98	15.5%
400	45%	131,400	13,710.23	15,650.71	1,940.48	14.2%
400	60%	175,200	17,435.37	19,773.35	2,337.98	13.4%
400	75%	219,000	21,160.50	23,895.98	2,735.48	12.9%

GS-SCHOOLS M Average Energy On-Peak %: 19%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 20%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Summer Peak (June - August)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
101	15%	11,060	2,056.92	2,414.15	357.23	17.4%
101	30%	22,119	3,107.70	3,579.19	471.49	15.2%
101	45%	33,179	4,158.59	4,744.34	585.75	14.1%
101	60%	44,238	5,209.37	5,909.38	700.01	13.4%
101	75%	55,298	6,260.26	7,074.53	814.27	13.0%
150	15%	16,425	2,817.22	3,312.64	495.42	17.6%
150	30%	32,850	4,377.86	5,042.98	665.12	15.2%
150	45%	49,275	5,938.51	6,773.32	834.81	14.1%
150	60%	65,700	7,499.16	8,503.66	1,004.50	13.4%
150	75%	82,125	9,059.80	10,234.00	1,174.20	13.0%
200	15%	21,900	3,593.08	4,229.52	636.44	17.7%
200	30%	43,800	5,673.94	6,536.64	862.70	15.2%
200	45%	65,700	7,754.81	8,843.76	1,088.95	14.0%
200	60%	87,600	9,835.67	11,150.88	1,315.21	13.4%
200	75%	109,500	11,916.53	13,458.00	1,541.47	12.9%
300	15%	32,850	5,144.81	6,063.28	918.47	17.9%
300	30%	65,700	8,266.11	9,523.96	1,257.85	15.2%
300	45%	98,550	11,387.40	12,984.64	1,597.24	14.0%
300	60%	131,400	14,508.69	16,445.32	1,936.63	13.3%
300	75%	164,250	17,629.99	19,906.00	2,276.01	12.9%
350	15%	38,325	5,920.68	6,980.16	1,059.48	17.9%
350	30%	76,650	9,562.19	11,017.62	1,455.43	15.2%
350	45%	114,975	13,203.70	15,055.08	1,851.38	14.0%
350	60%	153,300	16,845.20	19,092.54	2,247.34	13.3%
350	75%	191,625	20,486.71	23,129.99	2,643.28	12.9%
400	15%	43,800	6,696.54	7,897.04	1,200.50	17.9%
400	30%	87,600	10,858.27	12,511.28	1,653.01	15.2%
400	45%	131,400	15,019.99	17,125.52	2,105.53	14.0%
400	60%	175,200	19,181.72	21,739.76	2,558.04	13.3%
400	75%	219,000	23,343.44	26,353.99	3,010.55	12.9%

GS-SCHOOLS M Average Energy On-Peak %: 18%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
101	15%	11,060	1,760.92	2,084.22	323.30	18.4%
101	30%	22,119	2,515.73	2,919.36	403.63	16.0%
101	45%	33,179	3,270.62	3,754.57	483.95	14.8%
101	60%	44,238	4,025.43	4,589.71	564.28	14.0%
101	75%	55,298	4,780.32	5,424.92	644.60	13.5%
150	15%	16,425	2,377.63	2,822.66	445.03	18.7%
150	30%	32,850	3,498.70	4,063.02	564.32	16.1%
150	45%	49,275	4,619.76	5,303.38	683.62	14.8%
150	60%	65,700	5,740.82	6,543.75	802.93	14.0%
150	75%	82,125	6,861.89	7,784.11	922.22	13.4%
200	15%	21,900	3,006.97	3,576.22	569.25	18.9%
200	30%	43,800	4,501.72	5,230.03	728.31	16.2%
200	45%	65,700	5,996.47	6,883.85	887.38	14.8%
200	60%	87,600	7,491.23	8,537.66	1,046.43	14.0%
200	75%	109,500	8,985.98	10,191.48	1,205.50	13.4%
300	15%	32,850	4,265.65	5,083.32	817.67	19.2%
300	30%	65,700	6,507.77	7,564.05	1,056.28	16.2%
300	45%	98,550	8,749.90	10,044.77	1,294.87	14.8%
300	60%	131,400	10,992.03	12,525.49	1,533.46	14.0%
300	75%	164,250	13,234.16	15,006.21	1,772.05	13.4%
350	15%	38,325	4,894.99	5,836.88	941.89	19.2%
350	30%	76,650	7,510.80	8,731.05	1,220.25	16.2%
350	45%	114,975	10,126.62	11,625.23	1,498.61	14.8%
350	60%	153,300	12,742.43	14,519.41	1,776.98	13.9%
350	75%	191,625	15,358.25	17,413.58	2,055.33	13.4%
400	15%	43,800	5,524.32	6,590.43	1,066.11	19.3%
400	30%	87,600	8,513.83	9,898.06	1,384.23	16.3%
400	45%	131,400	11,503.33	13,205.69	1,702.36	14.8%
400	60%	175,200	14,492.83	16,513.32	2,020.49	13.9%
400	75%	219,000	17,482.34	19,820.95	2,338.61	13.4%

GS-SCHOOLS M Average Energy On-Peak %: 25%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Summer Shoulder (May, September & October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
401	15%	43,910	5,870.23	6,875.84	1,005.61	17.1%
401	30%	87,819	9,269.32	10,472.65	1,203.33	13.0%
401	45%	131,729	12,668.48	14,069.53	1,401.05	11.1%
401	60%	175,638	16,067.57	17,666.33	1,598.76	10.0%
401	75%	219,548	19,466.74	21,263.21	1,796.47	9.2%
600	15%	65,700	8,542.88	9,986.31	1,443.43	16.9%
600	30%	131,400	13,628.86	15,368.12	1,739.26	12.8%
600	45%	197,100	18,714.83	20,749.93	2,035.10	10.9%
600	60%	262,800	23,800.81	26,131.74	2,330.93	9.8%
600	75%	328,500	28,886.78	31,513.54	2,626.76	9.1%
800	15%	87,600	11,229.01	13,112.45	1,883.44	16.8%
800	30%	175,200	18,010.31	20,288.19	2,277.88	12.6%
800	45%	262,800	24,791.61	27,463.94	2,672.33	10.8%
800	60%	350,400	31,572.91	34,639.68	3,066.77	9.7%
800	75%	438,000	38,354.21	41,815.43	3,461.22	9.0%
1,000	15%	109,500	13,915.13	16,238.58	2,323.45	16.7%
1,000	30%	219,000	22,391.76	25,208.26	2,816.50	12.6%
1,000	45%	328,500	30,868.38	34,177.94	3,309.56	10.7%
1,000	60%	438,000	39,345.01	43,147.63	3,802.62	9.7%
1,000	75%	547,500	47,821.63	52,117.31	4,295.68	9.0%
1,500	15%	164,250	20,630.45	24,053.92	3,423.47	16.6%
1,500	30%	328,500	33,345.38	37,508.44	4,163.06	12.5%
1,500	45%	492,750	46,060.32	50,962.97	4,902.65	10.6%
1,500	60%	657,000	58,775.26	64,417.49	5,642.23	9.6%
1,500	75%	821,250	71,490.20	77,872.01	6,381.81	8.9%
3,000	15%	328,500	40,776.38	47,499.94	6,723.56	16.5%
3,000	30%	657,000	66,206.26	74,408.99	8,202.73	12.4%
3,000	45%	985,500	91,636.13	101,318.03	9,681.90	10.6%
3,000	60%	1,314,000	117,066.01	128,227.08	11,161.07	9.5%
3,000	75%	1,642,500	142,495.88	155,136.12	12,640.24	8.9%

GS-SCHOOLS L Average Energy On-Peak %: 20%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Summer Peak (June - August)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)
401	15%	43,910	6,278.40	7,538.02	1,259.62	20.1%
401	30%	87,819	10,085.65	11,796.99	1,711.34	17.0%
401	45%	131,729	13,892.99	16,056.05	2,163.06	15.6%
401	60%	175,638	17,700.23	20,315.02	2,614.79	14.8%
401	75%	219,548	21,507.57	24,574.08	3,066.51	14.3%
600	15%	65,700	9,153.61	10,977.09	1,823.48	19.9%
600	30%	131,400	14,850.30	17,349.68	2,499.38	16.8%
600	45%	197,100	20,547.00	23,722.27	3,175.27	15.5%
600	60%	262,800	26,243.70	30,094.86	3,851.16	14.7%
600	75%	328,500	31,940.40	36,467.45	4,527.05	14.2%
800	15%	87,600	12,043.31	14,433.49	2,390.18	19.8%
800	30%	175,200	19,638.90	22,930.27	3,291.37	16.8%
800	45%	262,800	27,234.50	31,427.06	4,192.56	15.4%
800	60%	350,400	34,830.10	39,923.85	5,093.75	14.6%
800	75%	438,000	42,425.69	48,420.63	5,994.94	14.1%
1,000	15%	109,500	14,933.01	17,889.88	2,956.87	19.8%
1,000	30%	219,000	24,427.50	28,510.87	4,083.37	16.7%
1,000	45%	328,500	33,922.00	39,131.85	5,209.85	15.4%
1,000	60%	438,000	43,416.49	49,752.83	6,336.34	14.6%
1,000	75%	547,500	52,910.99	60,373.82	7,462.83	14.1%
1,500	15%	164,250	22,157.25	26,530.87	4,373.62	19.7%
1,500	30%	328,500	36,399.00	42,462.35	6,063.35	16.7%
1,500	45%	492,750	50,640.74	58,393.82	7,753.08	15.3%
1,500	60%	657,000	64,882.48	74,325.30	9,442.82	14.6%
1,500	75%	821,250	79,124.23	90,256.77	11,132.54	14.1%
3,000	15%	328,500	43,830.00	52,453.85	8,623.85	19.7%
3,000	30%	657,000	72,313.48	84,316.80	12,003.32	16.6%
3,000	45%	985,500	100,796.97	116,179.75	15,382.78	15.3%
3,000	60%	1,314,000	129,280.45	148,042.70	18,762.25	14.5%
3,000	75%	1,642,500	157,763.94	179,905.65	22,141.71	14.0%

GS-SCHOOLS L Average Energy On-Peak %: 18%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 15%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($) (E) - (D)	% (F) / (D)
401	15%	43,910	5,212.96	6,339.00	1,126.04	21.6%
401	30%	87,819	7,954.79	9,398.98	1,444.19	18.2%
401	45%	131,729	10,696.68	12,459.02	1,762.34	16.5%
401	60%	175,638	13,438.52	15,518.99	2,080.47	15.5%
401	75%	219,548	16,180.41	18,579.03	2,398.62	14.8%
600	15%	65,700	7,559.45	9,183.07	1,623.62	21.5%
600	30%	131,400	11,661.99	13,761.63	2,099.64	18.0%
600	45%	197,100	15,764.52	18,340.20	2,575.68	16.3%
600	60%	262,800	19,867.06	22,918.76	3,051.70	15.4%
600	75%	328,500	23,969.60	27,497.33	3,527.73	14.7%
800	15%	87,600	9,917.76	12,041.45	2,123.69	21.4%
800	30%	175,200	15,387.81	18,146.21	2,758.40	17.9%
800	45%	262,800	20,857.86	24,250.96	3,393.10	16.3%
800	60%	350,400	26,327.91	30,355.72	4,027.81	15.3%
800	75%	438,000	31,797.96	36,460.47	4,662.51	14.7%
1,000	15%	109,500	12,276.07	14,899.84	2,623.77	21.4%
1,000	30%	219,000	19,113.64	22,530.78	3,417.14	17.9%
1,000	45%	328,500	25,951.20	30,161.73	4,210.53	16.2%
1,000	60%	438,000	32,788.76	37,792.67	5,003.91	15.3%
1,000	75%	547,500	39,626.33	45,423.61	5,797.28	14.6%
1,500	15%	164,250	18,171.85	22,045.81	3,873.96	21.3%
1,500	30%	328,500	28,428.20	33,492.23	5,064.03	17.8%
1,500	45%	492,750	38,684.54	44,938.64	6,254.10	16.2%
1,500	60%	657,000	48,940.89	56,385.05	7,444.16	15.2%
1,500	75%	821,250	59,197.23	67,831.47	8,634.24	14.6%
3,000	15%	328,500	35,859.20	43,483.73	7,624.53	21.3%
3,000	30%	657,000	56,371.89	66,376.55	10,004.66	17.7%
3,000	45%	985,500	76,884.58	89,269.38	12,384.80	16.1%
3,000	60%	1,314,000	97,397.27	112,162.21	14,764.94	15.2%
3,000	75%	1,642,500	117,909.96	135,055.03	17,145.07	14.5%

GS-SCHOOLS L Average Energy On-Peak %: 23%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 19%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2012.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical Service Bill Analysis

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount ($)	%
					(E) - (D)	(F) / (D)

No typical bill analysis is presented for the following Rate Schedules:

E-56 - Only 1 customer, increase consistent with E-32 L (11.13% base rate Increase, 6.06% net bill Increase).

E-36 M - Has a few customers, impact is the class average (14.78% base rate increase, 7.47% net bill increase).

E-36 XL - Revenue Credit Customer (7.59% base rate increase)

H5

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-12**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	118,311	-	118,311	4.15%	-	0.00%	94,439	-	94,439	3.27%	-	0.00%	1.
2.	1-50	102,321	2,561,032	220,632	7.74%	2,561,032	0.12%	112,031	2,956,587	206,470	7.14%	2,956,587	0.19%	2.
3.	51-100	104,742	8,369,418	325,374	11.42%	10,930,450	0.52%	124,099	9,788,186	330,569	11.43%	12,744,773	0.80%	3.
4.	101-150	113,377	14,880,824	438,751	15.40%	25,811,274	1.22%	134,721	17,579,309	465,290	16.09%	30,324,082	1.90%	4.
5.	151-200	112,631	20,695,693	551,382	19.35%	46,506,967	2.19%	148,172	27,052,622	613,462	21.22%	57,376,704	3.60%	5.
6.	201-250	114,326	26,991,933	665,708	23.37%	73,498,900	3.47%	164,808	38,633,881	778,270	26.92%	96,010,585	6.03%	6.
7.	251-300	117,902	34,012,908	783,610	27.50%	107,511,808	5.07%	180,168	51,550,160	958,438	33.15%	147,560,745	9.26%	7.
8.	301-350	121,041	41,241,730	904,651	31.75%	148,753,538	7.02%	185,845	62,794,011	1,144,283	39.58%	210,354,756	13.21%	8.
9.	351-400	121,157	47,603,859	1,025,808	36.00%	196,357,397	9.26%	184,591	71,912,339	1,328,874	45.96%	282,267,095	17.72%	9.
10.	401-450	120,181	53,497,704	1,145,989	40.22%	249,855,101	11.78%	176,214	77,759,841	1,505,088	52.06%	360,026,936	22.60%	10.
11.	451-500	117,988	58,695,817	1,263,977	44.36%	308,550,918	14.55%	163,791	80,758,378	1,668,879	57.73%	440,785,314	27.67%	11.
12.	501-550	113,914	62,614,194	1,377,891	48.36%	371,165,112	17.51%	148,901	81,138,129	1,817,780	62.88%	521,923,443	32.76%	12.
13.	551-600	109,133	65,690,751	1,487,024	52.19%	436,855,863	20.60%	133,839	79,863,661	1,951,619	67.51%	601,787,104	37.78%	13.
14.	601-650	103,897	67,980,611	1,590,921	55.84%	504,836,474	23.81%	118,229	76,688,116	2,069,848	71.59%	678,475,220	42.59%	14.
15.	651-700	97,970	69,229,715	1,688,891	59.28%	574,066,189	27.08%	103,275	72,342,503	2,173,123	75.17%	750,817,723	47.13%	15.
16.	701-750	91,923	69,763,227	1,780,814	62.50%	643,829,416	30.37%	90,679	68,218,712	2,263,802	78.30%	819,036,435	51.42%	16.
17.	751-800	86,532	70,195,772	1,867,346	65.54%	714,025,188	33.68%	78,223	62,912,812	2,342,025	81.01%	881,949,247	55.37%	17.
18.	801-850	80,696	69,685,762	1,948,042	68.37%	783,710,950	36.96%	68,123	58,310,552	2,410,148	83.37%	940,259,799	59.03%	18.
19.	851-900	75,002	68,694,328	2,023,044	71.01%	852,405,278	40.20%	58,870	53,459,990	2,469,018	85.40%	993,719,789	62.38%	19.
20.	901-950	69,252	67,046,317	2,092,296	73.44%	919,451,595	43.37%	50,776	48,735,236	2,519,794	87.16%	1,042,455,025	65.44%	20.
21.	951-1,000	64,698	66,032,499	2,156,994	75.71%	985,484,094	46.48%	44,254	44,772,577	2,564,048	88.69%	1,087,227,602	68.25%	21.
22.	1,001-1,100	114,776	126,020,715	2,271,770	79.74%	1,111,504,809	52.42%	71,565	77,831,529	2,635,613	91.16%	1,165,059,131	73.14%	22.
23.	1,101-1,200	96,932	116,565,457	2,368,702	83.14%	1,228,070,266	57.92%	54,384	64,809,011	2,689,997	93.05%	1,229,868,142	77.21%	23.
24.	1,201-1,300	80,658	105,431,532	2,449,360	85.97%	1,333,501,798	62.89%	41,144	53,286,351	2,731,141	94.47%	1,283,154,493	80.55%	24.
25.	1,301-1,400	67,907	95,854,162	2,517,267	88.35%	1,429,355,960	67.41%	31,419	43,963,308	2,762,560	95.56%	1,327,117,801	83.31%	25.
26.	1,401-1,500	56,947	86,347,159	2,574,214	90.35%	1,515,703,119	71.49%	24,369	36,634,109	2,786,929	96.40%	1,363,751,910	85.61%	26.
27.	1,501-1,600	47,034	76,246,321	2,621,248	92.00%	1,591,949,440	75.08%	18,991	30,520,532	2,805,920	97.06%	1,394,272,442	87.53%	27.
28.	1,601-1,700	39,054	67,381,274	2,660,302	93.37%	1,659,330,714	78.26%	14,871	25,444,887	2,820,791	97.57%	1,419,717,329	89.12%	28.
29.	1,701-1,800	32,083	58,708,757	2,692,385	94.50%	1,718,039,471	81.03%	12,053	21,873,042	2,832,844	97.99%	1,441,590,371	90.50%	29.
30.	1,801-1,900	26,611	51,487,492	2,718,996	95.43%	1,769,526,963	83.46%	9,569	18,361,062	2,842,413	98.32%	1,459,951,433	91.65%	30.
31.	1,901-2,000	21,825	44,503,142	2,740,821	96.20%	1,814,030,105	85.56%	7,977	16,132,181	2,850,390	98.59%	1,476,083,614	92.66%	31.
32.	2,001-2,250	62,756	145,149,972	2,803,577	98.40%	1,959,180,077	92.40%	22,455	51,532,853	2,872,845	99.37%	1,527,616,467	95.90%	32.
33.	2,251-2,500	23,803	67,561,352	2,827,380	99.24%	2,026,741,429	95.59%	8,918	25,141,171	2,881,763	99.68%	1,552,757,638	97.48%	33.
34.	2,501-3,000	14,645	51,777,309	2,842,025	99.75%	2,078,518,738	98.03%	6,131	21,552,826	2,887,894	99.89%	1,574,310,464	98.83%	34.
35.	3,001-4,000	3,921	18,076,705	2,845,946	99.89%	2,096,595,443	98.88%	1,775	8,143,664	2,889,669	99.95%	1,582,454,128	99.34%	35.
36.	4,001-5,000	2,913	19,210,637	2,848,859	99.99%	2,115,806,080	99.79%	1,276	8,293,414	2,890,945	100.00%	1,590,747,542	99.86%	36.
37.	5,001-10,000	222	2,998,581	2,849,081	100.00%	2,118,804,661	99.93%	90	1,198,652	2,891,035	100.00%	1,591,946,194	99.94%	37.
38.	10,001-20,000	33	1,436,335	2,849,114	100.00%	2,120,240,996	100.00%	25	1,014,833	2,891,060	100.00%	1,592,961,027	100.00%	38.
39.	over 20,000	-	-	2,849,114	100.00%	2,120,240,996	100.00%	-	-	2,891,060	100.00%	1,592,961,027	100.00%	39.

Average Number of Customers:	474,852	
Average Consumption:	744	kWh per bill
Median Consumption:	571	kWh per bill

Average Number of Customers:	481,843	
Average Consumption:	551	kWh per bill
Median Consumption:	433	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ET-1**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	12,300	-	12,300	1.48%	-	0.00%	13,467	-	13,467	1.60%	-	0.00%	2.
3.	51-100	2,926	80,350	15,226	1.84%	80,350	0.01%	3,425	95,433	16,892	2.01%	95,433	0.01%	3.
4.	101-150	3,451	269,014	18,677	2.25%	349,364	0.03%	5,515	426,669	22,407	2.66%	522,102	0.07%	4.
5.	151-200	4,956	623,770	23,633	2.85%	973,134	0.07%	7,328	928,749	29,735	3.53%	1,450,851	0.18%	5.
6.	201-250	4,957	875,077	28,590	3.45%	1,848,211	0.13%	9,926	1,763,708	39,661	4.71%	3,214,559	0.40%	6.
7.	251-300	5,268	1,196,319	33,858	4.09%	3,044,530	0.22%	13,951	3,180,324	53,612	6.36%	6,394,883	0.80%	7.
8.	301-350	6,111	1,696,086	39,969	4.82%	4,740,616	0.34%	19,227	5,343,609	72,839	8.65%	11,738,492	1.48%	8.
9.	351-400	7,059	2,312,898	47,028	5.67%	7,053,514	0.51%	24,566	8,049,943	97,405	11.56%	19,788,435	2.49%	9.
10.	401-450	8,248	3,117,715	55,276	6.67%	10,171,229	0.74%	29,062	10,968,872	126,467	15.01%	30,757,307	3.87%	10.
11.	451-500	9,387	4,019,349	64,663	7.80%	14,190,578	1.03%	32,582	13,934,210	159,049	18.88%	44,691,517	5.62%	11.
12.	501-550	10,310	4,932,163	74,973	9.05%	19,122,741	1.39%	34,495	16,478,521	193,544	22.97%	61,170,038	7.70%	12.
13.	551-600	11,629	6,146,438	86,602	10.45%	25,269,179	1.84%	35,735	18,854,137	229,279	27.21%	80,024,175	10.07%	13.
14.	601-650	12,555	7,264,078	99,157	11.96%	32,533,257	2.37%	36,696	21,200,883	265,975	31.57%	101,225,058	12.74%	14.
15.	651-700	13,561	8,527,509	112,718	13.60%	41,060,766	2.99%	36,161	22,704,662	302,136	35.86%	123,929,720	15.60%	15.
16.	701-750	14,379	9,764,032	127,097	15.33%	50,824,798	3.70%	36,127	24,500,038	338,263	40.15%	148,429,758	18.68%	16.
17.	751-800	14,987	10,930,685	142,084	17.14%	61,755,483	4.49%	35,303	25,712,505	373,566	44.34%	174,142,263	21.92%	17.
18.	801-850	15,810	12,323,700	157,894	19.05%	74,079,183	5.39%	34,464	26,829,428	408,030	48.43%	200,971,691	25.29%	18.
19.	851-900	16,318	13,539,590	174,212	21.02%	87,618,773	6.37%	32,967	27,318,266	440,997	52.35%	228,289,957	28.73%	19.
20.	901-950	16,801	14,787,734	191,013	23.05%	102,406,507	7.45%	31,793	27,937,878	472,790	56.12%	256,227,835	32.25%	20.
21.	951-1,000	17,126	15,931,275	208,139	25.11%	118,337,782	8.60%	30,302	28,155,482	503,092	59.72%	284,383,317	35.79%	21.
22.	1,001-1,100	17,646	17,301,072	225,785	27.24%	135,638,854	9.86%	28,361	27,769,341	531,453	63.08%	312,152,658	39.29%	22.
23.	1,101-1,200	36,720	38,785,108	262,505	31.67%	174,423,962	12.68%	51,286	54,035,755	582,739	69.17%	366,188,413	46.09%	23.
24.	1,201-1,300	37,034	42,822,281	299,539	36.14%	217,246,243	15.80%	44,637	51,503,849	627,376	74.47%	417,692,262	52.57%	24.
25.	1,301-1,400	37,406	47,003,450	336,945	40.65%	264,249,693	19.21%	37,930	47,563,840	665,306	78.97%	465,256,102	58.56%	25.
26.	1,401-1,500	37,447	50,802,583	374,392	45.17%	315,052,276	22.91%	31,659	42,880,253	696,965	82.73%	508,136,355	63.95%	26.
27.	1,501-1,600	36,889	53,759,085	411,281	49.62%	368,811,361	26.82%	26,133	38,010,316	723,098	85.83%	546,146,671	68.74%	27.
28.	1,601-1,700	35,643	55,539,167	446,924	53.92%	424,350,528	30.86%	21,517	33,465,717	744,615	88.38%	579,612,388	72.95%	28.
29.	1,701-1,800	34,125	56,592,898	481,049	58.04%	480,943,426	34.97%	17,635	29,196,437	762,250	90.48%	608,808,825	76.62%	29.
30.	1,801-1,900	33,002	58,043,117	514,051	62.02%	538,986,543	39.19%	14,320	25,141,019	776,570	92.18%	633,949,844	79.79%	30.
31.	1,901-2,000	30,812	57,277,192	544,863	65.74%	596,263,735	43.36%	11,528	21,393,674	788,098	93.55%	655,343,518	82.48%	31.
32.	2,001-2,250	29,067	56,963,250	573,930	69.25%	653,226,985	47.50%	9,426	18,437,637	797,524	94.66%	673,781,155	84.80%	32.
33.	2,251-2,500	114,394	256,502,528	688,324	83.05%	909,729,513	66.15%	26,220	58,101,768	823,744	97.78%	731,882,923	92.11%	33.
34.	2,501-3,000	67,636	185,305,181	755,960	91.21%	1,095,034,694	79.63%	10,009	27,274,982	833,753	98.96%	759,157,905	95.55%	34.
35.	3,001-4,000	53,612	182,514,088	809,572	97.68%	1,277,548,782	92.90%	6,055	20,562,924	839,808	99.68%	779,720,829	98.13%	35.
36.	4,001-5,000	13,048	57,572,743	822,620	99.25%	1,335,121,525	97.08%	1,498	6,623,109	841,306	99.86%	786,343,938	98.97%	36.
37.	5,001-10,000	5,922	36,252,513	828,542	99.96%	1,371,374,038	99.72%	1,072	6,782,325	842,378	99.99%	793,126,263	99.82%	37.
38.	10,001-20,000	279	3,518,603	828,821	100.00%	1,374,892,641	99.98%	98	1,244,105	842,476	100.00%	794,370,368	99.98%	38.
39.	over 20,000	12	343,078	828,833	100.00%	1,375,235,719	100.00%	4	178,566	842,480	100.00%	794,548,934	100.00%	39.

Average Number of Customers:	138,139	
Average Consumption:	1,659	kWh per bill
Median Consumption:	1,509	kWh per bill

Average Number of Customers:	140,413	
Average Consumption:	943	kWh per bill
Median Consumption:	820	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ET-2**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	28643	28,643	-	28,643	1.55%	-	0.00%	31,996	-	31,996	1.74%	-	0.00%	1.
2.	10238	10,238	264,252	38,881	2.10%	264,252	0.01%	14,285	367,348	46,281	2.52%	367,348	0.02%	2.
3.	10595	10,595	841,184	49,476	2.67%	1,105,436	0.04%	17,256	1,355,466	63,537	3.45%	1,722,814	0.11%	3.
4.	13001	13,001	1,684,998	62,477	3.37%	2,790,434	0.10%	21,529	2,787,199	85,066	4.63%	4,510,013	0.29%	4.
5.	13576	13,576	2,460,923	76,053	4.11%	5,251,357	0.19%	28,391	5,141,144	113,457	6.17%	9,651,157	0.61%	5.
6.	15004	15,004	3,492,939	91,057	4.92%	8,744,296	0.31%	38,814	9,010,825	152,271	8.28%	18,661,982	1.18%	6.
7.	17525	17,525	4,986,907	108,582	5.86%	13,731,203	0.48%	50,760	14,375,119	203,031	11.04%	33,037,101	2.09%	7.
8.	20312	20,312	6,826,167	128,894	6.96%	20,557,370	0.72%	63,277	21,141,831	266,308	14.48%	54,178,932	3.44%	8.
9.	23185	23,185	8,983,057	152,079	8.21%	29,540,427	1.04%	73,553	28,325,464	339,861	18.48%	82,504,396	5.23%	9.
10.	26203	26,203	11,505,572	178,282	9.63%	41,045,999	1.45%	81,227	35,422,685	421,088	22.90%	117,927,081	7.48%	10.
11.	29149	29,149	14,292,366	207,431	11.20%	55,338,365	1.95%	86,374	42,079,091	507,462	27.59%	160,006,172	10.14%	11.
12.	31771	31,771	17,216,349	239,202	12.91%	72,554,714	2.56%	88,917	47,858,503	596,379	32.43%	207,864,675	13.18%	12.
13.	34327	34,327	20,368,526	273,529	14.77%	92,923,240	3.28%	89,635	52,825,516	686,014	37.30%	260,690,191	16.53%	13.
14.	36377	36,377	23,458,043	309,906	16.73%	116,381,283	4.10%	88,488	56,673,539	774,502	42.11%	317,363,730	20.12%	14.
15.	38518	38,518	26,821,924	348,424	18.81%	143,203,207	5.05%	86,217	59,635,827	860,719	46.80%	376,999,557	23.90%	15.
16.	40415	40,415	30,223,514	388,839	20.99%	173,426,721	6.11%	83,155	61,767,503	943,874	51.32%	438,767,060	27.82%	16.
17.	41654	41,654	33,291,274	430,493	23.24%	206,717,995	7.29%	79,013	62,729,282	1,022,887	55.62%	501,496,342	31.80%	17.
18.	43317	43,317	36,851,433	473,810	25.58%	243,569,428	8.59%	74,264	62,762,664	1,097,151	59.66%	564,259,006	35.77%	18.
19.	44172	44,172	39,852,932	517,982	27.97%	283,422,360	9.99%	69,807	62,565,378	1,166,958	63.46%	626,824,384	39.74%	19.
20.	44613	44,613	42,551,355	562,595	30.37%	325,973,715	11.49%	64,688	61,298,406	1,231,646	66.97%	688,122,790	43.63%	20.
21.	45157	45,157	45,393,071	607,752	32.81%	371,366,786	13.09%	59,538	59,454,982	1,291,184	70.21%	747,577,772	47.40%	21.
22.	90918	90,918	98,412,529	698,670	37.72%	469,779,315	16.56%	105,304	113,134,421	1,396,488	75.94%	860,712,193	54.57%	22.
23.	90677	90,677	107,488,286	789,347	42.62%	577,267,601	20.35%	86,903	102,254,327	1,483,391	80.66%	962,966,520	61.05%	23.
24.	88939	88,939	114,592,719	878,286	47.42%	691,860,320	24.39%	71,204	91,062,542	1,554,595	84.53%	1,054,029,062	66.83%	24.
25.	86338	86,338	120,121,150	964,624	52.08%	811,981,470	28.62%	57,026	78,763,107	1,611,621	87.63%	1,132,792,169	71.82%	25.
26.	83311	83,311	124,490,577	1,047,935	56.58%	936,472,047	33.01%	45,511	67,514,692	1,657,132	90.11%	1,200,306,861	76.10%	26.
27.	79968	79,968	127,717,888	1,127,903	60.89%	1,064,189,935	37.51%	36,679	58,171,762	1,693,811	92.10%	1,258,478,623	79.79%	27.
28.	75226	75,226	127,906,918	1,203,129	64.96%	1,192,096,853	42.02%	28,771	48,575,887	1,722,582	93.67%	1,307,054,510	82.87%	28.
29.	70518	70,518	127,152,018	1,273,647	68.76%	1,319,248,871	46.50%	22,662	40,583,942	1,745,244	94.90%	1,347,638,452	85.44%	29.
30.	65167	65,167	124,216,704	1,338,814	72.28%	1,443,465,575	50.88%	17,886	33,854,227	1,763,130	95.87%	1,381,492,679	87.59%	30.
31.	60238	60,238	121,044,849	1,399,052	75.53%	1,564,510,424	55.15%	13,893	27,723,372	1,777,023	96.63%	1,409,216,051	89.35%	31.
32.	224648	224,648	515,625,891	1,623,700	87.66%	2,080,136,315	73.33%	37,504	84,713,795	1,814,527	98.67%	1,493,929,846	94.72%	32.
33.	119706	119,706	335,768,783	1,743,406	94.12%	2,415,905,098	85.16%	13,365	37,126,260	1,827,892	99.39%	1,531,056,106	97.07%	33.
34.	83503	83,503	290,592,183	1,826,909	98.63%	2,706,497,281	95.41%	7,694	26,610,199	1,835,586	99.81%	1,557,666,305	98.76%	34.
35.	17837	17,837	80,602,931	1,844,746	99.60%	2,787,100,212	98.25%	2,027	9,167,957	1,837,613	99.92%	1,566,834,262	99.34%	35.
36.	7099	7,099	44,078,721	1,851,845	99.98%	2,831,178,933	99.80%	1,275	8,173,799	1,838,888	99.99%	1,575,008,061	99.86%	36.
37.	358	358	4,637,580	1,852,203	100.00%	2,835,816,513	99.96%	117	1,444,197	1,839,005	100.00%	1,576,452,258	99.95%	37.
38.	22	22	997,483	1,852,225	100.00%	2,836,813,996	100.00%	20	806,504	1,839,025	100.00%	1,577,258,762	100.00%	38.
39.	0	-	-	1,852,225	100.00%	2,836,813,996	100.00%	-	-	1,839,025	100.00%	1,577,258,762	100.00%	39.

Average Number of Customers:	308,704		Average Number of Customers:	306,504	
Average Consumption:	1,532	kWh per bill	Average Consumption:	858	kWh per bill
Median Consumption:	1,355	kWh per bill	Median Consumption:	736	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ECT-2**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	1,620	-	1,620	0.29%	-	0.00%	1,746	-	1,746	0.31%	-	0.00%	1.
2.	1-50	865	22,546	2,485	0.44%	22,546	0.00%	1,229	31,499	2,975	0.53%	31,499	0.00%	2.
3.	51-100	952	73,663	3,437	0.61%	96,209	0.01%	1,538	119,625	4,513	0.81%	151,124	0.02%	3.
4.	101-150	993	127,039	4,430	0.79%	223,248	0.02%	1,910	244,344	6,423	1.15%	395,468	0.05%	4.
5.	151-200	1,147	204,877	5,577	0.99%	428,125	0.03%	2,450	438,484	8,873	1.59%	833,952	0.11%	5.
6.	201-250	1,211	278,188	6,788	1.21%	706,313	0.05%	3,293	755,763	12,166	2.18%	1,589,715	0.20%	6.
7.	251-300	1,436	402,538	8,224	1.47%	1,108,851	0.08%	4,646	1,303,201	16,812	3.01%	2,892,916	0.37%	7.
8.	301-350	1,740	576,689	9,964	1.78%	1,685,540	0.12%	6,285	2,078,389	23,097	4.13%	4,971,305	0.64%	8.
9.	351-400	2,065	788,950	12,029	2.14%	2,474,490	0.18%	7,843	2,989,452	30,940	5.53%	7,960,757	1.03%	9.
10.	401-450	2,355	1,019,415	14,384	2.56%	3,493,905	0.26%	9,520	4,106,434	40,460	7.23%	12,067,191	1.56%	10.
11.	451-500	2,823	1,365,402	17,207	3.07%	4,859,307	0.36%	11,178	5,387,208	51,638	9.23%	17,454,399	2.25%	11.
12.	501-550	3,146	1,681,119	20,353	3.63%	6,540,426	0.48%	12,615	6,715,949	64,253	11.49%	24,170,348	3.12%	12.
13.	551-600	3,525	2,061,406	23,878	4.26%	8,601,832	0.63%	13,712	7,993,606	77,965	13.94%	32,163,954	4.15%	13.
14.	601-650	4,014	2,551,107	27,892	4.97%	11,152,939	0.82%	14,657	9,284,226	92,622	16.56%	41,448,180	5.34%	14.
15.	651-700	4,459	3,059,697	32,351	5.77%	14,212,636	1.04%	15,809	10,815,325	108,431	19.39%	52,263,505	6.74%	15.
16.	701-750	4,815	3,548,634	37,166	6.62%	17,761,270	1.30%	16,491	12,114,012	124,922	22.33%	64,377,517	8.30%	16.
17.	751-800	5,265	4,148,272	42,431	7.56%	21,909,542	1.60%	17,234	13,533,393	142,156	25.42%	77,910,910	10.04%	17.
18.	801-850	5,539	4,644,628	47,970	8.55%	26,554,170	1.94%	17,730	14,819,999	159,886	28.59%	92,730,909	11.95%	18.
19.	851-900	5,991	5,326,800	53,961	9.62%	31,880,970	2.33%	18,174	16,111,616	178,060	31.84%	108,842,525	14.03%	19.
20.	901-950	6,302	5,922,319	60,263	10.74%	37,803,289	2.77%	18,086	16,946,726	196,146	35.07%	125,789,251	16.21%	20.
21.	951-1,000	6,749	6,686,514	67,012	11.94%	44,489,803	3.26%	18,356	18,128,112	214,502	38.35%	143,917,363	18.55%	21.
22.	1,001-1,100	14,427	15,401,597	81,439	14.52%	59,891,400	4.38%	36,172	38,464,544	250,674	44.82%	182,381,907	23.51%	22.
23.	1,101-1,200	15,669	18,313,354	97,108	17.31%	78,204,754	5.72%	34,344	39,992,846	285,018	50.96%	222,374,753	28.66%	23.
24.	1,201-1,300	16,855	21,409,618	113,963	20.31%	99,614,372	7.29%	32,635	41,298,269	317,653	56.79%	263,673,022	33.98%	24.
25.	1,301-1,400	17,884	24,516,996	131,847	23.50%	124,131,368	9.08%	29,755	40,657,501	347,408	62.11%	304,330,523	39.22%	25.
26.	1,401-1,500	18,282	26,932,592	150,129	26.76%	151,063,960	11.05%	26,883	39,448,492	374,291	66.92%	343,779,015	44.31%	26.
27.	1,501-1,600	18,634	29,344,442	168,763	30.08%	180,408,402	13.20%	23,970	37,598,966	398,261	71.21%	381,377,981	49.16%	27.
28.	1,601-1,700	19,465	32,626,964	188,228	33.55%	213,035,366	15.59%	21,500	35,903,264	419,761	75.05%	417,281,245	53.78%	28.
29.	1,701-1,800	19,501	34,665,428	207,729	37.03%	247,700,794	18.13%	18,328	32,464,097	438,089	78.33%	449,745,342	57.97%	29.
30.	1,801-1,900	19,716	37,051,030	227,445	40.54%	284,751,824	20.84%	16,274	30,475,841	454,363	81.24%	480,221,183	61.90%	30.
31.	1,901-2,000	19,401	38,430,794	246,846	44.00%	323,182,618	23.65%	14,013	27,655,505	468,376	83.74%	507,876,688	65.46%	31.
32.	2,001-2,250	91,485	208,570,314	338,331	60.31%	531,752,932	38.91%	44,687	100,407,362	513,063	91.73%	608,284,050	78.40%	32.
33.	2,251-2,500	75,816	210,889,477	414,147	73.82%	742,642,409	54.35%	20,913	57,568,024	533,976	95.47%	665,852,074	85.82%	33.
34.	2,501-3,000	88,905	309,678,377	503,052	89.67%	1,052,320,786	77.01%	15,580	53,624,809	549,556	98.26%	719,476,883	92.73%	34.
35.	3,001-4,000	34,328	153,954,805	537,380	95.79%	1,206,275,591	88.27%	5,107	22,872,942	554,663	99.17%	742,349,825	95.68%	35.
36.	4,001-5,000	22,123	139,044,074	559,503	99.73%	1,345,319,665	98.45%	4,191	26,988,890	558,854	99.92%	769,338,715	99.16%	36.
37.	5,001-10,000	1,400	17,942,789	560,903	99.98%	1,363,262,454	99.76%	426	5,727,470	559,280	99.99%	775,066,185	99.90%	37.
38.	10,001-20,000	120	3,266,040	561,023	100.00%	1,366,528,494	100.00%	33	797,113	559,313	100.00%	775,863,298	100.00%	38.
39.	over 20,000	-	-	561,023	100.00%	1,366,528,494	100.00%	-	-	559,313	100.00%	775,863,298	100.00%	39.

Average Number of Customers:	93,504		Average Number of Customers:	93,219	
Average Consumption:	2,436	kWh per bill	Average Consumption:	1,387	kWh per bill
Median Consumption:	2,178	kWh per bill	Median Consumption:	1,185	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ECT-2**
DESCRIPTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	kW BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kW) (L)	% of Total (M)	Line No.
1.	0	2,334	-	2,334	0.42%	-	0.00%	2,523	-	2,523	0.45%	-	0.00%	1.
2.	0-0.4	1,571	401	3,905	0.70%	401	0.01%	2,351	637	4,874	0.87%	637	0.02%	2.
3.	0.4-0.8	1,553	1,023	5,458	0.97%	1,424	0.03%	4,583	3,083	9,457	1.69%	3,720	0.12%	3.
4.	0.8-1.2	1,802	1,901	7,260	1.29%	3,325	0.07%	8,346	8,882	17,803	3.18%	12,602	0.42%	4.
5.	1.2-1.6	2,619	3,826	9,879	1.76%	7,151	0.16%	12,648	18,462	30,451	5.44%	31,064	1.04%	5.
6.	1.6-2.0	3,605	6,705	13,484	2.40%	13,856	0.31%	17,568	32,648	48,019	8.59%	63,712	2.14%	6.
7.	2.0-2.4	4,922	11,125	18,406	3.28%	24,981	0.56%	22,492	50,755	70,511	12.61%	114,467	3.85%	7.
8.	2.4-2.8	6,504	17,299	24,910	4.44%	42,280	0.94%	27,385	72,703	97,896	17.50%	187,170	6.29%	8.
9.	2.8-3.2	8,514	26,053	33,424	5.96%	68,333	1.52%	32,100	98,035	129,996	23.24%	285,205	9.58%	9.
10.	3.2-3.6	11,180	38,658	44,604	7.95%	106,991	2.38%	35,365	122,103	165,361	29.57%	407,308	13.68%	10.
11.	3.6-4.0	14,242	54,956	58,846	10.49%	161,947	3.61%	38,382	147,885	203,743	36.43%	555,193	18.65%	11.
12.	4.0-4.4	17,360	73,889	76,206	13.58%	235,836	5.25%	38,625	164,156	242,368	43.33%	719,349	24.16%	12.
13.	4.4-4.8	21,013	97,837	97,219	17.33%	333,673	7.43%	37,711	175,366	280,079	50.08%	894,715	30.06%	13.
14.	4.8-5.2	23,772	120,135	120,991	21.57%	453,808	10.11%	36,155	182,492	316,234	56.54%	1,077,207	36.19%	14.
15.	5.2-5.6	26,290	143,371	147,281	26.25%	597,179	13.30%	33,480	182,420	349,714	62.53%	1,259,627	42.31%	15.
16.	5.6-6.0	28,368	166,020	175,649	31.31%	763,199	17.00%	30,143	176,240	379,857	67.92%	1,435,867	48.23%	16.
17.	6.0-6.4	29,703	185,677	205,352	36.60%	948,876	21.13%	27,116	169,429	406,973	72.76%	1,605,296	53.93%	17.
18.	6.4-6.8	30,493	202,781	235,845	42.04%	1,151,657	25.65%	23,859	158,567	430,832	77.03%	1,763,863	59.25%	18.
19.	6.8-7.2	30,215	213,034	266,060	47.42%	1,364,691	30.39%	20,310	143,139	451,142	80.66%	1,907,002	64.06%	19.
20.	7.2-7.6	29,262	217,993	295,322	52.64%	1,582,684	35.25%	17,394	129,504	468,536	83.77%	2,036,506	68.41%	20.
21.	7.6-8.0	28,200	221,347	323,522	57.67%	1,804,031	40.18%	14,865	116,675	483,401	86.43%	2,153,181	72.33%	21.
22.	8.0-8.4	26,171	215,834	349,693	62.33%	2,019,865	44.99%	12,310	101,494	495,711	88.63%	2,254,675	75.74%	22.
23.	8.4-8.8	24,587	212,615	374,280	66.71%	2,232,480	49.72%	10,273	88,827	505,984	90.47%	2,343,502	78.72%	23.
24.	8.8-9.2	22,317	201,924	396,597	70.69%	2,434,404	54.22%	8,173	73,928	514,157	91.93%	2,417,430	81.21%	24.
25.	9.2-9.6	20,270	191,499	416,867	74.31%	2,625,903	58.48%	7,074	66,843	521,231	93.19%	2,484,273	83.45%	25.
26.	9.6-10.0	17,985	177,141	434,852	77.51%	2,803,044	62.43%	5,537	54,502	526,768	94.18%	2,538,775	85.28%	26.
27.	10.0-10.4	16,013	164,081	450,865	80.37%	2,967,125	66.08%	4,831	49,521	531,599	95.05%	2,588,296	86.95%	27.
28.	10.4-10.8	13,973	148,750	464,838	82.86%	3,115,875	69.40%	3,869	41,199	535,468	95.74%	2,629,495	88.33%	28.
29.	10.8-11.2	12,486	137,940	477,324	85.08%	3,253,815	72.47%	3,369	37,239	538,837	96.34%	2,666,734	89.58%	29.
30.	11.2-12.0	19,933	231,907	497,257	88.63%	3,485,722	77.63%	4,978	57,967	543,815	97.23%	2,724,701	91.53%	30.
31.	12.0 - 13.0	17,970	224,977	515,227	91.84%	3,710,699	82.64%	4,200	52,599	548,015	97.98%	2,777,300	93.30%	31.
32.	13.0 - 14.0	12,477	168,705	527,704	94.06%	3,879,404	86.40%	2,837	38,372	550,852	98.49%	2,815,672	94.58%	32.
33.	14.0 - 15.0	8,618	125,114	536,322	95.60%	4,004,518	89.19%	1,848	26,822	552,700	98.82%	2,842,494	95.49%	33.
34.	15.0 - 16.0	6,230	96,751	542,552	96.71%	4,101,269	91.34%	1,608	25,012	554,308	99.11%	2,867,506	96.33%	34.
35.	16.0 - 17.0	4,128	68,260	546,680	97.44%	4,169,529	92.86%	994	16,445	555,302	99.28%	2,883,951	96.88%	35.
36.	17.0 - 18.0	3,175	55,623	549,855	98.01%	4,225,152	94.10%	809	14,182	556,111	99.43%	2,898,133	97.36%	36.
37.	18.0 - 19.0	2,254	41,737	552,109	98.41%	4,266,889	95.03%	583	10,795	556,694	99.53%	2,908,928	97.72%	37.
38.	19.0 - 20.0	1,880	36,734	553,989	98.75%	4,303,623	95.85%	508	9,935	557,202	99.62%	2,918,863	98.05%	38.
39.	20.0 - 25.0	4,242	93,798	558,231	99.50%	4,397,421	97.94%	1,166	25,867	558,368	99.83%	2,944,730	98.92%	39.
40.	25.0 - 30.0	1,462	39,694	559,693	99.76%	4,437,115	98.82%	450	12,257	558,818	99.91%	2,956,987	99.33%	40.
41.	Over 30.0	1,328	52,881	561,021	100.00%	4,489,996	100.00%	492	19,884	559,310	100.00%	2,976,871	100.00%	41.

Average Number of Customers: 93,504
Average Load: 8.0 kW per bill
Median Load: 7.4 kW per bill

Average Number of Customers: 93,218
Average Load: 5.0 kW per bill
Median Load: 4.8 kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ECT-1**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	CONSUMPTION kWh BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kWh) (L)	% of Total (M)	Line No.
1.	0	419	-	419	0.26%	-	0.00%	485	-	485	0.30%	-	0.00%	1.
2.	1-50	134	3,847	553	0.35%	3,847	0.00%	165	4,524	650	0.40%	4,524	0.00%	2.
3.	51-100	170	12,647	723	0.46%	16,494	0.00%	286	22,261	936	0.58%	26,785	0.01%	3.
4.	101-150	200	25,434	923	0.58%	41,928	0.01%	372	47,417	1,308	0.81%	74,202	0.03%	4.
5.	151-200	276	49,007	1,199	0.76%	90,935	0.02%	556	98,567	1,864	1.16%	172,769	0.07%	5.
6.	201-250	294	66,746	1,493	0.94%	157,681	0.04%	710	161,298	2,574	1.60%	334,067	0.13%	6.
7.	251-300	364	101,118	1,857	1.17%	258,799	0.06%	1,005	278,421	3,579	2.22%	612,488	0.24%	7.
8.	301-350	427	139,693	2,284	1.44%	398,492	0.10%	1,305	427,999	4,884	3.03%	1,040,487	0.41%	8.
9.	351-400	505	190,422	2,789	1.76%	588,914	0.14%	1,698	640,822	6,582	4.09%	1,681,309	0.66%	9.
10.	401-450	552	236,009	3,341	2.11%	824,923	0.20%	2,061	880,005	8,643	5.37%	2,561,314	1.00%	10.
11.	451-500	639	304,956	3,980	2.51%	1,129,879	0.27%	2,540	1,213,196	11,183	6.95%	3,774,510	1.47%	11.
12.	501-550	746	393,734	4,726	2.98%	1,523,613	0.37%	2,711	1,430,285	13,894	8.63%	5,204,795	2.03%	12.
13.	551-600	826	477,207	5,552	3.50%	2,000,820	0.48%	3,061	1,768,075	16,955	10.53%	6,972,870	2.72%	13.
14.	601-650	977	613,058	6,529	4.12%	2,613,878	0.63%	3,430	2,151,120	20,385	12.66%	9,123,990	3.56%	14.
15.	651-700	1,073	727,154	7,602	4.80%	3,341,032	0.80%	3,534	2,393,796	23,919	14.86%	11,517,786	4.50%	15.
16.	701-750	1,232	896,466	8,834	5.57%	4,237,498	1.02%	3,963	2,883,595	27,882	17.32%	14,401,381	5.63%	16.
17.	751-800	1,379	1,072,742	10,213	6.45%	5,310,240	1.27%	4,071	3,165,824	31,953	19.85%	17,567,205	6.86%	17.
18.	801-850	1,407	1,165,645	11,620	7.33%	6,475,885	1.55%	4,266	3,530,979	36,219	22.49%	21,098,184	8.24%	18.
19.	851-900	1,495	1,313,499	13,115	8.28%	7,789,384	1.87%	4,346	3,815,384	40,565	25.19%	24,913,568	9.73%	19.
20.	901-950	1,635	1,519,367	14,750	9.31%	9,308,751	2.23%	4,561	4,232,119	45,126	28.03%	29,145,687	11.39%	20.
21.	951-1,000	1,784	1,744,651	16,534	10.43%	11,053,402	2.65%	4,650	4,549,078	49,776	30.91%	33,694,765	13.16%	21.
22.	1,001-1,100	3,799	4,007,082	20,333	12.83%	15,060,484	3.61%	9,498	10,008,257	59,274	36.81%	43,703,022	17.07%	22.
23.	1,101-1,200	4,096	4,727,964	24,429	15.42%	19,788,448	4.74%	9,288	10,710,032	68,562	42.58%	54,413,054	21.26%	23.
24.	1,201-1,300	4,399	5,518,933	28,828	18.19%	25,307,381	6.06%	9,169	11,486,522	77,731	48.28%	65,899,576	25.75%	24.
25.	1,301-1,400	4,629	6,271,960	33,457	21.11%	31,579,341	7.57%	8,493	11,486,724	86,224	53.55%	77,386,300	30.23%	25.
26.	1,401-1,500	4,790	6,967,589	38,247	24.14%	38,546,930	9.24%	8,061	11,719,620	94,285	58.56%	89,105,920	34.81%	26.
27.	1,501-1,600	5,050	7,854,616	43,297	27.32%	46,401,546	11.12%	7,221	11,210,101	101,506	63.04%	100,316,021	39.19%	27.
28.	1,601-1,700	5,149	8,520,457	48,446	30.57%	54,922,003	13.16%	6,517	10,779,019	108,023	67.09%	111,095,040	43.40%	28.
29.	1,701-1,800	5,295	9,294,491	53,741	33.91%	64,216,494	15.39%	5,881	10,310,593	113,904	70.74%	121,405,633	47.43%	29.
30.	1,801-1,900	5,292	9,816,212	59,033	37.25%	74,032,706	17.74%	5,172	9,591,865	119,076	73.96%	130,997,498	51.18%	30.
31.	1,901-2,000	5,226	10,223,675	64,259	40.55%	84,256,381	20.19%	4,643	9,069,463	123,719	76.84%	140,066,961	54.72%	31.
32.	2,001-2,250	24,666	55,494,526	88,925	56.12%	139,750,907	33.49%	16,165	36,037,993	139,884	86.88%	176,104,954	68.80%	32.
33.	2,251-2,500	20,577	56,496,967	109,502	69.10%	196,247,874	47.03%	8,551	23,353,515	148,435	92.19%	199,458,469	77.93%	33.
34.	2,501-3,000	25,899	89,324,325	135,401	85.45%	285,572,199	68.44%	7,135	24,404,397	155,570	96.62%	223,862,866	87.46%	34.
35.	3,001-4,000	11,753	52,268,415	147,154	92.87%	337,840,614	80.96%	2,692	11,956,435	158,262	98.29%	235,819,301	92.13%	35.
36.	4,001-5,000	10,338	65,751,414	157,492	99.39%	403,592,028	96.72%	2,458	15,874,582	160,720	99.82%	251,693,883	98.34%	36.
37.	5,001-10,000	873	10,865,527	158,365	99.94%	414,457,555	99.32%	255	3,283,495	160,975	99.98%	254,977,378	99.62%	37.
38.	10,001-20,000	93	2,830,013	158,458	100.00%	417,287,568	100.00%	35	977,323	161,010	100.00%	255,954,701	100.00%	38.
39.	over 20,000	-	-	158,458	100.00%	417,287,568	100.00%	-	-	161,010	100.00%	255,954,701	100.00%	39.

Average Number of Customers:	26,410		26,835	
Average Consumption:	2,633	kWh per bill	1,590	kWh per bill
Median Consumption:	2,293	kWh per bill	1,332	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ECT-1**
DESCRIPTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	kW BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kW) (L)	% of Total (M)	Line No.
1.	0	566	-	566	0.36%	-	0.00%	691	-	691	0.43%	-	0.00%	1.
2.	0-0.4	406	108	972	0.61%	108	0.01%	457	124	1,148	0.71%	124	0.01%	2.
3.	0.4-0.8	356	233	1,328	0.84%	341	0.02%	708	476	1,856	1.15%	600	0.06%	3.
4.	0.8-1.2	320	343	1,648	1.04%	684	0.05%	1,280	1,368	3,136	1.95%	1,968	0.19%	4.
5.	1.2-1.6	413	607	2,061	1.30%	1,291	0.09%	2,058	3,024	5,194	3.23%	4,992	0.49%	5.
6.	1.6-2.0	664	1,240	2,725	1.72%	2,531	0.18%	3,096	5,781	8,290	5.15%	10,773	1.05%	6.
7.	2.0-2.4	961	2,181	3,686	2.33%	4,712	0.34%	4,265	9,665	12,555	7.80%	20,438	1.99%	7.
8.	2.4-2.8	1,364	3,649	5,050	3.19%	8,361	0.60%	5,351	14,249	17,906	11.12%	34,687	3.38%	8.
9.	2.8-3.2	1,851	5,695	6,901	4.36%	14,056	1.00%	6,529	20,021	24,435	15.18%	54,708	5.33%	9.
10.	3.2-3.6	2,445	8,497	9,346	5.90%	22,553	1.61%	7,651	26,544	32,086	19.93%	81,252	7.92%	10.
11.	3.6-4.0	3,263	12,629	12,609	7.96%	35,182	2.51%	8,712	33,681	40,798	25.34%	114,933	11.20%	11.
12.	4.0-4.4	4,302	18,384	16,911	10.67%	53,566	3.81%	9,410	40,139	50,208	31.18%	155,072	15.11%	12.
13.	4.4-4.8	5,281	24,685	22,192	14.01%	78,251	5.57%	9,952	46,438	60,160	37.36%	201,510	19.64%	13.
14.	4.8-5.2	6,047	30,672	28,239	17.82%	108,923	7.76%	10,057	50,972	70,217	43.61%	252,482	24.60%	14.
15.	5.2-5.6	6,942	38,011	35,181	22.20%	146,934	10.46%	9,687	52,987	79,904	49.63%	305,469	29.77%	15.
16.	5.6-6.0	7,400	43,494	42,581	26.87%	190,428	13.56%	9,297	54,578	89,201	55.40%	360,047	35.08%	16.
17.	6.0-6.4	7,772	48,794	50,353	31.78%	239,222	17.04%	8,679	54,420	97,880	60.79%	414,467	40.39%	17.
18.	6.4-6.8	7,844	52,373	58,197	36.73%	291,595	20.77%	7,827	52,217	105,707	65.65%	466,684	45.47%	18.
19.	6.8-7.2	7,957	56,336	66,154	41.75%	347,931	24.78%	6,945	49,117	112,652	69.97%	515,801	50.26%	19.
20.	7.2-7.6	7,774	58,147	73,928	46.66%	406,078	28.92%	6,299	47,066	118,951	73.88%	562,867	54.85%	20.
21.	7.6-8.0	7,470	58,876	81,398	51.37%	464,954	33.11%	5,552	43,720	124,503	77.33%	606,587	59.11%	21.
22.	8.0-8.4	7,005	58,020	88,403	55.79%	522,974	37.24%	4,878	40,366	129,381	80.36%	646,953	63.04%	22.
23.	8.4-8.8	6,538	56,763	94,941	59.92%	579,737	41.28%	4,275	37,100	133,656	83.01%	684,053	66.66%	23.
24.	8.8-9.2	6,252	56,818	101,193	63.86%	636,555	45.33%	3,486	31,657	137,142	85.18%	715,710	69.74%	24.
25.	9.2-9.6	5,631	53,410	106,824	67.42%	689,965	49.13%	3,175	30,114	140,317	87.15%	745,824	72.67%	25.
26.	9.6-10.0	5,193	51,346	112,017	70.69%	741,311	52.79%	2,585	25,558	142,902	88.75%	771,382	75.17%	26.
27.	10.0-10.4	4,786	49,269	116,803	73.71%	790,580	56.30%	2,196	22,586	145,098	90.12%	793,968	77.37%	27.
28.	10.4-10.8	4,146	44,329	120,949	76.33%	834,909	59.46%	1,913	20,437	147,011	91.30%	814,405	79.36%	28.
29.	10.8-11.2	3,869	42,930	124,818	78.77%	877,839	62.51%	1,703	18,898	148,714	92.36%	833,303	81.20%	29.
30.	11.2-12.0	6,499	75,946	131,317	82.87%	953,785	67.92%	2,735	31,951	151,449	94.06%	865,254	84.31%	30.
31.	12.0 - 13.0	6,393	80,405	137,710	86.91%	1,034,190	73.65%	2,325	29,238	153,774	95.51%	894,492	87.16%	31.
32.	13.0 - 14.0	4,862	66,050	142,572	89.98%	1,100,240	78.35%	1,664	22,595	155,438	96.54%	917,087	89.36%	32.
33.	14.0 - 15.0	3,550	51,786	146,122	92.22%	1,152,026	82.04%	1,169	17,015	156,607	97.26%	934,102	91.02%	33.
34.	15.0 - 16.0	2,703	42,136	148,825	93.92%	1,194,162	85.04%	942	14,677	157,549	97.85%	948,779	92.45%	34.
35.	16.0 - 17.0	1,940	32,235	150,765	95.15%	1,226,397	87.33%	636	10,562	158,185	98.24%	959,341	93.48%	35.
36.	17.0 - 18.0	1,495	26,312	152,260	96.09%	1,252,709	89.21%	504	8,880	158,689	98.56%	968,221	94.35%	36.
37.	18.0 - 19.0	1,146	21,321	153,406	96.81%	1,274,030	90.73%	370	6,866	159,059	98.79%	975,087	95.01%	37.
38.	19.0 - 20.0	977	19,173	154,383	97.43%	1,293,203	92.09%	371	7,253	159,430	99.02%	982,340	95.72%	38.
39.	20.0 - 25.0	2,326	51,714	156,709	98.90%	1,344,917	95.77%	880	19,604	160,310	99.56%	1,001,944	97.63%	39.
40.	25.0 - 30.0	895	24,479	157,604	99.46%	1,369,396	97.52%	354	9,627	160,664	99.78%	1,011,571	98.57%	40.
41.	Over 30.0	851	34,865	158,455	100.00%	1,404,261	100.00%	347	14,678	161,011	100.00%	1,026,249	100.00%	41.

Average Number of Customers:	26,409		Average Number of Customers:	26,835	
Average Load:	9.0	kW per bill	Average Load:	6.0	kW per bill
Median Load:	7.9	kW per bill	Median Load:	5.7	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ET-SP**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	44	-	44	0.46%	-	0.00%	33	-	33	0.36%	-	0.00%	2.
3.	51-100	117	3,060	161	1.69%	3,060	0.02%	64	1,715	97	1.06%	1,715	0.02%	3.
4.	101-150	98	7,808	259	2.72%	10,868	0.08%	141	11,028	238	2.59%	12,743	0.15%	4.
5.	151-200	163	21,765	422	4.43%	32,633	0.24%	179	23,587	417	4.54%	36,330	0.41%	5.
6.	201-250	168	31,224	590	6.19%	63,857	0.46%	197	36,439	614	6.69%	72,769	0.83%	6.
7.	251-300	184	44,004	774	8.12%	107,861	0.78%	281	65,811	895	9.75%	138,580	1.58%	7.
8.	301-350	185	54,157	959	10.06%	162,018	1.17%	294	83,883	1,189	12.95%	222,463	2.53%	8.
9.	351-400	201	69,555	1,160	12.17%	231,573	1.68%	329	110,830	1,518	16.53%	333,293	3.79%	9.
10.	401-450	221	88,046	1,381	14.49%	319,619	2.32%	310	120,536	1,828	19.91%	453,829	5.17%	10.
11.	451-500	213	96,327	1,594	16.72%	415,946	3.01%	366	161,027	2,194	23.89%	614,856	7.00%	11.
12.	501-550	265	133,822	1,859	19.50%	549,768	3.98%	419	205,654	2,613	28.46%	820,510	9.34%	12.
13.	551-600	247	138,038	2,106	22.10%	687,806	4.98%	413	225,132	3,026	32.96%	1,045,642	11.90%	13.
14.	601-650	249	152,103	2,355	24.71%	839,909	6.09%	365	217,316	3,391	36.93%	1,262,958	14.38%	14.
15.	651-700	292	193,383	2,647	27.77%	1,033,292	7.49%	375	243,284	3,766	41.02%	1,506,242	17.15%	15.
16.	701-750	236	169,088	2,883	30.25%	1,202,380	8.71%	314	219,539	4,080	44.43%	1,725,781	19.65%	16.
17.	751-800	242	186,352	3,125	32.79%	1,388,732	10.06%	325	243,606	4,405	47.97%	1,969,387	22.42%	17.
18.	801-850	225	184,501	3,350	35.15%	1,573,233	11.40%	338	271,170	4,743	51.66%	2,240,557	25.51%	18.
19.	851-900	242	212,479	3,592	37.69%	1,785,712	12.94%	331	282,106	5,074	55.26%	2,522,663	28.72%	19.
20.	901-950	223	206,627	3,815	40.03%	1,992,339	14.44%	281	254,004	5,355	58.32%	2,776,667	31.61%	20.
21.	951-1,000	236	231,434	4,051	42.50%	2,223,773	16.11%	317	303,938	5,672	61.77%	3,080,605	35.07%	21.
22.	1,001-1,100	229	237,029	4,280	44.91%	2,460,802	17.83%	261	263,658	5,933	64.62%	3,344,263	38.07%	22.
23.	1,101-1,200	434	483,114	4,714	49.46%	2,943,916	21.33%	499	542,107	6,432	70.05%	3,886,370	44.24%	23.
24.	1,201-1,300	386	470,988	5,100	53.51%	3,414,904	24.75%	387	460,354	6,819	74.26%	4,346,724	49.48%	24.
25.	1,301-1,400	366	485,466	5,466	57.35%	3,900,370	28.26%	384	496,494	7,203	78.45%	4,843,218	55.14%	25.
26.	1,401-1,500	358	512,333	5,824	61.11%	4,412,703	31.98%	302	421,474	7,505	81.74%	5,264,692	59.93%	26.
27.	1,501-1,600	297	456,901	6,121	64.22%	4,869,604	35.29%	252	376,950	7,757	84.48%	5,641,642	64.22%	27.
28.	1,601-1,700	311	511,746	6,432	67.49%	5,381,350	39.00%	221	353,632	7,978	86.89%	5,995,274	68.25%	28.
29.	1,701-1,800	265	463,496	6,697	70.27%	5,844,846	42.35%	206	351,467	8,184	89.13%	6,346,741	72.25%	29.
30.	1,801-1,900	247	459,715	6,944	72.86%	6,304,561	45.69%	169	306,404	8,353	90.97%	6,653,145	75.74%	30.
31.	1,901-2,000	229	449,604	7,173	75.26%	6,754,165	48.94%	131	249,534	8,484	92.40%	6,902,679	78.58%	31.
32.	2,001-2,250	229	474,839	7,402	77.66%	7,229,004	52.38%	106	214,552	8,590	93.55%	7,117,231	81.02%	32.
33.	2,251-2,500	883	2,084,980	8,285	86.93%	9,313,984	67.49%	328	752,208	8,918	97.12%	7,869,439	89.59%	33.
34.	2,501-3,000	557	1,608,615	8,842	92.77%	10,922,599	79.15%	127	356,236	9,045	98.51%	8,225,675	93.64%	34.
35.	3,001-4,000	459	1,656,893	9,301	97.59%	12,579,492	91.16%	85	299,043	9,130	99.43%	8,524,718	97.05%	35.
36.	4,001-5,000	153	713,220	9,454	99.19%	13,292,712	96.33%	38	171,603	9,168	99.85%	8,696,321	99.00%	36.
37.	5,001-10,000	76	496,100	9,530	99.99%	13,788,812	99.92%	13	76,621	9,181	99.99%	8,772,942	99.87%	37.
38.	10,001-20,000	1	10,970	9,531	100.00%	13,799,782	100.00%	1	11,281	9,182	100.00%	8,784,223	100.00%	38.
39.	over 20,000	-	-	9,531	100.00%	13,799,782	100.00%	-	-	9,182	100.00%	8,784,223	100.00%	39.

Average Number of Customers:	1,589		1,530	
Average Consumption:	1,448	kWh per bill	957	kWh per bill
Median Consumption:	1,114	kWh per bill	780	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **ET-EV**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	2	-	2	0.15%	-	0.00%	1	-	1	0.08%	-	0.00%	2.
3.	51-100	4	76	6	0.44%	76	0.00%	5	113	6	0.48%	113	0.01%	3.
4.	101-150	4	289	10	0.73%	365	0.01%	8	670	14	1.11%	783	0.04%	4.
5.	151-200	5	628	15	1.09%	993	0.03%	6	744	20	1.59%	1,527	0.08%	5.
6.	201-250	2	378	17	1.23%	1,371	0.04%	2	349	22	1.75%	1,876	0.10%	6.
7.	251-300	2	459	19	1.38%	1,830	0.05%	10	2,295	32	2.55%	4,171	0.22%	7.
8.	301-350	4	1,074	23	1.67%	2,904	0.09%	2	551	34	2.71%	4,722	0.25%	8.
9.	351-400	3	993	26	1.89%	3,897	0.11%	11	3,593	45	3.58%	8,315	0.44%	9.
10.	401-450	9	3,346	35	2.54%	7,243	0.21%	10	3,765	55	4.38%	12,080	0.63%	10.
11.	451-500	7	2,994	42	3.05%	10,237	0.30%	15	6,372	70	5.57%	18,452	0.97%	11.
12.	501-550	8	3,728	50	3.63%	13,965	0.41%	22	10,436	92	7.32%	28,888	1.52%	12.
13.	551-600	9	4,826	59	4.28%	18,791	0.55%	23	12,628	115	9.16%	41,516	2.18%	13.
14.	601-650	10	5,727	69	5.01%	24,518	0.72%	19	10,925	134	10.67%	52,441	2.75%	14.
15.	651-700	12	7,536	81	5.88%	32,054	0.95%	26	16,987	160	12.74%	69,428	3.64%	15.
16.	701-750	18	12,949	99	7.18%	45,003	1.33%	22	14,913	182	14.49%	84,341	4.42%	16.
17.	751-800	17	12,399	116	8.42%	57,402	1.69%	42	31,406	224	17.83%	115,747	6.07%	17.
18.	801-850	14	11,010	130	9.43%	68,412	2.02%	35	28,016	259	20.62%	143,763	7.54%	18.
19.	851-900	16	13,273	146	10.60%	81,685	2.41%	46	38,662	305	24.28%	182,425	9.57%	19.
20.	901-950	15	13,157	161	11.68%	94,842	2.80%	34	30,501	339	26.99%	212,926	11.17%	20.
21.	951-1,000	17	15,861	178	12.92%	110,703	3.26%	41	38,855	380	30.25%	251,781	13.21%	21.
22.	1,001-1,100	13	12,688	191	13.86%	123,391	3.64%	32	32,168	412	32.80%	283,949	14.90%	22.
23.	1,101-1,200	29	31,613	220	15.97%	155,004	4.57%	85	90,961	497	39.57%	374,910	19.67%	23.
24.	1,201-1,300	29	34,737	249	18.07%	189,741	5.59%	69	81,729	566	45.06%	456,639	23.96%	24.
25.	1,301-1,400	49	62,839	298	21.63%	252,580	7.45%	72	92,704	638	50.80%	549,343	28.82%	25.
26.	1,401-1,500	30	41,954	328	23.80%	294,534	8.68%	65	90,018	703	55.97%	639,361	33.54%	26.
27.	1,501-1,600	33	49,050	361	26.20%	343,584	10.13%	54	79,844	757	60.27%	719,205	37.73%	27.
28.	1,601-1,700	59	94,933	420	30.48%	438,517	12.93%	65	103,407	822	65.45%	822,612	43.16%	28.
29.	1,701-1,800	49	82,985	469	34.03%	521,502	15.37%	48	80,948	870	69.27%	903,560	47.40%	29.
30.	1,801-1,900	44	79,174	513	37.23%	600,676	17.71%	52	92,537	922	73.41%	996,097	52.26%	30.
31.	1,901-2,000	54	102,256	567	41.15%	702,932	20.72%	44	83,332	966	76.91%	1,079,429	56.63%	31.
32.	2,001-2,250	40	80,327	607	44.05%	783,259	23.09%	37	73,904	1,003	79.86%	1,153,333	60.51%	32.
33.	2,251-2,500	237	551,309	844	61.25%	1,334,568	39.35%	114	260,917	1,117	88.93%	1,414,250	74.20%	33.
34.	2,501-3,000	179	505,289	1,023	74.24%	1,839,857	54.24%	69	192,389	1,186	94.43%	1,606,639	84.29%	34.
35.	3,001-4,000	210	745,798	1,233	89.48%	2,585,655	76.23%	40	137,114	1,226	97.61%	1,743,753	91.48%	35.
36.	4,001-5,000	74	337,640	1,307	94.85%	2,923,295	86.18%	14	62,440	1,240	98.73%	1,806,193	94.76%	36.
37.	5,001-10,000	70	458,483	1,377	99.93%	3,381,778	99.70%	16	99,909	1,256	100.00%	1,906,102	100.00%	37.
38.	10,001-20,000	1	10,120	1,378	100.00%	3,391,898	100.00%	-	-	1,256	100.00%	1,906,102	100.00%	38.
39.	over 20,000	-	-	1,378	100.00%	3,391,898	100.00%	-	-	1,256	100.00%	1,906,102	100.00%	39.

Average Number of Customers:	230		Average Number of Customers:	209	
Average Consumption:	2,461	kWh per bill	Average Consumption:	1,518	kWh per bill
Median Consumption:	1,117	kWh per bill	Median Consumption:	1,291	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-20**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	CONSUMPTION kWh BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kWh) (L)	% of Total (M)	Line No.
1.	0	65	-	65	2.67%	-	0.00%	53	-	53	2.18%	-	0.00%	1.
2.	1-100	11	424	76	3.13%	424	0.00%	9	387	62	2.55%	387	0.00%	2.
3.	101-200	4	558	80	3.29%	982	0.00%	18	2,774	80	3.29%	3,161	0.02%	3.
4.	201-300	13	3,367	93	3.82%	4,349	0.02%	31	7,798	111	4.56%	10,959	0.08%	4.
5.	301-400	17	5,986	110	4.52%	10,335	0.04%	38	13,464	149	6.13%	24,423	0.17%	5.
6.	401-500	19	8,533	129	5.30%	18,868	0.08%	42	19,001	191	7.85%	43,424	0.31%	6.
7.	501-750	55	34,905	184	7.57%	53,773	0.22%	119	73,288	310	12.75%	116,712	0.82%	7.
8.	751-1,000	66	57,997	250	10.28%	111,770	0.45%	115	99,588	425	17.48%	216,300	1.52%	8.
9.	1,001-1,500	123	154,679	373	15.34%	266,449	1.08%	189	234,432	614	25.25%	450,732	3.17%	9.
10.	1,501-2,000	119	208,249	492	20.23%	474,698	1.93%	188	323,582	802	32.98%	774,314	5.45%	10.
11.	2,001-3,000	244	604,829	736	30.26%	1,079,527	4.38%	300	741,268	1,102	45.31%	1,515,582	10.67%	11.
12.	3,001-4,000	189	657,803	925	38.03%	1,737,330	7.05%	254	886,111	1,356	55.76%	2,401,693	16.91%	12.
13.	4,001-5,000	185	825,782	1,110	45.64%	2,563,112	10.40%	260	1,160,067	1,616	66.45%	3,561,760	25.08%	13.
14.	5,001-7,500	324	1,982,818	1,434	58.96%	4,545,930	18.45%	314	1,870,099	1,930	79.36%	5,431,859	38.25%	14.
15.	7,501-10,000	285	2,489,047	1,719	70.68%	7,034,977	28.55%	161	1,341,169	2,091	85.98%	6,773,028	47.70%	15.
16.	10,001-15,000	269	3,266,193	1,988	81.74%	10,301,170	41.81%	141	1,704,450	2,232	91.78%	8,477,478	59.70%	16.
17.	15,001-20,000	143	2,452,276	2,131	87.62%	12,753,446	51.76%	79	1,352,550	2,311	95.02%	9,830,028	69.23%	17.
18.	20,001-25,000	99	2,200,726	2,230	91.69%	14,954,172	60.69%	38	847,430	2,349	96.59%	10,677,458	75.20%	18.
19.	25,001-30,000	58	1,600,142	2,288	94.08%	16,554,314	67.18%	23	610,964	2,372	97.53%	11,288,422	79.50%	19.
20.	30,001-35,000	30	967,718	2,318	95.31%	17,522,032	71.11%	15	481,585	2,387	98.15%	11,770,007	82.89%	20.
21.	35,001-40,000	25	936,597	2,343	96.34%	18,458,629	74.91%	9	335,023	2,396	98.52%	12,105,030	85.25%	21.
22.	40,001-50,000	30	1,335,632	2,373	97.57%	19,794,261	80.33%	14	648,051	2,410	99.10%	12,753,081	89.81%	22.
23.	50,001-75,000	36	2,124,803	2,409	99.05%	21,919,064	88.96%	18	1,086,258	2,428	99.84%	13,839,339	97.46%	23.
24.	75,001-100,000	9	762,430	2,418	99.42%	22,681,494	92.05%	4	360,186	2,432	100.00%	14,199,525	100.00%	24.
25.	100,001-125,000	6	699,467	2,424	99.67%	23,380,961	94.89%	-	-	2,432	100.00%	14,199,525	100.00%	25.
26.	125,001-150,000	5	677,706	2,429	99.88%	24,058,667	97.64%	-	-	2,432	100.00%	14,199,525	100.00%	26.
27.	150,001-200,000	2	321,373	2,431	99.96%	24,380,040	98.95%	-	-	2,432	100.00%	14,199,525	100.00%	27.
28.	200,001-300,000	1	259,930	2,432	100.00%	24,639,970	100.00%	-	-	2,432	100.00%	14,199,525	100.00%	28.
29.	300,001-400,000	-	-	2,432	100.00%	24,639,970	100.00%	-	-	2,432	100.00%	14,199,525	100.00%	29.
30.	400,001-500,000	-	-	2,432	100.00%	24,639,970	100.00%	-	-	2,432	100.00%	14,199,525	100.00%	30.
31.	500,001-750,000	-	-	2,432	100.00%	24,639,970	100.00%	-	-	2,432	100.00%	14,199,525	100.00%	31.
32.	750,001-1,000,000	-	-	2,432	100.00%	24,639,970	100.00%	-	-	2,432	100.00%	14,199,525	100.00%	32.
33.	Over 1,000,000	-	-	2,432	100.00%	24,639,970	100.00%	-	-	2,432	100.00%	14,199,525	100.00%	33.

Average Number of Customers:	405	
Average Consumption:	10,132	kWh per bill
Median Consumption:	5,680	kWh per bill

Average Number of Customers:	405	
Average Consumption:	5,839	kWh per bill
Median Consumption:	3,480	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-20**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	1	-	1	0.04%	-	0.00%	5	-	5	0.21%	-	0.00%	1.
2.	1-10	120	716	121	4.97%	716	0.46%	299	1,896	304	12.49%	1,896	1.89%	2.
3.	11-20	269	4,205	390	16.02%	4,921	3.16%	466	6,834	770	31.65%	8,730	8.72%	3.
4.	21-30	333	8,226	723	29.69%	13,147	8.43%	404	9,862	1,174	48.25%	18,592	18.57%	4.
5.	31-40	270	9,494	993	40.78%	22,641	14.52%	355	12,043	1,529	62.84%	30,635	30.59%	5.
6.	41-50	212	9,437	1,205	49.49%	32,078	20.57%	237	10,340	1,766	72.59%	40,975	40.92%	6.
7.	51-60	191	10,468	1,396	57.33%	42,546	27.28%	181	9,656	1,947	80.02%	50,631	50.56%	7.
8.	61-70	176	11,413	1,572	64.56%	53,959	34.60%	119	7,547	2,066	84.92%	58,178	58.10%	8.
9.	71-80	195	14,569	1,767	72.57%	68,528	43.94%	85	6,208	2,151	88.41%	64,386	64.30%	9.
10.	81-90	144	12,089	1,911	78.48%	80,617	51.70%	69	5,668	2,220	91.25%	70,054	69.96%	10.
11.	91-100	111	10,459	2,022	83.04%	91,076	58.40%	47	4,345	2,267	93.18%	74,399	74.30%	11.
12.	101-200	343	44,330	2,365	97.13%	135,406	86.83%	129	16,667	2,396	98.48%	91,066	90.95%	12.
13.	201-300	47	11,067	2,412	99.06%	146,473	93.93%	34	8,105	2,430	99.88%	99,171	99.04%	13.
14.	301-400	15	5,279	2,427	99.67%	151,752	97.31%	3	962	2,433	100.00%	100,133	100.00%	14.
15.	401-500	6	2,677	2,433	99.92%	154,429	99.03%	-	-	2,433	100.00%	100,133	100.00%	15.
16.	501-600	1	542	2,434	99.96%	154,971	99.38%	-	-	2,433	100.00%	100,133	100.00%	16.
17.	601-700	-	-	2,434	99.96%	154,971	99.38%	-	-	2,433	100.00%	100,133	100.00%	17.
18.	701-800	-	-	2,434	99.96%	154,971	99.38%	-	-	2,433	100.00%	100,133	100.00%	18.
19.	801-900	-	-	2,434	99.96%	154,971	99.38%	-	-	2,433	100.00%	100,133	100.00%	19.
20.	901-1000	1	970	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	20.
21.	1001-1100	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	21.
22.	1101-1200	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	22.
23.	1201-1300	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	23.
24.	1301-1400	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	24.
25.	1401-1500	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	25.
26.	1501-1600	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	26.
27.	1601-1700	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	27.
28.	1701-1800	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	28.
29.	1801-1900	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	29.
30.	1901-2000	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	30.
31.	2001-2100	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	31.
32.	2101-2200	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	32.
33.	2201-2300	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	33.
34.	2301-2400	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	34.
35.	2401-2500	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	35.
36.	2501-2600	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	36.
37.	2601-2700	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	37.
38.	2701-2800	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	38.
39.	2801-2900	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	39.
40.	2901-3000	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	40.
41.	Over 3000	-	-	2,435	100.00%	155,941	100.00%	-	-	2,433	100.00%	100,133	100.00%	41.

Average Number of Customers:	406		Average Number of Customers:	406	
Average Load:	64	kW per bill	Average Load:	41	kW per bill
Median Load:	50	kW per bill	Median Load:	31	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-30**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	8	-	8	0.03%	-	0.00%	10	-	10	0.04%	-	0.00%	1.
2.	1-100	19,794	517,062	19,802	74.68%	517,062	20.58%	19,815	517,119	19,825	74.74%	517,119	20.54%	2.
3.	101-200	3,255	456,822	23,057	86.96%	973,884	38.76%	3,199	448,606	23,024	86.80%	965,725	38.36%	3.
4.	201-300	1,291	306,872	24,348	91.82%	1,280,756	50.97%	1,287	306,178	24,311	91.65%	1,271,903	50.52%	4.
5.	301-400	959	299,926	25,307	95.44%	1,580,682	62.91%	1,006	315,315	25,317	95.44%	1,587,218	63.05%	5.
6.	401-500	431	172,630	25,738	97.07%	1,753,312	69.78%	439	175,829	25,756	97.10%	1,763,047	70.03%	6.
7.	501-750	140	77,836	25,878	97.59%	1,831,148	72.88%	129	70,473	25,885	97.58%	1,833,520	72.83%	7.
8.	751-1,000	67	53,496	25,945	97.85%	1,884,644	75.01%	67	53,492	25,952	97.84%	1,887,012	74.96%	8.
9.	1,001-1,500	537	548,891	26,482	99.87%	2,433,535	96.85%	540	551,425	26,492	99.87%	2,438,437	96.86%	9.
10.	1,501-2,000	13	21,265	26,495	99.92%	2,454,800	97.70%	13	21,264	26,505	99.92%	2,459,701	97.70%	10.
11.	2,001-3,000	7	13,137	26,502	99.95%	2,467,937	98.22%	7	13,136	26,512	99.95%	2,472,837	98.23%	11.
12.	3,001-4,000	7	18,380	26,509	99.97%	2,486,317	98.95%	7	18,378	26,519	99.97%	2,491,215	98.96%	12.
13.	4,001-5,000	7	26,274	26,516	100.00%	2,512,591	100.00%	7	26,272	26,526	100.00%	2,517,487	100.00%	13.
14.	5,001-7,500	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	14.
15.	7,501-10,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	15.
16.	10,001-15,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	16.
17.	15,001-20,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	17.
18.	20,001-25,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	18.
19.	25,001-30,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	19.
20.	30,001-35,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	20.
21.	35,001-40,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	21.
22.	40,001-50,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	22.
23.	50,001-75,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	23.
24.	75,001-100,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	24.
25.	100,001-125,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	25.
26.	125,001-150,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	26.
27.	150,001-200,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	27.
28.	200,001-300,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	28.
29.	300,001-400,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	29.
30.	400,001-500,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	30.
31.	500,001-750,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	31.
32.	750,001-1,000,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	32.
33.	Over 1,000,000	-	-	26,516	100.00%	2,512,591	100.00%	-	-	26,526	100.00%	2,517,487	100.00%	33.

Average Number of Customers:	4,419	
Average Consumption:	95	kWh per bill
Median Consumption:	37	kWh per bill

Average Number of Customers:	4,421	
Average Consumption:	95	kWh per bill
Median Consumption:	37	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 XS and S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	27,124	-	27,124	3.86%	-	0.00%	27,585	-	27,585	3.93%	-	0.00%	1.
2.	1-100	85,368	3,512,260	112,492	15.99%	3,512,260	0.15%	85,671	3,655,688	113,256	16.12%	3,655,688	0.20%	2.
3.	101-200	48,166	7,212,048	160,658	22.83%	10,724,308	0.46%	53,039	7,963,326	166,295	23.67%	11,619,014	0.65%	3.
4.	201-300	36,886	9,265,114	197,544	28.08%	19,989,422	0.86%	42,557	10,675,609	208,852	29.72%	22,294,623	1.25%	4.
5.	301-400	31,090	11,015,193	228,634	32.50%	31,004,615	1.34%	36,368	12,860,372	245,220	34.90%	35,154,995	1.97%	5.
6.	401-500	27,946	12,722,861	256,580	36.47%	43,727,476	1.89%	33,584	15,277,876	278,804	39.68%	50,432,871	2.83%	6.
7.	501-750	58,215	36,495,760	314,795	44.74%	80,223,236	3.47%	69,861	43,704,483	348,665	49.62%	94,137,354	5.27%	7.
8.	751-1,000	42,097	37,047,380	356,892	50.73%	117,270,616	5.07%	51,236	44,989,097	399,901	56.91%	139,126,451	7.79%	8.
9.	1,001-1,500	60,132	75,160,870	417,024	59.27%	192,431,486	8.32%	64,676	80,398,013	464,577	66.11%	219,524,464	12.30%	9.
10.	1,501-2,000	43,775	77,030,960	460,799	65.49%	269,462,446	11.65%	42,538	74,568,271	507,115	72.17%	294,092,735	16.47%	10.
11.	2,001-3,000	58,241	145,086,838	519,040	73.77%	414,549,284	17.92%	50,704	125,817,767	557,819	79.38%	419,910,502	23.52%	11.
12.	3,001-4,000	37,881	133,149,116	556,921	79.16%	547,698,400	23.67%	31,850	111,817,240	589,669	83.92%	531,727,742	29.79%	12.
13.	4,001-5,000	26,041	118,014,760	582,962	82.86%	665,713,160	28.77%	22,242	100,693,412	611,911	87.08%	632,421,154	35.43%	13.
14.	5,001-7,500	39,968	247,578,557	622,930	88.54%	913,291,717	39.47%	33,732	208,378,567	645,643	91.88%	840,799,721	47.10%	14.
15.	7,501-10,000	22,725	198,974,058	645,655	91.77%	1,112,265,775	48.07%	17,507	152,607,394	663,150	94.37%	993,407,115	55.65%	15.
16.	10,001-15,000	23,984	295,969,969	669,639	95.18%	1,408,235,744	60.86%	17,379	214,065,462	680,529	96.85%	1,207,472,577	67.64%	16.
17.	15,001-20,000	12,057	210,796,988	681,696	96.89%	1,619,032,732	69.97%	9,337	163,389,337	689,866	98.17%	1,370,861,914	76.79%	17.
18.	20,001-25,000	7,513	170,107,664	689,209	97.96%	1,789,140,396	77.32%	5,884	132,458,092	695,750	99.01%	1,503,320,006	84.21%	18.
19.	25,001-30,000	5,374	148,753,833	694,583	98.72%	1,937,894,229	83.75%	3,211	88,541,596	698,961	99.47%	1,591,861,602	89.17%	19.
20.	30,001-35,000	3,539	115,822,205	698,122	99.22%	2,053,716,434	88.76%	1,506	48,985,175	700,467	99.68%	1,640,846,777	91.92%	20.
21.	35,001-40,000	2,355	88,784,595	700,477	99.56%	2,142,501,029	92.59%	803	30,231,379	701,270	99.80%	1,671,078,156	93.61%	21.
22.	40,001-50,000	2,018	90,111,645	702,495	99.85%	2,232,612,674	96.49%	726	32,369,231	701,996	99.90%	1,703,447,387	95.42%	22.
23.	50,001-75,000	803	45,974,092	703,298	99.96%	2,278,586,766	98.47%	404	23,894,241	702,400	99.96%	1,727,341,628	96.76%	23.
24.	75,001-100,000	149	13,086,047	703,447	99.98%	2,291,672,813	99.04%	90	7,795,295	702,490	99.97%	1,735,136,923	97.20%	24.
25.	100,001-125,000	63	7,067,556	703,510	99.99%	2,298,740,369	99.35%	46	5,355,942	702,536	99.98%	1,740,492,865	97.50%	25.
26.	125,001-150,000	27	3,643,761	703,537	99.99%	2,302,384,130	99.50%	32	4,389,216	702,568	99.98%	1,744,882,081	97.74%	26.
27.	150,001-200,000	19	3,222,685	703,556	100.00%	2,305,606,815	99.64%	42	7,394,544	702,610	99.99%	1,752,276,625	98.16%	27.
28.	200,001-300,000	9	2,079,018	703,565	100.00%	2,307,685,833	99.73%	36	8,736,746	702,646	99.99%	1,761,013,371	98.65%	28.
29.	300,001-400,000	6	2,065,064	703,571	100.00%	2,309,750,897	99.82%	17	5,830,807	702,663	100.00%	1,766,844,178	98.97%	29.
30.	400,001-500,000	5	2,235,789	703,576	100.00%	2,311,986,686	99.92%	16	7,063,377	702,679	100.00%	1,773,907,555	99.37%	30.
31.	500,001-750,000	1	745,396	703,577	100.00%	2,312,732,082	99.95%	17	10,065,846	702,696	100.00%	1,783,973,401	99.93%	31.
32.	750,001-1,000,000	-	-	703,577	100.00%	2,312,732,082	99.95%	-	-	702,696	100.00%	1,783,973,401	99.93%	32.
33.	Over 1,000,000	1	1,153,353	703,578	100.00%	2,313,885,435	100.00%	1	1,202,859	702,697	100.00%	1,785,176,260	100.00%	33.

Average Number of Customers:	117,263	
Average Consumption:	3,289	kWh per bill
Median Consumption:	964	kWh per bill

Average Number of Customers:	117,116	
Average Consumption:	2,540	kWh per bill
Median Consumption:	760	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 XS & S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	26,536	-	26,536	3.77%	-	0.00%	27,375	-	27,375	3.90%	-	0.00%	1.
2.	1-10	434,998	1,521,343	461,534	65.60%	1,521,343	18.23%	460,876	1,356,816	488,251	69.48%	1,356,816	20.26%	2.
3.	11-20	124,811	1,797,882	586,345	83.34%	3,319,225	39.78%	121,843	1,620,630	610,094	86.82%	2,977,446	44.47%	3.
4.	21-30	48,880	1,207,961	635,225	90.28%	4,527,186	54.26%	40,840	989,428	650,934	92.63%	3,966,874	59.25%	4.
5.	31-40	23,356	820,039	658,581	93.60%	5,347,225	64.09%	19,682	682,715	670,616	95.43%	4,649,589	69.44%	5.
6.	41-50	13,844	628,397	672,425	95.57%	5,975,622	71.62%	11,731	523,845	682,347	97.10%	5,173,434	77.27%	6.
7.	51-60	10,163	564,421	682,588	97.02%	6,540,043	78.39%	7,763	428,038	690,110	98.21%	5,601,472	83.66%	7.
8.	61-70	6,557	431,324	689,145	97.95%	6,971,367	83.56%	4,756	287,757	694,866	98.89%	5,889,229	87.96%	8.
9.	71-80	5,179	393,194	694,324	98.68%	7,364,561	88.27%	3,212	216,531	698,078	99.34%	6,105,760	91.19%	9.
10.	81-90	3,962	341,317	698,286	99.25%	7,705,878	92.36%	1,746	140,001	699,824	99.59%	6,245,761	93.28%	10.
11.	91-100	2,513	241,227	700,799	99.60%	7,947,105	95.25%	904	92,980	700,728	99.72%	6,338,741	94.67%	11.
12.	101-200	2,497	297,855	703,296	99.96%	8,244,960	98.82%	1,542	193,502	702,270	99.94%	6,532,243	97.56%	12.
13.	201-300	166	40,449	703,462	99.98%	8,285,409	99.31%	192	52,309	702,462	99.97%	6,584,552	98.34%	13.
14.	301-400	67	23,842	703,529	99.99%	8,309,251	99.59%	75	24,243	702,537	99.98%	6,608,795	98.70%	14.
15.	401-500	22	9,590	703,551	100.00%	8,318,841	99.71%	45	9,393	702,582	99.98%	6,618,188	98.84%	15.
16.	501-600	10	5,392	703,561	100.00%	8,324,233	99.77%	19	8,467	702,601	99.99%	6,626,655	98.97%	16.
17.	601-700	4	2,623	703,565	100.00%	8,326,856	99.80%	5	11,007	702,606	99.99%	6,637,662	99.13%	17.
18.	701-800	3	2,263	703,568	100.00%	8,329,119	99.83%	11	6,798	702,617	99.99%	6,644,460	99.24%	18.
19.	801-900	5	4,271	703,573	100.00%	8,333,390	99.88%	16	5,075	702,633	99.99%	6,649,535	99.31%	19.
20.	901-1000	2	1,897	703,575	100.00%	8,335,287	99.90%	12	3,782	702,645	99.99%	6,653,317	99.37%	20.
21.	1001-1100	3	3,097	703,578	100.00%	8,338,384	99.94%	9	1,001	702,654	99.99%	6,654,318	99.38%	21.
22.	1101-1200	-	-	703,578	100.00%	8,338,384	99.94%	14	3,420	702,668	100.00%	6,657,738	99.43%	22.
23.	1201-1300	1	1,296	703,579	100.00%	8,339,680	99.96%	4	-	702,672	100.00%	6,657,738	99.43%	23.
24.	1301-1400	-	-	703,579	100.00%	8,339,680	99.96%	3	4,036	702,675	100.00%	6,661,774	99.49%	24.
25.	1401-1500	1	1,410	703,580	100.00%	8,341,090	99.97%	6	10,079	702,681	100.00%	6,671,853	99.64%	25.
26.	1501-1600	-	-	703,580	100.00%	8,341,090	99.97%	9	4,552	702,690	100.00%	6,676,405	99.71%	26.
27.	1601-1700	-	-	703,580	100.00%	8,341,090	99.97%	2	3,283	702,692	100.00%	6,679,688	99.76%	27.
28.	1701-1800	-	-	703,580	100.00%	8,341,090	99.97%	1	-	702,693	100.00%	6,679,688	99.76%	28.
29.	1801-1900	-	-	703,580	100.00%	8,341,090	99.97%	2	-	702,695	100.00%	6,679,688	99.76%	29.
30.	1901-2000	-	-	703,580	100.00%	8,341,090	99.97%	1	1,926	702,696	100.00%	6,681,614	99.79%	30.
31.	2001-2100	-	-	703,580	100.00%	8,341,090	99.97%	-	-	702,696	100.00%	6,681,614	99.79%	31.
32.	2101-2200	1	2,160	703,581	100.00%	8,343,250	100.00%	-	2,116	702,696	100.00%	6,683,730	99.82%	32.
33.	2201-2300	-	-	703,581	100.00%	8,343,250	100.00%	-	-	702,696	100.00%	6,683,730	99.82%	33.
34.	2301-2400	-	-	703,581	100.00%	8,343,250	100.00%	-	-	702,696	100.00%	6,683,730	99.82%	34.
35.	2401-2500	-	-	703,581	100.00%	8,343,250	100.00%	-	2,453	702,696	100.00%	6,686,183	99.86%	35.
36.	2501-2600	-	-	703,581	100.00%	8,343,250	100.00%	1	5,071	702,697	100.00%	6,691,254	99.93%	36.
37.	2601-2700	-	-	703,581	100.00%	8,343,250	100.00%	-	-	702,697	100.00%	6,691,254	99.93%	37.
38.	2701-2800	-	-	703,581	100.00%	8,343,250	100.00%	-	-	702,697	100.00%	6,691,254	99.93%	38.
39.	2801-2900	-	-	703,581	100.00%	8,343,250	100.00%	-	-	702,697	100.00%	6,691,254	99.93%	39.
40.	2901-3000	-	-	703,581	100.00%	8,343,250	100.00%	1	4,400	702,698	100.00%	6,695,654	100.00%	40.
41.	Over 3000	-	-	703,581	100.00%	8,343,250	100.00%							41.

Average Number of Customers:	117,264		
Average Load:	12	kW per bill	
Median Load:	6	kW per bill	

Average Number of Customers:	117,116		
Average Load:	10	kW per bill	
Median Load:	5	kW per bill	

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 Medium (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	486	-	486	1.92%	-	0.00%	342	-	342	1.35%	-	0.00%	1.
2.	1-100	8	639	494	1.95%	639	0.00%	14	1,063	356	1.40%	1,063	0.00%	2.
3.	101-200	18	2,595	512	2.02%	3,234	0.00%	21	3,120	377	1.49%	4,183	0.00%	3.
4.	201-300	19	4,830	531	2.10%	8,064	0.00%	25	6,159	402	1.59%	10,342	0.00%	4.
5.	301-400	8	2,834	539	2.13%	10,898	0.00%	28	9,519	430	1.70%	19,861	0.00%	5.
6.	401-500	12	5,708	551	2.18%	16,606	0.00%	11	5,280	441	1.74%	25,141	0.00%	6.
7.	501-750	16	9,779	567	2.24%	26,385	0.00%	25	16,039	466	1.84%	41,180	0.00%	7.
8.	751-1,000	15	13,312	582	2.30%	39,697	0.00%	28	24,878	494	1.95%	66,058	0.00%	8.
9.	1,001-1,500	26	34,088	608	2.40%	73,785	0.00%	58	72,734	552	2.18%	138,792	0.01%	9.
10.	1,501-2,000	36	64,425	644	2.55%	138,210	0.01%	56	98,192	608	2.40%	236,984	0.02%	10.
11.	2,001-3,000	84	209,800	728	2.88%	348,010	0.02%	122	302,534	730	2.88%	539,518	0.04%	11.
12.	3,001-4,000	68	241,114	796	3.15%	589,124	0.03%	90	315,353	820	3.23%	854,871	0.06%	12.
13.	4,001-5,000	69	310,109	865	3.42%	899,233	0.05%	97	436,178	917	3.62%	1,291,049	0.09%	13.
14.	5,001-7,500	205	1,304,203	1,070	4.23%	2,203,436	0.12%	312	1,964,214	1,229	4.85%	3,255,263	0.23%	14.
15.	7,501-10,000	259	2,311,549	1,329	5.25%	4,514,985	0.26%	423	3,741,724	1,652	6.51%	6,996,987	0.49%	15.
16.	10,001-15,000	521	6,573,765	1,850	7.31%	11,088,750	0.63%	941	11,958,231	2,593	10.22%	18,955,218	1.33%	16.
17.	15,001-20,000	611	10,914,535	2,461	9.73%	22,003,285	1.25%	1,258	22,266,110	3,851	15.19%	41,221,328	2.89%	17.
18.	20,001-25,000	810	18,355,447	3,271	12.93%	40,358,732	2.29%	1,706	38,726,832	5,557	21.91%	79,948,160	5.61%	18.
19.	25,001-30,000	1,016	28,156,533	4,287	16.95%	68,515,265	3.88%	1,878	51,932,475	7,435	29.32%	131,880,635	9.26%	19.
20.	30,001-35,000	1,211	39,619,636	5,498	21.73%	108,134,901	6.13%	1,901	61,901,378	9,336	36.81%	193,782,013	13.61%	20.
21.	35,001-40,000	1,487	56,092,128	6,985	27.61%	164,227,029	9.30%	2,000	75,089,926	11,336	44.70%	268,871,939	18.88%	21.
22.	40,001-50,000	3,199	145,128,919	10,184	40.26%	309,355,948	17.53%	3,438	154,351,100	14,774	58.26%	423,223,039	29.72%	22.
23.	50,001-75,000	6,378	393,554,784	16,562	65.47%	702,910,732	39.82%	4,897	299,261,295	19,671	77.57%	722,484,334	50.74%	23.
24.	75,001-100,000	3,624	313,631,088	20,186	79.79%	1,016,541,820	57.59%	2,499	215,918,786	22,170	87.42%	938,403,120	65.90%	24.
25.	100,001-125,000	2,096	234,905,278	22,282	88.08%	1,251,447,098	70.90%	1,263	140,598,800	23,433	92.40%	1,079,001,920	75.77%	25.
26.	125,001-150,000	1,254	171,877,067	23,536	93.04%	1,423,324,165	80.64%	765	104,551,780	24,198	95.42%	1,183,553,700	83.11%	26.
27.	150,001-200,000	1,192	205,612,112	24,728	97.75%	1,628,936,277	92.29%	834	142,556,094	25,032	98.71%	1,326,109,794	93.12%	27.
28.	200,001-300,000	542	122,907,971	25,270	99.89%	1,751,844,248	99.25%	246	56,413,981	25,278	99.68%	1,382,523,775	97.09%	28.
29.	300,001-400,000	17	5,622,082	25,287	99.96%	1,757,466,330	99.57%	36	12,487,847	25,314	99.82%	1,395,011,622	97.96%	29.
30.	400,001-500,000	4	1,786,331	25,291	99.97%	1,759,252,661	99.67%	22	9,660,485	25,336	99.91%	1,404,672,107	98.64%	30.
31.	500,001-750,000	5	3,005,593	25,296	99.99%	1,762,258,254	99.84%	18	10,778,791	25,354	99.98%	1,415,450,898	99.40%	31.
32.	750,001-1,000,000	1	857,640	25,297	100.00%	1,763,115,894	99.89%	3	2,469,992	25,357	99.99%	1,417,920,890	99.57%	32.
33.	Over 1,000,000	1	1,893,626	25,298	100.00%	1,765,009,520	100.00%	3	6,104,685	25,360	100.00%	1,424,025,575	100.00%	33.

Average Number of Customers:	4,418	
Average Consumption:	69,769	kWh per bill
Median Consumption:	58,198	kWh per bill

Average Number of Customers:	4,227	
Average Consumption:	56,152	kWh per bill
Median Consumption:	43,556	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 Medium (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	kW BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kW) (L)	% of Total (M)	Line No.
1.	0	120	-	120	0.45%	-	0.00%	149	-	149	0.59%	-	0.00%	1.
2.	1-10	80	346	200	0.75%	346	0.01%	114	489	263	1.04%	489	0.01%	2.
3.	11-20	33	488	233	0.88%	834	0.02%	66	987	329	1.30%	1,476	0.04%	3.
4.	21-30	55	1,320	288	1.09%	2,154	0.04%	78	1,991	407	1.60%	3,467	0.08%	4.
5.	31-40	59	2,006	347	1.31%	4,160	0.09%	131	4,756	538	2.12%	8,223	0.20%	5.
6.	41-50	48	2,100	395	1.49%	6,260	0.13%	202	9,275	740	2.92%	17,498	0.42%	6.
7.	51-60	76	4,051	471	1.78%	10,311	0.21%	435	24,488	1,175	4.63%	41,986	1.00%	7.
8.	61-70	106	6,724	577	2.18%	17,035	0.35%	802	52,839	1,977	7.80%	94,825	2.26%	8.
9.	71-80	236	17,282	813	3.07%	34,317	0.70%	1,337	101,557	3,314	13.07%	196,382	4.68%	9.
10.	81-90	492	40,625	1,305	4.92%	74,942	1.54%	1,680	143,864	4,994	19.69%	340,246	8.11%	10.
11.	91-100	958	88,119	2,263	8.54%	163,061	3.35%	1,814	173,298	6,808	26.85%	513,544	12.24%	11.
12.	101-200	14,415	1,988,568	16,678	62.92%	2,151,629	44.14%	11,811	1,673,791	18,619	73.42%	2,187,335	52.12%	12.
13.	201-300	6,324	1,485,040	23,002	86.78%	3,636,669	74.61%	4,669	1,141,625	23,288	91.83%	3,328,960	79.33%	13.
14.	301-400	2,874	946,581	25,876	97.63%	4,583,250	94.03%	1,539	522,445	24,827	97.90%	3,851,405	91.78%	14.
15.	401-500	508	209,392	26,384	99.54%	4,792,642	98.33%	288	127,556	25,115	99.04%	3,978,961	94.82%	15.
16.	501-600	66	34,250	26,450	99.79%	4,826,892	99.03%	87	48,317	25,202	99.38%	4,027,278	95.97%	16.
17.	601-700	24	14,815	26,474	99.88%	4,841,707	99.33%	32	20,691	25,234	99.51%	4,047,969	96.46%	17.
18.	701-800	19	13,413	26,493	99.95%	4,855,120	99.61%	29	21,627	25,263	99.62%	4,069,596	96.98%	18.
19.	801-900	2	1,734	26,495	99.96%	4,856,854	99.64%	19	16,258	25,282	99.70%	4,085,854	97.37%	19.
20.	901-1000	1	956	26,496	99.97%	4,857,810	99.66%	11	10,401	25,293	99.74%	4,096,255	97.61%	20.
21.	1001-1100	-	-	26,496	99.97%	4,857,810	99.66%	12	12,712	25,305	99.79%	4,108,967	97.92%	21.
22.	1101-1200	2	2,328	26,498	99.97%	4,860,138	99.71%	14	15,996	25,319	99.84%	4,124,963	98.30%	22.
23.	1201-1300	3	3,827	26,501	99.98%	4,863,965	99.79%	9	11,252	25,328	99.88%	4,136,215	98.57%	23.
24.	1301-1400	-	-	26,501	99.98%	4,863,965	99.79%	5	6,729	25,333	99.90%	4,142,944	98.73%	24.
25.	1401-1500	1	1,413	26,502	99.99%	4,865,378	99.82%	8	11,613	25,341	99.93%	4,154,557	99.00%	25.
26.	1501-1600	-	-	26,502	99.99%	4,865,378	99.82%	4	6,178	25,345	99.94%	4,160,735	99.15%	26.
27.	1601-1700	-	-	26,502	99.99%	4,865,378	99.82%	4	6,558	25,349	99.96%	4,167,293	99.31%	27.
28.	1701-1800	-	-	26,502	99.99%	4,865,378	99.82%	2	3,539	25,351	99.97%	4,170,832	99.39%	28.
29.	1801-1900	-	-	26,502	99.99%	4,865,378	99.82%	-	-	25,351	99.97%	4,170,832	99.39%	29.
30.	1901-2000	-	-	26,502	99.99%	4,865,378	99.82%	2	3,934	25,353	99.98%	4,174,766	99.48%	30.
31.	2001-2100	-	-	26,502	99.99%	4,865,378	99.82%	-	-	25,353	99.98%	4,174,766	99.48%	31.
32.	2101-2200	-	-	26,502	99.99%	4,865,378	99.82%	2	4,299	25,355	99.98%	4,179,065	99.59%	32.
33.	2201-2300	-	-	26,502	99.99%	4,865,378	99.82%	-	-	25,355	99.98%	4,179,065	99.59%	33.
34.	2301-2400	-	-	26,502	99.99%	4,865,378	99.82%	1	2,385	25,356	99.99%	4,181,450	99.64%	34.
35.	2401-2500	-	-	26,502	99.99%	4,865,378	99.82%	-	-	25,356	99.99%	4,181,450	99.64%	35.
36.	2501-2600	1	2,512	26,503	99.99%	4,867,890	99.87%	-	-	25,356	99.99%	4,181,450	99.64%	36.
37.	2601-2700	-	-	26,503	99.99%	4,867,890	99.87%	-	-	25,356	99.99%	4,181,450	99.64%	37.
38.	2701-2800	-	-	26,503	99.99%	4,867,890	99.87%	-	-	25,356	99.99%	4,181,450	99.64%	38.
39.	2801-2900	-	-	26,503	99.99%	4,867,890	99.87%	-	-	25,356	99.99%	4,181,450	99.64%	39.
40.	2901-3000	-	-	26,503	99.99%	4,867,890	99.87%	-	-	25,356	99.99%	4,181,450	99.64%	40.
41.	Over 3000	2	6,286	26,505	100.00%	4,874,176	100.00%	3	14,946	25,359	100.00%	4,196,396	100.00%	41.

Average Number of Customers:	4,418		Average Number of Customers:	4,227	
Average Load:	184	kW per bill	Average Load:	165	kW per bill
Median Load:	166	kW per bill	Median Load:	136	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 Large (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	48	-	48	1.02%	-	0.00%	80	-	80	1.70%	-	0.00%	1.
2.	1-100	-	-	48	1.02%	-	0.00%	-	-	80	1.70%	-	0.00%	2.
3.	101-200	-	-	48	1.02%	-	0.00%	-	-	80	1.70%	-	0.00%	3.
4.	201-300	-	-	48	1.02%	-	0.00%	-	-	80	1.70%	-	0.00%	4.
5.	301-400	-	-	48	1.02%	-	0.00%	2	639	82	1.74%	639	0.00%	5.
6.	401-500	-	-	48	1.02%	-	0.00%	1	479	83	1.76%	1,118	0.00%	6.
7.	501-750	-	-	48	1.02%	-	0.00%	1	599	84	1.78%	1,717	0.00%	7.
8.	751-1,000	-	-	48	1.02%	-	0.00%	4	3,455	88	1.87%	5,172	0.00%	8.
9.	1,001-1,500	-	-	48	1.02%	-	0.00%	1	1,198	89	1.89%	6,370	0.00%	9.
10.	1,501-2,000	1	1,799	49	1.04%	1,799	0.00%	1	1,797	90	1.91%	8,167	0.00%	10.
11.	2,001-3,000	3	6,894	52	1.10%	8,693	0.00%	5	13,360	95	2.02%	21,527	0.00%	11.
12.	3,001-4,000	1	3,297	53	1.12%	11,990	0.00%	1	3,834	96	2.04%	25,361	0.00%	12.
13.	4,001-5,000	1	4,163	54	1.14%	16,153	0.00%	7	31,981	103	2.19%	57,342	0.00%	13.
14.	5,001-7,500	7	42,372	61	1.29%	58,525	0.00%	9	60,622	112	2.38%	117,964	0.01%	14.
15.	7,501-10,000	4	34,221	65	1.37%	92,746	0.01%	10	87,165	122	2.59%	205,129	0.02%	15.
16.	10,001-15,000	18	219,384	83	1.76%	312,130	0.02%	19	223,717	141	3.00%	428,846	0.03%	16.
17.	15,001-20,000	11	192,588	94	1.99%	504,718	0.03%	15	255,502	156	3.31%	684,348	0.05%	17.
18.	20,001-25,000	20	454,889	114	2.41%	959,607	0.06%	18	391,400	174	3.70%	1,075,748	0.08%	18.
19.	25,001-30,000	24	656,143	138	2.92%	1,615,750	0.10%	18	496,417	192	4.08%	1,572,165	0.12%	19.
20.	30,001-35,000	19	606,358	157	3.32%	2,222,108	0.14%	24	786,109	216	4.59%	2,358,274	0.18%	20.
21.	35,001-40,000	15	574,406	172	3.64%	2,796,514	0.18%	14	521,323	230	4.89%	2,879,597	0.22%	21.
22.	40,001-50,000	37	1,660,373	209	4.42%	4,456,887	0.29%	55	2,498,679	285	6.05%	5,378,276	0.41%	22.
23.	50,001-75,000	84	5,248,882	293	6.20%	9,705,769	0.62%	137	8,694,442	422	8.97%	14,072,718	1.08%	23.
24.	75,001-100,000	93	8,146,967	386	8.16%	17,852,736	1.14%	234	20,938,477	656	13.94%	35,011,195	2.70%	24.
25.	100,001-125,000	160	18,075,486	546	11.55%	35,928,222	2.30%	275	31,484,840	931	19.78%	66,496,035	5.12%	25.
26.	125,001-150,000	202	27,894,117	748	15.82%	63,822,339	4.08%	386	54,238,951	1,317	27.98%	120,734,986	9.30%	26.
27.	150,001-200,000	644	113,794,402	1,392	29.44%	177,616,741	11.36%	873	155,205,779	2,190	46.53%	275,940,765	21.26%	27.
28.	200,001-300,000	1,489	369,851,736	2,881	60.93%	547,468,477	35.02%	1,179	291,893,320	3,369	71.57%	567,834,085	43.74%	28.
29.	300,001-400,000	755	259,206,255	3,636	76.90%	806,674,732	51.61%	519	179,090,484	3,888	82.60%	746,924,569	57.54%	29.
30.	400,001-500,000	311	138,972,389	3,947	83.48%	945,647,121	60.50%	249	112,395,760	4,137	87.89%	859,320,329	66.20%	30.
31.	500,001-750,000	419	252,771,112	4,366	92.34%	1,198,418,233	76.67%	337	207,377,859	4,474	95.05%	1,066,698,188	82.18%	31.
32.	750,001-1,000,000	214	182,790,889	4,580	96.87%	1,381,209,122	88.36%	164	142,964,279	4,638	98.53%	1,209,662,467	93.19%	32.
33.	Over 1,000,000	148	181,906,805	4,728	100.00%	1,563,115,927	100.00%	69	88,402,283	4,707	100.00%	1,298,064,750	100.00%	33.

Average Number of Customers:	788	
Average Consumption:	330,608	kWh per bill
Median Consumption:	260,184	kWh per bill

Average Number of Customers:	785	
Average Consumption:	275,773	kWh per bill
Median Consumption:	208,971	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 Large (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	kW BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kW) (L)	% of Total (M)	Line No.
1.	0	13	-	13	0.27%	-	0.00%	63	-	63	1.34%	-	0.00%	1.
2.	1-10	-	-	13	0.27%	-	0.00%	1	9	64	1.36%	9	0.00%	2.
3.	11-20	-	-	13	0.27%	-	0.00%	2	35	66	1.40%	44	0.00%	3.
4.	21-30	-	-	13	0.27%	-	0.00%	-	-	66	1.40%	44	0.00%	4.
5.	31-40	2	71	15	0.32%	71	0.00%	5	178	71	1.51%	222	0.01%	5.
6.	41-50	1	49	16	0.34%	120	0.00%	5	226	76	1.62%	448	0.01%	6.
7.	51-60	7	400	23	0.49%	520	0.01%	6	325	82	1.74%	773	0.03%	7.
8.	61-70	9	585	32	0.68%	1,105	0.03%	8	524	90	1.91%	1,297	0.04%	8.
9.	71-80	4	291	36	0.76%	1,396	0.04%	4	303	94	2.00%	1,600	0.05%	9.
10.	81-90	8	685	44	0.93%	2,081	0.06%	3	248	97	2.06%	1,848	0.06%	10.
11.	91-100	4	384	48	1.02%	2,465	0.07%	7	663	104	2.21%	2,511	0.08%	11.
12.	101-200	44	7,103	92	1.95%	9,568	0.27%	92	15,222	196	4.17%	17,733	0.58%	12.
13.	201-300	98	25,439	190	4.02%	35,007	0.99%	308	82,786	504	10.71%	100,519	3.30%	13.
14.	301-400	342	125,734	532	11.25%	160,741	4.54%	910	327,854	1,414	30.05%	428,373	14.08%	14.
15.	401-500	1,039	469,915	1,571	33.23%	630,656	17.82%	991	452,798	2,405	51.12%	881,171	28.97%	15.
16.	501-600	897	492,218	2,468	52.20%	1,122,874	31.73%	662	367,243	3,067	65.19%	1,248,414	41.04%	16.
17.	601-700	574	372,493	3,042	64.34%	1,495,367	42.26%	376	248,424	3,443	73.18%	1,496,838	49.21%	17.
18.	701-800	336	252,132	3,378	71.45%	1,747,499	49.39%	265	200,865	3,708	78.81%	1,697,703	55.81%	18.
19.	801-900	295	250,435	3,673	77.69%	1,997,934	56.47%	193	166,761	3,901	82.91%	1,864,464	61.29%	19.
20.	901-1000	180	170,775	3,853	81.49%	2,168,709	61.29%	120	115,425	4,021	85.46%	1,979,889	65.09%	20.
21.	1001-1100	140	146,225	3,993	84.45%	2,314,934	65.42%	76	81,272	4,097	87.08%	2,061,161	67.76%	21.
22.	1101-1200	86	98,935	4,079	86.27%	2,413,869	68.22%	112	131,688	4,209	89.46%	2,192,849	72.09%	22.
23.	1201-1300	89	111,621	4,168	88.16%	2,525,490	71.38%	95	121,021	4,304	91.48%	2,313,870	76.07%	23.
24.	1301-1400	82	110,722	4,250	89.89%	2,636,212	74.50%	74	101,145	4,378	93.05%	2,415,015	79.39%	24.
25.	1401-1500	77	111,956	4,327	91.52%	2,748,168	77.67%	56	82,393	4,434	94.24%	2,497,408	82.10%	25.
26.	1501-1600	73	113,427	4,400	93.06%	2,861,595	80.87%	42	66,764	4,476	95.13%	2,564,172	84.30%	26.
27.	1601-1700	58	95,663	4,458	94.29%	2,957,258	83.58%	51	86,031	4,527	96.22%	2,650,203	87.12%	27.
28.	1701-1800	48	83,850	4,506	95.30%	3,041,108	85.95%	33	59,838	4,560	96.92%	2,710,041	89.09%	28.
29.	1801-1900	45	83,739	4,551	96.26%	3,124,847	88.31%	32	61,057	4,592	97.60%	2,771,098	91.10%	29.
30.	1901-2000	31	60,578	4,582	96.91%	3,185,425	90.03%	28	54,709	4,620	98.19%	2,825,807	92.90%	30.
31.	2001-2100	30	61,655	4,612	97.55%	3,247,080	91.77%	20	41,182	4,640	98.62%	2,866,989	94.25%	31.
32.	2101-2200	28	60,236	4,640	98.14%	3,307,316	93.47%	10	21,539	4,650	98.83%	2,888,528	94.96%	32.
33.	2201-2300	21	47,149	4,661	98.58%	3,354,465	94.80%	11	24,753	4,661	99.06%	2,913,281	95.77%	33.
34.	2301-2400	21	49,281	4,682	99.03%	3,403,746	96.20%	10	23,674	4,671	99.28%	2,936,955	96.55%	34.
35.	2401-2500	12	29,408	4,694	99.28%	3,433,154	97.03%	3	7,270	4,674	99.34%	2,944,225	96.79%	35.
36.	2501-2600	4	10,208	4,698	99.37%	3,443,362	97.32%	7	17,929	4,681	99.49%	2,962,154	97.38%	36.
37.	2601-2700	8	20,956	4,706	99.53%	3,464,318	97.91%	3	7,964	4,684	99.55%	2,970,118	97.64%	37.
38.	2701-2800	4	11,048	4,710	99.62%	3,475,366	98.22%	3	8,330	4,687	99.62%	2,978,448	97.92%	38.
39.	2801-2900	4	11,376	4,714	99.70%	3,486,742	98.54%	-	-	4,687	99.62%	2,978,448	97.92%	39.
40.	2901-3000	2	5,860	4,716	99.75%	3,492,602	98.71%	4	11,811	4,691	99.70%	2,990,259	98.30%	40.
41.	Over 3000	12	45,710	4,728	100.00%	3,538,312	100.00%	14	51,595	4,705	100.00%	3,041,854	100.00%	41.

Average Number of Customers:	788	
Average Load:	748	kW per bill
Median Load:	588	kW per bill

Average Number of Customers:	784	
Average Load:	647	kW per bill
Median Load:	494	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 TOU XS & S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	CONSUMPTION kWh BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kWh) (L)	% of Total (M)	Line No.
1.	0	46	-	46	2.03%	-	0.00%	62	-	62	2.73%	-	0.00%	1.
2.	1-100	130	5,264	176	7.76%	5,264	0.03%	110	4,392	172	7.59%	4,392	0.03%	2.
3.	101-200	124	17,866	300	13.23%	23,130	0.11%	119	17,351	291	12.84%	21,743	0.13%	3.
4.	201-300	107	26,468	407	17.95%	49,598	0.24%	88	21,935	379	16.72%	43,678	0.26%	4.
5.	301-400	54	19,310	461	20.33%	68,908	0.34%	104	36,510	483	21.31%	80,188	0.48%	5.
6.	401-500	59	26,406	520	22.93%	95,314	0.47%	65	29,341	548	24.17%	109,529	0.66%	6.
7.	501-750	132	81,903	652	28.75%	177,217	0.87%	141	89,722	689	30.39%	199,251	1.20%	7.
8.	751-1,000	92	79,684	744	32.80%	256,901	1.26%	105	92,241	794	35.02%	291,492	1.76%	8.
9.	1,001-1,500	121	151,214	865	38.14%	408,115	2.00%	124	153,117	918	40.49%	444,609	2.69%	9.
10.	1,501-2,000	82	145,928	947	41.75%	554,043	2.72%	114	201,532	1,032	45.52%	646,141	3.91%	10.
11.	2,001-3,000	155	397,345	1,102	48.59%	951,388	4.67%	245	629,285	1,277	56.33%	1,275,426	7.71%	11.
12.	3,001-4,000	163	569,115	1,265	55.78%	1,520,503	7.46%	118	411,811	1,395	61.54%	1,687,237	10.20%	12.
13.	4,001-5,000	111	493,659	1,376	60.67%	2,014,162	9.88%	73	325,432	1,468	64.76%	2,012,669	12.17%	13.
14.	5,001-7,500	151	930,346	1,527	67.33%	2,944,508	14.45%	146	899,280	1,614	71.20%	2,911,949	17.60%	14.
15.	7,501-10,000	95	835,824	1,622	71.52%	3,780,332	18.55%	107	938,114	1,721	75.92%	3,850,063	23.27%	15.
16.	10,001-15,000	192	2,381,203	1,814	79.98%	6,161,535	30.23%	159	1,975,760	1,880	82.93%	5,825,823	35.21%	16.
17.	15,001-20,000	97	1,705,776	1,911	84.26%	7,867,311	38.60%	131	2,362,185	2,011	88.71%	8,188,008	49.49%	17.
18.	20,001-25,000	103	2,342,007	2,014	88.80%	10,209,318	50.10%	117	2,617,323	2,128	93.87%	10,805,331	65.31%	18.
19.	25,001-30,000	67	1,843,104	2,081	91.75%	12,052,422	59.14%	47	1,301,328	2,175	95.94%	12,106,659	73.18%	19.
20.	30,001-35,000	50	1,613,967	2,131	93.96%	13,666,389	67.06%	24	802,524	2,199	97.00%	12,909,183	78.03%	20.
21.	35,001-40,000	39	1,455,083	2,170	95.68%	15,121,472	74.20%	28	1,069,926	2,227	98.24%	13,979,109	84.49%	21.
22.	40,001-50,000	57	2,569,569	2,227	98.19%	17,691,041	86.81%	20	896,270	2,247	99.12%	14,875,379	89.91%	22.
23.	50,001-75,000	32	1,825,247	2,259	99.60%	19,516,288	95.76%	15	872,119	2,262	99.78%	15,747,498	95.18%	23.
24.	75,001-100,000	5	443,894	2,264	99.82%	19,960,182	97.94%	4	361,700	2,266	99.96%	16,109,198	97.37%	24.
25.	100,001-125,000	4	419,689	2,268	100.00%	20,379,871	100.00%	-	-	2,266	99.96%	16,109,198	97.37%	25.
26.	125,001-150,000	-	-	2,268	100.00%	20,379,871	100.00%	-	-	2,266	99.96%	16,109,198	97.37%	26.
27.	150,001-200,000	-	-	2,268	100.00%	20,379,871	100.00%	-	-	2,266	99.96%	16,109,198	97.37%	27.
28.	200,001-300,000	-	-	2,268	100.00%	20,379,871	100.00%	-	-	2,266	99.96%	16,109,198	97.37%	28.
29.	300,001-400,000	-	-	2,268	100.00%	20,379,871	100.00%	-	-	2,266	99.96%	16,109,198	97.37%	29.
30.	400,001-500,000	-	-	2,268	100.00%	20,379,871	100.00%	1	435,336	2,267	100.00%	16,544,534	100.00%	30.
31.	500,001-750,000	-	-	2,268	100.00%	20,379,871	100.00%	-	-	2,267	100.00%	16,544,534	100.00%	31.
32.	750,001-1,000,000	-	-	2,268	100.00%	20,379,871	100.00%	-	-	2,267	100.00%	16,544,534	100.00%	32.
33.	Over 1,000,000	-	-	2,268	100.00%	20,379,871	100.00%	-	-	2,267	100.00%	16,544,534	100.00%	33.

Average Number of Customers:	378	
Average Consumption:	8,986	kWh per bill
Median Consumption:	3,178	kWh per bill

Average Number of Customers:	378
Average Consumption:	7,298
Median Consumption:	2,490

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 TOU XS & S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	kW BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kW) (L)	% of Total (M)	Line No.
1.	0	39	-	39	1.72%	-	0.00%	39	-	39	1.72%	-	0.00%	1.
2.	1-10	1,023	3,446	1,062	46.76%	3,446	5.57%	1,023	3,446	1,062	46.76%	3,446	5.57%	2.
3.	11-20	298	4,318	1,360	59.89%	7,764	12.55%	298	4,318	1,360	59.89%	7,764	12.55%	3.
4.	21-30	178	4,488	1,538	67.72%	12,252	19.80%	178	4,488	1,538	67.72%	12,252	19.80%	4.
5.	31-40	184	6,372	1,722	75.83%	18,624	30.10%	184	6,372	1,722	75.83%	18,624	30.10%	5.
6.	41-50	135	6,147	1,857	81.77%	24,771	40.03%	135	6,147	1,857	81.77%	24,771	40.03%	6.
7.	51-60	101	5,612	1,958	86.22%	30,383	49.10%	101	5,612	1,958	86.22%	30,383	49.10%	7.
8.	61-70	64	4,170	2,022	89.04%	34,553	55.84%	64	4,170	2,022	89.04%	34,553	55.84%	8.
9.	71-80	57	4,288	2,079	91.55%	38,841	62.77%	57	4,288	2,079	91.55%	38,841	62.77%	9.
10.	81-90	60	5,117	2,139	94.19%	43,958	71.04%	60	5,117	2,139	94.19%	43,958	71.04%	10.
11.	91-100	49	4,640	2,188	96.35%	48,598	78.54%	49	4,640	2,188	96.35%	48,598	78.54%	11.
12.	101-200	65	7,992	2,253	99.21%	56,590	91.46%	65	7,992	2,253	99.21%	56,590	91.46%	12.
13.	201-300	14	3,374	2,267	99.82%	59,964	96.91%	14	3,374	2,267	99.82%	59,964	96.91%	13.
14.	301-400	3	1,143	2,270	99.96%	61,107	98.76%	3	1,143	2,270	99.96%	61,107	98.76%	14.
15.	401-500	-	-	2,270	99.96%	61,107	98.76%	-	-	2,270	99.96%	61,107	98.76%	15.
16.	501-600	-	-	2,270	99.96%	61,107	98.76%	-	-	2,270	99.96%	61,107	98.76%	16.
17.	601-700	-	-	2,270	99.96%	61,107	98.76%	-	-	2,270	99.96%	61,107	98.76%	17.
18.	701-800	1	768	2,271	100.00%	61,875	100.00%	1	768	2,271	100.00%	61,875	100.00%	18.
19.	801-900	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	19.
20.	901-1000	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	20.
21.	1001-1100	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	21.
22.	1101-1200	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	22.
23.	1201-1300	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	23.
24.	1301-1400	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	24.
25.	1401-1500	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	25.
26.	1501-1600	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	26.
27.	1601-1700	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	27.
28.	1701-1800	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	28.
29.	1801-1900	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	29.
30.	1901-2000	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	30.
31.	2001-2100	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	31.
32.	2101-2200	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	32.
33.	2201-2300	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	33.
34.	2301-2400	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	34.
35.	2401-2500	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	35.
36.	2501-2600	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	36.
37.	2601-2700	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	37.
38.	2701-2800	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	38.
39.	2801-2900	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	39.
40.	2901-3000	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	40.
41.	Over 3000	-	-	2,271	100.00%	61,875	100.00%	-	-	2,271	100.00%	61,875	100.00%	41.

Average Number of Customers:	379		Average Number of Customers:	379	
Average Load:	27	kW per bill	Average Load:	27	kW per bill
Median Load:	12	kW per bill	Median Load:	10	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 TOU Medium**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	1	-	1	0.22%	-	0.00%	1.
2.	1-100	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	2.
3.	101-200	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	3.
4.	201-300	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	4.
5.	301-400	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	5.
6.	401-500	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	6.
7.	501-750	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	7.
8.	751-1,000	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	8.
9.	1,001-1,500	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	9.
10.	1,501-2,000	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	10.
11.	2,001-3,000	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	11.
12.	3,001-4,000	1	3,853	1	0.22%	3,853	0.01%	2	9,297	3	0.66%	9,297	0.03%	12.
13.	4,001-5,000	1	4,897	2	0.44%	8,750	0.02%	7	43,049	10	2.21%	52,346	0.16%	13.
14.	5,001-7,500	1	5,057	3	0.66%	13,807	0.03%	7	58,126	17	3.76%	110,472	0.34%	14.
15.	7,501-10,000	3	25,125	6	1.32%	38,932	0.10%	13	163,122	30	6.64%	273,594	0.85%	15.
16.	10,001-15,000	10	123,881	16	3.52%	162,813	0.41%	13	223,249	43	9.51%	496,843	1.55%	16.
17.	15,001-20,000	11	201,987	27	5.95%	364,800	0.91%	17	358,641	60	13.27%	855,484	2.66%	17.
18.	20,001-25,000	10	235,762	37	8.15%	600,562	1.50%	17	448,620	77	17.04%	1,304,104	4.06%	18.
19.	25,001-30,000	11	303,452	48	10.57%	904,014	2.25%	22	686,421	99	21.90%	1,990,525	6.19%	19.
20.	30,001-35,000	17	549,789	65	14.32%	1,453,803	3.62%	32	1,181,303	131	28.98%	3,171,828	9.86%	20.
21.	35,001-40,000	11	411,419	76	16.74%	1,865,222	4.64%	64	2,813,389	195	43.14%	5,985,217	18.61%	21.
22.	40,001-50,000	43	2,020,350	119	26.21%	3,885,572	9.67%	87	5,073,709	282	62.39%	11,058,926	34.39%	22.
23.	50,001-75,000	118	7,524,384	237	52.20%	11,409,956	28.40%	52	4,465,100	334	73.89%	15,524,026	48.28%	23.
24.	75,001-100,000	65	5,808,751	302	66.52%	17,218,707	42.86%	57	6,226,474	391	86.50%	21,750,500	67.64%	24.
25.	100,001-125,000	61	6,931,709	363	79.96%	24,150,416	60.12%	19	2,510,065	410	90.71%	24,260,565	75.45%	25.
26.	125,001-150,000	33	4,515,895	396	87.22%	28,666,311	71.36%	24	3,930,806	434	96.02%	28,191,371	87.67%	26.
27.	150,001-200,000	38	6,631,247	434	95.59%	35,297,558	87.87%	18	3,963,164	452	100.00%	32,154,535	100.00%	27.
28.	200,001-300,000	17	3,911,781	451	99.34%	39,209,339	97.61%	-	-	452	100.00%	32,154,535	100.00%	28.
29.	300,001-400,000	3	961,991	454	100.00%	40,171,330	100.00%	-	-	452	100.00%	32,154,535	100.00%	29.
30.	400,001-500,000	-	-	454	100.00%	40,171,330	100.00%	-	-	452	100.00%	32,154,535	100.00%	30.
31.	500,001-750,000	-	-	454	100.00%	40,171,330	100.00%	-	-	452	100.00%	32,154,535	100.00%	31.
32.	750,001-1,000,000	-	-	454	100.00%	40,171,330	100.00%	-	-	452	100.00%	32,154,535	100.00%	32.
33.	Over 1,000,000	-	-	454	100.00%	40,171,330	100.00%	-	-	452	100.00%	32,154,535	100.00%	33.

Average Number of Customers:	76	
Average Consumption:	88,483	kWh per bill
Median Consumption:	73,209	kWh per bill

Average Number of Customers:	75	
Average Consumption:	71,138	kWh per bill
Median Consumption:	56,388	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 TOU Medium**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	1	-	1	0.22%	-	0.00%	1.
2.	1-10	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	2.
3.	11-20	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	3.
4.	21-30	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	4.
5.	31-40	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	-	0.00%	5.
6.	41-50	-	-	-	0.00%	-	0.00%	2	86	3	0.67%	86	0.10%	6.
7.	51-60	-	-	-	0.00%	-	0.00%	4	222	7	1.56%	308	0.35%	7.
8.	61-70	-	-	-	0.00%	-	0.00%	5	329	12	2.67%	637	0.72%	8.
9.	71-80	-	-	-	0.00%	-	0.00%	21	1,527	33	7.33%	2,164	2.44%	9.
10.	81-90	8	694	8	1.76%	694	0.65%	34	2,821	67	14.89%	4,985	5.63%	10.
11.	91-100	17	1,627	25	5.49%	2,321	2.17%	28	2,547	95	21.11%	7,532	8.51%	11.
12.	101-200	224	34,162	249	54.73%	36,483	34.16%	177	24,546	272	60.44%	32,078	36.24%	12.
13.	201-300	111	28,227	360	79.12%	64,710	60.59%	102	24,087	374	83.11%	56,165	63.45%	13.
14.	301-400	45	15,518	405	89.01%	80,228	75.12%	41	14,003	415	92.22%	70,168	79.27%	14.
15.	401-500	25	11,382	430	94.51%	91,610	85.78%	17	7,199	432	96.00%	77,367	87.41%	15.
16.	501-600	14	7,478	444	97.58%	99,088	92.78%	9	4,956	441	98.00%	82,323	93.01%	16.
17.	601-700	8	4,959	452	99.34%	104,047	97.43%	6	3,744	447	99.33%	86,067	97.24%	17.
18.	701-800	1	780	453	99.56%	104,827	98.16%	2	1,515	449	99.78%	87,582	98.95%	18.
19.	801-900	-	-	453	99.56%	104,827	98.16%	-	-	449	99.78%	87,582	98.95%	19.
20.	901-1000	1	954	454	99.78%	105,781	99.05%	1	932	450	100.00%	88,514	100.00%	20.
21.	1001-1100	1	1,015	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	21.
22.	1101-1200	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	22.
23.	1201-1300	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	23.
24.	1301-1400	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	24.
25.	1401-1500	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	25.
26.	1501-1600	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	26.
27.	1601-1700	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	27.
28.	1701-1800	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	28.
29.	1801-1900	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	29.
30.	1901-2000	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	30.
31.	2001-2100	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	31.
32.	2101-2200	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	32.
33.	2201-2300	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	33.
34.	2301-2400	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	34.
35.	2401-2500	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	35.
36.	2501-2600	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	36.
37.	2601-2700	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	37.
38.	2701-2800	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	38.
39.	2801-2900	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	39.
40.	2901-3000	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	40.
41.	Over 3000	-	-	455	100.00%	106,796	100.00%	-	-	450	100.00%	88,514	100.00%	41.

Average Number of Customers:	76		Average Number of Customers:	75	
Average Load:	235	kW per bill	Average Load:	197	kW per bill
Median Load:	189	kW per bill	Median Load:	163	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 TOU Large (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	7	-	7	2.00%	-	0.00%	8	-	8	2.40%	-	0.00%	1.
2.	1-100	-	-	7	2.00%	-	0.00%	-	-	8	2.40%	-	0.00%	2.
3.	101-200	-	-	7	2.00%	-	0.00%	-	-	8	2.40%	-	0.00%	3.
4.	201-300	-	-	7	2.00%	-	0.00%	-	-	8	2.40%	-	0.00%	4.
5.	301-400	-	-	7	2.00%	-	0.00%	-	-	8	2.40%	-	0.00%	5.
6.	401-500	-	-	7	2.00%	-	0.00%	-	-	8	2.40%	-	0.00%	6.
7.	501-750	-	-	7	2.00%	-	0.00%	-	-	8	2.40%	-	0.00%	7.
8.	751-1,000	-	-	7	2.00%	-	0.00%	1	804	9	2.70%	804	0.00%	8.
9.	1,001-1,500	-	-	7	2.00%	-	0.00%	1	1,447	10	3.00%	2,251	0.00%	9.
10.	1,501-2,000	-	-	7	2.00%	-	0.00%	1	1,607	11	3.30%	3,858	0.00%	10.
11.	2,001-3,000	-	-	7	2.00%	-	0.00%	-	-	11	3.30%	3,858	0.00%	11.
12.	3,001-4,000	-	-	7	2.00%	-	0.00%	-	-	11	3.30%	3,858	0.00%	12.
13.	4,001-5,000	-	-	7	2.00%	-	0.00%	-	-	11	3.30%	3,858	0.00%	13.
14.	5,001-7,500	4	26,080	11	3.14%	26,080	0.02%	-	-	11	3.30%	3,858	0.00%	14.
15.	7,501-10,000	-	-	11	3.14%	26,080	0.02%	2	17,281	13	3.90%	21,139	0.02%	15.
16.	10,001-15,000	2	24,876	13	3.71%	50,956	0.04%	-	-	13	3.90%	21,139	0.02%	16.
17.	15,001-20,000	3	58,179	16	4.57%	109,135	0.08%	4	70,006	17	5.11%	91,145	0.08%	17.
18.	20,001-25,000	3	68,611	19	5.43%	177,746	0.13%	5	117,106	22	6.61%	208,251	0.18%	18.
19.	25,001-30,000	1	29,691	20	5.71%	207,437	0.16%	4	106,336	26	7.81%	314,587	0.28%	19.
20.	30,001-35,000	4	132,005	24	6.86%	339,442	0.26%	1	32,954	27	8.11%	347,541	0.31%	20.
21.	35,001-40,000	-	-	24	6.86%	339,442	0.26%	1	39,384	28	8.41%	386,925	0.34%	21.
22.	40,001-50,000	-	-	24	6.86%	339,442	0.26%	1	42,197	29	8.71%	429,122	0.38%	22.
23.	50,001-75,000	4	253,979	28	8.00%	593,421	0.45%	7	463,280	36	10.81%	892,402	0.79%	23.
24.	75,001-100,000	11	946,083	39	11.14%	1,539,504	1.16%	17	1,552,477	53	15.92%	2,444,879	2.15%	24.
25.	100,001-125,000	21	2,405,962	60	17.14%	3,945,466	2.98%	12	1,356,524	65	19.52%	3,801,403	3.35%	25.
26.	125,001-150,000	17	2,359,700	77	22.00%	6,305,166	4.76%	22	3,078,571	87	26.13%	6,879,974	6.06%	26.
27.	150,001-200,000	35	6,513,125	112	32.00%	12,818,291	9.67%	30	5,140,966	117	35.14%	12,020,940	10.59%	27.
28.	200,001-300,000	66	16,812,186	178	50.86%	29,630,477	22.35%	75	18,493,812	192	57.66%	30,514,752	26.87%	28.
29.	300,001-400,000	62	21,984,536	240	68.57%	51,615,013	38.94%	56	19,767,791	248	74.47%	50,282,543	44.28%	29.
30.	400,001-500,000	40	18,329,381	280	80.00%	69,944,394	52.76%	34	14,966,268	282	84.68%	65,248,811	57.46%	30.
31.	500,001-750,000	37	21,788,876	317	90.57%	91,733,270	69.20%	21	12,648,162	303	90.99%	77,896,973	68.60%	31.
32.	750,001-1,000,000	8	6,741,084	325	92.86%	98,474,354	74.29%	11	10,010,968	314	94.29%	87,907,941	77.42%	32.
33.	Over 1,000,000	25	34,087,191	350	100.00%	132,561,545	100.00%	19	25,644,044	333	100.00%	113,551,985	100.00%	33.

Average Number of Customers:	58	
Average Consumption:	378,747	kWh per bill
Median Consumption:	297,011	kWh per bill

Average Number of Customers:	56	
Average Consumption:	340,997	kWh per bill
Median Consumption:	261,861	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-32 TOU Large (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	kW BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kW) (L)	% of Total (M)	Line No.
1.	0	-	-	-	0.00%	-	0.00%	5	-	5	1.51%	-	0.00%	1.
2.	1-10	1	8	1	0.28%	8	0.00%	3	14	8	2.41%	14	0.01%	2.
3.	11-20	3	36	4	1.14%	44	0.01%	1	12	9	2.71%	26	0.01%	3.
4.	21-30	-	-	4	1.14%	44	0.01%	-	-	9	2.71%	26	0.01%	4.
5.	31-40	1	40	5	1.42%	84	0.03%	1	38	10	3.01%	64	0.02%	5.
6.	41-50	-	-	5	1.42%	84	0.03%	1	48	11	3.31%	112	0.04%	6.
7.	51-60	1	60	6	1.70%	144	0.05%	-	-	11	3.31%	112	0.04%	7.
8.	61-70	1	68	7	1.99%	212	0.07%	-	-	11	3.31%	112	0.04%	8.
9.	71-80	-	-	7	1.99%	212	0.07%	-	-	11	3.31%	112	0.04%	9.
10.	81-90	-	-	7	1.99%	212	0.07%	-	-	11	3.31%	112	0.04%	10.
11.	91-100	-	-	7	1.99%	212	0.07%	1	96	12	3.61%	208	0.08%	11.
12.	101-200	4	496	11	3.13%	708	0.22%	4	583	16	4.82%	791	0.29%	12.
13.	201-300	5	1,332	16	4.55%	2,040	0.64%	7	1,943	23	6.93%	2,734	0.99%	13.
14.	301-400	16	5,870	32	9.09%	7,910	2.48%	47	17,123	70	21.08%	19,857	7.18%	14.
15.	401-500	60	27,293	92	26.14%	35,203	11.02%	51	23,240	121	36.45%	43,097	15.58%	15.
16.	501-600	49	27,263	141	40.06%	62,466	19.56%	44	24,518	165	49.70%	67,615	24.44%	16.
17.	601-700	40	26,458	181	51.42%	88,924	27.84%	37	23,809	202	60.84%	91,424	33.05%	17.
18.	701-800	33	24,743	214	60.80%	113,667	35.59%	23	17,144	225	67.77%	108,568	39.24%	18.
19.	801-900	30	25,217	244	69.32%	138,884	43.48%	16	13,558	241	72.59%	122,126	44.14%	19.
20.	901-1000	17	16,213	261	74.15%	155,097	48.56%	16	15,260	257	77.41%	137,386	49.66%	20.
21.	1001-1100	16	16,867	277	78.69%	171,964	53.84%	7	7,437	264	79.52%	144,823	52.35%	21.
22.	1101-1200	8	9,010	285	80.97%	180,974	56.66%	10	11,687	274	82.53%	156,510	56.57%	22.
23.	1201-1300	7	8,951	292	82.95%	189,925	59.46%	3	3,646	277	83.43%	160,156	57.89%	23.
24.	1301-1400	-	-	292	82.95%	189,925	59.46%	3	4,104	280	84.34%	164,260	59.37%	24.
25.	1401-1500	6	8,704	298	84.66%	198,629	62.19%	1	1,440	281	84.64%	165,700	59.89%	25.
26.	1501-1600	1	1,512	299	84.94%	200,141	62.66%	2	3,036	283	85.24%	168,736	60.99%	26.
27.	1601-1700	5	8,382	304	86.36%	208,523	65.29%	5	8,273	288	86.75%	177,009	63.98%	27.
28.	1701-1800	3	5,250	307	87.22%	213,773	66.93%	6	10,584	294	88.55%	187,593	67.81%	28.
29.	1801-1900	11	20,412	318	90.34%	234,185	73.32%	5	9,172	299	90.06%	196,765	71.12%	29.
30.	1901-2000	6	11,734	324	92.05%	245,919	77.00%	5	9,735	304	91.57%	206,500	74.64%	30.
31.	2001-2100	4	8,280	328	93.18%	254,199	79.59%	5	10,281	309	93.07%	216,781	78.36%	31.
32.	2101-2200	3	6,456	331	94.03%	260,655	81.61%	6	12,872	315	94.88%	229,653	83.01%	32.
33.	2201-2300	3	6,656	334	94.89%	267,311	83.69%	7	15,632	322	96.99%	245,285	88.66%	33.
34.	2301-2400	6	14,195	340	96.59%	281,506	88.14%	2	4,684	324	97.59%	249,969	90.35%	34.
35.	2401-2500	1	2,496	341	96.88%	284,002	88.92%	1	2,451	325	97.89%	252,420	91.24%	35.
36.	2501-2600	2	5,152	343	97.44%	289,154	90.53%	1	2,592	326	98.19%	255,012	92.18%	36.
37.	2601-2700	1	2,649	344	97.73%	291,803	91.36%	1	2,688	327	98.49%	257,700	93.15%	37.
38.	2701-2800	-	-	344	97.73%	291,803	91.36%	-	-	327	98.49%	257,700	93.15%	38.
39.	2801-2900	1	2,880	345	98.01%	294,683	92.26%	-	-	327	98.49%	257,700	93.15%	39.
40.	2901-3000	2	5,865	347	98.58%	300,548	94.10%	-	-	327	98.49%	257,700	93.15%	40.
41.	Over 3000	5	18,843	352	100.00%	319,391	100.00%	5	18,959	332	100.00%	276,659	100.00%	41.

Average Number of Customers: 58
Average Load: 907 kW per bill
Median Load: 684 kW per bill

Average Number of Customers: 55
Average Load: 833 kW per bill
Median Load: 600 kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-34, E-34 Primary, E-34 Transmission (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	CONSUMPTION kWh BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kWh) (L)	% of Total (M)	Line No.
1.	0	2	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-100,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	100.001-250,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	250,001-500,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	500,001-600,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	600,001-700,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	700,001-800,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	800,001-900,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	900,001-1,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	1,000,001-1,250,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	1,250,001-1,500,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	1,500,001-1,750,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	1,750,001-2,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	2,000,001-2,250,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	2,250,001-2,500,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	2,500,001-2,750,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	2,750,001-3,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	3,000,001-3,250,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	3,250,001-3,500,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	3,500,001-3,750,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	3,750,001-4,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	4,000,001-4,500,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	4,500,001-5,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	23.
24.	5,000,001-6,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	24.
25.	6,000,001-7,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	25.
26.	7,000,001-8,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	26.
27.	8,000,001-9,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	27.
28.	9,000,001-10,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	28.
29.	10,000,001-12,500,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	29.
30.	12,500,001-15,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	30.
31.	15,000,001-20,000,000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	31.
32.	20,000,001-30,000,000	4	3,655,399	6	4.26%	3,655,399	0.98%	2	1,408,533	2	1.32%	1,408,533	0.43%	32.
33.	Over 30,000,000	135	368,372,050	141	100.00%	372,027,449	100.00%	10	8,953,711	12	7.95%	10,362,244	3.20%	33.
								139	313,952,426	151	100.00%	324,314,670	100.00%	

Average Number of Customers:	24		Average Number of Customers:	25	
Average Consumption:	2,638,493	kWh per bill	Average Consumption:	2,147,779	kWh per bill
Median Consumption:	2,287,968	kWh per bill	Median Consumption:	1,953,431	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-34, E-34 Primary, E-34 Transmission (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	2	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-1000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	1001-1500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	1501-2000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	2001-2250	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	2251-2500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	2500-2750	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	2751-3000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	3001-3250	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	3251-3500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	3501-3750	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	3751-4000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	4001-4250	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	4251-4500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	4501-4750	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	4751-5000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	5001-5500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	5501-6000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	6001-6500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	6501-7000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	7001-7500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	7501-8000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	8001-8500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	23.
24.	8501-9000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	24.
25.	9001-9500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	25.
26.	9501-10000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	26.
27.	10001-12500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	27.
28.	12501-15000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	28.
29.	15001-17500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	29.
30.	17501-20000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	30.
31.	20001-22500	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	31.
32.	22501-25000	-	-	2	1.42%	-	0.00%	-	-	-	0.00%	-	0.00%	32.
33.	25001-27500	-	-	2	1.42%	-	0.00%	3	-	3	2.00%	-	0.00%	33.
34.	27501-30000	-	-	2	1.42%	-	0.00%	4	-	7	4.67%	-	0.00%	34.
35.	30001-32500	2	4,895	4	2.84%	4,895	0.69%	9	4,895	16	10.67%	4,895	0.69%	35.
36.	32501-35000	2	5,164	6	4.26%	10,059	1.42%	5	5,164	21	14.00%	10,059	1.42%	36.
37.	35001-37500	-	-	6	4.26%	10,059	1.42%	5	-	26	17.33%	10,059	1.42%	37.
38.	37501-40000	3	8,192	9	6.38%	18,251	2.58%	5	8,192	31	20.67%	18,251	2.58%	38.
39.	40001-60000	1	2,808	10	7.09%	21,059	2.98%	1	2,808	32	21.33%	21,059	2.98%	39.
40.	60001-80000	6	17,677	16	11.35%	38,736	5.48%	9	17,677	41	27.33%	38,736	5.48%	40.
41.	Over 80000	125	667,551	141	100.00%	706,287	100.00%	109	667,551	150	100.00%	706,287	100.00%	41.

Average Number of Customers:	24	
Average Load:	5,009	kW per bill
Median Load:	4,392	kW per bill

Average Number of Customers:	25	
Average Load:	4,709	kW per bill
Median Load:	3,744	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-35, E-35 Primary, E-35 Transmission (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	NUMBER OF BILLS BY BLOCK (H)	CONSUMPTION kWh BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kWh) (L)	% of Total (M)	Line No.
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-100,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	100.001-250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	250,001-500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	500,001-600,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	600,001-700,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	700,001-800,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	800,001-900,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	900,001-1,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	1,000,001-1,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	1,250,001-1,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	1,500,001-1,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	1,750,001-2,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	2,000,001-2,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	2,250,001-2,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	2,500,001-2,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	2,750,001-3,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	3,000,001-3,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	3,250,001-3,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	3,500,001-3,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	3,750,001-4,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	4,000,001-4,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	4,500,001-5,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	23.
24.	5,000,001-6,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	24.
25.	6,000,001-7,000,000	2	243,550	2	1.00%	243,550	0.03%	-	-	-	0.00%	-	0.00%	25.
26.	7,000,001-8,000,000	-	-	2	1.00%	243,550	0.03%	-	-	-	0.00%	-	0.00%	26.
27.	8,000,001-9,000,000	-	-	2	1.00%	243,550	0.03%	1	219,147	1	0.51%	219,147	0.03%	27.
28.	9,000,001-10,000,000	1	327,395	3	1.49%	570,945	0.07%	4	1,204,856	5	2.54%	1,424,003	0.21%	28.
29.	10,000,001-12,500,000	7	2,658,640	10	4.98%	3,229,585	0.42%	2	732,293	7	3.55%	2,156,296	0.32%	29.
30.	12,500,001-15,000,000	2	1,086,879	12	5.97%	4,316,464	0.57%	5	2,514,890	12	6.09%	4,671,186	0.69%	30.
31.	15,000,001-20,000,000	6	3,897,238	18	8.96%	8,213,702	1.08%	10	6,179,511	22	11.17%	10,850,697	1.60%	31.
32.	20,000,001-30,000,000	2	1,977,122	20	9.95%	10,190,824	1.34%	2	1,935,909	24	12.18%	12,786,606	1.88%	32.
33.	Over 30,000,000	181	751,789,845	201	100.00%	761,980,669	100.00%	173	666,752,403	197	100.00%	679,539,009	100.00%	33.

Average Number of Customers:	34		Average Number of Customers:	33	
Average Consumption:	3,790,949	kWh per bill	Average Consumption:	3,449,437	kWh per bill
Median Consumption:	3,173,798	kWh per bill	Median Consumption:	2,945,158	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-35, E-35 Primary, E-35 Transmission (excludes AG-1)**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-1000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	1001-1500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	1501-2000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	2001-2250	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	2251-2500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	2500-2750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	2751-3000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	3001-3250	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	3251-3500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	3501-3750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	3751-4000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	4001-4250	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	4251-4500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	4501-4750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	4751-5000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	5001-5500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	5501-6000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	6001-6500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	6501-7000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	7001-7500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	7501-8000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	8001-8500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	23.
24.	8501-9000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	24.
25.	9001-9500	-	-	-	0.00%	-	0.00%	1	1,488	1	0.54%	1,488	0.13%	25.
26.	9501-10000	-	-	-	0.00%	-	0.00%	1	1,545	2	1.08%	3,033	0.26%	26.
27.	10001-12500	-	-	-	0.00%	-	0.00%	-	-	2	1.08%	3,033	0.26%	27.
28.	12501-15000	-	-	-	0.00%	-	0.00%	-	-	2	1.08%	3,033	0.26%	28.
29.	15001-17500	-	-	-	0.00%	-	0.00%	-	-	2	1.08%	3,033	0.26%	29.
30.	17501-20000	-	-	-	0.00%	-	0.00%	-	-	2	1.08%	3,033	0.26%	30.
31.	20001-22500	1	2,025	1	0.50%	2,025	0.16%	1	2,160	3	1.61%	5,193	0.44%	31.
32.	22501-25000	-	-	1	0.50%	2,025	0.16%	3	6,768	6	3.23%	11,961	1.02%	32.
33.	25001-27500	1	2,268	2	0.99%	4,293	0.33%	3	6,998	9	4.84%	18,959	1.62%	33.
34.	27501-30000	2	4,646	4	1.98%	8,939	0.69%	3	7,286	12	6.45%	26,245	2.24%	34.
35.	30001-32500	-	-	4	1.98%	8,939	0.69%	3	7,660	15	8.06%	33,905	2.90%	35.
36.	32501-35000	1	2,587	5	2.48%	11,526	0.89%	2	5,260	17	9.14%	39,165	3.34%	36.
37.	35001-37500	1	2,649	6	2.97%	14,175	1.09%	4	11,056	21	11.29%	50,221	4.29%	37.
38.	37501-40000	1	2,793	7	3.47%	16,968	1.31%	3	8,582	24	12.90%	58,803	5.02%	38.
39.	40001-60000	4	11,481	11	5.45%	28,449	2.19%	4	11,725	28	15.05%	70,528	6.02%	39.
40.	60001-80000	4	11,893	15	7.43%	40,342	3.11%	158	1,100,479	186	100.00%	1,171,007	100.00%	40.
41.	Over 80000	187	1,258,707	202	100.00%	1,299,049	100.00%							41.

Average Number of Customers: 34
Average Load: 6,431 kW per bill
Median Load: 5,520 kW per bill

Average Number of Customers: 31
Average Load: 6,296 kW per bill
Median Load: 5,322 kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-36 XL**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	Line No.
1.								1.
2.		BILLING DETERMINANTS FOR E-36 CUSTOMERS ARE NOT UTILIZED						2.
3.		IN REVENUE REQUIREMENT CALCULATIONS						3.
4.								4.
5.								5.
6.								6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.
34.								34.
35.								35.
36.								36.
37.								37.
38.								38.
39.								39.
40.								40.
41.								41.

Average Number of Customers:
Average Load: kW per bill
Median Load: kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-36 XL**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	Line No.
1.								1.
2.								2.
3.		BILLING DETERMINANTS FOR E-36 CUSTOMERS ARE NOT UTILIZED						3.
4.		IN REVENUE REQUIREMENT CALCULATIONS						4.
5.								5.
6.								6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-221 and E-221-8T**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	408	-	408	4.62%	-	0.00%	658	-	658	7.51%	-	0.00%	1.
2.	1-100	470	20,427	878	9.95%	20,427	0.01%	637	27,313	1,295	14.78%	27,313	0.02%	2.
3.	101-200	202	30,106	1,080	12.24%	50,533	0.03%	319	46,744	1,614	18.43%	74,057	0.06%	3.
4.	201-300	146	36,052	1,226	13.89%	86,585	0.04%	201	49,098	1,815	20.72%	123,155	0.09%	4.
5.	301-400	133	47,924	1,359	15.40%	134,509	0.07%	185	65,658	2,000	22.83%	188,813	0.14%	5.
6.	401-500	107	48,435	1,466	16.61%	182,944	0.09%	148	67,756	2,148	24.52%	256,569	0.19%	6.
7.	501-750	242	153,487	1,708	19.35%	336,431	0.17%	346	216,861	2,494	28.47%	473,430	0.35%	7.
8.	751-1,000	241	213,359	1,949	22.08%	549,790	0.27%	289	251,146	2,783	31.77%	724,576	0.54%	8.
9.	1,001-1,500	400	493,128	2,349	26.62%	1,042,918	0.52%	423	524,832	3,206	36.60%	1,249,408	0.93%	9.
10.	1,501-2,000	329	570,798	2,678	30.35%	1,613,716	0.80%	376	658,251	3,582	40.90%	1,907,659	1.42%	10.
11.	2,001-3,000	488	1,226,589	3,166	35.88%	2,840,305	1.41%	547	1,361,031	4,129	47.14%	3,268,690	2.44%	11.
12.	3,001-4,000	409	1,431,558	3,575	40.51%	4,271,863	2.12%	428	1,506,915	4,557	52.03%	4,775,605	3.56%	12.
13.	4,001-5,000	351	1,589,118	3,926	44.49%	5,860,981	2.91%	361	1,626,207	4,918	56.15%	6,401,812	4.77%	13.
14.	5,001-7,500	640	3,947,583	4,566	51.74%	9,808,564	4.87%	680	4,220,361	5,598	63.91%	10,622,173	7.92%	14.
15.	7,501-10,000	534	4,673,201	5,100	57.79%	14,481,765	7.19%	466	4,074,239	6,064	69.23%	14,696,412	10.95%	15.
16.	10,001-15,000	640	7,909,984	5,740	65.04%	22,391,749	11.12%	663	8,134,642	6,727	76.80%	22,831,054	17.01%	16.
17.	15,001-20,000	461	8,039,034	6,201	70.27%	30,430,783	15.11%	398	6,922,414	7,125	81.34%	29,753,468	22.17%	17.
18.	20,001-25,000	402	9,030,559	6,603	74.82%	39,461,342	19.59%	279	6,257,924	7,404	84.53%	36,011,392	26.84%	18.
19.	25,001-30,000	333	9,131,326	6,936	78.59%	48,592,668	24.13%	213	5,823,508	7,617	86.96%	41,834,900	31.18%	19.
20.	30,001-35,000	296	9,642,337	7,232	81.95%	58,235,005	28.91%	154	5,016,859	7,771	88.72%	46,851,759	34.92%	20.
21.	35,001-40,000	219	8,228,823	7,451	84.43%	66,463,828	33.00%	153	5,736,824	7,924	90.47%	52,588,583	39.19%	21.
22.	40,001-50,000	332	14,926,086	7,783	88.19%	81,389,914	40.41%	212	9,392,693	8,136	92.89%	61,981,276	46.19%	22.
23.	50,001-75,000	425	25,979,827	8,208	93.01%	107,369,741	53.31%	238	14,472,401	8,374	95.60%	76,453,677	56.98%	23.
24.	75,001-100,000	252	21,793,265	8,460	95.86%	129,163,006	64.13%	136	11,641,114	8,510	97.16%	88,094,791	65.65%	24.
25.	100,001-125,000	109	12,086,632	8,569	97.10%	141,249,638	70.13%	71	7,811,065	8,581	97.97%	95,905,856	71.47%	25.
26.	125,001-150,000	63	8,680,488	8,632	97.81%	149,930,126	74.44%	46	6,417,780	8,627	98.49%	102,323,636	76.26%	26.
27.	150,001-200,000	88	14,929,878	8,720	98.81%	164,860,004	81.85%	69	11,766,474	8,696	99.28%	114,090,110	85.03%	27.
28.	200,001-300,000	58	13,777,181	8,778	99.47%	178,637,185	88.69%	43	10,620,729	8,739	99.77%	124,710,839	92.94%	28.
29.	300,001-400,000	19	6,307,315	8,797	99.68%	184,944,500	91.82%	9	3,182,358	8,748	99.87%	127,893,197	95.31%	29.
30.	400,001-500,000	10	4,372,255	8,807	99.80%	189,316,755	93.99%	5	2,212,806	8,753	99.93%	130,106,003	96.96%	30.
31.	500,001-750,000	11	6,396,201	8,818	99.92%	195,712,956	97.17%	4	2,533,136	8,757	99.98%	132,639,139	98.85%	31.
32.	750,001-1,000,000	7	5,700,425	8,825	100.00%	201,413,381	100.00%	2	1,544,419	8,759	100.00%	134,183,558	100.00%	32.
33.	Over 1,000,000	-	-	8,825	100.00%	201,413,381	100.00%	-	-	8,759	100.00%	134,183,558	100.00%	33.

Average Number of Customers:	1,471	
Average Consumption:	22,823	kWh per bill
Median Consumption:	6,742	kWh per bill

Average Number of Customers:	1,460	
Average Consumption:	15,320	kWh per bill
Median Consumption:	3,600	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-221 and E-221-8T**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)							WINTER (November through April)						
				CUMULATIVE							CUMULATIVE				
				BILLS		LOAD					BILLS		LOAD		
Line No.	BLOCK (kW) (A)	NUMBER OF BILLS BY BLOCK (B)	LOAD kW BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kW) (F)	% of Total (G)	Line No.	NUMBER OF BILLS BY BLOCK (H)	LOAD kW BY BLOCK (I)	Number (J)	% of Total (K)	Amount (kW) (L)	% of Total (M)	Line No.
1.	0	494	-	494	5.60%	-	0.00%	1	814	-	814	9.30%	-	0.00%	1.
2.	1-10	1,758	7,022	2,252	25.52%	7,022	0.92%	2	1,998	7,082	2,812	32.11%	7,082	1.05%	2.
3.	11-20	1,009	15,242	3,261	36.96%	22,264	2.93%	3	919	13,743	3,731	42.61%	20,825	3.08%	3.
4.	21-30	847	21,069	4,108	46.56%	43,333	5.69%	4	751	18,520	4,482	51.18%	39,345	5.82%	4.
5.	31-40	507	17,798	4,615	52.31%	61,131	8.03%	5	417	14,550	4,899	55.94%	53,895	7.97%	5.
6.	41-50	405	18,400	5,020	56.90%	79,531	10.45%	6	330	14,857	5,229	59.71%	68,752	10.17%	6.
7.	51-60	316	17,491	5,336	60.48%	97,022	12.75%	7	273	15,077	5,502	62.83%	83,829	12.40%	7.
8.	61-70	266	17,310	5,602	63.49%	114,332	15.02%	8	278	18,033	5,780	66.00%	101,862	15.07%	8.
9.	71-80	253	19,057	5,855	66.36%	133,389	17.52%	9	226	16,971	6,006	68.59%	118,833	17.58%	9.
10.	81-90	244	20,852	6,099	69.13%	154,241	20.26%	10	237	20,251	6,243	71.29%	139,084	20.57%	10.
11.	91-100	223	21,293	6,322	71.65%	175,534	23.06%	11	218	20,625	6,461	73.78%	159,709	23.62%	11.
12.	101-200	1,559	228,312	7,881	89.32%	403,846	53.06%	12	1,455	210,168	7,916	90.40%	369,877	54.71%	12.
13.	201-300	488	121,072	8,369	94.85%	524,918	68.96%	13	460	113,688	8,376	95.65%	483,565	71.53%	13.
14.	301-400	193	65,833	8,562	97.04%	590,751	77.61%	14	155	52,289	8,531	97.42%	535,854	79.26%	14.
15.	401-500	110	50,154	8,672	98.29%	640,905	84.20%	15	97	43,160	8,628	98.53%	579,014	85.64%	15.
16.	501-600	41	22,178	8,713	98.75%	663,083	87.12%	16	42	22,832	8,670	99.01%	601,846	89.02%	16.
17.	601-700	45	29,049	8,758	99.26%	692,132	90.93%	17	41	26,309	8,711	99.47%	628,155	92.91%	17.
18.	701-800	16	12,136	8,774	99.44%	704,268	92.53%	18	18	13,597	8,729	99.68%	641,752	94.92%	18.
19.	801-900	11	9,506	8,785	99.57%	713,774	93.78%	19	9	7,677	8,738	99.78%	649,429	96.06%	19.
20.	901-1000	15	13,817	8,800	99.74%	727,591	95.59%	20	2	1,812	8,740	99.81%	651,241	96.33%	20.
21.	1001-1100	6	6,238	8,806	99.81%	733,829	96.41%	21	4	4,148	8,744	99.85%	655,389	96.94%	21.
22.	1101-1200	1	1,116	8,807	99.82%	734,945	96.56%	22	-	-	8,744	99.85%	655,389	96.94%	22.
23.	1201-1300	-	-	8,807	99.82%	734,945	96.56%	23	1	1,236	8,745	99.86%	656,625	97.12%	23.
24.	1301-1400	5	6,746	8,812	99.88%	741,691	97.44%	24	5	6,762	8,750	99.92%	663,387	98.12%	24.
25.	1401-1500	-	-	8,812	99.88%	741,691	97.44%	25	-	-	8,750	99.92%	663,387	98.12%	25.
26.	1501-1600	1	1,590	8,813	99.89%	743,281	97.65%	26	1	1,542	8,751	99.93%	664,929	98.35%	26.
27.	1601-1700	1	1,692	8,814	99.90%	744,973	97.88%	27	1	1,656	8,752	99.94%	666,585	98.60%	27.
28.	1701-1800	6	10,590	8,820	99.97%	755,563	99.27%	28	1	1,710	8,753	99.95%	668,295	98.85%	28.
29.	1801-1900	3	5,580	8,823	100.00%	761,143	100.00%	29	1	1,890	8,754	99.97%	670,185	99.13%	29.
30.	1901-2000	-	-	8,823	100.00%	761,143	100.00%	30	3	5,886	8,757	100.00%	676,071	100.00%	30.
31.	2001-2100	-	-	8,823	100.00%	761,143	100.00%	31	-	-	8,757	100.00%	676,071	100.00%	31.
32.	2101-2200	-	-	8,823	100.00%	761,143	100.00%	32	-	-	8,757	100.00%	676,071	100.00%	32.
33.	2201-2300	-	-	8,823	100.00%	761,143	100.00%	33	-	-	8,757	100.00%	676,071	100.00%	33.
34.	2301-2400	-	-	8,823	100.00%	761,143	100.00%	34	-	-	8,757	100.00%	676,071	100.00%	34.
35.	2401-2500	-	-	8,823	100.00%	761,143	100.00%	35	-	-	8,757	100.00%	676,071	100.00%	35.
36.	2501-2600	-	-	8,823	100.00%	761,143	100.00%	36	-	-	8,757	100.00%	676,071	100.00%	36.
37.	2601-2700	-	-	8,823	100.00%	761,143	100.00%	37	-	-	8,757	100.00%	676,071	100.00%	37.
38.	2701-2800	-	-	8,823	100.00%	761,143	100.00%	38	-	-	8,757	100.00%	676,071	100.00%	38.
39.	2801-2900	-	-	8,823	100.00%	761,143	100.00%	39	-	-	8,757	100.00%	676,071	100.00%	39.
40.	2901-3000	-	-	8,823	100.00%	761,143	100.00%	40	-	-	8,757	100.00%	676,071	100.00%	40.
41.	Over 3000	-	-	8,823	100.00%	761,143	100.00%	41	-	-	8,757	100.00%	676,071	100.00%	41.
		Average Number of Customers:		1,471						Average Number of Customers:	1,460				
		Average Load:		86	kW per bill					Average Load:	77	kW per bill			
		Median Load:		36	kW per bill					Median Load:	28	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-47**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	Line No.
1.								1.
2.								2.
3.						22,972,396		3.
4.								4.
5.								5.
6.								6.
7.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-58**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	Line No.
1.								1.
2.								2.
3.						27,920,542		3.
4.								4.
5.								5.
6.								6.
7.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-59**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	Line No.
1.								1.
2.								2.
3.						99,086,769		3.
4.								4.
5.								5.
6.								6.
7.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **E-67**
DESCRIPTION: Classified Electric Rate Applicable to Specific Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	Line No.
1.	0	90	-	90	4.07%	-	0.00%	1.
2.	1-100	24	890	114	5.16%	890	0.01%	2.
3.	101-200	831	88,179	945	42.78%	89,069	1.30%	3.
4.	201-300	355	37,699	1,300	58.85%	126,768	1.84%	4.
5.	301-400	96	17,293	1,396	63.20%	144,061	2.10%	5.
6.	401-500	80	22,951	1,476	66.82%	167,012	2.43%	6.
7.	501-750	137	43,492	1,613	73.02%	210,504	3.06%	7.
8.	751-1,000	115	74,948	1,728	78.23%	285,452	4.15%	8.
9.	1,001-1,500	92	59,547	1,820	82.39%	344,999	5.02%	9.
10.	1,501-2,000	53	51,605	1,873	84.79%	396,604	5.77%	10.
11.	2,001-3,000	86	135,704	1,959	88.68%	532,308	7.74%	11.
12.	3,001-4,000	26	61,132	1,985	89.86%	593,440	8.63%	12.
13.	4,001-5,000	36	86,457	2,021	91.49%	679,897	9.89%	13.
14.	5,001-7,500	42	148,125	2,063	93.39%	828,022	12.05%	14.
15.	7,501-10,000	40	236,820	2,103	95.20%	1,064,842	15.49%	15.
16.	10,001-15,000	37	277,910	2,140	96.88%	1,342,752	19.53%	16.
17.	15,001-20,000	21	195,566	2,161	97.83%	1,538,318	22.38%	17.
18.	20,001-25,000	8	173,704	2,169	98.19%	1,712,022	24.91%	18.
19.	25,001-30,000	5	135,326	2,174	98.42%	1,847,348	26.88%	19.
20.	30,001-35,000	4	86,621	2,178	98.60%	1,933,969	28.14%	20.
21.	35,001-40,000	-	-	2,178	98.60%	1,933,969	28.14%	21.
22.	40,001-50,000	2	55,178	2,180	98.69%	1,989,147	28.94%	22.
23.	50,001-75,000	16	650,068	2,196	99.41%	2,639,215	38.40%	23.
24.	75,001-100,000	-	-	2,196	99.41%	2,639,215	38.40%	24.
25.	100,001-125,000	-	-	2,196	99.41%	2,639,215	38.40%	25.
26.	125,001-150,000	-	-	2,196	99.41%	2,639,215	38.40%	26.
27.	150,001-200,000	-	-	2,196	99.41%	2,639,215	38.40%	27.
28.	200,001-300,000	1	351,108	2,197	99.46%	2,990,323	43.50%	28.
29.	300,001-400,000	3	491,674	2,200	99.59%	3,481,997	50.66%	29.
30.	400,001-500,000	6	1,194,120	2,206	99.86%	4,676,117	68.03%	30.
31.	500,001-750,000	3	2,197,505	2,209	100.00%	6,873,622	100.00%	31.
32.	750,001-1,000,000	-	-	2,209	100.00%	6,873,622	100.00%	32.
33.	Over 1,000,000	-	-	2,209	100.00%	6,873,622	100.00%	33.

Average Number of Customers:	184	
Average Consumption:	3,112	kWh per bill
Median Consumption:	222	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2015 ADJUSTED

RATE SCHEDULE: **CONTRACT 12**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	Line No.
1.								1.
2.								2.
3.								3.
4.								4.
5.								5.
6.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A