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March 30, 2012

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

RE: Arizona Public Service Company's 2012 Resource Plan
Docket No. E-00000A-11-0113

Arizona Public Service Company submits its 2012 Resource Plan pursuant to A.A.C. R14-2-703(C), (D), (E), (F), (H), and (I). The confidential portion of this filing is being provided to Staff pursuant to an executed protective agreement in this matter.

If you have any questions regarding this information, please contact me at (602)250-2661.

Sincerely,

Jeffrey W. Johnson

JJ/cd

cc: Brian Bozzo
Terri Ford
Barbara Keene

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ARIZONA PUBLIC SERVICE COMPANY

2012 INTEGRATED RESOURCE PLAN

FILED IN COMPLIANCE WITH A.A.C. R14-2-703

MARCH 2012

FORWARD-LOOKING STATEMENTS

This report 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 you 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 us. A discussion of some of these risks and uncertainties is contained in our Annual Report on Form 10-K filed with the Securities and Exchange Commission, available on our corporate parent's website at www.pinnaclewest.com, which you should review carefully before placing any reliance on our forward-looking statements, financial statements or disclosures. We assume no obligation to update any forward-looking statements, even if our internal estimates change, except as may be required by applicable law.

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EXECUTIVE SUMMARY

When Arizona became a state in 1912, APS had already been providing energy to the territory for more than 25 years. While many things have changed over the past century, some things have not – a thriving Arizona requires reliable, affordable energy. Just as it has for over a century, APS will continue to ensure customers have the reliable and affordable energy they need.

Long-term resources require a long-term perspective. With a thorough and rigorous process for making critical decisions about assets that will last for decades, APS spends considerable time thinking about, and planning for, the future. Due to the time it takes to bring new electric generation plants into service, plans must be put in place years in advance of customer needs arising. For example, APS began planning the Palo Verde Nuclear Generating Station in the 1960s. This visionary plant – still the only one of its kind in the world not located near a natural body of water – was approved, financed in part by customers, and built in the 1970s and 80s. Starting in 1986, electricity has been reliably and cost-effectively generated at Palo Verde 24 hours a day, 7 days a week for customers across the Southwest.

The APS 2012 Resource Plan is the first formal resource plan filed with the Arizona Corporation Commission in 17 years. This document serves as a public forum for APS to outline its planning process and strategy for ensuring APS's customers have the reliable power supplies they need, today and in the future.

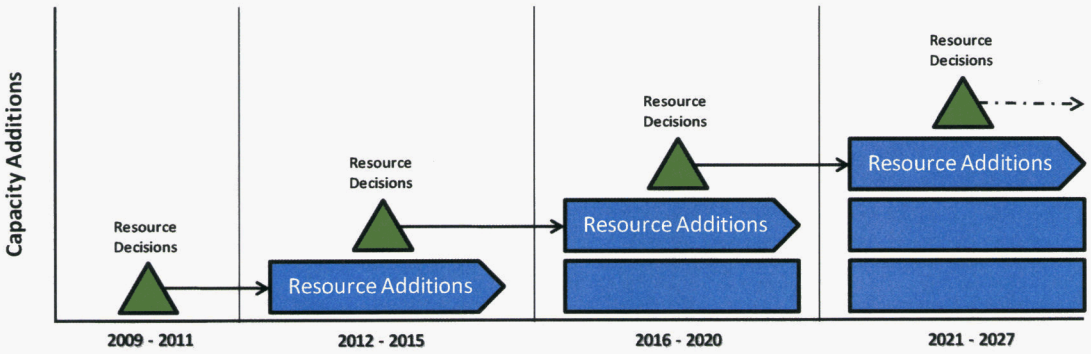

Figure 1 - Resource Planning Outlook

Forecasts indicate a return to growth: In the near-term, APS has sufficient resources to meet customer needs. Over the course of the next 15 years, however, APS anticipates that migration to the state, as well as growth in individual consumption, will result in a return to the historically high growth in energy needs that Arizona has experienced over the last several decades. In fact, APS forecasts approximately 3% average annual growth in nominal electricity requirements through 2027. Customer-centric resources, such as energy efficiency and distributed energy (e.g., rooftop solar systems), will help offset a portion of this forecasted growth; nonetheless, APS will need to add significant generating resources over the next 15 years to keep pace with customer demands. As depicted in Figure 1, the Company will begin putting plans in place over the next several years to ensure these resources are available when customers need them.

PLANNING PROCESS: CREATING THE RIGHT BALANCE

The objective of resource planning is to develop a long-term strategy aimed at meeting future customer energy needs, achieving regulatory targets, and managing environmental impacts, all at a reasonable cost. Multiple variables come into play, and all must be projected years into the future.

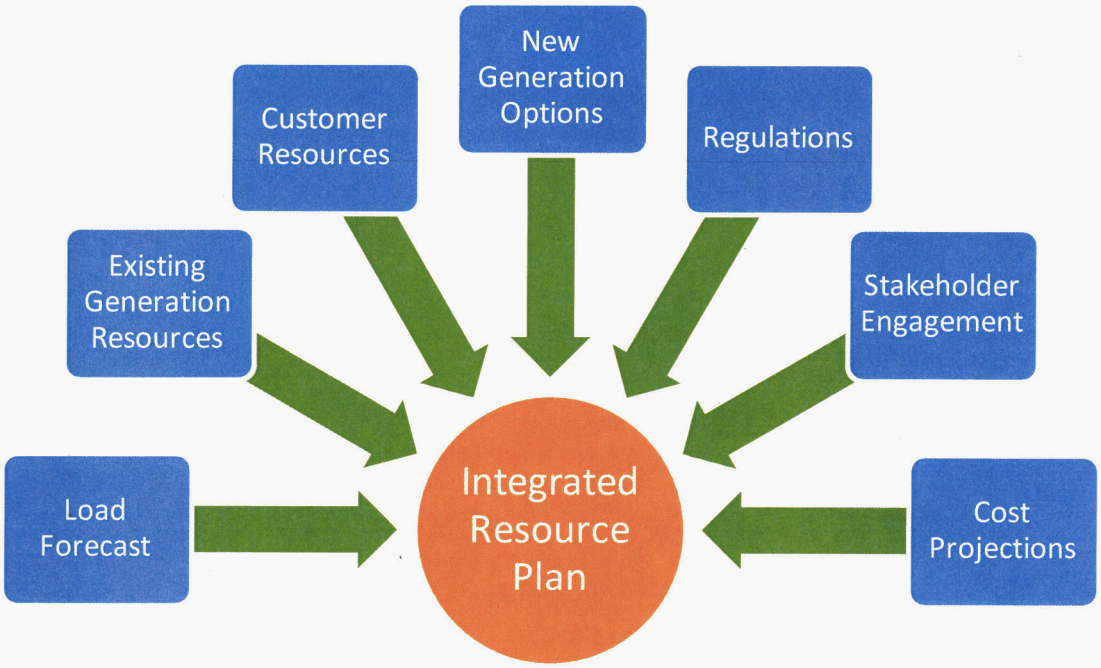

Figure 2 - Resource Planning Considerations

Regular dialogue with key stakeholders: These considerations are not developed in isolation; rather, APS has spent the last several years engaging key stakeholders to gain an understanding and appreciation of their areas of concern. This input is vital, as the decisions made today can and will impact how APS positions itself over the long-term on behalf of its customers.

Sufficient resources today create stability for tomorrow: The largest variable at play for APS in its development of the 2012 Resource Plan is the mix of future fuel sources that will provide the best overall value to customers. APS has a stable fleet of existing generation resources, including over 1,100 MW of nuclear generation, over 1,700 MW of coal-fired generation, and over 5,500 MW of natural gas resources and contracts. With those assets in mind, each future fuel source comes with its own set of benefits, challenges, and relative impact on APS operations, as highlighted in Figure 3.

Figure 3 - Sources of Power

Benefits and challenges exist regardless of the resource: Looking forward, each of these resources is likely to continue to play a part in how APS meets the needs of its customers. The extent to which each participates will be dependent upon their relative tradeoffs. For example, nuclear and coal today provide highly reliable, stably-priced generation; however, future nuclear and coal resources would likely face environmental complexities related to spent fuel storage (for nuclear) and greenhouse gas emissions (for coal), and require significant capital outlays. Natural gas is plentiful and highly flexible, which translates into a very robust fuel source to help follow the ever-changing electricity demands through the hours of the day and season-to-season. Historically, though, natural gas prices have been highly variable. Energy efficiency is today's most cost-effective resource, but it relies heavily on the participation of customers, and the acquisition costs of customer participation in the future is uncertain. Solar and wind are both renewable resources that provide zero-emission energy for APS customers. Solar, in particular, is a plentiful and cost-effective resource in the desert southwest region. Wind, while available in large quantities in New Mexico, is less ubiquitous in Arizona, and also has little correlation (from a production perspective) to when APS's customers use the most energy – hot summer afternoons. Both of these renewable resources, though, are intermittent in nature; solar is only available when the sun is shining, and wind energy is only available when the wind is blowing. This translates into a need for APS to have additional backup generation in the form of natural gas resources to manage the intermittent nature of solar and wind resources.

Part of the resource planning process is to understand the tradeoffs each resource brings, and making intelligent, informed decisions on the best interplay between all possible resources to reliably and cost-effectively serve customers over the long term.

RESOURCE PLANNING ANALYSIS: A RIGOROUS PROCESS

Acknowledging that there are many ways to accomplish the goal of having a reliable, affordable portfolio of resources, APS planners create a base set of assumptions for comparison against different alternatives and sensitivities to ensure the portfolio that is chosen is indeed the best option for customers. With that in mind, APS considered four

specific portfolios when creating the 2012 Resource Plan: the Base Case Portfolio, the Four Corners Contingency Portfolio, the Enhanced Renewable Portfolio, and the Coal Retirement Portfolio. These four simulations (see Table 1) provide alternative combinations of incremental renewable energy and natural gas generation, coupled with varying but declining amounts of baseload coal-fired generation.[1]

	Base Case (2012 Resource Plan)	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Description	Plan includes APS closing Four Corners units 1-3 and purchasing SCE's share of units 4-5; continues the current trajectory of EE and RE compliance	Contingency plan depicting the retirement of the Four Corners coal-fired plant; energy replaced by additional natural gas resources	Assumes 30% (after EE/DE) of energy needs met by renewable resources; includes the consummation of the Four Corners transaction	Assumes APS retires all coal-fired generation; energy replaced with a combination of natural gas and renewable resources
Resource Contributions (2027 Peak Capacity Contribution / % Energy Mix)				
Nuclear	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh
Coal	1,932 MW 26% MWh	962 MW 12.7% MWh	1,932 MW 22.5% MWh	0 MW 0 MWh
Natural Gas & Demand Response	7,424 MW 26.3% MWh	8,394 MW 39.6% MWh	7,138 MW 20.7% MWh	9,188 MW 46.3% MWh
Renewable Energy (RE) & Distributed Energy (DE)	1,141 MW 13.7% MWh	1,141 MW 13.7% MWh	1,427 MW 22.8% MWh	1,308 MW 19.7% MWh
Energy Efficiency (EE)	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh

Table 1 - Portfolios Considered in the 2012 IRP

All the portfolios were analyzed with a detailed production cost model that incorporates forecasted variables (such as future natural gas price estimates), and produces the anticipated generation production sequence (or dispatch) based upon the resources available. APS also calculates the likely future revenue requirements that result from each portfolio, then monitors the impact each portfolio would have on a set of key metrics (such as annual water use, natural gas burn, etc.) to provide a context for comparing and evaluating the portfolios.[2]

Finally, APS evaluated the sensitivity of each portfolio to several key inputs, providing a "stress test" for each portfolio. The main purpose of these stress tests was to ensure that the 2012 Resource Plan portfolio was sufficiently robust and diverse to maintain a low cost to customers while shielding them from undue price volatility.

[1] The percentages depicted are based on total energy requirements prior to EE and DE.
[2] A more complete description of the analytics performed and the results produced can be found starting in Section 3.1.

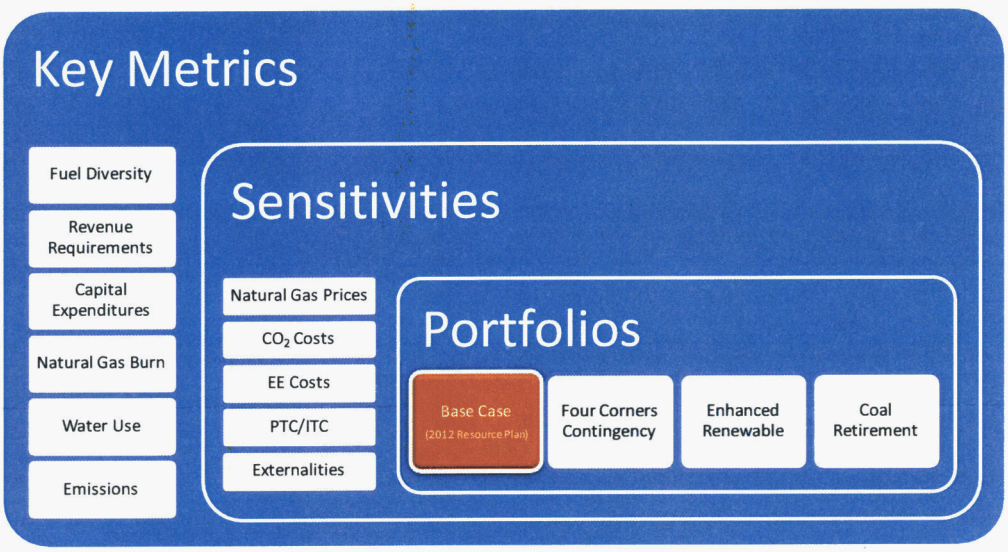

Figure 4 - 2012 IRP Analytics

A Resource Plan that's best for customers: Of all portfolios analyzed, the Base Case Portfolio provided the lowest potential cost as measured by both the net present value of future revenue requirements as well as the capital required to develop and/or procure the incremental resources depicted in each portfolio. The two portfolios that contemplate a partial or complete retirement of the APS coal fleet do show decreased environmental impacts; however, that reduction would come at the expense of significantly higher and more volatile costs for customers.

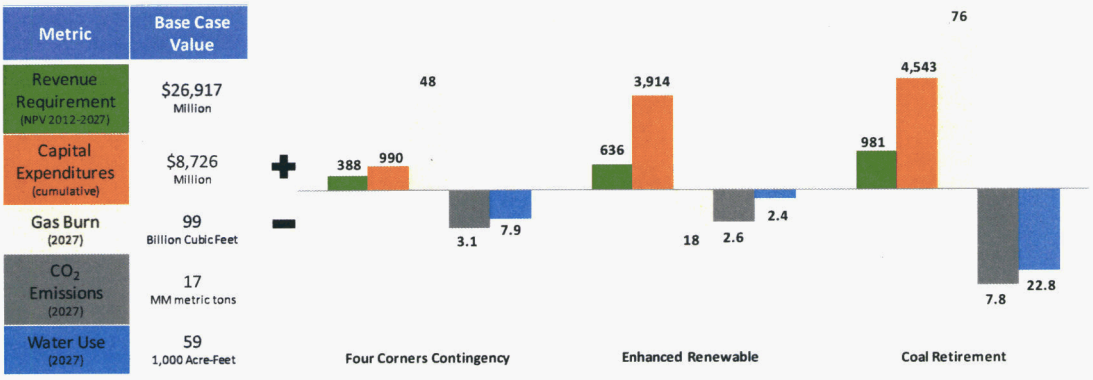

Figure 5 - Differences from Base Case in 2027

THE PLAN IN ACTION: MANAGING CUSTOMER GROWTH THROUGH FUEL DIVERSITY

Over the next 15 years, APS plans to add 2,000 MW of future customer-contingent resources in the form of energy efficiency, distributed energy, and demand response programs, and approximately 4,400 MW of future utility-scale natural gas and renewable energy resources. These additions will require a significant amount of interaction with both

customers and market participants to ensure that an adequate, reliable, and cost-effective supply of energy is readily available to keep pace with an anticipated 55% growth in energy consumption over that same horizon.

	2012	2017	2022	2027	2012-2027 Growth
	MW Contribution at Peak				
Total Load Requirements	**8,233**	**9,561**	**11,322**	**13,167**	**4,934**
Existing Resources					
APS-Owned Generation	6,264	6,443	6,443	6,443	179
Long-Term Contracts	2,284	1,295	67	35	(2,249)
Total Existing Resources	**8,548**	**7,738**	**6,510**	**6,478**	**(2,070)**
Future Customer Resources					
Energy Efficiency	80	791	1,308	1,525	1,444
Distributed Energy	65	154	236	353	288
Demand Response	83	205	330	350	267
Total Future Customer Resources	**228**	**1,150**	**1,874**	**2,228**	**2,000**
Future Generation Resources					
Natural Gas	0	213	2,326	3,712	3,712
Renewable Energy	64	460	612	749	685
Total Future Generation Resources	**64**	**673**	**2,938**	**4,462**	**4,397**
Total Resources	**8,840**	**9,561**	**11,322**	**13,167**	**4,327**

Table 2 - Summary of Resource Additions

Plans are already in place to meet near-term growth: APS already has embarked upon a series of resource decisions emphasizing renewable energy and energy efficiency that continue to place the Company on solid footing for the next several years.

The APS 2012 Resource Plan represents an increasingly diverse portfolio of resources. Over the next 15 years, APS will be meeting a significant amount of its energy growth with clean, zero-emission resources such as energy efficiency and renewable energy, not only helping to improve the environment, but also helping to mitigate the volatility of future fuel costs.

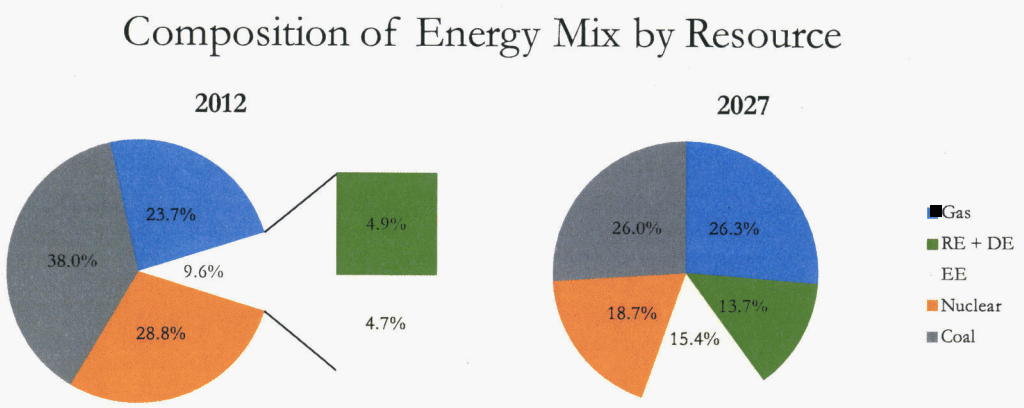

Figure 6 - Sources of Power: Resource Contributions to APS Energy Mix

To reliably and cost-effectively maintain APS's level of service to customers, clean energy resource growth will be accompanied by managed growth of the APS natural gas-fired generation fleet, as well as continued reliance on the high performance and stable costs of the Company's baseload coal and nuclear generation assets.

Mitigating future environmental and water costs: The increasing importance of clean energy resources will have a positive impact on overall carbon dioxide (CO_2) emissions and water consumption during the Planning Period. By 2027, despite anticipated customer growth and a 55% increase in energy required, APS will reduce the intensity with which it emits CO_2 by 26% and consumes water by more than 27% compared to 2012.

APS expects to invest almost $9 billion over the next 15 years to address customer needs: Meeting an annual average of 3% energy growth (prior to any customer programs) over the next 15 years will be challenging and will require a significant investment. Based on current cost forecasts, APS anticipates that cumulative capital investments for new resources of nearly $9 billion will be required by APS and/or market participants to keep up with the pace of customer growth. Should the economy recover at a faster rate than currently anticipated, this figure would undoubtedly grow.

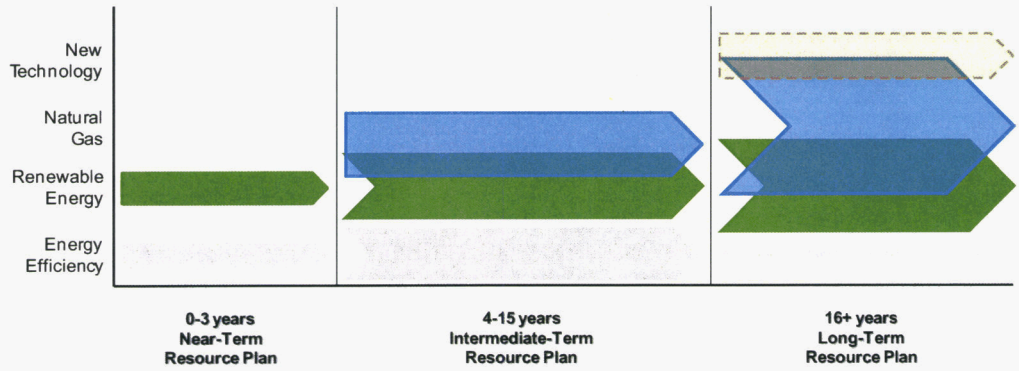

Figure 7 - 2012 Resource Plan Flexibility

After the near-term window, and as depicted in Figure 7, APS plans to continue its trajectory of meeting customer needs with renewable energy, energy efficiency, and natural gas resources. Should natural gas market conditions, future cost projections, or customer program participation warrant, APS could shift the makeup of its portfolio accordingly.

In all cases, APS is well positioned to not only meet customer needs today and in the future, but to do so in a cost-effective, reliable, and environmentally responsible manner.

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BACKGROUND

1.1 COMPANY OVERVIEW

APS is Arizona's largest and longest serving electric utility, serving Arizona's growing population since 1886. APS has over 6,500 employees and serves more than 1.1 million retail and wholesale customers in 11 of Arizona's 15 counties – a service territory of approximately 35,000 square miles. APS owns more than 33,000 miles of transmission and distribution lines and underground cable to deliver electricity to customers. APS also co-owns and operates the Palo Verde Nuclear Generating Station (PVNGS), a primary source of electricity for the Southwest and the largest nuclear generation facility in the United States, as well as two coal-fired plants and seven natural gas- and oil-fired plants, and is part owner in a third coal-fired plant. At present, APS generates more than five percent of its electricity from renewable resources, a number that APS expects to grow to almost 18% by 2027.[3]

1.2 EXISTING RESOURCES

1.2.1 Conventional Generation

Historically, APS has relied on conventional fossil fuel-fired generation to meet its customer demand. This group of generation assets has been reliable and cost-effective, and will continue to play an important role in the overall resource mix.

As APS enters into a new era in which renewable energy and energy efficiency become larger contributors to meeting projected energy needs, a discussion of existing assets as important components of the future energy mix is warranted.

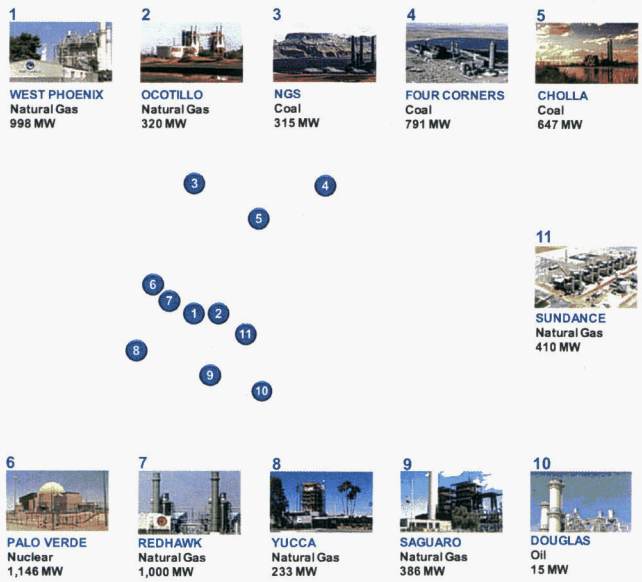

Figure 8 - Existing Conventional Resources (APS Share)

[3] After the effects of customer programs.

1.2.1.1 Coal

APS currently has 1,753 MW of coal-fired generation. This segment of the APS fleet has been the backbone of the Company's operations, providing reliable, stably-priced baseload power.

Four Corners: The five-unit, 2,100 MW Four Corners Power Plant, located on the Navajo Indian Reservation west of Farmington, New Mexico, is operated by APS. Fueled by low-sulfur coal from the nearby Navajo mine, the plant is owned by APS and five other utilities in the Southwest. APS's stake in Four Corners makes 791 MW of energy available to the APS system.

On November 22, 2010, APS filed an application with the Arizona Corporation Commission (ACC) to purchase Southern California Edison's (SCE) 48% share of Units 4 and 5.[4] The proposed transaction is beneficial to APS customers on many levels. APS views the proposed transaction as a vehicle to maintain reliable, stably-priced generation, reduce emissions and costs over other alternatives, while also retaining needed jobs and associated benefits to the local community.

By acquiring SCE's ownership interest in Four Corners, the Company avoids the risk that Units 4 and 5 may be forced to shut down due to California regulations limiting SCE's ability to continue importing coal power in the future. A shutdown of Units 4 and 5 would result in APS losing 231 MW of a reliable, stably-priced baseload resource now serving APS customers.

Also, rather than make the $586 million capital investment in Units 1-3 over the next five years to meet new environmental regulations, APS would shut down those older, less efficient units. Shutting down Units 1-3, combined with the potential retirement of Units 4 and 5, would result in APS losing 791 MW of reliable, stably-priced baseload generation.

Cholla: The 1,027 MW Cholla Power Plant is located in northeastern Arizona near Holbrook. APS operates the plant and owns Units 1, 2 and 3, which are capable of producing 647 MW of electricity. PacifiCorp owns the 380 MW Unit 4 – the largest unit at the plant. Cholla is fueled by coal from the Lee Ranch and El Segundo mines in New Mexico.

Navajo Generating Station: The Navajo Generating Station (NGS) is located in northern Arizona on the Navajo Indian Reservation near Page, and features three 750 MW coal-fired electric generating units. An electric railroad delivers coal to the plant from a mine on the Navajo and Hopi Indian Reservations at Black Mesa in northern Arizona. The plant is operated by Salt River Project, and is owned by a partnership of five utility companies and the U.S. Bureau of Reclamation. APS owns 14% of the plant, or 315 MW.

1.2.1.2 Nuclear

Palo Verde Nuclear Generating Station: PVNGS is located about 55 miles west of downtown Phoenix. Its three units are capable of generating 3,937 MW of electricity. Because of its desert location, Palo Verde is the only nuclear plant in the United States

[4] Docket No. E-01345A-10-0474. This application is currently pending Commission review and approval.

that does not sit near a large body of water. Instead, it uses treated effluent from several area municipalities to meet its cooling water needs, recycling approximately 20 billion gallons of wastewater each year.

Palo Verde is operated by APS and is owned by a consortium of seven utilities in the Southwest. APS owns 29.1% of the plant, or 1,146 MW.

1.2.1.3 Natural Gas

APS owns 3,362 MW of natural gas- and oil-fired generating capacity. These units provide both intermediate and peaking power for APS and its customers.

Redhawk: The Redhawk Power Station, which began operating in mid-2002, is comprised of two identical 500 MW natural gas-fueled combined-cycle units. The plant is owned and operated by APS. Located near PVNGS west of Phoenix, the station employs treated effluent purchased from Palo Verde to meet its cooling needs. Redhawk also is a zero liquid discharge site, meaning that the cooling water is continually reclaimed and reused and no water is released to the environment.

West Phoenix: Located in southwest Phoenix, the natural gas-fueled West Phoenix Power Plant has seven generating units – two combustion turbine units and five units that employ combined-cycle technology. Owned and operated by APS, West Phoenix generates 998 MW of electricity.

Ocotillo: Owned and operated by APS, the natural gas-fueled Ocotillo Power Plant, in Tempe, Arizona, has two steam and two combustion turbine units that are capable of generating 320 MW. Ocotillo also is the location for the Tempe/APS Joint Fire Training Center.

Sundance: The Sundance Generating Station in Coolidge, Arizona, is the newest member of the APS fossil fleet. APS purchased the 410 MW station in the spring of 2005. The simple-cycle, natural gas-fueled station consists of 10 quick-start combustion turbines.

Saguaro: The natural gas-fueled Saguaro Power Plant, north of Tucson, Arizona, has two steam units and three combustion turbine units. APS operates and owns all five of the generating units that have a combined capacity of 386 MW available to the APS system.

Douglas: The Douglas Power Plant, located in the town of Douglas in southeastern Arizona, is comprised of one 15 MW combustion turbine peaking unit and is put into service only when demand for electricity is high in the Douglas area.

Yucca: APS operates the natural gas-fueled Yucca Power Plant near Yuma in southwestern Arizona, and owns six combustion turbine units that produce 233 MW for APS customers. The plant also includes a 75 MW steam turbine and a 22 MW combustion turbine, both of which are owned by Imperial Irrigation District and operated by APS.

1.2.1.4 Purchased Power Agreements

APS receives capacity and energy from approximately 2,300 MW of long-term purchased power agreements (PPAs), which will expire by the end of 2024. These

contracts include demand response, renewable energy, heat rate options, and capacity purchases from merchant generators. APS and PacifiCorp also participate in a seasonal power exchange in which customers in the Pacific Northwest receive electricity from the APS system in the winter when their electricity demands are high and APS receives power in the summer, during APS's peak demand period.

1.2.2 Renewable Generation

The APS renewable portfolio provides over 380 MW of nameplate utility-scale capacity through a mixture of APS-owned solar facilities and various long-term purchased power contracts.

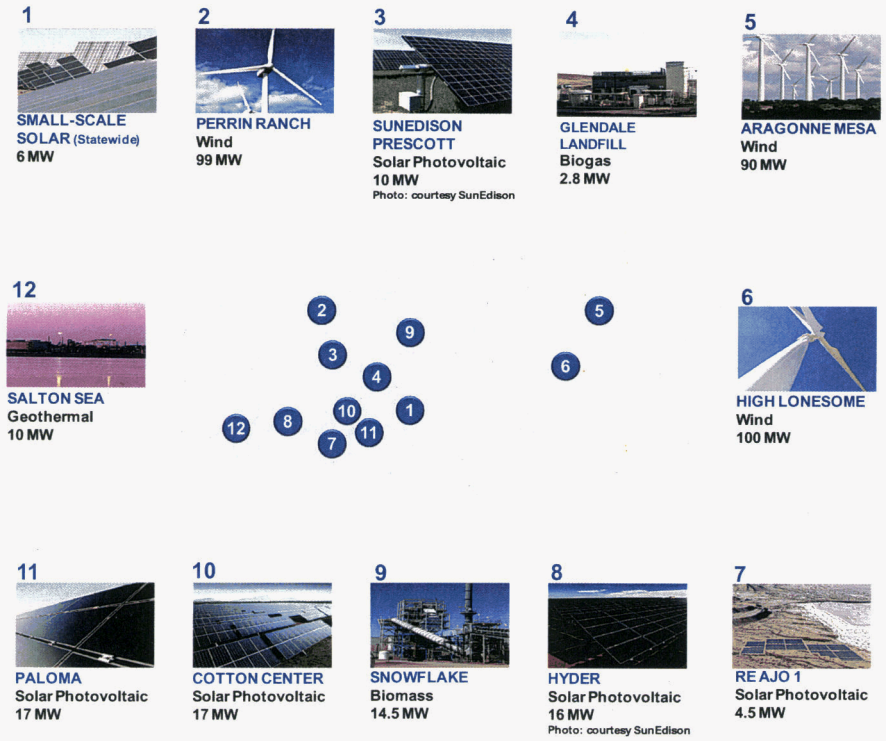

Figure 9 - Existing Renewable Generation (APS Share)

1.2.2.1 APS-Owned Facilities

Small-Scale Solar Projects: APS owns several small solar projects throughout the state of Arizona, totaling approximately 6 MW.

Paloma Solar Plant: The Paloma Solar Plant is a 17 MW photovoltaic facility located in Gila Bend, AZ. The plant began serving customers in the third quarter of 2011, and is comprised of 275,000 thin-film fixed tilt modules.

Cotton Center Solar Plant: The Cotton Center Plant is a 17 MW photovoltaic facility also located in Gila Bend, AZ. The plant began serving customers in the third quarter of

2011, and is comprised of about 80,000 polycrystalline modules on a single-axis tracking system.

Hyder Solar Plant: The Hyder Solar Plant is a 16 MW photovoltaic facility located in Hyder, AZ. The plant began serving customers in the fourth quarter of 2011, and is comprised of about 70,000 polycrystalline modules on a single-axis tracking system.

1.2.2.2 Purchased Power Agreements

Snowflake Biomass Project: The Snowflake 25 MW biomass plant, which commenced commercial operations on June 10, 2008, sells 14.5 MW of its output to APS under a 15-year PPA.

Aragonne Mesa Wind Project: APS has a 20-year PPA to purchase the entire 90 MW output of the Aragonne Mesa wind project located in New Mexico. This wind capacity is delivered to APS at the Four Corners switchyard. This project began making energy deliveries to APS in December 2006.

Salton Sea Geothermal Project: APS has a long-term PPA to purchase the output from a 10 MW geothermal power plant that is located in the Salton Sea area of southeastern California. This capacity is delivered to the APS system in Yuma. The project began delivering energy to APS in January 2006.

Glendale Biogas Project: Commencing operations in late January 2010, the 2.8 MW Glendale Energy Power Plant sells all its energy to APS under a 20-year PPA, which expires in 2029.

High Lonesome Wind Project: APS has a 30-year PPA to purchase the entire 100 MW output of the High Lonesome wind project, located in New Mexico. This wind capacity began delivering 97 MW to APS at the Four Corners switchyard in 2009.

Perrin Ranch Wind Project: APS has 25-year PPA to purchase the entire 99 MW output of the Perrin Ranch Wind project, located near Williams, AZ. This plant will reach commercial operation in 2012.

RE Ajo 1: APS has a 25-year PPA to purchase the entire output of the Ajo project, located near Ajo, AZ. The project, a 4.5 MW Crystalline PV Single Axis Tracking system, reached commercial operation in September 2011.

SunEdison Prescott Solar Plant: APS purchases the generation output from SunEdison under a 30-year agreement, which began in November 2011. The project is located 2 miles north of Prescott Regional Airport and is a 10 MW Crystalline PV Single Axis Tracking system.

1.2.3 Customer Programs

1.2.3.1 Energy Efficiency

By rule, APS is expected to achieve cumulative energy savings of 22% of its retail sales with energy efficiency (EE) programs by 2020.[5] APS's EE program portfolio includes a

[5] Arizona Administrative Code (A.A.C.) Rule R14-2-2404 (EE Standard).

balanced mix of programs targeted to address APS's diverse customer segments and market opportunities to both residential and non-residential customers. These programs are expected to produce cost-effective long-term energy consumption and demand savings. For programs implemented in 2012, the program cost to APS is estimated to be less than 1.6 cents per lifetime kWh saved (total estimated program dollars in 2012 divided by the total estimated kWh saved over the expected lifetime of all measures installed in 2012).[6]

1.2.3.2 Distributed Energy

The Renewable Energy Standard (RES) requires that APS satisfy a percentage of the annual renewable energy requirement through the addition of distributed energy (DE) resources.[7] The required DE percentage increases to 30% of the total RES requirement in 2012 and remains at that level each subsequent year. Since approval of APS's first DE plan in 2008, the Company has gained considerable experience and understanding of the opportunities and challenges associated with the deployment of DE at the scale required under the RES. In 2011, the Company exceeded both of the DE requirements for the first time since the establishment of the RES Standard in Arizona. Additional information pertaining to the total installed DE capacity, energy production, and total residential and non-residential compliance as a percentage of the 2011 target is provided in the annual RES Compliance Report.

APS has observed continued high levels of participation in its DE incentive programs despite declining incentive levels in recent years. The 2010 program year began with $3.00/Watt incentives and through demand-based reductions since that time, the 2012 program year began with $0.75/Watt incentives.

1.2.3.3 Demand Response

APS has several demand response (DR) programs underway or planned for the near future. APS Peak Solutions is a 100 MW commercial and industrial DR program for APS's Yuma and Phoenix metropolitan customers utilizing direct load control and manual load reduction. Peak Event Pricing (or Critical Peak Pricing) for residential customers is a rate rider which provides a high price signal over a small number of core summer peak days and hours. The Home Energy Information Pilot Program (HEI Pilot), approved in Decision No. 72214, is a comprehensive residential DR pilot designed to test available home area network technologies and determine the most effective communication devices, demand response strategies, and mix of in-home applications. This pilot also includes a prepay component, which is a "pay as you go" energy efficiency program that provides customers with the opportunity to prepay an amount toward their bill in lieu of paying a monthly bill on the electricity they have already consumed. Energy usage among participants will be monitored to measure the energy conservation impacts of prepay. The HEI Pilot program will be conducted over two summer seasons (2012 and 2013).

1.2.3.4 Time-of-Use Rates

Time-of-use (TOU) rates encourage customers to use less energy during peak hours by providing a higher-than-average energy price for peak hours when the cost to provide

[6] APS's 2012 Demand Side Management Implementation Plan. Docket No. E-01345A-11-0232.
[7] A.A.C. Rule R14-2-1805.

energy is typically higher, and a lower-than-average price during other off-peak hours. Some TOU rates can also provide incentives for customers to shift usage to off-peak hours by providing peak and off-peak demand charges, which are charges for the maximum kW use per month for the relevant time period. APS offers a number of residential and non-residential TOU rates to its customers, with over 50% of residential ratepayers on a TOU rate today.

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ASSESSING NEEDS AND RESOURCES

2.1 RESOURCE PLANNING CONSIDERATIONS

2.1.1 Goals of Resource Planning

In the past, the objective of resource planning was to ensure that a sufficient supply of resources would be reliably available to meet an anticipated level of demand at the lowest cost. Although reliability and cost-effectiveness remain integral in the resource planning process, there are other factors that must be considered. Environmental impacts, technological uncertainties, financial sustainability, and other risks have in recent years assumed a larger role. This broader spectrum of considerations, coupled with stalled action on the Congressional front regarding climate legislation, has forged a terrain of uncertainty that not only demands flexibility in the formulation of a resource plan but also vigilance in its execution.

In this environment, resource planning is a continuous process at APS involving constant monitoring of external factors, such as new technologies, economic/market conditions, and legislative/regulatory proposals. Actively engaging stakeholders in the discussion of these many factors and incorporating feedback is another input to the process. Internal considerations such as financial strength and the operating status of the current generation fleet are also important and undergo continuous review. As these various factors unfold throughout the Planning Period,[8] adjustments to the 2012 Resource Plan will be made as necessary in subsequent resource plans.[9]

Resource planning is not an absolute prediction regarding the future resource picture. The only certainty the Company has at the time of this filing is that over the course of the Planning Period, conditions will change and impact areas covered in this report. As such, this document should not be viewed as an end in itself but as a marker against which progress can be measured and future plans further refined.

The same rationale suggests the 2012 Resource Plan should not be viewed as transactional in nature. There is no certainty that resource options discussed in this report will actually come to fruition – especially resource options that occur in the later years of the Planning Period. Moving forward through the Planning Period, the set of circumstances governing the 2012 Resource Plan will change and updated resource plans will supplant this filing.

As an integral part of APS's business functions, resource planning is a collaborative process that draws from virtually every department within the Company in the overall pursuit of a single goal: identifying a combination of resources that meets the future electricity needs of APS's customers in a balanced and cost-effective manner based on current information, including input from key stakeholders. This goal must not only be met, but should be met in a way that continues to sustainably provide a high degree of reliability, affordability, environmental responsibility, sound risk management, and compliance with all applicable regulations.

[8] Planning Period refers to the current year and subsequent 15-year period thereafter (2012-2027).
[9] Pursuant to A.A.C. R14-2-703(E), APS is required to file a resource plan every two years.

Another goal of resource planning is to communicate to stakeholders and the ACC the costs and risks of plan implementation. As large financial commitments must be made by APS to ensure that customers are served with reliable energy, APS must be aligned with the ACC in making long-term resource planning and procurement decisions.

2.1.2 Factors Affecting Load Growth

Load forecasting is the foundational building block of resource planning, driving the quantity and timing of future resource needs. Weather, population growth, economic trends, and energy consumption behaviors are among the key variables that impact the Company's view of future resource needs. Accurately forecasting any one of these variables over a 15-year period is a challenge. Accurately forecasting them all is impossible; however, APS's robust forecasting process is structured to incorporate uncertainty to the best extent possible.

Over the next several years, the economic downturn is likely to continue to dampen APS's historically strong load growth; however, this trend is not anticipated to continue over the course of the Planning Period. By 2027, Arizona's population is projected to reach nearly 9 million. During that time, APS is projected to add approximately 600,000 customers and total electricity consumption is expected to grow approximately 55%, or 3% per year on average – nearly triple the average growth of electricity demand in the U.S.[10] This robust level of projected load growth is prior to taking any energy efficiency or distributed energy contributions into account.

As described above, many aspects of the utility business can have an impact on the long-term growth rate of electricity demand. These factors can typically be generalized into the following categories: economic growth, electricity prices, new technology, and customer program acceptance.

2.1.2.1 Economic Growth

The current economic environment is creating considerable uncertainty in the near-term outlook for customer load growth. Typically, growth in peak demand is predominantly driven by construction activity and associated building permits; however, both residential and commercial vacancies are at record levels. There are an estimated 30,000 vacant housing units within APS's portion of the metropolitan Phoenix region alone, representing approximately 100 MW of potential growth in demand. These vacancies, coupled with decreased energy usage from APS's small commercial customers, have dampened the Company's historically robust growth.

Over the long-term, the pace of economic growth is typically the single most important determinant of electricity demand. Arizona's historically high rate of population migration and corresponding growth in households and businesses (electric customers) have led to the state's rapid growth in electricity demand and the need for greater supply. Until the most recent economic recession, this rapid growth has been coupled with a steady and consistent expansion of economic well-being reflected in larger homes, more consumer electronics, and more commercial activity. APS expects that future growth will be affected by these factors as it has in the past. The ultimate pace of population growth, income levels, and the relative health of local industry will likely

[10] http://www.eia.gov/forecasts/aeo/MT_electric.cfm.

continue as dominant drivers of how much electricity will be demanded by customers in the future.

2.1.2.2 Electricity Prices

Despite the slow economic recovery, inflationary pressures on electricity prices are nonetheless expected. Several factors unique to the electric utility industry can have substantive impacts on the price consumers ultimately pay. Factors such as climate change legislation, the need for infrastructure development, the higher cost of emerging technologies, and the trajectory of fuel costs will likely influence the direction of power prices. In many cases, the cost of new generation is nearly double that of existing generation.

2.1.2.3 New Technologies

The emergence of new technologies presents uncertainties in the pace of future electricity demand. New technologies can reflect breakthroughs in the efficiency of existing appliances, transformational shifts in the use of electricity – electric vehicles replacing gasoline-powered vehicles, for example – or new uses like the pervasive penetration of personal computers and cell phones over the last two decades. The impact of new technologies on electricity consumption and peak demand is difficult to forecast due to the lack of deep historical data. Going forward, this is one area that will require close monitoring as these technologies become more widespread.

2.1.2.4 Customer Resources

Customer programs will make up an increasing percentage of the APS resource mix over the course of the Planning Period. Energy efficiency programs will contribute over 1,500 MW to meeting peak demand, distributed energy will contribute 350 MW, and demand response programs an additional 350 MW. Achieving these levels will require a significant amount of participation by APS's customer base, which can be challenging in the current economic climate. In addition, the costs associated with achieving these penetration levels over the next 15 years are uncertain.

2.1.3 Planning Environment

Many challenges exist related to creating long-term resource plans. Greehouse gas (GHG) regulations and legislation related to CO_2 are still being discussed, national economic trends are not broadly positive, and load growth in the APS service territory continues below historical norms. The uncertainty generated by these challenges is two-fold: (1) it precludes a certain forecast of operating conditions, particularly on the federal regulatory front; and (2) it makes the economic impact, specifically related to compliance costs, of those conditions impossible to predict.

Of the challenges mentioned above, legislative/regulatory uncertainty is one of the greatest concerns in the resource planning process. In the past several years, both the U.S. Congress and the Environmental Protection Agency (EPA) have considered bills and regulations that would regulate domestic GHG emissions. Although none have been enacted, APS expects legislative and regulatory proposals on this issue will continue. The actual economic and operational impact of climate change legislation depends on a variety of factors, none of which can be fully known until such legislation is passed and specific requirements are stated. These specifics may include the terms of the legislation with regard to number of

allowances, price caps, bankability, cost to reduce emissions or buy allowances in the marketplace, and the availability of offsets and mitigating factors to moderate the costs of compliance. Due to the uncertainty on this front, the Company will continue to monitor the potential range of impacts that climate change legislation may bring and will be prepared to implement appropriate strategies. Given current information, the 2012 Resource Plan has assumed a $12/metric ton (in 2011 dollars) add-on price for CO_2 emissions beginning in year 2019 and escalating at 5% above inflation thereafter.[11]

A challenge more specific to the APS service territory is load-growth uncertainty. APS recognizes the impact the current business cycle is having on near-term load growth, and this has been incorporated into the forecast. In the long-term, these near-term issues are expected to subside and have less impact and APS is still likely to meet substantial growth in demand. In the interim, APS must respond to the near-term operating landscape, which remains below historical load growth rates. Although this marks a departure from the growth outlook from previous years, it is not without advantages. The pause from high growth gives APS the opportunity to further explore new supply options, specifically demand-side management and renewable energy.

In assessing the various supply options, APS is cognizant that some technologies, as well as their associated costs, are still evolving and will require further evaluation before long-term financial commitments can be made.

2.1.4 Future Generation Needs

APS has sufficient existing long-term resources to meet forecasted customer needs through 2016; however, starting in 2017 the situation will change, and by 2020 additional customer and utility-scale resources totaling more than 3,300 MW will be required to meet capacity needs. By the end of the Planning Period, APS will need 6,690 MW of new customer and utility-scale resources to meet a total load requirement of 13,167 MW (including reserves).

As stated earlier, APS plans to meet a significant portion of this load requirement with customer-centric resources such as energy efficiency, distributed energy, and demand response. Those programs alone, though, will not offset the growing electricity needs of APS customers as a whole. APS will need to add a significant amount of utility-scale generation, whether it is renewable or conventional in nature. As described further in Section 2.1.6, the resource planning process specifically looks at addressing the best combination of generation resources on behalf of APS customers.

2.1.5 Transmission Growth

Maximizing use of the existing transmission system is important to the resource planning process, as well as the transmission planning process; however, adequate transmission must either currently exist or be planned and constructed to support future generation resources as well as potential contingency plans. APS's resource planning and transmission planning organizations coordinate to ensure system needs are met on a timely basis. APS has developed a transmission system that enables delivery of resources to APS load. APS owns all or a part of several major transmission paths in the states of Arizona, New Mexico, and Nevada. These transmission paths deliver energy from baseload, intermediate, peaking, and renewable facilities as well as various long-term purchase agreements.

[11] Arizona Public Service Greenhouse Gas Legislative Review and CO2 Price Outlook", Charles River Associates (November 4, 2011). *See* Appendix A.

Each year APS prepares and files with the ACC a ten-year transmission plan.[12] The 2012-2021 Ten-Year Transmission System Plan describes planned transmission lines of 115kV or higher that APS may construct over the next ten years. The APS investment needed to construct these projects is currently estimated to be approximately $550 million. These projects are designed to provide an increase in the ability to deliver both conventional and renewable resources to APS load centers. These new transmission projects, coupled with additional distribution and sub-transmission investments, will support continued reliable power delivery in APS's service territory, the state of Arizona, and the western United States.

The maps on the following pages illustrate the existing transmission infrastructure and planned additions that APS intends to construct over the 2012-2021 time period.[13]

[12] Pursuant to A.R.S. 40-360.02. The current 10-year plan was filed in Docket E-00000D-11-0017.

[13] Plans and in-service dates are subject to change depending on load growth and other factors.

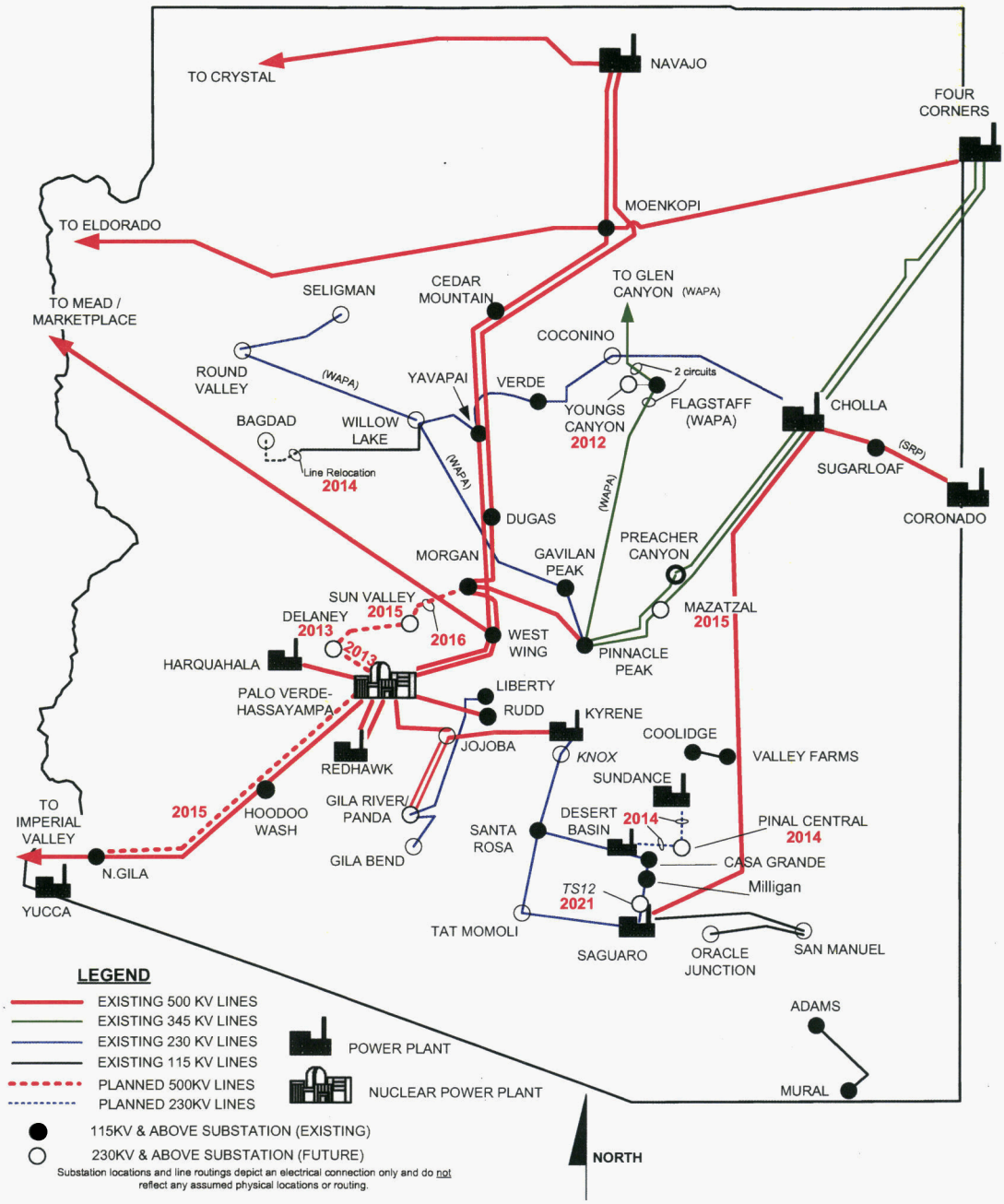

Figure 10 - APS Statewide Transmission System Plan (2012-2021)

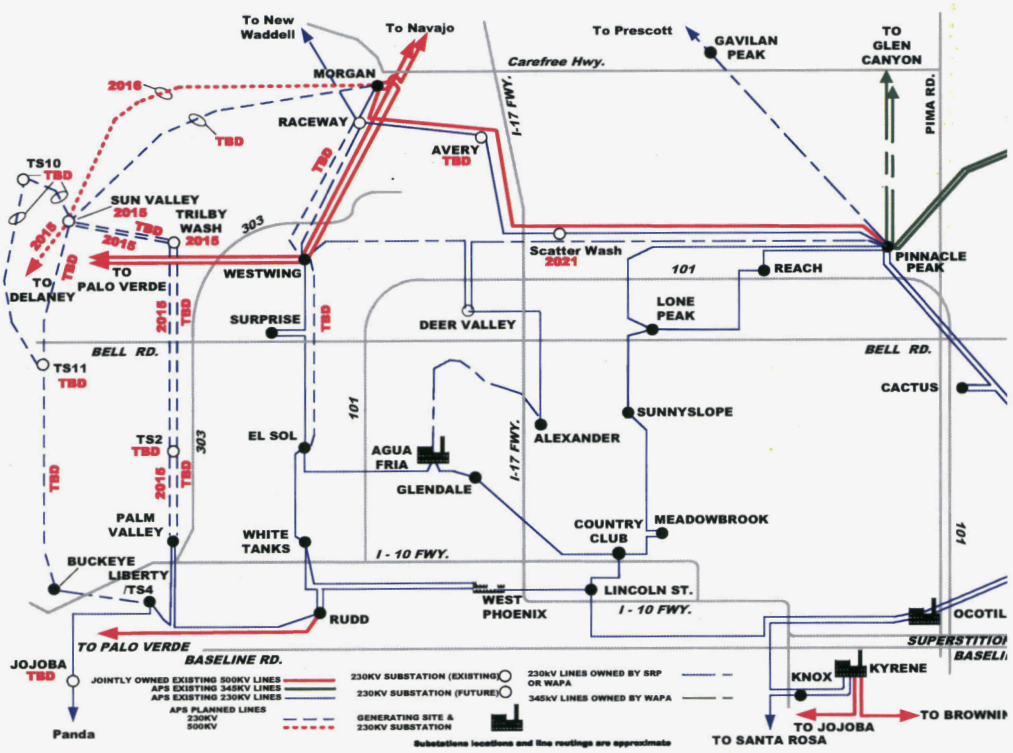

Figure 11 - Phoenix Metro Transmission Plan (2012-2021)

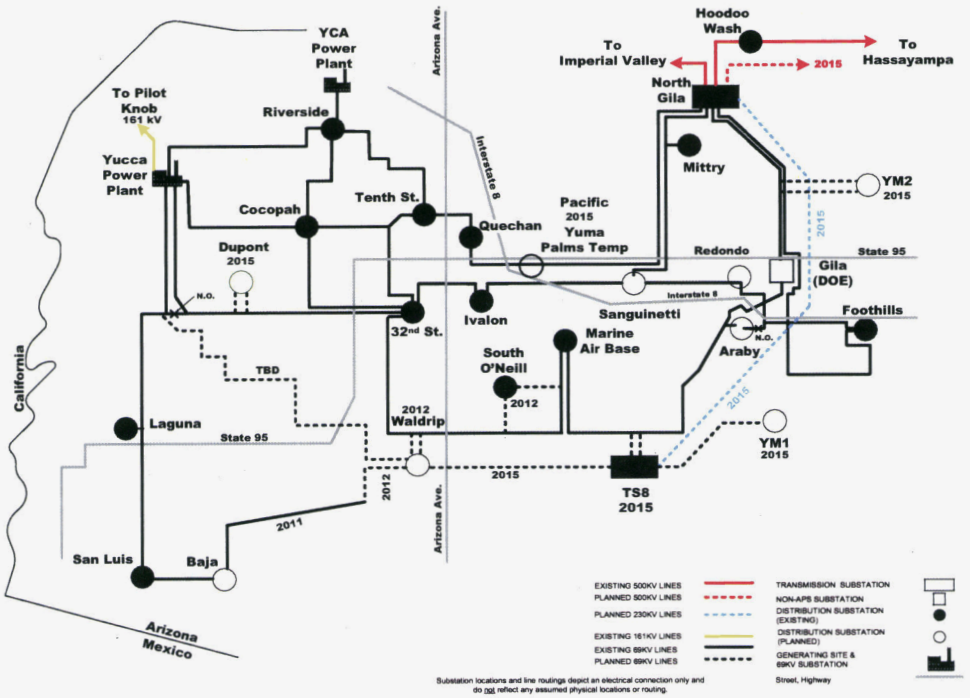

Figure 12 - Yuma Metro Transmission Plan (2012-2021)

2.1.6 Resource Selection Process

Adding adequate generation assets to keep up with 55% total load growth in a 15-year period will be a challenge. What marks this growth phase as particularly noteworthy is that it is being undertaken at a time when the industry's resource planning paradigm has shifted. Least-cost planning – the historical resource planning approach among many utilities – has given way to a more far-reaching approach, one that encapsulates environmental impact, diversity of resources, a more comprehensive view of technology, a greater reliance on customer-powered programs, and a more profound use of renewable resources.

To ensure APS selects a portfolio that meets the energy needs of APS customers throughout each day and across the changing seasons during the year, the resource planning process calls for a determination of the most appropriate balance between all resource options to best meet these needs. This concept helps categorize generating resources by the specific need that resource fulfills, while also noting construction lead times, operating costs, and reliability factors. Based on APS's customer demand profile, each resource can be described by four main categories: baseload, intermediate, peaking, and intermittent.

Baseload	Intermediate	Peaking	Intermittent
➢ Coal ➢ Nuclear ➢ Geothermal ➢ Biomass/Biogas	➢ Combined Cycle Natural Gas ➢ Energy Efficiency	➢ Combustion Turbine Natural Gas ➢ Demand Response	➢ Wind ➢ Solar
• Designed to run 24 hours/day • Reliable • Higher development cost • Lower marginal cost • Longer lead time for development[14] • Typically larger plant size	• Flexibility with natural gas combined cycle units • Primary benefits during daytime hours • 3-5 year development for conventional resources • Shorter development time for energy efficiency	• Reliable • Lower development cost • Higher marginal cost • Fast response capabilities • Primary benefits during high load conditions • 3-5 year development for conventional resources	• Lower reliability • Higher development costs • Lower operating costs • Integration and backup costs • 2-3 year development

Table 3 - Resource Options

[14] Development includes: site identification and acquisition; preliminary engineering, permitting, and final engineering; procurement and construction; and, testing to the point of commercial operation.

2.1.7 Stakeholder Involvement

APS held a series of workshops during 2010 and 2011 to inform and gather input from a wide array of interested stakeholders on how APS should think about future resource decisions. Four meetings were held in 2010 as APS was beginning to formulate its resource planning process. Topics included:

- Existing resource fleet and transmission system
- Load forecasts
- Energy efficiency
- Smart grid
- Demand response
- Utility water consumption
- Fuel supplies and markets
- Technology options and costs
- Externalities
- Resource procurement
- Portfolios and sensitivities

The meetings were well attended with approximately 35 to 50 stakeholders participating in each meeting. In addition, several stakeholders were invited to present on the items above to provide their respective positions for consideration.

Later in 2010, APS contracted with the Morrison Institute of Arizona State University to conduct an Informed Perception project on Arizona's energy resource options. The Informed Perception project consisted of a series of customer surveys covering preferences and concerns regarding utility energy resource options. Results of the Informed Perception project were filed with the ACC on May 26, 2011.[15] APS customers surveyed favored an increase in the use of renewable energy resources, such as solar and wind, and were interested in both the environmental impacts and reliability of energy choices.

On February 24, 2011, APS conducted a stakeholder meeting to discuss metrics and monetization costs for water and for sulfur oxide (SOx), particulate matter (PM10), and nitrogen oxide (NOx) emissions.

On August 1, 2011, APS held a final resource planning workshop to reintroduce the topics discussed in 2010 and provide stakeholders with an update on the resource planning process.

2.2 ANALYTICAL FRAMEWORK

Reliability, long-term economic costs, environmental impacts, and risk management are all considerations that must be balanced during the resource planning process. These and other factors provide the foundation for the appropriate resource selection, and ensure reliable, cost-effective, and environmentally conscious service from a diverse resource mix. Technical factors, governmental policy, social perceptions, and environmental responsibilities are all prisms through which resources must be viewed. Integrating these considerations into a

[15] Docket No. E-01345A-08-0172.

comprehensive resource framework helps ensure that a broad perspective has been applied to the process.

2.2.1 Reliability

Approximately 1.1 million customers rely on APS for reliable and cost-effective electric service. To ensure resources are available when needed, APS uses both probabilistic and deterministic approaches to assessing reliability for its generation and transmission systems. APS also considers the interplay between those two components on the utility system as a whole.

2.2.1.1 Generation

A Balanced Portfolio: In evaluating resource options, APS recognizes that each has its own reliability characteristics. Conventional resources such as natural gas, coal, and nuclear can generate electricity 24 hours a day. Conversely, renewable resources such as wind and solar generate electricity intermittently; that is, when the wind is blowing or the sun is shining. Although the intermittency of most renewable energy sources presents a unique set of challenges, it does not diminish their importance to the overall resource mix. Highly dispatchable, conventional power sources and intermittent power sources, in addition to customer programs, all have their place in the portfolio. The key is to strike the proper balance.

Reliability and Reserve Margins: APS's core business is to provide electric service when customers need it. APS's key reliability criterion states the Company should provide sufficient resources such that the expected probability of a service outage is less than or equal to one event in ten years. From a practical perspective, the resource planning process determines the quantity of capacity reserves that are required to satisfy this reliability criterion. The capacity reserves provide additional resources that can be called upon in the event that generating units experience unplanned shutdowns and/or customer loads are higher than anticipated.

2.2.1.2 Transmission

Adequacy: APS uses a deterministic approach for transmission system planning. Under this approach, which does not allow for randomness, system performance should meet certain specific criteria under normal conditions (all lines in-service) and for any single contingency condition (any one element out-of-service). In general, an adequately planned transmission system will:

- Provide an acceptable level of service that is cost-effective for normal and single contingency operating conditions;
- Maintain service in the event of any single contingency outage;
- Not result in overloaded equipment or unacceptable voltage conditions for single contingency outages;
- Not result in cascading for single or double contingency outages; and,
- Provide for the proper balance between transmission import capability and local generation requirements for an import-limited load area.

Although APS uses a deterministic approach for transmission system planning, the Western Electricity Coordinating Council's (WECC) reliability planning criteria provide

for exceptions based upon a probabilistic approach, which does allow for randomness.[16] APS uses these criteria when/where appropriate in the transmission planning process. Historical system reliability performance is analyzed on a periodic basis and the results are used in the design of planned facilities.

Regional Planning: As transmission additions must be integrated into regional plans, APS follows the WECC regional planning reliability criteria for system disturbance and performance levels: (1) WECC/NERC Reliability Criteria for Transmission System Planning and, (2) Minimum Operating Reliability Criteria. In addition, APS participates in numerous regional planning organizations and in the WestConnect organization.[17] Through membership and participation in these organizations, the needs of multiple entities, and the region as a whole, can be identified and studied.

Grid Integration: One of the more pressing needs of utilities recently is to integrate higher levels of renewable energy resources into the grid. Renewable energy resource projects are sited where nature provides abundance – that is, where the wind blows or the sun shines – and not necessarily where transmission paths already exist. As a matter of practice, APS routinely includes estimates of grid integration costs into its planning analytics. This is discussed in more detail in Section 2.2.3.2.

In recognition of the special transmission needs of renewable resources, the ACC in Decision No. 70635 (December 11, 2008) ordered utilities under its jurisdiction to develop plans to identify future renewable transmission projects (RTPs) and to develop plans and proposed funding mechanisms to construct the "top three" RTPs in their respective service territories. APS filed an application for approval of its Renewable Transmission Action Plan (RTAP) on January 29, 2010. APS received approval of its RTAP in Decision No. 72057 (January 6, 2011). This process and the ACC's approval of the APS RTAP are intended to support the growth of renewable resources in Arizona.

2.2.1.3 System Stability

The stability of the APS system and neighboring systems must be maintained at all times. To review system needs, APS and SRP conduct joint planning on issues such as system reliability and summer preparedness – how the respective systems are prepared for high summer temperatures. Each spring APS and SRP present to the ACC a coordinated plan to serve customers' electricity needs for the upcoming summer, including generation resources, reserve requirements, transmission capacity, and other issues as appropriate. Additionally, the Commission conducts a Biennial Transmission Assessment (BTA) to review the 10-year transmission plans which are developed and filed annually by APS. The primary objective of the BTA is to evaluate system reliability by assessing the adequacy of existing and planned transmission facilities to meet present and future energy needs in a reliable manner.

[16] WECC conducts a variety of studies and assessments required for the reliable planning and operation of the bulk electric system in the Western Interconnection.

[17] WestConnect is composed of utility companies providing electric transmission in the U.S. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to Western wholesale electricity markets.

2.2.2 Environment

2.2.2.1 Environmental Impact

Technological review: Technology choices for new fossil-fueled generators are reviewed for possible application within the APS fleet, such as new gas turbine models which are very fuel efficient and have low emissions. These units employ state-of-the-art pollution control equipment necessary to meet or exceed air quality regulations. APS is committed to using state-of-the-art technologies, but is also cognizant of the risk and high initial cost associated with such newer technologies. APS concentrates its focus on proven technologies that have successfully demonstrated industry-wide acceptance, efficiency, and reliability.

Water: In an effort to address the importance of water in APS's resource planning process, and in recognition of the importance of water as a resource in Arizona, APS utilizes the following assumptions and methodology: (1) the Company is now assuming dry-cooled technology for any newly constructed natural gas combined cycle generation additions as well as low-water-consuming combustion turbines; and, (2) for all generation, both existing and new construction, APS has performed a sensitivity analysis that values water by using a marginal-cost approach rather than simply relying on existing water costs.

Cost of compliance: Sulfur dioxide (SO_2) emissions have a cap-and-trade program in place to establish cost parameters, while other emissions do not. For SO_2 and other emissions, the costs of EPA-required emission controls are included in this report's prospective analyses.

Conversely, there currently are no laws that require a control technology, cap-and-trade system, or tax for CO_2 emissions. Nonetheless, given EPA and Congressional discussions on this issue, APS believes it prudent to incorporate the potential for GHG legislative impacts as a factor in the resource planning process. For the 2012 Resource Plan filing, APS has assumed a price of $12/metric ton (in 2011 dollars) starting in 2019 for CO_2 as a proxy for a potential CO_2 price in resource cost comparisons.

2.2.2.2 Externalities

Analyzing the environmental impacts of any business operation, much less imposing a monetary value on those impacts, presents significant challenges. Compounding that observation is the fact that there is a lack of consensus about certain emissions and their impacts. As knowledge about the environment improves, EPA or the Arizona Department of Environmental Quality (ADEQ) may need to establish new or modified environmental laws. Indeed, since the advent of the modern environmental laws in the early 1970s, the nation's environmental standards have become more stringent and covered a greater number of pollutants.

There may be impacts from business operations where science supports the need for regulation but the pollutant may not be addressed by environmental regulation, either because the laws have not established the jurisdiction to do so or because the regulatory agencies have yet to address the matter. The emission of GHGs is a prime example of this dilemma. In this area, APS believes it is appropriate to monetize the effects of the emissions as an interim approach until Congress, EPA, or ADEQ establish the relevant

standards. APS remains committed to complying with all applicable requirements and staying in tune with potential future regulations to provide reasonable monetization.

2.2.2.3 Environmental Regulations

Environmental regulations are promulgated on the federal (EPA, Congress), the state (ADEQ), and the county (Maricopa, Pinal, and Pima) levels.[18] EPA, specifically, is considering multiple regulations that may have an impact on APS operations.

Clean Air Act: The Clean Air Act (CAA) regulates air emissions from stationary and mobile sources. Numerous programs have been established to protect public health and welfare by controlling emissions of hazardous air pollutants.

Best Available Retrofit Technology (BART) – Within the next three to five years, APS may become subject to new environmental requirements under the CAA Regional Haze program. The Regional Haze program requires an analysis of the impacts of air emissions from certain industrial facilities and the installation of "best available retrofit technology" to control emissions at such facilities to improve visibility. The focus of the regulations is the reduction of NOx, SO_2, and PM emissions.

Mercury and Air Toxics Standard (MATS) – EPA proposed a rule regulating hazardous air pollutants (HAPs) on March 6, 2011, and signed the regulation on December 16, 2011. The rule set forth standards and requirements for reducing mercury and other HAP emissions from certain electric generating units.

National Ambient Air Quality Standards (NAAQS) – For the purpose of protecting public health and welfare, the CAA established NAAQS for six pollutants: ozone, NOx, SO_2, PM10, carbon monoxide (CO), and lead.

Climate Change and GHG Regulations – GHGs are air pollutants under the CAA and EPA has made a determination that the mix of atmospheric concentrations for six key GHGs threatens the public health and welfare of current and future generations. This finding is being litigated.

Clean Water Act: The Clean Water Act (CWA) establishes the basic structure for regulating discharges of pollutants into the waters of the United States and regulating quality standards for surface waters. Under the CWA, EPA has implemented pollution control programs such as setting wastewater standards for industry and water quality standards for all contaminants in surface waters.

Cooling Water Intake Structures – Section 316(b) of the Clean Water Act requires cooling water intake structures that withdraw water from a "water of the U.S." to reflect the best technology available for minimizing adverse environmental impacts. Currently, EPA is engaged in a new Section 316(b) Phase II and Phase III rulemaking process.

Effluent Limitation Guidelines (ELG) – A proposed rule is anticipated to be issued in 2012 and may impact the current discharge limits for Four Corners, West Phoenix and Ocotillo power plants.

[18] Additional information regarding environmental regulations can be found at response to Rule D.17.

Resource Conservation and Recovery Act: The Resource Conservation and Recovery Act (RCRA) gives EPA the authority to control hazardous waste from the "cradle-to-grave". RCRA also regulates the management of non-hazardous solid wastes, as well as environmental problems that could result from underground tanks storing petroleum and other hazardous substances.

Coal Combustion Residuals – In June 2010, EPA proposed new rules to regulate coal combustion residuals (CCRs) to prevent contaminants from leaching into ground water. EPA's final rule, expected in 2012, will affect the manner in which coal-fired power plants manage their ash disposal in surface impoundments and landfills.

Congress: None of the attempts to pass comprehensive climate change legislation in the 111th Congress were successful. As for the 112th Congress, a number of bills introduced are aimed at delaying, eliminating, defunding, or overseeing EPA's authority to regulate GHGs. Such legislation includes delaying any action by EPA to regulate GHG emissions from stationary sources for a fixed number of years, stripping EPA of any CAA authority to regulate GHG emissions, and cutting off funding for the implementation of the agency's GHG rules by prohibiting the use of funds to implement or enforce rules relating to the regulation of GHG emissions from stationary sources. Although the ultimate outcome of these numerous legislative efforts remains uncertain, these actions seem to indicate that it is unlikely any legislation aimed at further regulating GHG emissions will materialize over the next year.

Arizona Department of Environmental Quality: The ADEQ is Arizona's primary environmental regulatory agency, with the responsibility for developing and enforcing state regulations that implement Arizona environmental laws, and also for helping ensure that businesses and facilities operate according to federal environmental laws and regulations. Three programmatic divisions – Air Quality, Water Quality, and Waste Programs – carry out ADEQ's core responsibilities. In some areas, Arizona environmental laws go beyond the federal laws. Examples include the Arizona State Hazardous Air Pollutant (HAP) Program and the Arizona Aquifer Protection Permit Program.

Similar to EPA delegation authority, ADEQ may delegate some permitting and enforcement responsibilities to counties. As discussed in Section 2.2.4.4, ADEQ has delegated CAA permitting and enforcement authority to Pima, Pinal, and Maricopa counties.

2.2.3 Cost

2.2.3.1 Capital Investment

An investment of nearly $9 billion will be required during the Planning Period to meet future customer needs. This investment, projected regardless of whether APS constructs and owns new generation resources or whether resources are developed by market participants and sold to APS under long-term PPAs, does not include: (1) financial commitments to energy efficiency and distributed energy initiatives; (2) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing; and, (3) ongoing capital investment for existing owned generation.

2.2.3.2 Cost and Value

Managing the economic cost of delivering electric services is a key objective of resource planning. In the utility industry, the delivered cost analysis is a screening tool that has been commonly used for decades. Essentially, delivered cost is levelized cost plus the cost of transmission. Levelized cost analysis is an evaluation of energy costs comparing capital, operations and maintenance, performance, and fuel costs across several supply-side technologies. An overview of the total delivered cost ($/MWh-delivered) and the cost to construct ($/kW-installed) APS's major resource options are included in Figure 13.[19]

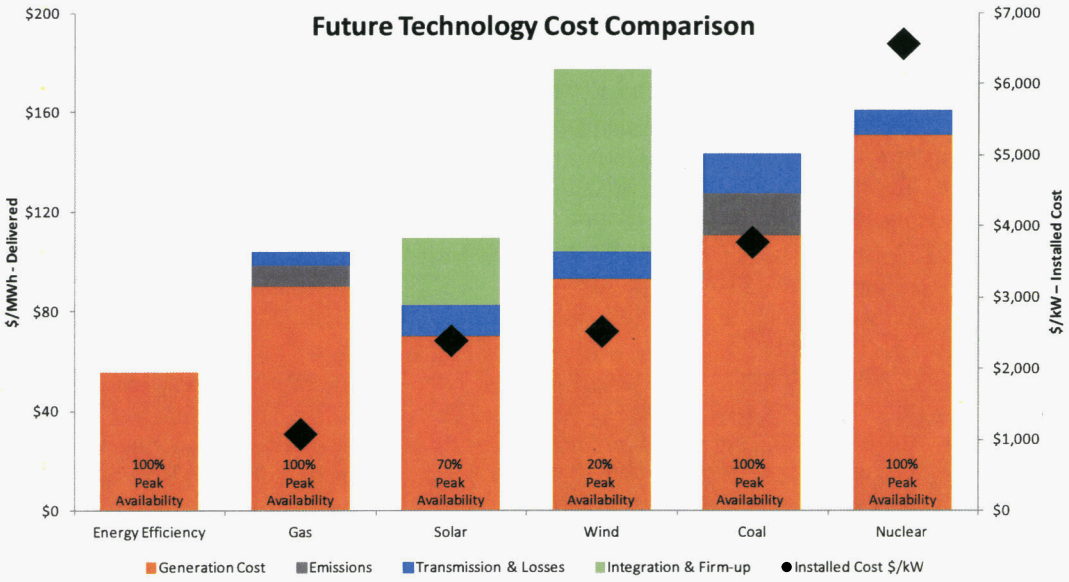

Figure 13 - Technology Cost Comparison: Delivered Cost and Installed Cost

The major components of the delivered cost analysis are capital cost, fuel cost, operation and maintenance (O&M) expenses, power plant fuel efficiency (heat rate), capacity factor, and transmission cost and losses. The resulting average delivered cost is a levelized cost over the estimated economic life of each technology and includes an estimate of the transmission costs that would be required to implement the particular resource. To illustrate the sensitivity of the costs to changes in assumptions, the average delivered cost is "stressed" by estimating the impact of a change in a single input assumption to the average delivered cost. Actual costs will vary for specific projects and sites. APS is including the assumption of hypothetical CO_2 emission costs directly in its delivered cost analysis.

In addition, system integration costs may be imposed by operation of some non-dispatchable resources such as wind and solar. Due to their intermittent nature, additional operating reserves may be needed on the rest of the system to effectively follow APS load and meet WECC reliability requirements. Based on a study performed by Northern Arizona University under the direction of Dr. Tom Acker, a system

[19] Values depicted are in 2015 dollars, including Allowance for Funds Used During Construction (AFUDC).

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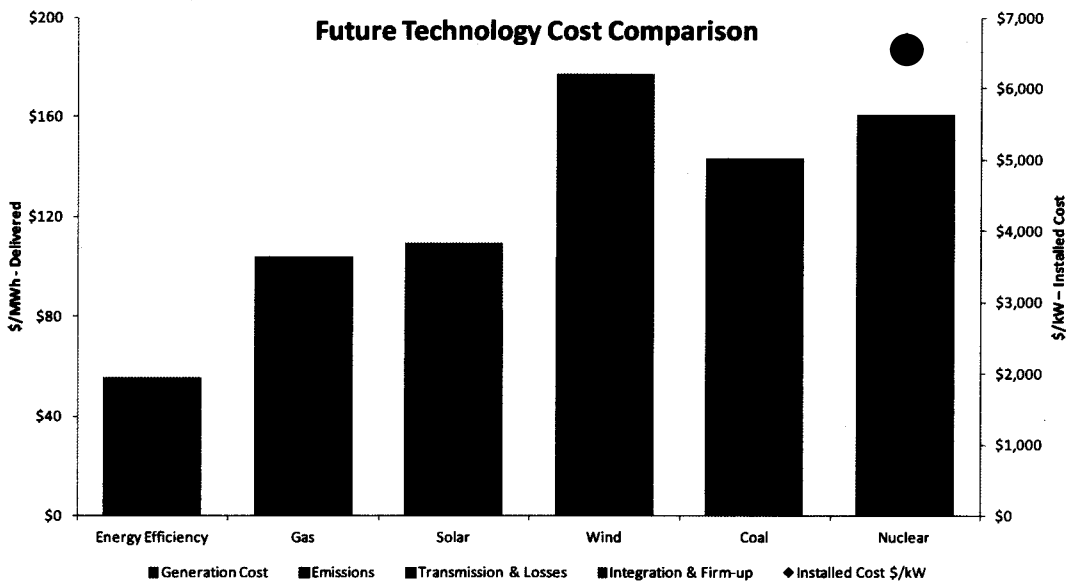

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integration cost of $3.25/MWh is added to wind generation.[20] As solar generation in Arizona is more predictable than wind, though still intermittent, APS assumes a lower integration cost for solar (without storage) of $2.50/MWh, per the Western Governors' Association's Western Renewable Energy Zone Generation and Transmission Model.[21] APS will reevaluate these figures as renewable penetration increases and more experience is gained in dealing with the integration of intermittent or variable generation.

2.2.3.3 Taxes

Production Tax Credit: Section 45 of the Internal Revenue Code provides for a production tax credit (PTC) for the generation of qualified energy from qualified facilities, with terms, including expiration date, specified for each technology type. Eligibility for the credit is contingent upon the generated electricity being sold to an unrelated entity. Qualified energy sources include wind, for which the PTC expires on December 31, 2012, and closed-loop biomass, open-loop biomass, solar, small irrigation solar, municipal solid waste, and marine and hydrokinetic renewable energy, for which the PTC expires on December 31, 2013.[22]

Investment Tax Credit: Section 48 of the Internal Revenue Code provides a package of investment tax credits (ITCs) for solar and other renewable energy developers. The amount of the ITC is 30% for solar placed in-service by December 31, 2016, and 30% for wind-energy systems placed in-service by December 31, 2012. Under current law, after December 31, 2012, large wind-energy systems will no longer qualify for ITC. As of January 1, 2017, the ITC will be reduced to 10% for solar technologies.

Since the PTC will expire and the ITC will be reduced (for solar) during the timeframe covered by the 2012 Resource Plan, a sensitivity analysis is included whereby the tax credits are extended beyond their scheduled expiration dates. For the PTC, this applies to all wind projects deployed after 2012 and for geothermal projects deployed after 2013. For the ITC, this applies to solar projects deployed after 2016.

2.2.4 Risk

2.2.4.1 Uncertainty

Recognizing uncertainty as inevitable is integral to the resource planning process. Although values for key variables such as fuel prices and demand can be forecast, they cannot be known with pinpoint accuracy. Also, some conditions are so unique that they simply cannot be modeled decades in advance, such as the magnitude of the current economic downturn and the delay in federal climate change legislation.

To ensure that uncertainty is addressed in a comprehensive fashion, APS is required to incorporate and evaluate the risks inherent in providing electricity.[23] Notwithstanding that much of the planning process is quantitative in nature, there is also a significant

[20] APS/NAU Wind Integration Study, 2007.
[21] Western Governors' Association Generation and Transmission Model Methodology and Assumptions, Version 2.0, June 2009. APS is currently undertaking an effort to update this figure during the first half of 2012.
[22] The PTC expiration dates pertain to the in-service dates of the qualified facility. The tax credits are earned based upon the production of the qualified facility over a period of time.
[23] A.A.C. R14-2-703.

qualitative assessment that is no less important to the process. Considerations under each category include, but are not limited to, the following:

Quantitative:

Price risk – Fuel sources needed for APS's generating units may be subject to price volatility.

Supply risk – Includes unexpected outages, intermittent resources, and potential counterparty defaults under a PPA.

Customer demand risk – energy consumption far into the future is difficult to predict, especially given the customer financial commitments necessary to advance energy efficiency and distributed energy programs.

Credit risk – APS may be exposed to losses in the event of nonpayment or nonperformance of a counterparty. Stringent credit practices mitigate this risk.

Cost of compliance risk – The cost of complying with future legislation or regulation is a consideration when making future resource choices. While it is impossible to predict with any accuracy the cost of complying with future legislation, APS has attempted to monetize the potential compliance costs by assuming a price on CO_2 emissions as well as by estimating environmental upgrade and ash disposal costs at some APS facilities. This in no way is a prediction of the timing or magnitude of the eventual cost of complying with potential GHG legislation or other EPA regulations.

Cost of construction risk – Developing new resources takes time and requires investment of capital prior to resources being placed into customer rates. Project lead time can be a significant risk to utilities since development of new resources can often span years, adding significant cumulative interest costs and placing stress on the financial strength of companies undertaking the development of new resources.

Qualitative:

Regulatory policy – The 2012 Resource Plan is based on what is known today. Policy decisions made by regulators could result in impacts to business operations, including resource planning decisions. Additionally, the timing and extent of future legislation cannot be predicted with accuracy. APS's ability to accurately forecast future service obligations to customers, in addition to the Company's ability to comply with energy efficiency and renewable energy standards, could also be affected by future regulatory policy decisions.

Financial uncertainty – Competition for available capital investment dollars, especially in today's uncertain economy, will require a strong financial profile. Maintaining APS's financial strength will be critical in implementing the 2012 Resource Plan so that APS will be able to play its part in Arizona's energy future. This will require, at a minimum, APS to retain its investment grade credit rating and will require APS to earn its authorized return on equity capital on a regular basis.

Accessible capital markets – As capital-intensive businesses, vertically integrated utilities such as APS require reliable access to the capital markets to fund investment in utility infrastructure not otherwise funded by operating cash flows. Access to external capital is also important for refinancing long-term debt that supports existing infrastructure investment as it matures. Recent disruption and distress in the capital markets, most evident in the months following the financial crisis in 2008, highlight the importance of having ready, reliable access to capital at a reasonable cost. Higher costs of capital, or an inability to raise the capital necessary to finance its business, can impact APS's ability to cost-effectively make needed investment in utility infrastructure, which causes higher costs for customers. APS cannot control market-driven events that impact conditions in the capital markets, but having a solid investment-grade credit rating can help ensure APS can reasonably access capital at favorable terms over the long run.

2.2.4.2 Fuel Markets

Fuel price and supply risk will always remain high on the list of resource considerations; however, as APS increases the contribution of energy efficiency and renewable energy in the resource mix, the Company's relative exposure to fuels will become proportionally less. Notwithstanding that long-term perspective, APS is still and will continue to be significantly exposed to fuel price risk, particularly to natural gas, for which a hedging program remains in place.

2.2.4.3 Technology

Although there is widespread agreement that new power plants should employ the most advanced commercially-available technology, defining exactly what that means is less clear. Many of these technologies are new to the market – particularly in the renewable energy space – and lack the requisite historical performance to ensure that they will still be viable in the years to come. Moreover, forecasting maintenance costs in a vacuum of operating data can be problematic at best and erroneous at worst.

The primary uncertainties for projects employing new commercial technology are:

Technological performance – Will it perform as expected?

Obsolescence – Will it last as long as expected?

Maintenance issues – Will the frequency and cost conform to forecasts?

Upgrades – How often will they be needed and at what cost?

Tax Incentives – Will they be renewed and at what levels?

APS is anticipating meeting its new resource requirements with a diverse mix of conventional generation, renewable resources, and customer programs. Each of these options is unique in its contribution to the APS resource portfolio and presents new opportunities while also introducing new risks.

Coal: New pulverized coal plants are capital intensive. The installed cost for a new pulverized coal plant is approximately $3,500 per kW, or $3.5 billion for a 1,000 MW coal plant. This is more than three times the cost of a new natural gas combined cycle plant. Also, pulverized coal units involve longer construction lead times. APS estimates

that it takes approximately nine years to go from the start of permitting to commercial operation.

In addition, pulverized coal plants have compliance cost risk related to potential environmental regulations. As discussed earlier in this report, EPA has already implemented air quality regulations governing new coal plants for certain emissions, and is expected to promulgate additional regulations in the future. In addition, APS believes that climate change policies will be put in place at the national level in the future pertaining to GHGs. It is uncertain how future programs will be structured or how commercially viable or technically feasible it will be to retrofit a pulverized coal unit to allow for carbon capture and sequestration. Because it is difficult to quantify the risk associated with new coal generation resources, APS does not believe that constructing new coal resources is in the best interests of its customers at this time and has not included the construction of new coal resources in the 2012 Resource Plan.

Nuclear: Nuclear power remains an important aspect of APS's CO_2-free resource mix; however, at this time, APS does not envision a need for additional baseload resources during the Planning Period. Despite the recent increase in federal support for nuclear power projects, including loan guarantees and the NRC's improved licensing process, the period from design to commissioning is double that for other technologies while payback periods are substantially longer. Another risk associated with nuclear power is the ultimate disposal of spent nuclear fuel. To date, the federal government has not succeeded in establishing a permanent repository for nuclear waste. Spent nuclear fuel from existing nuclear power plants continues to be stored at the individual power plant sites, either in spent fuel pools or in dry cask storage facilities. Finally, any utility considering the pursuit of new nuclear capacity must have considerable financial strength and commitments to undertake such a costly and time-consuming endeavor.

These uncertainties notwithstanding, APS will continue to closely follow developments in this industry as they relate to new construction, and may modify the Company's position should circumstances significantly change.

Natural Gas:

Natural Gas Combined Cycle (CC) – The primary risk associated with this technology is the price volatility of natural gas. Compliance cost with CO_2 regulation is also a concern as these widely used units emit CO_2, albeit at a lower rate than coal-fired generation plants.

Combustion Turbines (CT) – The primary risks associated with this technology are their relatively high operating costs. Although CTs emit CO_2, they are not expected to become a major source of CO_2 emissions because of the limited utilization of peaking units.

Utility-Scale Solar: Cost (including system integration cost) and intermittency are the two most salient risk factors in evaluating solar energy projects. Although a solar plant has no fuel costs once in operation, its development costs are substantially higher than for conventional generation. Also, solar energy projects require a significant amount of

land; for example, the land requirement for solar photovoltaic (PV) is 10 acres per MW compared to 0.03 acres per MW for a combustion turbine.[24]

Wind: Predominantly regional, wind energy production primarily occurs in the spring when APS customer loads are at reduced levels. Wind energy's contribution to meeting summer peak loads is expected to be a fraction of the rated generation output. In addition, because wind is an intermittent resource, system integration costs and back-up capacity must be factored in when evaluating wind against other resource options.

Geothermal: Location of geothermal resources is a key consideration in geothermal power as these naturally occurring resource locations are at a significant distance from APS load centers and transmission infrastructure. Moreover, a geothermal project must go through the identification, exploration, and drilling phases before production can begin, and lead times for these facilities tend to be longer and development costs higher than for other renewable resources. That being said, geothermal resources provide energy reliably both day and night.

Biomass and Biogas: Although biomass and biogas facilities utilize a combustion process that emits CO_2, they are widely considered "carbon neutral" as carbon emissions are offset by the prior absorption of carbon through photosynthesis that occurred throughout the lifecycle of the growth of the plants before they were harvested to produce the source of waste. Another important benefit of biomass and biogas generation resources is that some of these plants, primarily biogas-fueled, can be sited within areas of high demand. Favorable siting helps APS to incrementally increase its resource capacity with the potential for reduced transmission investment. Biomass and biogas resources are beneficial from an availability standpoint, providing their energy both night and day, unlike intermittent resources such as solar and wind; however, these resources are also small from a capacity standpoint.

Energy Efficiency: This resource plan discusses energy efficiency as an energy resource, capable of yielding savings that can displace future electric generation additions. All of the portfolios analyzed assume full compliance with the Commission's current EE Standard. Cost-effective energy efficiency has several near-term benefits, including its low cost relative to other resources and its zero-emission environmental quality. Still, important challenges remain to be addressed for APS to rely on energy efficiency for the long-term as a significant part of the Company's resource mix. These include:

Uncertainty regarding customer behavior and participation – Energy efficiency measures typically require customers to make an upfront investment in exchange for savings that occur over the lifetime of the product. Measuring and verifying future savings from energy not consumed is by its nature difficult. Customer outreach, education efforts, and the cost-effectiveness of the measures may fail to convince the necessary number of customers that this trade-off should be made.

Current limitations on energy efficiency compliance opportunities – The Commission's EE Standard does not allow APS to count all potential efficiency opportunities towards compliance. The Rules entirely exclude, for example, efficiency measures taken on APS's own system and count only a small portion of any legislatively-imposed requirements. The significant levels of energy efficiency

[24] 10 acres per MW includes land for any applicable roads or buildings, and adequate distance between arrays to minimize shading.

required for compliance with the Commission's rules may not be achievable if APS cannot include energy savings resulting from all possible efficiency opportunities.

Uncertainty regarding cost recovery – By their nature, energy efficiency measures erode utility revenues. In its pending rate settlement, APS has agreed to a limited Lost Fixed Cost Recovery Mechanism to be in effect through the settlement stay-out period (July 2016); however, APS will need a more comprehensive ratemaking mechanism to address the revenue-eroding impact of energy efficiency in order to comply with the Commission's increasing energy savings requirements after 2016. Moreover, from a resource parity perspective, a reasonable performance incentive is required for energy efficiency to be pursued on financial par with supply-side resources.

These and other issues will continue to be discussed in both the Energy Efficiency Implementation Plan and Integrated Resource Plan dockets. APS will continue to work with the Commission and other stakeholders to address these uncertainties throughout those and any other relevant proceedings.

Distributed Energy: The RES rules require that a portion of the renewable energy requirement be obtained from distributed energy and that the installed resources result from residential systems and non-residential systems in equal proportions.[25] The historic success of these programs is in part dependent upon tax incentives and direct utility incentive payments; however, recent significant drops in renewable system costs – and continued demand even with lower utility incentive payments – indicate these technologies will be less dependent upon incentives in the future. Growing demand for these technologies coupled with decreasing costs make it difficult if not impossible to predict future uptake.

Solar PV is the best developed of all renewable distributed energy generation technologies, with a market scale that has increased production efficiencies and lowered costs. It is also particularly suited to the Southwest as a result of the Arizona climate. APS believes that the majority of the distributed energy installations will continue to be solar hot water and solar PV systems.

Demand Response: Similar to energy efficiency, demand response programs are contingent upon customer participation. For a residential demand response program, likely focused on air conditioning load, APS anticipates that 75,000 customers or more would be targeted for future participation. Factors such as comfort impact, usability of technology, load reduction (kW) per household, and incentives for participation will all influence the ultimate cost effectiveness of such a program. Programs aimed at commercial and industrial customers such as Thermal Energy Storage (TES) and Standby Generation can require significant upfront capital investments by the customer in order to participate.

2.2.4.4 Permitting/Licensing

Construction of new electric facilities – whether for electric generation or for transmission – requires extensive permitting processes. Depending on the specifications of the facility and its location, the permitting process may take up to 24 months or more

[25] A.A.C. R14-2-1805.

before construction begins. Permits required by federal, state, and local authorities are described below.

Federal:

Environmental Assessment – Pursuant to the National Environmental Policy Act (NEPA), an environmental assessment (EA) is a concise document that: briefly provides sufficient evidence and analysis for determining whether or not to prepare an environmental impact statement (EIS) or a finding of no significant impact; aids an agency's compliance with NEPA when no EIS is necessary; and, facilitates the preparation of an EIS when one is necessary. Generally speaking, EAs are much more concise documents compared to an EIS.[26]

Environmental Impact Statement –NEPA requires federal agencies to perform an EIS prior to issuing licenses or permits for projects that may significantly affect the environment. The EIS describes the environmental impacts of a proposed action and alternative actions that may be taken instead of the one described in the document. An EIS may be required when a proposed development would be located on undisturbed land, is a federally funded project, or would be located on federal lands.

Right of Way for Use of Tribal Lands – When constructing generation facilities or installing transmission lines on tribal lands (such Four Corners and NGS power plants), a right-of-way easement from the Secretary of the Interior is required.

State:

Certificate of Environmental Compatibility – In Arizona, a Certificate of Environmental Compatibility from the ACC's Power Plant and Transmission Line Siting Committee must be received prior to proceeding with the construction of a new thermal electric, nuclear, or hydroelectric facility of 100 MW or more or of a transmission line of 115kV or more.[27] In assessing applications for the certificate, the Committee examines many factors, including the status of all applicable permits.

Title I Preconstruction Permit – The state of Arizona has full approval to implement the federal Title I preconstruction permit program established by the federal Clean Air Act, and is the local permitting authority for all of Arizona, except Maricopa County, Pima County, Pinal County, and Indian country. EPA administers this program for sources in Indian country, where the tribe does not have its own approved program or has agreed not to exert regulatory jurisdiction over a source.

Title I preconstruction permits, commonly known as "Prevention of Significant Deterioration" (PSD) permits in geographical locations that meet or exceed the NAAQS and as "Nonattainment New Source Review" (NNSR) permits in locations that fail to meet the NAAQS, must be obtained and effective prior to beginning actual construction of a new major source of air emissions, and prior to making a major modification to an existing source of air emissions. Title I permits are legally binding air quality permits that include enforceable emission limitations with which the emission source owner/operator must comply. These emission limitations are known as "Best Available Control Technology" (BACT) for attainment areas and as "Lowest Achievable Emission

[26] *See* http://ceq.hss.doe.gov/NEPA/regs/40/30-40.HTM#36.
[27] A.R.S. § 40-360.

Rate" (LAER) for nonattainment areas. These limits are then rolled into the Title V air quality permits referenced below.

Title V Air Quality Permit – The state of Arizona has full approval to implement the federal Title V operating permit program, established by the 1990 federal Clean Air Act Amendments. As the state agency charged with environmental affairs, ADEQ delegated this authority to 3 of the 15 counties within the state – Maricopa, Pima, and Pinal – with the remaining 12 counties continuing under ADEQ jurisdiction. EPA administers the Title V operating permit program in Indian country when the tribe does not have its own approved program or has agreed not to exert regulatory jurisdiction over a source. Title V permits must be obtained and effective for all major sources of air emissions. Title V permits are legally binding air quality permits that include enforceable conditions with which the emission-source owner/operator must comply. The permit conditions establish limits on the types and amounts of air pollution allowed, operating requirements for pollution control devices or pollution prevention activities, and monitoring and record-keeping requirements.

Aquifer Protection Permit – ADEQ also issues Aquifer Protection Permits (APPs) to power plants that have regulated facilities, such as impoundments, that have the potential to impact aquifer water quality. Power plants have monitoring programs that include collection of water quality samples from monitoring wells that are located down gradient of regulated facilities. These sample results are reported to ADEQ on frequencies established in the APP and provide evidence that aquifer water quality standards are met.

Local:

Maricopa County Air Quality Department (MCAQD) – The MCAQD issues Title I and Title V permits for facilities located within Maricopa County, which include Redhawk, West Phoenix, and Ocotillo. As with the ADEQ, the MCAQD requires a Title V permit for any major source of air emissions. The MCAQD also requires a Title I permit for any new major source of air emissions or for major modifications to existing sources of air emissions.

Other local agencies –APS's natural gas-fired Saguaro and Sundance plants are located in Pinal County and therefore are under the jurisdiction of the Pinal County Air Quality Control Department, which issues Title I and Title V permits for facilities located within Pinal County.

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PORTFOLIO & SENSITIVITY ANALYTICS

3.1 INPUTS & ASSUMPTIONS

The term "resource portfolio" refers to the entire set of resources over the planning time frame designed to meet customers' demand for electric energy. It includes the existing generation fleet and power contracts as well as potential future conventional, renewable, and energy efficiency measures. Portfolio analysis includes dispatch simulations and thus captures how an individual resource would be expected to operate on the APS system. To capture the long-term effects of resource portfolio additions later in the Planning Period, it is necessary to develop revenue requirements for several years beyond the 15-year window. In this filing, revenue requirements are calculated through 2041.

Sensitivity analysis refers to changing key uncertain variables to determine how various resource portfolio combinations would perform under certain future conditions. All technologies are subjected to a number of single-variable sensitivities related to fuel cost, carbon legislation, etc. In the context of portfolio analysis, the most uncertain variables with the greatest impact are chosen for further study. Results of these studies provide information on diversity, cost, environmental impacts, and overall risk to assist in the selection of a resource plan.

Scenario analysis refers to the grouping together of a set of sensitivity assumptions that would all likely occur in tandem. The goal of scenario analysis is to illustrate the impact to the portfolios of multiple sensitivities being stressed in a plausible manner.

Assumptions: Each of the resource portfolios assessed incorporates the following criteria:

Load forecast – The load forecast used throughout the following analysis is based on the best available data as of the end of the third quarter 2011, and is described in more detail in response to Rules C.1 through C.3 and E(a). The current load forecast assumes an annual average of 3% energy growth year-over-year, for a net 55% increase in load requirements prior to energy efficiency and distributed energy programs.

Reserves – Resources installed to maintain at least a 15% reserve margin at the time of APS's summer peak.

Inflation – APS assumes a future inflation of 2.5% per year, which is representative of inflation levels over the past ten years. Exceptions to this inflation assumption are described in response to Rule D.1(d).

Compliance with standards – All portfolios developed either meet or exceed compliance with the EE Standard and the RES.

Natural gas prices – The natural gas price curve utilized in the base case analyses was derived from an analysis of the forward market price curve for natural gas as of the end of the third quarter 2011:

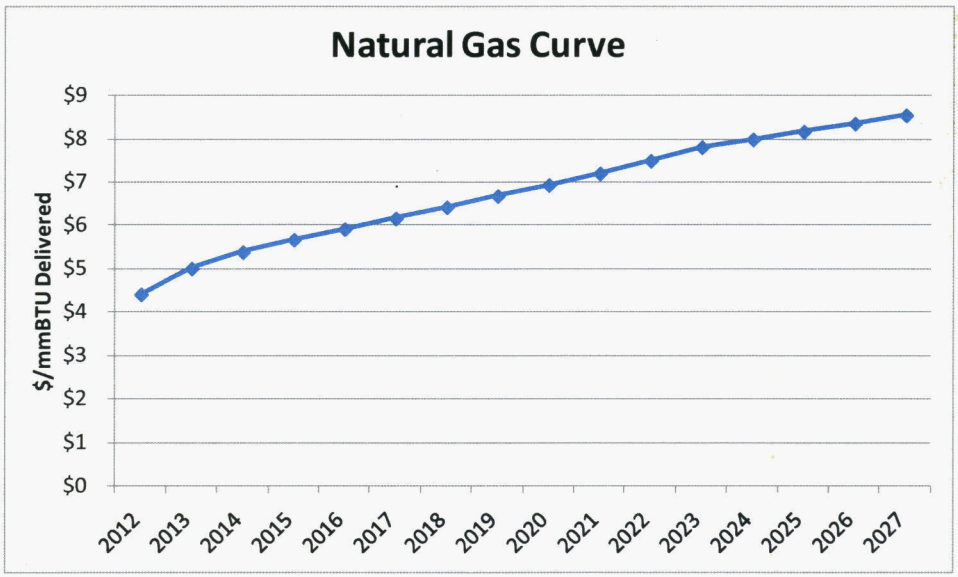

Figure 14 - Natural Gas Curve Base Forecast

Carbon costs – APS is incorporating the carbon cost recommendation provided by Charles River Associates, as detailed in Appendix A, where carbon costs arise in 2019 and escalate annually at 5% above inflation. For the base case, APS utilizes a hard cap of $50/metric ton, which is not reached during the 15-year Planning Period.

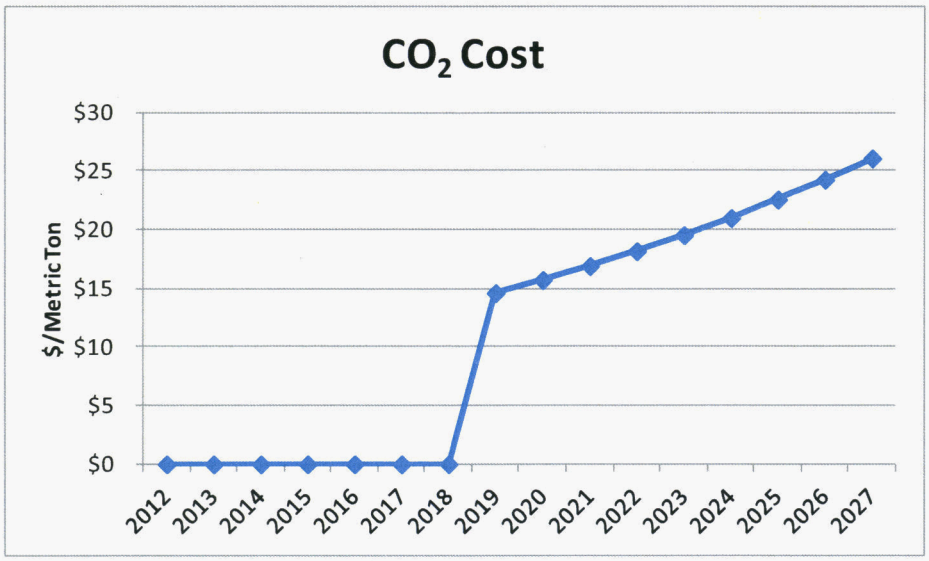

Figure 15 - Carbon Cost Base Forecast

EE costs – Energy Efficiency program costs are relatively well known in the near-term and are based on APS's 2012 DSM Implementation Plan filed on June 24, 2011.[28] Over the course of the Planning Period, APS assumes that existing programs will continue to

[28] Docket No. E-01345A-11-0232.

contribute towards the EE goals and will be replaced and/or expanded upon to meet the overall EE Standard of 22% by 2020. Post-2020, EE costs continue to be incurred as APS maintains the 22% standard as part of its resource mix. It is important to note that these costs are simply projections based upon current programs; actual future costs of energy efficiency programs are a significant unknown at this time, and could be more expensive than those currently in place.

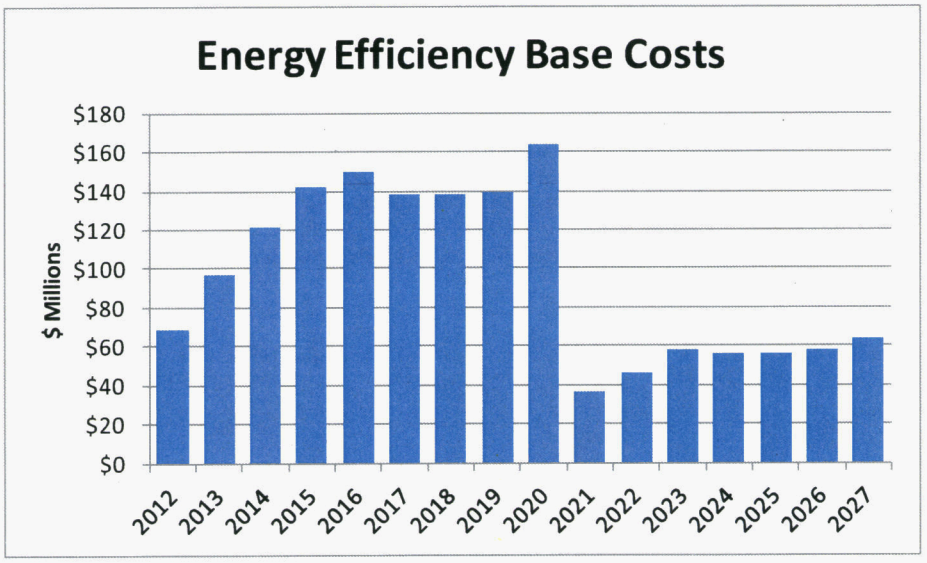

Figure 16 - Energy Efficiency Costs Base Forecast

PTC/ITC – APS assumes that the current tax provisions related to production tax credits and investment tax credits expire as detailed in Section 2.2.3.3 above.

Key Metrics: APS specifically monitored the impacts to a set of key metrics that provide insight into the holistic impact of each set of resource combinations. A high-level summary of these metrics is included below while comprehensive and detailed annual values are included in Attachments F.1(b)-F.1(d) for all cases modeled.

Fuel diversity – A more diverse portfolio relies on a greater number of fuel sources, thereby mitigating risks associated with any one particular source.

Portfolio costs[29] – Measured in terms of net present value (NPV) of revenue requirements over the Planning Period plus an extension period (another 15 years), as well as average system generation cost in $/MWh at the end of the study period.[30]

Cumulative capital expenditures – Cumulative capital expenditures are an indication of how much capital APS or market participants will need to obtain over the planning period to execute each portfolio.

[29] Portfolio costs represent the total costs of the resource additions from a generation and incremental transmission perspective. While it may be indicative of the increasing costs that will develop into future rates, these costs are not inclusive of all rate components (e.g., distribution costs, metering/billing costs, etc.).

[30] Average system generation cost, represented in $/MWh, is not intended to directly correlate to customer rates; rather, it is indicative of the per-unit cost of energy from APS generation resources as outlined in each portfolio, and does not include other components of customer rates such as distribution charges.

Natural gas burn – Natural gas burn gives an indication of the amount of gas cost risk inherent in each portfolio.

CO_2 emissions – Total emissions of CO_2 give an indication of the environmental impact and associated amount of carbon cost risk for each portfolio. Assumed carbon costs are modeled as a base assumption.

Water use – Water use is another important factor and is monetized as an externality value within the sensitivity analysis as well quantified in terms of acre-feet per year.

3.2 PORTFOLIOS

	Base Case (2012 Resource Plan)	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Description	Plan includes APS closing Four Corners units 1-3 and purchasing SCE's share of units 4-5; continues the current trajectory of EE and RE compliance	Contingency plan depicting the retirement of the Four Corners coal-fired plant; energy replaced by additional natural gas resources	Assumes 30% (after EE/DE) of energy needs met by renewable resources; includes the consummation of the Four Corners transaction	Assumes APS retires all coal-fired generation; energy replaced with a combination of natural gas and renewable resources
Resource Contributions (2027 Peak Capacity Contribution / % Energy Mix)				
Nuclear	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh
Coal	1,932 MW 26% MWh	962 MW 12.7% MWh	1,932 MW 22.5% MWh	0 MW 0 MWh
Natural Gas & Demand Response	7,424 MW 26.3% MWh	8,394 MW 39.6% MWh	7,138 MW 20.7% MWh	9,188 MW 46.3% MWh
Renewable Energy (RE) & Distributed Energy (DE)	1,141 MW 13.7% MWh	1,141 MW 13.7% MWh	1,427 MW 22.8% MWh	1,308 MW 19.7% MWh
Energy Efficiency (EE)	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh

Figure 17 - Overview of Portfolios in the 2012 IRP

3.2.1 Base Case Portfolio

The Base Case Portfolio is designed to deliver a portfolio of generation resources that does not overly rely on one specific fuel source during the 15-year Planning Period. This portfolio includes the addition of SCE's share of Four Corners Units 4 and 5, and the related retirements of Units 1, 2, and 3. No additional baseload resources (coal/nuclear) are added over the course of the Planning Period. APS achieves compliance levels of energy efficiency, and is slightly above compliance levels for renewable energy. The remaining growth is met with demand response and natural gas resources. The first conventional resource addition is estimated to occur in 2019.

Two important factors stand out about this portfolio. First, approximately 65% of energy growth is met by emissions-free resources. Second, this portfolio results in no single fuel source encompassing more than approximately 26% of APS's resource mix, contrasted with today where coal and nuclear make up two-thirds of APS's fuel mix. This more balanced approach will provide customers with greater protection from price volatility associated with

a single fuel source.[31] The Loads & Resources table for this portfolio can be found at Attachment F.1(a).

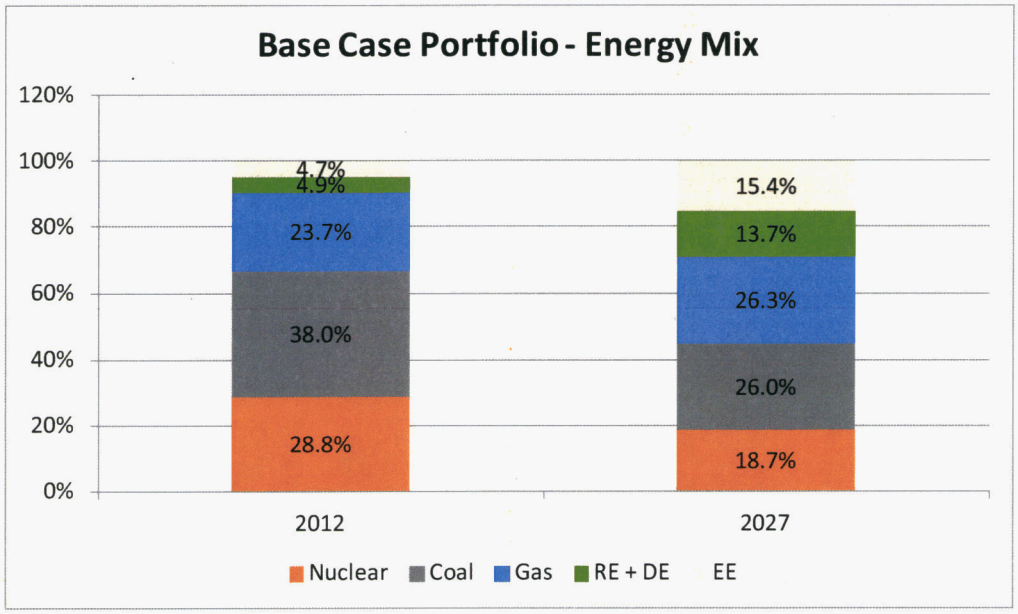

Figure 18 - Base Case Portfolio Energy Mix

3.2.2 Four Corners Contingency Portfolio

The Four Corners Contingency Portfolio differs from the Base Case Portfolio in one key aspect: the assumption for this portfolio is that the Four Corners transaction is ultimately not consummated.[32] As a result, all five units at Four Corners are retired over the next four years.[33] Due to these retirements, the portfolio calls for an additional combined cycle unit and 300 MW of additional combustion turbine units, starting with the combined cycle unit being added in 2016 and the first combustion turbine in 2017.

APS has developed this portfolio as a contingency plan if the Four Corners transaction should not occur. With the loss of such a large amount of baseload generation, APS would need to take swift and decisive action in the next five years in order to ensure reliable and affordable service to its customers. This portfolio is intended to depict what those decisions could entail. The Loads & Resources table for this portfolio can be found at Attachment F.1(a).

[31] The percentages depicted in the following figures are based on total energy requirements prior to EE and DE. The RES currently requires 15% of retail sales be met by renewable resources, which is calculated after the impacts of EE and DE. To illustrate EE's relative contribution to future resources, it is depicted on these graphs and all values are calculated from the load requirements prior to the impacts of EE and DE.

[32] Pending Commission review and approval. Docket No. E-01345A-10-0474.

[33] Units 1-3 assumed retired at the end of 2014 and units 4-5 assumed retired in the summer of 2016.

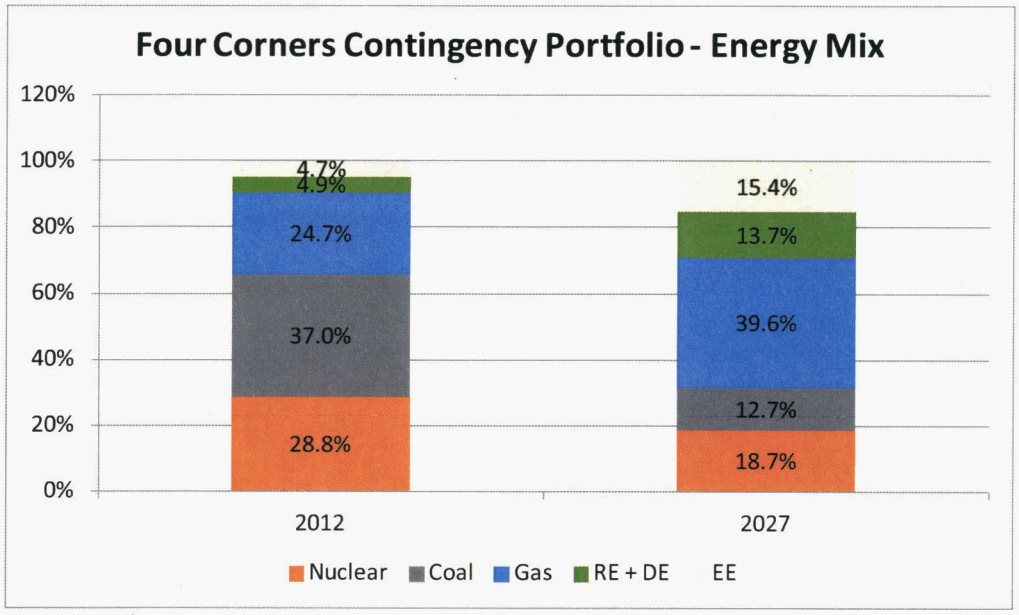

Figure 19 - Four Corners Contingency Portfolio Energy Mix

3.2.3 Enhanced Renewable Portfolio

The Enhanced Renewable Portfolio is designed to show the impacts of increasing the contribution of renewable energy to 30% of retail sales by 2025.[34] This portfolio includes the Four Corners transaction and a significant increase in renewable nameplate capacity compared to the Base Case Portfolio. Conventional generation is not added until 2020 (a combined cycle unit).

This portfolio provides a resource mix that significantly reduces the Company's reliance on natural gas and its associated price volatility. In addition, it envisions that over 90% of future energy growth is met by emissions-free resources. The Loads & Resources table for this portfolio can be found at Attachment F.1(a).

[34] After the effects of energy efficiency and distributed energy.

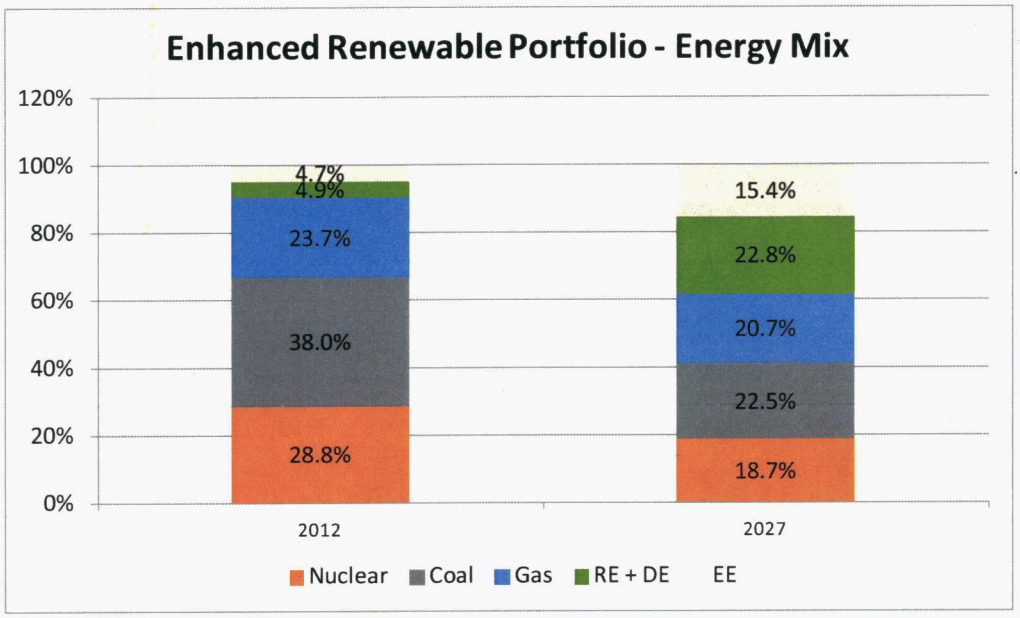

Figure 20 - Enhanced Renewable Portfolio Energy Mix

3.2.4 Coal Retirement Portfolio

The Coal Retirement Portfolio does just that; it shows the impact of retiring all of APS's coal units during the Planning Period. Similar to the Four Corners Contingency Portfolio, APS assumes Units 1-3 are retired at the end of 2014 and Units 4-5 are retired in the summer of 2016. NGS is then assumed to be retired at the end of 2019 and Cholla at the end of 2024. APS chose these dates based on the expiration of certain contracts related to fuel purchases and land rights.

Due to the retirement of over 1,700 MW of coal-fired generation, APS would significantly increase its reliance on natural gas and renewable energy. APS modeled replacing the coal production with 25% renewable energy and 75% natural gas generation. This results in APS adding four combined cycle gas plants during the Planning Period and over 1,000 MW of additional nameplate renewable capacity compared to the Base Case Portfolio.

This portfolio was developed to exemplify the impact stringent environmental requirements could have on the APS resource mix. The Loads & Resources table for this portfolio can be found at Attachment F.1(a).

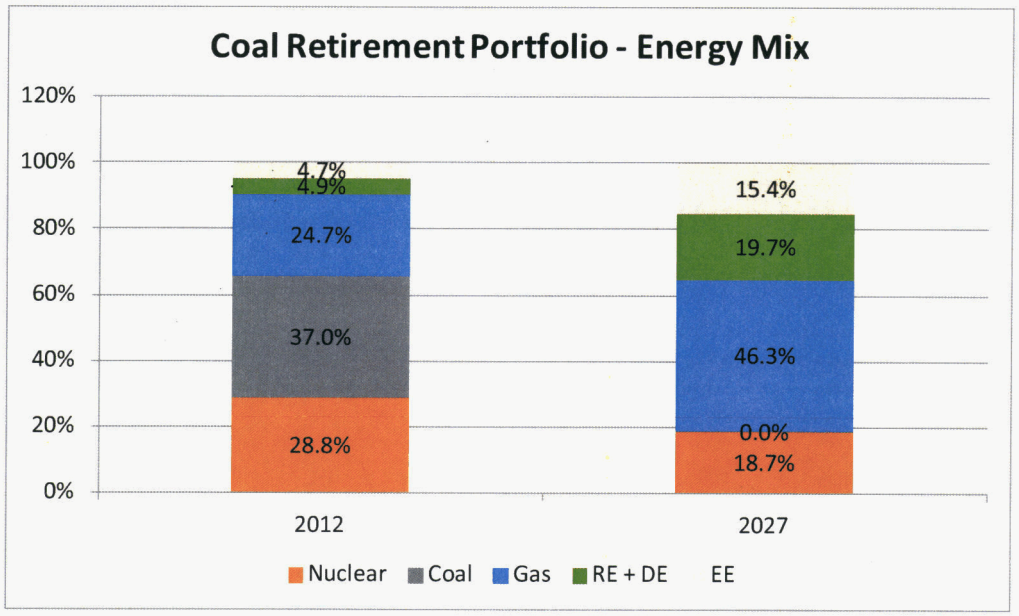

Figure 21 - Coal Retirement Portfolio Energy Mix

3.3 SENSITIVITIES

APS performed a series of single-variable sensitivities designed to test the robustness of each portfolio. Akin to a stress test, APS selected major cost inputs, such as gas prices and carbon costs, and reset their assumptions higher and/or lower to see what the impacts are to the portfolios' key metrics. This testing illustrates how the portfolio costs move comparatively with these relatively uncertain variables, and also provides an indication of whether or not the portfolios have any dispatch discretion between resources affected by those variables. A description of the sensitivities performed is included in the discussion below.

3.3.1 Natural Gas Prices

To illustrate the impact that natural gas price trajectory has on the relative economics of each portfolio listed above, APS stressed each portfolio with both a high and low case forward gas curve to account for a large range of potential outcomes. For consistency purposes, these cases vary 30% up and down from the base forecast. Portfolios that rely more heavily on natural gas-fired generation will be impacted the most from a cost perspective by this sensitivity.

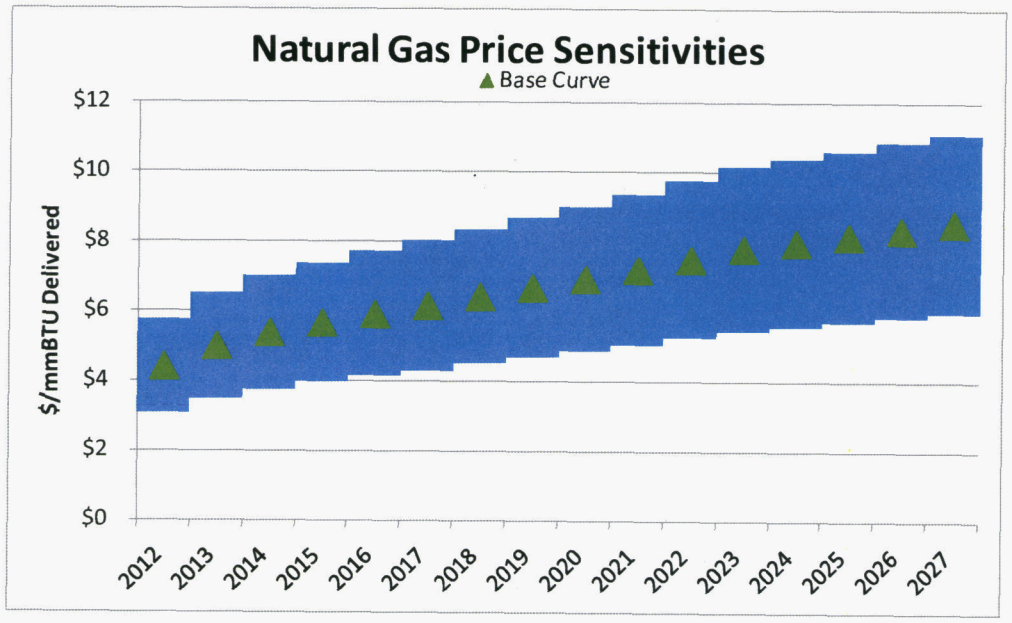

Figure 22 - Natural Gas Price Sensitivities

3.3.2 CO_2 Prices

As detailed in Appendix A, Charles River Associates provided APS with not only their view on a likely CO_2 price curve, but also on plausible high and low price curves based on their understanding of the legislative landscape. Portfolios that rely more heavily on carbon-intensive fuels like coal will be impacted most from a cost perspective by this sensitivity. The high carbon case assumes a higher starting price of $20/metric ton (in 2011 dollars), while the low carbon case provides a scenario where carbon legislation does not arise during the Planning Period.

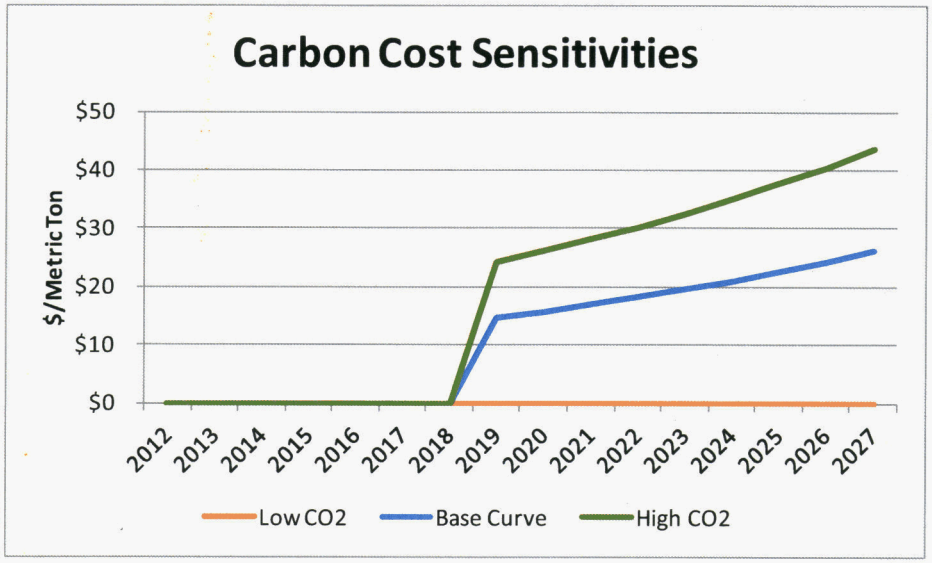

Figure 23 - Carbon Cost Sensitivities

3.3.3 Renewable Tax Credits

As described earlier, under the base assumptions, the PTC and ITC either expire or are reduced pursuant to current tax law. APS has chosen to develop a sensitivity analysis where those tax credits are both extended through the 15-year Planning Period. Portfolios that are more reliant on renewable resources are positively impacted by this assumption from a cost perspective.

3.3.4 Energy Efficiency Costs

Energy Efficiency costs for future compliance are a relative unknown, as they will rely heavily on the pace and adoption of newer, more efficient technologies during the coming decade. APS has modeled a plus and minus 30% cost swing to create high and low EE cost cases to illustrate the impact of future compliance cost risk. APS did not apply this variability in the first few years of the Planning Period; rather, the Company ramped into those values because costs in the early years are relatively well known and based on the 2012 DSM Implementation Plan filing.

A number of factors contribute to the potential for future EE costs to vary from planned costs. EE costs could be higher if additional investment in marketing and education is needed to generate increased participation in customer programs. Another possibility is that as the benefits of lower-cost existing programs are exhausted, the cost of achieving additional energy efficiency may become greater with time. In addition, new technologies may require a higher incentive to secure customer participation. Conversely, there is potential for future EE costs to be lower due to changes in codes, standards or distribution system efficiencies.

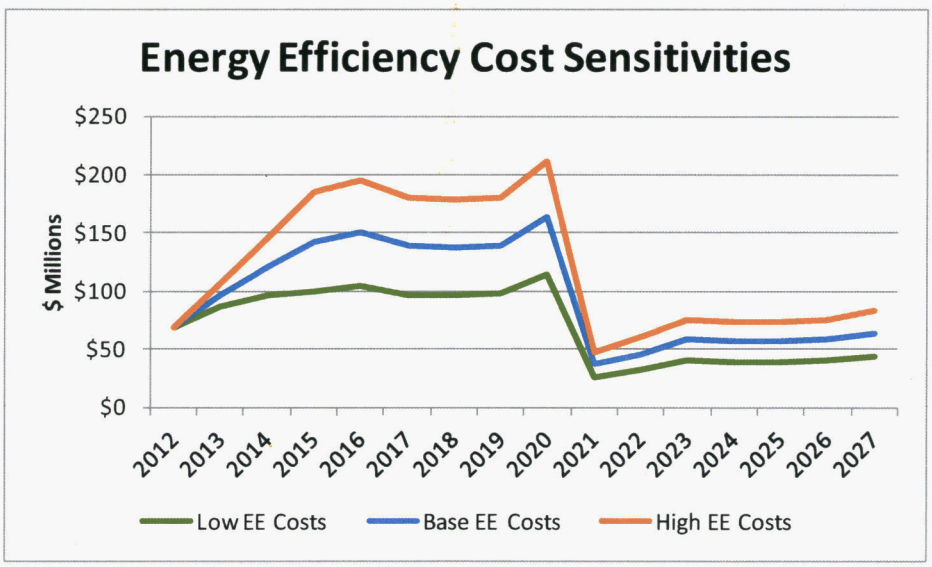

Figure 24 - EE Cost Sensitivities

3.3.5 Externalities

Dr. Ezra Hausman of Synapse Energy gave a presentation at the APS resource planning stakeholder meeting held on June 18, 2010, primarily dealing with the monetization of three emissions: SO_2, NOx, and PM. The calculations behind these monetizations were based on work performed by the National Academies of Science. APS has run sensitivity analyses where these externality costs, which attempt to quantify a societal impact from certain emissions, are included in the dispatch cost of APS resources. The externality cost for each emission is different for each APS plant due to factors such as proximity to population and emission control equipment. In addition, APS monetized the cost of water consumption at its generation facilities as part of the externalities sensitivity. These costs are based upon existing contracts for treated effluent water. The values are provided in response to Rule E.1(h).

3.4 SCENARIO ANALYSIS

To further demonstrate the impact of the sensitivities on each portfolio, APS created two distinct scenarios that incorporate the two extremes of the cost spectrum:

Low Cost Scenario: This scenario envisions a case where all of the major cost forecasts contained in the base assumptions are too high. This scenario applies the 30% lower natural gas price curve, the 30% lower EE cost curve, the extension of the PTC and ITC, and $0/metric ton cost for carbon emissions. The Low Cost Scenario effectively captures a reasonable "best case" for future revenue requirements.

High Cost Scenario: This scenario provides the opposite extreme from the Low Cost Scenario, in that it envisions a future where all of the major cost forecasts contained in the base assumptions are too low. This scenario applies the 30% higher natural gas price curve, the 30% higher EE cost curve, and the high carbon forecast provided by Charles River Associates in Appendix A. The High Cost Scenario captures a reasonable "worst case" for future revenue requirements.

3.5 RESULTS OF PORTFOLIO ANALYSIS

3.5.1 Summary of Portfolio Analytics

Portfolio	Affordability	Environment	Fuel Diversity
Base Case	•$26.9B NPV Revenue Requirements during Planning Period •$44.2B NPV Revenue Requirements through 2041 •86% increase in system costs per MWh by 2027 •$8.7B cumulative CapEx by 2027	•CO_2 intensity drops 26% by 2027 •Water intensity drops 27% by 2027 •65% of energy growth met by clean energy resources	•99 BCF annual natural gas burn in 2027 •Maintains coal fleet contribution •Compliance levels of EE/RE
Four Corners Contingency	•$27.3B NPV Revenue Requirements during Planning Period •$44.6B NPV Revenue Requirements through 2041 •86% increase in system costs per MWh by 2027 •$9.7B cumulative CapEx by 2027	•CO_2 intensity drops 39% by 2027 •Water intensity drops 37% by 2027 •65% of energy growth met by clean energy resources	•147 BCF annual natural gas burn in 2027 •Four Corners plant is retired at the end of 2015 and replaced by natural gas resources •Compliance levels of EE/RE
Enhanced Renewable	•$27.6B NPV Revenue Requirements during Planning Period •$45B NPV Revenue Requirements through 2041 •96% increase in system costs per MWh by 2027 •$12.6B cumulative CapEx by 2027	•CO_2 intensity drops 37% by 2027 •Water intensity drops 30% by 2027 •92% of energy growth met by clean energy resources	•82 BCF annual natural gas burn in 2027 •Maintains coal fleet contribution •Compliance levels of EE •Doubles RE contribution •Most balanced portfolio among fuel sources
Coal Retirement	•$27.9B NPV Revenue Requirements during Planning Period •$45.3B NPV Revenue Requirements through 2041 •92% increase in system costs per MWh by 2027 •$13.3B cumulative CapEx by 2027	•CO_2 intensity drops 60% by 2027 •Water intensity drops 55% by 2027 •83% of energy growth met by clean energy resources	•175 BCF annual natural gas burn in 2027 •Retires all coal plants by the end of 2024 and replaces energy production with 75% natural gas / 25% RE •Compliance levels of EE •Slightly higher than compliance levels of RE

Table 4 - Summary of Portfolio Analytics

3.5.2 Key Metric Comparison

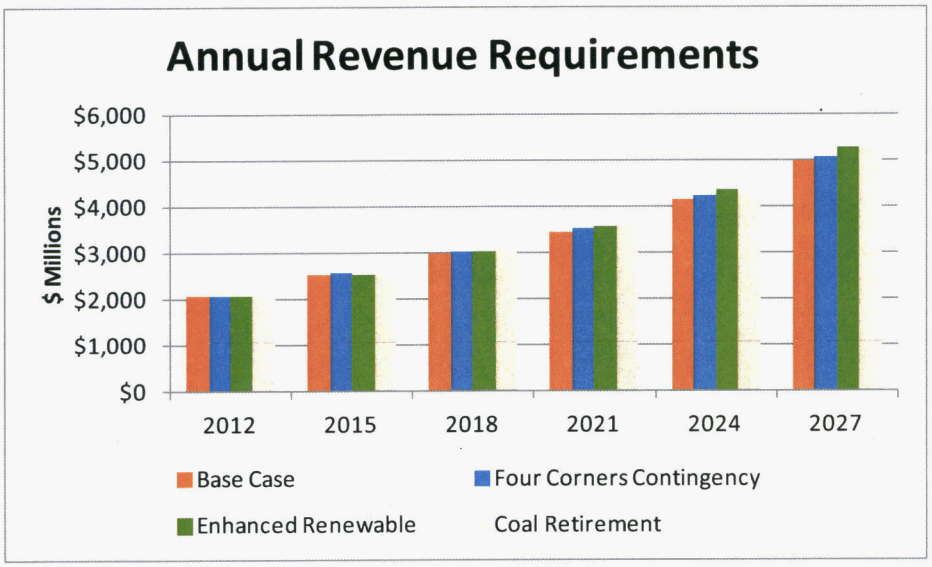

Figure 25 - Comparison of Annual Revenue Requirements

Annual revenue requirements will steadily rise over the course of the Planning Period, regardless of the portfolio selected.

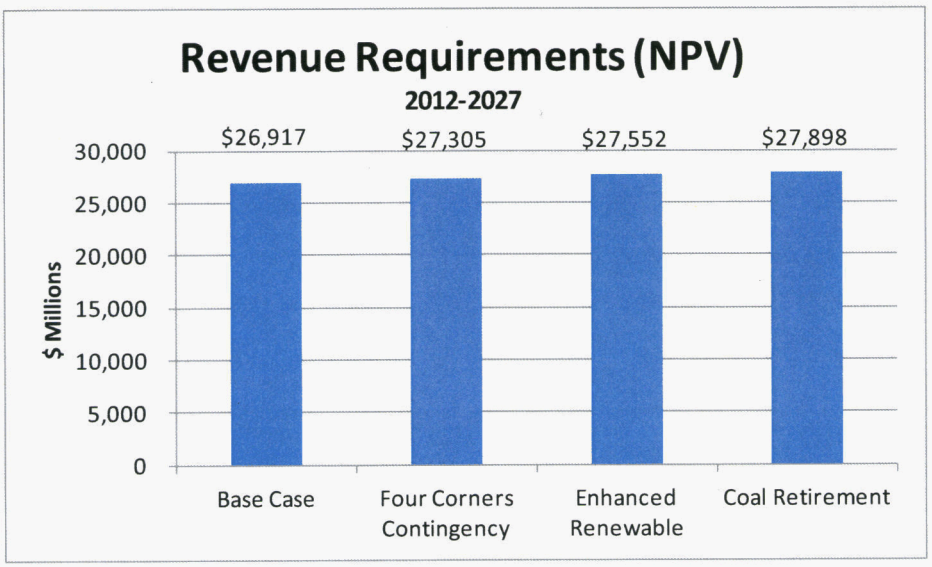

Figure 26 - Comparison of NPV Revenue Requirements (2012-2027)

The four portfolios analyzed have markedly similar 15-year NPV of revenue requirements for the 15-year Planning Period. The Base Case Portfolio has the lowest NPV revenue requirements during this window at $26.9B, while the Coal Retirement Portfolio is the most expensive at $27.9B, an increase of approximately 3.6%.

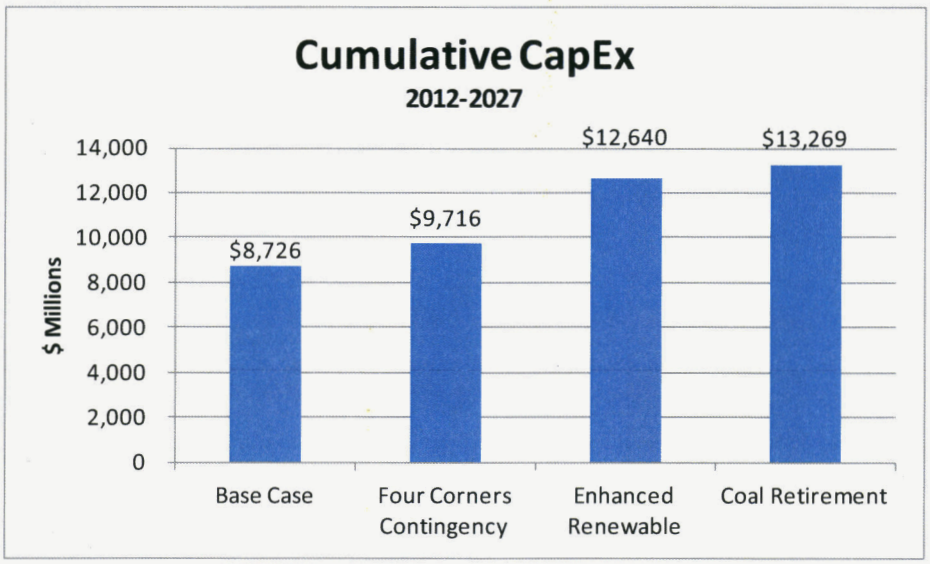

Figure 27 - Cumulative CapEx (2012-2027)

The Enhanced Renewable and the Coal Retirement portfolios both have markedly higher capital requirements compared to the Base Case and Four Corners Contingency portfolios. The Coal Retirement Portfolio is retiring over 1,700 MW of coal generation, replacing it with new natural gas and renewable energy resources. The Enhanced Renewable Portfolio is installing 1,300 MW (nameplate) more renewable energy than the first two portfolios while only decreasing new natural gas resources by approximately 300 MW. These capital expenditures would be borne by either APS or, in the alternative, by market participants who then contract with APS for the needed capacity and energy.

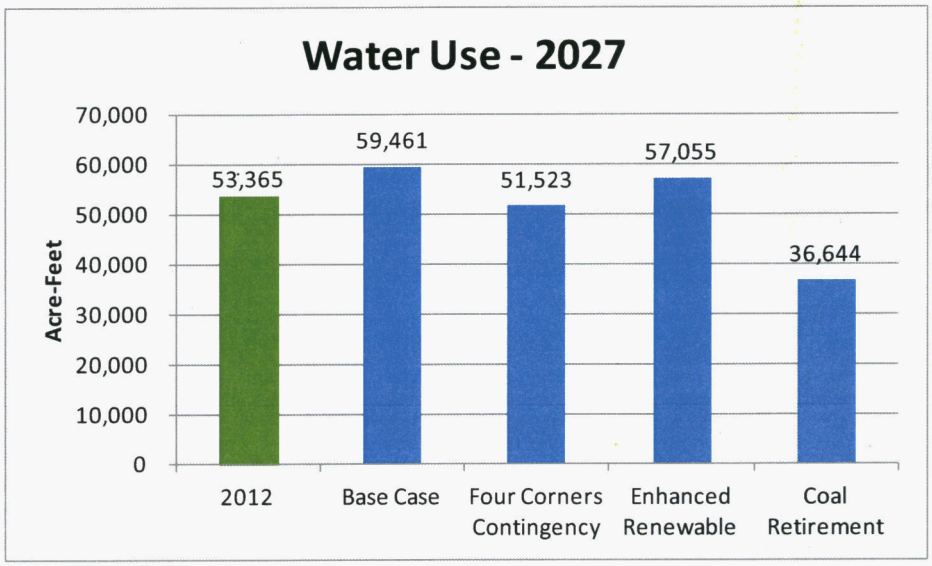

Figure 28 - 2027 Annual Water Use

To protect Arizona's most precious natural resource – namely, water – the Company has committed to examining technologies that limit the amount of water used to serve customers. APS will experience customer load growth of approximately 55% over the course of the Planning Period. Despite that daunting figure, the Base Case Portfolio shows a projected increase in water usage of only 11%. The Four Corners Contingency and Coal Retirement portfolios do show a decrease in overall water usage, which is driven directly by the retirement of APS's low-cost coal fleet.

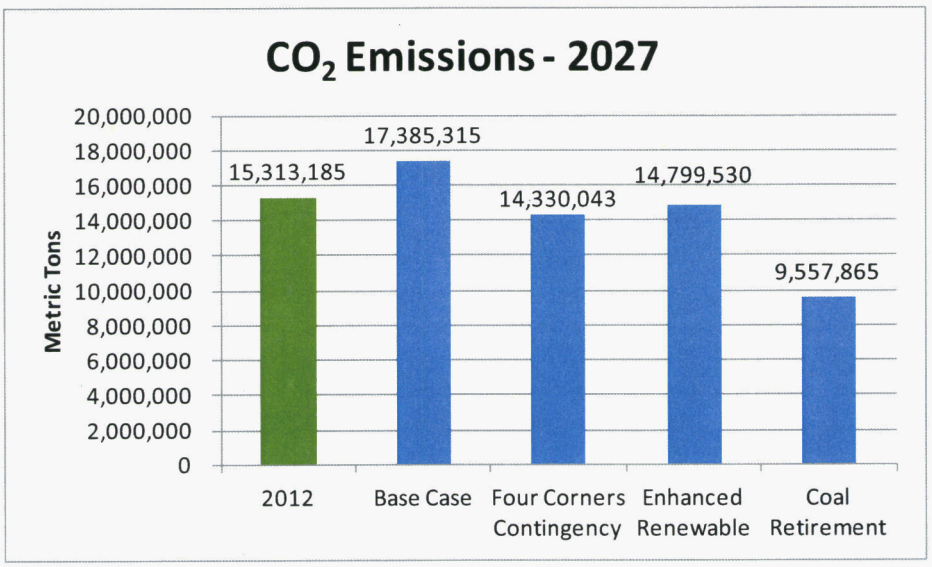

Figure 29 - 2027 Annual CO_2 Emissions

APS's CO_2 emissions profile is projected to be slightly higher (13.5%) in 2027 for the Base Case in spite of the rapidly increasing customer load requirements. This increase is due to the economic acquisition of the SCE share of Four Corners, and the addition of natural gas

resources to meet customer needs. The two portfolios that retire some or all of APS's coal fleet do show a marked decrease in CO_2 emissions.

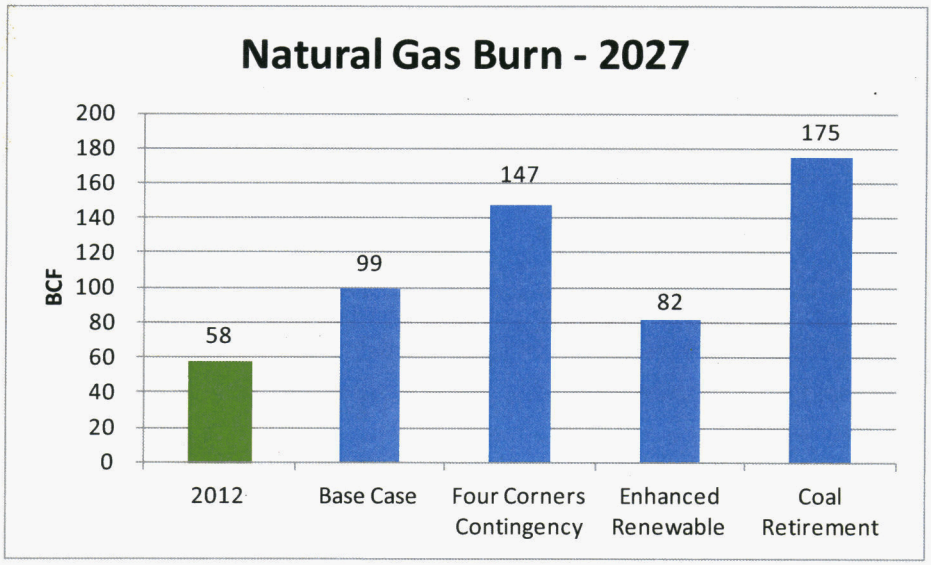

Figure 30 - 2027 Annual Natural Gas Burn

APS's annual gas burn will increase significantly during the Planning Period, with portfolios that retire coal assets showing the largest increases at 2.5-3 times above current levels. While natural gas prices are currently low, they have historically been very volatile.

3.5.3 Discussion of Results

The four portfolios analyzed using the base assumptions are markedly similar in customer cost. On an NPV basis, the total revenue requirements are within a 3.6% variance during the Planning Period. The Base Case Portfolio provides the lowest cumulative capital expenditures and revenue requirements of all portfolios analyzed. The two portfolios that retire some or all of APS's coal fleet do provide reduced CO_2 emissions and water usage; however, they come with the tradeoff of a significant increase in natural gas burn and higher cost. In addition, and as portrayed in Figure 18 through Figure 21, these portfolios do not provide the same level of fuel diversity as either the Base Case or Enhanced Renewable portfolios, and result in APS becoming largely dependent upon natural gas resources to meet future customer needs. The Enhanced Renewable Portfolio provides a comparatively lower natural gas burn than the Base Case Portfolio due to its increased reliance on renewable resources, which also results in modest improvements in CO_2 and water use. Detailed results of the base analysis can be found at Attachment F.1(b).

3.6 RESULTS OF SENSITIVITY AND SCENARIO ANALYSES

3.6.1 Summary of Sensitivity Analysis

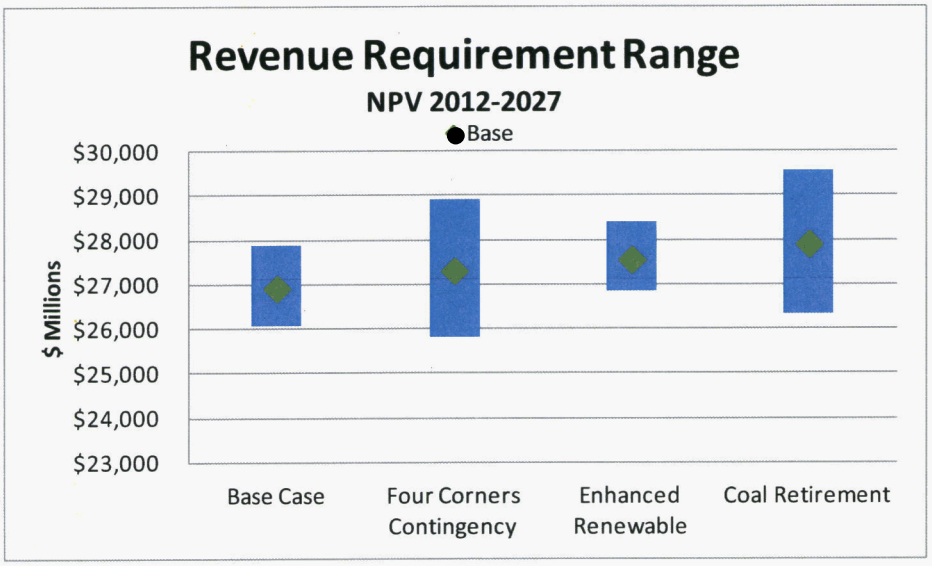

Figure 31 - Impact of Sensitivities on 2012-2027 Revenue Requirements

The Four Corners Contingency and Coal Retirement portfolios have the most variability in the potential NPV of revenue requirements after taking into account the sensitivity analytics discussed above. The single largest driver for this volatility is the price sensitivity to natural gas of plus or minus 30%. These two portfolios are heavily reliant on natural gas burn; therefore, they are the most affected by this sensitivity.

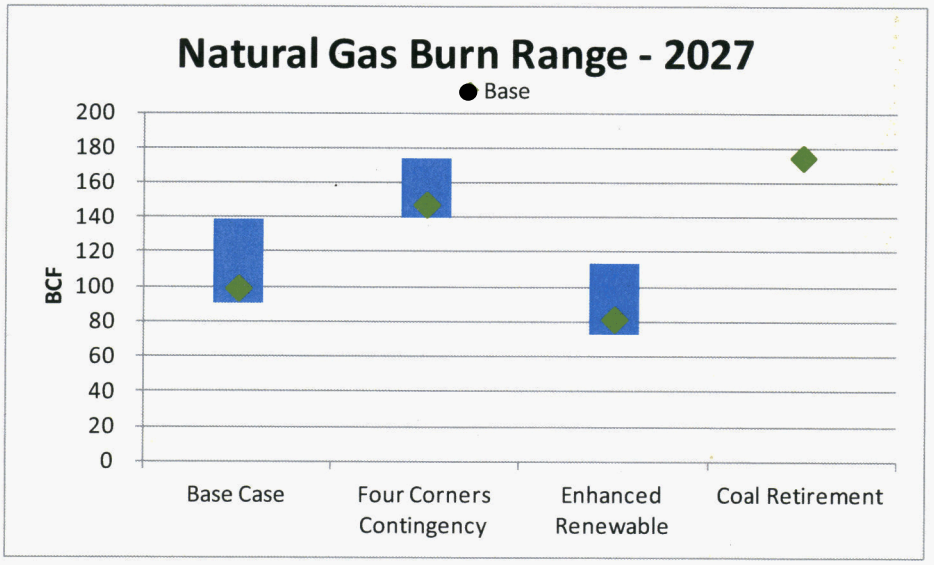

Figure 32 - Impact of Sensitivities on 2027 Natural Gas Burn

Natural gas burn is predominantly affected by the price sensitivity on natural gas. Portfolios that retain some or all of the APS coal fleet are capable of some level of fuel switching to mitigate increased natural gas prices. If natural gas prices are lower than predicted, these portfolios are also capable of "backing down" the coal fleet and increasing generation from natural gas resources to take advantage of the reduced dispatch cost. The Coal Retirement Portfolio, however, has no fuel switching capabilities and becomes a "price taker" on natural gas, unable to modify its dispatch should prices rise.

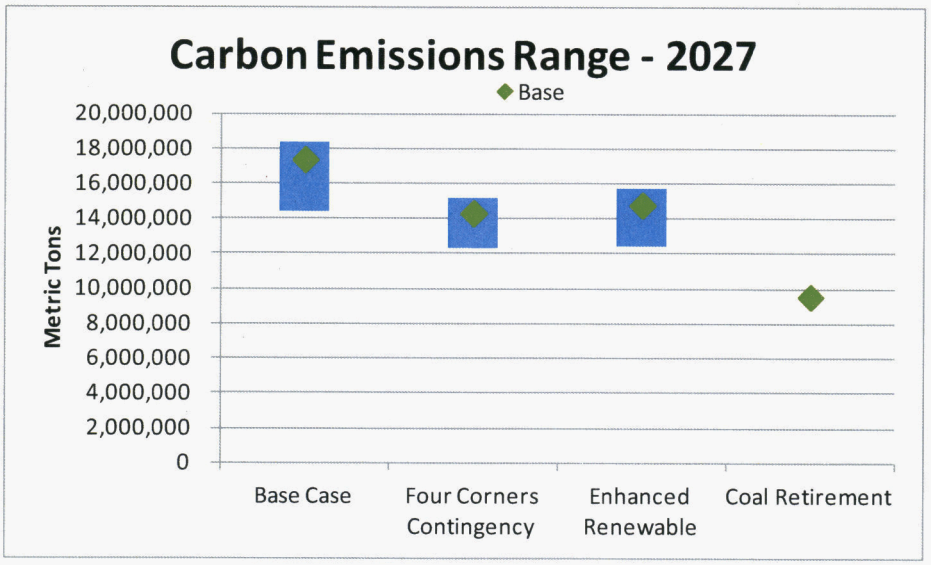

Figure 33 - Impact of Sensitivities on 2027 Carbon Emissions

CO_2 emissions are impacted by the natural gas and CO_2 price sensitivities. Increased natural gas prices or a lack of a carbon cost would increase the dispatch of coal generation (for those portfolios retaining coal), whereas low natural gas prices or a high carbon cost would shift

production away from coal and towards natural gas. As stated earlier, the Coal Retirement Portfolio is unable to modify its dispatch.

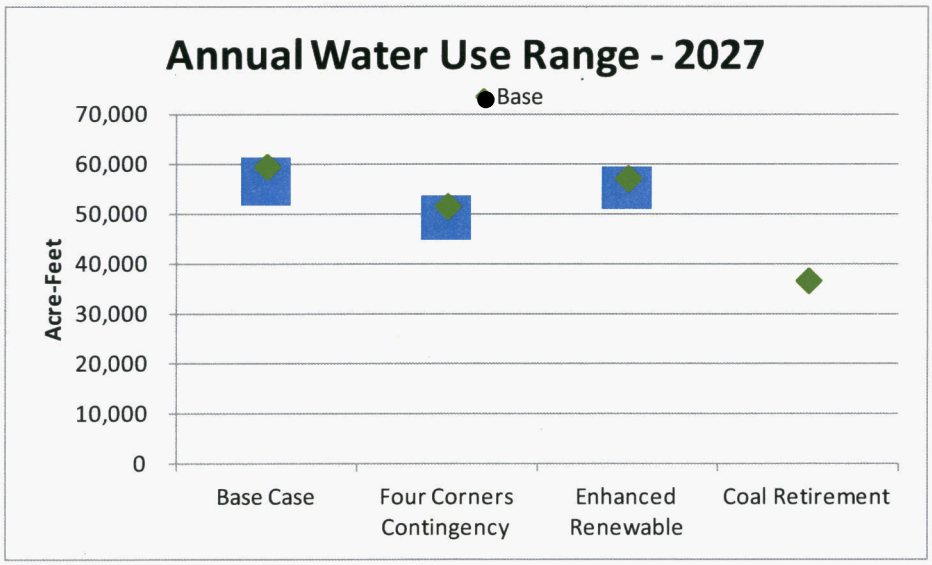

Figure 34 - Impact of Sensitivities on 2027 Water Use

Similar to CO_2 emissions, water use is driven primarily by natural gas and CO_2 price sensitivities and their impact on the dispatch prices of natural gas and coal-fired plants.

	Variability from Base Assumptions due to Sensitivity Analyses				
	Sensitivity	Base Case	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Revenue Requirements (2012-2027)	**Portfolio Value ($ Million)**	**$26,917**	**$27,305**	**$27,552**	**$27,898**
	Low Gas	-3.2%	-5.4%	-2.6%	-5.6%
	High Gas	3.6%	5.8%	3.1%	5.9%
	Low Carbon	-1.8%	-1.0%	-1.3%	-0.2%
	High Carbon	1.4%	0.8%	1.0%	0.2%
	Extended Tax Credits	-0.3%	-0.3%	-1.3%	-0.9%
	With Externalities	3.2%	2.8%	3.0%	2.5%
	Low EE	-0.8%	-0.8%	-0.8%	-0.8%
	High EE	0.8%	0.8%	0.8%	0.8%
Natural Gas Burn (2027)	**Portfolio Value (BCF)**	**99**	**147**	**82**	**175**
	Low Gas	39.4%	17.5%	39.4%	0.1%
	High Gas	-7.7%	-4.1%	-9.3%	0.0%
	Low Carbon	-8.4%	-5.0%	-10.3%	0.0%
	High Carbon	27.8%	12.7%	26.2%	0.0%
	Extended Tax Credits	0.0%	0.0%	0.0%	0.0%
	With Externalities	6.9%	4.6%	6.6%	-0.1%
	Low EE	0.0%	0.0%	0.0%	0.0%
	High EE	0.0%	0.0%	0.0%	0.0%
Carbon Emissions (2027)	**Portfolio Value (MM Metric Tons)**	**17**	**14**	**15**	**10**
	Low Gas	-17.2%	-13.8%	-16.2%	0.1%
	High Gas	4.6%	4.8%	5.3%	0.0%
	Low Carbon	5.5%	6.3%	6.6%	0.0%
	High Carbon	-13.0%	-10.2%	-12.0%	0.0%
	Extended Tax Credits	0.0%	0.0%	0.0%	0.0%
	With Externalities	-3.3%	-4.1%	-3.2%	0.0%
	Low EE	0.0%	0.0%	0.0%	0.0%
	High EE	0.0%	0.0%	0.0%	0.0%
Water Use (2027)	**Portfolio Value (Acre-Feet)**	**59,461**	**51,523**	**57,055**	**36,644**
	Low Gas	-13.3%	-13.0%	-11.0%	0.4%
	High Gas	2.5%	2.8%	2.8%	0.0%
	Low Carbon	3.2%	4.1%	3.7%	0.3%
	High Carbon	-9.0%	-10.7%	-7.3%	0.0%
	Extended Tax Credits	0.0%	0.0%	0.0%	0.0%
	With Externalities	-2.5%	-3.1%	-2.1%	-0.5%
	Low EE	0.0%	0.0%	0.0%	0.0%
	High EE	0.0%	0.0%	0.0%	0.0%
Overall Variance (Min/Max)	Revenue Requirements	7.0%	11.8%	5.9%	12.2%
	Natural Gas Burn (2027)	52.3%	23.7%	55.4%	0.1%
	CO_2 Emissions (2027)	27.4%	23.3%	27.2%	0.1%
	Water Use (2027)	19.0%	19.6%	16.4%	0.9%

Table 5 - Summary of Variability due to Sensitivities

3.6.2 Discussion of Sensitivity Results

When analyzing the results of the sensitivity screens, a key metric to focus on is the cost impact; namely, how susceptible is each portfolio to the price volatility inherent in each of the main cost inputs. Both the Four Corners Contingency and Coal Retirement portfolios have revenue requirement NPVs that fluctuate 11-12% (depending on the sensitivity) over the Planning Period. The Base Case and Enhanced Renewable portfolios show much less variation in Revenue Requirements, with 7% and 6% difference over the Planning Period, respectively.

Below is a brief description of the results of each sensitivity case. Detailed results of the sensitivity analyses are located in Attachment F.1(c). One item to note is the lack of impact any of the sensitivities have on the Coal Retirement Portfolio's non-cost metrics. Due to its maximization of natural gas resources, there is little fuel switching possible within that portfolio. As a result, it becomes the functional equivalent of a "price taker" of natural gas.

Natural Gas Prices: Natural gas prices exerted the largest impact on the portfolio results of all of the sensitivities analyzed by APS. Revenue requirements were more impacted – both positively and negatively – by natural gas prices than any other variable. High natural gas prices also resulted in fuel switching away from natural gas and towards coal-fired generation, which causes an increase in both water use and carbon emissions. APS's fuel mix in 2027 for the Base Case Portfolio would move from 26% coal and 26.3% natural gas to 28.7% coal and 23.6% natural gas. On the other hand, low natural gas prices significantly shift the dispatch of APS's resources towards gas-fired generation. APS's fuel mix in 2027 for the Base Case Portfolio would shift to only 15% coal and 37.3% natural gas.

Carbon Prices: Carbon prices have a markedly similar impact on fuel dispatch as natural gas prices, albeit for different reasons. While carbon prices have an impact to the dispatch cost of gas-fired generation, they more directly influence the dispatch position of the coal fleet. In 2027, coal generation fluctuated in the Base Case Portfolio from 17.9% of the energy mix in the high carbon price sensitivity up to 29% in the low carbon price case, with natural gas making up 34.4% and 23.3%, respectively. Because carbon pricing impacts both fuel sources to varying levels, the degree of fuel switching was slightly less prevalent than in the natural gas price sensitivities.

Externalities: Externality costs increased revenue requirements by 2.5 to 3.2%, depending upon the portfolio, with the portfolios where coal-fired generation is retired being marginally less impacted than those that retained all of APS's existing coal fleet. These costs also slightly impacted the dispatch of APS resources, with a 2.1% energy shift from coal towards natural gas in the Base Case Portfolio.

EE Costs: Energy efficiency costs have an identical impact in revenue requirements across all portfolios, as each portfolio assumes the same level of energy efficiency on the system due to its "must take" nature. Each portfolio's NPV of revenue requirements is impacted by plus or minus 0.8% when energy efficiency costs are shifted by 30% up or down. As this sensitivity impacts cost only and does not modify unit dispatch, there is no change to any of the other metrics.

PTC/ITC Extension: Similar to energy efficiency costs, the extension of the PTC and ITC past their current expiration dates only impacts the costs of renewable resources and therefore only causes a change in the revenue requirements metric. Portfolios that have

higher penetration levels of renewable energy, such as the Enhanced Renewable and Coal Retirement portfolios, are more impacted by this sensitivity.

3.6.3 Summary of Scenario Analysis

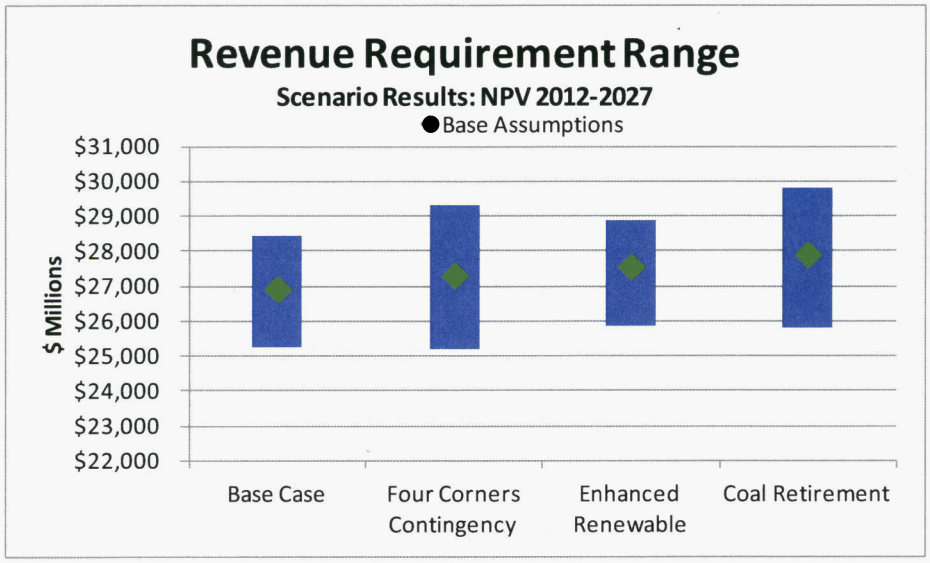

Figure 35 - Impact of Scenarios on 2012-2027 Revenue Requirements

	Variability from Base Assumptions due to Scenario Analyses				
	Sensitivity	Base Case	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Revenue Requirements (2012-2027)	**Portfolio Value ($ Million)**	**$26,917**	**$27,305**	**$27,552**	**$27,898**
	Low Cost Scenario	-6.3%	-7.7%	-6.1%	-7.5%
	High Cost Scenario	5.6%	7.3%	4.8%	6.9%
Natural Gas Burn (2027)	**Portfolio Value (BCF)**	**99**	**147**	**82**	**175**
	Low Cost Scenario	3.2%	0.9%	6.9%	0.1%
	High Cost Scenario	-4.4%	-2.2%	-6.0%	0.0%
Carbon Emissions (2027)	**Portfolio Value (MM Metric Tons)**	**17**	**14**	**15**	**10**
	Low Cost Scenario	-1.2%	-0.5%	-2.3%	0.2%
	High Cost Scenario	2.3%	2.2%	2.8%	0.0%
Water Use (2027)	**Portfolio Value (Acre-Feet)**	**59,461**	**51,523**	**57,055**	**36,644**
	Low Cost Scenario	-0.3%	0.0%	-1.3%	0.4%
	High Cost Scenario	1.1%	1.2%	1.5%	0.0%
Overall Variance (Min/Max)	Revenue Requirements	12.7%	16.2%	11.5%	15.5%
	Natural Gas Burn (2027)	8.0%	3.1%	13.7%	0.1%
	CO_2 Emissions (2027)	3.5%	2.7%	5.2%	0.2%
	Water Use (2027)	1.4%	1.2%	2.9%	0.4%

Table 6 - Summary of Scenario Analyses

3.6.4 Discussion of Scenario Results

The High Cost Scenario incorporates the higher curves for natural gas, carbon, and EE prices, while the Low Cost Scenario utilizes the lower curves for those key variables, in addition to extending the renewable tax credits. This method effectively puts a high and low

collar on the likely revenue requirements that would result from each portfolio created. The overall impact is that revenue requirements have a total range of 11.5 to 16.2%, depending on the portfolio.[35] By maximizing the highest-cost and lowest-cost curves for carbon, natural gas, and energy efficiency prices, fuel switching is relatively minor in each portfolio. This occurs because the higher dispatch price of gas-fired generators due to the higher natural gas curve is mostly offset by the higher dispatch price imposed upon coal-fired generation by the high carbon cost curve. These two scenarios illustrate the range of possible total costs for each portfolio and show the interplay between the key variables and how they impact resource dispatch. Detailed results of the scenario analyses can be found at Attachment F.1(d).

3.7 2012 RESOURCE PLAN

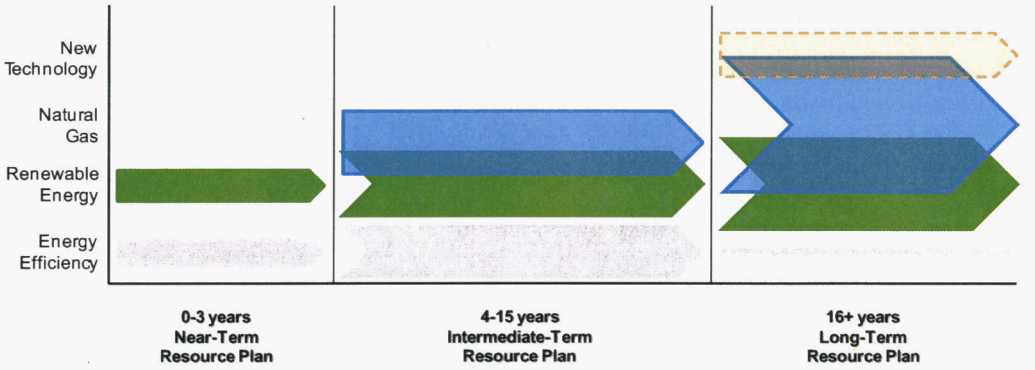

Figure 36 - 2012 Resource Plan: Sources of Energy Growth

APS has adequate plans in place to meet the near-term needs of customers, and several options exist for future resource decisions. The APS 2012 Resource Plan contains three distinct stages as resource decisions become more fluid through time: the Near-Term Resource Plan (0-3 years); the Intermediate-Term Resource Plan (4-15 years); and, the Long-Term Resource Plan (16+ years).

Near-Term Resource Plan: Over the next three years, APS plans to continue to pursue energy efficiency and renewable energy resources to comply with the EE Standard as well as the 2009 Settlement Agreement, which requires APS to obtain an estimated 10% of its energy needs from renewable resources by 2015.[36] As a result, additional generation of 1.7 GWh will come from new renewable resources beyond existing renewable resources or contracts as of the end of 2008. These existing commitments, coupled with the fact that APS is heading into the 2012 summer season with approximately 600 MW of excess capacity, result in no difference between any of the portfolios analyzed during this near-term period. Details on the activities that will occur during this stage can be found in the Action Plan.[37] The only potential differentiator during this time period is the status of the Four Corners transaction. Should that transaction not be consummated, APS would begin the process of building or acquiring combined cycle capacity during this stage in preparation for a need in 2016.

[35] Lowest forecast NPV of revenue requirements compared to the highest forecast NPV of revenue requirements for the Planning Period.
[36] Decision No. 71448 (December 30, 2009). *See* Exhibit A at p. 31, Paragraph XV.
[37] Response to Rules H.1-H.3.

Intermediate-Term Resource Plan: The second stage of the 2012 Resource Plan occurs between years 4 and 15 of the Planning Period. During this window, APS begins to add conventional generation resources in addition to the renewable energy and energy efficiency resources that were added during the near-term stage. APS foresees the ability to treat natural gas and renewable energy resources as competing levers during this time period, and resource decisions can be modified from the current plan based on the relative tradeoffs between those fuel sources throughout the intermediate-term stage. For example, APS plans to add over 3,700 MW of natural gas generation capacity and 749 MW of renewable coincident-peak capacity during this stage. In the event that solar, wind, geothermal, or other renewable resources change in value and become a more viable and cost-effective option than natural gas, future resource plans may reflect a balance more commensurate to the Enhanced Renewable Portfolio.

The intermediate-term stage is also where APS would modify its direction should coal-fired generation become cost prohibitive due to legislative or regulatory action taken on the federal level, or customer program participation does not meet the levels anticipated in the plan. Should this occur, APS would shift towards more natural gas and renewable generation than the current plan indicates. Because APS will be in front of the Commission on a bi-annual basis with its Integrated Resource Plan filings, there will be ample time to address the ramifications of such decisions so that APS and its stakeholders can be in agreement on the best path forward.

Long-Term Resource Plan: Beyond the Planning Period envisioned by the IRP rules, there are still many resource decisions that APS must consider to adequately plan for the future. Regardless of the approach today, APS will be moving towards a more natural gas-intensive portfolio 20 to 30 years in the future. The current APS coal fleet will be at or near retirement during this window. Managing the transition during the long-term stage will be key to managing the risk profile of the Company's energy resources. APS will continue to monitor new technology options, such as new nuclear capacity, to determine how best to structure this risk profile. As in the intermediate-term stage, renewable resources have the ability to diversify the overall portfolio of resources and provide mitigation against the inherent price volatility risks associated with a natural gas-dominated energy mix. In addition, energy efficiency programs likely will continue to provide some incremental energy benefit to APS. Future Integrated Resource Plan filings will address these outer years.

RESPONSE TO RULES: SECTION C – DEMAND

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(C), which specifically requires information related to system load forecasts.

RULE C.1

Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses.

A fifteen-year forecast of peak load by month and year by customer class is provided in Attachment C.1.(a) and a fifteen-year forecast of energy consumption is provided in Attachment C.1.(b). For the commercial and industrial classes, the information is consolidated into a category for customers with loads less than 3MW and a category for customers with loads greater than 3MW. Since demand response programs are treated as a resource, there is no load reduction in the forecast attributed to interruptible power.

RULE C.2

Disaggregation of the load forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures.

A disaggregation of the load forecast by month by year into a component in which no additional demand management measures are assumed is provided on the line labeled "Own Load Peak – After DE Before EE/DR" in Attachment C.2. Within the same exhibit, a disaggregation of the load forecast assuming the change in load due to additional forecast demand management measures is provided on the lines labeled "Energy Efficiency Programs" and "Demand Response Programs." Consistent with the definition of Demand Management in R14-2-701 of the Resource Planning Rules, both energy efficiency and demand response are included in the disaggregation because they include programs that could provide a beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time electricity usage. TOU rates may also be considered demand management measures. TOU rates have been in effect at APS since 1982 and have already been accounted for in the Total Own Load Peak forecast in Attachment C.2. APS estimates that residential TOU rates have reduced summer peak loads by over 100 MW.

RULE C.3

Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used.

The APS load forecast is developed using the most appropriate methods available given the data available for use and the historic performance of alternate techniques. The load forecast is developed from several different class-level analyses, which account for differences in the way customers use electricity. These analyses also reflect the high relative importance of regional population and economic growth as a determinant of future electricity demand. The following discussion outlines the methods used to prepare the load

forecasts for each relevant class of customer and, per the requirement of the Rules, provides a description of how the models are benchmarked and the justification for the forecast method.

Residential Load: The residential load forecast is the product of a residential customer forecast and a corresponding electricity-use-per-customer forecast. The residential customer forecast is tied to a forecast of statewide population by year, a forecast of the number of people per household, and a forecast of the share of a given region of the state which will be served by APS.

Historical population and household data are reported by the U.S. Census Bureau. The change in annual population is disaggregated into a component driven by net natural increase (number of births each year less the number of deaths each year) and a component driven by net migration. Each of these components is expressed as a growth rate, and these rates are extrapolated forward. The historic net natural increase rate (over the past 40 years) is remarkably stable at about one percent per year, so the extrapolation into the future reflects this constancy. The forecast of the net migration rate reflects the volatility of migration related to the business cycle in the overall economy and also a long-term trend toward a lower overall migration rate.

The forecast of population resulting from the application of these projected growth rates into the future is then benchmarked against other publicly available forecasts for reasonableness. Some of the publicly available sources include the U.S. Census Bureau, the Arizona Department of Commerce, and the University of Arizona Keller School of Management and Business.

The projected growth in population necessarily implies a growth in residential households, as well. The relationship between households and population is typically expressed as the number of people per household. The historical rate of people per household has declined substantially over the last 40 years as the population has aged, although the rate of decline has slowed in more recent years. This historic rate is extrapolated into the future by combining information about the percent of each age cohort who are heads of household with the projected age distribution in order to accurately reflect the impact the continued aging of the population will have on the number of people per household. The forecast of people per household is combined with the forecast of population to derive the residential household forecast.

The number of residential electric customers expected in the future is predominately influenced by the expected growth in residential households, adjusted for service territory shares of various regions within the state. For example, APS serves approximately 45% of Maricopa County, but has been receiving about 50% of the new households each year. APS serves none of Pima and Mohave counties, but almost all of Yuma, Yavapai, and Coconino counties. These historic trends in the share of new households within a region are extrapolated into the future and reflect an assessment of the degree to which those trends may continue. The result is a forecast of APS residential customers by year which reflects anticipated changes in migration rates, the age distribution of the population, and the regional location of new households.

The forecast of electricity use per customer is prepared using an end-use-based model which explicitly accounts for the electricity consumed by five large electricity-using applications in residential households and an amount of electricity for everything else. The five large applications are space cooling, space heating, water heating, refrigerators, and swimming

pool pumps. Historical saturation data for these end uses is compiled from appliance ownership surveys of APS customers. Forecasts of these saturations in combination with the number of residential customers determine how many electricity-using applications are expected to be active in the future.

Historical electricity use for the five large electricity-using applications mentioned above has been estimated from a statistical method called conditional demand analysis (CDA). CDA allows individual household billing data to be combined with appliance ownership and other household characteristics (such as size of home and number of people in the home), and the systematic correlations between household total electricity usage and appliance ownership result in estimates of electricity use for each separately identified end use. About half of average residential customer electricity use in desert areas can be accounted for by these five large uses. The Energy Information Administration (EIA) produces national estimates of annual usage per appliance for many electrical appliances, but due to the difference between the national average climate and Arizona's climate, these estimates cannot be used directly; however, the estimates from the EIA are useful for testing the reasonableness of the CDA estimates.

Electricity use for each of these applications is projected based on the most recent CDA estimates, an assumption of normal weather, known efficiency trends for new and replacement air-conditioning and electric heat units and refrigerators, and for increases in average home size. Normal weather reflects the most recent 10-year average of cooling degree-days, heating degree-days, and humidity. Remaining electricity usage related to unspecified appliances or electricity-using applications is correlated to average home size and projected based on the anticipated future average home size. Total projected annual residential electricity demand is the product of the projected average use per customer and the projected number of residential customers.

Other methods have been tried by or are available to APS to model residential usage. Econometric models relating usage to independent variables including weather, the real (inflation-adjusted) price of electricity, average home size, appliance ownership, and efficiency trends have been used in the past. The performance of these models has broken down, though, in certain circumstances such as in the late 1990s during a period of exceptional growth in home electronics and the summer of 2001 during the California energy crisis. Other modeling approaches include more detailed end use models or simpler trend or extrapolation models, but neither of these approaches is satisfactory. The cost of acquiring and maintaining more detailed end use data appears prohibitive, and the simpler techniques provide too little insight and accuracy.

Commercial and Industrial Customers Less Than 3 MW Load: The load forecast for the group of commercial and industrial customers with electric demand less than 3 MW is the product of a regression analysis of historical sales growth. A customer forecast is also produced, and the two together provide an implied use-per-customer forecast that serves as a useful diagnostic tool. The total class customer forecast is tied to the residential customer forecast in the long run and so anticipates the population and household growth explicitly accounted for in that forecast.

The regression analysis is a statistical multiple regression model which estimates the historical relationship between total commercial and industrial electricity demand (excluding mines) and overall economic growth in the APS service territory as measured by occupied commercial floor space. The regression model also includes variables for the real price of electricity and weather. The historical relationship is applied to a forecast of occupied

commercial floor space to arrive at a projected electricity demand level for commercial and industrial customers. The forecast of occupied commercial floor space is tied to the population forecast described above via per capita occupied commercial floor space. Historical data on per capita occupied commercial floor space are derived from occupancy data reported by CoStar, a company that tracks commercial real estate in Arizona, and population estimates from the U.S. Census Bureau. The real price of electricity is projected by including any known rate changes; otherwise, the real price is assumed constant over time. As with the residential model, normal weather is defined as the average of the last 10 years.

Once the forecast for total commercial and industrial demand has been completed, the forecast for specific customers with loads greater than 3 MW is subtracted from the total.

As with the residential sector, other modeling approaches are available, including end-use-based models or simpler extrapolative techniques. APS does not employ an end-use model for commercial and industrial sales because of cost; electricity-using appliances and machinery for commercial and industrial customers are much more heterogeneous than those used by residential customers, so the level of detail would need to be much higher to accommodate the differences. These more detailed data would also be more costly to collect from business customers, since the surveys would require a higher level of participation from business and facilities managers to explain the important building attributes. Simpler methods are avoided for the same reasons as in the residential sector – too little insight and accuracy.

Commercial and Industrial Customers Greater Than 3 MW Load: For customers with loads in excess of 3 MW, electricity demand forecasts are prepared individually. These forecasts are developed with input provided by customer account managers who are in routine communication with the customers and are knowledgeable about those customers' substantive near-term plans. In the absence of any additional information, these customers' loads are generally held constant in the outer years of the forecast. APS would be unlikely to find reliable independent causal variables to substitute for this method. No new customers are forecast for this group unless a specific new customer has been identified and it has been determined that the customer has a high probability of connecting to the system in the near future. Longer-term potential growth is captured in the econometric model of total commercial and industrial sales.

Irrigation and Street Light Customer Load: The irrigation and street light classes represent two very small components of the APS load requirement. The number of irrigation accounts has declined substantially over the last couple of decades as population growth has driven the conversion of agricultural land into residential and commercial uses. Street light electricity demand typically grows in line with overall electricity demand reflecting the natural expansion in cities and towns. The electricity demand for each of these classes is projected by trending both the number of customers and the average use per customer in the class.

Resale Customer Load: APS has sales contracts with a number of wholesale customers who are partial requirements customers. These customers are primarily electrical and irrigation districts located in western Maricopa County and in Pinal County whose main electricity demand comes from irrigation pumps within their territory. They are referred to as partial requirements because APS serves all of their electricity demand except for a portion which is supplied with federal hydroelectric preference power from the Colorado River. As a group, the districts' total electricity demand is neither expanding nor contracting. Year-to-year volatility emerges in the APS requirement due to changes in the availability of preference

power from one year to the next. The load forecast assumes total demand for these customers remains constant through the term of their contracts, with adjustments for known or expected deviations in preference power included. This view is also informed by discussions with the customers. APS would be unlikely to find reliable independent causal variables to substitute for this method.

In addition to this electrical and irrigation district load, APS serves three requirements customers who each have residential and commercial customers in addition to pumping load. For these customers, the load obligation is either contractually determined or small and stable; the load forecast maintains these loads through the terms of their respective contracts.

Energy Losses: Energy losses (energy furnished without charge and energy used by the load-serving entity) are measured as the difference between the total amount of electricity generated or purchased to meet APS system demands and the total amount of electricity consumed by APS customers at the customer meter level. The most recent five-year average of these energy losses is 7%. The forecast for energy losses is based on the historical rate plus an adjustment to losses due to the termination of energy wheeled for SCE from Four Corners after 2012.

Own Load Energy: Own load energy is the summation of the class-level electricity demands plus energy losses.

Peak Demand: The annual peak demands on the APS system are projected by trending the historical system load factor for the summer months of June-September and applying that load factor to the projected own load energy. Certain extra large loads are accounted for separately so that changes in their historical usage patterns do not distort the interpretation of the underlying trend for smaller customers. The historical pattern shows volatility from year to year, but overall stability within a range of 68% to 64% for those summer months. The use of historical data allows for a natural benchmarking of load factor. The adopted approach provides the greatest consistency between energy demand growth and peak demand growth with an assurance of reasonableness, accuracy (within an acceptable range), and ease of use.

There are relatively few alternatives to forecasting peak demand. Regression models would require the development of a set of causal variables, and a projected load factor implied by the model results would have to be calculated to gain assurance that the results agree with the historical trend. Class-based hourly load models may be another option, but currently they require more data precision than is presently available.

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RESPONSE TO RULES: SECTION D – SUPPLY

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(D), which specifically requires information related to system resources.

RULE D.1(a)

A 15-year resource plan, providing for each year: (a) Projected data for each of the items listed in subsection (B)(1), for each generating unit and purchased power source, including each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment.

Projected data for each generating unit and purchased power resource is provided in the attachments referenced in Table 7.

Projected Data for Generating Units	Attachment
B.1(a) In service date and book life	D.1(a)(1)
B.1(b) Type of generating unit or contract	D.1(a)(1)
B.1(c) Share of generating unit capacity in MW	D.1(a)(1)
B.1(d) Maximum generating unit capacity	D.1(a)(1)
B.1(e) Annual capacity factor	D.1(a)(2)
B.1(f) Average heat rate	D.1(a)(3)
B.1(g) Average fuel cost	D.1(a)(4)
B.1(h) Other variable O&M	D.1(a)(1)
B.1(i) Purchased power energy costs -long-term contracts	D.1(a)(5)
B.1(j) Fixed O&M of generating units ($/MW)	D.1(a)(6)
B.1(k) Demand charges for purchased power	D.1(a)(7)
B.1(l) Fuel type for each generating unit	D.1(a)(1)
B.1(m) Minimum capacity	D.1(a)(1)
B.1(n) Whether the generating unit must run if available	D.1(a)(1)
B.1(o) Description of each generating unit	D.1(a)(1)
B.1(p) Environmental impacts – CO_2	D.1(a)(8)
B.1(p) Environmental impacts – CO	D.1(a)(8)
B.1(p) Environmental impacts – VOC	D.1(a)(8)
B.1(p) Environmental impacts – NOx	D.1(a)(8)
B.1(p) Environmental impacts – SO_2	D.1(a)(8)
B.1(p) Environmental impacts – Hg	D.1(a)(8)
B.1(p) Environmental impacts – PM	D.1(a)(8)
B.1(q) Water consumption quantities and rates	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (fly ash)	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (bottom ash)	D.1(a)(8)

Table 7 - List of D.1(a) Attachments

RULE D.1(b) – B.2(a)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(a): A description of generating unit commitment procedures.

APS optimizes the use of its resources to serve native load in the most economical manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (e.g., wind and solar), fuel prices, contractual requirements, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level and the quantity of natural gas to be scheduled.

As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than to run generating units. The day-ahead trader compares these calculated block energy prices with actual power prices being offered in the market, then purchases either on-peak or off-peak blocks of energy, if economical. The model also calculates the breakeven price for making sales out of the Company's generating units, after taking into account native load and any other pre-existing power sales commitments. If economical, the day-ahead trader will make power sales in the market.

The day-ahead commitment plan is turned over to real-time operations to implement. The real-time traders update the load and available resource forecasts and re-run the unit commitment and dispatch model to fine-tune the commitment plan. They also check the hourly market to make purchases and sales of power to further optimize the system. Any demand response products that can be utilized within the day are also considered.

The real-time traders commit (start) and de-commit (shutdown) generating units as needed to meet load and sales commitments. They also update the plan as needed for generating unit or transmission outages, optimizing utilization of available resources.

For the duration of the Planning Period, the generating unit commitment procedures are not expected to change from one year to the next.

RULE D.1(b) – B.2(b)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(b): Production cost.

The production costs for the 15-year plan are provided in Table 8. "Production Costs" (defined in R14-2-701(33)) include variable O&M costs of producing electricity through APS-owned generation. "Fuel" includes the commodity portion of fuel costs for APS-owned generating units to meet APS native load plus a long-term sales contract. "Emissions" refers to the costs associated with any SO_2 and CO_2 emissions. "Purchases" includes the variable O&M and commodity portion of fuel costs for tolled generating units, costs for existing PPAs, and assumed future renewable purchased power costs and costs associated with short term market purchases represented in response to Rule D.1(b) – B.2(f). "Sales" are shown as a negative value and reflect revenue from a long-term wholesale sales contract that expires in 2020.

TOTAL PRODUCTION COSTS
2012 Resource Plan
(MILLIONS OF DOLLARS)

	Generation		Emissions	Purchases		Sales	Total
	Fuel	Variable O&M	SO2 & CO2	Demand	Energy		$Millions
2012	$457.9	$44.7	($0.1)	$108.9	$214.0	($2.5)	$822.9
2013	$461.0	$47.1	($0.1)	$110.0	$252.8	($4.5)	$866.3
2014	$472.9	$46.5	($0.1)	$110.8	$354.3	($3.9)	$980.5
2015	$481.1	$48.4	($0.1)	$112.0	$370.4	($8.3)	$1,003.6
2016	$541.2	$52.8	($0.1)	$112.6	$388.9	($9.6)	$1,085.9
2017	$660.5	$62.3	($0.1)	$137.1	$345.3	($11.0)	$1,194.1
2018	$768.3	$66.7	($0.1)	$121.7	$315.6	($12.5)	$1,259.7
2019	$798.1	$68.4	$59.1	$128.3	$332.3	($13.5)	$1,372.7
2020	$908.8	$78.8	$69.5	$74.1	$261.0	($13.3)	$1,378.9
2021	$948.8	$82.5	$76.8	$76.7	$359.6	$0.0	$1,544.4
2022	$1,024.6	$86.7	$100.0	$72.9	$352.4	$0.0	$1,636.6
2023	$1,120.7	$93.7	$114.8	$80.9	$378.2	$0.0	$1,788.3
2024	$1,184.4	$98.3	$134.0	$75.5	$376.2	$0.0	$1,868.3
2025	$1,232.9	$105.5	$159.6	$15.0	$411.7	$0.0	$1,924.8
2026	$1,314.3	$112.9	$204.3	$66.2	$414.9	$0.0	$2,112.6
2027	$1,413.8	$120.3	$289.8	$86.0	$437.0	$0.0	$2,346.7

Table 8 - Total Production Costs (2012-2027)

RULE D.1(b) – B.2(c)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(c): Reserve requirements.

The reserve requirements for the 2012 Resource Plan are provided in Attachment F.9(b) on line 4.

RULE D.1(b) - B.2(d)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(d): Spinning reserve.

APS is one of 15 members of the Southwest Reserve Sharing Group (SRSG).[38] Individual members' spinning reserve requirements are calculated using a formula that takes into account factors such as each member's hourly loads, purchase and sale transactions, and thermal generation. Currently, APS's SRSG spinning reserve requirement is normally supplied by units fueled by natural gas, depending on economics. If APS was not an SRSG member, this requirement would increase to at least 560 MW to cover the system's largest single hazard. Because SRSG calculations are dependent upon each member's system conditions and the interaction of those systems working together, each member's contribution to SRSG spinning reserve may change over time.

Forecast spinning reserves over the planning horizon are illustrated in Table 9. Half of these requirements can be met with units designed to start within 10 minutes.

[38] Additional information regarding SRSG can be found at www.srsg.org.

Year	Spinning Reserve Requirement
2012	320
2013	321
2014	323
2015	324
2016	329
2017	334
2018	340
2019	346
2020	352
2021	357
2022	366
2023	375
2024	383
2025	392
2026	401
2027	410

Table 9 - Forecast Spinning Reserve Requirement

RULE D.1(b) – B.2(e)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(e): Reliability of generating, transmission, and distribution systems.

Generation reliability

Generation reliability of a resource plan is typically measured in terms of reserve margins or loss of load probability (LOLP). APS's reserve criterion is based on LOLP of one outage in ten years, which translates to a 15% reserve requirement. To ensure a reliable generation system, reserves should be greater than or equal to 15%. Following are the annual reserve requirement amounts based on the 15% requirement (also shown on Attachment F.9(b), line 4).

Year	Reserve Requirement (MW)
2012	999
2013	1,005
2014	1,028
2015	1,054
2016	1,086
2017	1,119
2018	1,149
2019	1,178
2020	1,217
2021	1,325
2022	1,380
2023	1,434
2024	1,490
2025	1,546
2026	1,597
2027	1,641

Table 10 - Reserve Requirements

Transmission and Distribution Reliability

APS follows the Institute of Electrical and Electronics Engineers (IEEE) 1366 – 2003, "Guide for Electric Power Distribution Reliability Indices" for measuring reliability. Three of the most common indicators used for measuring reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI).

Forecasts for transmission and distribution reliability are provided in Attachment D.1.(b) and include the following key messages:

- Transmission reliability represents projections of the portion of total SAIFI, SAIDI, and CAIDI, respectively, due to outages at the transmission level and illustrates a general trend of improvement in transmission reliability during the 15-year Planning Period.
- Distribution reliability represents projections of the portion of total SAIFI, SAIDI, and CAIDI, respectively, due to outages at the distribution level and illustrates a general trend of improvement to APS's reliability. Forecast vs. actual data may vary depending upon weather patterns and unusual events. New distribution facilities are generally constructed underground due to local zoning rules. As underground facilities increase as a percentage of total facilities, the length of time it takes to locate, repair, and restore from the outage also increases due to the nature of underground facilities versus overhead facilities.

RULE D.1(b) – B.2(f)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(f): Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales related to short-term contracts.

APS does not forecast specific short-term purchase or sales contracts in the 15-year forecast; however, APS does anticipate a certain level of short-term market purchases as depicted in Attachment F.9(b) at line 32. These are assumed to be four-month summer purchases (June to September) with capacity and energy prices based on the cost of a new combustion turbine as indicated in Table 11. These purchases provide added flexibility to the resource plan and may be procured a year at a time, if needed, in the year prior to the need.

	Capacity MW	Demand Cost $/kW-Yr	Energy Cost $/MWh
2012	0	N/A	N/A
2013	0	N/A	N/A
2014	0	N/A	N/A
2015	0	N/A	N/A
2016	0	N/A	N/A
2017	213	$133.5	$79.0
2018	373	$137.0	$81.8
2019	403	$140.5	$84.5
2020	412	$144.1	$87.2
2021	424	$147.8	$90.1
2022	437	$151.6	$93.2
2023	473	$155.4	$96.6
2024	423	$159.4	$98.5
2025	38	$163.5	$100.4
2026	338	$167.7	$102.4
2027	444	$172.0	$104.4

NOTE: Currently there are no contracts in place for the capacity shown.
The capacity is assumed to be available from June to September each year
The demand costs are based on avoided capacity prices for a new CT.
The energy costs are based on fuel, startup, and O&M costs for a new CT.

Table 11 - Costs of Forecasted Short-Term Market Purchases

RULE D.1(b) – B.2(g)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(g): Energy losses.

Energy losses for the 15-year forecast are provided in Attachment C.1.(b) on the line labeled "Energy Losses".

RULE D.1(c)

A 15-year resource plan, providing for each year: (c) The capital cost, construction time, and construction spending schedule for each generating unit expected to be new or refurbished during the period.

Capital cost, construction time, and construction spending schedules are provided in Attachment D.1(c).

RULE D.1(d)

A 15-year resource plan, providing for each year: (d) The escalation levels assumed for each component of cost, such as, but not limited to, operating and maintenance, environmental compliance, system integration, backup capacity, and transmission delivery, for each generating unit and purchased power source.

The current estimate of future inflation is 2.5% per year, which is representative of inflation levels over the past ten years. Capital and O&M components of environmental compliance costs are also assumed to escalate at the general rate of inflation. Exceptions are: (1) fuel prices which are determined either through the forward market or contractual terms; (2) purchased power prices that are determined through contractual terms; (3) solar photovoltaic capital costs, which are expected to decline (in real terms) through 2018 as the technology matures, then escalate at the rate of inflation; and, (4) property taxes on generation and transmission resources which are assumed to escalate at 1% per year.

RULE D.1(e)

A 15-year resource plan, providing for each year: (e) If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected: (i) Identification of each power source or generating unit involved; (ii) The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and (iii) The reasons for discontinuation, decommissioning, mothballing, or derating.

(i) Identification of each power source or generating unit involved

As of the resource plan filing date, APS has assumed for analysis purposes the retirement of Four Corners Units 1-3 and acquisition of Southern California Edison's share of Four Corners Units 4 and 5, subject to the approval of the Arizona Corporation Commission, the California Public Utilities Commission, the Federal Energy Regulatory Commission, and other conditions specified in APS's ACC filing in Docket E-01345A-10-0474. If the proposed transaction does not come to fruition for whatever reason, disposition of Four Corners Units 1-3 has not yet been determined.

In addition to the analyzed retirement of Four Corners Units 1-3, APS has initiated site analysis at the Ocotillo, West Phoenix, Saguaro, and Yucca power plants. Some or all of the generating units, as well as site infrastructure, at these plant sites are anticipated in the near future to need some level of updating, repair, or replacement as these sites are critical in maintaining system reliability. At the time of this resource plan filing, the full extent of this effort is not known as site analysis is currently being evaluated. Finally, APS is investigating the potential for environmental upgrades at Cholla. Finalization of the cost projections for those upgrades could impact the long-term viability of one or more units at that site.

(ii) The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating

The cost to decommission Four Corners Units 1-3 is estimated to be $43 million in 2011 dollars. APS expects to start dismantling the Units upon closure and fully demolish the site along with Units 4-5, which is beyond the time frame of the Planning Period.

(iii) The reasons for discontinuing, decommissioning, or mothballing, or derating

Four Corners faces several complex environmental issues that threaten the plant's economic viability. On one front, the EPA has issued or is expected to soon issue a series of final regulations that could require the plant to install additional environmental controls in the near future. These include, among others, Clean Air Act Regional Haze rules (requiring certain plants, including Four Corners, to install Best Available Retrofit Technology to reduce haze in national parks and wilderness areas), regulations governing the disposal of coal combustion residuals, and strict emissions limitations for mercury and other hazardous air pollutants.[39] Environmental groups and EPA are investigating or have alleged a series of New Source Review (a Clean Air Act program) violations at coal units around the country, including Four Corners. In addition, there is the uncertain cost of potential federal carbon legislation, which, if enacted, will impact many energy resources but will strike at coal generation the hardest.

In 2010, EPA proposed a regional haze rulemaking that would require the Four Corners participants to install NOx emission controls on each of the plant's five units, and additional particulate controls on Units 1-3. If finalized as proposed, this rule could cause APS to invest more than $660 million in capital by 2016.

RULE D.1(f)

A 15-year resource plan, providing for each year: (f) The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period.

An explanation of capital and O&M costs for transmission, subtransmission and distribution facilities is provided below.

Transmission

A list of transmission projects, which includes capital costs for new or refurbished transmission facilities, is provided in Attachment D.1.(f)(1).

O&M costs are not assigned to individual projects and are planned as a total of all projected transmission O&M during budgeting activities as shown in Table 12. As new transmission facilities are added to the system, they are incorporated into normal activities per APS's various processes. The O&M costs shown are those associated with the newly added transmission facilities.

[39] For additional details, see the response to Rule D.17.

Year	O&M ($1,000s)
2012	[redacted]
2013	[redacted]
2014	[redacted]
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]

Redacted

Table 12 - O&M Costs for New or Refurbished Transmission

Subtransmission

APS annually conducts an analysis of its 69kV subtransmission system. The projects listed in Attachment D.1.(f)(2) include the subtransmission planned projects from APS's 2012-2021 Subtransmission Ten Year Plan dated January 2012. O&M costs are not assigned to individual projects and are planned as a total projected subtransmission O&M during budgeting activities. As new subtransmission facilities are added to the system, they are incorporated into normal activities. Subtransmission O&M costs are included with the transmission O&M costs provided above.

Distribution

APS plans its distribution system on a three-year basis. Because the dynamics of a distribution system are so heavily dependent on the level and location of electric load growth or reduction, forecasting with a high degree of accuracy beyond the three-year time frame is difficult and subject to the variations of economic activity. Also, distribution system improvements must be made in very small geographic locations so pinpointing exactly where the load changes will occur is problematic very far into the future. The forecasted expenditures for capital and O&M provided in Table 13 were developed based upon APS's past expenditures and its system coincident peak load forecast for 2012 to 2027. O&M costs are not assigned to individual projects and are planned as total projected distribution O&M during budgeting activities. As new distribution facilities are added to the system, they are incorporated into normal activities per APS's various processes. The O&M costs shown are those associated with the newly added distribution facilities.

Year	Capital ($1,000s)	O&M ($1,000s)
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]

Redacted

Table 13 - Distribution Planned Improvement Expenditures

RULE D.1(g)

A 15-year resource plan, providing for each year: (g) An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona.

An explanation of the need for and purpose of all expected new or refurbished transmission is provided in Attachments D.1(f)(1) and D.1(f)(2). The need and purpose of distribution facilities is discussed in response to D.1(f) above.

RULE D.1(h)

A 15-year resource plan, providing for each year: (h) Cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations.

Cost analyses and projections for the 2012 Resource Plan are provided in Attachment D.10. The cost of existing and expected environmental regulations is embedded within the capital and O&M figures.

RULE D.2

Documentation of the data, assumptions, and methods or models used to forecast production costs and power production for the 15-year resource plan, including the method by which the forecast was benchmarked.

Production Model

Data and assumptions related to resource dispatch and O&M costs as well as other system assumptions are well documented in response to Rule D.1(a) and D.1(b) above. APS uses Ventyx's PROMOD IV to simulate power production and production costs for the 15-year resource plan. PROMOD IV is one of the most widely used production simulation models in the United States by electric utilities. It was first developed in the 1970s and has been continually enhanced to keep up with utility dispatch methods. Inputs to PROMOD IV include hourly load, unit characteristics (including capacity inputs, heat rates, startup energy costs, and maintenance), fuel prices, environmental constraints, and transactions (including forward products with fixed volume and price, hourly or block options with strike prices, purchased dispatchable units, and non-dispatchable resource generation patterns and costs). PROMOD IV provides hourly system production costs, unit costs, and operating statistics (startups, energy output, runtime, capacity factor, fuel consumption and cost, emissions production and cost, and variable and fixed O&M).

Benchmarks

APS benchmarks the production simulation against the Company's budgeting tool, which itself is reconciled with actual system operations and production costs on a monthly basis. One important difference between resource planning and budgeting is that resource planning does not model the interchange market because APS believes that resource decisions should not be justified based on market outlook, which changes significantly from one year to the next and over which APS has no control. Decisions are made to optimize resources within the Company's control to serve native load. In real-time, however, APS of course takes advantage of market opportunities for the benefit of customers.

Assumptions

Data and system assumptions related to resource dispatch, fuel, and O&M costs are thoroughly documented in the response to Rules D.1(a) and D.1(b). Resource capital costs are documented in the response to Rule D.3. Financial assumptions and emissions costs used to forecast production costs and power production for the 2012 Resource Plan are included in Table 14 and Table 15 below.

FINANCIAL AND ECONOMIC ASSUMPTIONS – 2012 RESOURCE PLAN

COST OF CAPITAL

	Capital Ratio	Cost Rate	Weighted Cost of Capital	After-Tax Weighted Cost of Capital
Debt	46.06%	7.25%	3.34%	2.02%
Equity	53.94%	11.00%	5.93%	5.93%
Totals	100%		9.27%	7.95%
AFUDC Rate	9.10%			
Composite Income Tax	39.51%			

DEPRECIATION

	Book Life	Tax Life
Coal	32 Years	20 Years
Nuclear	32 Years	15 Years
Combined Cycle	32 Years	20 Years
Combustion Turbine	32 Years	15 Years
Transmission	50 Years	20 Years
Solar	20-32.6 Years	5 Years
Biomass / Wind	20 Years	5 Years
Geothermal	30 Years	5 Years

TAX CREDITS

	ITC	ITC Expires	PTC[3]	PTC Expires
Solar[1]	30%	12/31/2016	N/A	N/A
Wind	30%	12/31/2012	2.1¢/kWh	12/31/2012
Geothermal[1]	30%	12/31/2013	2.1¢/kWh	12/31/2013
Biomass[2]	30%	12/31/2013	1.1c/kWh	12/31/2013

Notes: (1) 30% ITC is reduced to 10% for geothermal after 12/31/2013 and reverts to 10% for solar after 12/31/2016

(2) Includes landfill gas, municipal solid waste, and open loop biomass. Closed-loop biomass qualifies for a 2.1¢/kWh PTC.

(3) Production tax credit values are for 2010 and are adjusted for inflation each year.

Table 14 - Financial and Economic Assumptions

Year	SO_2 Cost ($/Ton)[1]	CO_2 Cost ($/Metric Ton)[2]
2012	$2.0	$0.0
2013	$2.0	$0.0
2014	$2.0	$0.0
2015	$2.1	$0.0
2016	$2.1	$0.0
2017	$2.2	$0.0
2018	$2.2	$0.0
2019	$2.3	$14.6
2020	$2.4	$15.7
2021	$2.5	$16.9
2022	$2.6	$18.2
2023	$2.7	$19.5
2024	$2.8	$21.0
2025	$2.9	$22.6
2026	$3.0	$24.3
2027	$3.2	$26.1

1) SO_2 numbers are based on the 8/12/2011 SO_2 Forward Market Curve
2) CO_2 numbers based on guidance contained in Appendix A

Table 15 - Emissions Costs

RULE D.3

A description of each potential power source that was rejected; the capital costs, operating costs, and maintenance costs of each rejected source; and an explanation of the reasons for rejecting each source.

APS estimated the delivered cost of a broad spectrum of potential power sources, including conventional baseload, intermediate, and peaking resources as well as renewable solar, wind, geothermal and biomass/biogas resources. A number of those are represented in the 2012 Resource Plan based on resource need, economics, diversity, and operational characteristics. Attachment D.3 includes the description, capital costs, O&M costs, and performance characteristics for the resource technologies that were selected to be included in the 2012 Resource Plan as well as those technologies that were not selected.

Actual power sources will be acquired through the competitive procurement process detailed in the Action Plan provided in the response to Rule H. Furthermore, actual power sources procured may be different than those currently represented in the plan. The reasons that some of the resource options listed in Attachment D.3 are not represented in the 2012 Resource Plan are as follows:

- APS plans to meet or exceed the RES using a diverse set of renewable resources. Renewable resources represented in the 2012 Resource Plan include solar photovoltaic, solar thermal (trough with storage), wind, geothermal, and biomass/biogas. Though not specifically represented, solar thermal tower technologies could potentially become part of the APS resource mix by 2027,

depending on technology development and the outcome of competitive procurement processes. This technology is not currently included due to lack of commercial operational experience.

- APS does not plan to construct new coal or nuclear resources during the Planning Period. With the downturn in the economy causing a reduction in the load forecast, the amount of planned energy efficiency, and the slight net increase of existing coal generation resulting from the Four Corners transaction, APS does not expect to need new baseload generation during the Planning Period. Therefore, APS has not included new coal, integrated gasification combined cycle (IGCC), or new nuclear resources in its 2012 Resource Plan.

Note that while not in the 2012 Resource Plan, nuclear could potentially be part of a carbon mitigation strategy. For APS to successfully deploy new nuclear generation, other issues would need to be addressed such as cost uncertainty, regulatory treatment, ability to finance, impact on credit ratings, fuel storage, etc.

Attachment D.3 also provides cost and performance estimates for a variety of peaking combustion turbines. Because of the peaked nature of APS's load, as well as the need to integrate renewable generation included in the 2012 Resource Plan into the APS system, a significant increase in highly flexible peaking resources will be required by 2027. For natural gas-fired peaking resources, APS models LMS100 combustion turbines. They are more flexible in their operational characteristics in terms of their ability to quickly start/stop than the other natural gas resources considered. Selection of specific natural gas resources will be made through competitive procurement processes, and may be different than those represented in the plan.

RULE D.4

A 15-year forecast of self generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours).

The 15-year forecast of self generation in terms of annual peak production (MW) is provided in Attachment F.9(b) on line 23 of the Loads & Resources table. The forecast of annual energy production (MWh) is provided in Attachment C.1(b) on the line labeled "Distributed Energy Programs."

RULE D.5

Disaggregation of the forecast of subsection (D)(4) into two components, one reflecting the self generation projected if no additional efforts are made to encourage self generation, and one reflecting the self generation projected to result from the load-serving entity's institution of additional forecasted self generation measures.

In terms of annual peak and energy productions, the self-generation forecast of capacity and energy provided in the response to Rule D.4 assumes additional forecast self-generation measures. A disaggregation of this forecast based on an assumption that future incentives are discontinued is provided in Table 16.

	MW	MWh
2012	65	302,125
2013	75	353,812
2014	88	411,873
2015	96	448,646
2016	92	426,839
2017	91	424,117
2018	98	460,612
2019	103	484,335
2020	117	553,133
2021	139	656,410
2022	165	777,454
2023	196	923,209
2024	232	1,093,841
2025	275	1,294,416
2026	315	1,482,279
2027	353	1,656,856

Table 16 - Discontinuation of Incentives: Low Adoption Rate

A comparison of the low adoption scenario (discontinuation of incentives) to the base case forecast of self-generation is illustrated in Figure 37. The low adoption scenario illustrates customer adoption rates in an incentive-free market meeting or exceeding the rate anticipated where utility incentives still exist within the next five to eight years; however, continued high levels of customer participation using third-party-funded leases may accelerate this timeframe. This is a result of the expectation of a continued decline in photovoltaic system costs during the same time period. This low adoption scenario is based upon the best information available to APS at this time; however, the future of DE penetration is highly uncertain. Adoption could continue to occur even in the face of reduced and/or eliminated incentives due to market conditions and declining PV price curves.

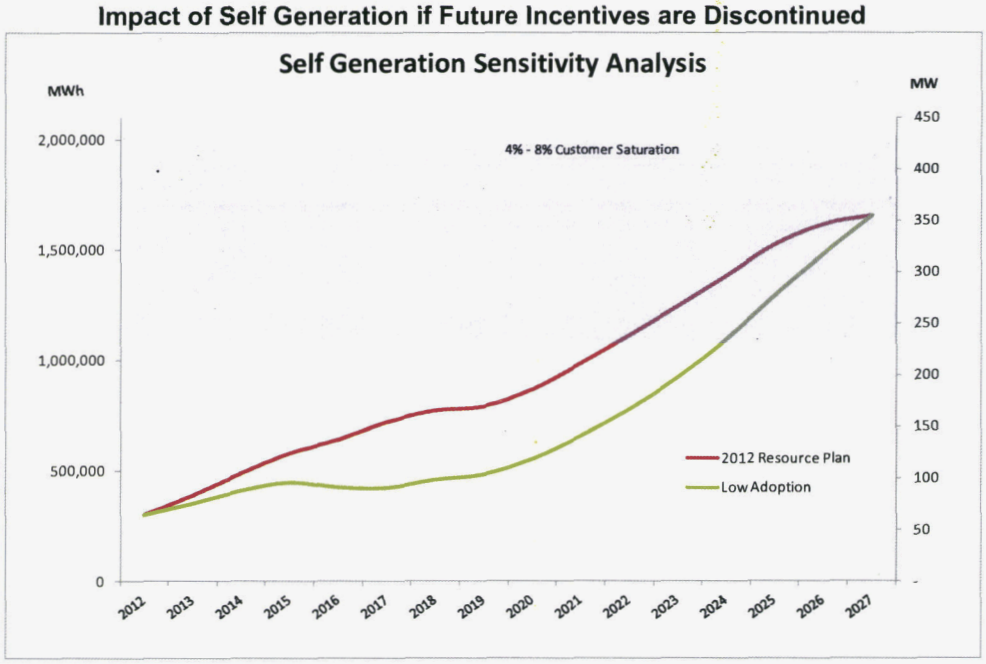

Figure 37 - Sensitivity Analysis of Projected Levels of Self-Generation

RULE D.6

A 15-year forecast of the annual capital costs and operating and maintenance costs of the self generation identified under subsections (D)(4) and (D)(5).

A forecast of total annual customer costs, with and without incentives continuing, that may potentially be incurred by customer investments in self generation during the 15-year planning period are provided in Table 17. [40]

[40] Capital costs represent new installations per year. O&M costs include costs incurred for installations that occurred in previous years.

	Base Case					Low Adoption Scenario			
	Capital		O&M			Capital		O&M	
Year	$M	$/Watt	$M	$/kW-yr		$M	$/Watt	$M	$/kW-yr
2012	[redacted]					[redacted]			
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									

Redacted

Table 17 - Forecast of Annual Self-Generation Costs Incurred by APS Customers

RULE D.7

Documentation of the analysis of the self generation under subsections (D)(4) through (6).

The 2012 Resource Plan reflects data incorporated into the Company's 2012 RES Implementation Plan based on the actual self generation installations and incentive funding commitments as of July 2011. The estimation of the energy output reflected in this case is contingent upon meeting the state-mandated RES rules as set forth in A.A.C. R14-2-1804. The low adoption rate scenario estimates the projected level of self-generation if APS were to discontinue all incentive programs in 2012 through 2027. The development of the low adoption scenario was based upon the best information available to APS at the time; however, the future of DE penetration is highly uncertain. Capacity and energy for both the renewable energy projected in the APS 2012 Resource Plan along with the scenario estimating the low adoption rate are visually represented in the response to Rule D.5.

It is important to note that while the tax credit assumptions included in this model carry considerable weight, that component is not assumed to change from the current plan. Federal tax credits for solar are authorized through 2016.

For each response given to Rules D.4 through D.6, APS assumes "self generation" to be solely renewable-based. APS does not forecast the penetration of diesel- or natural gas-fired standby and emergency generation at this time.

RULE D.8

A plan that considers using a wide range of resources and promotes fuel and technology diversity within its portfolio.

The APS 2012 Resource Plan employs a wide range of resources, both supply and demand side, and promotes fuel and technology diversity within the portfolio. On the supply side, the plan includes new renewable resources such as solar photovoltaic, solar thermal, wind, and geothermal; new natural gas resources such as combustion turbines and combined cycles; a wide variety of energy efficiency measures; and, demand response. The natural gas technologies reflect state-of-the-art power plants – new combined cycle resources are assumed to employ dry-cooling, and new combustion turbines will be highly efficient and operationally very flexible. As illustrated in Figure 38, the 2012 Resource Plan reflects a significant increase in resource diversity over the current energy mix.

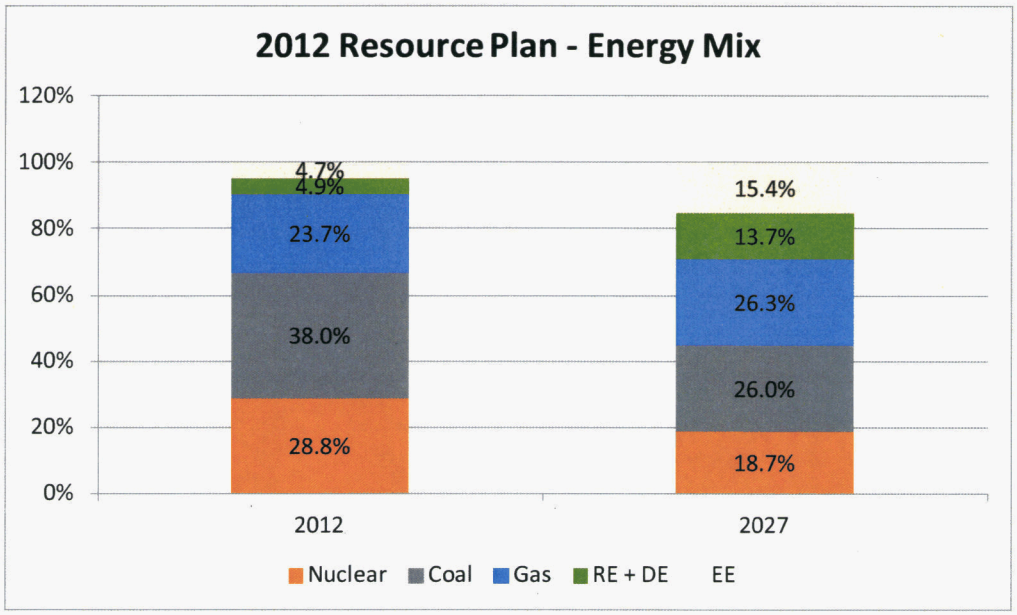

Figure 38 - Energy Mix (2012/2027)

RULE D.9

A calculation of the benefits of generation using renewable energy resources.

The estimated benefits of renewable energy resources (including distributed energy as well as energy from renewable contracts and resources) are listed in Table 18.

Renewable Energy Benefits

	Total Renewable Peak Capacity (MW)	Total Renewable Energy (GWh)	Avoided Gas Burn (BCF)	Avoided Emissions CO2 (Metric Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	Avoided Water Usage (Acre Feet)
2012	205	1,586	12	643,446	4	81	73	20	3	1,543
2013	255	2,118	16	858,864	5	109	98	27	4	2,060
2014	590	3,053	23	1,238,164	7	157	141	38	6	2,970
2015	664	3,459	26	1,402,990	8	177	159	43	7	3,365
2016	691	3,594	27	1,457,545	8	184	166	45	7	3,496
2017	707	3,674	28	1,490,219	8	189	169	46	7	3,574
2018	719	3,730	28	1,512,926	8	191	172	47	7	3,629
2019	782	4,028	30	1,633,854	9	207	186	50	8	3,919
2020	799	4,109	31	1,666,808	9	211	189	51	8	3,998
2021	905	4,861	37	1,971,529	11	249	224	61	9	4,729
2022	953	5,294	40	2,147,079	12	272	244	66	10	5,150
2023	1,019	5,650	43	2,291,748	13	290	260	71	11	5,497
2024	1,094	6,028	46	2,444,939	14	309	278	76	11	5,864
2025	1,148	6,401	48	2,596,151	14	328	295	80	12	6,227
2026	1,179	6,723	51	2,727,027	15	345	310	84	13	6,541
2027	1,193	6,798	51	2,757,121	15	349	313	85	13	6,613
TOTAL			**538**	**28,840,409**	**161**	**3,648**	**3,277**	**891**	**134**	**69,174**

Table 18 - Renewable Energy Benefits

RULE D.10

A plan that factors in the delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup capacity, and transmission delivery.

Revenue requirements for the 2012 Resource Plan are shown in Attachment D.10 and include the delivered costs of all the resource options as described above.

The attached revenue requirements reflect the annual revenue level required to supply APS customers' energy needs, including: (1) carrying costs on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs (commodity and fixed transport); (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency and distributed energy program and incentive costs; and, (6) power plant emission costs including SO_2 and CO_2. Revenue requirements as used in the resource plan filing do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.

Environmental compliance costs are embedded within the capital and O&M figures, and system integration costs are embedded in the purchased power costs for solar photovoltaic and wind technologies. The loads and resources plan factors in backup capacity and those costs are included within the total revenue requirement costs.

RULE D.11

Analysis of integration costs for intermittent resources.

System integration costs may be incurred by operation of some non-dispatchable resources such as wind or solar. Due to their intermittent and/or unpredictable nature, additional operating reserves may need to be carried on the rest of the system to effectively follow APS load and meet NERC reliability requirements. System integration costs depend upon many

factors, including the accuracy of forecasting the variable generation on a day-ahead and hour-ahead basis, real-time fluctuations, penetration levels of the variable resources on the utility system, resource mix, and fuel prices of the utility system. Based on a study performed by Northern Arizona University under the direction of Dr. Tom Acker for the APS system, a system integration cost of $3.25/MWh is added to wind.[41] Because solar generation in Arizona is more predictable than wind, though still intermittent, APS assumes a lower integration cost for solar (without storage) of $2.50/MWh.[42] APS will reevaluate integration costs as renewable penetration increases and more experience is gained in dealing with the integration of intermittent or variable generation.

RULE D.12

A plan to increase the efficiency of the load-serving entity's generation using fossil fuel.

APS operates and maintains the fleet of generating units to optimize efficiency by balancing expenditures with benefits achieved by those expenditures. Opportunities to increase unit efficiency are evaluated on a regular basis from both economic justification and environmental permitting perspectives.

APS's objective is to ensure unit reliability is maintained so that the units are available to meet the load demand. O&M and capital expenditures are planned to maximize equipment reliability, thus reducing the amount of time the units are unavailable due to equipment failures. For baseload units this reduces fuel costs that are incurred during unplanned startups and shutdowns. In addition, proper and timely maintenance reduces replacement power costs that can be incurred during forced outage events.

Plant components are maintained with the objective of meeting the original design performance specifications. When O&M expenditures to maintain the equipment become too high or the component condition is showing signs of degradation that may threaten unit reliability, the component will be evaluated for replacement. In these circumstances, the component will be evaluated for any changes that can be made that will result in improved unit efficiency. This evaluation considers environmental permit impacts to ensure compliance with regulatory requirements.

APS also increases the efficiency of its fossil generation fleet by its resource decisions going forward. For example, APS expects to increase the efficiency of its coal fleet through the execution of the proposed Four Corners transaction. The analysis supporting this transaction assumes retiring the three smaller, less efficient units (~10,750 Btu/kWh heat rate), and acquiring a greater share of the larger, more efficient units (~9,700 Btu/kWh heat rate). With that assumption, APS expects to improve the average heat rate (efficiency) of its coal fleet from 10,400 Btu/kWh to 10,000 Btu/kWh.

As APS adds new natural gas generation to its system, it considers adding generation that is more efficient than previous models. For example, combustion turbines installed in the 1970s had heat rates of about 14,000 Btu/kWh. Newer models such as those recently purchased at Sundance and recently installed at the Yucca Power Plant have heat rates of about 9,700 Btu/kWh. By the time APS installs combustion turbines represented in the 2012 Resource Plan in the second half of this decade, it is likely that the heat rates will be in

[41] APS/NAU Wind Integration Study, 2007.
[42] Western Governors' Association Generation and Transmission Model Methodology and Assumptions, Version 2.0, June 2009.

the 9,000 Btu/kWh range. Actual models and efficiencies will be determined through a competitive procurement process, and will be selected based on cost efficiency. As these higher efficiency units are added to the system, they will operate before the older less efficient units in the dispatch order, and result in more efficient use of natural gas.

Another aspect of efficiency applies to water consumption. If APS constructs new combined cycle generation as envisioned in the 2012 Resource Plan, the new units will likely have about the same heat rates as APS's recently constructed West Phoenix and Redhawk combined cycle generating units, but will use less water. While it is anticipated the new gas turbines will be more efficient, the plants will most likely utilize air-cooled condensers as opposed to conventional cooling towers. The parasitic load associated with operating air-cooled condensers causes a heat rate penalty in summer operating conditions such that the net effect is expected to be a heat rate comparable to the most recently installed combined cycle plants while using much less water.

A forecast of the reduction in water intensity measured as gallons per MWh for the 2012 Resource Plan is included in the response to Rule D.17. Many of the new technologies represented in the 2012 Resource Plan consume little to no water. Energy efficiency and wind generation consume none, while solar photovoltaic and future combustion turbines will have very low consumption rates.

RULE D.13

Data to support technology choices for supply-side resources.

Data to support technology choices for supply-side resources has been provided in Attachment D.3.

RULE D.14(a)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (a) How and when the program or measure will be implemented.

Current Programs

As required by the EE Standard, any proposed DR or EE program must be cost-effective, as evaluated by the Societal Cost Test. More details on the Societal Cost Test can be found in response to Rule D.14(e).

All programs proposed in the Company's 2012 DSM Plan are proven cost-effective and designed to achieve 1.75% of retail annual energy sales (or a cumulative 3.0% from the prior year). This is equivalent to approximately 533,000 MWh based on the EE rule, with the contribution of demand response programs capped at 10% of energy savings goals.[43]

Within the 2012 DSM Plan, thirteen EE programs and twenty DR programs (including eighteen rates) were proposed. This included seventeen residential programs and sixteen non-residential programs. These programs are detailed in Attachment D.14(a).

[43] Energy contribution of demand response programs for EE Standard compliance is based on the 2012 DR MW load reduction x 8760 hours x 50% load factor.

Future Programs

The Company will continue to evaluate existing and emerging technologies and measures to identify cost-effective programs that will deliver annual compliance with EE and DR targets and long-term resource planning needs. Because of the rapidly increasing targets, constant evaluation will be required. When new, unproven measures or technologies are identified, pilots will be crafted and deployed to assist APS in quantifying the resource potential to support future resource planning needs as well as assist in refining the resource cost-effectiveness calculations. Through pilots, APS will be able to gather data regarding the societal and program costs and benefits that can then be used to more accurately depict the program cost-effectiveness and viability.

Standby generation pilots have been identified for targeted deployment beginning in 2013 with a total potential deployment of approximately 150 MW within the fifteen-year resource planning horizon. In an effort to support the 2009 Rate Case Settlement requirements to deploy 250 MW of incremental DR, additional near-term pilots may be developed to better understand the customer participation requirements, churn rates, and offset per event for direct load control and peak events. Additionally, a reevaluation of the cost-effectiveness of thermal energy storage technologies in APS territory is underway to determine when this will become a viable program.

RULE D.14(b)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (b) The projected participation level by customer class for the program or measure.

The projected participation level by customer class for energy efficiency programs and measures is extremely difficult to quantify due to the characteristics and nature of the program in question. For example, for the residential lighting program involving Compact Fluorescent Lamp (CFL) bulbs (where APS has sold over 15 million bulbs since the program's inception), measuring the participation level by customer would involve making assumptions on the number of bulbs the "average" customer would purchase in a given year. As these programs may not exist 15 years into the future, or their components may be markedly different, projecting customer participation is not currently feasible; however, APS does estimate the number of measures needed to meet its goal for each year on a going-forward basis. A projected participation on a measure level is provided at Attachment D.14(b).

Projected demand response and time-of-use program participation is forecast at Table 19 and Table 20.

2012 Residential DR Programs

Time-Differentiated Rates	Expected Participants	
	2012	15 Year Horizon
1. ET-SP Time Advantage Super Peak	600	5,000
2. ET-1 Time Advantage (9am-9pm)	157,307	0
3. ECT-1R Combined Advantage (9am-9pm)	28,783	0
4. ET-2 Time Advantage (Noon – 7pm)	263,428	724,401
5. ECT-2 Combined Advantage (Noon – 7pm)	70,976	172,199
6. ET-EV Experimental Electric Vehicle Charging Rate Schedule[44]	560-630	15,000+
7. Peak Event Pricing[45]	1,000	5,000
8. Peak Time Rebate[46]	0	5,000
9. Home Energy Information Pilot	2,000	10,000-75,000

Table 19 - Expected Residential DR Program Participation

[44] Range provided is based on low-to-high EV and plug-in hybrid EV ("PHEV") sales projections.
[45] Customers are included in the parent rate schedule.
[46] Not expected until 2013, when APS anticipates 1,000 participants. Customers included in the parent rate schedule.

2012 Non-Residential DR Programs

Time-Differentiated Rates	Expected Participants	
	2012*	15 Year Horizon
1. E-20	408	408
2. E-221-8T	49	43
3. E-32 XS TOU	415	612
4. E-32 S TOU		
5. E-32 M TOU		
6. E-32 L TOU		
7. E-35	39	39
8. GS-Schools M	17	30
9. GS-Schools L		
10. Interruptible Rate[47]	0	8
11. Peak Solutions[48]	3,000	0

Table 20 - Expected Non-Residential DR Program Participation

* Total participants as of December, 2011

As more cost-effective EE measures and technologies are identified and standby generation, direct-load control, and thermal energy storage pilots are deployed, additional customer participation is expected. These pilots will assist in identifying long-term customer participation and revised customer offsets per event. Updated participation numbers will be included in the annual DSM filing.

RULE D.14(c)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (c) The expected change in peak demand and energy consumption resulting from the program or measure.

Depicted in Table 21 are the capacity and annual energy savings anticipated for 2012 energy efficiency programs. As related in response to Rule D.14(b), projecting a programmatic breakdown out 15 years into the future is not currently feasible; however, Attachments C.1(a) and C.1(b) provide annual aggregate capacity and energy savings forecasts.

Projections of future demand response and time-of-use impacts are located in Table 22.

[47] Not expected until 2013, when APS anticipates 3 participants. Customers included in the parent rate schedule.
[48] The underlying contract that supports this program expires at the end of 2024.

2012 Residential and Non-Residential EE Programs[49]

Program Name	Capacity Savings (MW)	Annual MWh Savings
Residential		
Consumer Products	13.4	135,000
Existing Homes	21.4	34,000
New Construction	6	11,000
Appliance Recycling	2.2	15,000
Low Income	0.3	2,000
Conservation Behavior	4.3	31,000
Multifamily	0.9	6,000
Shade Trees	0.5	1,000
Residential Sub-Total	**48.9**	**235,000**
Non-Residential		
Large Existing Facilities	21	152,000
New Construction	3.9	27,000
Small Business	7.2	32,000
Schools	4.4	33,000
Energy Information System	0.1	1,000
Non-Residential Sub-Total	**36.6**	**245,000**
Total	**85.5**	**480,000**

Table 21 - 2012 Energy Efficiency Capacity and Energy Contributions

2012 Residential and Non-Residential DR Programs

	2012		15 Year Horizon	
DR Programs	**Peak Demand Reduction (MW)**	**Annual Energy Reduction (MWh)[50]**	**Peak Demand Reduction (MW)**	**Annual Energy Reduction (MWh)**
Residential				
Future Direct Load Control	0	N/A	125	N/A
Non-Residential				
Peak Solutions[51]	100	N/A	0	N/A
Standby Generation	0	N/A	150	N/A
Future Programs	0	N/A	75	N/A
Time-of-Use Rates[52]	109	540	212	4,338

Table 22 - Expected DR Program Energy and Demand Contributions

[49] Numbers represent peak demand and energy reduction goals for 2012 as described in the APS 2012 DSM Implementation Plan filed with the ACC on 6/24/2011.

[50] While demand response programs are not anticipated to provide energy savings, they are allowed to contribute towards the EE Standard. Peak Solutions is calculated as contributing 438,000 MWh in 2012 towards the EE Standard.

[51] Expires prior to the end of the Planning Period.

[52] Demand reductions are estimated for all current residential rates, and energy reduction is estimated only for ET-SP and CPP-RES. APS has not at this time completed energy reduction analyses for the remaining residential rates, and has not conducted energy or demand reduction analyses for the non-residential rates.

Measurements, evaluation and research (MER) is a critical process for verification of EE program savings and cost effectiveness. Annually, APS contracts with a third-party consultant to measure and evaluate the EE programs and provide adjustments to calculations and processes that are then included in the Company's annual DSM Implementation Plan filing. The savings represented in the 2012 Resource Plan reflect updates from the 2011 EE programs measurement and evaluation results.

RULE D.14(d)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (d) The expected reductions in environmental impacts including air emissions, solid waste, and water consumption attributable to the program or measure.

EE programs as well as APS's non-residential load control and demand response pricing programs are all assumed to displace natural gas-fired generation. Because DR programs are designed to reduce only the top 1-2% of hours in the year, the impact is very small compared to EE programs that would encompass all hours.

Table 23 provides estimates of 2012 energy efficiency environmental impacts.

2012 Residential and Non-Residential EE Programs
Reduction of Environmental Impact

Residential					
	Water (Mil Gal)	SOx (lbs)	NOx (lbs)	CO_2 (Mil lbs)	PM10 (lbs)
1. Consumer Products	232	3,252	61,787	657	18,050
2. Existing Homes	116	1,625	30,880	328	9,021
3. New Construction	69	975	18,253	197	5,411
4. Appliance Recycling	29	406	7,719	82	2,255
5. Low Income Weatherization	11	156	2,957	31	864
6. Conservation Behavior Pilot	10	139	2,632	28	769
7. Multi-Family Construction	17	232	4,407	47	1,287
8. Shade Tree	6	90	1,714	18	501
Residential TOTAL:	490	6,875	130,619	1,389	38,158
Non-Residential					
1. Large Existing Facilities	649	9,104	172,985	1,839	50,535
2. New Construction	130	1,825	34,680	369	10,131
3. Small Business	165	2,318	44,033	468	12,863
4. Schools	147	2,063	39,205	417	11,453
5. Energy Information Systems	3	44	844	9	247
Non-Residential TOTAL:	1,094	15,355	291,747	3,102	85,229

Table 23 - 2012 EE Estimated Environmental Impact

The reductions in environmental impact for all existing DR programs are currently being evaluated, but are not available at this time. The estimated impacts on air emissions for the experimental residential peak event pricing and super peak programs are shown in Table 24.

2012 Residential Peak Event Pricing and Super Peak Pricing Programs Estimated Reduction in Air Emissions

	SOx (lbs)	NOx (lbs)	CO2 (Mil lbs)
Peak Event Pricing	0.3	4.9	0.047
Time Advantage Super Peak	0.4	7.8	0.083
TOTAL:	0.7	12.7	0.130

Table 24 - Estimated Environmental Impact from Select Rates

Estimated reductions in environmental impacts for APS's Peak Solutions program are shown in Table 25.[53]

	CO2 lbs	NOx lbs	PM10 lbs	SOx lbs	Water gallons
2008	0	0	0	0	0
2009	0	0	0	0	0
2010	19,401	2	1	0	6,878
2011	121,540	13	3	1	43,087
2012	1,141,223	118	32	6	404,570
2013	1,141,223	118	32	6	404,570
2014	1,141,223	118	32	6	404,570
2015	228,245	24	6	1	80,914
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
Total	3,792,853	391	106	19	1,344,587

Table 25 - Environmental Impact of Peak Solutions

[53] Estimates are only shown through 2015 as the current load forecast does not require the dispatch of this resource after that time period.

For other potential load reduction programs such as thermal energy storage, standby generation, and residential direct load control, the estimated environmental reductions are provided in the Demand Response Study.[54]

RULE D.14(e)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (e) The expected societal benefits, societal costs, and cost-effectiveness of the program or measure.

All DSM programs implemented must be proven cost-effective through the societal benefit-cost test (SCT). The SCT is structurally similar to the Total Resource Cost Test (TRC) but goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). The main difference between the SCT and TRC tests is the use of a societal discount rate and the capability to include the value of other societal benefits such as avoided environmental externalities (avoided pollution costs), non-energy benefits, reliability benefits, and fuel diversity.

While EE programs have long-established benefit-cost tests and measures, the real impact of load control and demand response pricing programs is the impact to peak capacity requirements. These programs behave similarly to a gas-fired generator by meeting the utility's load serving requirements via a reduction in the utility's load rather than by an increase in total generation. The 2008 Demand Response Study conducted an analysis of various DR programs based on estimated participation levels and the associated costs and benefits.

Table 26 provides details on the societal benefits, societal costs, and cost-effectiveness of the existing EE programs. As additional programs and measures are proposed in the Company's annual DSM Implementation Plans, the cost-effectiveness of each program will have a benefit-cost ratio greater than 1.0, indicating that the programs are net benefits to both APS and its customers.

[54] 2008 DR Study was filed in Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827 on June 27, 2008.

2012 Residential and Non-Residential EE Programs
Societal Costs, Benefits and Cost-Effectiveness

Residential				
	Societal Benefits ($1,000s)	**Societal Costs ($1,000s)**	**Net Benefits ($1,000s)**	**Benefit-Cost Ratio**
1. Consumer Products	37,056	8,161	28,895	4.54
2. Existing Homes	36,020	29,289	6,731	1.23
3. New Construction	21,619	9,570	12,049	2.26
4. Appliance Recycling	4,804	1,426	3,378	3.37
5. Low Income Weatherization	2,527	2,527	0	1.0
6. Conservation Behavior Pilot	1,240	1,048	192	1.18
7. Multi-Family Construction	2,959	1,929	1,030	1.53
8. Shade Tree	2,102	980	1,122	2.14
Residential TOTAL:	108,327	54,930	53,397	1.97
Non-Residential				
1. Large Existing Facilities	120,958	35,329	85,629	3.42
2. New Construction	25,109	6,706	18,403	3.74
3. Small Business	35,741	5,756	29,985	6.21
4. Schools	27,316	7,235	20,081	3.78
5. Energy Information Systems	645	103	542	6.26
Non-Residential TOTAL:	209,769	55,129	154,640	3.81

Table 26 - Benefit-Cost Ratios for EE Programs

The societal benefits, societal costs, and cost-effectiveness of future demand response programs are currently not known, as those programs have yet to be developed. Time-of-Use pricing programs are inherently designed to be revenue neutral. The societal benefits, societal costs, and cost effectiveness of APS's non-residential load management program, Peak Solutions, can be found in Table 27.

APS Peak Solutions Program
Societal Costs, Benefits and Cost-Effectiveness

	Societal Benefits ($1,000s)	**Societal Costs ($1,000s)**	**Net Benefits ($1,000s)**	**Benefit-Cost Ratio**
APS Peak Solutions	72,186	52,987	19,198	1.36

Table 27 - APS Peak Solutions Benefit-Cost Ratio

RULE D.14(f)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (f) The expected life of the measure.

Demand response pricing programs do not have a "measure life"; however, the established rate plans are expected to be in place throughout the Planning Period. The APS Peak Solutions program has been contracted through 2024. Table 28 presents the estimated measure life (in years) by EE program.

2012 Residential and Non-Residential EE Programs
Program and Measure Life

Residential	**Years**
1. Consumer Products	5.4
2. Existing Homes	10.7
3. New Construction	19.9
4. Appliance Recycling	6.1
5. Low Income Weatherization	17.5
6. Conservation Behavior Pilot	1.0
7. Multi-Family Construction	8.6
8. Shade Tree	20.0
Non-Residential	
1. Large Existing Facilities	13.5
2. New Construction	15.2
3. Small Business	16.3
4. Schools	14.1
5. Energy Information Systems	10.0

Table 28 - Expected Life of EE Programs

RULE D.14(g)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (g) The capital costs, operating costs, and maintenance costs of the measure, and the program costs.

The estimated costs for EE programs are included in the Table 29.

2012 Residential and Non-Residential EE Programs[55]
Program Costs

Residential	**Program Cost ($1,000s)**
1. Consumer Products	7,605
2. Existing Homes	15,629
3. New Construction	3,608
4. Appliance Recycling	1,734
5. Low Income Weatherization	2,779
6. Conservation Behavior Pilot	1,053
7. Multi-Family Construction	1,858
8. Shade Tree	447
Residential Program TOTAL:	34,713
Non-Residential	
1. Large Existing Facilities	18,124
2. New Construction	3,498
3. Small Business	4,654
4. Schools	3,614
5. Energy Information Systems	78
Non-Residential Program TOTAL:	29,968

Table 29 - EE Program Costs

The APS Peak Solutions program is administered through a contract with a third-party provider through 2024 that includes both energy and capacity payments. The expected program costs through the term of the Peak Solutions contract can be found in the Table 30.

[55] MER costs are an additional $2,500,000; the EE Performance Incentive is an additional $9,550,000.

Peak Solutions Program Costs

	[redacted]
2012	8,665
2013	[redacted]
2014	[redacted]
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]

Redacted

Table 30 - Forecasted Costs for APS Peak Solutions

Capital and O&M costs for potential customer load management and generation programs such as residential direct load control, thermal energy storage, or standby generation have been estimated in the Company's 2008 Demand Response Study. Once completed, the HEI Pilot will assist in quantifying the expected capital and O&M costs for future residential demand response and energy efficiency programs. Additionally, prior to the launch of the proposed standby generation pilot, updated capital and O&M costs will be gathered for various methods of deployment (e.g., harvesting of existing equipment and deployment of new equipment) to determine the most cost-effective program model.

RULE D.15

For each demand management measure that was considered but rejected: (a) A description of the measure; (b) The estimated change in peak demand and energy consumption from the measure; (c) The estimated cost-effectiveness of the measure; (d) The capital costs, operating costs and maintenance costs of the measure, and the program costs; and, (e) The reasons for rejecting the measure.

In 2007, APS commissioned an energy efficiency baseline study to review the technical, economic, and market potential for hundreds of residential and non-residential EE measures. In this study, a specific measure's energy savings, peak demand savings, resource cost, and multiple benefit-cost analyses were performed. APS then took the information gained from the baseline study and applied additional APS-specific data to determine the most beneficial programs to pursue from an energy reduction perspective; however, when the societal cost test was applied to these measures, the benefit-cost ratio was not greater than 1.0 and the measure was rejected.

Table 31 details the response to rules D.15(a) through D.15(d) for the EE measures that were considered but rejected. In response to D.15(e), all of the programs listed were not

pursued due to their not passing the SCT requirement. APS will continue to reevaluate beneficial measures and propose in subsequent DSM filings.

Residential and Non-Residential EE Programs
Rejected Measures and Programs

Rule D.15a	Rule D.15(b)		Rule D.15(c)	Rule D.15(d)
Description of the Measure	**kW Savings in peak demand (per unit)**	**kWh savings in energy consumption (per unit)**	**Estimated cost-effectiveness of the measure (SCT Result)**	**Incremental Measure Cost (per unit)**
Residential Clothes Washer Tier 1 (existing)[56]	0.02	163	0.2	$301.20
Residential Clothes Washer Tier 2 (existing)	0.03	202	0.4	$364.46
Residential Clothes Washer Tier 3 (existing)	0.03	232	0.5	$427.72
Residential Clothes Washer Adv (proposed)[57]	0.04	280	0.7	$467.33
Residential Clothes Washer Tier 1 (proposed)	0.03	202	0.7	$183.53
Residential Clothes Washer Tier 2 (proposed)	0.03	232	0.7	$283.67
Residential Clothes Washer Tier 3 (proposed)	0.04	258	0.8	$266.81
Residential Heat Pump Water Heaters	0.15	1,350	0.9	$1,191.62
Non-Residential Window Films	0.00	3	0.9	$5.00
Non-Residential Gaskets	0.01	104	0.8	$11.50

Table 31 - Rejected EE Measures and Programs

Due to the more limited nature of load reduction and management solutions on the market and direction from the Commission, APS conducted the 2008 Demand Response Study that reviewed demand response programs that could be implemented and their associated

[56] Existing clothes washer refers to clothes washers that are currently available on the market.
[57] Proposed clothes washer refers to the next generation of clothes washers that are not commercially-available today.

benefits-costs to APS and its customers. To date, no specific DR program has been rejected; however, APS developed the HEI Pilot to further the Company's understanding of residential DR.

RULE D.16

Analysis of future fuel supplies that are part of the resource plan.

A thorough and comprehensive fuel supply outlook for the period of 2011-2035 was prepared by IHS CERA for APS. IHS CERA's outlook for the North American gas and power sectors encompasses the fundamental technological, environmental, and economic factors driving the expectations for natural gas, coal, uranium, renewable energy, emissions costs, supply, demand, and prices from 2011 to 2035. In addition to the report providing an outlook for North America (48 states and Canada) as a whole, there is also added detail for the U.S. Western Region (comprising the Rocky Mountain states and states to the West), and the AZNMNV (Arizona-New Mexico-Nevada) power pool region. Based on this research, APS does not foresee any fuel supply issues during the Planning Period. A copy of this report will be provided upon request to the ACC under a confidentiality agreement.

RULE D.17

A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

Overview of Environmental Impacts

Emissions from fossil fuel-fired electric power generating facilities are highly regulated to protect public health and welfare through a myriad of programs administered at the federal, state, and local levels. Federal laws also provide for periodic tightening of emission reduction requirements as knowledge is gained as to the health impacts of pollutant emissions and emission control technologies.

EPA is currently pursuing an aggressive regulatory agenda with an unprecedented number of anticipated new and revised regulations on the horizon. Those regulations will likely govern byproducts of fossil-fuel combustion to generate electricity, air pollutant emissions, and solid and liquid waste discharges. Compliance with these emerging regulatory requirements will pose challenges to APS's ability to deliver reliable electric services at affordable costs. That being said, emissions from APS power plants have been reduced significantly in recent years. For example, SO_2 emissions have decreased by nearly 60% since 2003 as a result of the voluntary installation of additional pollution controls at the Cholla and Four Corners coal-fired power plants. APS will continue to proactively plan for and respond to future regulatory changes, and will be in full compliance by the deadlines established by law.

As part of the overall plan to reduce environmental impacts, APS filed an application on November 22, 2010, proposing to retire Four Corners Units 1-3 and purchase Southern California Edison's share of Units 4 and 5. The proposed transaction would result in reduced air emissions (see Figure 39), less solid waste from coal ash, and a reduction in water use. If this application is approved and the Company accelerates the retirement of Units 1-3, which are less efficient, the plant's capacity will be reduced from 2,100 MW to 1,540 MW and additional emission controls will be installed on Units 4 and 5, which are the more efficient units. As a result, the plant will burn approximately 2.6 million fewer tons of coal each year.

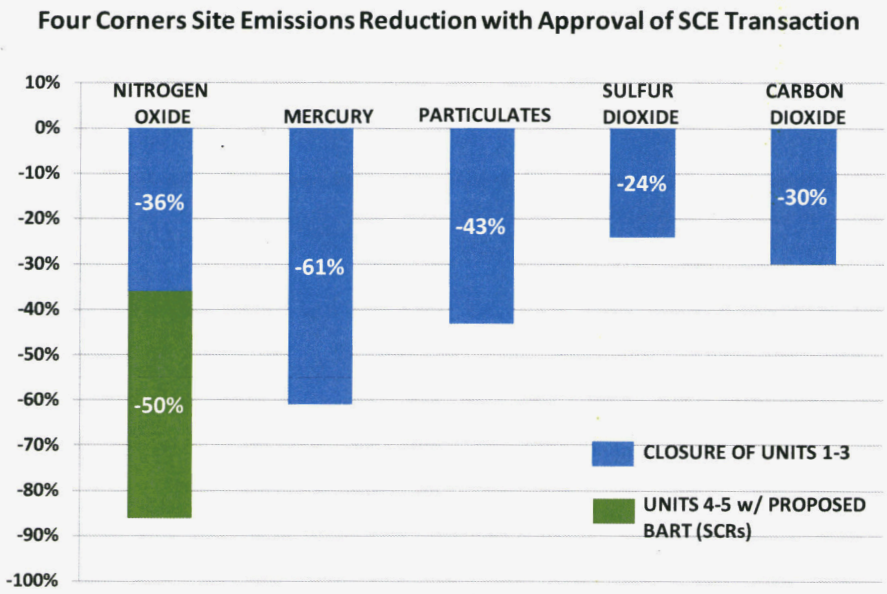

Figure 39 - Four Corners Site Emissions Reduction After Four Corners Transaction

The APS response to Rule D.17 is structured as outlined in the following matrix:

Issue	*Governing Regulations*	*Applicable Section*
Air Emissions	Clean Air Act Regulations 1. Visibility Protection–Regional Haze (BART) 2. Hazardous Air Pollutants – (MATS) 3. National Ambient Air Quality Standards (NAAQS) 4. Climate Change and GHG Regulations	A
Solid Waste	Resource Conservation and Recovery Act (RCRA): Coal Combustion Residuals	B
Other Factors	Clean Water Act Regulations: Section 316(b) Cooling Water Intake Structures	C
Water Consumption	Voluntary APS participation in various state and local initiatives	D

Table 32 - D.17 Governing Regulations

The sections below provide APS's plans to address each area of reduction and are prefaced with an overview of applicable existing and proposed environmental regulations and equipment. APS provides descriptions of its plans to comply with potential outcomes of those regulatory processes. As more information becomes available regarding proposed environmental regulations, the potential control technologies and timeframes for installation may change.

A. APS Plan for reducing Air Emissions under Clean Air Act Regulations

The CAA established numerous regulatory programs to protect public health and the environment. APS plants are equipped with all the currently required environmental monitoring and control equipment. This section describes a potential plan for using existing or additional equipment to reduce air emissions to meet requirements.

benefits-costs to APS and its customers. To date, no specific DR program has been rejected; however, APS developed the HEI Pilot to further the Company's understanding of residential DR.

RULE D.16

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Potential Plan for Reducing Air Emissions

Potential Regulation	Environmental Issue	Potential Future Control Technologies[1]	Design & Construction Timeframe 2012 2013 2014 2015 2016 2017
Four Corners (Units 4-5) Best Available Retrofit Technology (BART)	NOx - Visibility	Selective Catalytic Reduction (SCR)	
Mercury and Air Toxics Standards (MATS)	Hg, non-Hg heavy metals, and acid gasses	Activated Carbon will be needed	
Cholla	SO_2/PM	Unit 2 fabric filter (PM) installation & scrubber upgrade (SO_2) planned for 2014	
Best Available Retrofit Technology (BART)	NOx	ADEQ approved existing low NOx burners & overfire air; EPA may require SCR	
Mercury and Air Toxics Standards (MATS)	Hg, non-Hg heavy metals, and acid gasses	Existing fabric filters & scrubbers; Brominated Activated Carbon Injection; Unit 2 fabric filter installation & scrubber upgrade planned for 2014	
NGS **Best Available Retrofit Technology (BART)**	NOx	Existing low NOx burners and overfire air may meet standard; EPA may require SCR	
Mercury and Air Toxics Standards (MATS)	Hg, non-Hg heavy metals, and acid gasses	Modifications TBD by plant operator (SRP)	

Assumptions / Notes
1) Potential regulations are under development. Technologies and requirements for compliance are subject to change.

Table 33 - Potential Environmental Regulations Related to Air Quality

1. Visibility Protection -- Regional Haze BART

Background

The 1977 CAA Section 169(A) established a "national visibility goal" to eliminate human-caused visibility impairment in 156 "Class I Areas" (large National Parks and Wilderness

Areas, including the Grand Canyon National Park in Arizona and the Mesa Verde National Park in Colorado). EPA was directed to issue regulations to make "reasonable progress" toward the visibility goal. During the 1980s and 1990s, the focus of the visibility regulatory program was SO_2 emissions from western coal-fired power plants and application of BART for SO_2 and particulate emissions.

The 1990 CAA Amendments established the Grand Canyon Visibility Transport Commission with a charge to assist EPA in developing Regional Haze regulations. Among other measures, EPA's 1999 Regional Haze Rule called for application of BART for SO_2, PM, and NOx emissions from facilities that were constructed before 1977 and were operational after 1962 (designated "BART-eligible" sources).

Potential impacts on APS Operations (See Table 33)

Four Corners Power Plant

Four Corners consists of 5 units, all BART-eligible. All units are equipped with scrubbers removing around 90% of SO_2 emissions and older generation "low NOx burners" (LNBs). The smaller Units 1-3 remove particulates with Venturi scrubber systems while Units 4 and 5 use fabric filters.

In October 2010 EPA formally proposed a BART Rule for Four Corners. The rule if finalized would require APS to install additional NOx controls on all five units at the plant by 2016 or cease operations. On November 24, 2010, APS submitted a letter to EPA proposing an alternative to EPA's October BART proposal. Specifically, APS proposed to close Four Corners Units 1-3 by 2014 and to install post-combustion pollution controls for NOx on Units 4 and 5 by the end of 2018, provided that EPA agreed to resolution of other related issues. On February 10, 2011, EPA published a Supplemental BART proposal, wherein EPA proposed adoption of much of APS's November 2010 proposal, with revision of the NOx emission limitation for Units 4 and 5 to 0.098 lb/MMBtu, rather than the 0.11 lb/MMBtu proposed by EPA in October 2010. EPA has not finalized either the October 2010 or February 2011 BART proposals.

Cholla Power Plant

Cholla consists of four units; Units 2, 3, and 4 are BART-eligible units.[58] All units are equipped with SO_2 scrubbers, LNBs, and over-fire air (OFA). Units 3 and 4 have fabric filters to control particulates. Unit 2 is planned to be equipped with fabric filters which are scheduled to go in service in 2014. The Cholla Power Plant is regulated by the Arizona Department of Environmental Quality (ADEQ). ADEQ issued its proposed Regional Haze State Implementation Plan (SIP) in November 2010, which concluded the existing controls on all units (plus the fabric filter scheduled for Unit 2) constitute BART for all three pollutants. EPA has indicated it may disapprove certain elements of the Cholla BART analysis contained in the State's proposed regional haze implementation plan; however, APS believes that the Cholla BART analysis is both technically and legally correct and will support the state's Regional Haze SIP.

[58] Cholla Unit 1 went into service on May 1, 1962, which is prior to the August 7, 1962 BART eligibility date.

Navajo Generating Station

NGS consists of three identical 750 MW units which are all BART-eligible. They are equipped with scrubbers to remove 90% of the SO_2 emissions, LNBs to reduce NOx emissions and high-efficiency electrostatic precipitators (ESPs) to control particulate emissions. Similar to Four Corners, EPA required NGS to conduct a BART analysis, except that only NOx emissions were the focus of the BART process. EPA will address BART at NGS in a separate rulemaking, and has indicated that it will not issue a proposed rule until the Four Corners BART matter is finalized.

2. Mercury and Air Toxics Standard (MATS)

In the 1990 CAA Amendments, Congress established a new program designed to control HAPs. The program listed 187 HAPs and directed EPA to develop sector-by-sector regulatory programs requiring the application of "maximum achievable control technology" (MACT) standards – removal efficiency requirements, based on the best-performing control technologies available – to reduce HAPs emissions. Within the utility sector, the HAPs issue has focused primarily on mercury (Hg) emissions from coal-fired plants.

EPA signed the final MATS rule on December 16, 2011. The rule sets forth MACT standards and requirements for reducing mercury and other HAPs emissions from certain electric generating units. Under MATS the limit for Hg emissions from existing units was established at 1.2lb/trillion BTU.

Sources will have three years to comply with the MATS; however, EPA has endorsed the use of authority in the Clean Air Act for state permitting agencies to grant a fourth year to comply if needed for the installation of control systems if the source can establish adequate justification for the extension.

Potential Impacts on APS Operations (See Table 33)

Four Corners

Units 4 and 5 are already equipped with fabric filters and it is expected that they will be capable of meeting the required limits with operational changes only. If these operational changes are determined not to be sufficient, brominated active carbon injection may be required to ensure APS achieves the limits established in the MATS. Units 1-3 are not equipped to control HAP emissions within the limitations established in the MATS. Accordingly, those units, if not shut down as currently planned, would need to be retrofitted with fabric filters and potentially ACI to achieve the limit.

Cholla

MATS compliance is required by 2015, or 2016 if extended for an additional year as allowed under the rule. Cholla Units 1, 3 and 4 are equipped with fabric filters to control Hg and APS plans to retrofit Unit 2 with fabric filters by 2014. Activated carbon will be required.

Navajo Generating Station

NGS does not have fabric filters on any of its three units; instead, it is equipped with ESPs. Salt River Project, the plant operator, has been testing to identify an alternative to reduce emissions.

3. National Ambient Air Quality Standards (NAAQS)

The CAA established NAAQS for six pollutants: ozone, NO_2, SO_2, PM, CO, and, lead. These standards are set to protect public health and welfare. SIPs govern how emissions from various sources within a geographical area would be limited to attain the NAAQS levels. Such plans will set maximum allowed emission limits for various sources. The CAA also requires EPA to periodically review those standards and adjust the NAAQS levels based on the most current scientific data. A discussion of changes to the NAAQS and potential impacts of those NAAQS on APS operations is provided below. APS plans to follow the implementation of these changes to the NAAQS levels closely and to develop appropriate strategies to respond to future requirements as appropriate.

Impacts on APS Operations (None identified at this time)

Ozone

Ozone is formed in the air by chemical reactions between its precursors, NOx and volatile organic compounds (VOC), in the presence of sunlight. Accordingly, regulations to protect public health from exposure to ozone are directed at limiting NOx and VOC emissions from various sources.

All APS-owned coal-fired power plants and those gas/oil plants outside the Phoenix metro area are located in areas that are currently in attainment for ozone NAAQS. No additional NOx controls are planned for those facilities to comply with this standard.

Two actions are significant relative to the ozone NAAQS and APS generation facilities in Maricopa and Pinal counties. In 2009 ADEQ recommended the EPA classify portions of Maricopa and Pinal counties as non-attainment areas for ozone under the existing standard. In addition, the standard for ozone is under regulatory review and may be lowered from the existing 0.75 ppm to between 0.6 and 0.7 ppm, as early as 2013. APS believes the EPA will act on the ADEQ recommendation in 2012 and require the development of a SIP by 2015. Lowering the standard will be analyzed in 2013, and if adopted would worsen the severity of the non-attainment classification, potentially impacting the requirements of the SIP; however, since the major source of ozone in these areas is predominantly related to transportation, APS expects SIP requirements will focus on addressing transportation sources. While the implementation plan could include additional requirements on generation sources located in the non-attainment areas, APS currently has no plans for additional emission reductions at this time.

SO_2

Recently, EPA tightened the primary SO_2 NAAQS by establishing a new 1-hour SO_2 standard. Although all APS coal facilities are currently located in attainment areas, the new standard employs a more stringent modeling methodology for determining attainment status. New designations should be listed by June 2012. APS has no plans for additional SO_2 emission reductions; however, if the methodology results in a change in the current designation from attainment to non-attainment, additional SO_2 emission reductions measured could be required.

NOx

Recently, EPA also tightened the NOx NAAQS. Like it did for the SO_2 NAAQS, EPA may require the use of modeling to demonstrate attainment. The EPA is requiring the states to move monitors closer to roadways to pick up more of the motor vehicle NOx emissions before determining classifications. The state will submit non-attainment designations to EPA and SIPs will be required thereafter. It is unclear at this point whether the new NOx NAAQS will impact APS.

PM10

The non-attainment area of interest to APS at this time is the Phoenix metro area. Even if APS operations are not subject to any emission reduction requirements, there could be indirect impacts on APS due to constraints on economic activity and growth in the area. EPA is considering tightening this standard in the future.

PM2.5

Areas in the vicinity of all APS power plants including the Phoenix metro area are currently in attainment of the existing PM2.5 standard; however, EPA is in the process of developing a more stringent standard, and the Phoenix metro area may be designated non-attainment. Should this occur, APS may be required to install additional emission reduction controls; however, at this time it is not possible to predict what those requirements would be. The Phoenix metro area could be classified as non-attainment based on non-compliance due to dust storms and the re-entrainment of particulates deposited from the surrounding desert.

4. Climate Change and GHG Regulations

With respect to electric generating units, the main GHG targeted by the EPA is CO_2, a byproduct of fossil fuel combustion. Man-made CO_2 emissions in the United States (six billion tons/year, or about 5% of total CO_2 emissions) come from mobile sources, power generation, and industrial/commercial activities. Roughly 85% of CO_2 emissions associated with power generation come from coal combustion.

GHGs are air pollutants under the CAA and EPA has made a determination that the mix of atmospheric concentrations for six key GHGs threatens the public health and welfare of current and future generations (also known as the "endangerment finding"). The endangerment finding is being litigated and the outcome of GHG-related regulations and their impact on APS operations cannot be predicted.

APS Plans for Reducing CO_2 Emissions Rates

Currently, APS emits about 15.3 million metric tons of CO_2 per year. APS estimates that electricity sales will increase by approximately 55% by 2027; however, under its 2012 Resource Plan APS anticipates CO_2 emissions to have a slight increase over current levels, but anticipates a reduction in the emission rate of CO_2 of approximately 26% by 2027 as illustrated in Figure 40. The Resource Plan calls for energy efficiency programs, renewable energy, and gas-fired generation to be used to meet forecast energy growth, all positively impacting the amount of CO_2 emitted by APS.

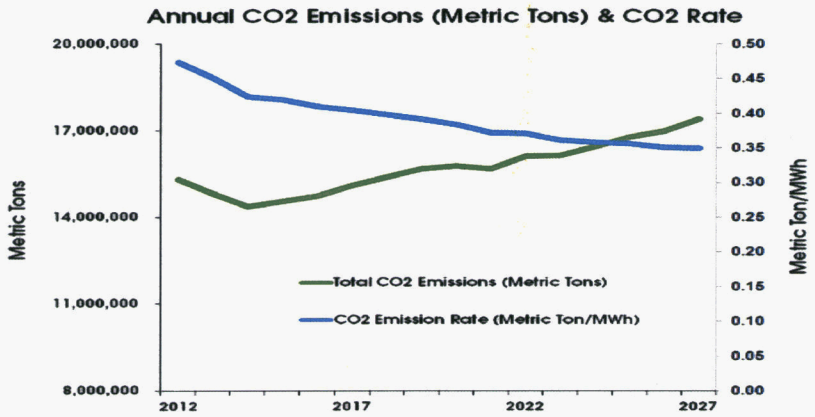

Figure 40 - Annual CO_2 Emissions and Rate

B. APS Plan for Addressing Resource Conservation and Recovery Act (RCRA) Solid Waste Regulations

Potential Environmental Regulations related to Solid Waste[1]			Engineering & Installation Timeframe				
Potential Regulation	**Environmental Issue**	**Potential Future Control Technologies[1]**	**2012**	**2013**	**2014**	**2015**	**2016**
Four Corners (Units 4-5) (includes APS and SCE shares) **Coal Combustion Residuals (CCR) (Subtitle D)**	Potential contaminants of coal ash disposed in surface impoundments and landfills	Close lined ash impoundment & evap. pond; construct new pond; install liners					
Cholla **Coal Combustion Residuals (CCR) (Subtitle D)**	Potential contaminants of coal ash disposed in surface impoundments and landfills	Close lined ash impoundment & evap. pond; construct new pond; install liners					
NGS **Coal Combustion Residuals (CCR) (Subtitle D)**	Potential contaminants of coal ash disposed in surface impoundments and landfills	Modifications TBD by plant operator (SRP)					

1) Proposed regulations are under development. Technologies and requirements for compliance are subject to change.

Table 34 - Coal Combustion Residuals

In December 2008, a surface impoundment dam at the Tennessee Valley Authority (TVA) Kingston Power Plant failed causing millions of gallons of CCRs to spill into the surrounding area. CCR is a term used to describe byproducts of coal combustion in electric steam generating units and consists primarily of a combination of fly ash, bottom ash, and flue-gas desulfurization sludge from the plant's pollution control equipment.

As a result of the TVA incident, Congress directed EPA to develop a federal regulatory program to address management of CCRs under the RCRA. CCR disposal is currently regulated under state programs, such as the Aquifer Protection Permit program in Arizona. After much controversy, EPA issued proposed regulations in June 2010, and sought public input and comment on two regulatory proposals – a hazardous waste regulatory approach under RCRA Subtitle C, and a non-hazardous solid waste approach under RCRA Subtitle D. The public comment period closed November 18, 2010, and EPA is expected to issue a final rule in 2012.

APS has assumed Subtitle D requirements (non-hazardous) for the 2012 Resource Plan. The following information includes an analysis of the requirements for Subtitle D at Four Corners and Cholla power plants. For the Navajo Generating Station, an assessment of requirements is being performed by the plant operator, Salt River Project. For informational purposes, a discussion of Subtitle C requirements is included in the response to Rule E(d).

RCRA Subtitle D Proposal

Under the RCRA Subtitle D option, EPA would promulgate federal non-hazardous waste regulations for the disposal of CCRs. These regulations would be self-implementing for CCR disposal facilities, directly enforceable by the states and citizens under RCRA's citizen suit provision. The Subtitle D rule would establish a federal floor for all CCR disposal units, meaning the individual state programs would have to be at least as stringent as the federal program, and could be more stringent. EPA would retain its broad statutory authority to take action against any CCR disposal facilities posing an imminent and substantial endangerment to human health and the environment.

To enhance the ability of the states and citizens to ensure compliance with these federal regulations, the rule would require facilities to make available to the public information regarding their compliance status. Additionally, because CCRs would be regulated as non-hazardous solid wastes under this option, the stigma associated with classifying CCRs as hazardous waste would not be present and, therefore, beneficial reuse would not be negatively impacted.[59]

Potential Impacts on APS Operations (See Table 34)

While regulation of CCRs under EPA's proposed Subtitle D option would impose additional costs on power plant operations, the program would offer much more flexibility than under RCRA's hazardous waste regulations. Rather than impacting many aspects of power plant operations at APS's Cholla and Four Corners power plants, Subtitle D regulations would primarily impact the CCR disposal units. Under this proposal, within five years from the effective date of the rule, APS would be required to either retrofit its existing surface impoundments with liners designed to meet required performance standards or close these

[59] Currently, over 43% (>50 million tons) of CCRs are beneficially used in applications such as manufacture of cement and concrete used in buildings, bridges, dams, and highways.

facilities and either build new lined surface impoundments or convert to dry handling and disposal of CCRs in engineered landfills.

C. Other Issues: Clean Water Act - Section 316(b) – Cooling Water Intake Structures

A plan for complying with potential regulations related to water is outlined in Table 35.

Potential Environmental Regulations for Clean Water Act			
			Engineering & Installation Timeframe
Potential Regulation	**Environmental Issue**	**Potential Future Control Technologies[1]**	**2012 2013 2014 2015**
Four Corners (Units 4-5) (includes APS and SCE shares)			
Clean Water Act - Section 316(b) - Cooling Water Intake Structures	Protect aquatic population	Install cooling towers or heavily modify intake structures and institute other site-specific measures	
Cholla			
Clean Water Act - Section 316(b) - Cooling Water Intake Structures	N/A	N/A	
NGS			
Clean Water Act - Section 316(b) - Cooling Water Intake Structures	Protect aquatic population	Modifications TBD by plant operator (SRP)	
(1) Proposed regulations are under development. Technologies and requirements for compliance are subject to change.			

Table 35 - Potential Environmental Regulations for Cooling Water Intake Structures

Section 316(b) of the Clean Water Act (CWA) regulates the location, design, construction, and capacity of cooling water intake structures at electric generating facilities. Section 316(b) requires cooling water intake structures that withdraw water from a "water of the U.S." to reflect the best technology available for minimizing adverse environmental impacts. Adverse environmental impacts include the impingement and entrainment of aquatic organisms (e.g., fish) at the cooling water intake structures.

There are two major types of cooling systems at steam electric generating plants. In a once-through system, water is withdrawn from a water body (a lake, river, or the ocean), used in the cooling cycle, and then returned to the water body from which it was withdrawn, at a slightly higher temperature. In a closed-cycle cooling system using cooling towers, water is circulated inside the tower to cool through evaporation, resulting in loss of water.

In 2004 EPA promulgated a Section 316(b) Phase II rule which established national standards for cooling water intake structures at existing steam electric generating facilities. Then, in 2006, EPA promulgated a Phase III rule which regulated new facilities and facilities with lower design flows. The Phase II and III rules were challenged in court and ultimately remanded to EPA for further consideration. Currently, EPA is engaged in a new Section

316(b) Phase II and Phase III rulemaking process, and a final version of the rule is expected to be released in July 2012.

EPA believes that changing from a once-through cooling system to cooling towers would be more protective of fish populations than other types of technologies, and may be considering "one-size-fits-all" rules requiring closed-cycle cooling systems rather than once-through cooling systems.

Potential Impacts on APS Operations (See Table 35)

The Four Corners Power Plant has two points of cooling water intake from water bodies that are classified waters of the U.S., and therefore is regulated under Section 316(b). These intakes are in Morgan Lake (tied directly to the generating units) and in the San Juan River, which supplies water to Morgan Lake. The Cholla Power Plant draws its cooling water from Cholla Reservoir, which is not a listed water of the U.S. Therefore, Cholla is not regulated under Section 316(b).

NGS's intake source for cooling water is Lake Powell, a body of water formed by a dammed portion of the Colorado River – a water of the U.S.

APS submitted comments to EPA discussing why APS believes the cooling water system at Four Corners should be classified as a closed-cycle system, and asking EPA to make such a determination. To date EPA has not responded to APS's request. APS plans to follow-up with EPA and request a final determination. If successful and EPA agrees that Four Corners is a closed-cycle cooling system, the impacts of the Section 316(b) rulemaking will be substantially reduced. If the APS argument is not successful, the rule could potentially require APS to install cooling towers at Four Corners.

A proposed rule was issued in April 2011, with a final rule to be completed by July 2012. Depending on what EPA determines to be the best technology available, the impacts to Four Corners could result in increased capital, operating and maintenance costs. APS commented on EPA's proposed rule and will continue to follow this rulemaking closely.

D. Reduction in Water Consumption Rate

Water is used for power generation primarily to cool the steam-cycle by removing waste heat. It is also used for power augmentation, emissions control, auxiliary cooling, supporting chemical treatment processes, domestic purposes, and for other miscellaneous plant uses. APS manages water resources using a multi-layered approach to reduce water intensity. APS's plan for reducing water consumption includes the following actions:

1. Employment of alternative cooling technologies for new generating resources;
2. Retirement of Four Corners Units 1-3;
3. Improve the efficiency of water utilization at APS's existing facilities; and,
4. Increase the reliance on energy efficiency and renewable energy resources.

Employment of Alternative Cooling Technologies for New Resources

For new facilities, APS evaluates alternative cooling technologies, water sources, and operating strategies in the best interests of the state, environment, and customers on a case-by-case basis; however, the use of alternative water supplies such as effluent and alternative cooling technologies to reduce potable water usage comes with an additional cost in terms of

capital investment and operations and maintenance costs, and may have an impact on unit efficiency. The factors influencing these decisions are diverse, including location, generator type, and renewable and alternative water availability. APS is developing a water supply portfolio that will provide a reliable mix of traditional, renewable, and reclaimed sources, minimizing where possible usage of groundwater and other potable water sources in favor of more sustainable resources. This approach is aimed at providing secure water supplies for power generation while fostering responsible water use.

Even though energy sales are forecast to significantly increase by approximately 55% during the Planning Period, water consumption will only have a minimal increase; in addition, due to the energy efficiency and renewable energy resources envisioned in the 2012 Resource Plan, the rate of water usage declines dramatically over the course of the Planning Period.

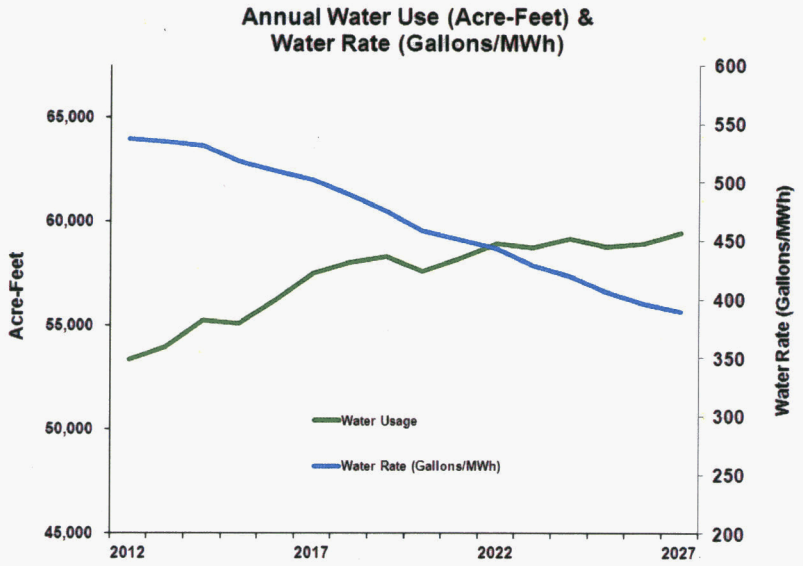

Figure 41 - Forecast of Water Consumption and Intensity

When new power plant generating unit options are being evaluated, the water consumption rates for each technology option are considered and evaluated. The most significant water-saving device that can be installed on new power plants with steam turbines is air-cooled condensers in lieu of conventional wet-cooling towers. Technology for new dry-cooled combined cycle plants is estimated to use 7 gallons/MWh as compared to wet-cooled combined cycle plants such as Redhawk, which uses 317 gallons/MWh. APS contracted the services of a third-party architect-engineer which estimated the equipment cost for an air-cooled condenser to be about $40 million based on a nominal 600 MW combined cycle power plant installed in the Arizona desert.

To reduce water consumption, APS's future cost estimates and performance projections assume dry cooling for newly constructed combined cycle generating units. Reduced water consumption, however, comes at the cost of reduced unit output, higher fuel consumption, and higher capital costs. The additional costs for combined cycle air-cooled condensers have been included in the 2012 Resource Plan.

APS also evaluates utilizing hybrid cooling technology at future thermal plants to reduce water consumption. Utilizing hybrid cooling technology at future thermal generating plants can come with tradeoffs. The actual tradeoffs for hybrid cooling technology are dependent on the supply of water available. The dry portion of the hybrid system would be sized to achieve a certain level of water savings, primarily achieved during the cooler months. An informal estimate provided by an architect-engineering firm has projected that the use of hybrid cooling technology could result in an increase in total project capital costs of up to 15%.

Retirement of Four Corners Units 1-3

In addition to evaluating alternative cooling technologies, there will also be further reductions in regional water consumption through the contemplated retirement of Four Corners Units 1-3. These units consume approximately 25,000 acre-feet annually. Even though APS has proposed to replace this retired generation with added capacity from Units 4 and 5, the region will still benefit through reduced water consumption.

Improving the Efficiency of Water Use at Existing Facilities

APS manages water resources using a multi-layered approach to reduce water intensity. One approach has been to pursue projects targeted to improve the efficiency of water utilization at APS's existing plants. A primary example is PVNGS, which not only uses reclaimed wastewater effluent for its water source but has focused on continual improvement in water treatment and operations to achieve over 25 cycles of concentration (on average) through the cooling water system. Redhawk, the newest combined cycle facility, also operates its cooling system on reclaimed water, achieving similar levels of efficiency. In 2010, 63% of all water used by APS was reclaimed water.

When considering water use and water efficiencies at power plants, APS considers not only the cost of projects, but also the potential impacts on society and the local environment. Understanding local and regional water use and trends is important to this decision-making. With that in mind, in 2009, APS formed a Water Resources Department, consolidating many existing water-oriented functions and experience into a centralized, enterprise-wide function. The vision of this department is "to secure a sustainable and cost-effective supply of water to enable reliable energy production for APS customers". A primary initiative of the Water Resources Department is to create a decision modeling center, consisting of a powerful database and computing infrastructure to allow modeling of groundwater supplies, surface water availability, and the characteristics of other water sources in conjunction with a variety of long-term energy production forecasts. By utilizing this quantitative approach in conjunction with geographic information systems, analysts and stakeholders can interactively examine and contextualize the impacts of various decisions and scenarios.

APS has also become more integrated into the Arizona water community. Participation in the Arizona Department of Water Resources' (ADWR) Water Resources Development Commission and in the Central Arizona Project's Acquisition, Development and Delivery Water program are two examples of activities where involvement is enabling improved communication with other water stakeholders, including regulators, municipalities, agricultural users, and other industries. As of late 2011, APS is now a representative on the Phoenix Active Management Area's (AMA) Groundwater Users Advisory Council (GUAC). This council makes recommendations to ADWR's Phoenix AMA Director on groundwater management and policy in the AMA. The Phoenix GUAC will be the primary mechanism for public comment and review during ADWR's development of the Phoenix AMA's Fourth

Management Plan, which will be completed in the summer of 2013. This integration into the broader water community has opened communication and facilitated partnering opportunities for the future.

Energy Efficiency and Renewable Energy Resources

DSM programs and renewable energy resources predominantly consume little or no water. The expansion of these programs in the 2012 Resource Plan contributes to a reduction in water consumption per MWh over the Planning Period.

Additional information regarding APS's efforts in reducing water usage can be found at Appendix B.

RESPONSE TO RULES: SECTION E – RISK

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(E), which specifically requires information related to risk analysis and mitigation.

RULE E.1(a)

Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis: (a) demand forecasts.

The risks involved with developing a demand forecast involve uncertainties related to: (1) customer growth; (2) electricity usage; and, (3) weather. Table 36 illustrates a probabilistic analysis used to identify and analyze the risks.

APS System Peak Demand Forecast (Probabilistic Analysis)																
Percentile	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
10th	6,956	7,058	7,311	7,484	7,778	8,063	8,347	8,655	8,972	9,190	9,447	9,777	10,112	10,362	10,664	10,960
20th	7,034	7,154	7,392	7,581	7,878	8,179	8,481	8,765	9,106	9,339	9,613	9,935	10,260	10,557	10,848	11,176
30th	7,106	7,232	7,463	7,658	7,961	8,263	8,572	8,861	9,192	9,442	9,729	10,057	10,367	10,663	10,995	11,304
40th	7,172	7,309	7,550	7,739	8,033	8,354	8,646	8,963	9,270	9,533	9,822	10,156	10,469	10,772	11,087	11,420
Forecast	7,234	7,377	7,616	7,813	8,118	8,441	8,742	9,059	9,372	9,625	9,942	10,257	10,569	10,884	11,203	11,527
60th	7,324	7,490	7,717	7,912	8,213	8,543	8,854	9,169	9,493	9,766	10,093	10,367	10,689	11,004	11,357	11,696
70th	7,448	7,636	7,844	8,044	8,340	8,667	8,996	9,338	9,654	9,946	10,245	10,556	10,896	11,205	11,551	11,899
80th	7,604	7,775	7,996	8,191	8,493	8,847	9,174	9,547	9,906	10,150	10,428	10,779	11,156	11,526	11,814	12,184
90th	7,765	7,952	8,209	8,423	8,714	9,024	9,406	9,824	10,177	10,405	10,740	11,087	11,552	11,913	12,238	12,560

Table 36 - Probabilistic Analysis of Peak Demand Forecast

RULE E.2(a)

A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (E)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects: (a) demand forecasts.

A probabilistic analysis can be used to understand risk by providing a range of demand scenarios consistent with historical variations that APS has seen in customer growth, electricity consumption, and weather. Levels of demand can be illustrated by using percentiles ranging from 10% to 90%. The 10th percentile represents the likelihood of a lower demand outcome which would minimize the costs associated with procuring additional resources but contains a risk of not building a sufficient amount of resources if the actual demand exceeded the forecast. At the other end of the spectrum is the 90th percentile, a scenario with a higher demand outcome than is currently planned for and greater costs for procuring additional resources, which carries the risk of building too many resources than what might be needed if the actual demand was less than the forecast.

In the near term, weather presents the greatest risk to the forecast. Peak demand typically occurs during July or August when temperatures can reach 114°F. In the last ten years, the temperature on peak day has been as high as 118°F. The 90th percentile is 116°F. Temperatures 2°F above the forecast of 114°F can add nearly 200 MW to peak. The second largest source of variation in the forecast is due to volatility in load factor. Historically the summer load factor has been in the range of 64% to 68%. For every 1 percentage point decrease in load factor, peak increases by about 100 MW. In the last 10 years, the 90th percentile load factor is 1.5% lower than the current forecast.

Due to the current economic environment there is uncertainty in the mid-term outlook for peak demand growth. Both residential and commercial vacancies are at record levels, posing additional risk to the forecast. In a more typical period, growth in peak demand would be preceded by construction activity and building permits. In the current environment of high vacancies, there can be growth in peak demand without new construction. In APS's service territory in metro Phoenix, there are an estimated 30,000 excess vacant housing units, representing about 100 MW of potential growth in demand. The forecast assumes those excess housing units are absorbed over the next few years, but a faster-than-forecast rate of absorption is a potential risk. Due to the recession, commercial and industrial (C&I< 3MW demand) usage has decreased over 6.4% since 2008 and office vacancy rates are above 20% in metro Phoenix. The forecast assumes that C&I usage remains below 2008 levels. If C&I usage grows faster than forecast and returns to 2008 levels, peak demand could be higher by 90 MW.

Customer growth and changes in use per customer are the most important long-term risks to the demand forecast. Population growth, business investment, and new technology development over the next 15 years could be quite different from the assumptions in the current forecast. The current forecast assumes a compound annual growth rate in residential customers of 2.7%. If residential growth averages 0.5% percentage points higher, then peak demand would be about 400 MW higher than forecast in 2027.

Methods for managing these risks and uncertainties include utilizing resource options that have relatively shorter development lead times. Shorter development lead times allow utilities to respond quickly to changes in demand scenarios. Also, timely updates to the forecast with new information help ensure forecasts remain current. Lastly, having access to liquid wholesale power market trading hubs allows utilities to either buy or sell energy as needed to balance energy demands with resources.

RULE E.3(a)

A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (E)(1): (a) demand forecasts.

APS manages demand forecast risk using three key methods. The APS 2012 Resource Plan envisions short-lead-time resources such as solar PV and natural gas combustion turbines. The development time for these resource types can be anywhere from one to five years. Utilizing short-lead-time resources allows APS to respond quickly as demand scenarios change. APS also carries a 15% reserve margin of additional capacity, over the amount of demand actually forecast, to be available should customer demand exceed expectations or generating units not perform as designed. Furthermore, APS benefits from transmission access to the Palo Verde wholesale trading hub. Because there are many wholesale market participants with access to Palo Verde, APS buys and sells capacity as needed to balance demand with resources.

RULE E.1(b)

Risk Identification: (b) the costs of demand management measures and power supply.

Demand Management Measures

Within the DSM market, the cost trajectory will vary depending on the program or measure, and timing. It is expected that as a whole, the cost per unit of energy saved through EE programs and measures will increase over time; the rate at which it increases will vary depending on technical developments, progression of building codes and appliance standards, persistence of behavioral changes after incentives disappear, and overall market penetration. That said, as future EE programs are designed and proposed, cost-effectiveness must still be proven, which will likely change the landscape of future EE measures as the "low-hanging fruit" with shorter measure lives (e.g., CFLs) are replaced by the next-generation, more efficient products (e.g., LEDs).

As with EE measures, the cost volatility of load management and demand response solutions continues to be an identified risk, though they are forecast to have an overall downward trajectory over the Planning Period. Costs will be largely influenced by development of new communication standards, increased technical efficiencies, and environmental considerations.

Home-area networks and distribution system communications are an emerging sector within the demand response arena. Communication standards and protocols are being developed to ensure seamless communication between utilities and load behind the customer meter. As these specifications mature, networks and consumer products will need to be updated to ensure compatibility and functionality, and will require financial investments from the utility and the customer. In the near-term of the Planning Period, utilities may experience an increase in IT costs, though the identified system efficiencies and customer services gained are expected to be positive investments from a finance, customer, and technical perspective. These investments can provide an IT backbone to help improve reliability, decrease outage and response time, and provide tailored energy management solutions for customers.

Other customer load response resources, such as standby generation, have demonstrated a downward trend in equipment and integration costs which has ultimately led to APS pursuing a standby generation pilot in 2013. The costs for new generators and harvesting existing generators have trended downward despite increased emission regulations and fuel costs. Harvesting is when APS works with customers who have existing on-site standby generators (e.g., hospitals for emergency back-up) that can be paralleled to the grid so that APS can have access to the generators in times of peak demand and the generators are not in use by the customer. In return for granting APS permission to take control of the generator during peak events, customers can receive O&M, fuel, or other financial incentives from APS. When harvesting generators, APS would retrofit the technologies as necessary to ensure compliance with current emissions regulations.

Power Supply

Analyses to identify risks and uncertainties of the costs of power supply are addressed in subsequent sections according to the source of cost uncertainty such as construction cost and fuel cost.

RULE E.2(b)

Risk Analysis: (b) the costs of demand management measures and power supply.

Demand Management Measures

APS has modeled a plus and minus 30% cost swing to create high and low EE cost sensitivities to illustrate the impact of future compliance cost risk over the planning horizon. In the first few years of the Planning Period, APS did not apply this variability as those costs are relatively well known and are based on the 2012 DSM Implementation Plan filing. The results of the analysis are provided in Attachment F.1(c).

Annually, on-going analyses will be performed to ensure that proposed and existing DSM programs are cost-effective and advantageous for APS and its customers.

Power Supply

Methods to manage the risks and uncertainties of the costs of power supply are addressed in subsequent sections according to the source of cost uncertainty such as construction cost and fuel cost.

RULE E.3(b)

Risk Mitigation Plan: (b) the costs of demand management measures and power supply.

Demand Management Measures

Embedded within the EE Standard is the cost-effectiveness requirement which acts as a mechanism to ensure that all DSM programs that are implemented provide a net benefit to APS and its customers. Annually, APS seeks to manage EE program costs by exploring innovative incentive models, creating additional technology options, and conducting MER on the programs.

Due to the varied nature of load management and demand response solutions, cost volatility can be more closely managed by strategically timing deployment of resources and diversifying procurement methods. The APS Peak Solutions program is managed through a long-term contract (through 2024) that has fixed energy and capacity payments through the term of the agreement. Customer load response solutions, such as standby generation, offer options to harvest existing equipment or deploy new, utility-owned assets, which have different economic benefits that APS can capitalize on.

Additionally, time-differentiated rate schedules and tariffs are eligible to be re-filed as necessary to assist in managing customer and Company impact. APS will have the opportunity to revisit these rates in the annual DSM Implementation Plan filings or through rate cases.

Power Supply

To mitigate the risks associated with the costs of power supply, APS optimizes the use of its resources to serve native load in the most economical manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI

GenTrader®/GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (wind/solar), fuel prices, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level, and the quantity of natural gas to be scheduled. As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than running generating units.

Primary elements of risk for real-time operations include loss of a generator or resource, and actual deviations from the load forecast. A minimum margin is built into transactions to account for unexpected risk factors. If there should be an unforeseen event, the model can be adjusted in real-time, which would in turn adjust the base cost/base value for future transactions.

APS also has access to the Palo Verde Hub, a major trading point in the Western Interconnection that provides access to a multitude of resources.

A risk-mitigation plan for the long-term cost of power supply includes strategies such as developing hedge programs to mitigate the volatility associated with natural gas prices and establishing long-term fuel agreements for coal and nuclear, as well as having a diversified portfolio of resources.

RULE E.1(c)

Risk Identification: (c) the availability of sources of power.

Risks involved in the availability of sources of power include the availability of the supply resource itself, availability of new generation equipment, timing of construction schedules, availability of credit-worthy counterparties, the commercial viability of certain technologies, and the availability of adequate transmission capacity to move the power to the load center where it is needed.

RULE E.2(c)

Risk Analysis: (c) the availability of sources of power.

One of the key risks that APS addresses on a daily basis is the potential of reduced generating availability and outages in the fleet of existing supply resources. This risk of an equipment or plant malfunction and unplanned shutdown is present on a continuous basis but is generally minimized through high standards in plant maintenance and operations. In addition, APS plant designs incorporate a reasonable level of redundancy at the equipment level so that single failures do not generally result in plant outages.

Providing for an allowance in the timing of construction schedules for planned generation is one way the construction schedule risk can be mitigated. When planning for summer peak resource requirements, an allowance can be made for the level of capacity a particular resource is allowed to contribute toward meeting that summer peak demand. For projects that are anticipated to reach commercial operation during the summer period of June – September, a risk-reducing strategy may be to not rely upon those projects' capacity for meeting that particular summer peak. In this way, construction schedule risk is mitigated.

Having additional resources available is another means of managing risk in the availability of sources of power. Utilities carry capacity reserve margins (excess resource capacity) in the event of resources being unavailable or customer demand being higher than anticipated. Capacity reserve margins are an effective means to help ensure sufficient power sources are available when needed.

Following robust procurement practices is another way to mitigate risk of availability of sources of power. Soliciting bids from a large number of third-party developers allows the Company to select projects that are more likely to be completed on time. Developers often may already own property, have permits in place, and have good queue positions for equipment.

When procuring energy from third-party vendors, an analysis of vendor credit quality is crucial to the success of a transaction. Poor credit quality or the inability of a vendor to obtain cost-effective and timely financing for their project will, in most circumstances, exclude that vendor from being considered. A thorough analysis of vendor credit quality helps mitigate these impacts.

Consideration of a wide range of technologies increases resource diversity and reduces technology performance risk. Being overly dependent on a single technology or depending on technologies that have yet to be proven in commercial applications may increase performance risk.

One of the single best, and most simple, means of managing risk in sources of power is resource diversity (i.e., not being overly reliant on one fuel source). Utilities with diverse sources of power supply are situated better when unforeseen problems emerge because they have other alternative sources of power to rely upon.

To optimize the economic alternatives of running generating units versus procuring energy from the market, having transmission access to liquid trading hubs is another means of helping to ensure availability of sources of power.

RULE E.3(c)

Risk Mitigation Plan: (c) the availability of sources of power.

Existing plant availability is maintained at very high levels through the application of effective preventative and predictive equipment maintenance. APS maintains an operational staff which is capable and highly trained. Programs are in place which promote the capture of data and evaluation of equipment failures and operational incidents to help prevent recurrence and reduce the risk of unexpected outages.

APS mitigates risk due to the timing of construction schedules by not including those projects' capacity as contributing toward meeting summer peak demand when their initial commercial operation date is anticipated to be during the summer (June – September). By mitigating construction schedule risk in this manner, system reliability is not compromised if projects are delayed.

As described in response to Rules E.1(a) – E.3(a), APS carries a 15% capacity reserve requirement that helps ensure sufficient power sources are available. APS's capacity reserve requirement for 2012 is 999 MW, as shown on line 4 of Attachment F.9(b).

The Company also mitigates risk by engaging in best practice procurement procedures. Whether APS signs a purchase power agreement, purchases an existing asset, or constructs new generation, the best projects are identified through broad market participation.

APS employs credit risk management practices that ensure the creditworthiness of all counterparties in energy procurement transactions has been thoroughly analyzed prior to making a transaction. In addition to determining the credit quality of potential counterparties, APS also may require a letter of credit, guarantee, or some other form of acceptable collateral prior to completing a transaction. In this manner, if a counterparty were to default on their contractual obligations, APS could retain the collateral of the defaulting counterparty to help offset any damages APS may have incurred as a result of the counterparty default.

APS employs a wide range of resources and is not overly dependent on any one specific resource, as illustrated by the diversity of the supply-side resources included in the 2012 Resource Plan. APS limits risk exposure by considering only sources of power reasonably believed to be commercially available within the planning time frame.

APS has taken steps to promote a contingency planning process that is designed to identify uncertainties in the existing resource plan and develop options for new resources and transmission capacity, which can be implemented in the identified timeframes. These options are intended to be executable compensatory measures in the event of failure of specific elements of the current resource plan.

In terms of renewable energy, the 2012 Resource Plan includes solar thermal, solar photovoltaic, wind, geothermal, biogas, and biomass. By considering commercially available resources such as those mentioned, APS mitigates technology performance risk.

To meet the new natural gas generation needs identified in APS 2012 Resource Plan, APS could choose to contract with or purchase available merchant generation, or construct new combustion turbines or combined cycle units. There are currently four merchant generators located near the Palo Verde hub with a total of about 5,000 MW of capacity.[60] This merchant capacity could potentially fill some of the natural gas generation needs identified in the 2012 Resource Plan by 2027. When APS chooses to construct new capacity, it is anticipated that there will be many manufacturers and many technology options to choose from, along with sufficient availability of new equipment.

Through its ownership interest in PVNGS, APS benefits from transmission access to the wholesale power market at the Palo Verde hub. Many market participants, as well as merchant generators, buy and sell wholesale power at the Palo Verde hub making access to that facility one of the means APS uses to manage the risk of power source availability.

RULE E.1(d)

Risk Identification: (d) the costs of compliance with existing and expected environmental regulations.

EPA is currently in various stages of promulgating environmental regulations which are expected to impact APS. Factors that will impact future costs of compliance include:

[60] APS has two purchase power agreements from these generators that will be expiring during the Planning Period.

- Capital and O&M costs pertaining to existing regulations are subject to cost increases triggered by inflation and/or limited supply;
- Existing regulations may change during the Planning Period;
- The requirements to comply with many of the proposed regulations have not been finalized so it is difficult to estimate precise costs of unknown regulations; and,
- New technology may be required to achieve compliance with proposed regulations and the cost of the new technology may be unknown.

APS monitors the regulatory landscape as potential environmental regulations evolve and become better defined. Throughout this process, APS environmental engineers develop refined cost analyses using scenarios containing a range of potential technology requirements to forecast the cost of possible outcomes.

Analysis of RCRA Subtitle C Proposal

Proposed regulations for RCRA include two different scenarios – Subtitle C (hazardous) and Subtitle D (non-hazardous). For planning purposes, APS has assumed Subtitle D will be the final ruling and has included cost estimates in the 2012 Resource Plan for Four Corners and Cholla. To manage the uncertainty of the cost of compliance, APS has also evaluated the requirements under proposed Subtitle C regulations. While the requirements for Subtitle D were discussed in the response to Rule D.17, an analysis is provided below of the potential impacts based upon proposed compliance requirements for Subtitle C.

Under the Subtitle C option, EPA is proposing to regulate CCRs as a hazardous waste, which is the most stringent and costly option available to EPA under federal law. Due to the stigma associated with hazardous waste, this option would likely eliminate the beneficial reuse of CCRs and harm small business such as marketers and end-users of CCRs.

The inflexible nature of RCRA's hazardous waste regulations would result in the regulation of many aspects of power plant operations at Four Corners, Cholla, and NGS, not just the CCR disposal operations. Under this proposal, within five years from the effective date of the rule, APS would be required to close its existing surface impoundments (used for wet disposal of CCRs) and convert all CCR handling systems to dry handling and dispose of CCRs in engineered lined landfills at both plants. The plants would also be required to obtain federal permits for the handling and disposal of CCRs, and all CCR handling operations would be required to meet very stringent hazardous waste requirements.

Historically, a portion of the ash produced at Cholla and Four Corners was beneficially reused in the manufacture of concrete and other applications; however, because of the liabilities associated with hazardous waste, it is unlikely that APS would continue to market fly ash for beneficial reuse and would dispose of the material in on-site landfills.

RULE E.2(d)

Risk Analysis: (d) the costs of compliance with existing and expected environmental regulations.

Available means for managing errors, risks and uncertainties include the following strategies:

- Obtain current information from sources such as federal/state agencies, industry publications, vendor presentations, discussions with other utilities,

market research, and third-party consulting organizations to maintain awareness of proposed changes to existing and expected regulations which will impact technology choices and cost;

- Serve on environmental control technology committees within industry organizations;
- Analyze commercially-viable options for technologies that will enable environmental compliance;
- Negotiate solutions with government agencies that balance cost and compliance;
- Update costs of technology needed for compliance throughout the development of the regulation and as expected regulations become finalized, including increases in cost due to inflation or limited supply; and,
- Pursue an expanded portfolio of non-emitting resources that includes energy efficiency, demand response, and renewable energy to defer the cost of additional environmental control technology by delaying new conventional fossil generation.

RULE E.3(d)

Risk Mitigation Plan: (d) the costs of compliance with existing and expected environmental regulations.

To manage risks and uncertainties with the cost of existing and expected environmental regulations, APS uses a multi-faceted plan which includes a combination of the following:

Obtain information from sources such as federal/state agencies and third party consulting firms to maintain awareness of proposed changes and to evaluate commercially-viable options for technology: For example, APS has used Black & Veatch, a global engineering consulting firm, to provide an initial evaluation and subsequent updates for commercially-viable technology that may be required for SCR installation at Four Corners as well as to provide cost estimates. As a risk mitigation strategy, APS also conducts market research to mitigate uncertainties when evaluating new and changing technologies to ensure that the most reasonable technologies are selected to balance cost while meeting environmental standards.

Serve on environmental control technology committees: Electric Power Research Institute (EPRI) and Utility Air Regulatory Group (UARG) are two organizations in which APS participates as members of committees involved with environmental control technologies.

Negotiate solutions with government agencies that balance cost and compliance: APS has been in negotiations with EPA since 2009 to develop a solution for controlling NOx emissions at Four Corners which balances environmental impacts with the cost of compliance (see response to Rule D.17).

Review and update cost estimates based on the latest information available: Throughout the process of developing environmental regulations, more rigorous cost estimates are continually produced by APS to reduce cost uncertainty.

Defer the cost of additional environmental control technology by pursuing a diverse portfolio of resources that includes energy efficiency, demand response, and renewable energy: As illustrated in the 2012 Resource Plan, APS is managing the risk of environmental regulations through ramping up non-emitting resources such as energy efficiency, demand response, and renewable

generation. This strategy defers the cost of additional environmental control technology by delaying the need to add conventional fossil generation.

RULE E.1(e)

Risk Identification: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

An analysis of several potential new environmental regulations which would require capital and O&M expenditures for environmental control equipment was discussed in detail within the response to Rules D.17 and E(d). In addition, an implementation plan was included which identified the potential technology and timeframe for design and installation based on the most current information available as of October 2011. As previously stated, most of these potential regulations are only partially defined at this time and some may not be finalized for years. Over the 15-year Planning Period, these regulations could be modified further resulting in changes to the technology needed for compliance, which would impact the forecast for compliance costs.

In addition to proposed regulations that APS is currently aware of, there are potential new regulations, such as Effluent Limitation Guidelines (ELGs) and GHG regulations, that may be promulgated during the Planning Period. Compliance costs could increase to an extent that is unknown at this time.

Analysis of Uncertainty related to Effluent Limitation Guidelines (ELGs)

The CWA regulates discharges to "waters of the U.S." through water quality standards and technology-based standards. Effluent Limitation Guidelines (ELGs) are technology-based standards developed by EPA on an industry-by-industry basis. The CWA requires that EPA periodically review and revise these standards as appropriate. APS has responded to the EPA Effluent Limitations Guideline Information Collection Request and expects that EPA will eventually promulgate effluent rules based on the data collected.

In 2010, EPA initiated a review of the ELGs applicable to the steam electric power generating sector through a formal information collection process. In this process EPA collected data from electric utilities, including APS, and will evaluate the data and other studies to determine the best available technology economically achievable by the industry. EPA will then propose revisions to the current ELGs based on the performance of that technology. The industry will be required to comply with the new, more stringent standards at some point in the future.

The ELGs would impact Four Corners, West Phoenix, and Ocotillo power plants, because these facilities have permitted industrial discharges. Four Corners discharges directly into a water of the U.S. at two locations. The West Phoenix and Ocotillo power plants are permitted to discharge into the municipal sewer systems, which are in turn permitted to discharge directly into a water of the U.S. In addition, the West Phoenix power plant is permitted to discharge directly into an adjacent irrigation canal, but as a normal practice does not use this discharge point.

Any revisions to the ELGs would impact the discharge limits and APS's Four Corners, West Phoenix, and Ocotillo power plants may be faced with increased capital and O&M expenses to achieve and maintain compliance; however, the nature and magnitude of those impacts cannot be assessed until EPA issues its proposed rule. EPA's latest regulatory agenda

indicates the proposed rule is due in June 2012, with a final rule expected in 2014. APS plans to follow this rule development process closely and will comment on the proposal.

Analysis of Uncertainty Pertaining to Greenhouse Gas Regulations

The inclusion of a cost for CO_2 emissions has been debated for years and is still likely to be several years away from a resolution. As detailed in Appendix A, Charles River Associates provided APS not only with guidance on a likely CO_2 price curve, but also on plausible high and low price curves based on their understanding of the legislative landscape (see Figure 23). Portfolios that rely more heavily on carbon-intensive fuels like coal will be impacted most from a cost perspective by this sensitivity.

RULE E.2(e)

Risk Analysis: (e) a description and analysis of available means for managing errors, risks and uncertainties of potential new or enhanced environmental regulations.

Available means for managing the risks and uncertainties with the analysis of new environmental regulations includes the following strategies:

- Obtain information from sources including federal/state agencies, industry publications, market research, and third-party consulting organizations to maintain awareness of proposed changes to existing and expected regulations which will impact technology choices and cost;
- Evaluate commercially viable options for technologies that will enable environmental compliance;
- Negotiate solutions with government agencies that balance cost and environmental impact;
- Update costs of technology needed for compliance as better information becomes available;
- Monitor legislative activities related to CO_2 and develop cost sensitivities to evaluate the potential impact; and,
- Develop additional options including scenarios containing minimum and maximum technology requirements to evaluate the range of possible outcomes.
- Incorporate a hypothetical carbon cost into resource planning analytics.

RULE E.3(e)

Risk Mitigation Plan: (e) a plan to manage the errors, risks and uncertainties identified of potential new or enhanced environmental regulations.

APS monitors the regulatory landscape as potential environmental regulations evolve and become more clearly defined. APS reviews and updates cost estimates based on the latest information available and utilizes the services of outside engineering firms as appropriate. As previously mentioned, APS has included a hypothetical cost of CO_2 in the 2012 Resource Plan based upon the guidance provided to APS by Charles River Associates. As decision dates for finalized regulations approach, consistently more rigorous cost estimates are produced to mitigate the risk of uncertainty relating to potential new environmental regulations.

APS is also partially insulated from the impacts of these regulations by its focus on advancing energy efficiency and renewable energy resources. These zero emissions sources help diversify the APS portfolio and mitigate the dependency on fossil-fueled generation. In addition, the planned retirement of Four Corners Units 1-3, coupled with the acquisition and environmental enhancements on Units 4-5, also helps mitigate against the uncertain costs associated with major modifications needed on Units 1-3 to meet these future regulations.

RULE E.1(f)

Risk Identification: (f) changes in fuel prices and availability.

As discussed in the response to Rule D.16, APS engaged the services of IHS CERA to analyze future fuel supplies and prices. A copy of this report will be provided upon request to the ACC under a confidentiality agreement.

Coal for APS power plants is currently purchased under long-term contracts with fixed prices and inflation-related escalators. For Four Corners, a condition of the proposed Four Corners transaction with SCE requires an extension of the BHP fuel agreement with terms reasonably acceptable to APS. As a result, APS and BHP are currently negotiating the contract. Additional risks for coal supply to power plants would be rail service interruptions and mine permit extensions. Uranium is an international commodity that is projected to be sufficient at current rates of extraction to last over 100 years. The primary risk for disruption of uranium supply would be in the area of contractual performance of both suppliers of uranium as well as performance of vendors in the processing of uranium into usable fuel.

Current natural gas supplies in North America in general, and the Desert Southwest specifically, are projected to last well over 50 years at the current rate of consumption. The primary reliability risk for natural gas supplies would be a disruption in natural gas pipeline transportation between the production basins and APS power plants. A disruption could occur involving pipeline rupture or lack of pipeline compression needed to move fuel through pipelines.

Natural gas prices present the greatest fuel price risk to APS. Natural gas prices have exhibited volatile and unpredictable behavior over the past decade as indicated in Figure 42.

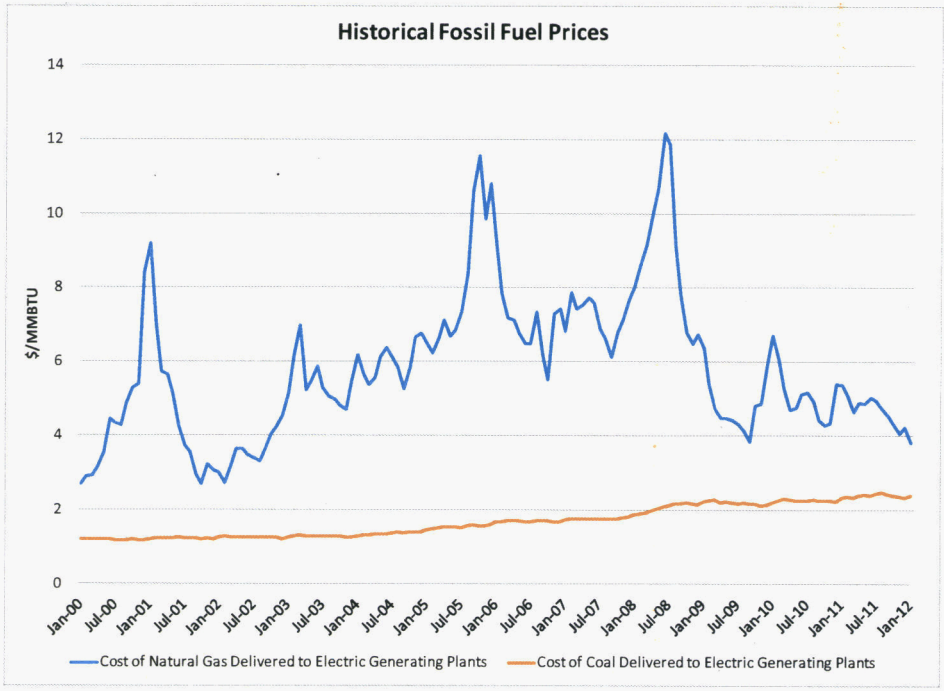

Figure 42 - Historical Fossil Fuel Prices

APS performs gas price sensitivity analyses on both the technology level and on a system level. APS evaluates natural gas generation assuming 30% higher natural gas prices in order to evaluate changes in relative position of natural gas units to other technologies. Sensitivities of plus and minus 30% are evaluated as illustrated in Attachment F.1(c).

RULE E.2(f)

Risk Analysis: (f) changes in fuel prices and availability.

The primary means for managing fuel price and supply risk include contracting for longer periods, contracting under fixed price arrangements, utilizing multiple vendors, and engaging in hedging activity. The primary means for managing exposure to any one particular type of fuel is to develop and maintain a diverse portfolio of resources that does not overly depend on any one fuel source.

Coal is typically contracted for under longer-term supply arrangements. Occasionally, utilities may choose to purchase a portion of their coal supply under long-term contract, and then rely upon shorter-term "spot" markets for the remainder of supply. While engaging in the spot market may add flexibility in the amount of coal purchased, the spot market prices are typically more volatile and there are no guarantees that supplies in the spot market will always be available.

Uranium fuel supplies and processing are typically contracted for using multiple vendors for longer terms. Utilizing multiple vendors reduces concentration risk in the event a supplier fails to perform their contractual obligations. Prices for uranium supplies and processing are typically contracted for under fixed prices but may include escalators tied to various indices. While it may theoretically be possible to hedge price risk associated with uranium linked to indices, finding other credit-worthy counterparties may be problematic.

Natural gas supply is typically contracted for under shorter-term fuel supply arrangements, while natural gas transportation is typically contracted for using fixed rates under longer-term arrangements. Even though natural gas supplies are typically contracted on a shorter-term basis, prices may be locked in for longer periods of time using forward financial swap instruments or futures contracts that lock in prices for specified delivery periods in the future.

RULE E.3(f)

Risk Mitigation Plan: (f) changes in fuel prices and availability.

Coal for APS power plants is currently purchased under long-term contracts with fixed price adjustments. APS benefits from coal suppliers having sources with proven reserves well in excess of what could be burned even beyond the Planning Period. Disruption of coal supply due to rail interruptions is managed by keeping additional inventory of coal on power plant sites. In order to accommodate interruptions in coal supply, APS typically maintains a 45-day reserve of coal at the Cholla plant, a 60-day reserve of coal at the Four Corners plant, and a 30-day reserve at NGS (operated by Salt River Project). Negotiations continue in an effort to arrive at mutually-agreeable terms for coal supplies to Four Corners post-2016.

For the Cholla Power Plant, transportation for coal is provided through firm long-term contracts with the Burlington Northern Santa Fe Railway. In the case of the Four Corners Power Plant, coal transportation is not required given the coal mine is located adjacent to Four Corners, thereby mitigating the risk of rail disruptions. Transportation of coal from the Kayenta mine to the Navajo Generating Station is provided by a dedicated rail owned by the co-owners of NGS and operated by the Salt River Project.

APS mitigates the risk of disruption in gas supply due to pipeline interruptions by contracting for natural gas transportation through long-term firm contracts over three separate pipelines – El Paso Natural Gas, TransCanada (North Baja), and Transwestern, to transport 100% of the gas needed to meet the system peak generation demand. In addition, APS benefits from dual pipeline supply capability at the following power plants: Redhawk, Yucca, Gila River (long-term PPA), and Sundance. All other power plants are served by the El Paso pipeline. Individual pipeline risk to those plants is mitigated since El Paso pipeline utilizes a redundant system that consists of multiple pipes. Additional pipes mitigate risk of a single pipe rupture since remaining pipes could continue operating.

In order to manage natural gas price volatility risk, APS employs a three-year hedge plan. The hedging parameters are 85% for year 1, 50 to 60% for year 2, and 30 to 40% for year 3. In hedging fuel supplies and prices, APS utilizes many different creditworthy counterparties to reduce concentration risk of a counterparty failing to perform their contractual obligations.

Uranium is an international commodity that is projected to be sufficient at current rates of extraction to last for 100 years. To mitigate supply as well as price risk, APS hedges uranium fuel supply under long-term contracts and utilizes multiple suppliers. Not only does APS hedge uranium fuel supplies through longer-term contracts, the Company also hedges fuel processing services directly with suppliers. In order to ensure fuel supplies are ready when needed, APS requires fuel suppliers to deliver fuel to Palo Verde 45 to 90 days in advance of an outage to help ensure fuel is ready when needed. This advanced delivery also allows APS time to inspect fuel assemblies prior to loading them into a unit.

Nuclear refueling outages normally avoid the summer months to meet the peak demand for power. Sufficient fuel is maintained on-site to meet the summer peak demand periods.

RULE E.1(g)

Risk Identification: (g) construction costs, capital costs, and operating costs.

The primary construction, capital, and operating cost risks are associated with the engineering, procurement, and construction (EPC) of new generating units. Engineering, procurement, and construction of modifications to generating units also have similar risks but the total costs at risk are typically smaller.

There are many factors that have the potential to negatively impact cost, scope, and schedule of construction projects. These factors include but are not limited to the following:

- Escalating material or labor costs beyond what has been anticipated;
- Force majeure, inclement weather, labor strikes, craft availability, and productivity risks;
- Quality assurance failure of one-of-a-kind engineered equipment or failure to pass customer and factory acceptance tests;
- Major equipment performance failure to operate at minimum guaranteed ratings;
- Material availability issues; and,
- Contractor non-performance.

In addition, if land acquisition is a prerequisite to a construction project, there are potential risks. Acquisition of private land is systematic and is approached with an offer letter, appraisal, and negotiations. Timing is critical to managing risk if condemnation is necessary and a court settlement is required. Generally, a timeframe of 2 years is estimated for land acquisition if condemnation is necessary.

Federal and state lands are secured through leases, or rights-of-way with each agency. Federal lands require a NEPA process that includes archaeological and biological studies for project impacts to threatened and endangered species. The estimated processing timeframe for a typical right-of-way application with Arizona State Land Department requires 24 months. A federal application (such as with the Forest Service or Bureau of Land Management) will typically require 36 months or longer, depending on impacts to species or archaeological sites.

RULE E.2(g)

Risk Analysis: (g) construction costs, capital costs, and operating costs.

Methods for managing risks and uncertainties include requiring liquidated damage provisions in contracts for EPC activities so as to mitigate the risk of various scenarios that may impact cost and schedule. Not all schedule impacts may be mitigated, however, especially if the impact is due to one-of-a-kind specifically engineered and manufactured equipment being damaged beyond repair or lost during shipping. This risk may be mitigated through purchasing of insurance for compensation of loss. It may also be beneficial to include

project milestones to document progress and determine contractor performance to those milestones.

To ensure vendors have the capability to perform the scope of work expected, a vendor analysis may be completed prior to contracting for services. Vendor analysis includes an examination of experience and capability to perform, as well as a thorough credit analysis to help determine which vendors have the financial capability to perform. As a result of this review, it may be appropriate to request letters of credit or other performance guarantees to serve as collateral from vendors. If a vendor fails to perform required services, they must forfeit any collateral they have provided.

When it is determined that equipment replacement or modifications are needed, it is important that project processes and controls are in place, well documented, and communicated in order to guide project work, set expectations, and measure progress against project milestones. Project control documents that are well communicated and measured against help serve to mitigate project cost and schedule risk.

In addition to vendor analysis and project control documents, it is also possible to conduct sensitivity analyses on project component costs to determine the overall magnitude of potential cost uncertainty. Sensitivities may be helpful in highlighting those cost components with the greatest potential to impact overall project cost uncertainty.

RULE E.3(g)

Risk Mitigation Plan: (g) construction costs, capital costs, and operating costs.

In the event of a delay in completing individual project tasks or in receiving project components, APS analyzes the overall project schedule to determine if the schedule can be reworked to avoid direct impact on the overall project completion date. Schedules are regularly analyzed for existing or potential problems that would affect the schedule or cost. The frequency of schedule analysis will vary from as often as daily to as infrequently as monthly depending on the type, complexity, and phase of the project. APS uses schedule analysis and progress measurement to identify potential risks as early as possible. Identifying potential delays as early as possible improves the probability that a corrective action or contingency plan will have the desired effect of maintaining originally scheduled completion dates.

Examples of schedule impacts and actions to mitigate include:

Construction completion after contract completion date: This risk is normally mitigated by regular schedule reviews and progress milestone measurement. APS also mitigates this risk by including contract provisions for liquidated damages, whereby vendors must forfeit collateral to APS in the event of missing contractually-agreed-to milestones or completion dates.

Contractor productivity less than planned due to factors such as inclement weather, labor strikes, and craft availability: In many instances, this risk is mitigated by requesting an increase in the number of critical craft personnel on site or the number of shifts being worked to return to the original completion schedule.

Equipment delivery delays: Some negative schedule impacts cannot be totally recovered. Examples are when one-of-a-kind specifically engineered and manufactured equipment

is lost or damaged during shipping to the construction site. To mitigate this risk, APS purchases insurance to compensate for a potential loss of this nature.

Impacts from uncertainties in cost are mitigated by the regular review and updating of cost estimates based on the latest industry information available. As the project start date approaches, consistently more rigorous cost estimates are produced to reduce the level of cost uncertainty.

In addition to assessing capital cost risk pertaining to the construction and installation of facilities, as well as land, land rights, structures, and equipment, APS also includes an allowance for funds used during construction in its capital cost estimates.

When it is determined that equipment replacements or modifications at existing power plants are required to improve plant efficiency or reliability, or to comply with new environmental regulations, APS has guidelines which are used to establish consistent, orderly, and efficient inter-discipline and inter-department communication for these projects. The project guidelines establish the level of project control needed to reduce the project risks, which could in turn increase costs or delay project completion.

Very large projects of sufficient size are controlled in a similar fashion; however, these projects may be so large and demanding that a new project organization with a separate dedicated staff will be created for the duration of the project.

Where capital or fuel costs can represent up to 75% of the total delivered cost of power for many technologies, non-fuel operating costs generally represent less than 10% of the delivered cost. Consequently, the sensitivity of power costs to non-fuel operating costs is typically far less than it is to capital or fuel.

RULE E.1(h)

Risk Identification: (h) other factors the load-serving entity wishes to consider.

APS performed a sensitivity analysis that included externalities in its portfolios. Externalities include NOx, SOx, PM10, and the marginal cost of water (all shown in Table 37). Values for NOx, SOx, and PM10 were specific to APS power plants and were based on the National Academies of Science study. Marginal cost of water was based on the cost of treated effluent at the Redhawk power plant. Values are dependent on fuel quality, emission controls, and location of the power plants in relation to population centers.

	SO2 Cost[1] ($/Ton)	NOx Cost[1] ($/Ton)	PM10 Cost[1] ($/Ton)
Cholla	3,280	1,256	200
Four Corners	3,074	1,275	189
Navajo	3,131	1,198	179
Ocotillo	8,946	5,560	1,319
West Phoenix	8,917	5,542	1,314
Saguaro	5,262	2,989	820
Yucca	6,227	864	323
Redhawk	8,918	5,542	1,314
Sundance	8,918	5,542	1,314
Future CT / CC	8,918	5,542	1,314
[1] Based on National Academies of Science Study			
Marginal Cost of water ($/Acre-Feet)			
2012	$722		
2013	$862		
2014	$983		
2015	$924		
2016	$749		
2017	$768		
2018	$793		
2019	$823		
2020	$854		
2021	$886		
2022	$921		
2023	$958		
2024	$998		
2025	$1,040		
2026	$1,085		
2027	$1,318		

Table 37 - Externalities - NOx, SOx, PM10, Marginal Cost of Water

As indicated in Attachment F.1(c), while inclusion of externalities did change the absolute value of portfolio costs, it had little impact on the relative economics of the portfolios, i.e., the Base Case Portfolio is still the lowest cost, and the Coal Retirement Portfolio is still the highest cost. Consideration of externalities has less impact on APS than many other companies due to three factors: (1) APS coal power plants burn lower sulfur coal than many eastern plants; (2) APS coal power plants already have emission controls in place; and, (3) APS coal power plants are located away from major population centers.

RULE E.2(h)

Risk Analysis: (h) other factors the load-serving entity wishes to consider.

The most effective way utilities can manage potential costs associated with externalities is to make resource choices that promote a clean resource mix. While fossil-fueled generation sources may have been the dominant choice years ago, renewable technology advancements and energy efficiency provide utility planners with cleaner resource choices that mitigate the risk of potential health effects associated with power generation.

RULE E.3(h)

Risk Mitigation Plan: (h) other factors the load-serving entity wishes to consider.

APS has included externalities in its sensitivity analysis to help inform the issue. In addition, APS is increasing its reliance of clean energy resources such as energy efficiency and renewable energy.

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RESPONSE TO RULES: SECTION F – SUMMARY OF 2012 RESOURCE PLAN

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(F), which specifically requires information related to the selected 15-year resource plan.

RULE F.1

Selects a portfolio of resources based upon comprehensive consideration of a wide range of supply- and demand-side options.

In creating the 2012 Resource Plan, APS analyzed four distinct portfolios for consideration composed of a mixture of technologies (as described further in Attachment D.3). APS monitored how each portfolio performed based on certain key metrics, including: natural gas burn; NPV of revenue requirements; cumulative capital expenditures; carbon emissions; water use; and, portfolio diversity. APS then stressed several key input variables, such as natural gas prices, carbon costs, energy efficiency costs, tax credits, and externalities, to determine the robustness of each portfolio (sensitivity analytics). Finally, APS combined several variables into low cost and high cost cases to see plausible boundaries on revenue requirements for each portfolio (scenario analytics). The results of the analytics for each portfolio can be found at:

Attachment F.1(a) – Loads and Resources Tables and Energy Mixes
Attachment F.1(b) – Analysis of Four Portfolios
Attachment F.1(c) – Sensitivity Analyses
Attachment F.1(d) – Scenario Analyses

Description of portfolios:

Base Case Portfolio: The Base Case Portfolio is designed to deliver a portfolio of generation resources that does not overly rely on one specific fuel source over the 15-year Planning Period. This portfolio includes the addition of SCE's share of Four Corners Units 4 and 5, and the related retirements of Units 1, 2, and 3. No additional baseload resources (coal/nuclear) are added over the course of the Planning Period. APS assumes compliance levels of energy efficiency, and plans for slightly exceeding compliance levels for renewable energy. The remaining growth is met with demand response and natural gas resources. The first conventional resource addition is estimated to occur in 2019.

Three important factors stand out about this portfolio. First and foremost, this is the lowest cost portfolio of all those considered. Second, approximately 65% of energy growth is met by emissions-free resources. Third, this portfolio results in no single fuel source encompassing more than 26% of APS's resource mix. Contrast that with today where coal and nuclear make up two-thirds of APS's fuel mix. This more balanced approach will provide customers with greater protection from price volatility associated with a single fuel source.

Four Corners Contingency Portfolio: The Four Corners Contingency Portfolio differs from the Base Case Portfolio in one key aspect: the assumption for this portfolio is that the Four Corners transaction is ultimately not consummated. As a result, all five units at Four Corners are retired over the next four years. Due to these retirements, the portfolio calls

for an additional combined cycle unit and 300 MW of additional combustion turbine units, starting with the combined cycle unit being added in 2016 and the first combustion turbine in 2017.

APS has developed this portfolio as a contingency plan should the Four Corners transaction not occur. With the loss of such a large amount of baseload generation, APS would need to take swift and decisive action in the next five years in order to ensure reliable and affordable service to its customers. This portfolio is intended to depict what those decisions could entail.

Enhanced Renewable Portfolio: The Enhanced Renewable Portfolio is designed to show the impacts of increasing the contribution of renewable energy to 30% of retail sales by 2025. This portfolio includes the Four Corners transaction and a significant increase in renewable nameplate capacity compared to the Base Case Portfolio. Conventional generation is not added until 2020 (combined cycle).

This portfolio provides a resource mix that significantly reduces the Company's reliance on natural gas and its associated price volatility. In addition, it envisions that over 90% of future energy growth is met by clean energy resources.

Coal Retirement Portfolio: The Coal Retirement Portfolio does just that; it shows the impact of retiring all of APS's coal units during the Planning Period. Similar to the Four Corners Contingency Portfolio, APS assumes Units 1-3 are retired at the end of 2014 and Units 4-5 are retired in the summer of 2016. Navajo Generating Station is then assumed to be retired at the end of 2019 and Cholla at the end of 2024. APS chose these dates based on the expiration of certain contracts related to fuel purchases and land rights.

Due to the retirement of over 1,700 MW of coal-fired generation, APS would significantly increase its reliance on natural gas and renewable energy. APS modeled replacing coal production with 25% renewable energy and 75% natural gas generation. This results in APS adding four combined cycle gas plants during the Planning Period and over 1,000 MW of additional nameplate renewable capacity compared to the Base Case Portfolio. This portfolio was developed to exemplify the impact stringent environmental requirements could have on the APS resource mix.

RULE F.2

Will result in the load-serving entity's reliably serving the demand for electric energy services.

The APS 2012 Resource Plan is designed to provide reliable power to its customers with the required operating reserves while allowing for unforeseen events such as higher-than-forecast customer demand and forced outages of several generators at one time. APS uses an LOLP reliability criterion of one event in ten years to provide the desired level of reliability. While there is not a standard prescribed by the WECC or NERC, a 1-in-10 LOLP is a common standard in the industry. APS has found that designing resource portfolios based on a 15% reserve margin provides better than 1-in-10 LOLP. APS's 2012 Resource Plan maintains a 15% or greater planning reserve margin for each year of the 15-year Planning Period as indicated in response to Rule D1(b)-B.2(e).

In addition to the reliability discussed above, APS also performs a Reliability Must Run study of its Phoenix and Yuma load pockets every two years as part of the ACC's Biennial Transmission Assessment. This study specifically looks at transmission-constrained load

pockets, and is done in conjunction with Southwest Area Transmission and other Arizona utilities. The last report, filed in January 2012, indicated that planned transmission along with existing transmission and local generation will be sufficient to provide better than 1-in-10 LOLP for the years studied.

RULE F.3

Will address the adverse environmental impacts of power production.

The APS 2012 Resource Plan includes in its base assumptions a hypothetical cost for carbon emissions implemented in 2019. In addition, and as further described in response to Rule D.17, APS has planned for several power plant emissions upgrades over the next decade to ensure full compliance with any potential new or enhanced environmental regulations. The APS 2012 Resource Plan includes a significant amount of energy efficiency and renewable energy – resources that provide energy to APS with no adverse environmental impacts. This allows APS to face a 55% increase in customer sales (prior to energy efficiency and distributed energy) with only moderate increases in CO_2 emissions and annual water use increases of 13.5% and 11.4%, respectively, over the 15-year Planning Period. Finally, APS has quantified the rates for multiple emissions for the reference plan, as depicted in Attachment D.1(a)(8).

RULE F.4

Will include renewable energy resources so as to meet or exceed the greater of the Annual Renewable Energy Requirement in R14-2-1804 or the following annual percentages of retail kWh sold by the load-serving entity.

As indicated in Table 38 below, the 2012 Resource Plan exceeds the amount of renewable energy required under the ACC RES for all years during the Planning Period. Note that in addition to the RES requirement, APS is required to achieve 1,700,000 MWh of incremental renewable generation by December 31, 2015, per ACC Decision No. 71448.

Calendar Year	ACC RES Requirement (Percent of Retail Sales During Calendar Year)	Renewable Generation in APS 2012 Resource Plan
2012	3.5%	5.04%
2013	4.0%	9.65%
2014	4.5%	10.39%
2015	5.0%	11.59%
2016	6.0%	11.58%
2017	7.0%	11.83%
2018	8.0%	11.56%
2019	9.0%	12.37%
2020	10.0%	12.48%
2021	11.0%	14.48%
2022	12.0%	15.35%
2023	13.0%	15.97%
2024	14.0%	16.62%
2025	15.0%	17.23%
2026	15.0%	17.51%
2027	15.0%	17.23%

Table 38 - Renewable Generation Included in 2012 Resource Plan (% of Retail Sales)

RULE F.5

Will include distributed generation energy resources so as to meet or exceed the greater of the Distributed Renewable Energy Requirement in R14-2-1805 or the following annual percentages as applied to the load-serving entity's Annual Renewable Energy Requirement:

2007	5.0%
2008	10.0%
2009	15.0%
2010	20.0%
2011	25.0%
After 2011	30.0%

The Distributed Renewable Energy Requirement in R14-2-1805 and the annual percentages in the Resource Planning Rules are the same. As indicated in Table 39, the distributed energy represented in the 2012 Resource Plan meets or exceeds the requirements in all years of the Planning Period.

Calendar Year	Distributed Generation Requirement (Percent of Annual Renewable Requirement)	Distributed Generation in APS 2012 Resource Plan (Percent of Annual Renewable Requirement)
2012	30%	36.16%
2013	30%	42.47%
2014	30%	44.63%
2015	30%	44.89%
2016	30%	39.62%
2017	30%	38.44%
2018	30%	32.91%
2019	30%	30.66%
2020	30%	30.57%
2021	30%	30.54%
2022	30%	30.52%
2023	30%	30.49%
2024	30%	30.48%
2025	30%	30.46%
2026	30%	30.45%
2027	30%	30.44%

Table 39 - Distributed Renewable Energy Included in 2012 Resource Plan

RULE F.6

Will address energy efficiency so as to meet any requirements set in rule by the Commission, or in an order of the Commission.

There are two ACC Decisions impacting energy efficiency represented in the 2012 Resource Plan. ACC Decision No. 71448 set forth energy efficiency requirements through 2012 based upon the 2009 rate case settlement as illustrated in Table 40. ACC Decision No. 71819 set forth Energy Efficiency Requirements provided in Table 41, which became effective January 1, 2011.

Year	ACC Energy Efficiency Requirement (Decision No. 71448)	Energy Efficiency in APS 2012 Resource Plan
2012	1.50%	1.71%

Table 40 - EE Included in the 2012 Resource Plan (% of Retail Sales)

Calendar Year	ACC Decision No. 71819 Energy Efficiency Standard (Percentage of Retail Sales)	Energy Efficiency Included in APS 2012 Resource Plan
2012	3.00%	3.07%
2013	5.00%	5.00%
2014	7.25%	7.25%
2015	9.50%	9.50%
2016	12.00%	12.00%
2017	14.50%	14.50%
2018	17.00%	17.00%
2019	19.50%	19.50%
2020	22.00%	22.00%
2021	22.00%	22.00%
2022	22.00%	22.00%
2023	22.00%	22.00%
2024	22.00%	22.00%
2025	22.00%	22.00%
2026	22.00%	22.00%
2027	22.00%	22.00%

Table 41 - Cumulative EE by Calendar Year (% of Retail Sales)

As indicated in Table 41, Energy Efficiency represented in the 2012 Resource Plan meets or exceeds the EE Standard in all years of the Planning Period.

RULE F.7

Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

As described in response to Rule F.1, APS performed a rigorous series of analytics on all of the potential portfolios under consideration. This effort was driven specifically towards identifying the most robust portfolio that would both provide a low-cost set of resources for customers while simultaneously mitigating potential future risks. The 2012 Resource Plan accomplishes both of these criteria. First and foremost, it is the lowest-cost plan of all those analyzed. Secondly, by maintaining a position in multiple fuel sources, APS has the ability to modify its dispatch of resources depending upon future price conditions. For example, should natural gas prices follow a lower trajectory than currently predicted, APS could increase its natural gas-fired generation to capitalize on this trend; conversely, should natural gas prices rise unexpectedly, APS could mitigate this exposure by increasing output at its more stably-priced coal-fired generation fleet. APS also manages future cost and environmental risks by assuming compliance with the EE Standard and the RES. Finally, APS has significant flexibility in how it meets future load forecast fluctuations by relying on resources that have relatively short development lead times, such as solar PV and natural gas plants, as well as relying upon the 15% reserve margin.

RULE F.8

Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2)-(7) and the uncertainty of future costs.

APS's 2012 Resource Plan, as outlined in Attachment F.9(b), meets the objectives set forth in Rules F.2 thru F.7 of the Resource Planning Rules, and is expected to achieve a reasonable long-term cost as shown in Attachment D.10. This plan is a diverse portfolio of resources that meets or exceeds reliability criteria, the EE Standard, the RES, and manages risks through the planning of flexible resource options and limiting exposure to natural gas prices and carbon emissions. As the future unfolds and conditions change, this plan can be easily modified to address changes. It provides a road map for the future, and will guide APS procurement efforts. Those efforts will ultimately result in the specific choices of resources to meet APS customer energy needs in a manner that balances reliability, cost, the environment, and risk.

RULE F.9(a)

Contains all of the following: (a) a complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized.

A complete description and documentation of the plan are contained in the following sections of this report:

Supply Conditions: All of the elements of APS's existing resource portfolio, including owned generation and purchase power contracts, are described and documented in the responses to Rule D.1. Information related to energy efficiency measures is included in the responses to Rule D.14.

Demand Conditions: Customer demand conditions are provided and documented in the responses to Rules C.1, C.2, and C.3.

Availability of Transmission: Transmission necessary to ensure availability for resource delivery is discussed in the responses to Rules D.1(b), D.1(d), D.1(f), D.1(g), and D.10.

Costs: Costs of individual supply-side resource technologies are contained in the response to Rules D.1 and D.3, while costs of individual demand side management measures are contained in the response to Rule D.14. Costs and system revenue requirements associated with the 2012 Resource Plan are contained in Attachment D.10.

Discount Rate: APS uses 7.95%, the Company's after-tax weighted cost of capital, as its discount rate.

RULE F.9(b)

Contains all of the following: (b) a comprehensive, self-explanatory load and resources table summarizing the plan.

The loads and resources table is provided at Attachment F.9(b).

RULE F.9(c)

Contains all of the following: (c) a brief executive summary.

The Executive Summary is included at the beginning of this document.

RULE F.9(d)

Contains all of the following: (d) an index to indicate where the responses to each filing requirement of these rules can be found.

APS has included a high-level Table of Contents for this document and its related Attachments and Appendices, as well as a detailed Index at the end of this document.

RULE F.9(e)

Contains all of the following: (e) definitions of the terms used in the plan.

The definitions of the terms used in the filing are contained in the Glossary included herein.

RESPONSE TO RULES: SECTION H – ACTION PLAN

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(H), which specifically requires information related to the action plan for the following three-year period.

RULES H.1-H.3

Includes a summary of actions to be taken on future resource acquisitions; Includes details on resource types, resources capacity, and resource timing; Covers the three-year period following the Commission's acknowledgement of the resource plan.

APS anticipates that the planned activities required during the 2013-2015 timeframe will be focused primarily on renewable energy procurement (including both distributed and non-distributed), expansion and implementation of energy efficiency programs, and preparation for future peaking resource needs.

Energy Procurement

A summary of the increase in utility-scale resources is provided in Table 42 followed by an in-depth overview and history of the procurement process.

Action	Project	MW	Technology	Agreement	In Service
2011 Photovoltaic	Yuma	35	Solar PV	EPC/Own	2013
2011 RE Small Gen	Maricopa County	15	Solar PV	PPA	2013
2011 RE Small Gen	Tonopah	15	Solar PV	PPA	2013
2012 Photovoltaic	Hyder II	14	Solar PV	EPC/Own	2013
2012 Photovoltaic	TBD	32	Solar PV	EPC/Own	2014
2012 RE Small Gen[61]	TBD	TBD	All RE Source	PPA	TBD
2013 Photovoltaic	TBD	50	Solar PV	EPC/Own	2015
2013 Conventional[62]	TBD	TBD	Natural Gas	EPC/Own/PPA	2016

Table 42 - Summary of Action Plan

APS uses the RFP process as the primary means for procuring both conventional and renewable energy to meet the current and forecasted APS load requirements. In developing the procurement plan and outlook, APS considers the expected time to procure and develop

[61] Need (MW) and timing will be driven by the level of DE achieved.

[62] In the event capacity does not materialize (e.g., the Four Corners transaction is not consummated or EE does not achieve targeted participation levels) natural gas resources would be required.

new resources, diversification of the resource portfolio using renewable energy to limit exposure to volatile fuel prices, such as natural gas, and regulatory requirements set by the ACC in meeting the RES targets. The following describes the protocols and processes that APS follows when procuring capacity and energy, along with an overview of procurement history, current activity, and the plan for energy procurement in the future.

Procurement Protocols

APS, as a load-serving entity, is governed by the Arizona Administrative Code R14-2-705 that describes the allowable methods for procurement and acquisition of wholesale conventional and renewable energy, capacity, and physical power hedge transactions, such as acquiring through third-party online trading applications, third-party energy brokers, RFP processes, or, under certain conditions, bilateral contracts. Additionally, the rules require that the RFP process is used as the primary acquisition process for energy and capacity, unless there are certain exceptions, at which time a bilateral contract can be executed and is acceptable. The exceptions to the RFP process may exist when APS is experiencing an emergency, a short-term acquisition needed to maintain system reliability, procuring other components of the resource such as fuel, transmission, or transportation, planning for two years or less, requiring a transaction to meet obligations for the RES, necessary for demand-side management or demand response programs, or considering an energy procurement because it represents an unanticipated market opportunity at a clear and significant discount.

Further, an independent monitor is required to oversee all RFP processes for procurement of new resources per A.A.C. R14-2-705.C. Pursuant to Decision No. 70032, and consistent with the current A.A.C. R14-2-706, APS submitted four qualified companies for approval by the ACC on January 29, 2008, to serve as independent monitors for APS RFPs. Each was approved by the ACC on March 28, 2008, for performing independent monitoring functions.

RFP Process

As described above, APS engages in the RFP process as the primary method to acquire long-term wholesale conventional and renewable energy and capacity, as required by A.A.C. R14-2-705. In addition to those rules, APS documented and filed a "Renewable Energy Competitive Procurement Procedure" in April 2007 that was certified for use by one of the independent monitors and which outlines a fair and unbiased competitive process for procuring renewable energy. When an RFP is issued, the entire communication and bidding process is conducted confidentially through an independent third-party electronic bidding platform. The following are major components of the process:

Applicability: APS procures for the wholesale acquisition of energy and capacity in accordance with the Resource Planning and Procurement Rules, as stated in A.A.C. R14-2-705.B. The Competitive Procurement Procedure applies to all solicitations initiated to meet the obligations in the approved APS RES Implementation Plan. This also covers renewable bilateral agreement opportunities which are outside of a solicitation period or scope to ensure that those remain unbiased, are subject to being screened with the same detailed evaluation criteria performed during a competitive solicitation, consider market trends, and are reviewed by an independent monitor.

Request for Proposal: Each RFP will contain a product description, which defines the timeframe, eligible technologies, capacity and energy requirements, deliverability requirements, and ownership structure. Further details include an RFP schedule with

specific dates for release of RFP documents and presentations, critical RFP deadlines, bid submittal instructions and requirements, and specific agreements required for bid acceptance. Lastly, the proposal review and evaluation process is outlined with specific quantitative and qualitative criteria for which bids are evaluated, along with the specific agreements and regulatory approvals, if applicable, required prior to execution.

Independent Monitor: The role of the independent monitor appointed by APS is to certify that the RFP process is fair, transparent, equitable among bidders, and conducted in accordance with A.A.C. R14-2-705 and the Competitive Procurement Process for renewable energy. During their monitoring process, starting with the RFP document preparation and ending with the final short-list selection, the independent monitor will evaluate APS on completeness and adequacy of RFP documents, monitor communications through the electronic bid platform, assure consistency of evaluations, provide recommendations on process improvement opportunities, and provide a documented certification of their review.

Procurement Conduct Standards: The Competitive Procurement Procedure further documents the rules that the RFP team must follow, such as not assisting bidders prepare bids, not giving preferential treatment to affiliates (if applicable), ensuring all bidders receive substantive information and documents throughout the bidding and competitive process, and abiding by all regulations regarding FERC Standards of Conduct and ACC Codes of Conduct.

Procurement Timeline

The procurement process typically takes six to nine months depending on the type and complexity of the solicitation. APS begins the RFP process by preparing the RFP document that outlines the scope and requirements for the resource being procured. During preparation of the RFP, APS selects and contracts with the independent monitor that will oversee the solicitation. Shortly thereafter, a press release is issued announcing the RFP to the general public that broadly describes the RFP, followed by issuance and publication of the RFP document. Within a couple of weeks, APS hosts a webinar that presents specific details about the RFP document and provides an avenue for potential bidders to ask questions prior to their bid preparation.

Once bidders have submitted their bids, APS begins their comprehensive evaluation process to determine the short-list to continue the process, based on both quantitative and qualitative factors that offer the best product and price to APS ratepayers while considering relevant risk factors for APS, such as bidder creditworthiness, experience and expertise, contracts, technical viability, etc. Once APS determines and communicates the short-list, the bidders continue through the competitive procurement process by meeting any remaining milestones, which may include items such as preliminary contract discussions, interconnection process, and site control, ultimately ending with an executed agreement, such as a PPA or an EPC to begin development of the resource. Depending on the technology and type of resource, the timeframe from contract execution to commercial operation date may take as little as under one year for existing assets to up to four years for a conventional combined cycle gas plant. Figure 43 illustrates the typical solicitation timeline.

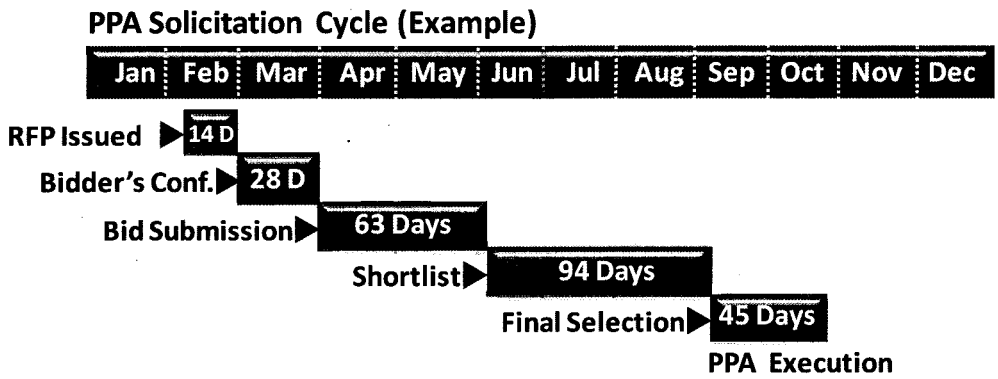

Figure 43 - Illustrative RFP Timeline

RFP History

APS has been actively engaged in the RFP process in recent years and has utilized this process extensively to competitively procure capacity and energy to meet APS's current and forecast load and regulatory requirements. In doing so, APS has issued RFPs as necessary to meet those requirements. Table 43 contains a brief listing of existing contracts or assets procured through an RFP process since 2003:

RFP Solicitation History (Contracted)

Year	RFP Type[63]	Contract	Technology	Capacity	Term/Years	COD / Delivery
2003	**Power Supply**	Own	Conventional	450	N/A	2005
2005	**RE-All Source**	PPA	Wind	90	20	2006
		PPA	Geothermal	10	23	2006
2005	**REL-All Source**	PPA(s)	Conventional	500	8-9	2007
		PPA	Conventional	150	10	2007
		PPA Toll	Conventional	510	10	2007
2005	**Yuma Peaking**	Own	Conventional	96	N/A	2008
2007	**RE-All Source**	PPA	Solar - CSP	250	30	2013
		PPA	Wind	100	30	2009
		PPA	Landfill Gas	3	20	2010
2007	**Demand Response**	PPA	Load Control	100	15	2010
2008	**Distributed Energy**	PPA	Solar - PV	15	25	2011
		PPA	Solar - PV	RECs	4	2012
		PPA	Solar - PV	1-5	N/A	2010
2009	**RE-Small Gen**	PPA	Solar - PV	4.5	25	2011
		PPA	Solar - PV	10	30	2011
2010	**RE-AZ Wind**	PPA	Wind	99	25	2011
2010	**RE-Small Gen**	PPA	Landfill Gas	3	20	2012
		PPA	Solar - PV	15	30	2012
2010	**AZ Sun (PV)**	Own (3)	Solar - PV	50	N/A	2011/12
		Own (1)	Solar - PV	19	N/A	2012

Table 43 - Summary of APS RFP History

[63] RE = Renewable Energy; REL = Reliability.

Current Utility-Scale Renewable Energy Procurement and Planned RFPs

During the 2013 to 2015 timeframe, APS expects to continue renewable resource development activities initiated through ongoing regulatory programs as currently approved by the ACC and to meet the renewable energy requirements outlined in the 2012 RES Implementation Plan and the 2009 Settlement Agreement. Two of those specific programs, the AZ Sun Program and the Renewable Energy Small Generation Program, are described below both historically and in the near-term procurement outlook during the 2013 to 2015 timeframe.

AZ Sun Program: The AZ Sun Program was approved by the ACC on March 17, 2010 (Decision No. 71502), authorizing APS to develop and own 100 MW of PV solar facilities in Arizona through a competitive procurement process and RFP solicitations. The goals of this program are to attract economies of scale, place resources where they will offer the greatest benefit to APS customers, offer easier financing for developers as supported by APS's balance sheet, and help diversify utility-scale renewable energy resources and mitigate risk through the ownership model versus relying on PPAs alone.

As requested by APS in the 2012 Implementation Plan, the ACC approved an additional 100 MW on January 18, 2012, to continue development of PV facilities under this program in 2013 through 2015.[64] To date under the AZ Sun program, 45 MW are commercially operating at the end of 2011, followed by an additional 24 MW and 35 MW currently expected for commercial operation in 2012 and 2013, respectively. APS will continue to procure the balance of the 200 MW through prorated RFP solicitations in 2012 and 2013 with expected commercial operation of 14 MW (2013), 32 MW (2014), and 50 MW (2015). These procurement efforts are outlined in Table 42.

Renewable Small Generation Program: The Small Generation Program was originally approved by the ACC as a pilot program in the 2009 RES Implementation Plan for 45,000 MWh that resulted in two PPAs for solar PV projects from the March 2009 RFP. The result was two projects totaling 14.5 MW that went online at the end of 2011. In 2010, based on the success of the Pilot Program, APS subsequently requested and obtained approval in the 2011 RES Implementation Plan that will allow APS to purchase an additional 200,000 MWh annually after the three-year deployment of the Small Generation Program through the competitive procurement process, where all source renewable energy is eligible to bid. The first of three planned RFP solicitations was issued in April 2010 that resulted in two PPAs, a 3 MW landfill gas and a 15 MW solar PV facility expected to be in commercial operation in 2012.

The second solicitation issued in April 2011 resulted in two executed solar PV PPAs, each 15 MW and expected to be in commercial operation in 2013. Due to the expected increases in distributed energy and expansion of those programs, as approved by the Commission on January 13, 2012, for the 2012-2016 Implementation Plan, the third all-source renewable energy RFP solicitation (originally expected to be issued in early 2012) was postponed. APS will continue to evaluate the levels of distributed energy deployment during 2012 to determine the timing and need of a future solicitation under this program.

[64] Decision No. 72737.

Distributed Renewable Energy

In addition to the utility-scale renewable energy projects, APS expects continued growth of distributed renewable energy programs and the associated increase in customer participation and incentive commitments as approved by the Commission on January 18, 2012 (Decision No. 72737) for the 2012-2016 RES Implementation Plan. The expected increases in distributed energy over the next several years from the DE program expansion, increased numbers of installed projects from the non-residential DE program, and the 2008 Distributed Energy RFP (which resulted in three executed contracts, including a 25-year PPA for a 15 MW PV system at a mine in Bagdad, Arizona, in full commercial operation at the end of 2011) will satisfy the need for distributed energy to help meet the 2009 Settlement Agreement.

Demand-Side Management Resources

Beginning in 2013, APS plans to pursue piloting a standby generation program. Advancing the standby generation program includes harvesting paralleled and unparalleled existing generators at customer facilities, as well as the installation of new generators. These initial efforts will focus on areas of the APS distribution system that are peak capacity constrained. APS is currently assessing the market to determine the economics of standby generation and will seek necessary cost recovery through the 2013 and/or 2014 DSM Implementation plans.

APS has designed the EE portfolio to comply with the EE Standard, resulting in 22% cumulative energy savings from demand-side resources by 2020. During this time, the Company plans to continue to file annual implementation plans that detail the delivery of the annual compliance target. The annual DSM filing will be comprised of a combination of existing programs and new programs, aimed at delivering cost-effective net benefits to APS and its customers.

The portfolio of demand response and load management solutions will continue to be refined based on learnings from the HEI Pilot, which explores residential customer offerings such as direct load control, enabling technologies, and critical peak pricing, and will provide a platform for future residential DR efforts. Opportunities identified through the HEI Pilot will be proposed in 2015.

Conventional Energy Resources

APS recognizes that conventional energy resources may be needed in the near-term to address resource uncertainties. APS is pursuing an initiative to provide options for new natural gas generating facilities, which acknowledges the long project development lead times for new facilities and addresses a number of resource uncertainties currently facing APS.

Early in 2011 APS's contingency planning efforts identified the combined uncertainty of future load growth and several resources included in the resource plan. The plan includes an assumption that the proposed Four Corners transaction is consummated resulting in additional system capacity. APS recognizes the uncertainty of the pending case before the Commission regarding the Four Corners coal plant, coupled with the ongoing coal fuel supply negotiations, and is preparing for contingencies in the event the transaction is not consummated. In addition, the current resource plan assumes that APS programs for distributed energy and energy efficiency will produce specific reductions in demand over the coming years. The level of APS customer participation can dramatically impact the need for

new generation. Finally, the near-term assumptions of load growth are lower than historical levels and a return to normal growth would accelerate the need for additional resources.

If some of the planned resources do not materialize there could be a need for additional natural gas generation within the metropolitan Phoenix area as early as the summer of 2016. While existing merchant generation may provide such resources, the availability and cost of merchant generation is not within APS's control. The objective of the APS's contingency planning efforts is to identify solutions under the Company's control that could individually or in combination serve to provide economic generation and transmission resources in the required timeframes.

The development timeframe for new gas-fired generation, at new or existing sites, is between 3 and 5 years. APS is identifying and developing solutions that could provide contingency resources in the near-term or can be delayed in time and serve needs for combined cycle and combustion turbine generation in the window of 2017 to 2021. The planning, engineering, and other development work being performed will not be wasted since those specific solutions will eventually be needed to meet future planned natural gas resource needs.

Pending the outcome of these efforts, APS may need to issue RFPs in the first half of 2013 for natural gas combined cycle and simple-cycle generation. The following resource options to address the capacity needs may be considered: (1) EPC; (2) asset purchase; or, (3) PPA to address the capacity needs. Each of these three options may be considered in the RFP and APS will evaluate each with respect to the timing of generation capacity needs, capital requirements for self-build versus merchant assets available, transmission availability, locational attributes, and resource cost considerations.

Additional activity during the timeframe of 2013 to 2015 may include initial development steps for one or more potential sites for natural gas generation designed to preserve resource procurement opportunities. These activities may include land acquisition, permitting, and consideration of interconnection requests.

RESPONSE TO RULES: SECTION I – OTHER FACTORS

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(I), which allows a utility to provide additional information related to environmental impacts for the Commission's consideration.

RULE I

A load-serving entity or any interested parties may also provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops.

APS has included data related to environmental impacts of its 2012 Resource Plan in multiple locations within this document. Environmental issues are discussed in Section 2.2.2. Water usage (expressed in annual Acre-Feet) has been included in all of APS's analytics discussed in the Section titled Portfolio & Sensitivity Analytics. Environmental plans are discussed at length in response to Rules D.17, E.1(d)-E.3(d), and E.1(e)-E.3(e). In addition, APS ran a sensitivity analysis that monetizes the costs of externalities. Externality costs are discussed in response to Rules E.1(h)-E.3(h). A table of emissions for each generator is found at Attachment D.1(a)(8). Attachments F.1(b)-F.1(d) contain the backup information for all of the model runs performed in support of this resource plan. Finally, Appendix A provides a discussion on carbon cost and legislation, and Appendix B provides an update on APS's efforts with regards to the water/energy nexus.

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AAC	Arizona Administrative Code
ACC	Arizona Corporation Commission
ACI	Activated Carbon Injection
ADD	Acquisition, Development and Deliver Water Program
ADEQ	Arizona Department of Environmental Quality
ADWR	Arizona Department of Water Resources
AF	Acre-Feet
AFUDC	Allowance for Funds Used During Construction
AMA	Active Management Area
APS	Arizona Public Service
ARS	Arizona Revised Statutes
BART	Best Available Retrofit Technology
BCF	Billion Cubic Feet
BTA	Biennial Transmission Assessment
Btu	British Thermal Unit
C&I	Commercial & Industrial
CAA	Clean Air Act
CAIDI	Customer Average Interruption Duration Index
CAMR	Clean Air Mercury Rule
CAP	Central Arizona Project
CC	Combined Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture & Sequestration
CDA	Conditional Demand Analysis
CEMS	Continuous Emissions Monitoring Systems
CFL	Compact Fluorescent Lamp

CO	Carbon Monoxide
CO_2	Carbon Dioxide
Commission	Arizona Corporation Commission
Company	Arizona Public Service
CP	Coincident Peak
CPP	Critical Peak Pricing
CSP	Concentrating Solar Power
CT	Combustion Turbine
CWA	Clean Water Act
DE	Distributed Energy
DLN	Dry Low NOx
DOE	U.S. Department of Energy
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EER	Energy Efficiency Ratio
EGU	Electric Generating Unit
EHV	Extra High Voltage
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ELG	Effluent Limitations Guidelines
EPA	Environmental Protection Agency
EPC	Engineer-Procure-Construct
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gas

GUAC	Groundwater Users Advisory Council
GWh	Gigawatt-Hours
HAN	Home Area Network
HAP	Hazardous Air Pollutant
HEI	Home Energy Information
Hg	Mercury
HPES	Home Performance with Energy Star®
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IRP	Integrated Resource Plan
IRR	Interruptible Rate Rider
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-Hour
LAER	Lowest Achievable Emission Rate
LNB	Low NOx Burners
LOLP	Loss of Load Probability
MACT	Maximum Achievable Control Technology
MAF	Million Acre-Feet
MATS	Mercury and Air Toxics Standard
MCAQD	Maricopa County Air Quality Department
MER	Measurement, Evaluation, and Research
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NAAQS	National Ambient Air Quality Standards
NAS	National Academies of Science
NEPA	National Environmental Policy Act

NERC	North American Electric Reliability Corporation
NGS	Navajo Generating Station
NNSR	Nonattainment New Source Review
NOx	Nitrogen Oxide
NPV	Net Present Value
NSPR	New Source Performance Review
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation & Maintenance
OFA	Over-fire Air
PHEV	Plug-in Hybrid Electric Vehicle
PM	Particulate Matter
PPA	Purchased Power Agreements
PPM	Parts per Million
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
RCRA	Resource Conservation & Recovery Act
RES	Renewable Energy Standard
RFP	Request for Proposal
RTAP	Renewable Transmission Action Plan
RTP	Renewable Transmission Project
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEER	Seasonal Energy Efficiency Ratio
SCE	Southern California Edison
SCR	Selective Catalytic Reduction
SCT	Societal Cost Test

SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SRSG	Southwest Reserve Sharing Group
TES	Thermal Energy Storage
TRC	Total Resource Cost Test
TOU	Time of Use
TVA	Tennessee Valley Authority
UARG	Utility Air Regulatory Group
VOC	Volatile Organic Compounds
WECC	Western Electricity Coordinating Council

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GLOSSARY

2012 Resource Plan	Represents APS's selection of an energy resource portfolio for the 2012-2027 period based upon a wide range of supply- and demand-side options. The 2012 Resource Plan assumes the approval of the proposed Four Corners application to purchase SCE's share of Four Corners Units 4 and 5, and to retire APS Units 1-3 at Four Corners.
Acquisition, Development and Deliver Water Program (ADD)	Relates to a public stakeholder process that resulted in a consensus regarding how new water supplies should be shared and paid for by water users in Central Arizona Project's (CAP) service area of Maricopa, Pinal and Pima counties, assuming CAP is the entity that acquires, develops and delivers those supplies.
Acre-foot	The volume of water that will cover an area of 1 acre to a depth of 1 foot. 1.0 acre foot equals approximately 325,851 gallons.
Activated Carbon Injection System (ACI)	An engineered mercury control system from which powdered activated carbon (PAC) is pneumatically injected from a storage silo into the flue gas ductwork of a coal-fired power plant or industrial boiler. The PAC adsorbs the vaporized mercury from the flue gas and is then collected with the fly ash in the facility's particulate collection device.[65]
Aquifer Protection Program in Arizona	An ADEQ program designed to protect the quality of Arizona drinking water. Includes two key requirements: (1) meet Aquifer Water Quality Standards at the Point of Compliance; and (2) demonstrate Best Available Demonstrated Control Technology.
Arizona Administrative Code (AAC)	The official compilation of rules that govern the state of Arizona's agencies, boards, and commissions.
Arizona Corporation Commission (ACC or Commission)	The Arizona Corporation Commission is comprised of five publically-elected persons who have full power to make reasonable rules, regulations and orders by which public service corporations shall be governed in doing business within the state of Arizona.
Arizona Department of Environmental Quality (ADEQ)	Administers a variety of programs to improve the health and welfare of citizens and ensure the quality of Arizona's air, land, and water resources meet healthful, regulatory standards.
Attainment	Any area that meets the national primary or secondary ambient air quality standard for a pollutant.
Baghouse	An air pollution abatement device that traps particulates (dust) by forcing gas streams through large filter bags, usually made of fiberglass or other synthetic fabrics and coatings.
Base Case Portfolio	Portfolio of resources assuming the Four Corners transaction is consummated.
Baseload Plant	An electric generating plant devoted to the production of electricity on a relatively continuous basis. Baseload plants are typically operated for the majority of the hours during a given year and are taken off-line relatively infrequently. Baseload plants usually have a low variable production cost relative to other production facilities available to the system.
Best Available Retrofit Technology (BART)	Under the Clean Air Act, states must require the installation of the best retrofit emission controls available as part of state strategies for meeting the regional haze rule. The BART requirement applies to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution.

[65] http://www.adaes.com/mercury/acis/

Biogas	Otherwise known as biomass gas, a medium Btu gas containing methane and carbon dioxide, resulting from the action of microorganisms on organic materials such as a landfill.
Biomass	Organic non-fossil material of biological origin constituting a renewable energy source that can be either processed into synthetic fuels or burned directly to produce steam or electricity.
British Thermal Unit (Btu)	Used to describe the heat content of fuel. The price of fuel is typically expressed in terms of dollars per million Btu (or $/MMBtu).
Brominated Activated Carbon Injection	A type of engineered mercury control system used to control mercury emissions.
Busbar Costs	The cost of producing electricity and delivering it to the transmission system at the power plant busbar. Includes construction, fuel, and operating and maintenance costs.
Cap and Trade	An approach used to control emissions by providing economic incentives for achieving reductions. A central authority (usually a government or international body) sets a limit or cap on the amount that can be emitted. Companies or other groups are issued emission permits and are required to hold an equivalent number of allowances (or credits) which represent the right to emit a specific amount. The total amount of allowances cannot exceed the cap, limiting total emissions to that level. Companies that need to increase their emissions must buy allowances from those that emit less. The transfer of allowances is referred to as a trade. In effect, the buyer is paying a charge for emitting, while the seller is being rewarded for having reduced emissions by more than was needed.
Capacity	The maximum amount of electricity a generation source can produce in any given moment. Capacity is usually measured in units of megawatts. It should be noted that most generation sources are not operated at their maximum capacity rating during all hours that they are generating electricity. ***See*** *Capacity Factor*
Capacity Factor	A value used to express the average production level of a generating unit over a given period of time. Capacity factor is expressed as a percentage of the maximum possible production if the generating unit had operated at its maximum capacity rating for all hours during the period. For example, a generating facility which operates at an average of 60% of its maximum capacity over a measured period has a capacity factor of 60% for that period.
Capacity Value	A resource's ability to reliably serve load during APS's top 90 load duration hours. Capacity value is calculated by dividing the average net capacity of the resource during APS's top 90 load hours by the resource's maximum hourly capacity.
Carbon Capture & Sequestration (CCS)	A technology under development to limit emissions of carbon by capturing and storing it away from the atmosphere.
Carbon Dioxide (CO_2)	A naturally occurring gas, and also a by-product of burning fossil fuels and biomass, as well as land-use changes and other industrial processes. It is the principal greenhouse gas that affects the Earth's radiative balance. ***See*** *Greenhouse Gas, Emissions*
Carbon Monoxide (CO)	A colorless, odorless, toxic gas produced by the incomplete combustion of carbon-containing substances. One of the major air pollutants, it is emitted in large quantities by exhaust of gasoline-powered vehicles.
Carrying Charges	Annual costs associated with investment in assets including depreciation, debt interest, equity return, income taxes, and property taxes.

Cascading	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
Class-Based Hourly Load Models	Methods for identifying the hourly pattern of electricity demand for groups of customers with similar characteristics.
Clean Air Act (CAA)	The primary federal law enacted by the U.S. Congress to govern the regulation of emissions into the atmosphere on a national level. The primary responsibility for administering the CAA was given to EPA which develops and enforces regulations to protect the general public from exposure to airborne contaminants.
Coal Combustion Residual (CCR)	Referred to as coal ash, CCRs are currently considered exempt wastes under the Beville amendment to the Resource Conservation and Recovery Act (RCRA). They are residues from the combustion of coal in power plants and captured by pollution control technologies, such as scrubbers.
Coal Retirement Portfolio	Shows the impact of retiring all of APS's coal-fired generation during the Planning Period.
Combined Cycle (CC)	Twin-stage natural gas-fired power plants that deliver higher fuel efficiency. In the first stage, a gaseous fuel source (natural gas, gaseous coal, etc.) is combusted in a gas turbine. The turbine is used to drive an electric generator. In the second stage, waste heat is captured from the gas turbine's hot exhaust gases in a heat recovery steam generator (HRSG). The steam that is produced in the HRSG is used to drive a steam turbine and produce additional electricity. This beneficial use of the residual heat content in the gas turbine's exhaust stream contributes to the excellent fuel efficiency of the combined cycle power plant.
Combustion Turbines (CT)	Also referred to as a simple cycle gas turbine, these electric generators operate on a principle similar to the engines on jet airplanes. Ambient air is compressed to high pressures in the compressor section of the machine. A gaseous fuel source is added to this compressed air and combusted in the combustor section. The resulting hot gases are then expanded through a turbine section that provides the driving force for both an electric generator and the compressor section.
Commercial Operation Date (COD)	The date when an operating utility formally declares a new generation resource to be available for the regular production of electricity.
Commodity Hedging Strategies	***See** Hedging*
Compact Fluorescent Lamp (CFL)	A type of fluorescent lamp. Compared to incandescent lamps giving the same amount of visible light, CFLs use less power and have a longer rated life.
Competitive Procurement Procedure	Any solicitation process initiated to meet APS energy requirements. The Competitive Procurement Process shall include, as appropriate, preparing and conducting the solicitation, bid evaluation and selection, and negotiating the definitive agreement(s), but shall not include management or implementation of such agreement(s) after their execution.
Concentrated Solar Power	Technologies that concentrate solar energy to generate electricity. This class of solar technologies includes solar trough, power towers, dish stirling, and concentrating photovoltaics.
Conditional Demand Analysis (CDA)	Statistical approach that allocates total household electricity demand during a period into components associated with a particular electricity-using appliance or end-use.

Consumption (Energy Use)	The total amount of electricity consumed over a period of time. Consumption varies from demand in that demand is the rate at which electricity is being used at any one given time.
Conventional Resources	Conventional generating resources include a broad class of technologies that use coal, nuclear, natural gas, or fuel oil to generate electricity.
Cooling Degree-day	A measure of how warm a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the base temperature (65 degrees) from the average of the day's high and low temperatures, with negative values set equal to zero. Each day's cooling degree-days are summed to create a cooling degree-day measure for a specified reference period. Cooling degree-days are used in energy analysis as an indicator of air conditioning energy requirements or use.
Critical Peak Pricing (CPP)	Time-of-use rate plan (also known as Peak Event Pricing) that provides an extremely high price signal during a limited number of hours on critical days (such as periods of high electrical demands, extreme temperatures, system outages, or other abnormal grid-related events).
Customer Average Interruption Duration Index (CAIDI)	The average outage duration for those customers experiencing an outage.
Customer Resources	Resource options which rely upon active participation by customers to produce either a reduction in energy consumption or peak demand. These customer-side resource programs include energy efficiency programs, demand response programs, and alternative rate schedules. Energy efficiency programs are directed at achieving reductions in customer energy consumption through more efficient equipment or improvements to a building's thermal envelope. Demand response programs generally target reductions during the highest usage periods of the year through special rate schedules (such as time-of-use prices), energy storage options, or other similar programs.
Day-Ahead Call Option	Provides the buyer of the option with the right, but not the obligation, to receive a predetermined amount of electric energy during a specified delivery period. The buyer usually pays a reservation fee (referred to as the option premium) to the seller to obtain this right. When the buyer exercises the right to receive energy, the buyer also pays the seller for the energy received based upon a predetermined price or formula. These call option contracts also specify how much advance notice the buyer must provide to the seller in order to receive energy. With a "day-ahead" option, the buyer must provide this notice on the day prior to receiving the energy.
Day-Ahead Trader	Trader that engages in forward markets that cover a 24-hour period in advance of a given day.
Delivered Cost	Refers to the cost of power produced by a generating unit (or a purchased power contract) where the cost of delivering the electric power from the generating source to the load center (area of customer consumption) has also been included in the cost.
Demand	The rate at which electricity is being used at any given time. Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time.
Demand Response (DR)	Mechanisms designed to provide incentives to customers to reduce their load in response to high electric market prices or electric system reliability concerns. Demand response measures could include direct load control programs, such as cycling of air conditioner load, or customer-initiated load reductions. Price response programs include real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buyback programs.

Demand-Side Management (DSM)	The planning, implementation, and monitoring of utility activities designed to encourage residential and business customers to modify patterns of electricity usage, including the timing and level of electricity demand.
Discount Rate	An interest rate used to convert future cash flows to present values.
Dispatchable	Generating units (or purchased power contracts) whose rate of power production can be adjusted or varied based upon economic or other considerations. Different types of generating units have varying degrees of dispatchability either for technical or economic reasons.
Distributed Energy	A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid or the customer's electrical system. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and solar photovoltaics.
Distribution	The delivery of energy to retail customers.
Dry Cooling	The typical steam power plant requires cooling water to improve overall cycle efficiency by returning the exhaust steam to a liquid state that can then be returned to the boiler to produce more steam. In a dry-cooled power plant, the exhaust steam is cooled by use of air-cooled condensers thereby eliminating the use of water from this portion of the power production process; however, the air-cooled condensers are more expensive and overall plant efficiency is reduced versus water-cooled plants.
Dry Low NOx	Combustion system method of reducing NOx emissions by pre-mixing air and fuel prior to ignition.
DSM Implementation Plan	Annual filing required for compliance with the Arizona Corporation Commission's Electric Energy Efficiency Standards, codified at A.A.C. RI4-2-2401, which includes the implementation strategy APS will use to achieve compliance with the EE Standard.
Effluent	Wastewater, treated or untreated, that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.
Electric Generating Units (EGU)	A solid fuel-fired steam generating unit that serves a generator who produces electricity for sale to the electric grid.
Emissions	Discharges into the atmosphere from stacks, other vents, and surface areas of commercial and industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhaust.
Energy	The amount of electricity a generation resource produces, or an end user consumes, in any given period of time. It is usually measured in units of kilowatt-hours, megawatt-hours, or gigawatt-hours.
Energy Efficiency	In the context of resource planning, energy efficiency refers to actions taken by consumers to reduce their overall consumption of electric energy. These reductions could be the result of installation of more efficient equipment, improvements to the thermal envelopes of structures, or behavioral changes. Energy efficiency improvements can be encouraged through utility-sponsored programs, mandated by building codes or other standards or simply implemented by the customer.
Energy Efficiency Standard (EE Standard)	Requirement codified in A.A.C. R14-2-2404 to achieve an accumulated energy savings equivalent to 22% of retail sales by the year 2020.
Energy Savings	A reduction in the amount of electricity used by end users as a result of participation in energy efficiency programs and load management programs.

Engineer-Procure-Construct (EPC)	A form of contracting arrangement in which the contractor will design the installation, procure the necessary materials, and construct it.
Enhanced Renewable Portfolio	Portfolio that relies on 30% renewable energy (after the impacts of energy efficiency and distributed energy) as part of the resource mix.
Environmental Impact Statement (EIS)	The statement required of federal agencies by Section 102 (C) of the National Environmental Policy Act of 1969 for major Federal actions that may significantly affect the quality of the human environment.
Environmental Protection Agency	A governmental agency established in 1970 to research, monitor, establish standards, and enforce activities to establish a cleaner, healthier environment.
Externalities	Occurs when an entity is engaged in an activity that creates harm or benefits for others as a byproduct, but that entity does not pay the costs of, or receive compensation for, the harm or benefits created. An example would be water use and water consumption.
Federal Energy Regulatory Commission	A governmental agency that regulates the interstate transmission of natural gas, oil, and electricity and wholesale power transactions. FERC also regulates natural gas and hydropower projects.
Federal Poverty Guidelines	Issued each year in the Federal Register by the Department of Health and Human Services. The guidelines are a simplification of the poverty thresholds for use for administrative purposes — for instance, determining financial eligibility for certain federal programs.
Flue Gas Desulfurization (FGD)	Equipment, also known as scrubbers, used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals such as lime are used as scrubbing media. Scrubbers are also used to capture particulates.
Force Majeure	Disruptions in service caused by natural disasters (earthquakes, hurricanes, floods, etc.); wars, riots, or other major upheaval; or, performance failures of parties outside the control of the contracting party.
Four Corners Contingency Portfolio	Assumes the Four Corners transaction is not consummated, resulting in plant closure. Energy is replaced with natural gas-fired generation.
Geothermal	Energy produced below the Earth's crust in a layer of hot and molten rock called magma, heating nearby rock and water that has seeped deep into the Earth. At geothermal power plants, wells are drilled into the rock to more effectively capture the hot water and steam to be used to drive electric generators.
Grand Canyon Visibility Transport Commission	Established by the U.S. Congress to assess the potential impacts of projected growth on atmospheric visibility at Grand Canyon National Park and to make recommendations to EPA on what measures could be taken to avoid such adverse impacts.
Greenhouse Gas (GHG)	A collection of gaseous substances, primarily consisting of carbon dioxide, methane, and nitrogen oxides, which have been shown to warm the earth's atmosphere by trapping solar radiation. Greenhouse gases also include chlorofluorocarbons, a group of chemicals used primarily in cooling systems and which are now either outlawed or severely restricted by most industrialized nations.
(Power) Grid	An interconnected network of electric power transmission lines. The United States power grid, which covers most of the country as well as parts of Canada and Mexico, is made up the Eastern Interconnection, Western Interconnection, and Texas Interconnection. These networks include extra-high-voltage connections between individual utilities, which transfer electrical energy from one part of the network to another. The Interconnects distribute electricity in their respective areas via a network of smaller units that enable better management of power distribution.

Hazardous Air Pollutants (HAP)	Substances covered by air quality criteria, which may cause or contribute to illness or death.
Heat Rate	A measure of the amount of thermal energy required to produce a given amount of electric energy. It is usually expressed in British thermal units per kilowatt-hour (Btu/kWh). The performance of a power plant is measured by its fuel consumption rate (Btu/hr) and the corresponding amount of electric energy generated; thus, heat rate can be used to indicate the efficiency with which thermal energy is converted into electric energy.
Heating Degree-day	A measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's heating degree-days are summed to create a heating degree-day measure for a specified reference period. Heating degree-days are used in energy analysis as an indicator of space heating energy requirements or use.
Heating, Ventilating and Air Conditioning (HVAC)	Technology which provides indoor air comfort.
Hedging	The attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks. For example, a company that has an obligation to purchase fuel oil in six months may want to eliminate the risk that prices will increase before that time. In this case, the company could hedge, or reduce, that risk by purchasing a futures contract that provides the right to purchase fuel oil at a fixed price. Any profit or loss on the futures contract should offset the effects of higher or lower oil prices at the time the company needs to buy oil.
Hg (Mercury)	***See*** Mercury
Hub	In the context of the electric grid, a hub is a location on the transmission network having a high concentration of interconnected transmission lines, generating sources, and/or counterparties willing to transact power trades such that this becomes a location having a great deal of commercial activity.
Hybrid Cooling	A type of technology that utilizes a combination of water cooling and dry cooling techniques. The relative contribution from each is dependent upon the plant design, weather conditions, and water consumption policies. ***See also*** Dry Cooling.
Independent Monitor	Appointed by APS under a scope of services agreement to certify that the RFP process is fair, transparent, equitable among bidders, and conducted in accordance with ACC R14-2-705 and the Competitive Procurement Process for renewable energy.
Integrated Gasification Combined Cycle (IGCC)	A power generation technology which allows a reduction of emissions by combining two technologies: (1) coal gasification, which uses coal to create a clean-burning gas; and, (2) combined cycle generation.
Intensity	Metric employed to characterize the emission of pollutants, relative to the power produced. For example, tons of CO_2 emitted per MWh or gallons of water used per MWh can be used to help characterize the energy intensity of the system resources independent of load growth.
Interconnection	A connection between two electric systems permitting the transfer of electric energy in either direction. Additionally, an interconnection refers to the facilities that connect a generator to a system.

Intermediate Resource	Generation resources that usually fulfill a somewhat flexible role in the generating system. During some times of the year, these generating units will be started in the morning hours, used to meet daytime peak loads and then brought off-line in the evening. The operation may change during heavier load times of the year when these units may operate in more of a baseload manner and remain on-line for all hours of the day.
Intermittent Resource	Generating resources that have some degree of variability in the production pattern, typically due to weather conditions. An example of an intermittent generating source is a wind project. The power output from the wind project is entirely dependent upon the wind conditions and will fluctuate with changes in wind conditions.
Investment Tax Credit (ITC)	Allows taxpayers to take a dollar-for-dollar reduction in the amount of federal income taxes that must be paid. Certain qualified facilities are characterized as energy property and are eligible for a 10% or 30% ITC, depending on the technology. A taxpayer cannot take both an ITC and PTC for a facility that could qualify for both; one must elect to receive either an ITC or PTC for each project.
Kilowatt (kW)	Unit of measure for demand. One thousand Watts.
Kilowatt-Hour (kWh)	Unit of measure for energy. The equivalent of one thousand Watts used steadily for one hour.
Landfill gas	Gas that is generated by decomposition of organic material at landfill disposal sites. The methane in landfill gas may be vented, flared, combusted to generate electricity, or used as thermal energy on-site.
Light-Emitting Diode (LED)	A semiconductor light source increasingly used for lighting. LEDs present many advantages over incandescent light sources including lower energy consumption, improved robustness, smaller size, faster switching, and greater durability and reliability.
Load	The moment-to-moment measurement of the power requirement in the entire system.
Load Center	A point at which the load of a given area is assumed to be concentrated.
Load Pocket	A geographic area that has a high demand of energy constrained by transmission import limitations. For example, the metro Phoenix area is considered a load pocket.
Loads & Resources Table	Presents the annual expected resource needs and additions.
Loss of Load Probability (LOLP)	Analysis performed to measure the ability of a system to reliably maintain service to load.
Losses on Peak	Total electric energy losses during the hour of greatest energy demand. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution equipment (wire, transformers, etc.).
Low NOx Burner (LNB)	A type of burner that is typically used in utility boilers to produce steam. Air used for combustion is split into two or more parts. The initial combustion, which occurs at a high temperature, takes place in an oxygen-deficient condition to form molecular nitrogen (N_2) instead of NOx. Further down the flame, additional air is added to complete the combustion after the nitrogen has been driven out of the coal as N_2.

Lowest Achievable Emission Rate (LAER)	The most stringent emission limitation derived from either of the following: (a) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or, (b) the most stringent emission limitation achieved in practice by such class or category of source. The emissions rate may result from a combination of emissions-limiting measures such as: (1) a change in the raw material processed; (2) a process modification; and, (3) add-on controls.
Major Event Day	A day in which the daily SAIDI exceeds a threshold value.
Major Modification	Any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.
Major Sources	Facilities that emit, or have the potential to emit, 10 tons per year of certain toxic air pollutants, or 25 tons per year of a mixture of air toxics. These sources may release air toxics from equipment leaks, when materials are transferred from one location to another, or during discharge through emission stacks or vents.
Maximum Achievable Control Technology (MACT)	The standards which are established by EPA to require the maximum degree of emission reduction that EPA determines to be achievable for hazardous air pollutants. These standards are authorized by Section 112 of the Clean Air Act.
Megawatt (MW)	One megawatt equals one million watts. ***See Watt***
Megawatt-Hour (MWh)	One million watt-hours ***See Watt-Hour***
Mercury	A naturally-occurring element that is found in air, water and soil. Coal contains mercury and when coal is burned, mercury is released into the environment.
Nameplate Rating	A rating for each generating unit that specifies the maximum expected output of the generating unit. This nameplate rating could be dependent upon specified conditions (like ambient temperature).
National Ambient Air Quality Standards (NAAQS)	The standards established by EPA under authority of the Clean Air Act that apply to outdoor air throughout the country. Primary standards are designed to protect human health, with an adequate margin of safety.
National Environmental Policy Act (NEPA)	Establishes a process by which federal agencies must study the environmental effects of their actions, so these effects can be taken into consideration during federal decision-making.
Net Dependable Capacity	The maximum capacity a generating unit can sustain over a period of time less the unit capacity (MW) utilized for the unit's station service or auxiliaries.
Net Present Value (NPV)	Method for evaluating the cost or profitability of an investment. Individual future cash amounts are discounted back to their present values and then summed.
New Source Performance Standards (NSPS)	Pollution control standards issued by the Environmental Protection Agency.
New Source Review (NSR)	A permitting program that was established by Congress as part of the 1977 Clean Air Act Amendments. NSR is a preconstruction permitting program to ensure air quality is not significantly degraded from the addition of new and modified factories, boilers, and power plants and that advances in pollution control occur with industrial expansion.
Nitrogen Oxide (NOx)	Compounds of nitrogen and oxygen formed by combustion under high temperature and high pressure and a major contributor to the formation of ozone.
Non-Attainment Area	Any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for the pollutant.

Nonattainment New Source Review (NNSR)	Applies to new major sources or major modifications at existing sources for pollutants where the area the source is located is not in attainment with the NAAQS. NNSR requirements are customized for the non-attainment area. All NNSR programs have to require: (1) the installation of the lowest achievable emission rate; (2) emission offsets; and, (3) opportunity for public involvement.
Non-distributed Renewable Energy	An energy resource that is replaced rapidly by a natural, ongoing process that is not nuclear or fossil fuel and is not located at the customer site.
Non-Spinning Reserves	A generating reserve not connected to the system but capable of serving demand within a specified time.
North American Electric Reliability Corporation (NERC)	NERC is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.
Nuclear Regulatory Commission (NRC)	The federal agency responsible for the regulation and inspection of nuclear power plants to assure safety.
Nuclear Fuel	Fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.
Off-Peak	Period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns.
On-Peak	Periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns.
Operation & Maintenance (O&M)	Actions taken after construction to ensure that facilities constructed will maintain performance by being properly operated and maintained to achieve normative efficiency levels in an optimum manner.
Over-fire Air (OFA)	The air pressure in a boiler furnace during occurrence of the main flame.
Ozone	Ozone, the triatomic form of oxygen (O_3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (photochemical smog). The layer of ozone that begins approximately 15 km above Earth and thins to an almost negligible amount at about 50 km, shields the Earth from harmful ultraviolet radiation from the sun.
Palo Verde Hub	An energy hub (*see Hub*) in the area of PVNGS located west of Phoenix, Arizona, where numerous regional counterparties engage in power transactions which form the basis for various indices. For example, the Dow Jones Palo Verde Electricity Price Indexes are volume-weighted averages of specifically-defined bilateral, wholesale, and physical transactions in the hub quoted in either $/MWh or $/MW.
Peak Demand	The greatest demand that occurred or is expected to occur during a prescribed time period.
Peak Time Rebates	An option for demand response pricing which will provide a rebate to customers who reduce usage during critical peak hours.
Peaking Resources	Technologies used to respond to high customer demands during the hot summer afternoons. These could include combustion turbines and DR measures and may include short-term market purchases.
Peaking Units	These generation units usually see relatively infrequent service during the non-summer months. During the summer, peaking units are used during the hot summer afternoons in response to high customer demands. It is not unusual for peaking units to operate less than 10% of the hours during the year.
Photovoltaic	The technology used to convert the sun's rays directly into electricity.
Planning Period	For the purpose of this filing, the timeframe of 2012-2027.

PM2.5	Very small pieces of solid or liquid matter which are less than 2.5 micrometers in diameter. Sources of fine particles include all types of combustion, including motor vehicles, power plants, residential wood burning, forest fires, agricultural burning, and some industrial processes.
PM10	Particles with diameters that are 10 micrometers or smaller. Sources of particles include combustion, crushing or grinding operations, and dust from paved or unpaved roads.
Preference Power	Federal hydropower and resources from the Colorado River system.
Prevention of Significant Deterioration (PSD)	EPA program in which state and/or federal permits are required in order to restrict emissions from new or modified sources in places where air quality already meets or exceeds primary and secondary ambient air quality standards.
Production Tax Credit (PTC)	Allows a tax credit for the generation of qualified energy from qualified facilities. The PTC amounts, credit periods, and definitions of qualified facilities are technology-specific. Qualified energy resources include: wind, closed-loop biomass, open-loop biomass, geothermal, solar, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic renewable energy. A taxpayer cannot take both an ITC and a PTC for a facility that could qualify for both – one must elect to receive either an ITC or PTC for each project.
PROMOD IV	A generator and portfolio modeling system developed by Ventyx which incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations.
Purchased Power Agreement (PPA)	A contractual agreement between two entities for the sale of electric energy and capacity from a specific generating unit, utility system, or unspecified wholesale market sources.
Real-Time Operations	Operational activity which manages the economic commitment of APS's generation resources to match the system load on a real-time basis. Requires making decisions to optimize system operation to provide lowest cost, reliable power to APS customers.
Real-Time Traders	Individuals involved solely in commodity trading of power, specifically electricity.
Regional Haze Rule	Requirements established by EPA to address source-by-source visibility impairment.
Regression Models	A statistical technique used to find relationships between variables for the purpose of predicting future values.
Renewable Energy	An energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
Renewable Energy Standard (RES)	Requirement codified at A.A.C. R14-2-1804 which requires regulated electric utilities within Arizona to generate 15 percent of their energy from renewable resources by 2025.
Renewable Energy Standard Implementation Plan	Requirement for Arizona's regulated utility companies to file annual implementation plans describing how they will comply with the Renewable Energy Standard rules.
Renewable Transmission Action Plan (RTAP)	Resulted from ACC Commission Order 70635, which directed regulated utilities to identify renewable transmission projects in their service territory to advance renewable resource expansion.
Request for Proposal (RFP)	A competitive solicitation for suppliers, often through a bidding process, to submit a proposal on a specific commodity or service.
Residential Direct Load Control	Demand response programs where the utility or a third-party contractor can remotely control customer-specific loads and reduce or cycle the energy consumption for a specified period of time.

Resource Conservation and Recovery Act	Gives EPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous solid wastes.
Resource Planning Rules	Codified at A.A.C. R14-2-703, the Resource Planning Rules require regulated electric utilities to file a plan for future generation needs.
Revenue Requirements	Annual revenue level required to supply customers energy needs, including: (1) carrying charges on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs; (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency program and incentive costs; (6) distributed energy program and incentive costs; and, (7) power plant emissions costs including SO_2 and CO_2. Revenue requirements as used in the resource plan filing do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.
Selective Catalytic Reduction Controls	A post-combustion pollution control technology that removes NOx emissions from an air stream. Ammonia (NH_3) is injected into the flue gas downstream from the combustion process and upstream from a catalyst bed. The NH_3 reacts with the NOx on the catalyst surface to form nitrogen (N_2) and water vapor (H_2O).
Simple Cycle	***See** Combustion Turbine*
Small Generation	Generation resource with a capacity of less than 20MW.
Smart Home Applications	Technology that provides real-time linkage and control between the utility, the consumer, and the consumer's various loads inside their home.
Societal Cost Test (SCT)	A variant of the Total Resource Cost Test. It measures the impacts of DSM on society as a whole by including externality costs of power generation not captured by the market.
Solar Photovoltaic (PV, or Solar PV)	A method of generating electrical power by converting solar radiation directly into electricity.
Solar Thermal	A method for harnessing solar energy for thermal energy.
Southern California Edison (SCE)	One of the largest electric utilities in California, serving more than 14 million people in a 50,000 square-mile area of central, coastal and Southern California, excluding the City of Los Angeles and certain other cities.
Southwest Reserve Sharing Group (SRSG)	A NERC-registered entity. SRSG participants share contingency reserves to maximize generator dispatch efficiency and contribute to electric reliability in the Western Interconnection.
Spinning Reserves	Available generating capacity that is synchronously connected to the electric grid and capable of automatically responding to frequency deviations on the system.
Spot Market	A commodities or securities market in which goods are sold for cash and delivered immediately.
Standby Generation	Customer-owned generation resources, typically diesel- or gas-fired, that provide customers with a guaranteed source of power in the event that either power quality or reliability issues occur with their local utility.
State Implementation Plan (SIP)	Plans developed by state and local air quality management agencies and submitted for approval to EPA to comply with the federal Clean Air Act.
Sulfur Dioxide (SO_2)	A colorless gas of compounds of sulfur and oxygen that is produced primarily by the combustion of fossil fuel.
Summer Peak	***See** Peak Demand*

System Average Interruption Duration Index (SAIDI)	Used as a reliability indicator by electric power utilities. SAIDI is the average annual outage duration experienced by the average customer.
System Average Interruption Frequency Index (SAIFI)	Used as a reliability indicator by electric power utilities. SAIFI is the average annual outage frequency experienced by the average customer.
Tennessee Valley Authority (TVA)	A corporation owned by the U.S. government which provides electricity for 9 million people in parts of seven southeastern states.
Thermal Energy Storage (TES) Cooling Programs	Systems that utilize a storage medium, such as chilled water or ice, which is "charged" during off-peak hours and then used as the cooling energy source during on-peak hours, offsetting the need to operate high-demand refrigeration equipment.
Total Own Load Peak	The greatest demand for energy during a specified time period by customers that APS has a requirement to serve.
Total Resource Cost Test (TRCT)	Measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's.
Transmission	The transportation of bulk energy along a network or grid of power lines. It is often intended to refer specifically to high-voltage (69,000 volts or higher) electricity of the type bought and sold on the wholesale market. An additional stage of service, referred to as distribution, is required to actually deliver usable low-voltage energy to an end-use customer.
Utility-Scale	A resource that is sized to provide power to a utility and not directly to an on-site customer.
Volatile Organic Compounds (VOC)	Types of organic compounds which have significant vapor pressures (evaporate easily, forming a gas) and which can affect the environment and human health.
Waters of the United States	Generally, those waters include the following: all waters which are currently used, or were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to the ebb and flow of the tide; all interstate waters; all other waters which could affect interstate or foreign commerce; tributaries of the above; and, wetlands adjacent to the above.
Watt-Hour	The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy sold to retail customers is commonly measured in kilowatt-hours.
Watt	The electrical unit of real power or rate of doing work; specifically, the rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor.
Welfare Effects	Positive and negative effects on the quality of life of people.
WestConnect	WestConnect is composed of utility companies providing electric transmission in the U.S. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to Western wholesale electricity markets.
Western Electricity Coordinating Council (WECC)	The regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.
Western Interconnection	The interconnected electrical systems that encompass the region of the Western Electricity Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between.

Wholesale Customer	Any party who purchases electricity in bulk for resale to end-use customers. Wholesale customers may include marketers, utilities and distribution companies, co-ops, and any other entity engaged in energy resale.
Wholesale Supplier	Wholesale energy sales can be made between producers, marketers, brokers, utility companies, and select high-volume, end-use customers, any of which is considered a wholesale supplier. The most common form of wholesale energy transaction is one made between energy producers or marketers and utility companies that serve the general public.
Zero Liquid Discharge	Cooling water is continually reclaimed and reused, and no water is released to the environment.

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APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	1,823	1,748	1,385	1,691	2,462	2,965	3,458	3,458	3,114	2,089	1,594	1,692
Comm+Ind <3 MW	1,563	1,499	1,617	1,696	2,101	2,152	2,463	2,463	2,222	1,957	1,389	1,591
Comm+Ind >3 MW	339	314	327	351	391	396	381	381	387	371	330	338
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5
Streetlights	0	0	0	0	0	0	0	0	0	0	39	0
Resale (x/off-system sales)	61	43	49	75	106	148	170	170	97	77	53	57
System Peak Prior to Losses	3,789	3,608	3,381	3,818	5,064	5,667	6,477	6,477	5,825	4,499	3,409	3,682
Losses On Peak	443	422	396	447	592	663	758	758	681	526	399	431
Total Own Load Peak	4,232	4,030	3,777	4,265	5,656	6,330	7,234	7,234	6,506	5,026	3,808	4,113
Energy Efficiency Programs	(56)	(55)	(58)	(59)	(63)	(76)	(80)	(80)	(72)	(63)	(51)	(56)
Distributed Energy Programs	(14)	(13)	(15)	(15)	(70)	(73)	(65)	(65)	(50)	(36)	(10)	(7)
Own Load After EE/DE	4,161	3,962	3,704	4,191	5,523	6,181	7,089	7,089	6,384	4,927	3,747	4,050

Year 2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	1,915	1,879	1,423	1,659	2,517	3,002	3,542	3,542	3,114	2,138	1,687	1,796
Comm+Ind <3 MW	1,630	1,594	1,683	1,677	2,107	2,247	2,533	2,533	2,250	1,914	1,422	1,656
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5
Streetlights	0	0	0	0	0	0	0	0	0	0	40	0
Resale (x/off-system sales)	61	42	41	66	96	133	152	152	88	67	43	51
System Peak Prior to Losses	3,945	3,829	3,475	3,754	5,111	5,779	6,604	6,604	5,839	4,490	3,523	3,843
Losses On Peak	462	448	407	439	598	676	773	773	683	525	412	450
Total Own Load Peak	4,407	4,277	3,882	4,194	5,709	6,455	7,377	7,377	6,522	5,016	3,935	4,292
Energy Efficiency Programs	(118)	(115)	(125)	(131)	(146)	(184)	(193)	(193)	(170)	(145)	(109)	(117)
Distributed Energy Programs	(18)	(17)	(25)	(17)	(89)	(92)	(82)	(82)	(64)	(46)	(13)	(9)
Own Load After EE/DE	4,271	4,145	3,732	4,045	5,475	6,179	7,102	7,102	6,288	4,825	3,812	4,166

APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	1,969	1,932	1,466	1,702	2,593	3,106	3,658	3,658	3,226	2,215	1,753	1,862
Comm+Ind <3 MW	1,685	1,646	1,742	1,728	2,192	2,344	2,631	2,631	2,329	1,990	1,483	1,724
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5
Streetlights	0	0	0	0	0	0	0	0	0	0	41	0
Resale (x/off-system sales)	55	35	41	66	96	133	152	152	88	67	43	51
System Peak Prior to Losses	4,049	3,928	3,577	3,849	5,272	5,980	6,818	6,818	6,030	4,643	3,652	3,977
Losses On Peak	474	460	419	450	617	700	798	798	706	543	427	465
Total Own Load Peak	4,523	4,388	3,996	4,299	5,889	6,679	7,616	7,616	6,736	5,187	4,080	4,442
Energy Efficiency Programs	(180)	(175)	(192)	(169)	(242)	(313)	(328)	(328)	(286)	(239)	(171)	(178)
Distributed Energy Programs	(22)	(21)	(31)	(23)	(114)	(118)	(105)	(105)	(81)	(57)	(16)	(12)
Own Load After EE/DE	4,321	4,192	3,773	4,107	5,534	6,249	7,182	7,182	6,369	4,891	3,892	4,253

Year 2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,038	2,000	1,522	1,736	2,683	3,240	3,819	3,819	3,358	2,305	1,830	1,944
Comm+Ind <3 MW	1,736	1,695	1,802	1,754	2,267	2,441	2,728	2,728	2,397	2,057	1,540	1,792
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5
Streetlights	0	0	0	0	0	0	0	0	0	0	42	0
Resale (x/off-system sales)	25	14	17	31	40	55	70	70	38	25	14	16
System Peak Prior to Losses	4,138	4,023	3,668	3,874	5,382	6,133	6,995	6,995	6,179	4,758	3,757	4,092
Losses On Peak	484	471	429	453	630	718	818	818	723	557	440	479
Total Own Load Peak	4,623	4,494	4,097	4,327	6,011	6,850	7,813	7,813	6,902	5,315	4,197	4,571
Energy Efficiency Programs	(244)	(237)	(262)	(245)	(348)	(460)	(482)	(482)	(417)	(343)	(216)	(241)
Distributed Energy Programs	(25)	(24)	(36)	(24)	(134)	(139)	(124)	(124)	(95)	(67)	(19)	(13)
Own Load After EE/DE	4,354	4,233	3,800	4,058	5,529	6,251	7,207	7,207	6,391	4,905	3,962	4,317

APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,123	2,044	1,561	1,840	2,805	3,378	3,992	3,992	3,528	2,410	1,906	2,028
Comm+Ind <3 MW	1,794	1,714	1,840	1,844	2,367	2,532	2,828	2,828	2,492	2,131	1,589	1,856
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	4	4	4	5	5	5	5	5	5	5	5	5
Streetlights	0	0	0	0	0	0	0	0	0	0	43	0
Resale (x/off-system sales)	25	14	17	31	40	55	70	70	38	25	14	16
System Peak Prior to Losses	4,282	4,086	3,746	4,066	5,603	6,361	7,268	7,268	6,445	4,937	3,884	4,240
Losses On Peak	501	478	438	476	656	744	850	850	754	578	454	496
Total Own Load Peak	4,783	4,564	4,184	4,542	6,259	7,105	8,118	8,118	7,199	5,515	4,338	4,736
Energy Efficiency Programs	(311)	(302)	(334)	(310)	(459)	(611)	(641)	(641)	(552)	(451)	(261)	(306)
Distributed Energy Programs	(28)	(26)	(40)	(25)	(149)	(148)	(137)	(137)	(106)	(74)	(21)	(15)
Own Load After EE/DE	4,444	4,237	3,810	4,207	5,651	6,346	7,339	7,339	6,542	4,990	4,056	4,415

Year 2017	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,223	2,173	1,664	1,916	2,928	3,529	4,179	4,179	3,684	2,514	1,998	2,118
Comm+Ind <3 MW	1,864	1,814	1,940	1,902	2,463	2,629	2,932	2,932	2,566	2,201	1,652	1,921
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	44	0
Resale (x/off-system sales)	25	14	17	31	40	55	70	70	38	25	14	16
System Peak Prior to Losses	4,451	4,315	3,948	4,200	5,821	6,609	7,557	7,557	6,673	5,110	4,039	4,394
Losses On Peak	521	505	462	491	681	773	884	884	781	598	473	514
Total Own Load Peak	4,972	4,820	4,410	4,692	6,502	7,382	8,441	8,441	7,453	5,708	4,512	4,908
Energy Efficiency Programs	(380)	(368)	(408)	(377)	(565)	(754)	(791)	(791)	(626)	(556)	(321)	(374)
Distributed Energy Programs	(34)	(32)	(46)	(30)	(165)	(158)	(154)	(154)	(120)	(73)	(25)	(18)
Own Load After EE/DE	4,559	4,420	3,955	4,284	5,771	6,469	7,497	7,497	6,707	5,079	4,166	4,517

Attachment C.1(a)

APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2018	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,324	2,269	1,733	2,001	3,038	3,677	4,360	4,360	3,848	2,634	2,084	2,207
Comm+Ind <3 MW	1,932	1,878	2,004	1,967	2,542	2,717	3,029	3,029	2,643	2,283	1,705	1,984
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	45	0
Resale (x/off-system sales)	20	11	15	27	37	51	62	62	34	21	10	10
System Peak Prior to Losses	4,615	4,471	4,078	4,347	6,008	6,840	7,827	7,827	6,911	5,308	4,175	4,540
Losses On Peak	540	523	477	509	703	800	916	916	809	621	488	531
Total Own Load Peak	5,155	4,995	4,555	4,856	6,710	7,641	8,742	8,742	7,720	5,929	4,664	5,071
Energy Efficiency Programs	(446)	(432)	(479)	(471)	(664)	(884)	(926)	(926)	(797)	(653)	(345)	(438)
Distributed Energy Programs	(38)	(35)	(46)	(33)	(176)	(166)	(164)	(164)	(128)	(70)	(28)	(20)
Own Load After EE/DE	4,671	4,527	4,030	4,352	5,870	6,591	7,652	7,652	6,795	5,206	4,291	4,613

Year 2019	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,427	2,365	1,801	2,074	3,161	3,825	4,545	4,545	4,023	2,751	2,169	2,298
Comm+Ind <3 MW	1,998	1,939	2,065	2,017	2,630	2,802	3,126	3,126	2,729	2,359	1,756	2,046
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	46	0
Resale (x/off-system sales)	20	11	15	27	37	51	62	62	34	21	10	10
System Peak Prior to Losses	4,784	4,628	4,207	4,470	6,218	7,073	8,110	8,110	7,172	5,502	4,311	4,694
Losses On Peak	560	542	492	523	728	828	949	949	839	644	504	549
Total Own Load Peak	5,344	5,170	4,699	4,993	6,946	7,901	9,059	9,059	8,012	6,146	4,816	5,243
Energy Efficiency Programs	(513)	(497)	(545)	(529)	(758)	(1,005)	(1,053)	(1,053)	(908)	(745)	(429)	(503)
Distributed Energy Programs	(39)	(36)	(40)	(34)	(180)	(169)	(168)	(168)	(131)	(95)	(29)	(20)
Own Load After EE/DE	4,792	4,636	4,115	4,430	6,007	6,727	7,838	7,838	6,972	5,305	4,358	4,720

Attachment C.1(a)

APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,527	2,413	1,844	2,150	3,283	4,001	4,733	4,733	4,182	2,857	2,262	2,397
Comm+Ind <3 MW	2,059	1,950	2,098	2,067	2,715	2,913	3,219	3,219	2,797	2,422	1,813	2,114
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	47	0
Resale (x/off-system sales)	20	11	15	27	37	51	62	62	34	21	10	10
System Peak Prior to Losses	4,945	4,687	4,283	4,596	6,425	7,360	8,391	8,391	7,399	5,671	4,463	4,860
Losses On Peak	579	548	501	538	752	861	982	982	866	663	522	569
Total Own Load Peak	5,523	5,236	4,784	5,133	7,177	8,221	9,372	9,372	8,265	6,334	4,986	5,429
Energy Efficiency Programs	(578)	(560)	(619)	(602)	(854)	(1,133)	(1,186)	(1,186)	(1,023)	(840)	(470)	(567)
Distributed Energy Programs	(43)	(39)	(41)	(39)	(197)	(180)	(184)	(184)	(144)	(68)	(32)	(22)
Own Load After EE/DE	4,902	4,636	4,125	4,492	6,125	6,909	8,002	8,002	7,098	5,426	4,484	4,839

Year 2021	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,617	2,551	1,954	2,234	3,401	4,145	4,929	4,929	4,354	2,968	2,343	2,489
Comm+Ind <3 MW	2,105	2,046	2,194	2,120	2,788	2,982	3,311	3,311	2,868	2,483	1,853	2,169
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	48	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,061	4,911	4,474	4,705	6,578	7,523	8,617	8,617	7,608	5,822	4,574	4,997
Losses On Peak	592	575	523	551	770	880	1,008	1,008	890	681	535	585
Total Own Load Peak	5,653	5,485	4,998	5,256	7,348	8,403	9,625	9,625	8,498	6,503	5,109	5,581
Energy Efficiency Programs	(622)	(603)	(656)	(571)	(919)	(1,218)	(1,276)	(1,276)	(1,017)	(904)	(496)	(610)
Distributed Energy Programs	(49)	(46)	(46)	(43)	(217)	(197)	(209)	(209)	(163)	(66)	(36)	(25)
Own Load After EE/DE	4,982	4,837	4,295	4,642	6,212	6,988	8,140	8,140	7,318	5,533	4,577	4,946

APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2022	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,727	2,648	2,031	2,331	3,541	4,310	5,129	5,129	4,530	3,084	2,433	2,583
Comm+Ind <3 MW	2,164	2,095	2,250	2,180	2,874	3,063	3,395	3,395	2,936	2,543	1,897	2,220
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	49	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,230	5,057	4,608	4,862	6,805	7,769	8,901	8,901	7,852	5,998	4,709	5,143
Losses On Peak	612	592	539	569	796	909	1,041	1,041	919	702	551	602
Total Own Load Peak	5,842	5,649	5,147	5,431	7,602	8,678	9,942	9,942	8,770	6,699	5,260	5,744
Energy Efficiency Programs	(638)	(618)	(671)	(661)	(943)	(1,249)	(1,308)	(1,308)	(1,129)	(927)	(508)	(626)
Distributed Energy Programs	(55)	(51)	(52)	(48)	(236)	(217)	(236)	(236)	(184)	(68)	(41)	(28)
Own Load After EE/DE	5,149	4,979	4,423	4,721	6,423	7,211	8,398	8,398	7,458	5,705	4,712	5,090

Year 2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,830	2,746	2,110	2,418	3,673	4,472	5,329	5,329	4,690	3,193	2,530	2,677
Comm+Ind <3 MW	2,215	2,143	2,306	2,226	2,950	3,137	3,476	3,476	2,985	2,592	1,945	2,269
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	3	3	3	4	4	4	4	4	4	4	4	4
Streetlights	0	0	0	0	0	0	0	0	0	0	50	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,383	5,203	4,742	4,995	7,013	8,005	9,182	9,182	8,061	6,155	4,856	5,285
Losses On Peak	630	609	555	584	820	937	1,074	1,074	943	720	568	618
Total Own Load Peak	6,013	5,812	5,297	5,579	7,833	8,942	10,257	10,257	9,004	6,875	5,424	5,903
Energy Efficiency Programs	(658)	(638)	(691)	(690)	(973)	(1,290)	(1,350)	(1,350)	(1,165)	(957)	(543)	(646)
Distributed Energy Programs	(62)	(57)	(58)	(54)	(256)	(239)	(264)	(264)	(206)	(78)	(45)	(32)
Own Load After EE/DE	5,293	5,117	4,547	4,835	6,604	7,413	8,642	8,642	7,633	5,841	4,836	5,226

APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	2,938	2,801	2,140	2,511	3,789	4,619	5,531	5,531	4,870	3,327	2,617	2,772
Comm+Ind <3 MW	2,268	2,147	2,313	2,277	3,007	3,194	3,556	3,556	3,051	2,664	1,982	2,317
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	51	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,543	5,261	4,779	5,139	7,184	8,208	9,462	9,462	8,307	6,361	4,980	5,427
Losses On Peak	649	616	559	601	841	960	1,107	1,107	972	744	583	635
Total Own Load Peak	6,192	5,877	5,338	5,740	8,025	9,169	10,569	10,569	9,279	7,105	5,562	6,062
Energy Efficiency Programs	(679)	(658)	(706)	(755)	(1,003)	(1,330)	(1,392)	(1,392)	(1,202)	(987)	(556)	(666)
Distributed Energy Programs	(68)	(61)	(70)	(60)	(276)	(261)	(294)	(294)	(229)	(146)	(50)	(35)
Own Load After EE/DE	5,445	5,157	4,562	4,925	6,745	7,578	8,884	8,884	7,848	5,972	4,956	5,361

Year 2025	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	3,047	2,950	2,256	2,603	3,922	4,793	5,735	5,735	5,040	3,445	2,714	2,874
Comm+Ind <3 MW	2,320	2,242	2,402	2,325	3,077	3,274	3,633	3,633	3,104	2,718	2,027	2,370
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	52	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,704	5,505	4,983	5,277	7,388	8,462	9,744	9,744	8,530	6,533	5,122	5,582
Losses On Peak	667	644	583	617	864	990	1,140	1,140	998	764	599	653
Total Own Load Peak	6,372	6,149	5,566	5,895	8,252	9,452	10,884	10,884	9,527	7,297	5,721	6,236
Energy Efficiency Programs	(702)	(680)	(733)	(683)	(1,037)	(1,374)	(1,438)	(1,438)	(1,241)	(1,019)	(573)	(688)
Distributed Energy Programs	(75)	(70)	(71)	(69)	(298)	(283)	(324)	(324)	(252)	(90)	(55)	(39)
Own Load After EE/DE	5,595	5,399	4,762	5,143	6,918	7,795	9,122	9,122	8,034	6,188	5,093	5,509

APS 2012 INTEGRATED RESOURCE PLAN

Arizona Public Service Company
Coincident Peak Demand By Month and Customer Class
2012 - 2027

Peak Demand (MW)

Year 2026	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	3,146	3,051	2,340	2,685	4,051	4,978	5,942	5,942	5,215	3,560	2,811	2,978
Comm+Ind <3 MW	2,360	2,288	2,459	2,361	3,143	3,362	3,711	3,711	3,159	2,767	2,070	2,423
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	53	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,844	5,652	5,125	5,396	7,583	8,734	10,029	10,029	8,759	6,697	5,264	5,739
Losses On Peak	684	661	600	631	887	1,022	1,173	1,173	1,025	784	616	671
Total Own Load Peak	6,528	6,313	5,725	6,027	8,471	9,756	11,203	11,203	9,784	7,481	5,879	6,410
Energy Efficiency Programs	(723)	(700)	(749)	(799)	(1,068)	(1,414)	(1,480)	(1,480)	(1,278)	(1,049)	(578)	(708)
Distributed Energy Programs	(80)	(74)	(82)	(70)	(313)	(299)	(344)	(344)	(268)	(106)	(59)	(41)
Own Load After EE/DE	5,726	5,538	4,895	5,159	7,090	8,043	9,379	9,379	8,238	6,325	5,243	5,661

Year 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	3,251	3,151	2,425	2,781	4,188	5,141	6,153	6,153	5,410	3,684	2,899	3,078
Comm+Ind <3 MW	2,405	2,331	2,516	2,410	3,214	3,426	3,790	3,790	3,231	2,823	2,103	2,471
Comm+Ind >3 MW	335	311	323	347	386	391	373	373	382	366	327	335
Irrigation	2	2	3	3	3	3	3	3	3	3	3	3
Streetlights	0	0	0	0	0	0	0	0	0	0	53	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,994	5,795	5,266	5,542	7,791	8,962	10,319	10,319	9,026	6,877	5,385	5,887
Losses On Peak	701	678	616	648	912	1,049	1,207	1,207	1,056	805	630	689
Total Own Load Peak	6,696	6,473	5,883	6,190	8,702	10,010	11,527	11,527	10,082	7,681	6,015	6,575
Energy Efficiency Programs	(744)	(721)	(784)	(761)	(1,100)	(1,457)	(1,525)	(1,525)	(1,199)	(1,081)	(588)	(730)
Distributed Energy Programs	(82)	(76)	(78)	(72)	(322)	(306)	(353)	(353)	(275)	(96)	(60)	(42)
Own Load After EE/DE	5,869	5,676	5,021	5,357	7,281	8,247	9,649	9,649	8,608	6,504	5,367	5,804

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2012													
Residential	1,076,070	803,035	820,069	771,258	1,032,146	1,436,939	1,837,603	1,721,557	1,432,172	924,171	801,120	920,922	13,577,062
Comm+Ind <3 MW	781,502	837,095	889,028	924,170	1,102,986	1,067,456	1,200,109	1,222,855	1,060,260	1,005,709	806,507	943,990	11,841,667
Comm+Ind >3 MW	246,860	235,272	249,774	247,291	262,426	269,374	284,369	284,052	280,678	268,312	249,227	251,865	3,129,500
Irrigation	511	776	771	1,641	2,650	2,616	2,639	2,213	1,966	2,418	1,411	1,345	20,957
Streetlights	11,024	10,674	12,299	12,523	13,348	9,982	12,218	12,430	10,750	12,751	12,927	12,034	142,960
Resale (x/off-system sales)	40,288	40,808	47,191	60,502	79,062	99,349	103,823	98,438	77,139	54,318	38,963	36,259	776,140
Sales Prior to EE/DE	2,156,255	1,927,660	2,019,132	2,017,385	2,492,618	2,885,716	3,440,761	3,341,545	2,862,965	2,267,679	1,910,155	2,166,415	29,488,286
Energy Efficiency Programs	(43,565)	(25,777)	(29,255)	(30,431)	(36,240)	(36,675)	(42,874)	(43,025)	(28,096)	(32,455)	(26,378)	(27,460)	(402,231)
Distributed Energy Programs	(20,008)	(23,305)	(28,737)	(32,975)	(35,582)	(26,156)	(28,153)	(28,880)	(21,261)	(23,973)	(17,211)	(15,884)	(302,125)
Total Sales	2,092,682	1,878,578	1,961,140	1,953,979	2,420,796	2,822,885	3,369,734	3,269,640	2,813,608	2,211,251	1,866,566	2,123,071	28,783,930
Energy Losses	152,960	138,127	143,185	144,016	176,698	205,262	239,691	231,324	193,155	145,516	127,660	149,682	2,047,276
Total Own Load Energy	2,245,642	2,016,705	2,104,325	2,097,995	2,597,494	3,028,147	3,609,425	3,500,964	3,006,763	2,356,767	1,994,226	2,272,753	30,831,206
Year 2013													
Residential	1,121,291	853,035	845,312	776,401	1,076,602	1,453,847	1,836,935	1,720,232	1,432,658	971,138	857,264	984,436	13,929,151
Comm+Ind <3 MW	846,631	851,212	954,432	923,731	1,118,763	1,150,869	1,191,860	1,198,117	1,086,832	970,023	838,318	1,002,356	12,133,144
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	655	782	812	1,577	2,586	2,706	2,562	2,122	1,961	2,297	1,439	1,390	20,889
Streetlights	11,999	11,150	13,284	12,816	13,876	11,066	12,368	12,474	11,188	12,645	13,469	12,920	149,255
Resale (x/off-system sales)	40,288	39,856	39,999	53,542	71,870	89,029	93,159	87,774	70,179	47,126	32,003	32,539	697,364
Sales Prior to EE/DE	2,265,460	1,989,220	2,101,157	2,012,586	2,543,029	2,973,613	3,417,586	3,300,787	2,879,701	2,267,991	1,988,934	2,283,739	30,023,803
Energy Efficiency Programs	(72,685)	(53,297)	(67,129)	(67,599)	(81,140)	(90,776)	(99,195)	(96,653)	(64,384)	(67,936)	(57,278)	(61,845)	(879,917)
Distributed Energy Programs	(27,702)	(27,454)	(38,211)	(41,411)	(45,496)	(35,715)	(35,215)	(35,787)	(27,467)	(29,384)	(22,522)	(21,231)	(387,595)
Total Sales	2,165,073	1,908,469	1,995,817	1,903,576	2,416,393	2,847,122	3,283,176	3,168,347	2,787,850	2,170,671	1,909,134	2,200,663	28,756,291
Energy Losses	135,711	122,717	126,009	121,538	155,088	180,237	202,516	190,975	171,368	132,386	114,312	133,623	1,786,480
Total Own Load Energy	2,300,784	2,031,186	2,121,826	2,025,114	2,571,481	3,027,359	3,485,692	3,359,322	2,959,218	2,303,057	2,023,446	2,334,286	30,542,771

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2014													
Residential	1,147,532	878,730	872,498	803,403	1,117,711	1,512,575	1,901,743	1,776,776	1,472,556	1,004,097	889,119	1,020,020	14,396,760
Comm+Ind <3 MW	878,930	882,614	991,319	961,596	1,164,009	1,199,076	1,231,887	1,239,905	1,121,256	1,007,602	872,132	1,042,685	12,593,011
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	627	768	797	1,561	2,559	2,668	2,500	2,069	1,908	2,251	1,410	1,363	20,481
Streetlights	12,211	11,445	13,662	13,191	14,264	11,358	12,572	12,735	11,368	12,949	13,804	13,220	152,779
Resale (x/off-system sales)	36,568	33,360	39,999	53,542	71,870	89,029	93,159	87,774	70,179	47,126	32,003	32,539	687,148
Sales Prior to EE/DE	2,320,464	2,040,102	2,165,593	2,077,812	2,629,745	3,080,802	3,522,563	3,399,327	2,954,150	2,338,787	2,054,909	2,359,925	30,944,179
Energy Efficiency Programs	(105,420)	(83,818)	(105,808)	(108,426)	(130,213)	(154,227)	(164,112)	(158,582)	(103,266)	(106,778)	(87,921)	(96,917)	(1,405,488)
Distributed Energy Programs	(34,591)	(34,812)	(48,742)	(53,123)	(58,388)	(45,752)	(44,643)	(45,409)	(34,506)	(37,075)	(28,278)	(26,561)	(491,880)
Total Sales	2,180,453	1,921,472	2,011,043	1,916,263	2,441,144	2,880,823	3,313,808	3,195,336	2,816,378	2,194,934	1,938,710	2,236,447	29,046,811
Energy Losses	139,696	123,699	128,769	122,682	157,391	183,197	207,852	199,327	179,234	136,809	120,778	140,727	1,840,161
Total Own Load Energy	2,320,149	2,045,171	2,139,812	2,038,945	2,598,535	3,064,020	3,521,660	3,394,663	2,995,612	2,331,743	2,059,488	2,377,174	30,886,972
Year 2015													
Residential	1,191,233	915,309	912,010	834,157	1,169,997	1,587,979	1,984,671	1,854,897	1,529,452	1,044,700	929,420	1,068,252	15,022,077
Comm+Ind <3 MW	904,806	915,006	1,031,600	993,030	1,210,752	1,251,884	1,273,744	1,285,658	1,157,482	1,042,406	906,704	1,087,527	13,060,599
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	621	758	790	1,537	2,530	2,648	2,452	2,035	1,869	2,213	1,391	1,348	20,192
Streetlights	12,531	11,756	14,069	13,490	14,677	11,723	12,805	13,041	11,576	13,241	14,162	13,595	156,666
Resale (x/off-system sales)	16,728	13,200	16,687	24,742	30,206	36,709	39,095	33,710	29,859	17,366	10,403	10,219	278,924
Sales Prior to EE/DE	2,370,515	2,089,214	2,222,474	2,111,475	2,687,494	3,157,039	3,593,469	3,469,409	3,007,121	2,384,688	2,108,521	2,431,039	31,632,458
Energy Efficiency Programs	(138,906)	(116,899)	(148,726)	(151,610)	(183,557)	(227,739)	(236,430)	(228,458)	(144,730)	(147,037)	(122,178)	(133,554)	(1,979,824)
Distributed Energy Programs	(39,424)	(40,845)	(57,454)	(62,366)	(69,015)	(54,202)	(52,266)	(53,325)	(40,194)	(43,302)	(33,076)	(31,123)	(576,592)
Total Sales	2,192,185	1,931,470	2,016,294	1,897,499	2,434,922	2,875,098	3,304,773	3,187,626	2,822,197	2,194,349	1,953,267	2,266,362	29,076,042
Energy Losses	135,683	120,510	129,442	121,436	152,912	185,107	212,510	200,628	177,570	137,137	121,439	138,176	1,832,550
Total Own Load Energy	2,327,868	2,051,980	2,145,736	2,018,935	2,587,834	3,060,205	3,517,283	3,388,254	2,999,767	2,331,486	2,074,706	2,404,538	30,908,592

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2016													
Residential	1,238,511	976,221	937,042	873,737	1,232,887	1,665,271	2,070,742	1,937,896	1,600,878	1,091,133	968,825	1,114,054	15,707,197
Comm+Ind <3 MW	931,004	971,326	1,052,249	1,032,695	1,264,566	1,298,369	1,312,269	1,330,431	1,201,959	1,080,746	937,333	1,125,653	13,538,600
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	609	766	769	1,526	2,522	2,620	2,409	2,004	1,848	2,188	1,370	1,330	19,961
Streetlights	12,781	12,291	14,231	13,852	15,140	11,986	13,003	13,326	11,848	13,562	14,484	13,893	160,397
Resale (x/off-system sales)	16,728	13,200	16,687	24,742	30,206	36,709	39,095	33,710	29,859	17,366	10,403	10,219	278,924
Sales Prior to EE/DE	2,444,229	2,206,989	2,268,296	2,191,071	2,804,653	3,281,051	3,718,220	3,597,435	3,123,275	2,469,757	2,178,856	2,515,247	32,799,079
Energy Efficiency Programs	(172,299)	(162,996)	(188,419)	(195,336)	(242,938)	(301,226)	(309,697)	(303,203)	(187,422)	(188,280)	(157,981)	(169,298)	(2,579,095)
Distributed Energy Programs	(40,676)	(49,297)	(62,452)	(69,426)	(77,117)	(59,970)	(57,536)	(59,059)	(44,616)	(48,111)	(36,667)	(34,555)	(639,482)
Total Sales	2,231,254	1,994,696	2,017,425	1,926,309	2,484,598	2,919,855	3,350,987	3,235,173	2,891,237	2,233,366	1,984,208	2,311,394	29,580,502
Energy Losses	141,036	125,057	128,976	124,216	160,159	187,633	213,501	204,799	179,600	140,042	122,251	144,750	1,872,020
Total Own Load Energy	2,372,290	2,119,753	2,146,401	2,050,525	2,644,757	3,107,488	3,564,488	3,439,972	3,070,837	2,373,408	2,106,459	2,456,144	31,452,522
Year 2017													
Residential	1,299,418	996,125	1,005,456	915,205	1,298,586	1,747,878	2,172,116	2,031,795	1,657,803	1,137,578	1,015,647	1,164,913	16,442,520
Comm+Ind <3 MW	970,073	980,377	1,119,821	1,072,677	1,319,075	1,347,860	1,361,325	1,381,487	1,232,880	1,116,580	974,146	1,167,608	14,043,909
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	610	741	782	1,518	2,518	2,604	2,389	1,989	1,814	2,166	1,364	1,319	19,814
Streetlights	13,136	12,294	14,877	14,197	15,583	12,265	13,278	13,651	11,995	13,843	14,851	14,222	164,192
Resale (x/off-system sales)	16,728	13,200	16,687	24,742	30,206	36,709	39,095	33,710	29,859	17,366	10,403	10,219	278,924
Sales Prior to EE/DE	2,544,561	2,235,922	2,404,941	2,272,858	2,925,300	3,413,412	3,868,905	3,742,700	3,211,234	2,552,295	2,262,852	2,608,379	34,043,359
Energy Efficiency Programs	(210,509)	(184,520)	(239,476)	(238,379)	(302,903)	(370,876)	(381,312)	(373,441)	(225,495)	(232,472)	(193,492)	(205,904)	(3,158,779)
Distributed Energy Programs	(49,632)	(51,158)	(72,321)	(77,687)	(86,379)	(66,576)	(64,063)	(66,143)	(49,589)	(54,275)	(41,875)	(39,562)	(719,260)
Total Sales	2,284,420	2,000,244	2,093,144	1,956,792	2,536,018	2,975,960	3,423,530	3,303,116	2,936,150	2,265,548	2,027,485	2,362,913	30,165,320
Energy Losses	143,570	127,999	132,102	124,738	162,558	190,991	218,065	212,319	188,225	142,833	126,456	146,831	1,916,687
Total Own Load Energy	2,427,990	2,128,243	2,225,246	2,081,530	2,698,576	3,166,951	3,641,595	3,515,435	3,124,375	2,408,381	2,153,941	2,509,744	32,082,007

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2018													
Residential	1,358,678	1,042,667	1,049,888	958,053	1,357,763	1,829,000	2,276,907	2,127,501	1,727,457	1,193,510	1,059,004	1,213,607	17,194,035
Comm+Ind <3 MW	1,005,164	1,016,939	1,158,149	1,112,241	1,363,577	1,395,936	1,413,143	1,431,768	1,272,116	1,160,155	1,005,939	1,205,209	14,540,336
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	611	740	778	1,513	2,507	2,594	2,385	1,984	1,800	2,163	1,355	1,312	19,742
Streetlights	13,452	12,595	15,213	14,540	15,929	12,560	13,587	13,978	12,224	14,207	15,184	14,519	167,988
Resale (x/off-system sales)	13,415	10,458	14,081	22,207	27,675	34,001	35,891	30,736	27,289	14,552	7,557	6,613	244,475
Sales Prior to EE/DE	2,635,916	2,316,584	2,485,427	2,353,073	3,026,783	3,540,187	4,022,615	3,886,035	3,317,769	2,649,349	2,335,480	2,691,358	35,260,576
Energy Efficiency Programs	(246,091)	(216,422)	(278,990)	(283,299)	(354,506)	(431,698)	(448,972)	(437,805)	(261,738)	(276,573)	(226,448)	(241,571)	(3,704,113)
Distributed Energy Programs	(53,002)	(55,278)	(77,735)	(83,247)	(92,194)	(71,011)	(68,623)	(70,968)	(53,154)	(58,829)	(45,391)	(42,998)	(772,430)
Total Sales	2,336,823	2,044,884	2,128,702	1,986,527	2,580,083	3,037,478	3,505,020	3,377,262	3,002,877	2,313,947	2,063,641	2,406,789	30,784,033
Energy Losses	146,450	129,931	136,025	128,456	162,911	190,304	228,494	217,605	187,932	147,580	130,136	153,825	1,959,649
Total Own Load Energy	2,483,273	2,174,815	2,264,727	2,114,983	2,742,994	3,227,782	3,733,514	3,594,867	3,190,809	2,461,527	2,193,777	2,560,614	32,743,682
Year 2019													
Residential	1,415,960	1,088,460	1,093,415	1,007,888	1,419,888	1,904,324	2,377,551	2,219,106	1,803,280	1,249,143	1,102,758	1,268,121	17,949,894
Comm+Ind <3 MW	1,036,960	1,051,032	1,193,444	1,158,943	1,409,396	1,435,243	1,459,724	1,476,894	1,314,569	1,201,261	1,036,801	1,247,788	15,022,055
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	606	737	773	1,515	2,501	2,574	2,376	1,973	1,794	2,159	1,347	1,311	19,666
Streetlights	13,745	12,886	15,528	14,978	16,305	12,785	13,869	14,278	12,493	14,558	15,517	14,885	171,827
Resale (x/off-system sales)	13,415	10,458	14,081	22,207	27,675	34,001	35,891	30,736	27,289	14,552	7,557	6,613	244,475
Sales Prior to EE/DE	2,725,282	2,396,758	2,564,559	2,450,050	3,135,097	3,655,023	4,170,113	4,023,055	3,436,308	2,746,435	2,410,421	2,788,816	36,501,917
Energy Efficiency Programs	(279,629)	(248,435)	(317,001)	(330,231)	(405,171)	(486,620)	(512,968)	(495,970)	(302,164)	(317,363)	(257,576)	(281,474)	(4,234,602)
Distributed Energy Programs	(53,199)	(56,718)	(79,543)	(85,813)	(94,466)	(72,250)	(70,252)	(72,628)	(54,515)	(60,513)	(46,582)	(44,350)	(790,829)
Total Sales	2,392,454	2,091,605	2,168,015	2,034,006	2,635,460	3,096,153	3,586,893	3,454,457	3,079,629	2,368,559	2,106,263	2,462,992	31,476,486
Energy Losses	153,717	133,142	139,262	129,197	169,216	199,503	229,907	217,906	192,152	149,289	131,996	154,507	1,999,794
Total Own Load Energy	2,546,171	2,224,747	2,307,277	2,163,203	2,804,676	3,295,656	3,816,800	3,672,363	3,271,781	2,517,848	2,238,259	2,617,499	33,476,280

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2020													
Residential	1,473,061	1,159,451	1,119,016	1,046,849	1,483,262	2,003,822	2,474,802	2,308,260	1,865,008	1,294,568	1,150,956	1,324,967	18,704,022
Comm+Ind <3 MW	1,067,266	1,111,228	1,210,291	1,191,294	1,455,628	1,496,381	1,498,305	1,518,811	1,345,308	1,231,931	1,071,115	1,291,573	15,489,131
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	601	751	759	1,508	2,498	2,588	2,357	1,957	1,774	2,142	1,346	1,313	19,594
Streetlights	14,032	13,460	15,662	15,268	16,695	13,207	14,086	14,560	12,673	14,824	15,884	15,274	175,625
Resale (x/off-system sales)	13,415	10,458	14,081	22,207	27,675	34,001	35,891	30,736	27,289	14,552	7,557	6,613	244,475
Sales Prior to EE/DE	2,812,971	2,528,533	2,607,127	2,521,645	3,245,090	3,816,095	4,306,143	4,154,392	3,528,935	2,822,779	2,493,299	2,889,838	37,726,847
Energy Efficiency Programs	(311,948)	(299,687)	(351,978)	(370,513)	(451,890)	(562,936)	(573,309)	(554,986)	(340,139)	(352,991)	(292,122)	(321,630)	(4,784,129)
Distributed Energy Programs	(56,731)	(67,642)	(85,200)	(93,725)	(103,540)	(79,783)	(76,416)	(79,312)	(59,226)	(66,069)	(51,247)	(48,928)	(867,819)
Total Sales	2,444,292	2,161,204	2,169,949	2,057,407	2,689,660	3,173,376	3,656,418	3,520,094	3,129,570	2,403,719	2,149,930	2,519,280	32,074,899
Energy Losses	156,225	138,412	137,477	132,005	171,812	205,266	235,737	223,766	198,511	154,307	137,378	159,353	2,050,249
Total Own Load Energy	2,600,517	2,299,616	2,307,426	2,189,412	2,861,472	3,378,642	3,892,155	3,743,860	3,328,081	2,558,026	2,287,308	2,678,633	34,125,148
Year 2021													
Residential	1,523,974	1,180,826	1,197,834	1,090,093	1,548,849	2,081,670	2,571,606	2,408,390	1,946,357	1,349,909	1,193,646	1,376,096	19,469,250
Comm+Ind <3 MW	1,087,608	1,115,187	1,278,953	1,225,433	1,500,699	1,533,044	1,536,939	1,565,306	1,387,585	1,269,375	1,097,353	1,325,636	15,923,118
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	590	731	776	1,503	2,494	2,570	2,342	1,955	1,771	2,139	1,336	1,306	19,513
Streetlights	14,234	13,463	16,362	15,599	17,103	13,446	14,334	14,903	12,973	15,174	16,201	15,584	179,376
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,871,002	2,543,392	2,741,243	2,577,147	3,328,477	3,896,826	4,405,923	4,270,622	3,625,569	2,901,359	2,554,977	2,968,720	38,685,257
Energy Efficiency Programs	(319,104)	(303,400)	(394,737)	(397,437)	(487,342)	(603,677)	(614,566)	(601,202)	(366,038)	(377,487)	(317,077)	(341,931)	(5,123,998)
Distributed Energy Programs	(68,264)	(70,472)	(99,637)	(106,360)	(117,821)	(90,153)	(86,533)	(90,197)	(67,362)	(75,081)	(57,931)	(55,404)	(985,215)
Total Sales	2,483,634	2,169,520	2,246,869	2,073,350	2,723,314	3,202,996	3,704,824	3,579,223	3,192,169	2,448,791	2,179,969	2,571,385	32,576,044
Energy Losses	158,325	138,684	142,899	134,818	174,410	210,904	238,559	223,668	198,219	151,984	138,942	163,367	2,074,779
Total Own Load Energy	2,641,959	2,308,204	2,389,768	2,208,168	2,897,724	3,413,900	3,943,383	3,802,891	3,390,388	2,600,775	2,318,911	2,734,752	34,650,823

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2022													
Residential	1,586,018	1,227,109	1,247,225	1,137,415	1,621,874	2,168,055	2,665,240	2,500,375	2,024,441	1,403,609	1,240,618	1,429,273	20,251,252
Comm+Ind <3 MW	1,115,416	1,142,733	1,312,816	1,261,060	1,549,068	1,571,100	1,565,725	1,600,874	1,423,127	1,301,091	1,124,455	1,358,046	16,325,511
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	588	728	774	1,501	2,500	2,560	2,319	1,943	1,764	2,130	1,330	1,301	19,438
Streetlights	14,547	13,739	16,724	15,975	17,575	13,707	14,524	15,186	13,241	15,496	16,548	15,908	183,170
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,961,165	2,617,494	2,824,857	2,660,470	3,450,349	4,021,518	4,528,510	4,398,446	3,739,456	2,987,088	2,629,392	3,054,626	39,873,371
Energy Efficiency Programs	(323,453)	(309,960)	(405,255)	(405,611)	(507,393)	(617,974)	(626,297)	(618,352)	(374,466)	(387,197)	(325,259)	(350,760)	(5,251,977)
Distributed Energy Programs	(76,833)	(79,430)	(112,504)	(120,374)	(133,822)	(101,506)	(97,003)	(101,573)	(76,007)	(84,698)	(65,336)	(62,475)	(1,111,561)
Total Sales	2,560,879	2,228,104	2,307,098	2,134,485	2,809,134	3,302,038	3,805,210	3,678,521	3,288,983	2,515,193	2,238,797	2,641,391	33,509,833
Energy Losses	163,250	143,087	146,436	136,884	180,127	217,532	247,184	228,182	205,079	158,076	143,958	168,588	2,138,383
Total Own Load Energy	2,724,129	2,371,191	2,453,534	2,271,369	2,989,261	3,519,570	4,052,394	3,906,703	3,494,062	2,673,269	2,382,755	2,809,979	35,648,216
Year 2023													
Residential	1,647,748	1,274,595	1,297,857	1,180,303	1,689,785	2,254,214	2,772,443	2,602,427	2,089,295	1,453,225	1,290,662	1,480,981	21,033,535
Comm+Ind <3 MW	1,143,152	1,170,622	1,347,106	1,290,093	1,590,303	1,609,016	1,604,682	1,642,470	1,447,893	1,328,171	1,153,555	1,387,807	16,714,870
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	587	724	773	1,493	2,496	2,550	2,311	1,940	1,746	2,119	1,328	1,293	19,360
Streetlights	14,859	14,027	17,105	16,294	17,987	13,994	14,813	15,529	13,431	15,788	16,925	16,219	186,971
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,050,942	2,693,153	2,910,159	2,732,702	3,559,903	4,145,870	4,674,951	4,542,434	3,829,248	3,064,065	2,708,911	3,136,398	41,048,736
Energy Efficiency Programs	(335,086)	(320,004)	(419,138)	(415,042)	(529,700)	(636,633)	(646,938)	(639,402)	(380,784)	(402,546)	(335,655)	(358,759)	(5,419,687)
Distributed Energy Programs	(85,785)	(88,958)	(126,236)	(134,769)	(150,338)	(113,662)	(108,740)	(114,009)	(84,534)	(94,653)	(73,328)	(69,866)	(1,244,878)
Total Sales	2,630,071	2,284,191	2,364,785	2,182,891	2,879,865	3,395,575	3,919,273	3,789,023	3,363,930	2,566,866	2,299,928	2,707,773	34,384,171
Energy Losses	166,120	146,957	149,886	140,908	186,338	219,143	253,737	236,291	212,640	162,926	149,807	174,342	2,199,095
Total Own Load Energy	2,796,191	2,431,148	2,514,671	2,323,799	3,066,203	3,614,718	4,173,010	4,025,314	3,576,570	2,729,792	2,449,735	2,882,115	36,583,266

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2024													
Residential	1,706,200	1,361,109	1,306,791	1,233,564	1,747,246	2,324,630	2,885,007	2,697,638	2,170,659	1,518,772	1,334,597	1,534,769	21,820,982
Comm+Ind <3 MW	1,167,394	1,235,831	1,338,425	1,330,076	1,618,557	1,633,167	1,649,998	1,677,936	1,483,323	1,367,463	1,176,005	1,418,648	17,096,823
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	584	742	748	1,495	2,480	2,524	2,314	1,930	1,742	2,121	1,318	1,289	19,287
Streetlights	15,138	14,716	17,037	16,738	18,271	14,181	15,167	15,827	13,715	16,189	17,239	16,544	190,762
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,133,912	2,845,583	2,910,319	2,826,392	3,645,886	4,240,598	4,833,188	4,673,399	3,946,322	3,169,307	2,775,600	3,221,348	42,221,854
Energy Efficiency Programs	(349,057)	(357,174)	(409,360)	(440,175)	(541,738)	(643,824)	(674,507)	(655,124)	(394,845)	(420,899)	(341,290)	(374,154)	(5,602,147)
Distributed Energy Programs	(89,760)	(107,991)	(135,740)	(150,587)	(166,290)	(125,284)	(121,478)	(126,500)	(94,039)	(105,650)	(81,184)	(77,545)	(1,382,048)
Total Sales	2,695,095	2,380,418	2,365,219	2,235,630	2,937,858	3,471,490	4,037,203	3,891,775	3,457,438	2,642,758	2,353,126	2,769,649	35,237,659
Energy Losses	174,135	151,713	152,184	144,798	188,043	225,511	260,920	243,692	218,869	168,834	152,333	179,895	2,260,927
Total Own Load Energy	2,869,230	2,532,131	2,517,403	2,380,428	3,125,901	3,697,001	4,298,123	4,135,467	3,676,307	2,811,592	2,505,459	2,949,544	37,498,586
Year 2025													
Residential	1,773,914	1,374,663	1,388,055	1,282,401	1,814,359	2,420,615	2,983,519	2,785,426	2,242,159	1,572,841	1,386,107	1,595,273	22,619,332
Comm+Ind <3 MW	1,198,047	1,228,643	1,400,597	1,363,787	1,655,387	1,676,129	1,677,566	1,706,352	1,510,202	1,394,565	1,203,998	1,454,560	17,469,833
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	583	721	762	1,494	2,475	2,524	2,295	1,913	1,729	2,107	1,319	1,289	19,211
Streetlights	15,499	14,650	17,727	17,122	18,653	14,519	15,368	16,074	13,934	16,479	17,602	16,933	194,560
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,232,639	2,851,862	3,054,459	2,909,323	3,750,206	4,379,883	4,959,450	4,789,833	4,044,907	3,250,754	2,855,467	3,318,153	43,396,936
Energy Efficiency Programs	(361,140)	(341,068)	(437,647)	(456,161)	(556,837)	(673,621)	(692,429)	(670,831)	(409,887)	(433,546)	(350,320)	(392,348)	(5,775,835)
Distributed Energy Programs	(104,485)	(109,245)	(154,058)	(166,603)	(183,646)	(138,647)	(133,233)	(138,939)	(103,335)	(116,305)	(89,732)	(85,872)	(1,524,100)
Total Sales	2,767,014	2,401,549	2,462,754	2,286,559	3,009,723	3,567,615	4,133,788	3,980,063	3,531,685	2,700,903	2,415,415	2,839,933	36,097,001
Energy Losses	176,824	152,520	158,597	147,097	193,297	228,742	269,733	257,680	228,278	174,909	155,158	183,744	2,326,579
Total Own Load Energy	2,943,838	2,554,069	2,621,351	2,433,656	3,203,020	3,796,357	4,403,521	4,237,743	3,759,963	2,875,812	2,570,573	3,023,677	38,423,580

Arizona Public Service Company
Energy Consumption by Month by Customer Class
2012 - 2027

Energy Consumption (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Year 2026													
Residential	1,826,519	1,422,438	1,442,674	1,322,172	1,877,566	2,519,272	3,092,718	2,888,654	2,319,884	1,626,078	1,437,965	1,654,088	23,430,028
Comm+Ind <3 MW	1,215,391	1,252,689	1,434,496	1,385,339	1,689,112	1,724,778	1,715,291	1,744,781	1,540,943	1,421,057	1,231,620	1,487,933	17,843,430
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	575	717	761	1,481	2,460	2,528	2,289	1,908	1,720	2,094	1,318	1,287	19,138
Streetlights	15,721	14,923	18,122	17,381	19,023	14,956	15,666	16,410	14,188	16,778	17,970	17,299	198,437
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,302,802	2,923,952	3,143,371	2,970,892	3,847,493	4,527,630	5,106,666	4,931,821	4,153,618	3,330,769	2,935,314	3,410,705	44,585,033
Energy Efficiency Programs	(364,443)	(351,743)	(455,315)	(466,060)	(569,178)	(703,051)	(711,638)	(691,355)	(421,476)	(442,139)	(365,688)	(403,747)	(5,945,833)
Distributed Energy Programs	(108,566)	(115,670)	(163,686)	(175,929)	(194,847)	(148,523)	(141,583)	(147,622)	(109,532)	(123,182)	(95,394)	(91,316)	(1,615,850)
Total Sales	2,829,793	2,456,539	2,524,370	2,328,903	3,083,468	3,676,056	4,253,445	4,092,844	3,622,610	2,765,448	2,474,232	2,915,642	37,023,350
Energy Losses	182,860	160,454	163,879	149,919	198,936	236,256	273,868	262,672	232,245	178,605	161,056	189,155	2,389,905
Total Own Load Energy	3,012,653	2,616,993	2,688,249	2,478,822	3,282,404	3,912,312	4,527,313	4,355,516	3,854,855	2,944,053	2,635,288	3,104,797	39,413,255
Year 2027													
Residential	1,886,990	1,472,949	1,499,260	1,369,935	1,946,390	2,604,568	3,194,012	2,992,312	2,406,275	1,685,245	1,486,038	1,710,947	24,254,921
Comm+Ind <3 MW	1,239,056	1,279,714	1,470,838	1,416,445	1,726,323	1,756,872	1,745,783	1,782,810	1,577,268	1,452,850	1,255,626	1,518,902	18,222,487
Comm+Ind >3 MW	244,596	233,185	247,318	244,519	259,332	266,096	280,702	280,068	276,883	264,762	246,441	250,098	3,094,000
Irrigation	576	718	764	1,483	2,463	2,523	2,282	1,909	1,724	2,096	1,316	1,287	19,141
Streetlights	15,522	14,926	18,185	17,398	19,041	14,905	15,615	16,419	14,213	16,794	17,954	17,299	198,271
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,386,740	3,001,492	3,236,365	3,049,780	3,953,549	4,644,964	5,238,394	5,073,518	4,276,363	3,421,747	3,007,375	3,498,533	45,788,820
Energy Efficiency Programs	(371,298)	(363,540)	(474,569)	(479,280)	(586,966)	(722,801)	(729,964)	(716,077)	(434,143)	(452,434)	(380,657)	(411,488)	(6,123,217)
Distributed Energy Programs	(109,651)	(118,700)	(168,513)	(180,775)	(200,185)	(151,922)	(144,824)	(151,603)	(112,653)	(126,551)	(97,766)	(93,713)	(1,656,856)
Total Sales	2,905,791	2,519,252	2,593,283	2,389,725	3,166,398	3,770,241	4,363,606	4,205,838	3,729,567	2,842,762	2,528,952	2,993,332	38,008,747
Energy Losses	184,611	162,320	165,172	151,923	204,660	241,188	284,844	273,324	243,799	181,423	161,197	191,865	2,446,326
Total Own Load Energy	3,090,402	2,681,572	2,758,455	2,541,648	3,371,058	4,011,429	4,648,450	4,479,162	3,973,366	3,024,185	2,690,149	3,185,197	40,455,073

Arizona Public Service Company
Coincident Peak Demand By Month and Year Aggregated by Demand Management
2012 - 2027

Peak Demand (MW)

Year 2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	4,232	4,030	3,777	4,265	5,656	6,330	7,234	7,234	6,506	5,026	3,808	4,113
Distributed Energy Programs	(14)	(13)	(15)	(15)	(70)	(73)	(65)	(65)	(50)	(36)	(10)	(7)
Own Load Peak - After DE Before EE/DR	4,218	4,017	3,762	4,250	5,586	6,257	7,169	7,169	6,456	4,990	3,798	4,105
Energy Efficiency Programs	(56)	(55)	(58)	(59)	(63)	(76)	(80)	(80)	(72)	(63)	(51)	(56)
Demand Response Programs	-	-	-	-	-	(83)	(83)	(83)	(83)	-	-	-
Own Load Peak After EE/DR/DE	4,161	3,962	3,704	4,191	5,523	6,098	7,006	7,006	6,301	4,927	3,747	4,050

Year 2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	4,407	4,277	3,882	4,194	5,709	6,455	7,377	7,377	6,522	5,016	3,935	4,292
Distributed Energy Programs	(18)	(17)	(25)	(17)	(89)	(92)	(82)	(82)	(64)	(46)	(13)	(9)
Own Load Peak - After DE Before EE/DR	4,389	4,260	3,857	4,176	5,621	6,363	7,294	7,294	6,459	4,970	3,922	4,283
Energy Efficiency Programs	(118)	(115)	(125)	(131)	(146)	(184)	(193)	(193)	(170)	(145)	(109)	(117)
Demand Response Programs	-	-	-	-	-	(83)	(83)	(83)	(83)	-	-	-
Own Load Peak After EE/DR/DE	4,271	4,145	3,732	4,045	5,475	6,097	7,019	7,019	6,206	4,825	3,812	4,166

Year 2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	4,523	4,388	3,996	4,299	5,889	6,679	7,616	7,616	6,736	5,187	4,080	4,442
Distributed Energy Programs	(22)	(21)	(31)	(23)	(114)	(118)	(105)	(105)	(81)	(57)	(16)	(12)
Own Load Peak - After DE Before EE/DR	4,501	4,367	3,965	4,276	5,775	6,561	7,511	7,511	6,655	5,130	4,063	4,431
Energy Efficiency Programs	(180)	(175)	(192)	(169)	(242)	(313)	(328)	(328)	(286)	(239)	(171)	(178)
Demand Response Programs	-	-	-	-	-	(83)	(83)	(83)	(83)	-	-	-
Own Load Peak After EE/DR/DE	4,321	4,192	3,773	4,107	5,534	6,166	7,100	7,100	6,286	4,891	3,892	4,253

Arizona Public Service Company
Coincident Peak Demand By Month and Year Aggregated by Demand Management
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Peak Demand (MW)

Year 2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	4,623	4,494	4,097	4,327	6,011	6,850	7,813	7,813	6,902	5,315	4,197	4,571
Distributed Energy Programs	(25)	(24)	(36)	(24)	(134)	(139)	(124)	(124)	(95)	(67)	(19)	(13)
Own Load Peak - After DE Before EE/DR	4,597	4,470	4,062	4,303	5,877	6,711	7,689	7,689	6,807	5,248	4,178	4,557
Energy Efficiency Programs	(244)	(237)	(262)	(245)	(348)	(460)	(482)	(482)	(417)	(343)	(216)	(241)
Demand Response Programs	-	-	-	-	-	(98)	(98)	(98)	(98)	-	-	-
Own Load Peak After EE/DR/DE	4,354	4,233	3,800	4,058	5,529	6,154	7,110	7,110	6,293	4,905	3,962	4,317

Year 2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	4,783	4,564	4,184	4,542	6,259	7,105	8,118	8,118	7,199	5,515	4,338	4,736
Distributed Energy Programs	(28)	(26)	(40)	(25)	(149)	(148)	(137)	(137)	(106)	(74)	(21)	(15)
Own Load Peak - After DE Before EE/DR	4,754	4,539	4,144	4,517	6,110	6,957	7,981	7,981	7,094	5,441	4,317	4,721
Energy Efficiency Programs	(311)	(302)	(334)	(310)	(459)	(611)	(641)	(641)	(552)	(451)	(261)	(306)
Demand Response Programs	-	-	-	-	-	(165)	(165)	(165)	(165)	-	-	-
Own Load Peak After EE/DR/DE	4,444	4,237	3,810	4,207	5,651	6,181	7,174	7,174	6,377	4,990	4,056	4,415

Year 2017	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	4,972	4,820	4,410	4,692	6,502	7,382	8,441	8,441	7,453	5,708	4,512	4,908
Distributed Energy Programs	(34)	(32)	(46)	(30)	(165)	(158)	(154)	(154)	(120)	(73)	(25)	(18)
Own Load Peak - After DE Before EE/DR	4,938	4,789	4,363	4,662	6,337	7,224	8,288	8,288	7,333	5,635	4,487	4,891
Energy Efficiency Programs	(380)	(368)	(408)	(377)	(565)	(754)	(791)	(791)	(626)	(556)	(321)	(374)
Demand Response Programs	-	-	-	-	-	(205)	(205)	(205)	(205)	-	-	-
Own Load Peak After EE/DR/DE	4,559	4,420	3,955	4,284	5,771	6,264	7,292	7,292	6,502	5,079	4,166	4,517

Arizona Public Service Company
Coincident Peak Demand By Month and Year Aggregated by Demand Management
2012 - 2027

Peak Demand (MW)

Year 2018	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	5,155	4,995	4,555	4,856	6,710	7,641	8,742	8,742	7,720	5,929	4,664	5,071
Distributed Energy Programs	(38)	(35)	(46)	(33)	(176)	(166)	(164)	(164)	(128)	(70)	(28)	(20)
Own Load Peak - After DE Before EE/DR	5,117	4,959	4,509	4,822	6,534	7,475	8,578	8,578	7,592	5,859	4,636	5,052
Energy Efficiency Programs	(446)	(432)	(479)	(471)	(664)	(884)	(926)	(926)	(797)	(653)	(345)	(438)
Demand Response Programs	-	-	-	-	-	(230)	(230)	(230)	(230)	-	-	-
Own Load Peak After EE/DR/DE	4,671	4,527	4,030	4,352	5,870	6,361	7,422	7,422	6,564	5,206	4,291	4,613

Year 2019	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	5,344	5,170	4,699	4,993	6,946	7,901	9,059	9,059	8,012	6,146	4,816	5,243
Distributed Energy Programs	(39)	(36)	(40)	(34)	(180)	(169)	(168)	(168)	(131)	(95)	(29)	(20)
Own Load Peak - After DE Before EE/DR	5,304	5,133	4,659	4,958	6,765	7,732	8,891	8,891	7,880	6,051	4,787	5,223
Energy Efficiency Programs	(513)	(497)	(545)	(529)	(758)	(1,005)	(1,053)	(1,053)	(908)	(745)	(429)	(503)
Demand Response Programs	0	0	0	0	0	(255)	(255)	(255)	(255)	0	0	0
Own Load Peak After EE/DR/DE	4,792	4,636	4,115	4,430	6,007	6,472	7,582	7,582	6,717	5,305	4,358	4,720

Year 2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	5,523	5,236	4,784	5,133	7,177	8,221	9,372	9,372	8,265	6,334	4,986	5,429
Distributed Energy Programs	(43)	(39)	(41)	(39)	(197)	(180)	(184)	(184)	(144)	(68)	(32)	(22)
Own Load Peak - After DE Before EE/DR	5,480	5,197	4,744	5,094	6,979	8,041	9,188	9,188	8,121	6,266	4,954	5,407
Energy Efficiency Programs	(578)	(560)	(619)	(602)	(854)	(1,133)	(1,186)	(1,186)	(1,023)	(840)	(470)	(567)
Demand Response Programs	-	-	-	-	-	(280)	(280)	(280)	(280)	-	-	-
Own Load Peak After EE/DR/DE	4,902	4,636	4,125	4,492	6,125	6,628	7,722	7,722	6,818	5,426	4,484	4,839

Arizona Public Service Company
Coincident Peak Demand By Month and Year Aggregated by Demand Management
2012 - 2027

Peak Demand (MW)

Year 2021	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	5,653	5,485	4,998	5,256	7,348	8,403	9,625	9,625	8,498	6,503	5,109	5,581
Distributed Energy Programs	(49)	(46)	(46)	(43)	(217)	(197)	(209)	(209)	(163)	(66)	(36)	(25)
Own Load Peak - After DE Before EE/DR	5,604	5,440	4,951	5,213	7,131	8,206	9,416	9,416	8,334	6,437	5,073	5,556
Energy Efficiency Programs	(622)	(603)	(656)	(571)	(919)	(1,218)	(1,276)	(1,276)	(1,017)	(904)	(496)	(610)
Demand Response Programs	-	-	-	-	-	(305)	(305)	(305)	(305)	-	-	-
Own Load Peak After EE/DR/DE	4,982	4,837	4,295	4,642	6,212	6,683	7,835	7,835	7,012	5,533	4,577	4,946

Year 2022	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	5,842	5,649	5,147	5,431	7,602	8,678	9,942	9,942	8,770	6,699	5,260	5,744
Distributed Energy Programs	(55)	(51)	(52)	(48)	(236)	(217)	(236)	(236)	(184)	(68)	(41)	(28)
Own Load Peak - After DE Before EE/DR	5,787	5,597	5,094	5,382	7,366	8,461	9,706	9,706	8,586	6,632	5,220	5,716
Energy Efficiency Programs	(638)	(618)	(671)	(661)	(943)	(1,249)	(1,308)	(1,308)	(1,129)	(927)	(508)	(626)
Demand Response Programs	-	-	-	-	-	(330)	(330)	(330)	(330)	-	-	-
Own Load Peak After EE/DR/DE	5,149	4,979	4,423	4,721	6,423	6,881	8,068	8,068	7,127	5,705	4,712	5,090

Year 2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	6,013	5,812	5,297	5,579	7,833	8,942	10,257	10,257	9,004	6,875	5,424	5,903
Distributed Energy Programs	(62)	(57)	(58)	(54)	(256)	(239)	(264)	(264)	(206)	(78)	(45)	(32)
Own Load Peak - After DE Before EE/DR	5,952	5,755	5,239	5,525	7,577	8,703	9,992	9,992	8,798	6,798	5,378	5,872
Energy Efficiency Programs	(658)	(638)	(691)	(690)	(973)	(1,290)	(1,350)	(1,350)	(1,165)	(957)	(543)	(646)
Demand Response Programs	-	-	-	-	-	(355)	(355)	(355)	(355)	-	-	-
Own Load Peak After EE/DR/DE	5,293	5,117	4,547	4,835	6,604	7,058	8,287	8,287	7,277	5,841	4,836	5,226

Arizona Public Service Company
Coincident Peak Demand By Month and Year Aggregated by Demand Management
2012 - 2027

	Peak Demand (MW)											
Year 2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	6,192	5,877	5,338	5,740	8,025	9,169	10,569	10,569	9,279	7,105	5,562	6,062
Distributed Energy Programs	(68)	(61)	(70)	(60)	(276)	(261)	(294)	(294)	(229)	(146)	(50)	(35)
Own Load Peak - After DE Before EE/DR	6,124	5,815	5,268	5,680	7,749	8,908	10,276	10,276	9,050	6,959	5,512	6,027
Energy Efficiency Programs	(679)	(658)	(706)	(755)	(1,003)	(1,330)	(1,392)	(1,392)	(1,202)	(987)	(556)	(666)
Demand Response Programs	-	-	-	-	-	(355)	(355)	(355)	(355)	-	-	-
Own Load Peak After EE/DR/DE	5,445	5,157	4,562	4,925	6,745	7,223	8,528	8,528	7,493	5,972	4,956	5,361
Year 2025	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	6,372	6,149	5,566	5,895	8,252	9,452	10,884	10,884	9,527	7,297	5,721	6,236
Distributed Energy Programs	(75)	(70)	(71)	(69)	(298)	(283)	(324)	(324)	(252)	(90)	(55)	(39)
Own Load Peak - After DE Before EE/DR	6,297	6,079	5,495	5,826	7,955	9,169	10,560	10,560	9,275	7,207	5,665	6,197
Energy Efficiency Programs	(702)	(680)	(733)	(683)	(1,037)	(1,374)	(1,438)	(1,438)	(1,241)	(1,019)	(573)	(688)
Demand Response Programs	-	-	-	-	-	(350)	(350)	(350)	(350)	-	-	-
Own Load Peak After EE/DR/DE	5,595	5,399	4,762	5,143	6,918	7,445	8,772	8,772	7,684	6,188	5,093	5,509
Year 2026	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	6,528	6,313	5,725	6,027	8,471	9,756	11,203	11,203	9,784	7,481	5,879	6,410
Distributed Energy Programs	(80)	(74)	(82)	(70)	(313)	(299)	(344)	(344)	(268)	(106)	(59)	(41)
Own Load Peak - After DE Before EE/DR	6,449	6,239	5,643	5,957	8,157	9,457	10,859	10,859	9,516	7,374	5,821	6,369
Energy Efficiency Programs	(723)	(700)	(749)	(799)	(1,068)	(1,414)	(1,480)	(1,480)	(1,278)	(1,049)	(578)	(708)
Demand Response Programs	-	-	-	-	-	(350)	(350)	(350)	(350)	-	-	-
Own Load Peak After EE/DR/DE	5,726	5,538	4,895	5,159	7,090	7,693	9,029	9,029	7,888	6,325	5,243	5,661

Arizona Public Service Company
Coincident Peak Demand By Month and Year Aggregated by Demand Management
2012 - 2027

	Peak Demand (MW)											
Year 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Own Load Peak	6,696	6,473	5,883	6,190	8,702	10,010	11,527	11,527	10,082	7,681	6,015	6,575
Distributed Energy Programs	(82)	(76)	(78)	(72)	(322)	(306)	(353)	(353)	(275)	(96)	(60)	(42)
Own Load Peak - After DE Before EE/DR	6,614	6,397	5,805	6,118	8,381	9,704	11,174	11,174	9,808	7,585	5,954	6,533
Energy Efficiency Programs	(744)	(721)	(784)	(761)	(1,100)	(1,457)	(1,525)	(1,525)	(1,199)	(1,081)	(588)	(730)
Demand Response Programs	-	-	-	-	-	(350)	(350)	(350)	(350)	-	-	-
Own Load Peak After EE/DR/DE	5,869	5,676	5,021	5,357	7,281	7,897	9,299	9,299	8,258	6,504	5,367	5,804

Power Supply - Estimates for 2012-2027

	B1 a		B1 b	B1 c	B1 d			B1 f			B1 h	B1 l	B1 m	B1 n	B1 o
Plant/Unit/Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [10]
Palo Verde															
Unit 1	1986	2044	Steam	382	1,336	382	382					Uranium	382	Must Run	Baseload
Unit 2	1986	2045	Steam	382	1,336	382	382					Uranium	382	Must Run	Baseload
Unit 3	1988	2047	Steam	382	1,339	382	382					Uranium	382	Must Run	Baseload
Four Corners [2]															
Unit 1	1963	2012	Steam	170	170	170	170					Coal	110	No	Baseload
Unit 2	1963	2012	Steam	170	170	170	170					Coal	110	No	Baseload
Unit 3	1964	2012	Steam	220	220	220	220					Coal	150	No	Baseload
Unit 4	1969	2038	Steam	116	750	116	116					Coal	60	Must Run	Baseload
Unit 5	1970	2038	Steam	116	750	116	116					Coal	60	Must Run	Baseload
Navajo Generating Station															
Unit 1	1974	2026	Steam	105	750	105	105					Coal	50	Must Run	Baseload
Unit 2	1974	2026	Steam	105	750	105	105					Coal	50	Must Run	Baseload
Unit 3	1975	2026	Steam	105	750	105	105					Coal	50	Must Run	Baseload
Cholla															
Unit 1	1962	2028	Steam	116	116	116	116					Coal	30	No	Baseload
Unit 2	1978	2033	Steam	260	260	260	260					Coal	75	No	Baseload
Unit 3	1980	2035	Steam	271	271	271	271					Coal	75	No	Baseload
Ocotillo															
Unit 1 ST	1960	2020	Steam	110	110	110	110					Gas	20	No	Peaking
Unit 2 ST	1960	2020	Steam	110	110	110	110					Gas	20	No	Peaking
Unit 1 CT	1972	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Saguaro															
Unit 1 ST	1954	2020	Steam	110	110	110	110					Gas	25	No	Peaking
Unit 2 ST	1955	2020	Steam	100	100	100	100					Gas	25	No	Peaking
Unit 1 CT	1972	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 3 CT	2002	2037	Combustion Turbine	79	79	79	76					Gas	40	No	Peaking
West Phoenix															
Unit 1 CC	1976	2028	Combined Cycle	88	92	92	85					Gas	20	No	Intermediate
Unit 2 CC	1976	2028	Combined Cycle	88	92	92	85					Gas	20	No	Intermediate
Unit 3 CC	1976	2028	Combined Cycle	88	92	92	85					Gas	50	No	Intermediate
Unit 4 CC	2001	2036	Combined Cycle	117	120	123	110					Gas	77	No	Intermediate
Unit 5 CC	2003	2038	Combined Cycle	506	549	568	533					Gas	270	No	Intermediate
Unit 1 CT	1972	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2020	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Redhawk															
Unit 1 CC	2002	2037	Combined Cycle	492	506	506	500					Gas	250	No	Intermediate
Unit 2 CC	2002	2037	Combined Cycle	492	506	506	500					Gas	250	No	Intermediate
Sundance															
Unit 1 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 2 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 3 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 4 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 5 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 6 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking

Redacted

Power Supply - Estimates for 2012-2027

	B1 a		B1 b	B1 c	B1 d			B1 f			B1 h	B1 l	B1 m	B1 n	B1 o
Plant/Unit/Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [10]
Unit 7 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 8 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 9 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Unit 10 CT	2002	2037	Combustion Turbine	42	44	44	41					Gas	20	No	Peaking
Yucca															
Unit 1 CT	1971	2020	Combustion Turbine	19	22	22	18					Gas	2	No	Peaking
Unit 2 CT	1971	2020	Combustion Turbine	19	22	22	18					Gas	2	No	Peaking
Unit 3 CT	1973	2020	Combustion Turbine	55	62	62	52					Gas	5	No	Peaking
Unit 4 CT	1974	2020	Combustion Turbine	54	61	61	51					Oil	5	No	Peaking
Unit 5 CT	2008	2043	Combustion Turbine	48	49	49	47					Gas	20	No	Peaking
Unit 6 CT	2008	2043	Combustion Turbine	48	49	49	47					Gas	20	No	Peaking
Douglas															
Unit 1 CT	1972	2020	Combustion Turbine	16	19	19	15					Oil	2	No	Peaking
				6,288	**12,530**	**12,530**	**6,261**								
Future Units															
Future Unit 1 CC w DB	2020	2052	Combined Cycle	672	716	716	665					Gas	230	No	Intermediate
Future Unit 2 CC w DB	2025	2057	Combined Cycle	672	716	716	665					Gas	159	No	Intermediate
Future Unit 1 CT	2019	2051	Combustion Turbine	103	106	106	102					Gas	51	No	Peaking
Future Unit 2 CT	2020	2052	Combustion Turbine	103	106	106	102					Gas	47	No	Peaking
Future Units CT [3]	2021	2053	Combustion Turbine	616	635	635	613					Gas	47	No	Peaking
Future Units CT [4]	2022	2054	Combustion Turbine	410	424	424	408					Gas	47	No	Peaking
Future Units CT [5]	2023	2055	Combustion Turbine	205	212	212	204					Gas	47	No	Peaking
Future Units CT [6]	2024	2056	Combustion Turbine	308	318	318	306					Gas	47	No	Peaking
Future Units CT [5]	2027	2059	Combustion Turbine	205	212	212	204					Gas	47	No	Peaking
				2,780	**2,915**	**2,915**	**2,759**								
Renewables															
APS Solar [7]	1997-2006	2013-2023	Renewable	4.6	4.6	2	2					Solar	N/A	No	Intermittent
Saguaro Solar	2005	2022	Renewable	1	1	1	1					Solar	N/A	No	Intermittent
Aragonne Mesa Wind (Superior) RFP Renew	2007	2026	Renewable	90	90	16	18					Wind	N/A	No	Intermittent
Salton Sea CE Turbo #1	2006	2029	Renewable	10	10	10	10					Geothermal	N/A	No	Intermittent
SWMP Biomass (Abitibi) [8]	2008	2023	Renewable	14.5	14.5	15	14.5					Biogas	N/A	No	Baseload
High Lonesome Wind - NM	2009	2039	Renewable	100	100	17	17					Wind	N/A	No	Intermittent
Sexton - City of Glendale Landfill	2010	2029	Renewable	2.86	2.86	3	2.66					Biomass	N/A	No	Baseload
Solana CSP	2013	2043	Renewable	283	283	161	270					Solar	N/A	No	Intermittent
NEW Geothermal (80MW in 2021)	2021	2045	Renewable	80	80	80	80					Geothermal	N/A	No	Baseload
WIND Owned NM (100MW in 2022)	2022	2046	Renewable	100	100	18	18					Wind	N/A	No	Intermittent
WIND NM (100MW in 2027)	2027	2051	Renewable	100	100	18	18					Wind	N/A	No	Intermittent
WIND AZ (100MW in 2025)	2025	2049	Renewable	100	100	20	20					Wind	N/A	No	Intermittent
WIND Owned AZ (100MW in 2026)	2026	2050	Renewable	100	100	20	20					Wind	N/A	No	Intermittent
PERRIN RANCH WIND (99MW in 2012)	2012	2036	Renewable	99	99	20	20					Wind	N/A	No	Intermittent
AZ Sun: Hyder II	2013	2039	Renewable	13.8	14	0	11					Solar	N/A	No	Intermittent
AZ Sun: Cotton Center	2011	2036	Renewable	17.7	18	0	12					Solar	N/A	No	Intermittent
AZ Sun: Hyder I	2011	2036	Renewable	15.4	15	0	11					Solar	N/A	No	Intermittent
AZ Sun: Chino Valley	2012	2037	Renewable	19.6	20	0	10					Solar	N/A	No	Intermittent
AZ Sun - Paloma	2011	2036	Renewable	17.3	17	0	10					Solar	N/A	No	Intermittent
AZ Sun PV 4	2013	2037	Renewable	17	17	0	9					Solar	N/A	No	Intermittent
AZ Sun2 PV - Future Project 1	2013	2037	Renewable	18	18	0	9					Solar	N/A	No	Intermittent
AZ Sun2 PV - Future Project 2	2014	2038	Renewable	32	32	0	16					Solar	N/A	No	Intermittent

Redacted

Power Supply - Estimates for 2012-2027

	B1 a		B1 b	B1 c	B1 d			B1 f			B1 h	B1 l	B1 m	B1 n	B1 o
Plant/Unit/Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [10]
AZ Sun2 PV - Future Project 3	2015	2039	Renewable	50	50	0	25					Solar	N/A	No	Intermittent
Solar Fixed PV Other 1	2013	2038	Renewable	32	32	0	16					Solar	N/A	No	Intermittent
Solar Fixed PV Other 2	2014	2039	Renewable	32	32	0	16					Solar	N/A	No	Intermittent
Solar Fixed PV Other 3	2015	2039	Renewable	93	93	0	47					Solar	N/A	No	Intermittent
Solar Owned New (SAT) PV	2019	2048	Renewable	100	100	0	73					Solar	N/A	No	Intermittent
Solar Owned New (SAT) PV	2024	2053	Renewable	100	100	0	73					Solar	N/A	No	Intermittent
Solar PPA New (SAT) PV	2023	2052	Renewable	100	100	0	73					Solar	N/A	No	Intermittent
Small Gen RFP (Ajo S)	2011	2036	Renewable	4	4	0	3					Solar	N/A	No	Intermittent
Small Gen RFP (Prescott S)	2011	2041	Renewable	10	10	0	6					Solar	N/A	No	Intermittent
Small Gen RFP (Tonopah) - Future Project	2013	2042	Renewable	14	14	0	10					Solar	N/A	No	Intermittent
Small Gen RFP (WM Landfil) - Future Project	2012	2032	Renewable	3	3	3	3					Solar	N/A	No	Intermittent
				1,774	1,774	1,774	942								
Contracts															
SRP - Firm / Eastern Mining Load	1955	2020	Contract	38	38	19	38					N/A	N/A	No	Baseload
PACIFICORP Div Exch	1990	2020	Contract	480	480	(480)	480					N/A	N/A	No	Intermediate
DR Contract (On Peak)	2009	2024	Contract	105	105	0	105					N/A	N/A	No	Peaking
Recurrent Bagdad SAT PV - DE Contract	2012	2036	Contract	14	14	0	8					N/A	N/A	No	Peaking
CC Tolling # 1 1A	2007	2017	Tolling	248	248	248	238					Gas	165	No	Intermediate
CC Tolling # 1 2A	2007	2017	Tolling	248	248	248	238					Gas	165	No	Intermediate
CC Tolling # 1 3A	2007	2017	Tolling	45	45	45	45					Gas	45	No	Intermediate
CC Tolling # 2 1A	2010	2019	Tolling	250	250	0	250					Gas	150	No	Intermediate
CC Tolling # 2 2A	2010	2019	Tolling	250	250	0	250					Gas	150	No	Intermediate
CC Tolling # 2 3A	2010	2019	Tolling	79	79	0	79					Gas	79	No	Intermediate
Market Call Option [9]	2007	2015	Call Option	150	150	0	150					Gas	25	No	Peaking
Market Call Option [9]	2007	2015	Call Option	50	50	0	50					Gas	25	No	Peaking
Market Call Option [9]	2008	2015	Call Option	75	75	0	75					Gas	25	No	Peaking
Market Call Option [9]	2008	2015	Call Option	225	225	0	225					Gas	25	No	Peaking
Gas Call Option	2007	2021	Call Option	150	150	0	150					Gas	50	No	Peaking
				2,408	2,408	2,408	2,381								

Redacted

Notes:
(1) Fuel not included
(2) For analysis purposes, units 1, 2, and 3 (560 MW) to retire and the owned capacity on units 4, and 5 to increase total 739 MW by 9/30/2012
(3) Consist of 6 units of 103 MW each
(4) Consists of 4 units of 103 MW each
(5) Consists of 2 units of 103 MW each
(6) Consists of 3 units of 103 MW each
(7) Consists of several small solar projects of 17.36 yrs book life
(8) Capacity step down to 14.5MW by Sep 2011 and to 10MW by Jan 2013
(9) Jun - Sep Summer months only
(10) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.

ANNUAL CAPACITY FACTOR - B1 e

UNIT	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Palo Verde																
Unit 1																
Unit 2																
Unit 3																
Four Corners																
Unit 1 [1]																
Unit 2 [1]																
Unit 3 [1]																
Unit 4																
Unit 5																
Navajo Generating Station																
Unit 1																
Unit 2																
Unit 3																
Cholla																
Unit 1																
Unit 2																
Unit 3																
Ocotillo																
Unit 1 ST																
Unit 2 ST																
Unit 1 CT																
Unit 2 CT																
Saguaro																
Unit 1 ST																
Unit 2 ST																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
West Phoenix																
Unit 1 CC																
Unit 2 CC																
Unit 3 CC																
Unit 4 CC																
Unit 5 CC																
Unit 1 CT																
Unit 2 CT																
Redhawk																
Unit 1 CC																
Unit 2 CC																
Sundance																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
Unit 4 CT																
Unit 5 CT																
Unit 6 CT																
Unit 7 CT																
Unit 8 CT																
Unit 9 CT																
Unit 10 CT																
Yucca																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
Unit 4 CT																
Unit 5 CT																
Unit 6 CT																
Douglas																
Unit 1 CT																
Future Units																

Redacted

ANNUAL CAPACITY FACTOR - B1 e

UNIT	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Future Unit 1 CC																
Future Unit 2 CC																
Future Unit 1 CT																
Future Unit 2 CT																
Future Unit 3 CT																
Future Unit 4 CT																
Future Unit 5 CT																
Future Unit 6 CT																
Future Unit 7 CT																
Future Unit 8 CT																
Future Unit 9 CT																
Future Unit 10 CT																
Future Unit 11 CT																
Future Unit 12 CT																
Future Unit 13 CT																
Future Unit 14 CT																
Future Unit 15 CT																
Future Unit 16 CT																
Future Unit 17 CT																
Future Unit 18 CT																
Future Unit 19 CT																
Renewables																
APS Solar, Saguaro Solar																
Aragonne Mesa Wind (Superior) RFP Renew																
Salton Sea CE Turbo #1																
SWMP Biomass (Abitibi)																
High Lonesome Wind - NM																
Sexton - City of Glendale Landfill																
Solana CSP																
NEW Geothermal (80MW in 2021)																
WIND NM (100MW in 2027)																
WIND AZ (100MW in 2025)																
WIND Owned AZ (100MW in 2026)																
WIND Owned NM (100MW in 2022)																
PERRIN RANCH WIND (99MW in 2012)																
AZ Sun [2]																
Solar Fixed PV Other 1-3																
Solar Owned New (SAT) PV,																
Solar PPA New (SAT) PV																
Small Gen RFP (Ajo S) - Future Project																
Small Gen RFP (Prescott S) - Future Project																
Small Gen RFP (Tonopah) - Future Project																
Small Gen RFP (WM Landfil) - Future Project																
Contracts																
SRP - Firm / Eastern Mining Load																
PACIFICORP Div Exch																
CC Tolling # 1																
CC Tolling # 2																
Market Call Option																
Gas Call Option																
Short term Purchases																
Recurrent Bagdad SAT PV- DE Contract																

Redacted

Notes:
(1) For analysis purposes, units 1, 2, and 3 to retire by 9/30/2012
(2) AZ Sun: Cotton Center, Hyder I, Hyder II, Chino Valley, Paloma, PV 4, AZ Sun2 PV - Future Projects 1-3

APS 2012 INTEGRATED RESOURCE PLAN

AVERAGE HEAT RATE - 1B f (Btu/kWh)																
UNIT	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Palo Verde																
Unit 1	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385
Unit 2	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Unit 3	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377
Four Corners																
Unit 1	10,776	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit 2	10,789	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit 3	10,762	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit 4	9,719	9,702	9,733	9,706	9,728	9,769	9,765	9,772	9,774	9,773	9,765	9,789	9,775	9,762	9,770	9,769
Unit 5	9,719	9,714	9,735	9,729	9,739	9,737	9,772	9,786	9,792	9,782	9,804	9,806	9,779	9,788	9,778	9,789
NGS																
Unit 1	10,093	10,081	10,093	10,084	10,094	10,090	10,074	10,079	10,079	10,096	10,087	10,081	10,087	10,081	10,086	10,077
Unit 2	10,072	10,077	10,068	10,067	10,075	10,086	10,083	10,076	10,069	10,072	10,077	10,071	10,074	10,070	10,068	10,072
Unit 3	10,095	10,087	10,079	10,083	10,085	10,074	10,079	10,080	10,072	10,086	10,082	10,090	10,084	10,079	10,090	10,105
Cholla																
Unit 1	10,707	10,726	10,678	10,737	10,526	10,415	10,462	10,525	10,460	10,470	10,453	10,449	10,512	10,527	10,585	10,585
Unit 2	11,055	11,083	10,975	11,107	10,865	10,705	10,764	10,876	10,824	10,817	10,816	10,827	10,878	10,900	10,905	10,936
Unit 3	10,866	10,895	10,860	10,880	10,719	10,590	10,682	10,756	10,710	10,707	10,709	10,698	10,734	10,765	10,819	10,882
Ocotillo																
Unit 1 ST	13,062	12,706	12,790	14,194	13,640	13,995	14,368	14,173	13,791	13,779	13,956	13,903	13,989	-	15,385	14,475
Unit 2 ST	13,345	13,317	13,250	14,542	14,337	14,341	14,420	13,867	13,807	13,789	13,559	13,807	14,457	17,010	15,116	14,179
Unit 1 CT	19,099	-	-	-	15,010	15,754	18,179	14,927	15,826	15,010	-	-	15,757	-	-	15,757
Unit 2 CT	22,261	-	-	-	15,259	15,060	17,872	15,259	15,401	15,591	-	16,254	16,254	-	-	16,254
Saguaro																
Unit 1 ST	-	-	15,643	-	14,896	15,370	15,467	14,344	14,510	13,659	14,037	14,071	14,029	-	14,979	14,037
Unit 2 ST	-	-	15,713	-	15,601	15,605	16,304	14,298	15,022	14,421	-	14,890	14,982	-	-	14,764
Unit 1 CT	22,261	-	-	-	15,591	15,401	16,761	15,591	15,591	16,254	-	16,254	16,254	-	-	-
Unit 2 CT	19,077	-	-	-	15,259	15,117	14,970	15,010	16,040	15,757	-	15,757	15,757	-	-	15,757
Unit 3 CT	13,233	14,312	14,015	-	12,388	12,907	13,208	12,990	13,356	14,400	15,023	13,451	13,663	-	15,225	13,340
West Phoenix																
Unit 1 CC	11,563	11,528	11,715	12,862	11,674	11,070	11,271	11,407	11,144	10,612	10,368	10,212	10,083	10,424	10,126	10,156
Unit 2 CC	11,662	11,501	11,505	13,102	11,904	11,015	11,351	11,375	11,220	10,625	10,351	10,282	10,084	10,439	10,165	10,229
Unit 3 CC	10,691	10,743	10,804	11,019	10,692	10,351	10,404	10,278	10,245	10,009	9,906	9,861	9,792	10,044	9,876	9,883
Unit 4 CC	9,075	9,126	9,100	9,164	9,185	8,956	8,977	8,950	8,944	8,858	8,756	8,724	8,696	8,849	8,755	8,748
Unit 5 CC	7,773	7,858	7,858	7,891	7,834	7,759	7,752	7,733	7,695	7,666	7,675	7,669	7,710	7,724	7,718	7,719
Unit 1 CT	16,550	-	-	-	16,254	15,591	15,374	15,401	15,591	16,254	-	16,254	16,254	-	-	16,254
Unit 2 CT	16,212	-	-	-	15,757	15,259	14,970	15,010	15,259	15,757	-	-	-	-	-	15,757
Redhawk																
Unit 1 CC	7,691	7,512	7,497	7,569	7,578	7,472	7,447	7,460	7,377	7,412	7,314	7,327	7,351	7,359	7,299	7,316
Unit 2 CC	7,666	7,479	7,463	7,452	7,452	7,397	7,403	7,338	7,300	7,357	7,243	7,246	7,287	7,296	7,252	7,243

APS 2012 INTEGRATED RESOURCE PLAN

AVERAGE HEAT RATE - 1B f (Btu/kWh)																
UNIT	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Sundance																
Unit 1 CT	11,794	11,426	11,382	13,213	11,409	11,349	11,251	11,293	11,091	10,701	10,487	10,466	10,445	10,622	10,547	10,471
Unit 2 CT	11,506	11,385	11,274	12,880	11,519	11,439	11,312	11,301	11,129	10,659	10,473	10,430	10,409	10,610	10,499	10,466
Unit 3 CT	11,407	11,097	11,374	12,308	11,446	11,434	11,230	11,350	11,134	10,696	10,519	10,472	10,451	10,669	10,577	10,512
Unit 4 CT	11,238	10,970	11,221	12,189	11,554	11,442	11,252	11,390	11,105	10,804	10,562	10,486	10,488	10,727	10,563	10,515
Unit 5 CT	11,479	11,222	11,243	12,131	11,432	11,408	11,337	11,322	11,148	10,804	10,566	10,473	10,488	10,720	10,562	10,486
Unit 6 CT	11,567	11,180	11,333	14,178	11,605	11,357	11,339	11,310	11,071	10,792	10,577	10,463	10,475	10,721	10,538	10,456
Unit 7 CT	11,306	11,133	11,123	11,825	11,316	11,350	11,313	11,378	11,124	10,863	10,589	10,464	10,480	10,697	10,498	10,448
Unit 8 CT	11,036	11,033	11,009	11,773	11,845	11,630	11,518	11,392	11,156	10,857	10,588	10,453	10,456	10,676	10,457	10,454
Unit 9 CT	11,102	11,173	10,983	11,721	11,653	11,439	11,556	11,374	11,281	10,891	10,562	10,422	10,451	10,657	10,442	10,411
Unit 10 CT	10,970	10,929	10,941	11,695	11,557	11,214	11,255	11,270	11,356	10,849	10,547	10,384	10,444	10,627	10,426	10,383
Yucca																
Unit 1 CT	14,543	18,771	-	-	14,582	15,284	14,665	14,517	15,706	14,581	-	-	-	-	-	14,582
Unit 2 CT	14,543	16,752	-	-	14,582	15,284	14,665	14,517	15,706	14,582	-	-	-	-	-	14,582
Unit 3 CT	14,494	13,868	17,824	-	13,782	15,902	14,027	14,085	14,124	13,796	-	13,868	13,868	-	-	13,839
Unit 4 CT	-	-	-	-	16,013	18,760	-	16,450	13,884	-	-	-	-	-	-	-
Unit 5 CT	10,853	10,838	10,961	11,729	11,107	10,984	10,881	10,838	10,811	10,474	10,268	10,262	10,206	10,376	10,326	10,286
Unit 6 CT	10,822	10,731	10,910	11,395	11,116	10,956	10,926	10,858	10,879	10,484	10,302	10,257	10,197	10,374	10,345	10,327
Douglas																
Unit 1 CT	-	-	-	-	31,056	20,353	-	15,368	16,726	-	-	-	-	-	-	-
Future Units																
Future Unit 1 CC	-	-	-	-	-	-	-	-	7,203	7,236	7,225	7,192	7,187	7,160	7,182	7,171
Future Unit 2 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	7,206	7,236	7,215
Future Unit 1 CT	-	-	-	-	-	-	-	10,642	11,071	10,598	10,578	10,378	10,441	10,685	10,401	10,399
Future Unit 2 CT	-	-	-	-	-	-	-	-	10,294	10,695	10,610	10,415	10,406	10,741	10,446	10,374
Future Unit 3 CT	-	-	-	-	-	-	-	-	-	10,716	10,546	10,427	10,381	10,730	10,522	10,308
Future Unit 4 CT	-	-	-	-	-	-	-	-	-	10,763	10,481	10,411	10,260	10,554	10,550	10,382
Future Unit 5 CT	-	-	-	-	-	-	-	-	-	10,619	10,302	10,344	10,193	10,513	10,401	10,217
Future Unit 6 CT	-	-	-	-	-	-	-	-	-	10,577	10,257	10,254	10,090	10,577	10,412	10,107
Future Unit 7 CT	-	-	-	-	-	-	-	-	-	11,039	10,399	10,417	10,157	10,617	10,373	10,086
Future Unit 8 CT	-	-	-	-	-	-	-	-	-	10,166	10,275	10,374	10,180	10,679	10,399	10,166
Future Unit 9 CT	-	-	-	-	-	-	-	-	-	-	10,394	10,388	10,194	10,908	10,277	10,169
Future Unit 10 CT	-	-	-	-	-	-	-	-	-	-	10,417	10,409	10,224	10,854	10,207	10,240
Future Unit 11 CT	-	-	-	-	-	-	-	-	-	-	11,035	10,359	10,269	11,044	10,477	10,276
Future Unit 12 CT	-	-	-	-	-	-	-	-	-	-	9,972	10,430	10,301	11,173	10,553	10,381
Future Unit 13 CT	-	-	-	-	-	-	-	-	-	-	-	10,476	10,342	11,359	10,841	10,466
Future Unit 14 CT	-	-	-	-	-	-	-	-	-	-	-	10,139	10,493	11,478	11,007	10,451
Future Unit 15 CT	-	-	-	-	-	-	-	-	-	-	-	-	10,662	11,987	11,424	10,618
Future Unit 16 CT	-	-	-	-	-	-	-	-	-	-	-	-	11,045	12,149	11,363	10,511
Future Unit 17 CT	-	-	-	-	-	-	-	-	-	-	-	-	10,375	11,020	10,508	10,752
Future Unit 18 CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,519
Future Unit 19 CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,280

APS 2012 INTEGRATED RESOURCE PLAN

AVERAGE FUEL COST - B1 g ($/MMBtu)																
FUEL	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Uranium																
Coal - Four Corners																
Coal - NGS																
Coal - Cholla																
Gas	4.42	5.02	5.40	5.68	5.93	6.17	6.43	6.69	6.95	7.21	7.51	7.82	8.00	8.18	8.37	8.56

Redacted

APS 2012 INTEGRATED RESOURCE PLAN

	ENERGY COST FOR LONG TERM CONTRACT ($/MWh)															
UNIT	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Renewables																
Aragonne Mesa Wind (Superior) RFP Renew																
Salton Sea CE Turbo #1																
SWMP Biomass (Abitibi)																
High Lonesome Wind - NM																
Sexton - City of Glendale Landfill																
Solana CSP																
NEW Geothermal (80MW in 2021)																
WIND NM (100MW in 2027)																
WIND AZ (100MW in 2025)																
PERRIN RANCH WIND (99MW in 2012)																
Solar Fixed PV Other 1-3																
Solar PPA New (SAT) PV																
Small Gen RFP (Ajo S) - Future Project																
Small Gen RFP (Prescott S) - Future Project																
Small Gen RFP (Tonopah) - Future Project																
Small Gen RFP (WM Landfil) - Future Project																
Recurrent Bagdad SAT PV - DE Contract																
Contracts																
SRP - Firm / Eastern Mining Load [1]																
CC Tolling # 1 [2]																
CC Tolling # 2 [2]																
Market Call Option [2]																
Gas Call Option [2]																

Redacted

Notes
(1) Based on Palo Verde Day-Ahead Index
(2) Based on gas price

FIXED OPERATING AND MAINTENANCE - 1B j ($/MW)

PLANT	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Palo Verde 1, 2, 3																
Four Corners 1, 2, 3																
Four Corners 4, 5																
NGS 1, 2, 3																
Cholla																
Ocotillo ST 1,2																
Ocotillo CT 1,2																
Saguaro ST 1, 2																
Saguaro / Douglas																
West Phoenix CC 1, 2, 3																
West Phoenix CC 4																
West Phoenix CC 5																
West Phoenix CT 1, 2								Redacted								
Redhawk																
Sundance																
Yucca CT 1, 2, 3, 4																
Yucca CT 5, 6																
WIND Owned NM (100MW in 2022)																
WIND Owned AZ (100MW in 2026)																
AZ Sun: Hyder II																
AZ Sun: Cotton Center																
AZ Sun: Hyder I																
AZ Sun: Chino Valley																
AZ Sun - Paloma																
AZ Sun PV 4																
AZ Sun2 PV - Future Project 1																
AZ Sun2 PV - Future Project 2																
AZ Sun2 PV - Future Project 3																
Solar Owned New (SAT) PV																
Solar Owned New (SAT) PV																
Future Units																
Future Unit CC																
Future Unit CT																

DEMAND CHARGES FOR PURCHASED POWER - B1 k ($/kW-Yr)																
Contract	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
CC Tolling # 1	Redacted															
CC Tolling # 2 [1]																
Market Call Option																
Market Call Option																
Market Call Option																
Market Call Option																
Gas Call Option																

Note:

		CO_2 EMISSIONS - 1B p (Metric Tons)															
UNIT	RATE [1] (lb/MMBtu)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 2																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Saguaro																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT									**Redacted**								
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT																	

		CO_2 EMISSIONS - 1B p (Metric Tons)															
UNIT	RATE [1] (lb/MMBtu)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	
Future Units																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 1 CT																	
Future Unit 2 CT																	
Future Unit 3 CT																	
Future Unit 4 CT																	
Future Unit 5 CT																	
Future Unit 6 CT																	
Future Unit 7 CT																	
Future Unit 8 CT																	
Future Unit 9 CT																	
Future Unit 10 CT																	
Future Unit 11 CT																	
Future Unit 12 CT																	
Future Unit 13 CT								Redacted									
Future Unit 14 CT																	
Future Unit 15 CT																	
Future Unit 16 CT																	
Future Unit 17 CT																	
Future Unit 18 CT																	
Future Unit 19 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [2]																	
Total		15,313,185	14,811,182	14,379,059	14,549,660	14,745,803	15,105,853	15,390,145	15,667,773	15,759,875	15,673,326	16,098,342	16,131,683	16,432,683	16,778,098	16,982,746	17,385,315

Notes:
(1) Emission rates are as of 2012

		CO EMISSIONS - 1B p (Metric Tons)															
UNIT	RATE [1] (lb/MMBtu)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 2																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Saguaro																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	

Redacted

APS 2012 INTEGRATED RESOURCE PLAN

		CO EMISSIONS - 1B p (Metric Tons)															
UNIT	**RATE [1] (lb/MMBtu)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	
Future Units																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 1 CT																	
Future Unit 2 CT																	
Future Unit 3 CT																	
Future Unit 4 CT																	
Future Unit 5 CT																	
Future Unit 6 CT																	
Future Unit 7 CT																	
Future Unit 8 CT																	
Future Unit 9 CT																	
Future Unit 10 CT																	
Future Unit 11 CT																	
Future Unit 12 CT																	
Future Unit 13 CT																	
Future Unit 14 CT																	
Future Unit 15 CT																	
Future Unit 16 CT																	
Future Unit 17 CT																	
Future Unit 18 CT																	
Future Unit 19 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [2]																	
Total		**1,892**	**1,885**	**1,823**	**1,862**	**1,861**	**1,893**	**1,948**	**1,981**	**1,949**	**1,918**	**1,972**	**1,942**	**1,972**	**1,988**	**1,983**	**2,015**

Redacted

Notes:
(1) Emission rates are as of 2012

		VOC EMISSIONS - 1B p (Metric Tons)															
UNIT	RATE [1] (lb/MWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 2																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Saguaro																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	

Redacted

APS 2012 INTEGRATED RESOURCE PLAN

		VOC EMISSIONS - 1B p (Metric Tons)															
UNIT	**RATE [1] (lb/MWh)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	
Future Units																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 1 CT																	
Future Unit 2 CT																	
Future Unit 3 CT																	
Future Unit 4 CT																	
Future Unit 5 CT																	
Future Unit 6 CT																	
Future Unit 7 CT																	
Future Unit 8 CT																	
Future Unit 9 CT																	
Future Unit 10 CT																	
Future Unit 11 CT																	
Future Unit 12 CT																	
Future Unit 13 CT																	
Future Unit 14 CT																	
Future Unit 15 CT																	
Future Unit 16 CT																	
Future Unit 17 CT																	
Future Unit 18 CT																	
Future Unit 19 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [2]																	
Total		137	126	129	120	136	158	161	156	159	156	160	167	171	160	161	168

Redacted

Notes:
(1) Emission rates are as of 2012

APS 2012 INTEGRATED RESOURCE PLAN

		NOx EMISSIONS - 1B p (Metric Tons)															
UNIT	**RATE [1] (lb/MMBtu)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4 [3]																	
Unit 5 [3]																	
NGS																	
Unit 1 [4]																	
Unit 2 [4]																	
Unit 3 [4]																	
Cholla																	
Unit 1 [5]																	
Unit 2 [5]																	
Unit 3 [5]																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Saguaro																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	

Redacted

APS 2012 INTEGRATED RESOURCE PLAN

		NOx EMISSIONS - 1B p (Metric Tons)															
UNIT	**RATE [1] (lb/MMBtu)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	
Future Units																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 1 CT																	
Future Unit 2 CT																	
Future Unit 3 CT																	
Future Unit 4 CT																	
Future Unit 5 CT																	
Future Unit 6 CT																	
Future Unit 7 CT																	
Future Unit 8 CT																	
Future Unit 9 CT																	
Future Unit 10 CT																	
Future Unit 11 CT																	
Future Unit 12 CT																	
Future Unit 13 CT																	
Future Unit 14 CT																	
Future Unit 15 CT																	
Future Unit 16 CT																	
Future Unit 17 CT																	
Future Unit 18 CT																	
Future Unit 19 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [2]																	
Total		**25,887**	**22,831**	**21,015**	**21,494**	**19,793**	**13,736**	**7,278**	**5,763**	**5,574**	**5,480**	**5,526**	**5,527**	**5,581**	**5,065**	**4,844**	**4,919**

Redacted

Notes:
(1) Emission rates are as of 2012

SO2 EMISSIONS - 1B p (Metric Tons)																	
UNIT	RATE [1] (lb/MMBtu)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4 [2]																	
Unit 5 [2]																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 2 [3]																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Saguaro																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	

Redacted

APS 2012 INTEGRATED RESOURCE PLAN

		SO2 EMISSIONS - 1B p (Metric Tons)															
UNIT	**RATE [1] (lb/MMBtu)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	
Future Units																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 1 CT																	
Future Unit 2 CT																	
Future Unit 3 CT																	
Future Unit 4 CT																	
Future Unit 5 CT																	
Future Unit 6 CT																	
Future Unit 7 CT																	
Future Unit 8 CT																	
Future Unit 9 CT																	
Future Unit 10 CT																	
Future Unit 11 CT																	
Future Unit 12 CT																	
Future Unit 13 CT																	
Future Unit 14 CT																	
Future Unit 15 CT																	
Future Unit 16 CT																	
Future Unit 17 CT																	
Future Unit 18 CT																	
Future Unit 19 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [4]																	
Total		**8,386**	**9,428**	**6,226**	**3,960**	**4,557**	**5,111**	**4,753**	**4,496**	**4,596**	**4,520**	**4,591**	**4,541**	**4,536**	**4,233**	**4,130**	**4,163**

Redacted

Notes:
(1) Emission rates are as of 2012

Hg EMISSIONS - 1B p (Metric Tons)																	
UNIT	RATE [1] (lb/Trillion Btu)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1 [2]																	
Unit 2 [3]																	
Unit 3 [4]																	
Cholla																	
Unit 1 [5]																	
Unit 2 [6]																	
Unit 3 [7]																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Saguaro																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	

Redacted

		Hg EMISSIONS - 1B p (Metric Tons)															
UNIT	RATE [1] (lb/Trillion Btu)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	
Future Units																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 1 CT																	
Future Unit 2 CT																	
Future Unit 3 CT																	
Future Unit 4 CT																	
Future Unit 5 CT																	
Future Unit 6 CT																	
Future Unit 7 CT																	
Future Unit 8 CT																	
Future Unit 9 CT																	
Future Unit 10 CT																	
Future Unit 11 CT																	
Future Unit 12 CT																	
Future Unit 13 CT																	
Future Unit 14 CT																	
Future Unit 15 CT																	
Future Unit 16 CT																	
Future Unit 17 CT																	
Future Unit 18 CT																	
Future Unit 19 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [8]																	
Total		0.308	0.172	0.118	0.074	0.076	0.077	0.078	0.078	0.079	0.078	0.080	0.077	0.079	0.080	0.079	0.080

Redacted

Notes:
(1) Emission rates are as of 2012

PM10 EMISSIONS - 1B p (Metric Tons)																	
UNIT	RATE [1] (lb/MMBtu)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 2 [2]																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Saguaro																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	

Redacted

APS 2012 INTEGRATED RESOURCE PLAN

		PM10 EMISSIONS - 1B p (Metric Tons)															
UNIT	**RATE [1] (lb/MMBtu)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Unit 10 CT																	
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	
Future Units																	
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 1 CT																	
Future Unit 2 CT																	
Future Unit 3 CT																	
Future Unit 4 CT																	
Future Unit 5 CT																	
Future Unit 6 CT																	
Future Unit 7 CT																	
Future Unit 8 CT																	
Future Unit 9 CT																	
Future Unit 10 CT																	
Future Unit 11 CT																	
Future Unit 12 CT																	
Future Unit 13 CT																	
Future Unit 14 CT																	
Future Unit 15 CT																	
Future Unit 16 CT																	
Future Unit 17 CT																	
Future Unit 18 CT																	
Future Unit 19 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
Short term Purchases																	
Other Contracts [3]																	
Total		**1,166**	**932**	**818**	**816**	**861**	**898**	**891**	**890**	**902**	**890**	**912**	**907**	**921**	**925**	**927**	**933**

Redacted

Notes:
(1) Emission rates are as of 2012

APS 2012 INTEGRATED RESOURCE PLAN

COAL FLY ASH COLLECTED - 1B r (Metric Tons)																	
UNIT	**RATE [1] (lb/MMBtu)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 2																	
Unit 3																	
Total		**942,965**	**989,616**	**941,315**	**998,686**	**956,442**	**932,332**	**950,067**	**984,298**	**977,666**	**964,213**	**986,674**	**928,012**	**934,651**	**975,638**	**959,770**	**957,405**

Redacted

(1) Emission rates are as of 2012

APS 2012 INTEGRATED RESOURCE PLAN

COAL ASH BOTTOM COLLECTED - 1B r (Metric Tons)																	
UNIT	**RATE [1] (lb/MMBtu)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Four Corners																	
Unit 1																	
Unit 2																	
Unit 3																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 2																	
Unit 3																	
Total		**235,729**	**247,390**	**235,316**	**249,658**	**239,098**	**233,070**	**237,504**	**246,061**	**244,403**	**241,040**	**246,655**	**231,991**	**233,650**	**243,897**	**239,930**	**239,339**

Redacted

(1) Emission rates are as of 2012

APS 2012 INTEGRATED RESOURCE PLAN

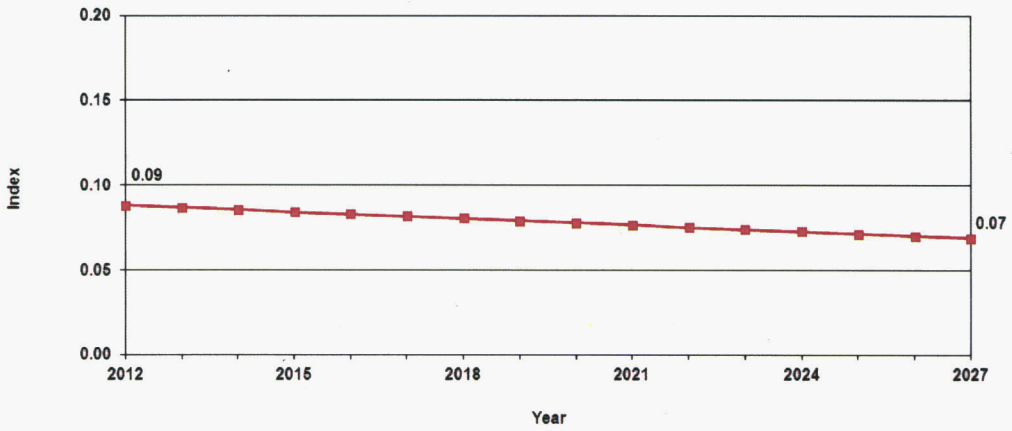
		WATER CONSUMPTION -1B q (Acre-Feet)															
PLANT	**RATES (gal/MWh)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Palo Verde Units 1, 2, 3																	
Four Corners Units 1, 2, 3, 4, 5																	
Navajo Generating Station Units 1, 2, 3																	
Cholla Units 1, 2, 3																	
Ocotillo Units 1, 2 ST Ocotillo Units 1, 2 CT																	
Saguaro Units 1, 2 ST Saguaro Units 1, 2, 3 CT																	
West Phoenix Units 1, 2, 3, 4, 5 CC																	
West Phoenix Units 1, 2 CT																	
Redhawk Units 1, 2 CC																	
Sundance Units 1-10 CT																	
Yucca Units 1, 2, 3 CT Yucca Units 4, 3 CT																	
Future Unit CC																	
Future Unit CT																	
Salton Sea CE Turbo #1																	
SWMP Biomass (Abitibi)																	
Sexton - City of Glendale Landfill																	
Solana CSP																	
SRP - Firm / Eastern Mining Load																	
CC Tolling # 1																	
CC Tolling # 2																	
Market Call Option																	
Gas Call Option																	
Small GEN WM LANDFILL																	
NEW Geothermal (80MW in 2021)																	
Total		**53,365**	**53,986**	**52,486**	**55,107**	**56,243**	**57,498**	**58,031**	**58,288**	**57,599**	**58,192**	**58,937**	**58,715**	**59,153**	**58,802**	**58,919**	**59,458**

Redacted

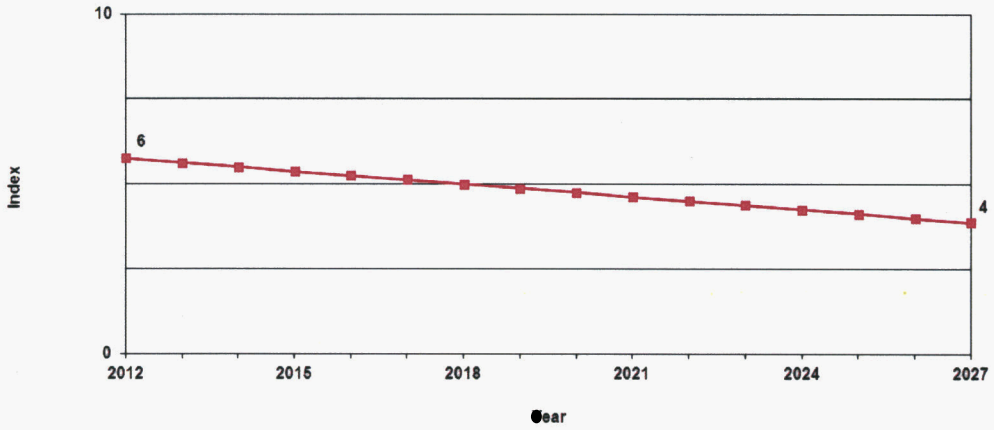
Note:
Water consumption rates are based on plant actual.

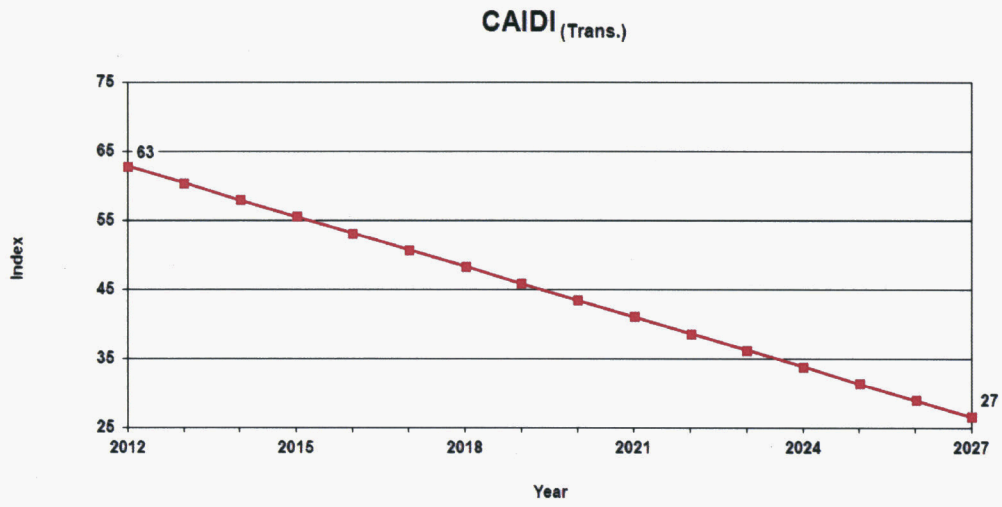
Transmission Reliability

SAIFI (Trans.)



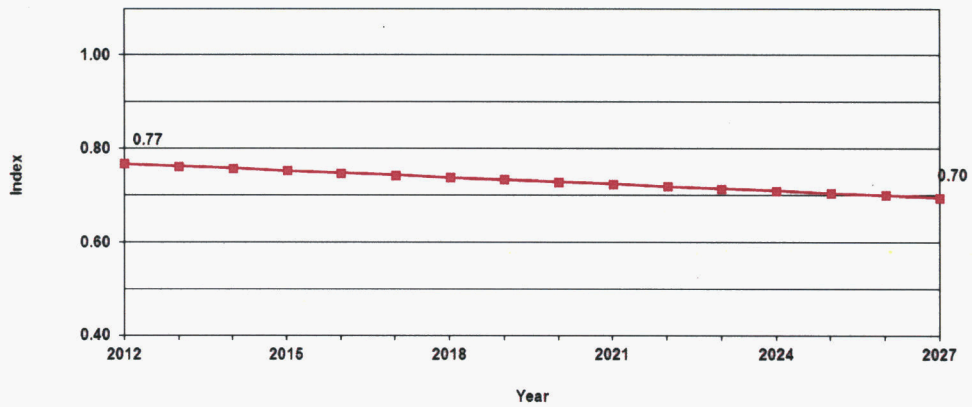
SAIDI (Trans.)



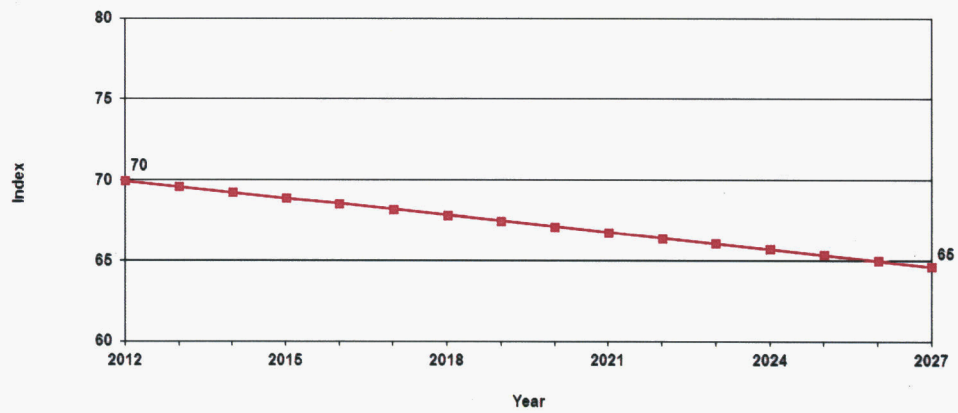

CAIDI (Trans.)
75
65
55
45
35
25
63
27
Index
2012
2015
2018
2021
2024
2027
Year

Distribution Reliability

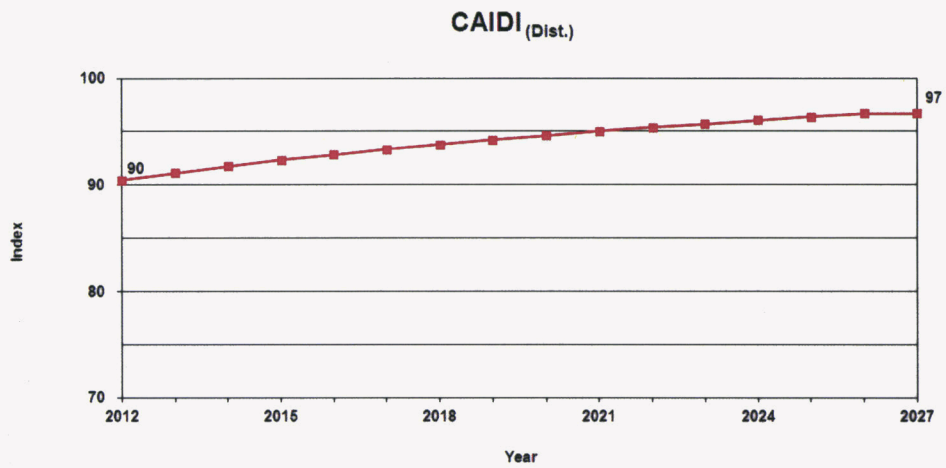
SAIFI (Dist.)



SAIDI (Dist.)



APS 2012 INTEGRATED RESOURCE PLAN



CAPITAL COSTS AND CONSTRUCTION SPENDING SCHEDULE FOR NEW GENERATING UNITS

($Millions)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	CAPITAL COSTS THRU 2027 Total
1 PEAKING GENERATION																	
1 FUTURE CT						$12.0	$61.4	$50.4									$123.8
1 FUTURE CT							$12.3	$63.0	$51.6								$126.9
6 FUTURE CT								$75.5	$387.1	$317.5							$780.1
4 FUTURE CT									$51.6	$264.6	$216.9						$533.1
2 FUTURE CT										$26.5	$135.6	$111.2					$273.2
3 FUTURE CT											$40.7	$208.5	$170.9				$420.1
2 FUTURE CT														$29.2	$149.7	$122.7	$301.6
SUB TOTAL						$12.0	$73.7	$188.9	$490.4	$608.5	$393.2	$319.6	$170.9	$29.2	$149.7	$122.7	$2,558.7
2 COMBINED CYCLE GENERATION																	
1 FUTURE CC						$34.4	$176.3	$397.7	$111.2								$719.6
1 FUTURE CC											$38.9	$199.5	$449.9	$125.8			$814.1
SUB TOTAL						$34.4	$176.3	$397.7	$111.2		$38.9	$199.5	$449.9	$125.8			$1,533.7
3 RENEWABLES																	
FUTURE SOLAR	$326.7	$241.9	$227.1	$469.6	$0.0	$132.2	$33.9	$57.9			$149.5	$316.0	$65.5				$2,020.2
FUTURE WIND										$164.2	$112.2			$509.1	$126.9	$331.6	$1,244.0
FUTURE GEOTHERMAL										$521.4							$521.4
SUB TOTAL	$326.7	$241.9	$227.1	$469.6		$132.2	$33.9	$57.9		$685.6	$261.8	$316.0	$65.5	$509.1	$126.9	$331.6	$3,785.6
4 GRAND TOTAL	$326.7	$241.9	$227.1	$469.6		$178.6	$283.9	$644.4	$601.5	$1,294.0	$693.9	$835.1	$686.3	$664.1	$276.5	$454.4	$7,878.0
5 CUMULATIVE TOTAL	$326.7	$568.7	$795.8	$1,265.3	$1,265.3	$1,443.9	$1,727.8	$2,372.2	$2,973.7	$4,267.8	$4,961.6	$5,796.7	$6,483.0	$7,147.1	$7,423.6	$7,878.0	

NOTES
1) Capital costs include APS-owned construction and resources constructed and owned by other companies where the power is sold to APS through long term purchased power agreements.
2) PPA resource capital costs are embedded in purchased power energy costs for the 2012 APS Resource Plan.
3) Acquisition of Four Corners 4 and 5 is not included in the numbers above.
4) Capital costs do not include interest during construction.

Arizona Public Service Company
Planned Transmission Facilities
2012-2027

Project Description	I/S	Participants	kV	Rating (MVA)	Total Cost ($ millions)	Length (miles)	Purpose
Youngs Canyon 345 kV Interconnection	2012	None	345	150	Redacted	N/A	Provide a second transmission source into the Flagstaff area and prevents service interruption of up to 40MW of load for an extended period of time for the loss of the existing 230/69kV Coconino Substation.
Palo Verde-Delaney line	2013	APS (80%), SRP(10%), CAP(10%)	500	TBD		15	Increase the export scheduling capability from the Palo Verde area to provide access to both solar and gas resources.
Bagdad Relocation	2014	None	115	N/A		5.5	Freeport McMoRan (HFMI) has future plans to expand the mine in the location of the existing 115kV line from Prescott.
Desert Basin-Pinal Central line	2014	APS (50%), SRP(50%)	230	TBD		21	Improve the reliability of the 230kV system in the adjacent area by reducing the loading on existing lines in the area, increasing local system capacity and creating one of the 230kV components of the proposed transmission system for the central Arizona area.
Pinal Central-Sundance line	2014	APS(75%), ED2(25%)	230	TBD		6	Serve increasing loads in Pinal County, and the APS system, and improve reliability and continuity of service to the communities in the adiacent area.

Arizona Public Service Company
Planned Transmission Facilities
2012-2027

Project Description	I/S	Participants	kV	Rating (MVA)	Total Cost ($ millions)	Length (miles)	Purpose
Delaney-Sun Valley line	2015	APS (80%), SRP(10%), CAP(10%)	500	TBD	Redacted	28	Serve projected need for electric energy in the area immediately north and west of the Phoenix Metropolitan area; increase import capability in the Phoenix area as well as export scheduling capability from the Palo Verde area to access solar and gas resources.
Hassayampa-N.Gila #2 line	2015	APS(40%), SRP(20%), IID(20%) &WMIDD(20%)	500	TBD	Redacted	110	Increase the import capability for the Yuma area and export/scheduling capability from the Palo Verde area to provide access to both solar and gas resources.
Mazatzal loop-in of the Cholla-Pinnacle Peak	2015	None	345	150	Redacted	1	Provide the electric source and support to the subtransmission system in the area of Payson and the surrounding communities.
N.Gila-TS8 line	2015	None	230	TBD	Redacted	13	Serve the need for electric energy, improved reliability and continuity of service for the greater Yuma area.
Palm Valley-TS2-Trilby Wash line	2015	None	230	TBD	Redacted	12	Serve the need for electric energy in the western Phoenix Metropolitan area and additional import capability into the greater Phoenix area. The proposed second 230kV source for Trilby Wash provides improved system reliability for communities such as El Mirage, Surprise, Youngtown, Goodyear and Buckeye.

Arizona Public Service Company
Planned Transmission Facilities
2012-2027

Project Description	I/S	Participants	kV	Rating (MVA)	Total Cost ($ millions)	Length (miles)	Purpose
Sun Valley-Trilby Wash line	2015	None	230	TBD		15	Serve the need for electric energy in the western Phoenix Metropolitan area and additional import capability into the greater Phoenix area. The proposed second 230kV source for Trilby Wash provides improved system reliability for communities such as El Mirage, Surprise, Youngtown, Goodyear and Buckeye.
Morgan-Sun Valley line	2016	APS (80%), SRP(10%), CAP(10%)	500	TBD		40	Serve the need for electric energy in the Phoenix Metropolitan area; increase the import capability to the Phoenix area; increase the export/scheduling capability from the Palo Verde area including both solar and gas resources.
Saguaro (TS12): Relocate the 230kV yard and install a 230/69kV transformer	2021	None	230	188	Redacted	1	Provide electric energy in southern Pinal County as well as increase the reliability and continuity of service for these areas.
Scatter Wash loop-in of Pinnacle Peak-Raceway	2021	None	230	188		1	Provide electric energy in the northern portions of the Phoenix Metropolitan area; increase the reliability and continuity of service for these areas.
Palo Verde East line	2025	TBD	TBD	TBD		40	Connect new resources to the 230kV infrastructure in the valley.
CT connect costs	2019-2024	TBD	230-500	TBD		TBD	Connect new resources.
CC connect costs	2020-2025	TBD	230-500	TBD		TBD	Connect new resources.

Arizona Public Service Company

SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Black Peak-Eagle Eye 69kV line rebuild	2012	69	191	Redacted	41	Loss of the Eagle Eye-Salome 69kV line causes overload of 6%, causes voltage deviations of 13% and necessitates the shedding of up to 2.2MW of load.
Baja 69kV 14.4MVAR cap bank	2012	69	0	Redacted	N/A	Improve area voltage profile during base case and N-1 conditions.
Black Peak 161/69kV Xfmr replacement	2012	69	100	Redacted	N/A	Loss of the Eagle Eye-Salome 69kV line loads the existing 35MVA transformer to 127%.
Country Club-Evans Churchill 69kV line rebuild	2012	69	191	Redacted	1.3	Loss of Fillmore-West Phoenix 69kV line causes overload of 4%.
Estrellita-Willis (GY5) 69kV Line	2012	69	191	Redacted	6	Provide 69kV source to planned GY5 69/12kV Substation in Estrella Ranch to meet load growth.
Fillmore-West Phoenix 69kV line rebuild	2012	69	191	Redacted	3.1	Loss of Country Club-Evans Churchill 69kV line causes overload of 2%.
Fillmore 69kV Switches	2012	69	0	Redacted	N/A	Match substation switch ratings to Fillmore-McDowell 69kV line rating.
Gateway-Gavilan Peak 69kV Line	2012	69	191	Redacted	11.3	Loss of Deadman Wash-New River 69kV line overloads Biscuit Flats-Gateway 69kV line by 4%; loss of Adobe-Deer Valley 69kV line overloads Deer Valley-Rose Garden 69kV
McDowell 69kV Line Breakers	2012	69	0	Redacted	N/A	Eliminate dual radial 69kV substation configuration.

Arizona Public Service Company
SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Waldrip 69kV Switching Station	2012	69	191		13.5	Loop the San Luis and Baja 69/12kV Substations into the Yuma 69kV system. The new 69kV line configuration will prevent shedding of up to 48MW of load for loss of the Yucca-Laguna 69kV line.
Woody Mountain 69kV 7.2MVAR cap bank	2012	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Youngs Canyon 345/69kV Substation	2012	345, 69	150		12.5	Provides a second transmission source into the Flagstaff area and prevents service interruption to up to 40MW of load for an extended period of time for the loss of the existing Coconino 230/69kV Substation.
Youngs Canyon 69kV 14.4 MVAR cap	2012	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Canal 69kV Line Breakers	2013	69	0	Redacted	N/A	Prevent loss of one 69/12kV transformer for loss of either the Alexander-Canal or Canal-Honeywell 69kV line; avoid overloading remaining 69/12kV transformer for loss of other transformer; prevent loss of a 69kV line if a 69/12kV transformer fails.
Cotton Center-Gila Bend 69kV line rebuild	2013	69	191		19	Loss of Liberty-Panda 230kV line overloads existing conductor by 2%; rebuild is Network Upgrade for Solana (Q44) Generation Interconnection.
Downing 69kV Reconfigure	2013	69	0		0.2	Without removing the Rawhide 69kV line from Downing, loss of either 69kV line originating from Pinnacle Peak going to Downing overloads the other line by 3%. Both lines already have 795ACSS conductor.

Arizona Public Service Company

SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
East End-Raintree 69kV Line	2013	69	191	Redacted	2.5	Loss of Downing-Pinnacle Peak 69kV line overloads Altadena-East End 69kV line by 4.5%; loss of Rawhide-Pinnacle Peak 69kV line overloads Downing-East End 69kV line by 7%.
GY5 69kV 14.4MVAR cap bank	2013	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Owens(P1) 69kV 10.8 MVAR cap bank	2013	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Rawhide 69kV 28.8MVAR cap bank	2013	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Riverside-Yucca 69kV line rebuild	2013	69	191		4.6	Loss of the Yucca Center-Yucca East 69kV bus tie prevents Yucca East from delivering its full generation output to the Yuma system.
Sturm Ruger 69kV In & Out Conversion	2013	69	108		1.7	Improve reliability to area.
Sturm Ruger 69kV 7.2 MVAR cap bank	2013	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Hereford-Palominas 69kV Line Don Luis-Mural 69kV line rebuild San Pedro (4) breaker ring bus San Pedro 69kV in and out	2013-14	69	191		7	The new system improvements will comply with the 5th BTA Assessment of providing Cochise County with continuity of service for loss of a transmission line.
Bald Mountain-Dewey 69kV line rebuild	2014	69	108		8.5	Loss of Sundog Tap-Sundog 69kV line overloads Bald Mountain-Dewey 69kV line by 3% and prevent load shedding of 2MW.

Arizona Public Service Company

SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Biscuit Flats-Pioneer 69kV line reconductor	2014	69	191		0.7	Loss of Gavilan Peak #11 230/69kV tranformer overloads Biscuit Flats-Gateway 69kV line by 3%.
Cave Creek-Gavilan Peak 69kV Line	2014	69	191		9.2	Improve reliability in the Cave Creek area by providing a second source into Cave Creek 69/12kV Substation; create a 69kV network in the Northeast Valley.
Festival Ranch-Sun Valley 69kV Line	2014	69	191		5	Provide 69kV source from new Sun Valley 230/69kV Substation.
Flores 69kV 7.2MVAR cap bank	2014	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Prescott City 69kV line relocate	2014	69	0		1	Provide service to relocated Prescott City 69/12kV Substation.
TS8 230/69kV Substation and 69kV system Improvements	2014-15	230, 69	188	**Redacted**	19.3	TS8 230/69kV transformer and adjacent 69kV line rebuilds will increase transmission system reliability and ability to deliver power within the Yuma area.
White Spar-Wickenburg 69kV Rebuild	2014-17	69	108		45	The 69kV line is over 60 years old and deteriorating, rebuilding it will improve the reliability to the area.
Altadena-Thompson Peak 69kV line reconductor	2015	69	191		4.5	Loss of Pinnacle Peak-Rawhide 69kV line overloads existing conductor by 10%.
Antelope 69kV lines in and out	2015	69	108		0.2	Provide two 69kV sources to the Antelope 69/12kV Substation.
Antelope 69kV 7.2MVAR cap bank	2015	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.

Arizona Public Service Company
SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Bald Mountain 69kV 7.2MVAR cap bank	2015	69	0	Redacted	N/A	Improve area voltage profile during base case and N-1 conditions.
Jojoba 69kV Switchyard	2015	69	0	Redacted	16.5	Provide backup power to Estrellita and GY5 Substations; improve reliability by providing another 69kV tie between the Metro Western to Buckeye areas.
Mazatzal 345/69kV Substation	2015	345, 69	150	Redacted	0.5	Prevent shedding 11MW during outage of Owens-Preacher Canyon 69kV line.
Monte Cristo 69kV Line Breakers	2015	69	0	Redacted	N/A	Prevent loss of one 69/12kV transformer for loss of either the Deer Valley-Monte Cristo or Loma Vista-Monte Cristo 69kV line. The loss of a transformer overloads the adjacent transformer by 34%. The line breakers will also prevent the loss of a line if a transformer fails.
Phillips 69kV Switchyard	2015	69	0	Redacted	0.3	Improve system reliability and reduce line exposure for the Buckeye area.
Trilby Wash 230/69kV Substation	2015	230, 69	188	Redacted	0.2	Loss of a Westwing 230/69kV transformer overloads remaining unit by 24%; loss of McMicken-Westwing 69kV line overloads McMicken-Surprise 69kV line by 14%.
Childs-Tonto 69kV line rebuild	2015-17	69	108	Redacted	30	The 69kV line is over 45 years old and deteriorating, rebuilding it will improve the reliability to the area.
Paulden-Williams 69kV line rebuild	2015-19	69	108	Redacted	50	The 69kV line is over 60 years old and deteriorating, rebuilding it will improve the reliability to the area.

Arizona Public Service Company

SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Buckeye #2 230/69kV Transformer Replacement	2016	230, 69	188	Redacted	N/A	Loss of Buckeye #6 230/69kV transformers overloads Buckeye #2 230/69kV transformer by 24%; loss of Gila Bend-Panda 230kV line overloads Buckeye #6 230/69kV transformer bv 24%.
Fairview 2-69kV 7.2MVAR cap banks	2016	69	0	Redacted	N/A	Improve area voltage profile during base case and N-1 conditions.
Moon Valley 69kV Line Breakers	2016	69	0	Redacted	N/A	Prevent loss of one 69/12kV transformer for loss of either the Lookout-Moon Valley or Moon Valley-Sunnyslope 69kV line. The loss of a transformer overloads the adjacent transformer by 34%. The line breakers will also prevent the loss of a line if a transformer fails.
Quartzsite 69kV 7.2MVAR cap bank	2016	69	0	Redacted	N/A	Improve area voltage profile during base case and N-1 conditions.
Stagecoach 69kV 14.4MVAR cap bank	2016	69	0	Redacted	N/A	Improve area voltage profile during base case and N-1 conditions.
Sundog upgrade 69kV cap bank to 14.4MVAR	2016	69	0	Redacted	N/A	Improve area voltage profile during base case and N-1 conditions.
Valley Farms 69kV 14.4MVAR cap bank	2016	69	0	Redacted	N/A	Improve area voltage profile during base case and N-1 conditions.
Verde-Yavapai 69kV line rebuild	2016	69	108	Redacted	2.3	The 69kV line is over 30 years old and deteriorating, rebuilding it will improve the reliability to the area.
Casa Grande-Thornton 69kV line rebuild	2017	69	190	Redacted	1.5	Loss of Milligan 230/69kV transformer overloads existing conductor by 3.1%.

Arizona Public Service Company

SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Mummy Mountain 69kV Line Breakers	2017	69	0	Redacted	N/A	Prevent loss of one 69/12kV transformer for loss of either the Camelback-Mummy Mountain or Mummy Mountain-Orangewood 69kV line. The loss of a transformer overloads the adjacent transformer by 21%. The line breakers will also prevent the loss of a line if a transformer fails.
Mummy Mountain-Orangewood 69kV line rebuild	2017	69	108	Redacted	2.5	Loss of Camelback-Ocotillo 69kV line overloads existing conductor by 14%.
Palm Valley-Pebblecreek 69kV line reconductor	2017	69	191	Redacted	2	Loss of Litchfield-White Tanks 69kV line overloads existing conductor by 4%.
Sarival-Wildflower 69kV line reconductor	2017	69	191	Redacted	4	Loss of Coldwater-White Tanks 69kV line overloads existing conductor by 7%.
Sundog-Willow Lake 69kV line rebuild	2017	69	191	Redacted	2.3	Loss of Bald Mountain-Dewey 69kV line overloads Willow Lake-Sundog 69kV line by 3%; prevent shedding of 2MW.
Altadena-Cactus 69kV Line	2018	69	191	Redacted	4	Loss of Cactus-Raintree 69kV line overloads Cactus-Chaparral 69kV line by 4%; loss of Downing-Pinnacle Peak 69kV line overloads Altadena-Shea 69kV line by 5%.
Copper Canyon-Quail Springs 69kV	2018	69	191	Redacted	10	Loss of Cottonwood tap-Verde 69kV line overloads Copper Canyon-Hayfield 69kV line by 3.5%; prevent shedding 3MW.
Dewey - Dugas 69kV line rebuild	2018	69	191	Redacted	6.6	Loss of the Dugas – Morgan 500kV line will load the Cordes Tap - Dugas 69kV line to 101.7% in 2018. To prevent an overload of 1.7% the 6.6 mile 69kV line will be rebuilt to 795ACSS.

Arizona Public Service Company

SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Javelina-Surprise 69kV line rebuild	2018	69	191	Redacted	6.7	Loss of Hearn-Waddel 69kV line overloads Javelina-Surprise 69kV line by 6%; loss of Javelina-Surprise 69kV line overloads Dysart-Surprise 69kV line by 3%.
Kachina 2-69kV 14.4MVAR cap bank	2018	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Raceway 2nd 230/69kV Transformer	2018	230, 69	188		N/A	Loss of a Westwing 230/69kV transformer overloads the adjacent unit by 21%.
Shaw 69kV Line Breakers	2018	69	0		N/A	Prevent loss of a 69/12kV transformer for loss of either the Cheryl-Shaw or Shaw-Sunnyslope 69kV line. The loss of a transformer overloads the adjacent transformer by 21%. The line breakers will also prevent the loss of a line if a transformer fails.
Palm Valley 2nd 230/69kV Transformer	2019	230, 69	188		N/A	Loss of Buckeye-Watson 69kV line overloads existing Palm Valley 230/69kV transformer by 25%.
Waldrip 69kV 14.4 MVAR cap bank	2019	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Hearn-Waddell 69kV line reconductor	2020	69	191		3.3	Loss of Javelina-Surprise 69kV line overloads existing conductor by 5%; eliminate 3-point relaying and improve reliability.
Hearn 69kV 28.8MVAR cap bank	2020	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Pebble Creek 69kV 28.8MVAR cap bank	2020	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.

Arizona Public Service Company
SubTransmission Plan

Project Description	In-Service	kV	Rating (MVA)	Total Cost ($000)	Length (miles)	Purpose
Valencia 69kV lines in and out	2020	69	191		0.2	Provide two 69kV sources for the two 69/12kV, 41MVA transformers.
Valley Farms 2nd 69kV cap bank 14.4MVAR	2020	69	0		N/A	Improve area voltage profile during base case and N-1 conditions.
Fain-Lonesome Valley 69kV line rebuild	2021	69	108		3.5	Loss of Sundog tap-Sundog 69kV line overloads existing conductor by 1%
Jomax-Scatter Wash 69kV Line	2021	69	191		7.5	Provides 69kV source for new area 69/12kV substations needed to serve growth in the Northeast Valley.
Old Home Manor-Paulden 69kV line rebuild	2021	69	108	Redacted	8	Loss of Grey Bears Tap-Willow Lake 69kV line overloads existing conductor by 1%.
Saguaro (TS12): Relocate the 230kV yard and install a 230/69kV Transformer	2021	230, 69	100		4.5	The new 230/69kV transformer and adjacent 69kV line is needed to serve the planned SE10 substation located at Red Rock.
Scatter Wash 230/69kV Substation	2021	230, 69	188		3	Loss of the Adobe-Deer Valley 69kV line overloads Deer Valley-Rose Garden 69kV line by 4%; provides another 230 source to support growth in northern Metro area.
Yavapai 2nd 230/69kV Transformer	2021	230, 69	188		N/A	Loss of the Yavapai-Willow Lake 230kV line overloads the existing transformer by 24%.

CONVENTIONAL GENERATION TECHNOLOGIES

PLANT	Location	Annual Capacity MW	Summer Capacity MW	Winter Capacity MW	Capital Costs $ Million	Capital Costs $/kW	Fixed O&M $/kW-Yr	Var O&M $/MWh	Heat Rate BTU/kWh	Lead Time Years	Capacity Factor %	CO_2 Emission lbs/MWh	Water Consumption gal/MWh
Coal													
Cholla 5 450MW Hybrid	Cholla	477	472	481	1,357	2,846	15.65	4.90	9,008	9	75%	1,847	491
Cholla 6 450MW Hybrid	Cholla	477	472	481	1,142	2,396	13.01	4.90	9,008	5	75%	1,847	491
Cholla 5&6 900MW Hybrid	Cholla	953	944	962	2,499	2,622	15.65	4.90	9,008	9	75%	1,847	491
Cholla 5 750MW Hybrid	Cholla	776	771	779	2,059	2,654	11.63	4.88	8,905	9	75%	1,826	491
Cholla 5 490MW IGCC	Cholla	490	459	518	2,130	4,347	20.27	3.30	9,136	9	75%	1,964	491
Gas Greenfield													
One 7FA, Chilled Inlet	Maricopa	203	200	209	142.9	716	3.85	5.18	10,073	3	10%	1,229	0
Two 7FA, Chilled Inlet	Maricopa	406	399	418	245.4	615	3.85	5.18	10,073	3	10%	1,229	0
Four 7EA, Chilled Inlet	Maricopa	327	319	342	275.4	863	5.49	5.50	11,911	3	10%	1,453	0
Six LM6000PC Sprint, Chilled Inlet	Maricopa	283	277	295	297.1	1,073	7.44	5.37	9,723	3	10%	1,186	54
Six LM6000PF Sprint DLN, Chilled Inlet	Maricopa	269	266	274	303.2	1,138	7.44	5.37	9,373	3	10%	1,144	28
Three LMS100PA High Temp, Low Water	Maricopa	310	306	318	310.0	1,012	5.20	4.86	9,072	3	10%	1,107	33
Three LMS100PA, Chilled Inlet	Maricopa	306	301	314	296.7	985	5.20	4.86	8,932	3	10%	1,107	197
One 2X1 CC 7FA, Chilled Inlet, DB on, CT (Wet)	Maricopa	694	681	719	543.5	798	4.88	4.32	6,473	4	75%	880	302
2x1 CC 7FA, Chilled Inlet, DB On, ACC	Maricopa	684	665	716	593.4	892	4.99	4.05	7,311	4	75%	902	7
Gas Brownfield													
One Redhawk 7FA, Chilled Inlet	Redhawk	203	200	209	135.5	679	3.85	5.18	10,073	3	10%	1,229	0
Two Redhawk 7FA, Chilled Inlet	Redhawk	406	399	418	237.1	594	3.85	5.18	10,073	3	10%	1,229	0
Two Redhawk 7EA, Chilled Inlet	Redhawk	164	159	171	149.9	940	5.49	5.50	11,911	3	10%	1,453	0
Two Sundance LM6000PC Sprint, Chilled Inlet	Sundance	94	92	98	120.7	1,308	7.44	5.37	9,723	3	10%	1,186	54
Two Sundance LM6000PF Sprint DLN, Chilled Inlet	Sundance	90	89	91	123.0	1,384	7.44	5.37	9,373	3	10%	1,144	28
Two Yucca LM6000PC Sprint, Chilled Inlet	Yucca	94	92	98	122.1	1,323	7.44	5.37	9,723	3	10%	1,186	54
Two Yucca LM6000PF Sprint DLN, Chilled Inlet	Yucca	90	89	91	124.4	1,400	7.44	5.37	9,373	3	10%	1,144	28
Three RH LMS100PA High Temp, Low Water	Redhawk	310	306	318	299.9	979	5.20	4.86	9,072	3	10%	1,107	33
Three Redhawk LMS100PA, Chilled Inlet, Wet Secondary	Redhawk	306	301	314	285.9	949	5.20	4.86	8,932	3	10%	1,107	197
2X0 P&W SP60 FT8-3 Mech Chillers	Maricopa	59	57	62	91.0	805	14.41	4.97	10,662	3	10%	1,301	85
Six Unit Wartsila 18V50	Maricopa	110	110	110	139.0	1,262	16.04	5.53	8,365	3	10%	984	0
Nuclear AP 1000 Hybrid	Palo Verde	400	400	400	1812.5	4531	52.01	0.34	10,386	10	75%	0.00	552

Notes:
1 Costs are in year-2011 dollars.
2 Capital costs are overnight construction costs; $/kW is based on summer capacity rating.
3 Capital cost for IGCC does not include CO_2 capture.
4 Lead time for Cholla 6 is contingent on Cholla 5 already built.
5 Lead time is based on construction schedule.
6 The following two conventional technologies were included in the 2012 Resource Plan:
Three LMS100PA High Temp, Low Water
2x1 CC 7FA, Chilled Inlet, DB On, ACC

RENEWABLE GENERATION TECHNOLOGIES

PLANT	Capacity in MW	Capital Costs in $Million	Capital Costs in $/kW	Fixed O&M $/kW-Yr	Var O&M $/MWh	Water Use Gal/MWh	Capacity Factor	Capacity Value	UsefulLife Years	Market Price 2015 $/MWh
Utility-Scale Generation										
Thin Film Solar PV - Fixed	17	31	1,783	25	0	0	27%	50%	25	Redacted
Thin Film Solar PV - Single Axis	17	34	1,998	25	0	0	29%	70%	25	
Parabolic Trough, Gas Hybrid	125	513	4,102	59	0	338	29%	100%	30	
Parabolic Trough, Salt Storage	125	774	6,196	66	0	338	40%	100%	30	
Central Receiver (Power Tower), Salt Storage	125	573	4,585	66	0	338	40%	100%	30	
CSP Hybrid Cooled, 6 hrs Storage	125	852	6,815	68	18	338	41%	100%	30	
CSP Hybrid Cooled, No Storage	125	564	4,512	64	22	338	30%	70%	30	
High Capacity Factor Wind	100	214	2,138	34	0	0	35%	20%	20	
Low Capacity Factor Wind	100	219	2,190	34	0	0	28%	20%	20	
Geothermal	20	93	4,639	81	8	764	86%	100%	30	
Biomass	25	120	4,783	110	5	764	85%	100%	20	
Biogas	5	8	1,536	57	14	764	85%	100%	20	

Notes:

1 Costs are in 2011$.

2 Capital cost for thin film PV is expected to decline over time and stablize in year 2018 at about $1,737/kW for fixed and $1,947/kW for single axis.

3 The following five renewable technologies were included in the 2012 Resource Plan:
Thin Film Solar PV - Fixed
Thin Film Solar PV - Single Axis
High Capacity Factor Wind
Low Capacity Factor Wind
Geothermal

TOTAL REVENUE REQUIREMENTS
2012 RESOURCE PLAN

(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	Emission Costs	DE-EE .Costs	$	$/MWh
2012	$582.6	$457.9	$44.7	$385.6	$8.3	$1,479.1	$108.9	$214.0	$322.9	($2.5)	$65.4	$24.8	$2.1	$148.1	$2,040.0	$66.2
2013	$675.6	$461.0	$47.1	$408.3	$8.3	$1,600.2	$110.0	$252.8	$362.7	($4.5)	$56.9	$28.7	$2.2	$183.3	$2,229.6	$73.0
2014	$695.0	$472.9	$46.5	$404.2	$20.5	$1,639.1	$110.8	$354.3	$465.1	($3.9)	$64.8	$27.0	$2.5	$217.6	$2,412.2	$78.1
2015	$747.1	$481.1	$48.4	$394.9	$44.7	$1,716.2	$112.0	$370.4	$482.5	($8.3)	$54.3	$25.9	$3.0	$235.8	$2,509.4	$81.2
2016	$817.5	$541.2	$52.8	$350.6	$69.7	$1,831.8	$112.6	$388.9	$501.5	($9.6)	$64.8	$22.9	($0.1)	$252.8	$2,664.2	$84.7
2017	$852.7	$660.5	$62.3	$373.9	$79.8	$2,029.2	$137.1	$345.3	$482.4	($11.0)	$73.6	$19.6	($0.1)	$247.7	$2,841.5	$88.6
2018	$892.5	$768.3	$66.7	$372.7	$80.1	$2,180.2	$121.7	$315.6	$437.3	($12.5)	$78.7	$17.1	($0.1)	$252.4	$2,953.1	$90.2
2019	$920.2	$798.1	$68.4	$362.5	$78.3	$2,227.5	$128.3	$332.3	$460.6	($13.5)	$78.8	$14.9	$59.1	$258.6	$3,086.0	$92.2
2020	$1,027.3	$908.8	$78.8	$356.1	$80.4	$2,451.3	$74.1	$261.0	$335.1	($13.3)	$83.7	$12.4	$69.5	$288.2	$3,227.0	$94.6
2021	$1,150.3	$948.8	$82.5	$383.9	$80.7	$2,646.2	$76.7	$359.6	$436.3	$0.0	$88.1	$17.0	$76.8	$167.3	$3,431.7	$99.0
2022	$1,272.6	$1,024.6	$86.7	$401.3	$80.6	$2,865.8	$72.9	$352.4	$425.3	$0.0	$91.2	$16.2	$100.0	$182.8	$3,681.2	$103.3
2023	$1,344.8	$1,120.7	$93.7	$418.3	$80.0	$3,057.4	$80.9	$378.2	$459.1	$0.0	$112.8	$18.0	$114.8	$201.0	$3,963.1	$108.3
2024	$1,417.6	$1,184.4	$98.3	$414.2	$79.0	$3,193.5	$75.5	$376.2	$451.7	$0.0	$115.8	$17.5	$134.0	$202.3	$4,114.7	$109.7
2025	$1,533.6	$1,232.9	$105.5	$440.4	$91.5	$3,403.9	$15.0	$411.7	$426.7	$0.0	$118.6	$18.6	$161.3	$211.7	$4,340.8	$113.0
2026	$1,621.1	$1,314.3	$112.9	$466.8	$99.1	$3,614.1	$66.2	$414.9	$481.1	$0.0	$130.6	$17.9	$207.0	$217.0	$4,667.6	$118.4
2027	$1,647.4	$1,413.8	$120.3	$472.2	$101.4	$3,755.0	$86.0	$437.0	$522.9	$0.0	$153.0	$19.7	$292.0	$226.3	$4,969.0	$122.8
2028	$1,591.4	$1,481.8	$124.0	$471.5	$113.7	$3,782.5	$95.0	$549.6	$644.6	$0.0	$159.2	$24.9	$378.7	$235.0	$5,224.9	$125.9
2029	$1,605.2	$1,611.1	$134.9	$469.4	$121.6	$3,942.2	$98.4	$551.7	$650.1	$0.0	$183.0	$24.0	$473.1	$237.8	$5,510.3	$129.4
2030	$1,682.1	$1,730.4	$143.2	$501.2	$137.5	$4,194.3	$87.2	$545.7	$632.9	$0.0	$206.6	$23.2	$590.2	$240.8	$5,888.0	$134.9
2031	$1,740.4	$1,840.0	$149.9	$512.4	$145.8	$4,388.5	$94.1	$548.7	$642.8	$0.0	$222.7	$22.3	$660.6	$244.0	$6,180.9	$138.1
2032	$1,794.9	$1,991.3	$160.4	$526.1	$162.4	$4,635.1	$101.8	$552.0	$653.7	$0.0	$243.0	$21.3	$724.7	$246.1	$6,524.0	$141.2
2033	$1,894.1	$2,135.0	$170.9	$542.5	$186.3	$4,928.8	$90.1	$552.6	$642.7	$0.0	$272.3	$20.3	$786.6	$247.8	$6,898.4	$146.3
2034	$1,985.8	$2,286.3	$180.8	$559.5	$197.0	$5,209.4	$96.3	$555.9	$652.1	$0.0	$292.1	$19.2	$866.4	$248.9	$7,288.1	$150.8
2035	$2,060.1	$2,465.6	$193.7	$576.2	$213.6	$5,509.2	$104.0	$559.3	$663.3	$0.0	$336.6	$18.1	$942.1	$249.4	$7,718.7	$155.9
2036	$2,141.5	$2,637.1	$207.6	$588.9	$221.2	$5,796.3	$111.8	$563.7	$675.5	$0.0	$375.9	$16.9	$1,046.9	$249.4	$8,160.8	$160.1
2037	$2,294.9	$2,779.4	$219.4	$601.9	$239.3	$6,134.9	$104.3	$531.1	$635.4	$0.0	$392.6	$15.6	$1,098.3	$248.5	$8,525.3	$164.2
2038	$2,319.4	$2,984.0	$231.1	$627.4	$265.8	$6,427.7	$119.9	$601.8	$721.6	$0.0	$458.6	$20.0	$1,100.1	$246.9	$8,974.9	$169.0
2039	$2,333.5	$3,346.7	$261.0	$519.4	$316.7	$6,777.3	$123.3	$649.0	$772.3	$0.0	$551.0	$23.2	$1,025.5	$244.4	$9,393.5	$173.0
2040	$2,554.4	$3,535.5	$280.2	$541.4	$341.2	$7,252.8	$123.4	$719.2	$842.6	$0.0	$586.2	$29.2	$1,043.0	$240.8	$9,994.6	$179.2
2041	$2,618.5	$3,690.9	$293.7	$556.6	$362.3	$7,522.0	$131.0	$753.7	$884.7	$0.0	$586.2	$30.4	$1,062.6	$236.1	$10,321.9	$182.1
CPW@ 7.95%																
(2012-2027)	$8,523.6	$6,698.0	$602.3	$3,497.8	$517.7	$19,839.4	$885.8	$2,959.2	$3,845.0	($50.1)	$717.6	$186.8	$455.8	$1,922.2	$26,916.7	$91.0
(2012-2041)	$13,251.3	$12,187.7	$1,042.4	$4,791.3	$987.8	$32,260.5	$1,134.5	$4,354.4	$5,488.9	($50.1)	$1,461.3	$240.2	$2,334.3	$2,513.8	$44,248.9	$107.6

APS 2012 INTEGRATED RESOURCE PLAN

Program Type	Name	Deployment	Residential EE Program Description
Residential EE	1. Consumer Products	On-going	The Consumer Products program targets deployment of energy using products at home, through partnership with local retailers. Compact fluorescent lamps (CFLs), pool timers, and variable-speed pool pumps with high efficiency motors are measures incented through this program.
Residential EE	2. Existing Homes	On-going	The Existing Homes program provides incentives for heating ventilation, and air conditioning (HVAC) measures and compliance with Home Performance with ENERGY STAR® (HPES). The HVAC programs include the AC Rebate, Duct Test and Repair, and HVAC diagnostics for tuning-up existing HVAC units. The AC Rebate offers financial incentives to homeowners for buying EE equipment (≥13 SEER/10.8EER) that is installed in accordance with the program requirement for air flow, refrigerant charge, and sizing.
Residential EE	3. New Construction	On-going	The Residential New Construction program promotes high efficiency construction practices for new homes through builder incentives. The program emphasizes the "whole building" approach to improving EE and includes field testing of homes to ensure compliance with APS performance standards that are based off the EPA ENERGY STAR Homes program. In 2012, APS updated the New Construction program to meet Version 3 ENERGY STAR requirements which will provide 80% greater savings than Version 2 in Arizona.
Residential EE	4. Appliance Recycling	On-going	The Appliance Recycling program targets the removal of functional second refrigerators and freezers in residential households. APS offers a $30 rebate with free pick-up and recycling of operable second refrigerators and freezers.
Residential EE	5. Low Income Weatherization	On-going	APS's Energy Wise Low Income Weatherization program is designed to improve the energy efficiency, safety, and health attributes of homes occupied by customers whose income falls within 200% of the Federal Poverty Guidelines. The weatherization component of this program serves low-income customers with various home improvement measures, including cooling system repair and replacement, insulation, sunscreens, water heaters, window repairs and improvements, as well as other general household repairs. These programs are administered by various community action agencies throughout APS's service territory.
Residential EE	6. Conservation Behavior Pilot	On-going	The Residential Conservation Behavior Pilot program provides participating residential customers with periodic reports containing information designed to help motivate them to adopt energy conservation behaviors. The program provides direct-mailed reports to participants to show how the energy usage in their home compares with energy efficient and other similar homes.
Residential EE	7. Multi-Family Construction	On-going	The Multi-Family Energy Efficiency Program (MEEP) is a program that targets multi-family properties and dormitories with EE measures and solutions designed to promote energy savings. The MEEP has two different approaches. The first provides CFLs, showerheads, and faucet aerators to retrofit each dwelling in a community, at no cost. The second track provides a per-unit incentive for new construction and major renovation projects that meet or exceed the EE guidelines outlined in one of the four Builder Option Packages.[1]
Residential EE	8. Shade Tree	On-going	APS's Shade Tree program is designed to provide a free shade tree to all APS customers who participate in an APS Shade Tree workshop. Tree planting workshops educate customers on successful tree planting and care techniques and provide a customer-specific site map indicating the ideal tree planting location for energy efficiency. Up to 5,000 trees are distributed through the program.

Program Type	Name	Deployment	Residential DR Program Description
Residential DR	1. ET-SP Time Advantage Super Peak	On-going	ET-SP is a static super peak time-of-use rate providing a high price signal during a small number of core peak hours and standard time-of-use pricing for other time periods. This may also be referred to as a three-part time-of-use rate in that price signals are provided for super-peak hours, on-peak hours, and off-peak hours. In addition, the pricing plan provides price signals for three seasons: Super Peak summer season which is June through August; summer season, which consists of May, September, and October; and, winter which runs November through April.
Residential DR	2. ET-1 Time Advantage (9am-9pm)	Frozen to new customers	ET-1 (Time Advantage) has an energy-only rate with an on-peak period from 9am-9pm. The program has been in place since 1982. In a previous rate case approved under A.C.C. Decision No. 71448, APS closed the series ET-1 rate to new customers. APS anticipates closing the rate to all customers within the next five years and transitioning any remaining customers to the ET-2 or ECT-2 rates.
Residential DR	3. ECT-1R Combined Advantage (9am-9pm)	Frozen to new customers	ECT-1R (Combined Advantage) includes both demand and energy charges. Similar to the ET-1 rate schedule, the peak hours are from 9am-9pm. APS anticipates closing the rate to all customers within the next five years and transitioning any remaining customers to the ET 2 or ECT-2 rates.
Residential DR	4. ET-2 Time Advantage (Noon – 7pm)	On-going	ET-2 (Time Advantage) has an energy-only rate with an on-peak period from Noon- 7:00pm.
Residential DR	5. ECT-2 Combined Advantage (Noon – 7pm)	On-going	ECT-2 (Combined Advantage) includes demand and energy charges with a peak period of Noon – 7:00pm.
Residential DR	6. ET-EV Experimental Electric Vehicle Charging Rate Schedule	On-going	ET-EV is offered to residential customers who own a qualified electric vehicle (EV) and will be charging them in the individual residence. This rate schedule provides a price signal aimed at encouraging residential customers to charge an EV during hours when demand on the distribution system is low and when the load on the secondary transformer is less, thereby reducing any potential distribution system impacts posed by the EV load.
Residential DR	7. Peak Event Pricing (also referred to as Critical Peak Pricing)	On-going	Provides a high price signal over a small number of core summer peak days and hours. The program can be called on when the Company is experiencing extreme temperatures, very high electrical demand, high market electric costs, or is experiencing a major generation or transmission disturbance. The critical peak price signal is "dynamic" in that it is callable by APS for up to 18 days and 90 hours per year, weekdays during the months June through September. APS declares a "critical event" day and notifies participants by 4:00 p.m. the prior day. During the event the customer is charged an additional $0.40 per kWh for consumption during the hours 2 p.m. to 7pm. The customer also receives a discount of approximately $0.019 per kWh for all consumption during the June through September billing cycles. The prices are designed so that the monthly discounts equal the critical peak charges for the typical customer. Therefore, to save money, the customer must be able to reduce usage during critical hours.
Residential DR	8. PTR-RES (Peak Time Rebate)	2013	The proposed Peak Time Rebate program, to be available for ET-2 customers, is similar to Peak Event Pricing in that it will have the same number of peak event days and hours, and the same customer notification process. A distinction is that instead of providing a high charge it will give an energy discount or rebate of $0.25 per kWh for all kWh reduced during the critical hours. The kWh reduction will be determined by comparing the actual metered usage during those hours with a baseline load which reflects the customer's typical or expected usage during those hours. The Company has designed a specific baseline estimation protocol, which uses the customer's actual load data for other similar hours during days when a critical event was not called. In the event the customer exceeds the baseline load during a Peak Event, the customer will receive no credit. Thr program is expected to be implemented in 2013 and will be available for two years with the option to continue the program into future years.

Residential DR	9. Home Energy Information Pilot	2012	The Home Energy Information Pilot Program (HEI Pilot), approved in ACC Decision 72214, is a comprehensive residential DR pilot designed to test available home area network technologies and determine communication devices, demand response strategies, and mix of smart home applications that can be most effectively employed in a residential setting. This information will provide essential learnings for rolling out a full-scale, residential DR program in the future.
Program Type	**Name**	**Deployment**	**Non-Residential EE Program Description**
Non-Residential EE	1. Large Existing Facilities	On-going	The Large Existing Facilities program is targeted at customers with an aggregate monthly peak demand greater than 100 kW and provides prescriptive incentives to owners and operators of large non-residential facilities for EE improvements in lighting, HVAC, motors, building envelope, and refrigeration measures. Incentives are also provided to customers who conduct qualifying energy studies. The largest customers (electric usage ≥40,000 MWh per year) may qualify to self direct the amount they pay toward DSM costs for their own EE projects. Custom incentives are also provided for EE measures not covered by the prescriptive incentives. Customers may also participate in the Direct Install family of measures in the areas of lighting and refrigeration for any facilities with a peak monthly demand of 400 kW and less.
Non-Residential EE	2. New Construction	On-going	The Non-Residential New Construction program includes three components: (1) design assistance; (2) prescriptive measures; and, (3) customer efficiency measures. Design assistance involves efforts to integrate EE into a customer's design process to influence equipment/system selection early on in the process. Prescriptive incentives are available for EE improvements in measures such as lighting, HVAC, motors, building envelope, and refrigeration applications. Whole Building Design is a component within the New Construction custom efficiency measures that influences customers, developers, and design professionals to design, build, and invest in higher performing building through a stepped performance incentive structure with the financial incentives increasing as the building performance improves.
Non-Residential EE	3. Small business	On-going	The Small Business program targets customers that have a maximum peak aggregated demand of 100 kW or less. The program provides prescriptive incentives to small business owners for EE improvements in lighting, HVAC motors, building envelope, and refrigeration applications. In addition, a customer in the Small Business program may participate in the Direct Install family of measures in the areas of lighting and refrigeration and may also qualify to receive APS-arranged program financing. Small Business participants may also receive incentives for energy studies and custom efficiency measures.
Non-Residential EE	4. Schools	On-going	The Schools program is designed to set aside funding for K-12 public, private, and charter school buildings. Schools can receive up to a maximum of $100,000 in incentives per year. EE incentives for Schools are the same as in the Large Existing Facilities (for existing school facilities) and New Construction (for new school construction and major renovation projects) programs. In addition, any size school may receive Direct Install measure incentives and is eligible to receive APS-arranged program financing for their EE projects.
Non-Residential EE	5. Energy Information Systems	On-going	The Energy Information Systems program is a subscription service for software that provides 15-minute interval electric usage data to large non-residential customers through a web-based energy information tool. This tool provides users with information that can be used to improve or monitor energy usage patterns, reduce energy use, reduce demands during on-peak periods, and to better manage overall energy operations.

Program Type	Name	Deployment	Non-Residential DR Program Description
Non-Residential DR	1. E-20	Frozen to new customers	Intended for houses of worship, E-20 was implemented in 1996. On-peak and off-peak charges are included for both energy and demand. This rate was frozen to new customers as of January 1, 2011.
Non-Residential DR	2. E-221-8T	On-going	Designed for water pumping customers, the E-221-8T rate was implemented in 1986. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	3. E-32 XS TOU	On-going	For business customers, the E-32TOU rates (which include extra small, small, medium, and large customers) were implemented in 2005 and are available for customers with less than 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	4. E-32 S TOU		
Non-Residential DR	5. E-32 M TOU		
Non-Residential DR	6. E-32 L TOU		
Non-Residential DR	7. E-35	On-going	E-35 was implemented in 1988 for extra large business customers exceeding 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	8. GS-Schools M	On-going	Designed for public and private schools providing primarily on-site K-12 education, the GS-Schools TOU rates were implemented in 2010 and are available to schools with less than 3 MW of monthly peak demand. The rates contain energy charges for three seasons including summer peak (June-August), summer shoulder (May, September and October) and winter (November through April). The demand charge is computed based on the monthly maximum demand.
Non-Residential DR	9. GS-Schools L		
Non-Residential DR	10. IRR-Interruptible Rate	Pending Rate Case Settlement	The proposed rider rate Schedule IRR in the 2011 rate case provides interruptible service for extra-large general service customers who can interrupt at least 500 kW of load when requested by the Company. Under this service, the customer can choose between two curtailment options, two notification options, and a one-year or five-year agreement. The customer receives capacity and energy payments for the interruptible load based on these options. The customer may also incur a penalty for failing to curtail when requested.
Non-Residential DR	11. Peak Solutions	On-going	APS Peak Solutions is a DR program approved in ACC Decision 71104 that offers financial incentives to eligible commercial and industrial customers to reduce their electricity usage during APS's summer peak periods (June through September) between 12:00 noon and 8:00 p.m. daily. Load reductions are often for HVAC systems, lighting, refrigeration, and industrial processes.[2]

1 Details on the Builder Option Packages can be found in Decision No. 72060 (Docket No. E-01345A-10-0219).

2 APS Peak Solutions Application filed, 11/6/2008, Docket E-01345A-08-0569.

Expected EE Program Participation[1]

Residential Program Name	Measure or Unit	Estimated Participation in 2012
Consumer Products	CFL Bulbs	2,810,000
	Variable Speed Motors	1,000
Appliance Recycling	Refrigerators	9,000
	Freezers	1,000
Energy Star Homes	Version 3	1,750
	Second Tier – HERS 60	250
Home Performance with Energy Star	Audits	4,500
	Low Flow Shower Heads	2,850
	Low Flow Aerators	7,125
	CFL Bulbs	38,000
	Air Sealing (only)	400
	Duct Test & Repair	2,100
	Insulation (only)	300
	Insulation & Air Sealing	750
	Shade Screens	150
Residential HVAC	Equipment Rebates	14,600
	Duct Test & Repair	2,100
	Advanced Tune-ups	6,000
Multi-Family	Low Flow Shower Heads	7,500
	Low Flow Aerators	1,550
	CFL Bulbs	60,000
	Builder Option Package 1	50
	Builder Option Package 2	50
	Builder Option Package 3	40
	Builder Option Package Retrofit	100
Shade Trees	Trees Planted	5,000
Behavioral	Reports Generated	80,000
Non-Residential Program Name		
Large Existing	No. of Applications Paid	1,550
Large New Construction	No. of Applications Paid	80
Small Business	No. of Applications Paid	1,500
Schools	No. of Applications Paid	255
Energy Information Syst.	No. of Meters	50

[1] Additional details pertaining to EE programs were provided in the revised APS 2012 DSM Implementation Plan filed with the ACC on June 24, 2011. Docket No. E-01345A-11-0232

Resource Additions in the 2012 Resource Plan (MW Contribution at Peak)

Base Case Portfolio	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Load Requirements	**8,233**	**8,382**	**8,644**	**8,867**	**9,205**	**9,561**	**9,891**	**10,237**	**10,590**	**10,950**	**11,322**	**11,691**	**12,059**	**12,430**	**12,799**	**13,167**
Conventional Resources																
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Coal	1,753	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
Natural Gas[1]	5,583	5,676	5,676	5,590	5,089	4,802	4,962	5,094	5,273	5,417	5,688	5,928	6,184	6,464	6,764	7,074
Combined Cycles	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	2,563	2,563	2,563	2,563	2,563	3,228	3,228	3,228
Combustion Turbines	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,566	1,668	2,280	2,688	2,892	3,198	3,198	3,198	3,402
Market Purchases	2,221	2,314	2,314	2,228	1,727	1,440	1,600	1,630	1,042	574	437	473	423	38	338	444
Total Conventional Resources	**8,482**	**8,754**	**8,754**	**8,668**	**8,167**	**7,880**	**8,040**	**8,172**	**8,351**	**8,495**	**8,766**	**9,005**	**9,261**	**9,541**	**9,841**	**10,152**
Renewable Energy																
Wind	47	53	53	53	53	53	53	53	53	53	71	71	71	91	97	99
Solar	56	81	389	442	453	451	450	508	507	505	504	552	593	593	594	596
Geothermal	10	10	10	10	10	10	10	10	10	90	90	90	90	90	90	90
Biomass/Biogas	17	17	17	17	17	17	17	17	17	17	17	3	3	3	3	3
Total Renewable Energy	**131**	**161**	**469**	**522**	**533**	**531**	**531**	**589**	**588**	**666**	**682**	**716**	**757**	**777**	**784**	**788**
Customer Resources																
Energy Efficiency	80	193	328	482	641	791	926	1,053	1,186	1,276	1,308	1,350	1,392	1,438	1,480	1,525
Distributed Energy	65	82	105	124	137	154	164	168	184	209	236	264	294	324	344	353
Demand Response	83	83	83	98	165	205	230	255	280	305	330	355	355	350	350	350
Total Customer Resources	**228**	**358**	**516**	**704**	**944**	**1,150**	**1,321**	**1,477**	**1,651**	**1,790**	**1,874**	**1,970**	**2,041**	**2,112**	**2,174**	**2,228**
Total Resources	**8,840**	**9,273**	**9,739**	**9,893**	**9,644**	**9,561**	**9,891**	**10,237**	**10,590**	**10,950**	**11,322**	**11,691**	**12,059**	**12,430**	**12,799**	**13,167**

Portfolio Differences from Base Case

Four Corners Contingency Portfolio	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	0	(179)	(179)	(739)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)	(970)
Natural Gas[1]	0	0	0	0	665	970	970	970	970	970	970	970	970	970	970	970
Combined Cycles	0	0	0	0	665	665	665	665	665	665	665	665	665	665	665	665
Combustion Turbines	0	0	0	0	0	102	204	306	306	306	306	306	306	306	306	306
Market Purchases	0	0	0	0	0	203	101	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Enhanced Renewable Portfolio	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Natural Gas[1]	0	0	0	0	0	(109)	(197)	(193)	(227)	(236)	(273)	(238)	(260)	(272)	(279)	(286)
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	(665)	0	0
Combustion Turbines	0	0	0	0	0	0	0	(102)	(204)	(306)	(306)	(204)	(306)	0	0	(204)
Market Purchases	0	0	0	0	0	(109)	(197)	(91)	(23)	70	33	(34)	46	393	(279)	(82)
Solar	2	2	3	3	3	109	147	143	152	161	173	138	110	122	129	136
Geothermal	0	0	0	0	0	0	50	50	75	75	100	100	150	150	150	150
Coal Retirement Portfolio	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Coal	0	(179)	(179)	(739)	(970)	(970)	(970)	(970)	(1,285)	(1,285)	(1,285)	(1,285)	(1,285)	(1,932)	(1,932)	(1,932)
Natural Gas[1]	0	0	0	0	665	844	806	820	1,104	1,099	1,091	1,129	1,160	1,778	1,771	1,764
Combined Cycles	0	0	0	0	665	665	665	665	665	1,330	1,330	1,330	1,330	1,330	1,330	1,330
Combustion Turbines	0	0	0	0	0	0	102	102	408	(204)	(204)	(204)	(204)	0	306	408
Market Purchases	0	0	0	0	0	179	39	53	31	(27)	(35)	3	34	448	135	26
Wind	0	0	0	0	0	18	18	18	31	31	31	31	31	45	45	45
Solar	1	2	2	2	2	108	146	132	149	154	162	124	94	109	116	123

[1]The breakdown between combined cycles, combustion turbines, and market purchases is for planning assumptions only. It does not represent what APS may elect do do during the procurement process. Those decisions will be made based on market conditions and economics at that time.

BASE CASE PORTFOLIO

Loads & Resources - MW Contribution at Peak

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Requirements																
APS Peak Demand	7,234	7,377	7,616	7,813	8,118	8,441	8,742	9,059	9,372	9,625	9,942	10,257	10,569	10,884	11,203	11,527
Annual Load Growth %		2.0%	3.2%	2.6%	3.9%	4.0%	3.6%	3.6%	3.5%	2.7%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%
Reserve Requirements	999	1,005	1,028	1,054	1,086	1,119	1,149	1,178	1,217	1,325	1,380	1,434	1,490	1,546	1,597	1,641
Total Load Requirements	8,233	8,382	8,644	8,867	9,205	9,561	9,891	10,237	10,590	10,950	11,322	11,691	12,059	12,430	12,799	13,167
Existing Resources																
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Coal	1,753	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
Natural Gas	5,583	5,676	5,676	5,590	5,089	4,589	4,589	4,589	3,992	3,512	3,362	3,362	3,362	3,362	3,362	3,362
Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
Combustion / Steam Turbines	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	480	480	0	0	0	0	0	0	0
Tolling Agreements	1,060	1,060	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0
Market / Call Options / Hedges	681	774	774	688	187	187	187	187	150	150	0	0	0	0	0	0
Renewable Energy	66	72	71	71	71	71	71	70	70	70	70	55	55	55	55	39
Wind	28	33	33	33	33	33	33	33	33	33	33	33	33	33	33	17
Solar	11	11	11	11	11	11	11	10	10	10	10	9	9	9	9	9
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Biomass/Biogas	17	17	17	17	17	17	17	17	17	17	17	3	3	3	3	3
Total Existing Resources	8,548	8,826	8,825	8,739	8,238	7,738	7,738	7,737	7,140	6,660	6,510	6,495	6,494	6,494	6,494	6,478
Customer Resources																
Energy Efficiency	80	193	328	482	641	791	926	1,053	1,186	1,276	1,308	1,350	1,392	1,438	1,480	1,525
Distributed Energy	65	82	105	124	137	154	164	168	184	209	236	264	294	324	344	353
Demand Response	83	83	83	98	165	205	230	255	280	305	330	355	355	350	350	350
Existing DR	83	83	83	83	105	105	105	105	105	105	105	105	105	0	0	0
Future DR	0	0	0	15	60	100	125	150	175	200	225	250	250	350	350	350
Total Customer Resources	228	358	516	704	944	1,150	1,321	1,477	1,651	1,790	1,874	1,970	2,041	2,112	2,174	2,228
Future Resources																
Natural Gas[1]	0	0	0	0	0	213	373	505	1,281	1,905	2,326	2,566	2,822	3,102	3,402	3,712
Combined Cycle	0	0	0	0	0	0	0	0	665	665	665	665	665	1,330	1,330	1,330
Combustion / Steam Turbines	0	0	0	0	0	0	0	102	204	816	1,224	1,428	1,734	1,734	1,734	1,938
Short-Term Market Purchases	0	0	0	0	0	213	373	403	412	424	437	473	423	38	338	444
Renewable Energy	64	89	398	451	462	460	459	519	518	595	612	661	702	722	729	749
Wind	20	20	20	20	20	20	20	20	20	20	38	38	38	58	64	82
Solar	45	70	378	431	442	440	439	499	498	496	494	543	584	584	586	588
Geothermal	0	0	0	0	0	0	0	0	0	80	80	80	80	80	80	80
Total Future Resources	64	89	398	451	462	673	832	1,024	1,799	2,500	2,938	3,227	3,524	3,824	4,131	4,462
TOTAL RESOURCES	**8,840**	**9,273**	**9,739**	**9,893**	**9,644**	**9,561**	**9,891**	**10,237**	**10,590**	**10,950**	**11,322**	**11,691**	**12,059**	**12,430**	**12,799**	**13,167**

[1]The breakdown between combined cycles, combustion turbines, and market purchases is for planning assumptions only. It does not represent what APS may elect do do during the procurement process. Those decisions will be made based on market conditions and economics at that time.

FOUR CORNERS CONTINGENCY PORTFOLIO

Loads & Resources - MW Contribution at Peak

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Requirements																
APS Peak Demand	7,234	7,377	7,616	7,813	8,118	8,441	8,742	9,059	9,372	9,625	9,942	10,257	10,569	10,884	11,203	11,527
Annual Load Growth %		2.0%	3.2%	2.6%	3.9%	4.0%	3.6%	3.6%	3.5%	2.7%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%
Reserve Requirements	999	1,005	1,028	1,054	1,086	1,119	1,149	1,178	1,217	1,325	1,380	1,434	1,490	1,546	1,597	1,641
Total Load Requirements	8,233	8,382	8,644	8,867	9,205	9,561	9,891	10,237	10,590	10,950	11,322	11,691	12,059	12,430	12,799	13,167
Existing Resources																
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Coal	1,753	1,753	1,753	1,193	962	962	962	962	962	962	962	962	962	962	962	962
Natural Gas	5,583	5,676	5,676	5,590	5,089	4,589	4,589	4,589	3,992	3,512	3,362	3,362	3,362	3,362	3,362	3,362
Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
Combustion / Steam Turbines	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	480	480	0	0	0	0	0	0	0
Tolling Agreements	1,060	1,060	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0
Market / Call Options / Hedges	681	774	774	688	187	187	187	187	150	150	0	0	0	0	0	0
Renewable Energy	66	72	71	71	71	71	71	70	70	70	70	55	55	55	55	39
Wind	28	33	33	33	33	33	33	33	33	33	33	33	33	33	33	17
Solar	11	11	11	11	11	11	11	10	10	10	10	9	9	9	9	9
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Biomass/Biogas	17	17	17	17	17	17	17	17	17	17	17	3	3	3	3	3
Total Existing Resources	8,548	8,647	8,646	8,000	7,268	6,768	6,768	6,767	6,170	5,690	5,540	5,525	5,524	5,524	5,524	5,508
Customer Resources																
Energy Efficiency	80	193	328	482	641	791	926	1,053	1,186	1,276	1,308	1,350	1,392	1,438	1,480	1,525
Distributed Energy	65	82	105	124	137	154	164	168	184	209	236	264	294	324	344	353
Demand Response	83	83	83	98	165	205	230	255	280	305	330	355	355	350	350	350
Existing DR	83	83	83	83	105	105	105	105	105	105	105	105	105	0	0	0
Future DR	0	0	0	15	60	100	125	150	175	200	225	250	250	350	350	350
Total Customer Resources	228	358	516	704	944	1,150	1,321	1,477	1,651	1,790	1,874	1,970	2,041	2,112	2,174	2,228
Future Resources																
Natural Gas[1]	0	0	0	0	665	1,183	1,343	1,475	2,251	2,875	3,296	3,536	3,792	4,072	4,372	4,682
Combined Cycle	0	0	0	0	665	665	665	665	1,330	1,330	1,330	1,330	1,330	1,995	1,995	1,995
Combustion / Steam Turbines	0	0	0	0	0	102	204	408	510	1,122	1,530	1,734	2,040	2,040	2,040	2,244
Short-Term Market Purchases	0	0	0	0	0	416	474	402	411	423	436	472	422	37	337	443
Renewable Energy	64	89	398	451	462	460	459	519	518	595	612	661	702	722	729	749
Wind	20	20	20	20	20	20	20	20	20	20	38	38	38	58	64	82
Solar	45	70	378	431	442	440	439	499	498	496	494	543	584	584	586	588
Geothermal	0	0	0	0	0	0	0	0	0	80	80	80	80	80	80	80
Total Future Resources	64	89	398	451	1,127	1,643	1,802	1,994	2,769	3,470	3,908	4,197	4,494	4,794	5,101	5,432
TOTAL RESOURCES	**8,840**	**9,094**	**9,560**	**9,154**	**9,339**	**9,561**	**9,891**	**10,237**	**10,590**	**10,950**	**11,322**	**11,691**	**12,059**	**12,430**	**12,799**	**13,167**

[1]The breakdown between combined cycles, combustion turbines, and market purchases is for planning assumptions only. It does not represent what APS may elect do do during the procurement process. Those decisions will be made based on market conditions and economics at that time.

APS 2012 INTEGRATED RESOURCE PLAN

ENHANCED RENEWABLE PORTFOLIO

Loads & Resources - MW Contribution at Peak

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Requirements																
APS Peak Demand	7,234	7,377	7,616	7,813	8,118	8,441	8,742	9,059	9,372	9,625	9,942	10,257	10,569	10,884	11,203	11,527
Annual Load Growth %		2.0%	3.2%	2.6%	3.9%	4.0%	3.6%	3.6%	3.5%	2.7%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%
Reserve Requirements	999	1,005	1,028	1,054	1,086	1,119	1,149	1,178	1,217	1,325	1,380	1,434	1,490	1,546	1,597	1,641
Total Load Requirements	8,233	8,382	8,644	8,867	9,205	9,561	9,891	10,237	10,590	10,950	11,322	11,691	12,059	12,430	12,799	13,167
Existing Resources																
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Coal	1,753	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
Natural Gas	5,583	5,676	5,676	5,590	5,089	4,589	4,589	4,589	3,992	3,512	3,362	3,362	3,362	3,362	3,362	3,362
Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
Combustion / Steam Turbines	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	480	480	0	0	0	0	0	0	0
Tolling Agreements	1,060	1,060	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0
Market / Call Options / Hedges	681	774	774	688	187	187	187	187	150	150	0	0	0	0	0	0
Renewable Energy	66	72	72	72	72	70	69	68	67	67	67	52	52	51	51	35
Wind	28	33	33	33	33	33	33	33	33	33	33	33	33	33	33	17
Solar	12	12	11	11	11	9	9	7	7	6	6	6	6	5	5	5
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Biomass/Biogas	17	17	17	17	17	17	17	17	17	17	17	3	3	3	3	3
Total Existing Resources	8,548	8,826	8,825	8,739	8,238	7,736	7,736	7,734	7,137	6,657	6,506	6,492	6,491	6,491	6,491	6,475
Customer Resources																
Energy Efficiency	80	193	328	482	641	791	926	1,053	1,186	1,276	1,308	1,350	1,392	1,438	1,480	1,525
Distributed Energy	65	82	105	124	137	154	164	168	184	209	236	264	294	324	344	353
Demand Response	83	83	83	98	165	205	230	255	280	305	330	355	355	350	350	350
Existing DR	83	83	83	83	105	105	105	105	105	105	105	105	105	0	0	0
Future DR	0	0	0	15	60	100	125	150	175	200	225	250	250	350	350	350
Total Customer Resources	228	358	516	704	944	1,150	1,321	1,477	1,651	1,790	1,874	1,970	2,041	2,112	2,174	2,228
Future Resources																
Natural Gas[1]	0	0	0	0	0	104	177	312	1,054	1,669	2,053	2,328	2,562	2,830	3,123	3,426
Combined Cycle	0	0	0	0	0	0	0	0	665	665	665	665	665	665	1,330	1,330
Combustion / Steam Turbines	0	0	0	0	0	0	0	0	0	510	918	1,224	1,428	1,734	1,734	1,734
Short-Term Market Purchases	0	0	0	0	0	104	177	312	389	494	470	439	469	431	59	362
Renewable Energy	66	91	400	453	464	571	658	714	748	835	888	902	965	997	1,011	1,039
Wind	20	20	20	20	20	20	20	20	20	20	38	38	38	58	64	82
Solar	46	72	380	433	444	551	588	644	653	660	671	684	697	709	717	727
Geothermal	0	0	0	0	0	0	50	50	75	155	180	180	230	230	230	230
Total Future Resources	66	91	400	453	464	675	835	1,026	1,802	2,504	2,941	3,230	3,527	3,827	4,134	4,465
TOTAL RESOURCES	**8,842**	**9,275**	**9,742**	**9,896**	**9,646**	**9,561**	**9,891**	**10,237**	**10,590**	**10,950**	**11,322**	**11,691**	**12,059**	**12,430**	**12,799**	**13,167**

[1]The breakdown between combined cycles, combustion turbines, and market purchases is for planning assumptions only. It does not represent what APS may elect do do during the procurement process. Those decisions will be made based on market conditions and economics at that time.

COAL RETIREMENT PORTFOLIO

Loads & Resources - MW Contribution at Peak

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Requirements																
APS Peak Demand	7,234	7,377	7,616	7,813	8,118	8,441	8,742	9,059	9,372	9,625	9,942	10,257	10,569	10,884	11,203	11,527
Annual Load Growth %		2.0%	3.2%	2.6%	3.9%	4.0%	3.6%	3.6%	3.5%	2.7%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%
Reserve Requirements	999	1,005	1,028	1,054	1,086	1,119	1,149	1,178	1,217	1,325	1,380	1,434	1,490	1,546	1,597	1,641
Total Load Requirements	8,233	8,382	8,644	8,867	9,205	9,561	9,891	10,237	10,590	10,950	11,322	11,691	12,059	12,430	12,799	13,167
Existing Resources																
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Coal	1,753	1,753	1,753	1,193	962	962	962	962	647	647	647	647	647	0	0	0
Natural Gas	5,583	5,676	5,676	5,590	5,089	4,589	4,589	4,589	3,992	3,512	3,362	3,362	3,362	3,362	3,362	3,362
Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
Combustion / Steam Turbines	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	480	480	0	0	0	0	0	0	0
Tolling Agreements	1,060	1,060	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0
Market / Call Options / Hedges	681	774	774	688	187	187	187	187	150	150	0	0	0	0	0	0
Renewable Energy	66	72	72	72	72	70	69	68	67	67	68	53	52	52	52	36
Wind	28	33	33	33	33	33	33	33	33	33	33	33	33	33	33	17
Solar	12	12	11	11	11	9	9	7	7	7	7	7	6	6	6	6
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Biomass/Biogas	17	17	17	17	17	17	17	17	17	17	17	3	3	3	3	3
Total Existing Resources	8,548	8,647	8,646	8,000	7,268	6,766	6,766	6,765	5,852	5,372	5,222	5,207	5,207	4,560	4,560	4,544
Customer Resources																
Energy Efficiency	80	193	328	482	641	791	926	1,053	1,186	1,276	1,308	1,350	1,392	1,438	1,480	1,525
Distributed Energy	65	82	105	124	137	154	164	168	184	209	236	264	294	324	344	353
Demand Response	83	83	83	98	165	205	230	255	280	305	330	355	355	350	350	350
Existing DR	83	83	83	83	105	105	105	105	105	105	105	105	105	0	0	0
Future DR	0	0	0	15	60	100	125	150	175	200	225	250	250	350	350	350
Total Customer Resources	228	358	516	704	944	1,150	1,321	1,477	1,651	1,790	1,874	1,970	2,041	2,112	2,174	2,228
Future Resources																
Natural Gas[1]	0	0	0	0	665	1,057	1,179	1,325	2,386	3,004	3,417	3,695	3,981	4,880	5,173	5,476
Combined Cycle	0	0	0	0	665	665	665	665	1,330	1,995	1,995	1,995	1,995	2,660	2,660	2,660
Combustion / Steam Turbines	0	0	0	0	0	0	102	204	612	612	1,020	1,224	1,530	1,734	2,040	2,346
Short-Term Market Purchases	0	0	0	0	0	392	412	456	444	397	402	476	456	486	473	470
Renewable Energy	66	91	400	453	464	588	625	671	701	784	808	819	830	879	893	920
Wind	20	20	20	20	20	38	38	38	51	51	69	69	69	102	108	126
Solar	46	71	380	433	444	550	588	633	650	653	659	670	681	696	704	713
Geothermal	0	0	0	0	0	0	0	0	0	80	80	80	80	80	80	80
Total Future Resources	66	91	400	453	1,129	1,645	1,805	1,996	3,087	3,788	4,226	4,514	4,811	5,758	6,066	6,396
TOTAL RESOURCES	**8,842**	**9,096**	**9,562**	**9,157**	**9,341**	**9,561**	**9,891**	**10,237**	**10,590**	**10,950**	**11,322**	**11,691**	**12,059**	**12,430**	**12,799**	**13,167**

[1]The breakdown between combined cycles, combustion turbines, and market purchases is for planning assumptions only. It does not represent what APS may elect do do during the procurement process. Those decisions will be made based on market conditions and economics at that time.

ENERGY MIX
BASE CASE PORTFOLIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,294	7,671	1,588	1,510	32,370
2013	9,324	13,154	6,288	2,102	2,018	32,886
2014	9,270	12,663	6,314	3,057	2,580	33,884
2015	9,270	13,213	5,535	3,487	3,193	34,697
2016	9,298	13,024	6,224	3,586	3,835	35,966
2017	9,269	12,987	6,944	3,662	4,455	37,318
2018	9,270	13,095	7,517	3,718	5,039	38,638
2019	9,270	13,353	7,720	4,016	5,605	39,964
2020	9,315	13,345	8,032	4,102	6,192	40,987
2021	9,261	13,138	8,269	4,849	6,565	42,082
2022	9,270	13,397	8,700	5,281	6,709	43,358
2023	9,270	12,730	10,088	5,638	6,889	44,615
2024	9,297	12,832	10,634	6,025	7,082	45,868
2025	9,275	13,204	10,997	6,389	7,267	47,132
2026	9,270	12,991	11,982	6,711	7,450	48,405
2027	9,270	12,918	13,068	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.0%	23.7%	4.9%	4.7%	100.0%
2013	28.4%	40.0%	19.1%	6.4%	6.1%	100.0%
2014	27.4%	37.4%	18.6%	9.0%	7.6%	100.0%
2015	26.7%	38.1%	16.0%	10.0%	9.2%	100.0%
2016	25.9%	36.2%	17.3%	10.0%	10.7%	100.0%
2017	24.8%	34.8%	18.6%	9.8%	11.9%	100.0%
2018	24.0%	33.9%	19.5%	9.6%	13.0%	100.0%
2019	23.2%	33.4%	19.3%	10.0%	14.0%	100.0%
2020	22.7%	32.6%	19.6%	10.0%	15.1%	100.0%
2021	22.0%	31.2%	19.7%	11.5%	15.6%	100.0%
2022	21.4%	30.9%	20.1%	12.2%	15.5%	100.0%
2023	20.8%	28.5%	22.6%	12.6%	15.4%	100.0%
2024	20.3%	28.0%	23.2%	13.1%	15.4%	100.0%
2025	19.7%	28.0%	23.3%	13.6%	15.4%	100.0%
2026	19.2%	26.8%	24.8%	13.9%	15.4%	100.0%
2027	18.7%	26.0%	26.3%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
FOUR CORNERS CONTINGENCY PORTFOLIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,977	7,988	1,588	1,510	32,370
2013	9,324	12,154	7,288	2,102	2,018	32,886
2014	9,270	12,024	6,953	3,057	2,580	33,884
2015	9,270	8,512	10,236	3,487	3,193	34,697
2016	9,298	7,771	11,477	3,586	3,835	35,966
2017	9,269	7,289	12,643	3,662	4,455	37,318
2018	9,270	7,526	13,085	3,718	5,039	38,638
2019	9,270	7,014	14,060	4,016	5,605	39,965
2020	9,315	6,876	14,502	4,102	6,192	40,987
2021	9,261	6,746	14,661	4,849	6,565	42,082
2022	9,270	6,865	15,232	5,281	6,709	43,358
2023	9,270	6,808	16,010	5,638	6,889	44,615
2024	9,297	6,923	16,542	6,025	7,082	45,868
2025	9,275	6,507	17,694	6,389	7,267	47,132
2026	9,270	6,324	18,649	6,711	7,450	48,405
2027	9,270	6,325	19,661	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	37.0%	24.7%	4.9%	4.7%	100.0%
2013	28.4%	37.0%	22.2%	6.4%	6.1%	100.0%
2014	27.4%	35.5%	20.5%	9.0%	7.6%	100.0%
2015	26.7%	24.5%	29.5%	10.0%	9.2%	100.0%
2016	25.9%	21.6%	31.9%	10.0%	10.7%	100.0%
2017	24.8%	19.5%	33.9%	9.8%	11.9%	100.0%
2018	24.0%	19.5%	33.9%	9.6%	13.0%	100.0%
2019	23.2%	17.6%	35.2%	10.0%	14.0%	100.0%
2020	22.7%	16.8%	35.4%	10.0%	15.1%	100.0%
2021	22.0%	16.0%	34.8%	11.5%	15.6%	100.0%
2022	21.4%	15.8%	35.1%	12.2%	15.5%	100.0%
2023	20.8%	15.3%	35.9%	12.6%	15.4%	100.0%
2024	20.3%	15.1%	36.1%	13.1%	15.4%	100.0%
2025	19.7%	13.8%	37.5%	13.6%	15.4%	100.0%
2026	19.2%	13.1%	38.5%	13.9%	15.4%	100.0%
2027	18.7%	12.7%	39.6%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
ENHANCED RENEWABLE PORTFOLIO

	ENERGY (GWH)					
	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,294	7,671	1,588	1,510	32,370
2013	9,324	13,154	6,288	2,102	2,018	32,886
2014	9,270	12,663	6,314	3,057	2,580	33,884
2015	9,270	13,213	5,535	3,487	3,193	34,697
2016	9,298	13,024	6,224	3,586	3,835	35,966
2017	9,269	12,783	6,591	4,220	4,455	37,318
2018	9,270	12,679	6,701	4,949	5,039	38,638
2019	9,270	12,493	6,791	5,806	5,605	39,965
2020	9,315	12,276	6,830	6,373	6,192	40,987
2021	9,261	11,907	6,956	7,393	6,565	42,082
2022	9,270	11,967	7,109	8,302	6,709	43,358
2023	9,270	11,315	8,203	8,938	6,889	44,615
2024	9,297	11,146	8,337	10,007	7,082	45,868
2025	9,275	11,478	8,191	10,920	7,267	47,132
2026	9,270	11,138	9,304	11,243	7,450	48,405
2027	9,270	11,170	10,285	11,317	7,641	49,683

	ENERGY MIX %					
	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.0%	23.7%	4.9%	4.7%	100.0%
2013	28.4%	40.0%	19.1%	6.4%	6.1%	100.0%
2014	27.4%	37.4%	18.6%	9.0%	7.6%	100.0%
2015	26.7%	38.1%	16.0%	10.0%	9.2%	100.0%
2016	25.9%	36.2%	17.3%	10.0%	10.7%	100.0%
2017	24.8%	34.3%	17.7%	11.3%	11.9%	100.0%
2018	24.0%	32.8%	17.3%	12.8%	13.0%	100.0%
2019	23.2%	31.3%	17.0%	14.5%	14.0%	100.0%
2020	22.7%	30.0%	16.7%	15.5%	15.1%	100.0%
2021	22.0%	28.3%	16.5%	17.6%	15.6%	100.0%
2022	21.4%	27.6%	16.4%	19.1%	15.5%	100.0%
2023	20.8%	25.4%	18.4%	20.0%	15.4%	100.0%
2024	20.3%	24.3%	18.2%	21.8%	15.4%	100.0%
2025	19.7%	24.4%	17.4%	23.2%	15.4%	100.0%
2026	19.2%	23.0%	19.2%	23.2%	15.4%	100.0%
2027	18.7%	22.5%	20.7%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
COAL RETIREMENT PORTFOLIO

	ENERGY (GWH)							ENERGY MIX %					
	Nuclear	Coal	Gas	RE + DE Renew	EE	Total		Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,977	7,988	1,588	1,510	32,370	**2012**	28.8%	37.0%	24.7%	4.9%	4.7%	100.0%
2013	9,324	12,154	7,288	2,102	2,018	32,886	**2013**	28.4%	37.0%	22.2%	6.4%	6.1%	100.0%
2014	9,270	12,024	6,953	3,057	2,580	33,884	**2014**	27.4%	35.5%	20.5%	9.0%	7.6%	100.0%
2015	9,270	8,512	10,236	3,487	3,193	34,697	**2015**	26.7%	24.5%	29.5%	10.0%	9.2%	100.0%
2016	9,298	7,771	11,477	3,586	3,835	35,966	**2016**	25.9%	21.6%	31.9%	10.0%	10.7%	100.0%
2017	9,269	7,153	11,921	4,520	4,455	37,318	**2017**	24.8%	19.2%	31.9%	12.1%	11.9%	100.0%
2018	9,270	7,345	12,129	4,855	5,039	38,638	**2018**	24.0%	19.0%	31.4%	12.6%	13.0%	100.0%
2019	9,270	6,683	12,974	5,432	5,605	39,965	**2019**	23.2%	16.7%	32.5%	13.6%	14.0%	100.0%
2020	9,315	4,187	15,126	6,166	6,192	40,987	**2020**	22.7%	10.2%	36.9%	15.0%	15.1%	100.0%
2021	9,261	3,938	15,411	6,908	6,565	42,082	**2021**	22.0%	9.4%	36.6%	16.4%	15.6%	100.0%
2022	9,270	4,087	15,951	7,340	6,709	43,358	**2022**	21.4%	9.4%	36.8%	16.9%	15.5%	100.0%
2023	9,270	3,956	16,803	7,697	6,889	44,615	**2023**	20.8%	8.9%	37.7%	17.3%	15.4%	100.0%
2024	9,297	3,948	17,453	8,089	7,082	45,868	**2024**	20.3%	8.6%	38.1%	17.6%	15.4%	100.0%
2025	9,275	0	21,220	9,370	7,267	47,132	**2025**	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	9,270	0	21,992	9,693	7,450	48,405	**2026**	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	9,270	0	23,005	9,767	7,641	49,683	**2027**	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

TOTAL REVENUE REQUIREMENTS

BASE CASE PORTFOLIO

(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	Emission Costs	DE-EE Costs	$	$/MWH
2012	$582.6	$457.9	$44.7	$385.6	$8.3	$1,479.1	$108.9	$214.0	$322.9	($2.5)	$65.4	$24.8	$2.1	$148.1	$2,040.0	$66.2
2013	$675.6	$461.0	$47.1	$408.3	$8.3	$1,600.2	$110.0	$252.8	$362.7	($4.5)	$56.9	$28.7	$2.2	$183.3	$2,229.6	$73.0
2014	$695.0	$472.9	$46.5	$404.2	$20.5	$1,639.1	$110.8	$354.3	$465.1	($3.9)	$64.8	$27.0	$2.5	$217.6	$2,412.2	$78.1
2015	$747.1	$481.1	$48.4	$394.9	$44.7	$1,716.2	$112.0	$370.4	$482.5	($8.3)	$54.3	$25.9	$3.0	$235.8	$2,509.4	$81.2
2016	$817.5	$541.2	$52.8	$350.6	$69.7	$1,831.8	$112.6	$388.9	$501.5	($9.6)	$64.8	$22.9	($0.1)	$252.8	$2,664.2	$84.7
2017	$852.7	$660.5	$62.3	$373.9	$79.8	$2,029.2	$137.1	$345.3	$482.4	($11.0)	$73.6	$19.6	($0.1)	$247.7	$2,841.5	$88.6
2018	$892.5	$768.3	$66.7	$372.7	$80.1	$2,180.2	$121.7	$315.6	$437.3	($12.5)	$78.7	$17.1	($0.1)	$252.4	$2,953.1	$90.2
2019	$920.2	$798.1	$68.4	$362.5	$78.3	$2,227.5	$128.3	$332.3	$460.6	($13.5)	$78.8	$14.9	$59.1	$258.6	$3,086.0	$92.2
2020	$1,027.3	$908.8	$78.8	$356.1	$80.4	$2,451.3	$74.1	$261.0	$335.1	($13.3)	$83.7	$12.4	$69.5	$288.2	$3,227.0	$94.6
2021	$1,150.3	$948.8	$82.5	$383.9	$80.7	$2,646.2	$76.7	$359.6	$436.3	$0.0	$88.1	$17.0	$76.8	$167.3	$3,431.7	$99.0
2022	$1,272.6	$1,024.6	$86.7	$401.3	$80.6	$2,865.8	$72.9	$352.4	$425.3	$0.0	$91.2	$16.2	$100.0	$182.8	$3,681.2	$103.3
2023	$1,344.8	$1,120.7	$93.7	$418.3	$80.0	$3,057.4	$80.9	$378.2	$459.1	$0.0	$112.8	$18.0	$114.8	$201.0	$3,963.1	$108.3
2024	$1,417.6	$1,184.4	$98.3	$414.2	$79.0	$3,193.5	$75.5	$376.2	$451.7	$0.0	$115.8	$17.5	$134.0	$202.3	$4,114.7	$109.7
2025	$1,533.6	$1,232.9	$105.5	$440.4	$91.5	$3,403.9	$15.0	$411.7	$426.7	$0.0	$118.6	$18.6	$161.3	$211.7	$4,340.8	$113.0
2026	$1,621.1	$1,314.3	$112.9	$466.8	$99.1	$3,614.1	$66.2	$414.9	$481.1	$0.0	$130.6	$17.9	$207.0	$217.0	$4,667.6	$118.4
2027	$1,647.4	$1,413.8	$120.3	$472.2	$101.4	$3,755.0	$86.0	$437.0	$522.9	$0.0	$153.0	$19.7	$292.0	$226.3	$4,969.0	$122.8
2028	$1,591.4	$1,481.8	$124.0	$471.5	$113.7	$3,782.5	$95.0	$549.6	$644.6	$0.0	$159.2	$24.9	$378.7	$235.0	$5,224.9	$125.9
2029	$1,605.2	$1,611.1	$134.9	$469.4	$121.6	$3,942.2	$98.4	$551.7	$650.1	$0.0	$183.0	$24.0	$473.1	$237.8	$5,510.3	$129.4
2030	$1,682.1	$1,730.4	$143.2	$501.2	$137.5	$4,194.3	$87.2	$545.7	$632.9	$0.0	$206.6	$23.2	$590.2	$240.8	$5,888.0	$134.9
2031	$1,740.4	$1,840.0	$149.9	$512.4	$145.8	$4,388.5	$94.1	$548.7	$642.8	$0.0	$222.7	$22.3	$660.6	$244.0	$6,180.9	$138.1
2032	$1,794.9	$1,991.3	$160.4	$526.1	$162.4	$4,635.1	$101.8	$552.0	$653.7	$0.0	$243.0	$21.3	$724.7	$246.1	$6,524.0	$141.2
2033	$1,894.1	$2,135.0	$170.9	$542.5	$186.3	$4,928.8	$90.1	$552.6	$642.7	$0.0	$272.3	$20.3	$786.6	$247.8	$6,898.4	$146.3
2034	$1,985.8	$2,286.3	$180.8	$559.5	$197.0	$5,209.4	$96.3	$555.9	$652.1	$0.0	$292.1	$19.2	$866.4	$248.9	$7,288.1	$150.8
2035	$2,060.1	$2,465.6	$193.7	$576.2	$213.6	$5,509.2	$104.0	$559.3	$663.3	$0.0	$336.6	$18.1	$942.1	$249.4	$7,718.7	$155.9
2036	$2,141.5	$2,637.1	$207.6	$588.9	$221.2	$5,796.3	$111.8	$563.7	$675.5	$0.0	$375.9	$16.9	$1,046.9	$249.4	$8,160.8	$160.1
2037	$2,294.9	$2,779.4	$219.4	$601.9	$239.3	$6,134.9	$104.3	$531.1	$635.4	$0.0	$392.6	$15.6	$1,098.3	$248.5	$8,525.3	$164.2
2038	$2,319.4	$2,984.0	$231.1	$627.4	$265.8	$6,427.7	$119.9	$601.8	$721.6	$0.0	$458.6	$20.0	$1,100.1	$246.9	$8,974.9	$169.0
2039	$2,333.5	$3,346.7	$261.0	$519.4	$316.7	$6,777.3	$123.3	$649.0	$772.3	$0.0	$551.0	$23.2	$1,025.5	$244.4	$9,393.5	$173.0
2040	$2,554.4	$3,535.5	$280.2	$541.4	$341.2	$7,252.8	$123.4	$719.2	$842.6	$0.0	$586.2	$29.2	$1,043.0	$240.8	$9,994.6	$179.2
2041	$2,618.5	$3,690.9	$293.7	$556.6	$362.3	$7,522.0	$131.0	$753.7	$884.7	$0.0	$586.2	$30.4	$1,062.6	$236.1	$10,321.9	$182.1
CPW@ 7.95%																
(2012-2027)	$8,523.6	$6,698.0	$602.3	$3,497.8	$517.7	$19,839.4	$885.8	$2,959.2	$3,845.0	($50.1)	$717.6	$186.8	$455.8	$1,922.2	$26,916.7	$91.0
(2012-2041)	$13,251.3	$12,187.7	$1,042.4	$4,791.3	$987.8	$32,260.5	$1,134.5	$4,354.4	$5,488.9	($50.1)	$1,461.3	$240.2	$2,334.3	$2,513.8	$44,248.9	$107.6

TOTAL REVENUE REQUIREMENTS

FOUR CORNERS CONTINGENCY PORTFOLIO

(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	Emission Costs	DE-EE Costs	$	$/MWh
2012	$592.0	$460.3	$44.6	$394.6	$8.3	$1,499.8	$108.9	$219.2	$328.1	($2.5)	$65.0	$24.8	$1.8	$148.1	$2,065.1	$67.0
2013	$624.8	$475.1	$45.3	$354.8	$8.3	$1,508.3	$110.0	$267.7	$377.6	($4.5)	$63.7	$28.7	$1.2	$183.3	$2,158.4	$70.7
2014	$639.1	$484.6	$44.9	$356.6	$20.5	$1,545.6	$110.8	$364.2	$475.0	($3.9)	$63.5	$27.0	$2.0	$217.6	$2,326.9	$75.3
2015	$690.1	$519.2	$48.5	$336.4	$44.7	$1,639.0	$112.0	$441.5	$553.5	($8.3)	$81.1	$25.9	$23.4	$235.8	$2,550.5	$82.5
2016	$826.4	$574.7	$54.2	$277.4	$71.4	$1,804.0	$112.6	$455.0	$567.6	($9.6)	$91.6	$22.9	$39.2	$252.8	$2,768.5	$88.0
2017	$868.9	$726.5	$66.4	$279.2	$83.1	$2,024.2	$164.2	$380.1	$544.2	($11.0)	$103.1	$19.6	($0.1)	$247.7	$2,927.8	$91.3
2018	$896.3	$855.6	$74.6	$277.4	$83.9	$2,187.8	$135.5	$332.5	$468.0	($12.5)	$111.8	$17.1	($0.1)	$252.4	$3,024.5	$92.4
2019	$942.3	$901.6	$78.0	$274.7	$82.0	$2,278.5	$128.1	$348.3	$476.5	($13.5)	$117.8	$14.9	$15.7	$258.6	$3,148.4	$94.0
2020	$1,049.8	$1,033.0	$90.0	$281.8	$82.7	$2,537.3	$74.0	$265.5	$339.5	($13.3)	$122.0	$12.4	$21.7	$288.2	$3,307.8	$96.9
2021	$1,169.3	$1,075.8	$94.4	$295.0	$82.4	$2,716.9	$76.5	$364.4	$440.9	$0.0	$130.1	$17.0	$26.1	$167.3	$3,498.4	$101.0
2022	$1,285.4	$1,169.8	$99.9	$305.2	$94.4	$2,954.7	$72.7	$352.5	$425.2	$0.0	$142.0	$16.2	$45.2	$182.8	$3,766.1	$105.6
2023	$1,345.5	$1,260.0	$105.9	$320.4	$101.8	$3,133.5	$80.7	$377.9	$458.6	$0.0	$153.4	$18.0	$60.6	$201.0	$4,025.1	$110.0
2024	$1,408.5	$1,330.5	$111.2	$332.9	$115.7	$3,298.8	$75.3	$376.4	$451.7	$0.0	$169.9	$17.5	$77.4	$202.3	$4,217.6	$112.5
2025	$1,523.9	$1,399.0	$120.2	$349.4	$136.3	$3,528.7	$14.8	$411.7	$426.6	$0.0	$176.3	$18.6	$89.7	$211.7	$4,451.5	$115.9
2026	$1,603.1	$1,485.2	$127.9	$358.9	$145.1	$3,720.2	$66.0	$415.0	$481.0	$0.0	$197.7	$17.9	$130.5	$217.0	$4,764.2	$120.9
2027	$1,615.4	$1,586.2	$135.3	$369.4	$146.0	$3,852.4	$85.8	$436.7	$522.5	$0.0	$214.5	$19.7	$210.5	$226.3	$5,045.9	$124.7
2028	$1,558.4	$1,664.5	$139.9	$381.8	$156.9	$3,901.5	$94.8	$549.8	$644.6	$0.0	$222.1	$24.9	$289.2	$235.0	$5,317.3	$128.1
2029	$1,567.6	$1,782.9	$149.4	$393.4	$163.4	$4,056.7	$98.3	$551.3	$649.6	$0.0	$249.5	$24.0	$386.3	$237.8	$5,603.9	$131.6
2030	$1,633.1	$1,906.0	$158.1	$406.3	$178.6	$4,282.2	$87.0	$545.8	$632.8	$0.0	$274.8	$23.2	$498.7	$240.8	$5,952.5	$136.3
2031	$1,689.5	$2,042.3	$167.0	$418.5	$185.5	$4,502.9	$93.9	$548.7	$642.6	$0.0	$303.1	$22.3	$550.9	$244.0	$6,265.7	$140.0
2032	$1,737.8	$2,200.2	$178.1	$431.6	$200.5	$4,748.2	$101.6	$551.9	$653.5	$0.0	$328.2	$21.3	$611.3	$246.1	$6,608.7	$143.0
2033	$1,816.8	$2,341.6	$188.8	$446.3	$206.7	$5,000.2	$89.9	$552.5	$642.4	$0.0	$355.3	$20.3	$673.3	$247.8	$6,939.2	$147.1
2034	$1,892.0	$2,499.9	$199.6	$461.7	$222.0	$5,275.3	$96.1	$555.9	$651.9	$0.0	$381.6	$19.2	$745.9	$248.9	$7,322.8	$151.5
2035	$1,969.1	$2,660.0	$211.3	$475.7	$228.5	$5,544.6	$103.8	$559.2	$663.0	$0.0	$418.5	$18.1	$826.6	$249.4	$7,720.2	$155.9
2036	$2,031.8	$2,841.5	$225.8	$486.9	$245.5	$5,831.6	$111.6	$563.6	$675.2	$0.0	$453.5	$16.9	$925.9	$249.4	$8,152.5	$159.9
2037	$2,138.3	$3,016.3	$239.4	$499.2	$252.8	$6,146.1	$104.1	$531.2	$635.3	$0.0	$488.9	$15.6	$961.4	$248.5	$8,495.8	$163.6
2038	$2,166.1	$3,166.7	$250.2	$516.8	$269.8	$6,369.6	$119.7	$601.7	$721.4	$0.0	$522.4	$20.0	$984.1	$246.9	$8,864.4	$166.9
2039	$2,195.8	$3,338.0	$265.8	$529.0	$295.3	$6,623.8	$123.3	$649.0	$772.3	$0.0	$547.1	$23.2	$1,012.0	$244.4	$9,222.7	$169.9
2040	$2,273.9	$3,534.9	$280.2	$541.3	$305.7	$6,936.0	$123.4	$719.2	$842.6	$0.0	$585.4	$29.2	$1,042.8	$240.8	$9,676.8	$173.5
2041	$2,347.3	$3,690.5	$293.8	$556.6	$322.6	$7,210.7	$131.0	$753.7	$884.7	$0.0	$585.4	$30.4	$1,062.4	$236.1	$10,009.6	$176.5
CPW@ 7.95%																
(2012-2027)	$8,437.1	$7,377.1	$653.4	$2,881.4	$598.4	$19,947.3	$910.5	$3,127.1	$4,037.6	($50.1)	$975.1	$186.8	$286.0	$1,922.2	$27,304.8	$92.3
(2012-2041)	$12,936.5	$13,277.2	$1,129.9	$3,977.2	$1,122.7	$32,443.5	$1,158.7	$4,522.3	$5,681.0	($50.1)	$1,879.0	$240.2	$1,937.2	$2,513.8	$44,644.7	$108.5

TOTAL REVENUE REQUIREMENTS
ENHANCED RENEWABLE PORTFOLIO

(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	Emission Costs	DE-EE Costs	$	$/MWh
2012	$582.6	$457.9	$44.7	$385.6	$8.3	$1,479.1	$108.9	$214.0	$322.9	($2.5)	$65.4	$24.8	$2.1	$148.1	$2,040.0	$66.2
2013	$675.6	$461.0	$47.1	$408.3	$8.3	$1,600.2	$110.0	$252.8	$362.7	($4.5)	$56.9	$28.7	$2.2	$183.3	$2,229.6	$73.0
2014	$695.0	$472.9	$46.5	$404.2	$20.5	$1,639.1	$110.8	$354.3	$465.1	($3.9)	$64.8	$27.0	$2.5	$217.6	$2,412.2	$78.1
2015	$747.1	$481.1	$48.4	$394.9	$44.7	$1,716.2	$112.0	$370.4	$482.5	($8.3)	$54.3	$25.9	$3.0	$235.8	$2,509.4	$81.2
2016	$817.5	$541.2	$52.8	$350.6	$69.7	$1,831.8	$112.6	$388.9	$501.5	($9.6)	$64.8	$22.9	($0.1)	$252.8	$2,664.2	$84.7
2017	$874.8	$644.0	$61.3	$376.8	$79.8	$2,036.8	$123.9	$366.6	$490.5	($11.0)	$71.5	$19.6	($0.1)	$247.7	$2,855.0	$89.0
2018	$950.6	$722.6	$64.4	$378.6	$80.1	$2,196.3	$97.0	$392.6	$489.6	($12.5)	$72.6	$17.1	($0.1)	$252.4	$3,015.4	$92.1
2019	$974.8	$742.2	$63.7	$368.3	$77.8	$2,226.8	$119.0	$456.9	$575.9	($13.5)	$70.9	$14.9	$45.1	$258.6	$3,178.7	$95.0
2020	$1,076.3	$824.9	$73.1	$364.4	$79.7	$2,418.4	$75.0	$423.3	$498.3	($13.3)	$72.7	$12.4	$50.1	$288.2	$3,326.9	$97.5
2021	$1,186.1	$852.9	$76.3	$391.8	$79.9	$2,587.0	$91.9	$550.1	$642.0	$0.0	$76.7	$17.0	$53.7	$167.3	$3,543.6	$102.3
2022	$1,317.9	$902.8	$79.4	$412.3	$79.4	$2,791.9	$83.5	$578.1	$661.6	$0.0	$77.3	$16.2	$69.6	$182.8	$3,799.3	$106.6
2023	$1,416.2	$978.0	$85.1	$430.0	$91.7	$3,001.0	$81.9	$633.9	$715.7	$0.0	$94.0	$18.0	$79.9	$201.0	$4,109.6	$112.3
2024	$1,504.2	$1,013.8	$87.9	$429.6	$112.7	$3,148.0	$89.8	$698.3	$788.1	$0.0	$94.3	$17.5	$89.8	$202.3	$4,339.9	$115.7
2025	$1,601.0	$1,054.2	$90.6	$457.9	$122.5	$3,326.1	$87.6	$764.7	$852.3	$0.0	$96.2	$18.6	$113.0	$211.7	$4,617.9	$120.2
2026	$1,762.6	$1,122.6	$99.8	$486.5	$136.7	$3,608.2	$27.8	$767.7	$795.5	$0.0	$103.8	$17.9	$151.7	$217.0	$4,894.0	$124.2
2027	$1,812.5	$1,207.1	$106.6	$493.5	$145.1	$3,764.9	$80.2	$789.6	$869.8	$0.0	$124.1	$19.7	$231.9	$226.3	$5,236.8	$129.4
2028	$1,706.2	$1,270.6	$110.2	$492.2	$158.5	$3,737.7	$105.7	$903.2	$1,008.9	$0.0	$127.9	$24.9	$314.1	$235.0	$5,448.5	$131.3
2029	$1,702.2	$1,377.1	$118.4	$490.3	$164.7	$3,852.7	$107.9	$904.1	$1,012.0	$0.0	$146.5	$24.0	$403.2	$237.8	$5,676.3	$133.3
2030	$1,774.6	$1,485.0	$125.6	$522.6	$179.2	$4,086.9	$95.2	$898.5	$993.7	$0.0	$165.4	$23.2	$513.9	$240.8	$6,023.9	$138.0
2031	$1,830.1	$1,584.2	$132.5	$534.4	$185.6	$4,266.9	$100.4	$901.6	$1,002.0	$0.0	$181.3	$22.3	$577.7	$244.0	$6,294.2	$140.6
2032	$1,882.5	$1,719.2	$141.1	$548.6	$201.1	$4,492.6	$106.4	$905.7	$1,012.1	$0.0	$198.4	$21.3	$637.5	$246.1	$6,608.1	$143.0
2033	$1,959.8	$1,846.6	$150.2	$565.1	$207.8	$4,729.5	$113.5	$905.4	$1,018.9	$0.0	$223.7	$20.3	$694.6	$247.8	$6,934.7	$147.0
2034	$2,036.2	$1,981.9	$159.4	$582.2	$223.2	$4,982.9	$118.4	$908.7	$1,027.1	$0.0	$239.9	$19.2	$767.1	$248.9	$7,285.2	$150.7
2035	$2,130.1	$2,148.9	$171.2	$600.1	$229.8	$5,280.0	$103.3	$912.1	$1,015.4	$0.0	$280.9	$18.1	$836.2	$249.4	$7,680.0	$155.1
2036	$2,223.7	$2,307.6	$184.1	$613.8	$246.1	$5,575.4	$109.0	$917.3	$1,026.3	$0.0	$317.5	$16.9	$932.2	$249.4	$8,117.6	$159.2
2037	$2,351.6	$2,437.1	$194.8	$626.8	$253.0	$5,863.2	$120.4	$884.0	$1,004.4	$0.0	$332.0	$15.6	$983.0	$248.5	$8,446.7	$162.7
2038	$2,380.6	$2,628.1	$205.4	$653.0	$270.5	$6,137.7	$126.7	$954.5	$1,081.2	$0.0	$394.5	$20.0	$984.7	$246.9	$8,864.8	$167.0
2039	$2,431.2	$2,970.1	$233.1	$546.8	$336.0	$6,517.3	$114.4	$1,001.9	$1,116.3	$0.0	$480.7	$23.2	$914.2	$244.4	$9,296.0	$171.2
2040	$2,664.6	$3,148.0	$250.9	$569.9	$373.1	$7,006.6	$123.9	$1,073.0	$1,196.9	$0.0	$515.2	$29.2	$934.7	$240.8	$9,923.3	$177.9
2041	$2,724.7	$3,292.0	$263.5	$585.8	$397.4	$7,263.5	$133.0	$1,106.6	$1,239.5	$0.0	$515.2	$30.4	$954.3	$236.1	$10,239.0	$180.6
CPW@ 7.95%																
(2012-2027)	$8,839.1	$6,188.5	$568.3	$3,547.7	$568.7	$19,712.3	$886.8	$3,910.2	$4,797.0	($50.1)	$651.4	$186.8	$332.6	$1,922.2	$27,552.3	$93.2
(2012-2041)	$13,774.9	$10,971.1	$958.1	$4,897.9	$1,114.5	$31,716.5	$1,154.8	$6,163.2	$7,318.0	($50.1)	$1,274.9	$240.2	$1,988.5	$2,513.8	$45,001.8	$109.4

TOTAL REVENUE REQUIREMENTS

COAL RETIREMENT PORTFOLIO

(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	Emission Costs	DE-EE Costs	$	$/MWH
2012	$604.3	$460.3	$44.6	$394.6	$8.3	$1,512.1	$108.9	$219.2	$328.1	($2.5)	$65.0	$24.8	$1.8	$148.1	$2,077.4	$67.4
2013	$636.8	$475.1	$45.3	$354.8	$8.3	$1,520.3	$110.0	$267.7	$377.6	($4.5)	$63.7	$28.7	$1.2	$183.3	$2,170.3	$71.1
2014	$651.1	$484.6	$44.9	$356.6	$20.5	$1,557.7	$110.8	$364.2	$475.0	($3.9)	$63.5	$27.0	$2.0	$217.6	$2,338.9	$75.7
2015	$708.7	$519.2	$48.5	$336.4	$44.7	$1,657.6	$112.0	$441.5	$553.5	($8.3)	$81.1	$25.9	$23.4	$235.8	$2,569.1	$83.1
2016	$850.5	$574.7	$54.2	$277.4	$71.4	$1,828.2	$112.6	$455.0	$567.6	($9.6)	$91.6	$22.9	$39.2	$252.8	$2,792.7	$88.8
2017	$918.5	$694.7	$63.8	$280.4	$82.7	$2,040.1	$163.3	$403.5	$566.8	($11.0)	$98.5	$19.6	($0.1)	$247.7	$2,961.7	$92.3
2018	$964.6	$808.8	$71.5	$272.8	$83.6	$2,201.3	$130.1	$383.0	$513.2	($12.5)	$105.0	$17.1	($0.1)	$252.4	$3,076.3	$94.0
2019	$984.7	$847.3	$74.1	$273.8	$81.6	$2,261.5	$139.5	$394.8	$534.2	($13.5)	$110.6	$14.9	$5.3	$258.6	$3,171.5	$94.7
2020	$1,138.5	$1,014.0	$87.1	$276.4	$94.3	$2,610.3	$84.3	$340.2	$424.4	($13.3)	$126.9	$12.4	($13.7)	$288.2	$3,435.3	$100.7
2021	$1,291.5	$1,051.3	$95.6	$287.6	$113.6	$2,839.6	$78.2	$435.0	$513.2	$0.0	$131.0	$17.0	($14.2)	$167.3	$3,653.9	$105.4
2022	$1,396.2	$1,137.6	$100.8	$289.8	$123.0	$3,047.4	$73.1	$428.2	$501.3	$0.0	$143.2	$16.2	$1.1	$182.8	$3,892.0	$109.2
2023	$1,445.7	$1,229.1	$106.8	$282.3	$123.4	$3,187.4	$86.9	$453.7	$540.6	$0.0	$155.3	$18.0	$12.5	$201.0	$4,114.8	$112.5
2024	$1,473.2	$1,303.0	$112.6	$289.8	$134.2	$3,312.8	$86.3	$452.8	$539.1	$0.0	$172.9	$17.5	$24.1	$202.3	$4,268.6	$113.8
2025	$1,658.3	$1,432.4	$113.1	$296.7	$168.1	$3,668.5	$96.3	$512.5	$608.8	$0.0	$215.1	$18.6	($20.6)	$211.7	$4,702.1	$122.4
2026	$1,808.3	$1,517.4	$120.6	$297.6	$186.2	$3,930.1	$96.8	$515.7	$612.6	$0.0	$236.1	$17.9	$13.9	$217.0	$5,027.5	$127.6
2027	$1,747.4	$1,618.8	$127.9	$306.4	$203.8	$4,004.4	$98.5	$537.4	$635.9	$0.0	$253.7	$19.7	$85.7	$226.3	$5,225.7	$129.2
2028	$1,706.5	$1,690.4	$133.0	$315.6	$208.8	$4,054.3	$88.4	$650.6	$739.0	$0.0	$263.7	$24.9	$157.8	$235.0	$5,474.7	$131.9
2029	$1,724.0	$1,808.0	$142.5	$325.9	$221.6	$4,221.9	$90.2	$651.9	$742.1	$0.0	$291.5	$24.0	$247.3	$237.8	$5,764.6	$135.4
2030	$1,762.0	$1,933.6	$151.4	$333.5	$226.4	$4,406.9	$96.1	$646.5	$742.6	$0.0	$317.4	$23.2	$348.3	$240.8	$6,079.2	$139.2
2031	$1,799.4	$2,060.7	$160.6	$342.4	$239.5	$4,602.7	$101.5	$649.5	$751.0	$0.0	$339.8	$22.3	$391.5	$244.0	$6,351.3	$141.9
2032	$1,839.9	$2,215.2	$171.5	$352.1	$244.3	$4,823.1	$107.6	$653.1	$760.7	$0.0	$368.9	$21.3	$443.8	$246.1	$6,663.9	$144.2
2033	$1,888.2	$2,348.8	$181.7	$362.8	$257.7	$5,039.2	$114.7	$653.3	$768.1	$0.0	$400.8	$20.3	$495.9	$247.8	$6,972.0	$147.8
2034	$1,940.3	$2,496.5	$191.4	$373.7	$262.4	$5,264.4	$119.9	$656.7	$776.5	$0.0	$427.6	$19.2	$555.4	$248.9	$7,292.1	$150.9
2035	$2,016.4	$2,654.8	$203.0	$385.4	$277.3	$5,536.9	$104.8	$660.0	$764.8	$0.0	$457.9	$18.1	$622.2	$249.4	$7,649.4	$154.5
2036	$2,082.2	$2,840.1	$217.0	$395.2	$283.0	$5,817.5	$110.6	$664.6	$775.1	$0.0	$497.0	$16.9	$701.5	$249.4	$8,057.4	$158.0
2037	$2,154.6	$3,021.9	$230.0	$406.3	$298.2	$6,111.0	$122.3	$631.9	$754.2	$0.0	$541.3	$15.6	$731.8	$248.5	$8,402.4	$161.8
2038	$2,175.6	$3,180.1	$240.8	$422.9	$321.9	$6,341.3	$128.3	$702.4	$830.8	$0.0	$570.5	$20.0	$754.2	$246.9	$8,763.6	$165.0
2039	$2,234.9	$3,356.7	$256.0	$436.2	$331.4	$6,615.1	$116.1	$749.8	$865.9	$0.0	$606.1	$23.2	$779.4	$244.4	$9,134.1	$168.2
2040	$2,318.1	$3,555.1	$269.9	$447.1	$347.1	$6,937.3	$125.5	$820.3	$945.7	$0.0	$643.9	$29.2	$808.2	$240.8	$9,605.1	$172.2
2041	$2,385.0	$3,715.0	$283.4	$460.5	$371.7	$7,215.7	$134.6	$854.5	$989.0	$0.0	$643.9	$30.4	$827.8	$236.1	$9,942.9	$175.4
CPW@ 7.95%																
(2012-2027)	$8,955.8	$7,274.0	$641.3	$2,779.0	$686.8	$20,336.9	$967.0	$3,454.2	$4,421.1	($50.1)	$1,006.6	$186.8	$74.4	$1,922.2	$27,898.0	$94.3
(2012-2041)	$13,662.5	$13,209.9	$1,098.8	$3,676.4	$1,327.8	$32,975.4	$1,228.5	$5,094.3	$6,322.8	($50.1)	$2,020.0	$240.2	$1,283.3	$2,513.8	$45,305.4	$110.1

APS 2012 INTEGRATED RESOURCE PLAN

Annual Revenue Requirements

($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,040.0	$2,065.1	$2,040.0	$2,077.4
2013	$2,229.6	$2,158.4	$2,229.6	$2,170.3
2014	$2,412.2	$2,326.9	$2,412.2	$2,338.9
2015	$2,509.4	$2,550.5	$2,509.4	$2,569.1
2016	$2,664.2	$2,768.5	$2,664.2	$2,792.7
2017	$2,841.5	$2,927.8	$2,855.0	$2,961.7
2018	$2,953.1	$3,024.5	$3,015.4	$3,076.3
2019	$3,086.0	$3,148.4	$3,178.7	$3,171.5
2020	$3,227.0	$3,307.8	$3,326.9	$3,435.3
2021	$3,431.7	$3,498.4	$3,543.6	$3,653.9
2022	$3,681.2	$3,766.1	$3,799.3	$3,892.0
2023	$3,963.1	$4,025.1	$4,109.6	$4,114.8
2024	$4,114.7	$4,217.6	$4,339.9	$4,268.6
2025	$4,340.8	$4,451.5	$4,617.9	$4,702.1
2026	$4,667.6	$4,764.2	$4,894.0	$5,027.5
2027	$4,969.0	$5,045.9	$5,236.8	$5,225.7
2028	$5,224.9	$5,317.3	$5,448.5	$5,474.7
2029	$5,510.3	$5,603.9	$5,676.3	$5,764.6
2030	$5,888.0	$5,952.5	$6,023.9	$6,079.2
2031	$6,180.9	$6,265.7	$6,294.2	$6,351.3
2032	$6,524.0	$6,608.7	$6,608.1	$6,663.9
2033	$6,898.4	$6,939.2	$6,934.7	$6,972.0
2034	$7,288.1	$7,322.8	$7,285.2	$7,292.1
2035	$7,718.7	$7,720.2	$7,680.0	$7,649.4
2036	$8,160.8	$8,152.5	$8,117.6	$8,057.4
2037	$8,525.3	$8,495.8	$8,446.7	$8,402.4
2038	$8,974.9	$8,864.4	$8,864.8	$8,763.6
2039	$9,393.5	$9,222.7	$9,296.0	$9,134.1
2040	$9,994.6	$9,676.8	$9,923.3	$9,605.1
2041	$10,321.9	$10,009.6	$10,239.0	$9,942.9
CPW (2012-2027)	$26,916.7	$27,304.8	$27,552.3	$27,898.0
CPW (2012-2041)	$44,248.9	$44,644.7	$45,001.8	$45,305.4
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost

($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$66.2	$67.0	$66.2	$67.4
2013	$73.0	$70.7	$73.0	$71.1
2014	$78.1	$75.3	$78.1	$75.7
2015	$81.2	$82.5	$81.2	$83.1
2016	$84.7	$88.0	$84.7	$88.8
2017	$88.6	$91.3	$89.0	$92.3
2018	$90.2	$92.4	$92.1	$94.0
2019	$92.2	$94.0	$95.0	$94.7
2020	$94.6	$96.9	$97.5	$100.7
2021	$99.0	$101.0	$102.3	$105.4
2022	$103.3	$105.6	$106.6	$109.2
2023	$108.3	$110.0	$112.3	$112.5
2024	$109.7	$112.5	$115.7	$113.8
2025	$113.0	$115.9	$120.2	$122.4
2026	$118.4	$120.9	$124.2	$127.6
2027	$122.8	$124.7	$129.4	$129.2

Cumulative Capital Spending

New Generation Plus Incremental Transmission

($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$620.7	$326.7	$620.7	$326.7
2013	$862.7	$599.8	$862.7	$599.8
2014	$1,089.8	$986.7	$1,089.8	$986.7
2015	$1,559.3	$1,827.9	$1,685.1	$2,068.1
2016	$1,559.3	$2,018.0	$1,846.3	$2,265.4
2017	$1,737.9	$2,321.1	$2,341.6	$2,889.9
2018	$2,021.8	$2,716.7	$3,046.3	$3,796.0
2019	$2,671.0	$3,426.0	$4,103.8	$4,866.9
2020	$3,293.8	$4,075.0	$4,982.3	$6,033.3
2021	$4,599.4	$5,439.5	$6,598.8	$7,175.0
2022	$5,314.2	$6,223.9	$7,780.0	$7,792.8
2023	$6,197.8	$7,153.1	$9,053.4	$9,139.1
2024	$6,937.8	$7,927.7	$10,192.1	$10,188.1
2025	$7,655.6	$8,645.4	$11,761.4	$11,742.9
2026	$8,009.9	$8,999.7	$12,123.4	$12,385.3
2027	$8,726.0	$9,715.8	$12,640.1	$13,269.2

Notes:

(1) Capital investment projected is regardless of whether APS constructs and owns new generation resources or whether resources are purchased by APS under long-term PPAs with market participants.

(2) Capital spending excludes: (a) financial commitments to energy efficiency and distributed energy initiatives; (b) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing; and (c) ongoing capital investment for existing owned generation.

(3) Includes SCE's share of Four Corners Units 4 and 5.

Annual Natural Gas Burns

(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	57.7	60.2	57.7	60.2
2013	47.2	54.8	47.2	54.8
2014	47.7	52.4	47.7	52.4
2015	41.9	77.2	41.9	77.2
2016	47.1	85.9	47.1	85.9
2017	52.8	95.2	50.2	89.9
2018	57.6	99.0	51.4	92.1
2019	57.7	103.8	51.4	96.5
2020	60.3	107.3	52.5	112.8
2021	62.5	108.9	54.1	114.1
2022	67.3	115.6	56.6	119.6
2023	78.3	121.8	65.2	126.2
2024	82.7	126.4	67.5	131.7
2025	83.6	132.8	68.1	160.9
2026	90.9	139.9	75.0	167.0
2027	99.2	147.5	81.6	174.7

Annual CO2 Emissions

(Metric Tons)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	15,313,185	15,415,395	15,313,185	15,415,395
2013	14,811,182	15,317,092	14,811,182	15,317,092
2014	14,379,059	15,053,149	14,379,059	15,053,149
2015	14,549,660	12,440,855	14,549,660	12,440,855
2016	14,745,803	12,299,340	14,745,803	12,299,340
2017	15,105,853	12,422,465	14,778,167	12,007,916
2018	15,390,145	12,871,279	14,681,209	12,319,489
2019	15,667,773	12,729,660	14,506,102	11,985,023
2020	15,759,875	12,758,372	14,304,539	10,491,171
2021	15,673,326	12,713,428	14,028,196	10,283,077
2022	16,098,342	13,078,286	14,178,470	10,653,986
2023	16,131,683	13,352,651	14,109,870	10,890,802
2024	16,432,683	13,736,109	14,035,149	11,195,712
2025	16,778,098	13,678,362	14,328,791	8,792,028
2026	16,982,746	13,893,267	14,381,894	9,132,531
2027	17,385,315	14,330,043	14,799,530	9,557,865

Annual Water Use
(Acre-Feet)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	53,365	53,261	53,365	53,261
2013	53,986	53,661	53,986	53,661
2014	55,258	55,017	55,258	55,017
2015	55,107	53,524	55,107	53,524
2016	56,243	53,042	56,243	53,042
2017	57,501	52,958	56,740	52,072
2018	58,035	53,418	57,313	52,284
2019	58,297	52,675	56,618	51,143
2020	57,606	51,041	55,916	45,280
2021	58,197	51,519	56,128	44,618
2022	58,941	52,164	56,828	45,189
2023	58,720	52,051	56,353	44,865
2024	59,156	52,391	57,038	44,930
2025	58,802	51,009	57,130	36,198
2026	58,919	50,994	56,481	36,341
2027	59,461	51,523	57,055	36,644

Annual Revenue Requirements
Low Gas Price Sensitivity
($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$1,990.4	$2,011.9	$1,990.4	$2,024.2
2013	$2,184.5	$2,101.6	$2,184.5	$2,113.6
2014	$2,352.9	$2,263.9	$2,352.9	$2,276.0
2015	$2,455.5	$2,430.2	$2,455.5	$2,448.8
2016	$2,595.8	$2,625.9	$2,595.8	$2,650.0
2017	$2,753.4	$2,754.3	$2,776.3	$2,800.2
2018	$2,854.2	$2,841.9	$2,932.5	$2,909.6
2019	$2,982.5	$2,951.1	$3,100.6	$2,991.1
2020	$3,110.1	$3,098.4	$3,233.5	$3,218.8
2021	$3,327.4	$3,282.0	$3,468.2	$3,434.8
2022	$3,548.8	$3,529.7	$3,691.5	$3,657.6
2023	$3,816.2	$3,763.5	$4,006.1	$3,852.3
2024	$3,951.0	$3,938.0	$4,223.8	$3,985.3
2025	$4,167.1	$4,155.9	$4,477.6	$4,307.3
2026	$4,465.3	$4,446.2	$4,721.3	$4,608.5
2027	$4,754.0	$4,702.6	$5,072.1	$4,777.0
2028	$4,973.6	$4,948.2	$5,240.9	$5,005.3
2029	$5,237.9	$5,200.2	$5,477.1	$5,260.8
2030	$5,580.4	$5,514.7	$5,790.0	$5,538.2
2031	$5,825.6	$5,783.1	$6,009.0	$5,774.4
2032	$6,130.3	$6,085.3	$6,293.7	$6,041.5
2033	$6,463.2	$6,375.7	$6,588.4	$6,310.9
2034	$6,811.5	$6,712.6	$6,900.2	$6,588.9
2035	$7,200.1	$7,066.2	$7,260.7	$6,900.1
2036	$7,609.4	$7,458.8	$7,665.4	$7,254.0
2037	$7,938.0	$7,756.6	$7,949.6	$7,545.9
2038	$8,310.7	$8,079.5	$8,294.8	$7,861.2
2039	$8,574.0	$8,398.3	$8,578.2	$8,180.4
2040	$9,116.4	$8,799.5	$9,153.0	$8,593.5
2041	$9,400.8	$9,089.0	$9,430.1	$8,883.7
CPW (2012-2027)	$26,058.7	$25,828.9	$26,829.7	$26,345.5
CPW (2012-2041)	$42,250.6	$41,753.4	$43,339.5	$42,080.5
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
Low Gas Price Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$64.6	$65.3	$64.6	$65.7
2013	$71.5	$68.8	$71.5	$69.2
2014	$76.2	$73.3	$76.2	$73.7
2015	$79.4	$78.6	$79.4	$79.2
2016	$82.5	$83.5	$82.5	$84.3
2017	$85.8	$85.9	$86.5	$87.3
2018	$87.2	$86.8	$89.6	$88.9
2019	$89.1	$88.2	$92.6	$89.4
2020	$91.1	$90.8	$94.8	$94.3
2021	$96.0	$94.7	$100.1	$99.1
2022	$99.5	$99.0	$103.6	$102.6
2023	$104.3	$102.9	$109.5	$105.3
2024	$105.4	$105.0	$112.6	$106.3
2025	$108.5	$108.2	$116.5	$112.1
2026	$113.3	$112.8	$119.8	$116.9
2027	$117.5	$116.2	$125.4	$118.1

ENERGY MIX
BASE CASE PORTFOLIO - LOW GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	9,103	10,863	1,588	1,510	32,370
2013	9,324	10,258	9,184	2,102	2,018	32,886
2014	9,270	10,443	8,534	3,057	2,580	33,884
2015	9,270	11,295	7,453	3,487	3,193	34,697
2016	9,298	10,556	8,692	3,586	3,835	35,966
2017	9,269	10,758	9,174	3,662	4,455	37,318
2018	9,270	10,326	10,285	3,718	5,039	38,638
2019	9,270	8,266	12,807	4,016	5,605	39,964
2020	9,315	8,130	13,247	4,102	6,192	40,987
2021	9,261	7,612	13,795	4,849	6,565	42,082
2022	9,270	8,025	14,071	5,281	6,709	43,358
2023	9,270	7,849	14,969	5,638	6,889	44,615
2024	9,297	8,052	15,414	6,025	7,082	45,869
2025	9,275	7,882	16,320	6,389	7,267	47,132
2026	9,270	7,483	17,490	6,711	7,450	48,405
2027	9,270	7,458	18,529	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	28.1%	33.6%	4.9%	4.7%	100.0%
2013	28.4%	31.2%	27.9%	6.4%	6.1%	100.0%
2014	27.4%	30.8%	25.2%	9.0%	7.6%	100.0%
2015	26.7%	32.6%	21.5%	10.0%	9.2%	100.0%
2016	25.9%	29.3%	24.2%	10.0%	10.7%	100.0%
2017	24.8%	28.8%	24.6%	9.8%	11.9%	100.0%
2018	24.0%	26.7%	26.6%	9.6%	13.0%	100.0%
2019	23.2%	20.7%	32.0%	10.0%	14.0%	100.0%
2020	22.7%	19.8%	32.3%	10.0%	15.1%	100.0%
2021	22.0%	18.1%	32.8%	11.5%	15.6%	100.0%
2022	21.4%	18.5%	32.5%	12.2%	15.5%	100.0%
2023	20.8%	17.6%	33.6%	12.6%	15.4%	100.0%
2024	20.3%	17.6%	33.6%	13.1%	15.4%	100.0%
2025	19.7%	16.7%	34.6%	13.6%	15.4%	100.0%
2026	19.2%	15.5%	36.1%	13.9%	15.4%	100.0%
2027	18.7%	15.0%	37.3%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

FOUR CORNERS CONTINGENCY PORTFOLIO - LOW GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	8,865	11,101	1,588	1,510	32,370
2013	9,324	9,516	9,926	2,102	2,018	32,886
2014	9,270	9,842	9,134	3,057	2,580	33,884
2015	9,270	7,197	11,551	3,487	3,193	34,697
2016	9,298	6,635	12,613	3,586	3,835	35,966
2017	9,269	6,463	13,469	3,662	4,455	37,318
2018	9,270	5,387	15,224	3,718	5,039	38,638
2019	9,270	3,601	17,472	4,016	5,605	39,965
2020	9,315	3,489	17,888	4,102	6,192	40,987
2021	9,261	3,087	18,320	4,849	6,565	42,082
2022	9,270	3,355	18,741	5,281	6,709	43,358
2023	9,270	3,479	19,339	5,638	6,889	44,615
2024	9,297	3,624	19,841	6,025	7,082	45,868
2025	9,275	3,137	21,064	6,389	7,267	47,132
2026	9,270	2,871	22,103	6,711	7,450	48,405
2027	9,270	2,836	23,150	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	27.4%	34.3%	4.9%	4.7%	100.0%
2013	28.4%	28.9%	30.2%	6.4%	6.1%	100.0%
2014	27.4%	29.0%	27.0%	9.0%	7.6%	100.0%
2015	26.7%	20.7%	33.3%	10.0%	9.2%	100.0%
2016	25.9%	18.4%	35.1%	10.0%	10.7%	100.0%
2017	24.8%	17.3%	36.1%	9.8%	11.9%	100.0%
2018	24.0%	13.9%	39.4%	9.6%	13.0%	100.0%
2019	23.2%	9.0%	43.7%	10.0%	14.0%	100.0%
2020	22.7%	8.5%	43.6%	10.0%	15.1%	100.0%
2021	22.0%	7.3%	43.5%	11.5%	15.6%	100.0%
2022	21.4%	7.7%	43.2%	12.2%	15.5%	100.0%
2023	20.8%	7.8%	43.3%	12.6%	15.4%	100.0%
2024	20.3%	7.9%	43.3%	13.1%	15.4%	100.0%
2025	19.7%	6.7%	44.7%	13.6%	15.4%	100.0%
2026	19.2%	5.9%	45.7%	13.9%	15.4%	100.0%
2027	18.7%	5.7%	46.6%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

ENHANCED RENEWABLE PORTFOLIO - LOW GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	9,103	10,863	1,588	1,510	32,370
2013	9,324	10,258	9,184	2,102	2,018	32,886
2014	9,270	10,443	8,534	3,057	2,580	33,884
2015	9,270	11,295	7,453	3,487	3,193	34,697
2016	9,298	10,556	8,692	3,586	3,835	35,966
2017	9,269	10,421	8,952	4,220	4,455	37,318
2018	9,270	9,803	9,577	4,949	5,039	38,638
2019	9,270	7,689	11,595	5,806	5,605	39,964
2020	9,315	7,486	11,620	6,373	6,192	40,987
2021	9,261	7,104	11,758	7,393	6,565	42,082
2022	9,270	7,421	11,655	8,302	6,709	43,358
2023	9,270	7,162	12,356	8,938	6,889	44,615
2024	9,297	7,189	12,294	10,007	7,082	45,868
2025	9,275	7,606	12,064	10,920	7,267	47,132
2026	9,270	7,015	13,427	11,243	7,450	48,405
2027	9,270	6,782	14,673	11,317	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	28.1%	33.6%	4.9%	4.7%	100.0%
2013	28.4%	31.2%	27.9%	6.4%	6.1%	100.0%
2014	27.4%	30.8%	25.2%	9.0%	7.6%	100.0%
2015	26.7%	32.6%	21.5%	10.0%	9.2%	100.0%
2016	25.9%	29.3%	24.2%	10.0%	10.7%	100.0%
2017	24.8%	27.9%	24.0%	11.3%	11.9%	100.0%
2018	24.0%	25.4%	24.8%	12.8%	13.0%	100.0%
2019	23.2%	19.2%	29.0%	14.5%	14.0%	100.0%
2020	22.7%	18.3%	28.4%	15.5%	15.1%	100.0%
2021	22.0%	16.9%	27.9%	17.6%	15.6%	100.0%
2022	21.4%	17.1%	26.9%	19.1%	15.5%	100.0%
2023	20.8%	16.1%	27.7%	20.0%	15.4%	100.0%
2024	20.3%	15.7%	26.8%	21.8%	15.4%	100.0%
2025	19.7%	16.1%	25.6%	23.2%	15.4%	100.0%
2026	19.2%	14.5%	27.7%	23.2%	15.4%	100.0%
2027	18.7%	13.7%	29.5%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
COAL RETIREMENT PORTFOLIO - LOW GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	8,865	11,101	1,588	1,510	32,370
2013	9,324	9,516	9,926	2,102	2,018	32,886
2014	9,270	9,842	9,134	3,057	2,580	33,884
2015	9,270	7,197	11,551	3,487	3,193	34,697
2016	9,298	6,635	12,613	3,586	3,835	35,966
2017	9,269	6,219	12,855	4,520	4,455	37,318
2018	9,270	5,172	14,303	4,855	5,039	38,638
2019	9,270	3,304	16,354	5,432	5,605	39,965
2020	9,315	1,609	17,704	6,166	6,192	40,987
2021	9,261	977	18,372	6,908	6,565	42,082
2022	9,270	1,026	19,012	7,340	6,709	43,358
2023	9,270	1,069	19,690	7,697	6,889	44,615
2024	9,297	1,151	20,250	8,089	7,082	45,868
2025	9,275	0	21,220	9,370	7,267	47,132
2026	9,270	0	21,992	9,693	7,450	48,405
2027	9,270	0	23,005	9,767	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	27.4%	34.3%	4.9%	4.7%	100.0%
2013	28.4%	28.9%	30.2%	6.4%	6.1%	100.0%
2014	27.4%	29.0%	27.0%	9.0%	7.6%	100.0%
2015	26.7%	20.7%	33.3%	10.0%	9.2%	100.0%
2016	25.9%	18.4%	35.1%	10.0%	10.7%	100.0%
2017	24.8%	16.7%	34.4%	12.1%	11.9%	100.0%
2018	24.0%	13.4%	37.0%	12.6%	13.0%	100.0%
2019	23.2%	8.3%	40.9%	13.6%	14.0%	100.0%
2020	22.7%	3.9%	43.2%	15.0%	15.1%	100.0%
2021	22.0%	2.3%	43.7%	16.4%	15.6%	100.0%
2022	21.4%	2.4%	43.8%	16.9%	15.5%	100.0%
2023	20.8%	2.4%	44.1%	17.3%	15.4%	100.0%
2024	20.3%	2.5%	44.1%	17.6%	15.4%	100.0%
2025	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Annual Natural Gas Burns
Low Gas Price Sensitivity
(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	80.5	82.3	80.5	82.3
2013	68.2	73.8	68.2	73.8
2014	63.4	68.2	63.4	68.2
2015	55.6	86.1	55.6	86.1
2016	64.3	93.6	64.3	93.6
2017	67.9	100.5	66.4	96.1
2018	75.8	112.3	70.8	105.8
2019	91.9	126.4	84.7	118.9
2020	95.4	130.2	85.3	131.1
2021	100.3	134.1	87.1	135.8
2022	105.4	140.6	89.5	143.1
2023	112.5	145.3	95.2	148.2
2024	116.3	150.0	96.2	153.3
2025	121.3	156.9	96.3	161.0
2026	130.3	165.0	104.9	167.2
2027	138.3	173.2	113.8	174.8

Annual CO2 Emissions
Low Gas Price Sensitivity
(Metric Tons)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	13,438,374	13,567,879	13,438,374	13,567,879
2013	13,151,628	13,799,932	13,151,628	13,799,932
2014	13,137,166	13,806,286	13,137,166	13,806,286
2015	13,476,808	11,680,065	13,476,808	11,680,065
2016	13,397,089	11,642,277	13,397,089	11,642,277
2017	13,908,642	11,935,140	13,499,460	11,460,545
2018	13,860,823	11,609,375	13,081,250	11,041,913
2019	12,859,576	10,797,715	11,856,456	10,070,282
2020	12,886,888	10,829,427	11,678,911	9,099,044
2021	12,632,062	10,599,700	11,396,375	8,644,977
2022	13,124,657	11,055,077	11,671,877	8,942,200
2023	13,409,428	11,440,093	11,798,301	9,272,498
2024	13,781,043	11,858,688	11,847,344	9,642,185
2025	13,871,545	11,755,128	12,202,456	8,800,464
2026	13,964,296	11,915,886	12,125,815	9,143,650
2027	14,394,250	12,350,433	12,400,997	9,564,800

Annual Water Use
Low Gas Price Sensitivity
(Acre-Feet)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	49,902	49,815	49,902	49,815
2013	50,975	50,820	50,975	50,820
2014	52,963	52,687	52,963	52,687
2015	53,223	51,995	53,223	51,995
2016	54,143	51,726	54,143	51,726
2017	55,898	51,931	54,941	50,924
2018	55,756	50,784	54,865	49,609
2019	53,578	47,452	52,174	46,080
2020	51,790	45,376	50,560	41,095
2021	51,280	44,974	50,228	38,986
2022	52,332	45,864	51,252	39,160
2023	52,541	46,140	51,207	39,238
2024	53,007	46,568	52,026	39,482
2025	51,614	44,889	52,369	36,323
2026	51,042	44,461	50,997	36,462
2027	51,570	44,825	50,806	36,777

Annual Revenue Requirements
High Gas Price Sensitivity
($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,105.5	$2,133.6	$2,105.5	$2,145.9
2013	$2,290.2	$2,233.1	$2,290.2	$2,245.0
2014	$2,482.6	$2,405.5	$2,482.6	$2,417.6
2015	$2,575.2	$2,677.3	$2,575.2	$2,695.9
2016	$2,743.0	$2,917.5	$2,743.0	$2,941.6
2017	$2,938.9	$3,102.0	$2,946.4	$3,125.5
2018	$3,063.0	$3,216.3	$3,113.8	$3,253.9
2019	$3,194.6	$3,352.7	$3,270.6	$3,356.7
2020	$3,344.7	$3,526.3	$3,424.2	$3,663.7
2021	$3,557.9	$3,729.8	$3,651.2	$3,889.7
2022	$3,821.9	$4,018.6	$3,914.6	$4,148.8
2023	$4,134.3	$4,302.6	$4,252.0	$4,396.5
2024	$4,301.1	$4,512.4	$4,490.3	$4,568.9
2025	$4,530.0	$4;766.6	$4,772.2	$5,096.6
2026	$4,872.6	$5,099.8	$5,057.9	$5,446.5
2027	$5,196.9	$5,406.5	$5,415.7	$5,673.9
2028	$5,468.8	$5,699.3	$5,641.4	$5,943.3
2029	$5,796.6	$6,016.0	$5,901.4	$6,267.6
2030	$6,201.7	$6,395.1	$6,269.3	$6,618.6
2031	$6,508.9	$6,745.2	$6,556.7	$6,927.7
2032	$6,886.9	$7,127.4	$6,898.8	$7,284.9
2033	$7,286.6	$7,489.4	$7,244.0	$7,632.1
2034	$7,707.6	$7,913.9	$7,624.9	$7,995.2
2035	$8,206.4	$8,360.2	$8,068.3	$8,398.5
2036	$8,689.8	$8,833.5	$8,545.7	$8,860.6
2037	$9,080.8	$9,232.4	$8,896.0	$9,258.9
2038	$9,630.8	$9,653.3	$9,406.8	$9,666.0
2039	$10,235.9	$10,054.7	$10,007.1	$10,087.9
2040	$10,882.9	$10,565.7	$10,683.5	$10,616.7
2041	$11,258.7	$10,947.1	$11,045.0	$11,002.6
CPW (2012-2027)	$27,884.8	$28,889.3	$28,406.8	$29,549.1
CPW (2012-2041)	$46,321.4	$47,643.9	$46,756.2	$48,627.6
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
High Gas Price Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$68.3	$69.2	$68.3	$69.6
2013	$75.0	$73.1	$75.0	$73.5
2014	$80.4	$77.9	$80.4	$78.3
2015	$83.3	$86.6	$83.3	$87.2
2016	$87.2	$92.8	$87.2	$93.5
2017	$91.6	$96.7	$91.8	$97.4
2018	$93.5	$98.2	$95.1	$99.4
2019	$95.4	$100.2	$97.7	$100.3
2020	$98.0	$103.3	$100.3	$107.4
2021	$102.7	$107.6	$105.4	$112.3
2022	$107.2	$112.7	$109.8	$116.4
2023	$113.0	$117.6	$116.2	$120.2
2024	$114.7	$120.3	$119.7	$121.8
2025	$117.9	$124.1	$124.2	$132.6
2026	$123.6	$129.4	$128.3	$138.2
2027	$128.5	$133.6	$133.9	$140.3

ENERGY MIX
BASE CASE PORTFOLIO - HIGH GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,888	7,077	1,588	1,510	32,370
2013	9,324	13,628	5,814	2,102	2,018	32,886
2014	9,270	12,979	5,998	3,057	2,580	33,884
2015	9,270	13,457	5,291	3,487	3,193	34,697
2016	9,298	13,249	5,999	3,586	3,835	35,966
2017	9,269	13,074	6,857	3,662	4,455	37,318
2018	9,270	13,164	7,448	3,718	5,039	38,638
2019	9,270	13,906	7,167	4,016	5,605	39,964
2020	9,315	14,003	7,374	4,102	6,192	40,987
2021	9,261	13,864	7,543	4,849	6,565	42,082
2022	9,270	14,060	8,037	5,281	6,709	43,358
2023	9,270	13,471	9,347	5,638	6,889	44,615
2024	9,297	13,606	9,859	6,025	7,082	45,868
2025	9,275	14,113	10,089	6,389	7,267	47,132
2026	9,270	14,156	10,817	6,711	7,450	48,405
2027	9,270	14,241	11,745	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	39.8%	21.9%	4.9%	4.7%	100.0%
2013	28.4%	41.4%	17.7%	6.4%	6.1%	100.0%
2014	27.4%	38.3%	17.7%	9.0%	7.6%	100.0%
2015	26.7%	38.8%	15.2%	10.0%	9.2%	100.0%
2016	25.9%	36.8%	16.7%	10.0%	10.7%	100.0%
2017	24.8%	35.0%	18.4%	9.8%	11.9%	100.0%
2018	24.0%	34.1%	19.3%	9.6%	13.0%	100.0%
2019	23.2%	34.8%	17.9%	10.0%	14.0%	100.0%
2020	22.7%	34.2%	18.0%	10.0%	15.1%	100.0%
2021	22.0%	32.9%	17.9%	11.5%	15.6%	100.0%
2022	21.4%	32.4%	18.5%	12.2%	15.5%	100.0%
2023	20.8%	30.2%	21.0%	12.6%	15.4%	100.0%
2024	20.3%	29.7%	21.5%	13.1%	15.4%	100.0%
2025	19.7%	29.9%	21.4%	13.6%	15.4%	100.0%
2026	19.2%	29.2%	22.3%	13.9%	15.4%	100.0%
2027	18.7%	28.7%	23.6%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
FOUR CORNERS CONTINGENCY PORTFOLIO - HIGH GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,597	7,368	1,588	1,510	32,370
2013	9,324	12,630	6,812	2,102	2,018	32,886
2014	9,270	12,373	6,604	3,057	2,580	33,884
2015	9,270	8,695	10,053	3,487	3,193	34,697
2016	9,298	7,921	11,327	3,586	3,835	35,966
2017	9,269	7,347	12,584	3,662	4,455	37,318
2018	9,270	7,547	13,064	3,718	5,039	38,638
2019	9,270	7,644	13,429	4,016	5,605	39,965
2020	9,315	7,643	13,734	4,102	6,192	40,987
2021	9,261	7,533	13,874	4,849	6,565	42,082
2022	9,270	7,572	14,525	5,281	6,709	43,358
2023	9,270	7,533	15,285	5,638	6,889	44,615
2024	9,297	7,675	15,790	6,025	7,082	45,868
2025	9,275	7,355	16,846	6,389	7,267	47,132
2026	9,270	7,324	17,649	6,711	7,450	48,405
2027	9,270	7,409	18,577	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.9%	22.8%	4.9%	4.7%	100.0%
2013	28.4%	38.4%	20.7%	6.4%	6.1%	100.0%
2014	27.4%	36.5%	19.5%	9.0%	7.6%	100.0%
2015	26.7%	25.1%	29.0%	10.0%	9.2%	100.0%
2016	25.9%	22.0%	31.5%	10.0%	10.7%	100.0%
2017	24.8%	19.7%	33.7%	9.8%	11.9%	100.0%
2018	24.0%	19.5%	33.8%	9.6%	13.0%	100.0%
2019	23.2%	19.1%	33.6%	10.0%	14.0%	100.0%
2020	22.7%	18.6%	33.5%	10.0%	15.1%	100.0%
2021	22.0%	17.9%	33.0%	11.5%	15.6%	100.0%
2022	21.4%	17.5%	33.5%	12.2%	15.5%	100.0%
2023	20.8%	16.9%	34.3%	12.6%	15.4%	100.0%
2024	20.3%	16.7%	34.4%	13.1%	15.4%	100.0%
2025	19.7%	15.6%	35.7%	13.6%	15.4%	100.0%
2026	19.2%	15.1%	36.5%	13.9%	15.4%	100.0%
2027	18.7%	14.9%	37.4%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

ENHANCED RENEWABLE PORTFOLIO - HIGH GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,888	7,077	1,588	1,510	32,370
2013	9,324	13,628	5,814	2,102	2,018	32,886
2014	9,270	12,979	5,998	3,057	2,580	33,884
2015	9,270	13,457	5,291	3,487	3,193	34,697
2016	9,298	13,249	5,999	3,586	3,835	35,966
2017	9,269	12,881	6,493	4,220	4,455	37,318
2018	9,270	12,740	6,639	4,949	5,039	38,638
2019	9,270	13,120	6,164	5,806	5,605	39,965
2020	9,315	12,972	6,134	6,373	6,192	40,987
2021	9,261	12,585	6,277	7,393	6,565	42,082
2022	9,270	12,628	6,448	8,302	6,709	43,358
2023	9,270	12,024	7,494	8,938	6,889	44,615
2024	9,297	11,890	7,594	10,007	7,082	45,868
2025	9,275	12,273	7,396	10,920	7,267	47,132
2026	9,270	12,268	8,174	11,243	7,450	48,405
2027	9,270	12,433	9,022	11,317	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	39.8%	21.9%	4.9%	4.7%	100.0%
2013	28.4%	41.4%	17.7%	6.4%	6.1%	100.0%
2014	27.4%	38.3%	17.7%	9.0%	7.6%	100.0%
2015	26.7%	38.8%	15.2%	10.0%	9.2%	100.0%
2016	25.9%	36.8%	16.7%	10.0%	10.7%	100.0%
2017	24.8%	34.5%	17.4%	11.3%	11.9%	100.0%
2018	24.0%	33.0%	17.2%	12.8%	13.0%	100.0%
2019	23.2%	32.8%	15.4%	14.5%	14.0%	100.0%
2020	22.7%	31.6%	15.0%	15.5%	15.1%	100.0%
2021	22.0%	29.9%	14.9%	17.6%	15.6%	100.0%
2022	21.4%	29.1%	14.9%	19.1%	15.5%	100.0%
2023	20.8%	27.0%	16.8%	20.0%	15.4%	100.0%
2024	20.3%	25.9%	16.6%	21.8%	15.4%	100.0%
2025	19.7%	26.0%	15.7%	23.2%	15.4%	100.0%
2026	19.2%	25.3%	16.9%	23.2%	15.4%	100.0%
2027	18.7%	25.0%	18.2%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
COAL RETIREMENT PORTFOLIO - HIGH GAS PRICE SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,597	7,368	1,588	1,510	32,370
2013	9,324	12,630	6,812	2,102	2,018	32,886
2014	9,270	12,373	6,604	3,057	2,580	33,884
2015	9,270	8,695	10,053	3,487	3,193	34,697
2016	9,298	7,921	11,327	3,586	3,835	35,966
2017	9,269	7,217	11,857	4,520	4,455	37,318
2018	9,270	7,376	12,099	4,855	5,039	38,638
2019	9,270	7,415	12,243	5,432	5,605	39,965
2020	9,315	4,997	14,316	6,166	6,192	40,987
2021	9,261	4,915	14,433	6,908	6,565	42,082
2022	9,270	4,959	15,079	7,340	6,709	43,358
2023	9,270	4,883	15,876	7,697	6,889	44,615
2024	9,297	4,914	16,487	8,089	7,082	45,868
2025	9,275	0	21,220	9,370	7,267	47,132
2026	9,270	0	21,992	9,693	7,450	48,405
2027	9,270	0	23,005	9,767	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.9%	22.8%	4.9%	4.7%	100.0%
2013	28.4%	38.4%	20.7%	6.4%	6.1%	100.0%
2014	27.4%	36.5%	19.5%	9.0%	7.6%	100.0%
2015	26.7%	25.1%	29.0%	10.0%	9.2%	100.0%
2016	25.9%	22.0%	31.5%	10.0%	10.7%	100.0%
2017	24.8%	19.3%	31.8%	12.1%	11.9%	100.0%
2018	24.0%	19.1%	31.3%	12.6%	13.0%	100.0%
2019	23.2%	18.6%	30.6%	13.6%	14.0%	100.0%
2020	22.7%	12.2%	34.9%	15.0%	15.1%	100.0%
2021	22.0%	11.7%	34.3%	16.4%	15.6%	100.0%
2022	21.4%	11.4%	34.8%	16.9%	15.5%	100.0%
2023	20.8%	10.9%	35.6%	17.3%	15.4%	100.0%
2024	20.3%	10.7%	35.9%	17.6%	15.4%	100.0%
2025	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Annual Natural Gas Burns
High Gas Price Sensitivity
(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	53.4	55.6	53.4	55.6
2013	44.0	51.4	44.0	51.4
2014	45.5	50.0	45.5	50.0
2015	40.2	75.8	40.2	75.8
2016	45.6	84.8	45.6	84.8
2017	52.2	94.7	49.5	89.4
2018	57.1	98.9	51.0	91.9
2019	54.5	100.7	47.6	92.7
2020	56.8	103.8	48.5	108.9
2021	58.7	105.1	50.8	109.0
2022	63.6	112.0	52.8	114.9
2023	74.1	118.1	61.4	121.2
2024	78.4	122.6	63.5	126.3
2025	78.6	128.3	63.7	160.9
2026	84.3	134.6	68.3	167.0
2027	91.5	141.5	74.1	174.7

Annual CO2 Emissions
High Gas Price Sensitivity
(Metric Tons)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	15,625,177	15,740,954	15,625,177	15,740,954
2013	15,065,057	15,574,419	15,065,057	15,574,419
2014	14,547,551	15,244,034	14,547,551	15,244,034
2015	14,680,927	12,535,756	14,680,927	12,535,756
2016	14,864,154	12,376,838	14,864,154	12,376,838
2017	15,152,745	12,449,091	14,829,942	12,037,198
2018	15,424,746	12,882,392	14,712,990	12,336,585
2019	15,980,843	13,134,311	14,877,669	12,444,028
2020	16,152,517	13,254,318	14,740,798	11,009,242
2021	16,109,993	13,227,838	14,467,718	10,907,247
2022	16,499,985	13,544,960	14,605,152	11,219,098
2023	16,590,460	13,831,925	14,574,701	11,490,372
2024	16,910,956	14,229,240	14,524,507	11,814,988
2025	17,343,742	14,231,203	14,847,279	8,791,714
2026	17,699,596	14,537,074	15,095,057	9,132,177
2027	18,191,626	15,015,645	15,587,560	9,557,376

Annual Water Use
High Gas Price Sensitivity
(Acre-Feet)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	53,883	53,815	53,883	53,815
2013	54,366	54,070	54,366	54,070
2014	55,464	55,257	55,464	55,257
2015	55,257	53,672	55,257	53,672
2016	56,354	53,148	56,354	53,148
2017	57,507	52,950	56,759	52,074
2018	58,040	53,388	57,323	52,270
2019	58,698	53,575	57,138	52,180
2020	58,215	52,159	56,631	46,457
2021	58,912	52,674	56,859	46,082
2022	59,601	53,222	57,548	46,529
2023	59,520	53,150	57,160	46,323
2024	60,011	53,505	57,921	46,433
2025	59,792	52,218	58,063	36,195
2026	60,236	52,395	57,885	36,338
2027	60,944	52,969	58,628	36,647

Annual Revenue Requirements ($Millions)
Low CO2 Cost Sensitivity

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,040.0	$2,065.1	$2,040.0	$2,077.4
2013	$2,229.6	$2,158.4	$2,229.6	$2,170.3
2014	$2,412.2	$2,326.9	$2,412.2	$2,338.9
2015	$2,509.4	$2,550.5	$2,509.4	$2,569.1
2016	$2,664.2	$2,768.5	$2,664.2	$2,792.7
2017	$2,841.5	$2,927.8	$2,855.0	$2,961.7
2018	$2,953.1	$3,024.5	$3,015.4	$3,076.3
2019	$3,021.5	$3,128.5	$3,127.7	$3,159.1
2020	$3,151.7	$3,280.2	$3,270.0	$3,442.6
2021	$3,347.3	$3,465.7	$3,483.6	$3,656.2
2022	$3,573.6	$3,713.9	$3,724.5	$3,879.5
2023	$3,838.8	$3,956.5	$4,023.2	$4,088.4
2024	$3,970.6	$4,130.8	$4,244.4	$4,228.2
2025	$4,166.4	$4,349.8	$4,499.4	$4,721.8
2026	$4,439.7	$4,615.9	$4,726.0	$5,013.7
2027	$4,651.4	$4,812.6	$4,981.2	$5,139.4
2028	$4,818.6	$5,003.0	$5,109.4	$5,315.9
2029	$5,005.0	$5,186.4	$5,239.9	$5,515.5
2030	$5,260.1	$5,417.8	$5,467.1	$5,728.4
2031	$5,473.6	$5,676.2	$5,666.9	$5,958.2
2032	$5,738.8	$5,949.7	$5,907.7	$6,217.8
2033	$6,028.9	$6,208.3	$6,156.2	$6,473.6
2034	$6,324.7	$6,512.0	$6,424.7	$6,734.7
2035	$6,687.9	$6,833.8	$6,743.0	$7,025.1
2036	$7,015.9	$7,154.2	$7,080.2	$7,353.8
2037	$7,329.3	$7,472.6	$7,357.4	$7,669.2
2038	$7,813.1	$7,831.7	$7,805.6	$8,008.5
2039	$8,327.8	$8,157.2	$8,319.6	$8,354.0
2040	$8,899.2	$8,581.9	$8,918.9	$8,796.0
2041	$9,214.5	$8,902.3	$9,222.9	$9,115.4
CPW (2012-2027)	$26,430.0	$27,032.5	$27,197.1	$27,842.1
CPW (2012-2041)	$41,740.3	$42,607.0	$42,833.9	$44,036.6
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
Low CO2 Cost Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$66.2	$67.0	$66.2	$67.4
2013	$73.0	$70.7	$73.0	$71.1
2014	$78.1	$75.3	$78.1	$75.7
2015	$81.2	$82.5	$81.2	$83.1
2016	$84.7	$88.0	$84.7	$88.8
2017	$88.6	$91.3	$89.0	$92.3
2018	$90.2	$92.4	$92.1	$93.9
2019	$90.3	$93.5	$93.4	$94.4
2020	$92.4	$96.1	$95.8	$100.9
2021	$96.6	$100.0	$100.5	$105.5
2022	$100.2	$104.2	$104.5	$108.8
2023	$104.9	$108.2	$110.0	$111.8
2024	$105.9	$110.2	$113.2	$112.8
2025	$108.4	$113.2	$117.1	$122.9
2026	$112.6	$117.1	$119.9	$127.2
2027	$115.0	$119.0	$123.1	$127.0

ENERGY MIX
BASE CASE PORTFOLIO - LOW CO2 COST SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,294	7,671	1,588	1,510	32,370
2013	9,324	13,154	6,288	2,102	2,018	32,886
2014	9,270	12,663	6,314	3,057	2,580	33,884
2015	9,270	13,213	5,535	3,487	3,193	34,697
2016	9,298	13,024	6,224	3,586	3,835	35,966
2017	9,269	12,987	6,944	3,662	4,455	37,318
2018	9,270	13,096	7,515	3,718	5,039	38,638
2019	9,270	13,869	7,204	4,016	5,605	39,964
2020	9,315	13,984	7,393	4,102	6,192	40,987
2021	9,261	13,854	7,554	4,849	6,565	42,082
2022	9,270	14,041	8,056	5,281	6,709	43,358
2023	9,270	13,461	9,358	5,638	6,889	44,615
2024	9,297	13,622	9,843	6,025	7,082	45,868
2025	9,275	14,151	10,050	6,389	7,267	47,132
2026	9,270	14,272	10,701	6,711	7,450	48,405
2027	9,270	14,427	11,559	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.0%	23.7%	4.9%	4.7%	100.0%
2013	28.4%	40.0%	19.1%	6.4%	6.1%	100.0%
2014	27.4%	37.4%	18.6%	9.0%	7.6%	100.0%
2015	26.7%	38.1%	16.0%	10.0%	9.2%	100.0%
2016	25.9%	36.2%	17.3%	10.0%	10.7%	100.0%
2017	24.8%	34.8%	18.6%	9.8%	11.9%	100.0%
2018	24.0%	33.9%	19.4%	9.6%	13.0%	100.0%
2019	23.2%	34.7%	18.0%	10.0%	14.0%	100.0%
2020	22.7%	34.1%	18.0%	10.0%	15.1%	100.0%
2021	22.0%	32.9%	17.9%	11.5%	15.6%	100.0%
2022	21.4%	32.4%	18.6%	12.2%	15.5%	100.0%
2023	20.8%	30.2%	21.0%	12.6%	15.4%	100.0%
2024	20.3%	29.7%	21.5%	13.1%	15.4%	100.0%
2025	19.7%	30.0%	21.3%	13.6%	15.4%	100.0%
2026	19.2%	29.5%	22.1%	13.9%	15.4%	100.0%
2027	18.7%	29.0%	23.3%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
FOUR CORNERS CONTINGENCY - LOW CO2 COST SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,977	7,988	1,588	1,510	32,370
2013	9,324	12,154	7,288	2,102	2,018	32,886
2014	9,270	12,024	6,953	3,057	2,580	33,884
2015	9,270	8,512	10,236	3,487	3,193	34,697
2016	9,298	7,771	11,477	3,586	3,835	35,966
2017	9,269	7,289	12,643	3,662	4,455	37,318
2018	9,270	7,528	13,083	3,718	5,039	38,638
2019	9,270	7,621	13,453	4,016	5,605	39,965
2020	9,315	7,636	13,741	4,102	6,192	40,987
2021	9,261	7,535	13,873	4,849	6,565	42,082
2022	9,270	7,569	14,528	5,281	6,709	43,358
2023	9,270	7,536	15,283	5,638	6,889	44,615
2024	9,297	7,723	15,742	6,025	7,082	45,868
2025	9,275	7,467	16,734	6,389	7,267	47,132
2026	9,270	7,518	17,455	6,711	7,450	48,405
2027	9,270	7,712	18,274	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	37.0%	24.7%	4.9%	4.7%	100.0%
2013	28.4%	37.0%	22.2%	6.4%	6.1%	100.0%
2014	27.4%	35.5%	20.5%	9.0%	7.6%	100.0%
2015	26.7%	24.5%	29.5%	10.0%	9.2%	100.0%
2016	25.9%	21.6%	31.9%	10.0%	10.7%	100.0%
2017	24.8%	19.5%	33.9%	9.8%	11.9%	100.0%
2018	24.0%	19.5%	33.9%	9.6%	13.0%	100.0%
2019	23.2%	19.1%	33.7%	10.0%	14.0%	100.0%
2020	22.7%	18.6%	33.5%	10.0%	15.1%	100.0%
2021	22.0%	17.9%	33.0%	11.5%	15.6%	100.0%
2022	21.4%	17.5%	33.5%	12.2%	15.5%	100.0%
2023	20.8%	16.9%	34.3%	12.6%	15.4%	100.0%
2024	20.3%	16.8%	34.3%	13.1%	15.4%	100.0%
2025	19.7%	15.8%	35.5%	13.6%	15.4%	100.0%
2026	19.2%	15.5%	36.1%	13.9%	15.4%	100.0%
2027	18.7%	15.5%	36.8%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
ENHANCED RENEWABLE PORTFOLIO - LOW CO2 COST SENSITIVITY

	ENERGY (GWH)							ENERGY MIX %					
	Nuclear	Coal	Gas	RE + DE Renew	EE	Total		Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,294	7,671	1,588	1,510	32,370	**2012**	28.8%	38.0%	23.7%	4.9%	4.7%	100.0%
2013	9,324	13,154	6,288	2,102	2,018	32,886	**2013**	28.4%	40.0%	19.1%	6.4%	6.1%	100.0%
2014	9,270	12,663	6,314	3,057	2,580	33,884	**2014**	27.4%	37.4%	18.6%	9.0%	7.6%	100.0%
2015	9,270	13,213	5,535	3,487	3,193	34,697	**2015**	26.7%	38.1%	16.0%	10.0%	9.2%	100.0%
2016	9,298	13,024	6,224	3,586	3,835	35,966	**2016**	25.9%	36.2%	17.3%	10.0%	10.7%	100.0%
2017	9,269	12,783	6,591	4,220	4,455	37,318	**2017**	24.8%	34.3%	17.7%	11.3%	11.9%	100.0%
2018	9,270	12,682	6,698	4,949	5,039	38,638	**2018**	24.0%	32.8%	17.3%	12.8%	13.0%	100.0%
2019	9,270	13,093	6,191	5,806	5,605	39,965	**2019**	23.2%	32.8%	15.5%	14.5%	14.0%	100.0%
2020	9,315	12,963	6,143	6,373	6,192	40,987	**2020**	22.7%	31.6%	15.0%	15.5%	15.1%	100.0%
2021	9,261	12,609	6,254	7,393	6,565	42,082	**2021**	22.0%	30.0%	14.9%	17.6%	15.6%	100.0%
2022	9,270	12,631	6,445	8,302	6,709	43,358	**2022**	21.4%	29.1%	14.9%	19.1%	15.5%	100.0%
2023	9,270	12,047	7,471	8,938	6,889	44,615	**2023**	20.8%	27.0%	16.7%	20.0%	15.4%	100.0%
2024	9,297	11,917	7,566	10,007	7,082	45,868	**2024**	20.3%	26.0%	16.5%	21.8%	15.4%	100.0%
2025	9,275	12,332	7,338	10,920	7,267	47,132	**2025**	19.7%	26.2%	15.6%	23.2%	15.4%	100.0%
2026	9,270	12,455	7,987	11,243	7,450	48,405	**2026**	19.2%	25.7%	16.5%	23.2%	15.4%	100.0%
2027	9,270	12,676	8,779	11,317	7,641	49,683	**2027**	18.7%	25.5%	17.7%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

COAL RETIREMENT PORTFOLIO - LOW CO2 COST SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,977	7,988	1,588	1,510	32,370
2013	9,324	12,154	7,288	2,102	2,018	32,886
2014	9,270	12,024	6,953	3,057	2,580	33,884
2015	9,270	8,512	10,236	3,487	3,193	34,697
2016	9,298	7,771	11,477	3,586	3,835	35,966
2017	9,269	7,153	11,921	4,520	4,455	37,318
2018	9,270	7,347	12,127	4,855	5,039	38,638
2019	9,270	7,375	12,283	5,432	5,605	39,965
2020	9,315	5,018	14,296	6,166	6,192	40,987
2021	9,261	4,970	14,379	6,908	6,565	42,082
2022	9,270	5,016	15,022	7,340	6,709	43,358
2023	9,270	4,949	15,811	7,697	6,889	44,615
2024	9,297	5,045	16,357	8,089	7,082	45,868
2025	9,275	0	21,220	9,370	7,267	47,132
2026	9,270	0	21,992	9,693	7,450	48,405
2027	9,270	0	23,005	9,767	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	37.0%	24.7%	4.9%	4.7%	100.0%
2013	28.4%	37.0%	22.2%	6.4%	6.1%	100.0%
2014	27.4%	35.5%	20.5%	9.0%	7.6%	100.0%
2015	26.7%	24.5%	29.5%	10.0%	9.2%	100.0%
2016	25.9%	21.6%	31.9%	10.0%	10.7%	100.0%
2017	24.8%	19.2%	31.9%	12.1%	11.9%	100.0%
2018	24.0%	19.0%	31.4%	12.6%	13.0%	100.0%
2019	23.2%	18.5%	30.7%	13.6%	14.0%	100.0%
2020	22.7%	12.2%	34.9%	15.0%	15.1%	100.0%
2021	22.0%	11.8%	34.2%	16.4%	15.6%	100.0%
2022	21.4%	11.6%	34.6%	16.9%	15.5%	100.0%
2023	20.8%	11.1%	35.4%	17.3%	15.4%	100.0%
2024	20.3%	11.0%	35.7%	17.6%	15.4%	100.0%
2025	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Annual Natural Gas Burns
Low CO2 Cost Sensitivity
(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	57.7	60.2	57.7	60.2
2013	47.2	54.8	47.2	54.8
2014	47.7	52.4	47.7	52.4
2015	41.9	77.2	41.9	77.2
2016	47.1	85.9	47.1	85.9
2017	52.8	95.2	50.2	89.9
2018	57.6	99.0	51.4	92.0
2019	55.2	101.7	48.0	93.4
2020	57.6	104.9	48.9	109.6
2021	59.8	106.4	51.0	109.6
2022	63.9	112.3	53.1	114.8
2023	74.4	118.3	61.5	121.1
2024	78.5	122.5	63.7	125.8
2025	78.7	128.0	63.7	160.9
2026	84.0	133.8	67.6	167.1
2027	90.8	140.1	73.2	174.7

Annual CO2 Emissions
Low CO2 Cost Sensitivity
(Metric Tons)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	15,313,185	15,415,395	15,313,185	15,415,395
2013	14,811,182	15,317,092	14,811,182	15,317,092
2014	14,379,059	15,053,149	14,379,059	15,053,149
2015	14,549,660	12,440,855	14,549,660	12,440,855
2016	14,745,803	12,299,340	14,745,803	12,299,340
2017	15,105,853	12,422,465	14,778,167	12,007,916
2018	15,391,178	12,872,886	14,682,654	12,320,753
2019	15,981,577	13,120,263	14,878,488	12,427,736
2020	16,160,853	13,255,670	14,752,275	11,027,204
2021	16,131,477	13,229,494	14,501,984	10,942,316
2022	16,512,417	13,556,352	14,631,996	11,269,796
2023	16,605,143	13,845,850	14,608,394	11,547,162
2024	16,948,348	14,272,789	14,570,190	11,913,092
2025	17,393,848	14,319,622	14,908,295	8,794,451
2026	17,794,691	14,681,674	15,234,319	9,140,038
2027	18,335,588	15,230,604	15,772,347	9,560,346

Annual Water Use
Low CO2 Cost Sensitivity
(Acre-Feet)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	53,365	53,261	53,365	53,261
2013	53,986	53,661	53,986	53,661
2014	55,258	55,017	55,258	55,017
2015	55,107	53,524	55,107	53,524
2016	56,243	53,042	56,243	53,042
2017	57,501	52,958	56,740	52,072
2018	58,037	53,423	57,315	52,288
2019	58,978	53,621	57,408	52,204
2020	58,344	52,225	56,754	46,578
2021	59,121	52,741	57,100	46,266
2022	59,723	53,337	57,688	46,759
2023	59,656	53,266	57,349	46,569
2024	60,263	53,711	58,160	46,816
2025	60,074	52,534	58,316	36,281
2026	60,563	52,888	58,313	36,418
2027	61,379	53,632	59,160	36,740

Annual Revenue Requirements
High CO2 Cost Sensitivity
($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,040.0	$2,065.1	$2,040.0	$2,077.4
2013	$2,229.6	$2,158.4	$2,229.6	$2,170.3
2014	$2,412.2	$2,326.9	$2,412.2	$2,338.9
2015	$2,509.4	$2,550.5	$2,509.4	$2,569.1
2016	$2,664.2	$2,768.5	$2,664.2	$2,792.7
2017	$2,841.5	$2,927.8	$2,855.0	$2,961.7
2018	$2,953.2	$3,024.5	$3,015.4	$3,076.3
2019	$3,139.8	$3,168.8	$3,224.2	$3,185.2
2020	$3,285.8	$3,330.7	$3,374.9	$3,434.9
2021	$3,497.5	$3,527.7	$3,594.2	$3,659.7
2022	$3,764.0	$3,808.9	$3,862.7	$3,909.9
2023	$4,056.3	$4,081.9	$4,189.7	$4,143.4
2024	$4,223.4	$4,288.4	$4,427.5	$4,310.9
2025	$4,475.7	$4,544.1	$4,702.9	$4,688.3
2026	$4,837.4	$4,891.4	$5,006.4	$5,036.8
2027	$5,195.8	$5,229.2	$5,413.5	$5,282.8
2028	$5,497.9	$5,544.8	$5,664.0	$5,579.8
2029	$5,858.4	$5,891.9	$5,984.9	$5,929.5
2030	$6,309.7	$6,313.8	$6,401.3	$6,311.2
2031	$6,633.5	$6,655.2	$6,682.8	$6,612.1
2032	$7,022.7	$7,039.5	$7,047.8	$6,959.3
2033	$7,437.9	$7,409.9	$7,417.4	$7,302.5
2034	$7,883.2	$7,840.7	$7,815.2	$7,662.2
2035	$8,361.2	$8,287.1	$8,267.1	$8,064.1
2036	$8,875.8	$8,784.9	$8,767.4	$8,524.8
2037	$9,409.1	$9,273.8	$9,242.9	$8,981.5
2038	$10,013.4	$9,796.8	$9,796.8	$9,461.6
2039	$10,514.8	$10,327.1	$10,300.3	$9,968.3
2040	$11,294.0	$10,977.1	$11,088.6	$10,595.5
2041	$11,820.8	$11,509.7	$11,583.1	$11,095.5
CPW (2012-2027)	$27,285.8	$27,534.3	$27,833.0	$27,957.7
CPW (2012-2041)	$46,163.0	$46,270.4	$46,656.4	$46,354.5
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
High CO2 Cost Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$66.2	$67.0	$66.2	$67.4
2013	$73.0	$70.7	$73.0	$71.1
2014	$78.1	$75.3	$78.1	$75.7
2015	$81.2	$82.5	$81.2	$83.1
2016	$84.7	$88.0	$84.7	$88.8
2017	$88.6	$91.3	$89.0	$92.3
2018	$90.2	$92.4	$92.1	$94.0
2019	$93.8	$94.7	$96.3	$95.1
2020	$96.3	$97.6	$98.9	$100.7
2021	$100.9	$101.8	$103.7	$105.6
2022	$105.6	$106.8	$108.4	$109.7
2023	$110.9	$111.6	$114.5	$113.3
2024	$112.6	$114.4	$118.1	$115.0
2025	$116.5	$118.3	$122.4	$122.0
2026	$122.7	$124.1	$127.0	$127.8
2027	$128.4	$129.3	$133.8	$130.6

APS 2012 INTEGRATED RESOURCE PLAN

ENERGY MIX

BASE CASE PORTFOLIO - HIGH CO2 COST SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,294	7,671	1,588	1,510	32,370
2013	9,324	13,154	6,288	2,102	2,018	32,886
2014	9,270	12,663	6,314	3,057	2,580	33,884
2015	9,270	13,213	5,535	3,487	3,193	34,697
2016	9,298	13,024	6,224	3,586	3,835	35,966
2017	9,269	12,987	6,944	3,662	4,455	37,318
2018	9,270	13,092	7,520	3,718	5,039	38,638
2019	9,270	10,871	10,202	4,016	5,605	39,964
2020	9,315	11,002	10,375	4,102	6,192	40,987
2021	9,261	10,656	10,752	4,849	6,565	42,082
2022	9,270	10,860	11,237	5,281	6,709	43,358
2023	9,270	10,228	12,591	5,638	6,889	44,615
2024	9,297	10,091	13,374	6,025	7,082	45,868
2025	9,275	9,556	14,645	6,389	7,267	47,132
2026	9,270	9,002	15,971	6,711	7,450	48,405
2027	9,270	8,914	17,073	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.0%	23.7%	4.9%	4.7%	100.0%
2013	28.4%	40.0%	19.1%	6.4%	6.1%	100.0%
2014	27.4%	37.4%	18.6%	9.0%	7.6%	100.0%
2015	26.7%	38.1%	16.0%	10.0%	9.2%	100.0%
2016	25.9%	36.2%	17.3%	10.0%	10.7%	100.0%
2017	24.8%	34.8%	18.6%	9.8%	11.9%	100.0%
2018	24.0%	33.9%	19.5%	9.6%	13.0%	100.0%
2019	23.2%	27.2%	25.5%	10.0%	14.0%	100.0%
2020	22.7%	26.8%	25.3%	10.0%	15.1%	100.0%
2021	22.0%	25.3%	25.5%	11.5%	15.6%	100.0%
2022	21.4%	25.0%	25.9%	12.2%	15.5%	100.0%
2023	20.8%	22.9%	28.2%	12.6%	15.4%	100.0%
2024	20.3%	22.0%	29.2%	13.1%	15.4%	100.0%
2025	19.7%	20.3%	31.1%	13.6%	15.4%	100.0%
2026	19.2%	18.6%	33.0%	13.9%	15.4%	100.0%
2027	18.7%	17.9%	34.4%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

APS 2012 INTEGRATED RESOURCE PLAN

ENERGY MIX

FOUR CORNERS CONTINGENCY PORTFOLIO - HIGH CO2 COST SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,977	7,988	1,588	1,510	32,370
2013	9,324	12,154	7,288	2,102	2,018	32,886
2014	9,270	12,024	6,953	3,057	2,580	33,884
2015	9,270	8,512	10,236	3,487	3,193	34,697
2016	9,298	7,771	11,477	3,586	3,835	35,966
2017	9,269	7,289	12,643	3,662	4,455	37,318
2018	9,270	7,523	13,088	3,718	5,039	38,638
2019	9,270	5,208	15,865	4,016	5,605	39,965
2020	9,315	5,244	16,133	4,102	6,192	40,987
2021	9,261	4,978	16,430	4,849	6,565	42,082
2022	9,270	5,145	16,952	5,281	6,709	43,358
2023	9,270	4,977	17,841	5,638	6,889	44,615
2024	9,297	4,948	18,517	6,025	7,082	45,868
2025	9,275	4,193	20,008	6,389	7,267	47,132
2026	9,270	3,788	21,185	6,711	7,450	48,405
2027	9,270	3,763	22,224	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	37.0%	24.7%	4.9%	4.7%	100.0%
2013	28.4%	37.0%	22.2%	6.4%	6.1%	100.0%
2014	27.4%	35.5%	20.5%	9.0%	7.6%	100.0%
2015	26.7%	24.5%	29.5%	10.0%	9.2%	100.0%
2016	25.9%	21.6%	31.9%	10.0%	10.7%	100.0%
2017	24.8%	19.5%	33.9%	9.8%	11.9%	100.0%
2018	24.0%	19.5%	33.9%	9.6%	13.0%	100.0%
2019	23.2%	13.0%	39.7%	10.0%	14.0%	100.0%
2020	22.7%	12.8%	39.4%	10.0%	15.1%	100.0%
2021	22.0%	11.8%	39.0%	11.5%	15.6%	100.0%
2022	21.4%	11.9%	39.1%	12.2%	15.5%	100.0%
2023	20.8%	11.2%	40.0%	12.6%	15.4%	100.0%
2024	20.3%	10.8%	40.4%	13.1%	15.4%	100.0%
2025	19.7%	8.9%	42.5%	13.6%	15.4%	100.0%
2026	19.2%	7.8%	43.8%	13.9%	15.4%	100.0%
2027	18.7%	7.6%	44.7%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

ENHANCED RENEWABLE PORTFOLIO - HIGH CO2 COST SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,294	7,671	1,588	1,510	32,370
2013	9,324	13,154	6,288	2,102	2,018	32,886
2014	9,270	12,663	6,314	3,057	2,580	33,884
2015	9,270	13,213	5,535	3,487	3,193	34,697
2016	9,298	13,024	6,224	3,586	3,835	35,966
2017	9,269	12,783	6,591	4,220	4,455	37,318
2018	9,270	12,676	6,704	4,949	5,039	38,638
2019	9,270	10,119	9,165	5,806	5,605	39,965
2020	9,315	10,077	9,030	6,373	6,192	40,987
2021	9,261	9,508	9,354	7,393	6,565	42,082
2022	9,270	9,635	9,441	8,302	6,709	43,358
2023	9,270	8,970	10,548	8,938	6,889	44,615
2024	9,297	8,808	10,675	10,007	7,082	45,868
2025	9,275	8,951	10,719	10,920	7,267	47,132
2026	9,270	8,299	12,143	11,243	7,450	48,405
2027	9,270	8,061	13,395	11,317	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.0%	23.7%	4.9%	4.7%	100.0%
2013	28.4%	40.0%	19.1%	6.4%	6.1%	100.0%
2014	27.4%	37.4%	18.6%	9.0%	7.6%	100.0%
2015	26.7%	38.1%	16.0%	10.0%	9.2%	100.0%
2016	25.9%	36.2%	17.3%	10.0%	10.7%	100.0%
2017	24.8%	34.3%	17.7%	11.3%	11.9%	100.0%
2018	24.0%	32.8%	17.4%	12.8%	13.0%	100.0%
2019	23.2%	25.3%	22.9%	14.5%	14.0%	100.0%
2020	22.7%	24.6%	22.0%	15.5%	15.1%	100.0%
2021	22.0%	22.6%	22.2%	17.6%	15.6%	100.0%
2022	21.4%	22.2%	21.8%	19.1%	15.5%	100.0%
2023	20.8%	20.1%	23.6%	20.0%	15.4%	100.0%
2024	20.3%	19.2%	23.3%	21.8%	15.4%	100.0%
2025	19.7%	19.0%	22.7%	23.2%	15.4%	100.0%
2026	19.2%	17.1%	25.1%	23.2%	15.4%	100.0%
2027	18.7%	16.2%	27.0%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

COAL RETIREMENT PORTFOLIO - HIGH CO2 COST SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,977	7,988	1,588	1,510	32,370
2013	9,324	12,154	7,288	2,102	2,018	32,886
2014	9,270	12,024	6,953	3,057	2,580	33,884
2015	9,270	8,512	10,236	3,487	3,193	34,697
2016	9,298	7,771	11,477	3,586	3,835	35,966
2017	9,269	7,153	11,921	4,520	4,455	37,318
2018	9,270	7,342	12,133	4,855	5,039	38,638
2019	9,270	4,945	14,712	5,432	5,605	39,965
2020	9,315	2,810	16,503	6,166	6,192	40,987
2021	9,261	2,319	17,029	6,908	6,565	42,082
2022	9,270	2,460	17,578	7,340	6,709	43,358
2023	9,270	2,282	18,477	7,697	6,889	44,615
2024	9,297	2,105	19,296	8,089	7,082	45,868
2025	9,275	0	21,220	9,370	7,267	47,132
2026	9,270	0	21,992	9,693	7,450	48,405
2027	9,270	0	23,005	9,767	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	37.0%	24.7%	4.9%	4.7%	100.0%
2013	28.4%	37.0%	22.2%	6.4%	6.1%	100.0%
2014	27.4%	35.5%	20.5%	9.0%	7.6%	100.0%
2015	26.7%	24.5%	29.5%	10.0%	9.2%	100.0%
2016	25.9%	21.6%	31.9%	10.0%	10.7%	100.0%
2017	24.8%	19.2%	31.9%	12.1%	11.9%	100.0%
2018	24.0%	19.0%	31.4%	12.6%	13.0%	100.0%
2019	23.2%	12.4%	36.8%	13.6%	14.0%	100.0%
2020	22.7%	6.9%	40.3%	15.0%	15.1%	100.0%
2021	22.0%	5.5%	40.5%	16.4%	15.6%	100.0%
2022	21.4%	5.7%	40.5%	16.9%	15.5%	100.0%
2023	20.8%	5.1%	41.4%	17.3%	15.4%	100.0%
2024	20.3%	4.6%	42.1%	17.6%	15.4%	100.0%
2025	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Annual Natural Gas Burns
High CO2 Cost Sensitivity
(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	57.7	60.2	57.7	60.2
2013	47.2	54.8	47.2	54.8
2014	47.7	52.4	47.7	52.4
2015	41.9	77.2	41.9	77.2
2016	47.1	85.9	47.1	85.9
2017	52.8	95.2	50.2	89.9
2018	57.7	99.1	51.5	92.1
2019	73.6	114.7	66.8	106.6
2020	74.7	116.7	66.2	120.3
2021	77.9	119.3	69.3	123.3
2022	84.2	126.7	72.4	130.4
2023	94.8	133.7	81.1	137.3
2024	100.9	139.6	83.4	144.6
2025	108.3	148.8	85.1	160.8
2026	118.2	158.0	94.1	167.0
2027	126.8	166.1	103.0	174.7

Annual CO2 Emissions
High CO2 Cost Sensitivity
(Metric Tons)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	15,313,185	15,415,395	15,313,185	15,415,395
2013	14,811,182	15,317,092	14,811,182	15,317,092
2014	14,379,059	15,053,149	14,379,059	15,053,149
2015	14,549,660	12,440,855	14,549,660	12,440,855
2016	14,745,803	12,299,340	14,745,803	12,299,340
2017	15,105,853	12,422,465	14,778,167	12,007,916
2018	15,388,223	12,869,345	14,679,453	12,317,251
2019	14,248,739	11,676,916	13,156,333	10,978,362
2020	14,447,984	11,809,911	13,069,309	9,709,131
2021	14,280,156	11,682,955	12,679,133	9,361,555
2022	14,658,760	12,063,058	12,845,563	9,705,233
2023	14,700,260	12,273,737	12,761,185	9,905,457
2024	14,891,071	12,598,692	12,714,835	10,151,204
2025	14,727,769	12,356,701	12,892,349	8,791,296
2026	14,732,659	12,431,920	12,781,750	9,131,905
2027	15,130,529	12,868,732	13,027,634	9,557,088

Annual Water Use
High CO2 Cost Sensitivity
(Acre-Feet)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	53,365	53,261	53,365	53,261
2013	53,986	53,661	53,986	53,661
2014	55,258	55,017	55,258	55,017
2015	55,107	53,524	55,107	53,524
2016	56,243	53,042	56,243	53,042
2017	57,501	52,958	56,740	52,072
2018	58,032	53,413	57,310	52,279
2019	56,009	50,437	54,451	48,994
2020	55,538	49,048	53,936	43,645
2021	56,037	49,308	53,866	42,584
2022	56,668	49,900	54,541	43,013
2023	56,335	49,513	53,926	42,497
2024	56,316	49,344	54,539	41,911
2025	54,521	46,780	54,375	36,196
2026	53,773	45,820	52,963	36,335
2027	54,113	45,988	52,906	36,644

Annual Revenue Requirements
Extended ITC-PTC Sensitivity
($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,040.0	$2,065.1	$2,040.0	$2,077.4
2013	$2,229.6	$2,158.4	$2,229.6	$2,170.3
2014	$2,412.2	$2,326.9	$2,412.2	$2,338.9
2015	$2,509.4	$2,550.5	$2,509.4	$2,569.1
2016	$2,664.2	$2,768.5	$2,664.2	$2,792.7
2017	$2,841.5	$2,927.8	$2,845.1	$2,948.6
2018	$2,953.1	$3,024.5	$2,992.6	$3,052.1
2019	$3,082.1	$3,144.6	$3,137.0	$3,144.6
2020	$3,220.7	$3,301.5	$3,276.2	$3,396.1
2021	$3,414.4	$3,481.0	$3,473.3	$3,600.7
2022	$3,659.8	$3,744.7	$3,718.3	$3,836.2
2023	$3,932.0	$3,994.0	$4,010.0	$4,050.5
2024	$4,080.2	$4,183.1	$4,226.1	$4,206.3
2025	$4,297.8	$4,408.4	$4,481.9	$4,618.5
2026	$4,620.8	$4,717.5	$4,753.3	$4,933.4
2027	$4,912.9	$4,989.9	$5,088.9	$5,124.2
2028	$5,157.6	$5,250.0	$5,291.2	$5,363.5
2029	$5,444.7	$5,538.3	$5,522.5	$5,656.6
2030	$5,823.8	$5,888.3	$5,873.1	$5,974.1
2031	$6,118.0	$6,202.9	$6,146.2	$6,248.8
2032	$6,462.2	$6,546.9	$6,462.4	$6,563.6
2033	$6,837.9	$6,878.7	$6,791.9	$6,874.1
2034	$7,228.8	$7,263.5	$7,144.8	$7,196.6
2035	$7,660.5	$7,662.0	$7,542.2	$7,556.1
2036	$8,103.6	$8,095.3	$7,982.0	$7,966.3
2037	$8,469.4	$8,439.9	$8,313.9	$8,313.7
2038	$8,902.6	$8,792.1	$8,717.1	$8,659.7
2039	$9,308.1	$9,137.3	$9,136.6	$9,018.2
2040	$9,887.1	$9,569.3	$9,743.0	$9,468.2
2041	$10,207.7	$9,895.4	$10,053.5	$9,800.5
CPW (2012-2027)	$26,822.9	$27,211.0	$27,200.4	$27,655.5
CPW (2012-2041)	$43,990.0	$44,385.8	$44,285.4	$44,807.6
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
Extended ITC-PTC Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$66.2	$67.0	$66.2	$67.4
2013	$73.0	$70.7	$73.0	$71.1
2014	$78.1	$75.3	$78.1	$75.7
2015	$81.2	$82.5	$81.2	$83.1
2016	$84.7	$88.0	$84.7	$88.8
2017	$88.6	$91.3	$88.7	$91.9
2018	$90.2	$92.4	$91.4	$93.2
2019	$92.1	$93.9	$93.7	$93.9
2020	$94.4	$96.7	$96.0	$99.5
2021	$98.5	$100.5	$100.2	$103.9
2022	$102.7	$105.0	$104.3	$107.6
2023	$107.5	$109.2	$109.6	$110.7
2024	$108.8	$111.6	$112.7	$112.2
2025	$111.9	$114.7	$116.6	$120.2
2026	$117.2	$119.7	$120.6	$125.2
2027	$121.4	$123.3	$125.8	$126.7

Annual Revenue Requirements
Externalities Sensitivity
($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,148.9	$2,174.6	$2,148.9	$2,186.9
2013	$2,347.6	$2,277.4	$2,347.6	$2,289.3
2014	$2,523.0	$2,449.8	$2,523.0	$2,461.9
2015	$2,611.1	$2,615.2	$2,611.1	$2,633.7
2016	$2,757.8	$2,802.9	$2,757.8	$2,827.0
2017	$2,928.4	$2,998.5	$2,940.2	$3,031.4
2018	$3,030.3	$3,098.6	$3,090.8	$3,148.9
2019	$3,164.6	$3,220.9	$3,251.9	$3,240.8
2020	$3,307.0	$3,380.1	$3,401.5	$3,499.1
2021	$3,515.9	$3,574.3	$3,618.5	$3,718.1
2022	$3,770.1	$3,847.0	$3,880.1	$3,962.5
2023	$4,054.6	$4,108.6	$4,191.8	$4,187.8
2024	$4,211.6	$4,305.2	$4,421.9	$4,343.6
2025	$4,438.6	$4,539.1	$4,699.7	$4,746.8
2026	$4,768.3	$4,855.3	$4,975.8	$5,077.2
2027	$5,087.2	$5,152.7	$5,336.0	$5,283.3
2028	$5,348.1	$5,428.8	$5,551.4	$5,538.3
2029	$5,637.6	$5,716.4	$5,788.9	$5,828.9
2030	$6,020.5	$6,074.1	$6,141.2	$6,147.9
2031	$6,318.3	$6,392.3	$6,411.0	$6,426.0
2032	$6,666.9	$6,739.5	$6,734.7	$6,743.5
2033	$7,039.6	$7,070.3	$7,064.4	$7,054.5
2034	$7,431.9	$7,456.1	$7,415.1	$7,382.6
2035	$7,864.4	$7,854.3	$7,813.5	$7,743.3
2036	$8,314.1	$8,293.0	$8,258.1	$8,155.6
2037	$8,687.1	$8,645.6	$8,595.7	$8,504.5
2038	$9,145.6	$9,018.0	$9,022.7	$8,866.9
2039	$9,561.1	$9,380.3	$9,455.0	$9,235.3
2040	$10,162.5	$9,845.2	$10,084.0	$9,714.6
2041	$10,496.3	$10,185.3	$10,407.8	$10,056.5
CPW (2012-2027)	$27,778.6	$28,066.9	$28,372.3	$28,591.4
CPW (2012-2041)	$45,461.8	$45,731.3	$46,138.2	$46,203.2
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
Externalities Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$69.7	$70.5	$69.7	$70.9
2013	$76.9	$74.6	$76.9	$75.0
2014	$81.7	$79.3	$81.7	$79.7
2015	$84.5	$84.6	$84.5	$85.2
2016	$87.7	$89.1	$87.7	$89.9
2017	$91.3	$93.5	$91.6	$94.5
2018	$92.5	$94.6	$94.4	$96.2
2019	$94.5	$96.2	$97.1	$96.8
2020	$96.9	$99.1	$99.7	$102.5
2021	$101.5	$103.2	$104.4	$107.3
2022	$105.8	$107.9	$108.8	$111.2
2023	$110.8	$112.3	$114.6	$114.5
2024	$112.3	$114.8	$117.9	$115.8
2025	$115.5	$118.1	$122.3	$123.5
2026	$121.0	$123.2	$126.2	$128.8
2027	$125.7	$127.4	$131.9	$130.6

ENERGY MIX
BASE CASE PORTFOLIO - EXTERNALITIES SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,535	8,431	1,588	1,510	32,370
2013	9,324	12,509	6,933	2,102	2,018	32,886
2014	9,270	12,162	6,815	3,057	2,580	33,884
2015	9,270	12,873	5,875	3,487	3,193	34,697
2016	9,298	12,698	6,550	3,586	3,835	35,966
2017	9,269	12,846	7,086	3,662	4,455	37,318
2018	9,270	12,948	7,663	3,718	5,039	38,638
2019	9,270	12,458	8,615	4,016	5,605	39,964
2020	9,315	12,596	8,781	4,102	6,192	40,987
2021	9,261	12,452	8,955	4,849	6,565	42,082
2022	9,270	12,740	9,357	5,281	6,709	43,358
2023	9,270	12,135	10,683	5,638	6,889	44,615
2024	9,297	12,085	11,380	6,025	7,082	45,868
2025	9,275	12,399	11,802	6,389	7,267	47,132
2026	9,270	12,205	12,768	6,711	7,450	48,405
2027	9,270	11,894	14,092	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	35.6%	26.0%	4.9%	4.7%	100.0%
2013	28.4%	38.0%	21.1%	6.4%	6.1%	100.0%
2014	27.4%	35.9%	20.1%	9.0%	7.6%	100.0%
2015	26.7%	37.1%	16.9%	10.0%	9.2%	100.0%
2016	25.9%	35.3%	18.2%	10.0%	10.7%	100.0%
2017	24.8%	34.4%	19.0%	9.8%	11.9%	100.0%
2018	24.0%	33.5%	19.8%	9.6%	13.0%	100.0%
2019	23.2%	31.2%	21.6%	10.0%	14.0%	100.0%
2020	22.7%	30.7%	21.4%	10.0%	15.1%	100.0%
2021	22.0%	29.6%	21.3%	11.5%	15.6%	100.0%
2022	21.4%	29.4%	21.6%	12.2%	15.5%	100.0%
2023	20.8%	27.2%	23.9%	12.6%	15.4%	100.0%
2024	20.3%	26.3%	24.8%	13.1%	15.4%	100.0%
2025	19.7%	26.3%	25.0%	13.6%	15.4%	100.0%
2026	19.2%	25.2%	26.4%	13.9%	15.4%	100.0%
2027	18.7%	23.9%	28.4%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

FOUR CORNERS CONTINGENCY PORTFOLIO - EXTERNALITIES SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,231	8,735	1,588	1,510	32,370
2013	9,324	11,646	7,796	2,102	2,018	32,886
2014	9,270	11,630	7,347	3,057	2,580	33,884
2015	9,270	8,408	10,340	3,487	3,193	34,697
2016	9,298	7,684	11,564	3,586	3,835	35,966
2017	9,269	7,271	12,661	3,662	4,455	37,318
2018	9,270	7,292	13,319	3,718	5,039	38,638
2019	9,270	5,996	15,077	4,016	5,605	39,965
2020	9,315	6,014	15,363	4,102	6,192	40,987
2021	9,261	5,883	15,524	4,849	6,565	42,082
2022	9,270	6,078	16,019	5,281	6,709	43,358
2023	9,270	6,072	16,747	5,638	6,889	44,615
2024	9,297	6,120	17,345	6,025	7,082	45,868
2025	9,275	5,639	18,562	6,389	7,267	47,132
2026	9,270	5,470	19,504	6,711	7,450	48,405
2027	9,270	5,295	20,691	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	34.7%	27.0%	4.9%	4.7%	100.0%
2013	28.4%	35.4%	23.7%	6.4%	6.1%	100.0%
2014	27.4%	34.3%	21.7%	9.0%	7.6%	100.0%
2015	26.7%	24.2%	29.8%	10.0%	9.2%	100.0%
2016	25.9%	21.4%	32.2%	10.0%	10.7%	100.0%
2017	24.8%	19.5%	33.9%	9.8%	11.9%	100.0%
2018	24.0%	18.9%	34.5%	9.6%	13.0%	100.0%
2019	23.2%	15.0%	37.7%	10.0%	14.0%	100.0%
2020	22.7%	14.7%	37.5%	10.0%	15.1%	100.0%
2021	22.0%	14.0%	36.9%	11.5%	15.6%	100.0%
2022	21.4%	14.0%	36.9%	12.2%	15.5%	100.0%
2023	20.8%	13.6%	37.5%	12.6%	15.4%	100.0%
2024	20.3%	13.3%	37.8%	13.1%	15.4%	100.0%
2025	19.7%	12.0%	39.4%	13.6%	15.4%	100.0%
2026	19.2%	11.3%	40.3%	13.9%	15.4%	100.0%
2027	18.7%	10.7%	41.6%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

ENHANCED RENEWABLE PORTFOLIO - EXTERNALITIES SENSITIVTY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,535	8,431	1,588	1,510	32,370
2013	9,324	12,509	6,933	2,102	2,018	32,886
2014	9,270	12,162	6,815	3,057	2,580	33,884
2015	9,270	12,873	5,875	3,487	3,193	34,697
2016	9,298	12,698	6,550	3,586	3,835	35,966
2017	9,269	12,652	6,722	4,220	4,455	37,318
2018	9,270	12,541	6,839	4,949	5,039	38,638
2019	9,270	11,533	7,751	5,806	5,605	39,965
2020	9,315	11,569	7,537	6,373	6,192	40,987
2021	9,261	11,192	7,671	7,393	6,565	42,082
2022	9,270	11,214	7,863	8,302	6,709	43,358
2023	9,270	10,637	8,881	8,938	6,889	44,615
2024	9,297	10,497	8,986	10,007	7,082	45,869
2025	9,275	10,881	8,788	10,920	7,267	47,132
2026	9,270	10,540	9,902	11,243	7,450	48,405
2027	9,270	10,356	11,099	11,317	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	35.6%	26.0%	4.9%	4.7%	100.0%
2013	28.4%	38.0%	21.1%	6.4%	6.1%	100.0%
2014	27.4%	35.9%	20.1%	9.0%	7.6%	100.0%
2015	26.7%	37.1%	16.9%	10.0%	9.2%	100.0%
2016	25.9%	35.3%	18.2%	10.0%	10.7%	100.0%
2017	24.8%	33.9%	18.0%	11.3%	11.9%	100.0%
2018	24.0%	32.5%	17.7%	12.8%	13.0%	100.0%
2019	23.2%	28.9%	19.4%	14.5%	14.0%	100.0%
2020	22.7%	28.2%	18.4%	15.5%	15.1%	100.0%
2021	22.0%	26.6%	18.2%	17.6%	15.6%	100.0%
2022	21.4%	25.9%	18.1%	19.1%	15.5%	100.0%
2023	20.8%	23.8%	19.9%	20.0%	15.4%	100.0%
2024	20.3%	22.9%	19.6%	21.8%	15.4%	100.0%
2025	19.7%	23.1%	18.6%	23.2%	15.4%	100.0%
2026	19.2%	21.8%	20.5%	23.2%	15.4%	100.0%
2027	18.7%	20.8%	22.3%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

COAL RETIREMENT PORTFOLIO - EXTERNALITIES SENSITIVITY

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	11,231	8,735	1,588	1,510	32,370
2013	9,324	11,646	7,796	2,102	2,018	32,886
2014	9,270	11,630	7,347	3,057	2,580	33,884
2015	9,270	8,408	10,340	3,487	3,193	34,697
2016	9,298	7,684	11,564	3,586	3,835	35,966
2017	9,269	7,105	11,969	4,520	4,455	37,318
2018	9,270	7,092	12,382	4,855	5,039	38,638
2019	9,270	5,684	13,974	5,432	5,605	39,965
2020	9,315	3,399	15,915	6,166	6,192	40,987
2021	9,261	3,069	16,279	6,908	6,565	42,082
2022	9,270	3,215	16,823	7,340	6,709	43,358
2023	9,270	3,150	17,609	7,697	6,889	44,615
2024	9,297	3,091	18,310	8,089	7,082	45,868
2025	9,275	0	21,220	9,370	7,267	47,132
2026	9,270	0	21,992	9,693	7,450	48,405
2027	9,270	0	23,005	9,767	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	34.7%	27.0%	4.9%	4.7%	100.0%
2013	28.4%	35.4%	23.7%	6.4%	6.1%	100.0%
2014	27.4%	34.3%	21.7%	9.0%	7.6%	100.0%
2015	26.7%	24.2%	29.8%	10.0%	9.2%	100.0%
2016	25.9%	21.4%	32.2%	10.0%	10.7%	100.0%
2017	24.8%	19.0%	32.1%	12.1%	11.9%	100.0%
2018	24.0%	18.4%	32.0%	12.6%	13.0%	100.0%
2019	23.2%	14.2%	35.0%	13.6%	14.0%	100.0%
2020	22.7%	8.3%	38.8%	15.0%	15.1%	100.0%
2021	22.0%	7.3%	38.7%	16.4%	15.6%	100.0%
2022	21.4%	7.4%	38.8%	16.9%	15.5%	100.0%
2023	20.8%	7.1%	39.5%	17.3%	15.4%	100.0%
2024	20.3%	6.7%	39.9%	17.6%	15.4%	100.0%
2025	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

Annual Natural Gas Burns
Externalities Sensitivity
(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	63.0	65.4	63.0	65.4
2013	51.8	58.3	51.8	58.3
2014	51.1	55.1	51.1	55.1
2015	44.1	77.7	44.1	77.7
2016	49.3	86.3	49.3	86.3
2017	53.6	94.9	50.9	89.9
2018	58.1	99.8	52.0	93.0
2019	63.2	110.0	57.8	102.5
2020	64.9	112.4	56.9	117.3
2021	66.7	114.1	58.8	119.4
2022	71.5	120.4	61.8	125.1
2023	81.9	126.2	69.8	131.3
2024	87.4	131.4	71.8	137.2
2025	88.8	138.0	72.0	160.7
2026	95.9	145.2	78.8	167.0
2027	106.0	154.2	87.0	174.6

Annual CO2 Emissions
Externalities Sensitivity
(Metric Tons)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	14,875,158	14,966,117	14,875,158	14,966,117
2013	14,492,550	15,037,121	14,492,550	15,037,121
2014	14,116,241	14,829,670	14,116,241	14,829,670
2015	14,367,078	12,376,430	14,367,078	12,376,430
2016	14,566,849	12,244,293	14,566,849	12,244,293
2017	14,992,394	12,403,130	14,671,130	11,973,395
2018	15,287,244	12,707,808	14,581,302	12,145,493
2019	15,143,834	12,118,697	13,933,594	11,383,886
2020	15,312,896	12,245,386	13,879,325	10,022,887
2021	15,265,621	12,200,878	13,593,003	9,760,890
2022	15,707,754	12,610,359	13,716,219	10,136,984
2023	15,779,737	12,915,280	13,702,094	10,413,209
2024	15,998,261	13,265,848	13,648,583	10,696,101
2025	16,309,995	13,168,117	13,974,579	8,789,483
2026	16,533,807	13,402,741	14,032,671	9,137,086
2027	16,803,440	13,738,039	14,327,564	9,558,370

Annual Water Use
Externalities Sensitivity
(Acre-Feet)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	52,689	52,568	52,689	52,568
2013	53,565	53,284	53,565	53,284
2014	54,791	54,660	54,791	54,660
2015	54,776	53,349	54,776	53,349
2016	55,865	52,882	55,865	52,882
2017	57,160	52,811	56,405	51,903
2018	57,606	52,865	56,891	51,747
2019	56,987	51,383	55,294	49,875
2020	56,379	49,951	54,771	44,251
2021	57,009	50,417	54,873	43,506
2022	57,776	51,117	55,484	43,996
2023	57,659	51,009	55,129	43,713
2024	57,988	51,264	55,952	43,728
2025	57,616	49,826	56,131	36,014
2026	57,773	49,840	55,590	36,157
2027	57,980	49,943	55,859	36,456

APS 2012 INTEGRATED RESOURCE PLAN

Annual Revenue Requirements

Low EE Cost Sensitivity

($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,040.0	$2,065.1	$2,040.0	$2,077.4
2013	$2,219.9	$2,148.7	$2,219.9	$2,160.6
2014	$2,387.9	$2,302.6	$2,387.9	$2,314.7
2015	$2,466.7	$2,507.8	$2,466.7	$2,526.4
2016	$2,619.2	$2,723.5	$2,619.2	$2,747.7
2017	$2,800.0	$2,886.3	$2,813.5	$2,920.2
2018	$2,911.7	$2,983.1	$2,974.0	$3,034.9
2019	$3,044.3	$3,106.8	$3,137.0	$3,129.9
2020	$3,178.1	$3,258.9	$3,278.0	$3,386.4
2021	$3,420.8	$3,487.5	$3,532.7	$3,643.0
2022	$3,667.5	$3,752.3	$3,785.5	$3,878.2
2023	$3,945.7	$4,007.7	$4,092.2	$4,097.4
2024	$4,097.8	$4,200.7	$4,323.1	$4,251.7
2025	$4,323.9	$4,434.6	$4,601.0	$4,685.2
2026	$4,650.2	$4,746.8	$4,876.6	$5,010.1
2027	$4,949.9	$5,026.8	$5,217.7	$5,206.6
2028	$5,204.3	$5,296.7	$5,427.9	$5,454.1
2029	$5,490.0	$5,583.6	$5,656.0	$5,744.3
2030	$5,868.0	$5,932.5	$6,003.9	$6,059.2
2031	$6,161.1	$6,246.0	$6,274.5	$6,331.6
2032	$6,505.0	$6,589.7	$6,589.1	$6,644.9
2033	$6,880.3	$6,921.1	$6,916.6	$6,953.8
2034	$7,271.1	$7,305.7	$7,268.1	$7,275.0
2035	$7,702.8	$7,704.4	$7,664.2	$7,633.5
2036	$8,146.4	$8,138.1	$8,103.1	$8,043.0
2037	$8,512.6	$8,483.0	$8,433.9	$8,389.6
2038	$8,964.0	$8,853.6	$8,854.0	$8,752.7
2039	$9,384.9	$9,214.1	$9,287.4	$9,125.4
2040	$9,988.4	$9,670.6	$9,917.1	$9,598.9
2041	$10,318.7	$10,006.3	$10,235.7	$9,939.6
CPW (2012-2027)	$26,688.3	$27,076.4	$27,323.8	$27,669.5
CPW (2012-2041)	$43,980.9	$44,376.7	$44,733.8	$45,037.5
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
Low EE Cost Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$66.2	$67.0	$66.2	$67.4
2013	$72.7	$70.3	$72.7	$70.7
2014	$77.3	$74.6	$77.3	$74.9
2015	$79.8	$81.1	$79.8	$81.7
2016	$83.3	$86.6	$83.3	$87.4
2017	$87.3	$90.0	$87.7	$91.0
2018	$88.9	$91.1	$90.8	$92.7
2019	$90.9	$92.8	$93.7	$93.5
2020	$93.1	$95.5	$96.1	$99.2
2021	$98.7	$100.6	$102.0	$105.1
2022	$102.9	$105.3	$106.2	$108.8
2023	$107.9	$109.6	$111.9	$112.0
2024	$109.3	$112.0	$115.3	$113.4
2025	$112.5	$115.4	$119.7	$121.9
2026	$118.0	$120.4	$123.7	$127.1
2027	$122.4	$124.3	$129.0	$128.7

Annual Revenue Requirements
High EE Cost Sensitivity
($Millions)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,040.0	$2,065.1	$2,040.0	$2,077.4
2013	$2,239.3	$2,168.1	$2,239.3	$2,180.0
2014	$2,436.4	$2,351.1	$2,436.4	$2,363.2
2015	$2,552.1	$2,593.1	$2,552.1	$2,611.7
2016	$2,709.2	$2,813.5	$2,709.2	$2,837.7
2017	$2,883.1	$2,969.3	$2,896.6	$3,003.3
2018	$2,994.5	$3,065.9	$3,056.8	$3,117.7
2019	$3,127.7	$3,190.1	$3,220.3	$3,213.2
2020	$3,275.9	$3,356.7	$3,375.8	$3,484.2
2021	$3,442.7	$3,509.3	$3,554.6	$3,664.8
2022	$3,695.0	$3,779.8	$3,813.1	$3,905.7
2023	$3,980.5	$4,042.5	$4,127.0	$4,132.2
2024	$4,131.6	$4,234.4	$4,356.8	$4,285.5
2025	$4,357.7	$4,468.4	$4,634.8	$4,719.0
2026	$4,685.0	$4,781.7	$4,911.5	$5,044.9
2027	$4,988.1	$5,065.0	$5,255.9	$5,244.8
2028	$5,245.5	$5,337.9	$5,469.1	$5,495.3
2029	$5,530.5	$5,624.1	$5,696.5	$5,784.9
2030	$5,907.9	$5,972.4	$6,043.8	$6,099.2
2031	$6,200.6	$6,285.5	$6,313.9	$6,371.0
2032	$6,543.0	$6,627.7	$6,627.1	$6,682.9
2033	$6,916.6	$6,957.3	$6,952.8	$6,990.1
2034	$7,305.2	$7,339.9	$7,302.3	$7,309.2
2035	$7,734.6	$7,736.1	$7,695.9	$7,665.2
2036	$8,175.2	$8,166.9	$8,132.0	$8,071.9
2037	$8,538.1	$8,508.6	$8,459.5	$8,415.2
2038	$8,985.7	$8,875.3	$8,875.7	$8,774.5
2039	$9,402.2	$9,231.4	$9,304.7	$9,142.8
2040	$10,000.7	$9,682.9	$9,929.4	$9,611.2
2041	$10,325.2	$10,012.9	$10,242.2	$9,946.1
CPW (2012-2027)	$27,145.1	$27,533.2	$27,780.7	$28,126.4
CPW (2012-2041)	$44,516.8	$44,912.6	$45,269.7	$45,573.4
NPV Rate	7.95%	7.95%	7.95%	7.95%

Annual Average System Cost
High EE Cost Sensitivity
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$66.2	$67.0	$66.2	$67.4
2013	$73.3	$71.0	$73.3	$71.4
2014	$78.9	$76.1	$78.9	$76.5
2015	$82.6	$83.9	$82.6	$84.5
2016	$86.1	$89.5	$86.1	$90.2
2017	$89.9	$92.6	$90.3	$93.6
2018	$91.5	$93.6	$93.4	$95.2
2019	$93.4	$95.3	$96.2	$96.0
2020	$96.0	$98.4	$98.9	$102.1
2021	$99.4	$101.3	$102.6	$105.8
2022	$103.7	$106.0	$107.0	$109.6
2023	$108.8	$110.5	$112.8	$113.0
2024	$110.2	$112.9	$116.2	$114.3
2025	$113.4	$116.3	$120.6	$122.8
2026	$118.9	$121.3	$124.6	$128.0
2027	$123.3	$125.2	$129.9	$129.6

ANNUAL REVENUE REQUIREMENTS
LOW COST SCENARIO
($MILLIONS)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$1,990.4	$2,011.9	$1,990.4	$2,024.2
2013	$2,174.8	$2,091.9	$2,174.8	$2,103.9
2014	$2,328.7	$2,239.7	$2,328.7	$2,251.7
2015	$2,412.9	$2,387.6	$2,412.9	$2,406.2
2016	$2,550.8	$2,580.9	$2,550.8	$2,605.0
2017	$2,711.9	$2,712.8	$2,724.9	$2,745.6
2018	$2,812.8	$2,800.4	$2,868.3	$2,844.0
2019	$2,876.2	$2,886.2	$2,964.5	$2,913.7
2020	$2,984.6	$3,012.2	$3,084.9	$3,134.9
2021	$3,196.5	$3,213.4	$3,308.2	$3,367.6
2022	$3,404.0	$3,430.1	$3,529.0	$3,561.9
2023	$3,621.7	$3,633.3	$3,780.1	$3,733.9
2024	$3,736.7	$3,787.4	$3,976.0	$3,856.5
2025	$3,923.1	$3,981.0	$4,200.1	$4,227.2
2026	$4,176.6	$4,223.1	$4,413.7	$4,483.5
2027	$4,353.5	$4,382.9	$4,649.9	$4,570.8
2028	$4,493.5	$4,539.5	$4,748.9	$4,715.9
2029	$4,638.0	$4,694.1	$4,851.7	$4,884.9
2030	$4,866.1	$4,895.3	$5,059.2	$5,064.2
2031	$5,066.5	$5,116.7	$5,246.3	$5,260.0
2032	$5,297.1	$5,350.8	$5,459.1	$5,477.3
2033	$5,555.2	$5,575.1	$5,684.0	$5,698.1
2034	$5,817.8	$5,838.2	$5,921.6	$5,919.2
2035	$6,120.4	$6,113.2	$6,192.0	$6,167.0
2036	$6,408.9	$6,392.5	$6,491.0	$6,445.4
2037	$6,701.1	$6,661.5	$6,752.2	$6,711.4
2038	$7,075.1	$6,956.6	$7,098.7	$6,991.2
2039	$7,394.6	$7,230.2	$7,430.7	$7,275.5
2040	$7,896.8	$7,579.8	$7,964.1	$7,641.2
2041	$8,159.2	$7,847.4	$8,220.6	$7,909.4
CPW (2012-2027)	$25,224.8	$25,203.1	$25,878.5	$25,803.6
CPW (2012-2041)	$39,226.1	$39,157.6	$40,212.8	$40,032.7
NPV Rate	7.95%	7.95%	7.95%	7.95%

APS 2012 INTEGRATED RESOURCE PLAN

ANNUAL AVERAGE SYSTEM COST

LOW COST SCENARIO

($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$64.6	$65.3	$64.6	$65.7
2013	$71.2	$68.5	$71.2	$68.9
2014	$75.4	$72.5	$75.4	$72.9
2015	$78.1	$77.2	$78.1	$77.8
2016	$81.1	$82.1	$81.1	$82.8
2017	$84.5	$84.6	$84.9	$85.6
2018	$85.9	$85.5	$87.6	$86.9
2019	$85.9	$86.2	$88.6	$87.0
2020	$87.5	$88.3	$90.4	$91.9
2021	$92.2	$92.7	$95.5	$97.2
2022	$95.5	$96.2	$99.0	$99.9
2023	$99.0	$99.3	$103.3	$102.1
2024	$99.6	$101.0	$106.0	$102.8
2025	$102.1	$103.6	$109.3	$110.0
2026	$106.0	$107.1	$112.0	$113.8
2027	$107.6	$108.3	$114.9	$113.0

ENERGY MIX

BASE CASE PORTFOLIO
LOW COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	9,103	10,863	1,588	1,510	32,370
2013	9,324	10,258	9,184	2,102	2,018	32,886
2014	9,270	10,443	8,534	3,057	2,580	33,884
2015	9,270	11,295	7,453	3,487	3,193	34,697
2016	9,298	10,556	8,692	3,586	3,835	35,966
2017	9,269	10,758	9,174	3,662	4,455	37,318
2018	9,270	10,332	10,279	3,718	5,039	38,638
2019	9,270	11,206	9,867	4,016	5,605	39,964
2020	9,315	11,563	9,814	4,102	6,192	40,987
2021	9,261	11,612	9,795	4,849	6,565	42,082
2022	9,270	11,886	10,211	5,281	6,709	43,358
2023	9,270	11,717	11,101	5,638	6,889	44,615
2024	9,297	11,895	11,570	6,025	7,082	45,868
2025	9,275	12,294	11,907	6,389	7,267	47,132
2026	9,270	12,382	12,591	6,711	7,450	48,405
2027	9,270	12,497	13,489	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	28.1%	33.6%	4.9%	4.7%	100.0%
2013	28.4%	31.2%	27.9%	6.4%	6.1%	100.0%
2014	27.4%	30.8%	25.2%	9.0%	7.6%	100.0%
2015	26.7%	32.6%	21.5%	10.0%	9.2%	100.0%
2016	25.9%	29.3%	24.2%	10.0%	10.7%	100.0%
2017	24.8%	28.8%	24.6%	9.8%	11.9%	100.0%
2018	24.0%	26.7%	26.6%	9.6%	13.0%	100.0%
2019	23.2%	28.0%	24.7%	10.0%	14.0%	100.0%
2020	22.7%	28.2%	23.9%	10.0%	15.1%	100.0%
2021	22.0%	27.6%	23.3%	11.5%	15.6%	100.0%
2022	21.4%	27.4%	23.6%	12.2%	15.5%	100.0%
2023	20.8%	26.3%	24.9%	12.6%	15.4%	100.0%
2024	20.3%	25.9%	25.2%	13.1%	15.4%	100.0%
2025	19.7%	26.1%	25.3%	13.6%	15.4%	100.0%
2026	19.2%	25.6%	26.0%	13.9%	15.4%	100.0%
2027	18.7%	25.2%	27.2%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX

FOUR CORNERS CONTINGENCY PORTFOLIO

LOW COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	8,865	11,101	1,588	1,510	32,370
2013	9,324	9,516	9,926	2,102	2,018	32,886
2014	9,270	9,842	9,134	3,057	2,580	33,884
2015	9,270	7,197	11,551	3,487	3,193	34,697
2016	9,298	6,635	12,613	3,586	3,835	35,966
2017	9,269	6,463	13,469	3,662	4,455	37,318
2018	9,270	5,392	15,219	3,718	5,039	38,638
2019	9,270	5,642	15,432	4,016	5,605	39,965
2020	9,315	5,814	15,563	4,102	6,192	40,987
2021	9,261	5,853	15,554	4,849	6,565	42,082
2022	9,270	6,141	15,956	5,281	6,709	43,358
2023	9,270	6,300	16,518	5,638	6,889	44,615
2024	9,297	6,496	16,970	6,025	7,082	45,868
2025	9,275	6,118	18,083	6,389	7,267	47,132
2026	9,270	6,033	18,940	6,711	7,450	48,405
2027	9,270	6,174	19,812	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	27.4%	34.3%	4.9%	4.7%	100.0%
2013	28.4%	28.9%	30.2%	6.4%	6.1%	100.0%
2014	27.4%	29.0%	27.0%	9.0%	7.6%	100.0%
2015	26.7%	20.7%	33.3%	10.0%	9.2%	100.0%
2016	25.9%	18.4%	35.1%	10.0%	10.7%	100.0%
2017	24.8%	17.3%	36.1%	9.8%	11.9%	100.0%
2018	24.0%	14.0%	39.4%	9.6%	13.0%	100.0%
2019	23.2%	14.1%	38.6%	10.0%	14.0%	100.0%
2020	22.7%	14.2%	38.0%	10.0%	15.1%	100.0%
2021	22.0%	13.9%	37.0%	11.5%	15.6%	100.0%
2022	21.4%	14.2%	36.8%	12.2%	15.5%	100.0%
2023	20.8%	14.1%	37.0%	12.6%	15.4%	100.0%
2024	20.3%	14.2%	37.0%	13.1%	15.4%	100.0%
2025	19.7%	13.0%	38.4%	13.6%	15.4%	100.0%
2026	19.2%	12.5%	39.1%	13.9%	15.4%	100.0%
2027	18.7%	12.4%	39.9%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
ENHANCED RENEWABLE PORTFOLIO
LOW COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	9,103	10,863	1,588	1,510	32,370
2013	9,324	10,258	9,184	2,102	2,018	32,886
2014	9,270	10,443	8,534	3,057	2,580	33,884
2015	9,270	11,295	7,453	3,487	3,193	34,697
2016	9,298	10,556	8,692	3,586	3,835	35,966
2017	9,269	10,421	8,952	4,220	4,455	37,318
2018	9,270	9,810	9,570	4,949	5,039	38,638
2019	9,270	10,365	8,919	5,806	5,605	39,965
2020	9,315	10,550	8,557	6,373	6,192	40,987
2021	9,261	10,211	8,651	7,393	6,565	42,082
2022	9,270	10,432	8,644	8,302	6,709	43,358
2023	9,270	10,116	9,402	8,938	6,889	44,615
2024	9,297	10,189	9,294	10,007	7,082	45,868
2025	9,275	10,725	8,945	10,920	7,267	47,132
2026	9,270	10,528	9,914	11,243	7,450	48,405
2027	9,270	10,492	10,963	11,317	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	28.1%	33.6%	4.9%	4.7%	100.0%
2013	28.4%	31.2%	27.9%	6.4%	6.1%	100.0%
2014	27.4%	30.8%	25.2%	9.0%	7.6%	100.0%
2015	26.7%	32.6%	21.5%	10.0%	9.2%	100.0%
2016	25.9%	29.3%	24.2%	10.0%	10.7%	100.0%
2017	24.8%	27.9%	24.0%	11.3%	11.9%	100.0%
2018	24.0%	25.4%	24.8%	12.8%	13.0%	100.0%
2019	23.2%	25.9%	22.3%	14.5%	14.0%	100.0%
2020	22.7%	25.7%	20.9%	15.5%	15.1%	100.0%
2021	22.0%	24.3%	20.6%	17.6%	15.6%	100.0%
2022	21.4%	24.1%	19.9%	19.1%	15.5%	100.0%
2023	20.8%	22.7%	21.1%	20.0%	15.4%	100.0%
2024	20.3%	22.2%	20.3%	21.8%	15.4%	100.0%
2025	19.7%	22.8%	19.0%	23.2%	15.4%	100.0%
2026	19.2%	21.7%	20.5%	23.2%	15.4%	100.0%
2027	18.7%	21.1%	22.1%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
COAL RETIREMENT PORTFOLIO
LOW COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2011	9,225	9,421	11,153	1,045	1,430	32,274
2012	9,306	8,865	11,101	1,588	1,510	32,370
2013	9,324	9,516	9,926	2,102	2,018	32,886
2014	9,270	9,842	9,134	3,057	2,580	33,884
2015	9,270	7,197	11,551	3,487	3,193	34,697
2016	9,298	6,635	12,613	3,586	3,835	35,966
2017	9,269	6,219	12,855	4,520	4,455	37,318
2018	9,270	5,178	14,297	4,855	5,039	38,638
2019	9,270	5,312	14,345	5,432	5,605	39,965
2020	9,315	3,160	16,153	6,166	6,192	40,987
2021	9,261	3,017	16,332	6,908	6,565	42,082
2022	9,270	3,298	16,740	7,340	6,709	43,358
2023	9,270	3,389	17,370	7,697	6,889	44,615
2024	9,297	3,480	17,921	8,089	7,082	45,868
2025	9,275	0	21,220	9,370	7,267	47,132
2026	9,270	0	21,992	9,693	7,450	48,405
2027	9,270	0	23,005	9,767	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2011	28.6%	29.2%	34.6%	3.2%	4.4%	100.0%
2012	28.8%	27.4%	34.3%	4.9%	4.7%	100.0%
2013	28.4%	28.9%	30.2%	6.4%	6.1%	100.0%
2014	27.4%	29.0%	27.0%	9.0%	7.6%	100.0%
2015	26.7%	20.7%	33.3%	10.0%	9.2%	100.0%
2016	25.9%	18.4%	35.1%	10.0%	10.7%	100.0%
2017	24.8%	16.7%	34.4%	12.1%	11.9%	100.0%
2018	24.0%	13.4%	37.0%	12.6%	13.0%	100.0%
2019	23.2%	13.3%	35.9%	13.6%	14.0%	100.0%
2020	22.7%	7.7%	39.4%	15.0%	15.1%	100.0%
2021	22.0%	7.2%	38.8%	16.4%	15.6%	100.0%
2022	21.4%	7.6%	38.6%	16.9%	15.5%	100.0%
2023	20.8%	7.6%	38.9%	17.3%	15.4%	100.0%
2024	20.3%	7.6%	39.1%	17.6%	15.4%	100.0%
2025	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ANNUAL NATURAL GAS BURNS
LOW COST SCENARIO
(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	80.5	82.3	80.5	82.3
2013	68.2	73.8	68.2	73.8
2014	63.4	68.2	63.4	68.2
2015	55.6	86.1	55.6	86.1
2016	64.3	93.6	64.3	93.6
2017	67.9	100.5	66.4	96.1
2018	75.7	112.3	70.7	105.7
2019	72.9	113.9	66.5	106.3
2020	73.1	115.6	64.8	120.9
2021	73.8	116.2	66.7	121.4
2022	77.6	120.5	67.6	125.1
2023	85.0	125.3	74.0	130.3
2024	89.0	129.4	74.6	135.1
2025	89.9	135.5	73.6	161.1
2026	95.2	142.1	79.5	167.4
2027	102.4	148.7	87.2	175.0

ANNUAL CO2 EMISSIONS
LOW COST SCENARIO
(METRIC TONS)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	13,438,374	13,567,879	13,438,374	13,567,879
2013	13,151,628	13,799,932	13,151,628	13,799,932
2014	13,137,166	13,806,286	13,137,166	13,806,286
2015	13,476,808	11,680,065	13,476,808	11,680,065
2016	13,397,089	11,642,277	13,397,089	11,642,277
2017	13,908,642	11,935,140	13,499,460	11,460,545
2018	13,864,237	11,612,117	13,085,235	11,044,880
2019	14,509,117	11,940,467	13,344,492	11,203,300
2020	14,795,520	12,144,165	13,359,975	9,901,796
2021	14,871,719	12,197,448	13,096,164	9,743,492
2022	15,282,152	12,668,017	13,330,756	10,209,845
2023	15,584,775	13,069,593	13,446,765	10,577,218
2024	15,944,139	13,501,855	13,519,421	10,940,084
2025	16,301,119	13,469,783	13,922,937	8,807,756
2026	16,667,878	13,746,542	14,052,444	9,155,417
2027	17,179,683	14,263,708	14,454,919	9,573,298

ANNUAL WATER USE
LOW COST SCENARIO
(ACRE-FEET)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	49,902	49,815	49,902	49,815
2013	50,975	50,820	50,975	50,820
2014	52,963	52,687	52,963	52,687
2015	53,223	51,995	53,223	51,995
2016	54,143	51,726	54,143	51,726
2017	55,898	51,931	54,941	50,924
2018	55,763	50,793	54,872	49,620
2019	56,897	51,161	55,119	49,630
2020	56,538	49,961	54,702	44,209
2021	57,498	50,614	54,867	43,632
2022	58,018	51,476	55,510	44,326
2023	58,166	51,597	55,185	44,251
2024	58,736	52,035	56,216	44,459
2025	58,401	50,698	56,521	36,328
2026	58,633	50,814	55,948	36,471
2027	59,302	51,507	56,288	36,802

ANNUAL REVENUE REQUIREMENTS
HIGH COST SCENARIO
($MILLIONS)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$2,105.5	$2,133.6	$2,105.5	$2,145.9
2013	$2,299.9	$2,242.7	$2,299.9	$2,254.7
2014	$2,506.8	$2,429.7	$2,506.8	$2,441.8
2015	$2,617.8	$2,719.9	$2,617.8	$2,738.5
2016	$2,788.0	$2,962.5	$2,788.0	$2,986.6
2017	$2,980.4	$3,143.6	$2,988.0	$3,167.0
2018	$3,104.4	$3,257.8	$3,155.2	$3,295.3
2019	$3,278.1	$3,408.2	$3,345.0	$3,404.6
2020	$3,443.5	$3,594.2	$3,510.0	$3,707.4
2021	$3,625.7	$3,762.5	$3,700.0	$3,896.8
2022	$3,907.8	$4,068.0	$3,978.4	$4,170.6
2023	$4,234.2	$4,366.4	$4,324.7	$4,430.8
2024	$4,413.5	$4,587.2	$4,569.1	$4,609.9
2025	$4,661.5	$4,850.7	$4,864.5	$5,099.8
2026	$5,037.4	$5,213.2	$5,180.3	$5,473.1
2027	$5,424.0	$5,577.4	$5,595.9	$5,750.2
2028	$5,755.7	$5,923.5	$5,880.0	$6,069.2
2029	$6,148.0	$6,306.0	$6,202.0	$6,452.8
2030	$6,634.7	$6,763.3	$6,650.7	$6,870.7
2031	$6,992.5	$7,149.8	$6,982.5	$7,208.0
2032	$7,421.3	$7,576.5	$7,372.6	$7,599.6
2033	$7,872.6	$7,983.3	$7,767.6	$7,980.8
2034	$8,356.6	$8,459.6	$8,205.3	$8,382.4
2035	$8,906.4	$8,960.9	$8,709.9	$8,828.9
2036	$9,465.7	$9,509.6	$9,256.1	$9,341.6
2037	$10,033.0	$10,050.5	$9,772.1	$9,849.8
2038	$10,703.9	$10,610.1	$10,391.5	$10,374.1
2039	$11,369.5	$11,185.4	$11,048.5	$10,929.6
2040	$12,211.5	$11,893.2	$11,897.1	$11,611.8
2041	$12,782.6	$12,470.5	$12,435.8	$12,156.7
CPW (2012-2027)	$28,433.9	$29,298.2	$28,862.1	$29,810.6
CPW (2012-2041)	$48,493.6	$49,495.0	$48,671.3	$49,917.2
NPV Rate	7.95%	7.95%	7.95%	7.95%

ANNUAL AVERAGE SYSTEM COST
HIGH COST SCENARIO
($/MWh)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	$68.3	$69.2	$68.3	$69.6
2013	$75.3	$73.4	$75.3	$73.8
2014	$81.2	$78.7	$81.2	$79.1
2015	$84.7	$88.0	$84.7	$88.6
2016	$88.6	$94.2	$88.6	$95.0
2017	$92.9	$98.0	$93.1	$98.7
2018	$94.8	$99.5	$96.4	$100.6
2019	$97.9	$101.8	$99.9	$101.7
2020	$100.9	$105.3	$102.9	$108.6
2021	$104.6	$108.6	$106.8	$112.5
2022	$109.6	$114.1	$111.6	$117.0
2023	$115.7	$119.4	$118.2	$121.1
2024	$117.7	$122.3	$121.8	$122.9
2025	$121.3	$126.2	$126.6	$132.7
2026	$127.8	$132.3	$131.4	$138.9
2027	$134.1	$137.9	$138.3	$142.1

ENERGY MIX
BASE CASE PORTFOLIO
HIGH COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,888	7,077	1,588	1,510	32,370
2013	9,324	13,628	5,814	2,102	2,018	32,886
2014	9,270	12,979	5,998	3,057	2,580	33,884
2015	9,270	13,457	5,291	3,487	3,193	34,697
2016	9,298	13,249	5,999	3,586	3,835	35,966
2017	9,269	13,074	6,857	3,662	4,455	37,318
2018	9,270	13,163	7,448	3,718	5,039	38,638
2019	9,270	13,734	7,339	4,016	5,605	39,964
2020	9,315	13,716	7,661	4,102	6,192	40,987
2021	9,261	13,489	7,918	4,849	6,565	42,082
2022	9,270	13,729	8,368	5,281	6,709	43,358
2023	9,270	13,051	9,767	5,638	6,889	44,615
2024	9,297	13,156	10,309	6,025	7,082	45,868
2025	9,275	13,608	10,593	6,389	7,267	47,132
2026	9,270	13,574	11,399	6,711	7,450	48,405
2027	9,270	13,601	12,385	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	39.8%	21.9%	4.9%	4.7%	100.0%
2013	28.4%	41.4%	17.7%	6.4%	6.1%	100.0%
2014	27.4%	38.3%	17.7%	9.0%	7.6%	100.0%
2015	26.7%	38.8%	15.2%	10.0%	9.2%	100.0%
2016	25.9%	36.8%	16.7%	10.0%	10.7%	100.0%
2017	24.8%	35.0%	18.4%	9.8%	11.9%	100.0%
2018	24.0%	34.1%	19.3%	9.6%	13.0%	100.0%
2019	23.2%	34.4%	18.4%	10.0%	14.0%	100.0%
2020	22.7%	33.5%	18.7%	10.0%	15.1%	100.0%
2021	22.0%	32.1%	18.8%	11.5%	15.6%	100.0%
2022	21.4%	31.7%	19.3%	12.2%	15.5%	100.0%
2023	20.8%	29.3%	21.9%	12.6%	15.4%	100.0%
2024	20.3%	28.7%	22.5%	13.1%	15.4%	100.0%
2025	19.7%	28.9%	22.5%	13.6%	15.4%	100.0%
2026	19.2%	28.0%	23.5%	13.9%	15.4%	100.0%
2027	18.7%	27.4%	24.9%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
FOUR CORNERS CONTINGENCY PORTFOLIO
HIGH COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,597	7,368	1,588	1,510	32,370
2013	9,324	12,630	6,812	2,102	2,018	32,886
2014	9,270	12,373	6,604	3,057	2,580	33,884
2015	9,270	8,695	10,053	3,487	3,193	34,697
2016	9,298	7,921	11,327	3,586	3,835	35,966
2017	9,269	7,347	12,584	3,662	4,455	37,318
2018	9,270	7,544	13,067	3,718	5,039	38,638
2019	9,270	7,264	13,809	4,016	5,605	39,965
2020	9,315	7,149	14,228	4,102	6,192	40,987
2021	9,261	6,988	14,420	4,849	6,565	42,082
2022	9,270	7,077	15,019	5,281	6,709	43,358
2023	9,270	6,990	15,829	5,638	6,889	44,615
2024	9,297	7,144	16,322	6,025	7,082	45,868
2025	9,275	6,814	17,387	6,389	7,267	47,132
2026	9,270	6,766	18,208	6,711	7,450	48,405
2027	9,270	6,849	19,137	6,785	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.9%	22.8%	4.9%	4.7%	100.0%
2013	28.4%	38.4%	20.7%	6.4%	6.1%	100.0%
2014	27.4%	36.5%	19.5%	9.0%	7.6%	100.0%
2015	26.7%	25.1%	29.0%	10.0%	9.2%	100.0%
2016	25.9%	22.0%	31.5%	10.0%	10.7%	100.0%
2017	24.8%	19.7%	33.7%	9.8%	11.9%	100.0%
2018	24.0%	19.5%	33.8%	9.6%	13.0%	100.0%
2019	23.2%	18.2%	34.6%	10.0%	14.0%	100.0%
2020	22.7%	17.4%	34.7%	10.0%	15.1%	100.0%
2021	22.0%	16.6%	34.3%	11.5%	15.6%	100.0%
2022	21.4%	16.3%	34.6%	12.2%	15.5%	100.0%
2023	20.8%	15.7%	35.5%	12.6%	15.4%	100.0%
2024	20.3%	15.6%	35.6%	13.1%	15.4%	100.0%
2025	19.7%	14.5%	36.9%	13.6%	15.4%	100.0%
2026	19.2%	14.0%	37.6%	13.9%	15.4%	100.0%
2027	18.7%	13.8%	38.5%	13.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
ENHANCED RENEWABLE PORTFOLIO
HIGH COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,888	7,077	1,588	1,510	32,370
2013	9,324	13,628	5,814	2,102	2,018	32,886
2014	9,270	12,979	5,998	3,057	2,580	33,884
2015	9,270	13,457	5,291	3,487	3,193	34,697
2016	9,298	13,249	5,999	3,586	3,835	35,966
2017	9,269	12,881	6,493	4,220	4,455	37,318
2018	9,270	12,740	6,640	4,949	5,039	38,638
2019	9,270	12,939	6,345	5,806	5,605	39,965
2020	9,315	12,670	6,436	6,373	6,192	40,987
2021	9,261	12,214	6,649	7,393	6,565	42,082
2022	9,270	12,272	6,804	8,302	6,709	43,358
2023	9,270	11,585	7,933	8,938	6,889	44,615
2024	9,297	11,433	8,051	10,007	7,082	45,869
2025	9,275	11,826	7,844	10,920	7,267	47,132
2026	9,270	11,722	8,720	11,243	7,450	48,405
2027	9,270	11,860	9,595	11,317	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	39.8%	21.9%	4.9%	4.7%	100.0%
2013	28.4%	41.4%	17.7%	6.4%	6.1%	100.0%
2014	27.4%	38.3%	17.7%	9.0%	7.6%	100.0%
2015	26.7%	38.8%	15.2%	10.0%	9.2%	100.0%
2016	25.9%	36.8%	16.7%	10.0%	10.7%	100.0%
2017	24.8%	34.5%	17.4%	11.3%	11.9%	100.0%
2018	24.0%	33.0%	17.2%	12.8%	13.0%	100.0%
2019	23.2%	32.4%	15.9%	14.5%	14.0%	100.0%
2020	22.7%	30.9%	15.7%	15.5%	15.1%	100.0%
2021	22.0%	29.0%	15.8%	17.6%	15.6%	100.0%
2022	21.4%	28.3%	15.7%	19.1%	15.5%	100.0%
2023	20.8%	26.0%	17.8%	20.0%	15.4%	100.0%
2024	20.3%	24.9%	17.6%	21.8%	15.4%	100.0%
2025	19.7%	25.1%	16.6%	23.2%	15.4%	100.0%
2026	19.2%	24.2%	18.0%	23.2%	15.4%	100.0%
2027	18.7%	23.9%	19.3%	22.8%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ENERGY MIX
COAL RETIREMENT PORTFOLIO
HIGH COST SCENARIO

ENERGY (GWH)

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	9,306	12,597	7,368	1,588	1,510	32,370
2013	9,324	12,630	6,812	2,102	2,018	32,886
2014	9,270	12,373	6,604	3,057	2,580	33,884
2015	9,270	8,695	10,053	3,487	3,193	34,697
2016	9,298	7,921	11,327	3,586	3,835	35,966
2017	9,269	7,217	11,857	4,520	4,455	37,318
2018	9,270	7,374	12,100	4,855	5,039	38,638
2019	9,270	7,021	12,636	5,432	5,605	39,965
2020	9,315	4,487	14,826	6,166	6,192	40,987
2021	9,261	4,297	15,051	6,908	6,565	42,082
2022	9,270	4,369	15,669	7,340	6,709	43,358
2023	9,270	4,235	16,524	7,697	6,889	44,615
2024	9,297	4,300	17,101	8,089	7,082	45,868
2025	9,275	0	21,220	9,370	7,267	47,132
2026	9,270	0	21,992	9,693	7,450	48,405
2027	9,270	0	23,005	9,767	7,641	49,683

ENERGY MIX %

	Nuclear	Coal	Gas	RE + DE Renew	EE	Total
2012	28.8%	38.9%	22.8%	4.9%	4.7%	100.0%
2013	28.4%	38.4%	20.7%	6.4%	6.1%	100.0%
2014	27.4%	36.5%	19.5%	9.0%	7.6%	100.0%
2015	26.7%	25.1%	29.0%	10.0%	9.2%	100.0%
2016	25.9%	22.0%	31.5%	10.0%	10.7%	100.0%
2017	24.8%	19.3%	31.8%	12.1%	11.9%	100.0%
2018	24.0%	19.1%	31.3%	12.6%	13.0%	100.0%
2019	23.2%	17.6%	31.6%	13.6%	14.0%	100.0%
2020	22.7%	10.9%	36.2%	15.0%	15.1%	100.0%
2021	22.0%	10.2%	35.8%	16.4%	15.6%	100.0%
2022	21.4%	10.1%	36.1%	16.9%	15.5%	100.0%
2023	20.8%	9.5%	37.0%	17.3%	15.4%	100.0%
2024	20.3%	9.4%	37.3%	17.6%	15.4%	100.0%
2025	19.7%	0.0%	45.0%	19.9%	15.4%	100.0%
2026	19.2%	0.0%	45.4%	20.0%	15.4%	100.0%
2027	18.7%	0.0%	46.3%	19.7%	15.4%	100.0%

Notes:

(1) EE includes 1094.384 GWh (2005 to 2010 YTD)

(2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

(3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ANNUAL NATURAL GAS BURNS
HIGH COST SCENARIO
(BCF)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	53.4	55.6	53.4	55.6
2013	44.0	51.4	44.0	51.4
2014	45.5	50.0	45.5	50.0
2015	40.2	75.8	40.2	75.8
2016	45.6	84.8	45.6	84.8
2017	52.2	94.7	49.5	89.4
2018	57.1	99.0	51.0	91.9
2019	54.8	101.9	48.1	93.9
2020	57.6	105.3	49.7	110.4
2021	59.9	107.1	51.7	111.1
2022	65.2	114.4	54.5	117.7
2023	76.1	120.7	63.4	124.3
2024	80.5	125.1	65.6	129.3
2025	81.0	130.9	65.7	160.8
2026	87.2	137.3	70.8	167.0
2027	94.8	144.3	76.7	174.7

ANNUAL CO2 EMISSIONS
HIGH COST SCENARIO
(METRIC TONS)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	15,625,177	15,740,954	15,625,177	15,740,954
2013	15,065,057	15,574,419	15,065,057	15,574,419
2014	14,547,551	15,244,034	14,547,551	15,244,034
2015	14,680,927	12,535,756	14,680,927	12,535,756
2016	14,864,154	12,376,838	14,864,154	12,376,838
2017	15,152,745	12,449,091	14,829,942	12,037,198
2018	15,424,510	12,880,618	14,712,722	12,335,590
2019	15,877,578	12,884,609	14,763,056	12,188,212
2020	15,966,610	12,932,496	14,539,620	10,679,011
2021	15,869,261	12,867,941	14,220,623	10,509,582
2022	16,278,747	13,212,665	14,360,815	10,825,735
2023	16,313,064	13,468,075	14,272,504	11,059,158
2024	16,618,914	13,875,426	14,217,903	11,408,510
2025	17,016,398	13,872,232	14,544,893	8,791,538
2026	17,326,909	14,169,123	14,734,410	9,131,567
2027	17,786,320	14,650,396	15,208,177	9,557,221

ANNUAL WATER USE
HIGH COST SCENARIO
(ACRE-FEET)

Year	Base Case Portfolio	Four Corners Contingency Portfolio	Enhanced Renewable Portfolio	Coal Retirement Portfolio
2012	53,883	53,815	53,883	53,815
2013	54,366	54,070	54,366	54,070
2014	55,464	55,257	55,464	55,257
2015	55,257	53,672	55,257	53,672
2016	56,354	53,148	56,354	53,148
2017	57,507	52,950	56,759	52,074
2018	58,039	53,383	57,323	52,267
2019	58,490	52,932	56,924	51,517
2020	57,797	51,381	56,204	45,669
2021	58,441	51,828	56,402	45,122
2022	59,125	52,429	57,070	45,569
2023	58,967	52,276	56,620	45,255
2024	59,453	52,658	57,386	45,433
2025	59,187	51,381	57,539	36,195
2026	59,518	51,521	57,257	36,337
2027	60,128	52,140	57,929	36,646

2012 RESOURCE PLAN

Loads & Resources - MW Contribution at Peak

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Requirements																
APS Peak Demand	7,234	7,377	7,616	7,813	8,118	8,441	8,742	9,059	9,372	9,625	9,942	10,257	10,569	10,884	11,203	11,527
Annual Load Growth %		2.0%	3.2%	2.6%	3.9%	4.0%	3.6%	3.6%	3.5%	2.7%	3.3%	3.2%	3.0%	3.0%	2.9%	2.9%
Reserve Requirements	999	1,005	1,028	1,054	1,086	1,119	1,149	1,178	1,217	1,325	1,380	1,434	1,490	1,546	1,597	1,641
Total Load Requirements	8,233	8,382	8,644	8,867	9,205	9,561	9,891	10,237	10,590	10,950	11,322	11,691	12,059	12,430	12,799	13,167
Existing Resources																
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Coal	1,753	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
Natural Gas	5,583	5,676	5,676	5,590	5,089	4,589	4,589	4,589	3,992	3,512	3,362	3,362	3,362	3,362	3,362	3,362
Combined Cycle	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
Combustion / Steam Turbines	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	480	480	0	0	0	0	0	0	0
Tolling Agreements	1,060	1,060	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0	0	0
Market / Call Options / Hedges	681	774	774	688	187	187	187	187	150	150	0	0	0	0	0	0
Renewable Energy	66	72	71	71	71	71	71	70	70	70	70	55	55	55	55	39
Wind	28	33	33	33	33	33	33	33	33	33	33	33	33	33	33	17
Solar	11	11	11	11	11	11	11	10	10	10	10	9	9	9	9	9
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Biomass/Biogas	17	17	17	17	17	17	17	17	17	17	17	3	3	3	3	3
Total Existing Resources	8,548	8,826	8,825	8,739	8,238	7,738	7,738	7,737	7,140	6,660	6,510	6,495	6,494	6,494	6,494	6,478
Customer Resources																
Energy Efficiency	80	193	328	482	641	791	926	1,053	1,186	1,276	1,308	1,350	1,392	1,438	1,480	1,525
Distributed Energy	65	82	105	124	137	154	164	168	184	209	236	264	294	324	344	353
Demand Response	83	83	83	98	165	205	230	255	280	305	330	355	355	350	350	350
Existing DR	83	83	83	83	105	105	105	105	105	105	105	105	105	0	0	0
Future DR	0	0	0	15	60	100	125	150	175	200	225	250	250	350	350	350
Total Customer Resources	228	358	516	704	944	1,150	1,321	1,477	1,651	1,790	1,874	1,970	2,041	2,112	2,174	2,228
Future Resources																
Natural Gas[1]	0	0	0	0	0	213	373	505	1,281	1,905	2,326	2,566	2,822	3,102	3,402	3,712
Combined Cycle	0	0	0	0	0	0	0	0	665	665	665	665	665	1,330	1,330	1,330
Combustion / Steam Turbines	0	0	0	0	0	0	0	102	204	816	1,224	1,428	1,734	1,734	1,734	1,938
Short-Term Market Purchases	0	0	0	0	0	213	373	403	412	424	437	473	423	38	338	444
Renewable Energy	64	89	398	451	462	460	459	519	518	595	612	661	702	722	729	749
Wind	20	20	20	20	20	20	20	20	20	20	38	38	38	58	64	82
Solar	45	70	378	431	442	440	439	499	498	496	494	543	584	584	586	588
Geothermal	0	0	0	0	0	0	0	0	0	80	80	80	80	80	80	80
Total Future Resources	64	89	398	451	462	673	832	1,024	1,799	2,500	2,938	3,227	3,524	3,824	4,131	4,462
TOTAL RESOURCES	**8,840**	**9,273**	**9,739**	**9,893**	**9,644**	**9,561**	**9,891**	**10,237**	**10,590**	**10,950**	**11,322**	**11,691**	**12,059**	**12,430**	**12,799**	**13,167**

(1) The breakdown between combined cycles, combustion turbines, and market purchases is for planning assumptions only. It does not represent what APS may elect do do during the procurement process. Those decisions will be made based on market conditions and economics at that time.

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CRA Charles River Associates

Arizona Public Service

Greenhouse Gas Legislative Review and CO_2 Price Outlook

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November 4, 2011

Barclay Gibbs consults to electric utilities, power project investors, and large industrial users of electricity. Using CRA's proprietary North American Electricity & Environment Model (NEEM), Mr. Gibbs has evaluated the impact of various Federal and state policies on generation technology expansion plans, electricity prices, and generation asset value. He has evaluated the reliability implications of proposed federal air pollution regulations and forecasted SO2 and NOx prices under those regulations, forecasted prices for Renewable Energy Credits (RECs), assessed the costs and benefits of expanding transmission to access remote windpower, evaluated the producer and consumer impacts of proposed export tariff changes in a North American electricity market, and forecasted the fuel cost pass-through from a utility to a large industrial user of electricity. Recently, he has worked on a market power evaluation of various proposed allocation schemes under EPA's proposed Clean Air Transport Rule (CATR). He also assessed the impacts of short-term coal market constraints on allowance prices under EPA's final Cross-State Air Pollution Rule (CSAPR). Prior to joining CRA International, Mr. Gibbs was a managing consultant in the Technology Strategy and Management Group at Navigant Consulting where he consulted on energy efficiency policy and bioenergy. Mr. Gibbs holds an M.S. in Technology & Policy from Massachusetts Institute of Technology, an M.A. in Applied Economics from Johns Hopkins University, an M.S. in Environmental Systems Engineering from Clemson University, and a B.S. in Chemical Engineering from Bucknell University.

The conclusions set forth herein are based on independent research and publicly available material. The views expressed herein are the views and opinions of the author and do not reflect or represent the views of Charles River Associates or any of the organizations with which the author is affiliated. Any opinion expressed herein shall not amount to any form of guarantee that the author or Charles Rivers Associates has determined or predicted future events or circumstances, and no such reliance may be inferred or implied. The author and Charles River Associates accept no duty of care or liability of any kind whatsoever to any party, and no responsibility for damages, if any, suffered by any party as a result of decisions made, or not made, or actions taken, or not taken, based on this paper. Detailed information about Charles River Associates, a registered trade name of CRA International, Inc., is available at www.crai.com.

Introduction

Arizona Public Service (APS) is embarking on its 2012 Integrated Resource Planning (IRP) process. In early August 2011, APS engaged Charles River Associates (CRA) to provide a review of recent Greenhouse Gas (GHG) policy developments and the current outlook for Federal CO_2 pricing. This policy paper reviews the major recent developments in GHG policy, discusses some of the more significant and recent legislative proposals to curb U.S. GHG emissions, and provides recommendations for CO_2 prices in the current APS IRP.

Exhibit 1 summarizes some of the major historical elements of GHG policy development over the last 20 years, with particular emphasis on the more recent years. During the years 2007-2010, many federal legislative proposals addressing climate change surfaced. Since the summer of 2010, there has been almost no attention on federal climate change legislation. The policy debate in Washington has shifted more to EPA actions such as the Cross-State Air Pollution Rule (CSAPR), Air Toxics (formerly Utility MACT), once-through cooling regulations (316b), coal ash regulation, and EPA's own regulation of GHGs.

Exhibit 1. GHG Policy Timeline

Event	Description	Year	Comment
UN Framework Convention on Climate Change (UNFCCC), Rio de Janeiro	Nations agree to voluntary reduction of emissions, with "common but differentiated responsibilities"	1992	This "Earth Summit" is often cited as the beginning of global climate policy negotiation
Kyoto Protocol negotiated	First Internationally Binding Treaty; 160 Countries; 37 Developed Nations agree to cut emissions 5% below 1990 levels by 2012	1997	The Kyoto Protocol was never submitted to the US Senate for ratification
McCain (R-AZ) -Lieberman (D-CT) Climate Stewardship Act proposed in US Senate	First major U.S. Climate Bill	2003	Defeated in the Senate 55-43
European Emissions Trading System (ETS) begins	Europe establishes a cap-and-trade system for CO_2, aimed at Kyoto compliance	2005	Controversies over profits based on allocation scheme
California's AB32 Policy signed into Law	Emissions reduction goals are roughly in-line with Kyoto	2006	Cap-and-trade start date was recently delayed until 2013
Bingaman (D-NM) – Specter (R-PA) propose the Low Carbon Economy Act of 2007	Cap-and-trade climate bill with a relatively low safety valve (called a Technology Accelerator Payment, TAP) of \$12/tonne of $CO_{2\ Eq.}$	2007	Bill never made it out of the Senate Environment and Public Works committee
Lieberman (I-CT) –Warner (R-VA) Climate Security Act	Highly prominent climate bill makes it to main Senate floor but dies in a procedural vote	Oct 2007-June 2008	June 2008 marks the end of significant climate change debate during the Bush Administration

Exhibit 1. GHG Policy Timeline (cont.)

RGGI Cap-and-Trade program begins	10 Northeast states begin cap-and-trade policy that reduces emissions by 10% by 2018	Fall 2008	Allowances have typically traded at the minimum reservation price in recent years. *Gov. Chris Christie has recently announced withdrawal of NJ.*
Waxman (D-CA) –Markey (D-MA) American Clean Energy and Security Act (ACES) is passed by the House		June 2009	Reflects optimism for US Climate legislation in the early days of the Obama administration
A bill competing with Waxman-Markey is introduced	Kerry (D-MA) – Boxer (D-CA)	Fall 2009	
Conference of Parties 15 (COP15), Copenhagen Accord	High-profile, regular meeting of the Conference of the Parties to the UNFCCC	Dec. 2009	Non-binding agreement on emissions targets. A significant outcome was $100B/yr pledged from rich countries to poor countries. Generally viewed as achieving less progress than anticipated.
Negotiations on a grand compromise involving Senators Kerry (D-MA), Lieberman (I-CT), and Graham (R-SC) break down	Graham withdraws from negotiations, citing immigration politics	April 2010	Symptomatic of intensifying partisanship in Washington, particularly around regulation
Kerry (D-MA) – Lieberman (I-CT) American Power Act is proposed	The two senators move forward without Senator Graham	May 2010	Nothing substantial happened with this proposal
Waxman (D-CA) -Markey (D-MA) American Clean Energy and Security Act (ACES) dies in the Senate	Originally passed by the House in June 2009, the Waxman-Markey bill dies in the Senate	June 2010	Climate change legislation takes a back seat to other priorities on Capitol Hill.
The US House of Representatives becomes Republican-controlled and the Democratic majority in the Senate is weakened	Anti-regulation sentiment by incoming Republicans diminishes chances for comprehensive U.S. Climate policy, particularly under current economic conditions	Nov. 2010	
EPA prepares to regulate GHGs as part of NSPS		Scheduled 2011	

Summary of Recent Greenhouse Gas Policy Developments

Recent Federal Legislative Proposals

Bingaman-Specter (S.1766, Low Carbon Economy Act of 2007)

The Bingaman-Specter bill was introduced by Senators Jeff Bingaman (D-NM) and Arlen Specter (R-PA) in July 2007. The bill was more modest in its emissions reduction goals than many of the other major climate proposals. Its goals were to reduce economy-wide GHG emissions to 2006 levels by 2020 and to 1990 levels by 2030. In addition, the bill contained a cost-containment provision called the Technology Accelerator Payment (TAP) which was essentially a safety valve price of $12/tonne $CO_{2\,Eq.}$ starting in 2012, rising at 5% above inflation.[1] The TAP would have been paid into a fund that would have been used to hasten low-carbon technology development.

The Low Carbon Economy Act of 2007 never made it out of the Senate Environment and Public Works Committee.

Lieberman-Warner (S.2191, America's Climate Security Act)

The Lieberman-Warner bill was a high-profile piece of legislation introduced by Senators Joseph Lieberman (I-CT) and John Warner (R-VA) during October 2007. It was later amended by the Boxer amendment (D-CA). The cap-and-trade policy would have covered more than 75% of U.S. GHG emissions, including the six major GHGs (CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons) emitted from the electric, industrial, and transportation sectors. The proposal would have capped U.S. emissions at 2005 levels in 2012 before cutting them by 15% by 2020 and 70% by 2050.

After much publicized debate while the bill resided within the Senate Environment and Public Works Committee (EPW), the bill was killed in the Senate during June 2008. It was defeated by a procedural vote (cloture) without undergoing any significant debate on the Senate floor.

Waxman-Markey (HR.2454, American Clean Energy and Security Act of 2009) and Kerry-Lieberman (American Power Act)

The Waxman-Markey bill originally proposed during the Spring of 2009 by House Representatives Henry Waxman (D-CA) and Edward Markey (D-MA). The bill included a combined energy efficiency and renewable energy standard, reaching 20% by 2020. The economy-wide GHG emissions reductions would have been 3% by 2012 (relative to

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[1] $CO_{2\,Eq.}$ indicates *carbon dioxide equivalents*. This measure incorporates the differing global warming potentials (GWPs) of the various GHGs (CO_2 has a GWP of 1.0). A tonne is a metric ton, which is about 10% larger than a short ton.

2005 levels), 20% by 2020, 42% by 2030, and 83% by 2050. Heavy industry would not have been covered by the cap until 2014. The bill covered the same GHGs as Lieberman-Warner, with the addition of nitrogen trifluoride. The bill passed the House during June 2009.

In 2010, after the International Copenhagen Summit (COP15), the Kerry (D-MA)-Lieberman (I-CT)-Graham (R-SC) compromise negotiations received a lot of attention, as an alternative to Waxman-Markey in the Senate. The possibility for compromise was sought by this trio of Republican, Democratic, and Independent Senators representing northern as well as southern constituents. Compromise was being crafted around promotion of offshore oil drilling and delaying the implementation of GHG constraints on heavy industry. After Senator Graham pulled out of the negotiations (due to issues pertaining to immigration reform and the BP Gulf oil spill), Senators Kerry and Lieberman introduced the bill, the American Power Act, without Senator Graham. The American Power Act's GHG coverage and proposed emissions reductions were similar to those in Waxman-Markey. Public estimates of their allowance prices were similar also. The bill included a price floor of \$12/tonne $CO_{2\ Eq.}$, increasing at 3% over inflation and a price ceiling of \$25/tonne of $CO_{2\ Eq.}$, increasing at 5% over inflation. Because of the mechanism used for cost containment, the price ceiling could be broken under scenarios such as zero supply of international offsets.

The American Power Act included provisions to encourage the use of natural gas in the transportation fleet, to delay the implementation of GHG policy on heavy industry until 2016 (the rest of the economy would have been required to begin emissions reductions in 2013), to support offshore oil and gas development, and to support nuclear power development.

Little more happened in the Senate with regard to these two legislative proposals during the summer of 2010 as climate change took a backseat to other issues in the public discourse. Since the mid-term elections in the fall of 2010, there have been no major legislative proposals for addressing climate change.

Some State and Regional Level Developments

California's AB32

California's AB32 policy was signed into law by Governor Schwarzenegger in 2006. AB32 requires California to reduce its GHG emissions to 1990 levels by 2020 and 80% below 1990 levels by 2050. The 2020 cap represents an approximate 15% cut below 2012 emissions. The intended implementation schedule would have covered electricity (including imports[2]) and large industrial facilities in 2012, followed by distributors of fuels and natural gas by 2015.

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[2] The coverage of emissions from out-of-state generators that produce electricity for export to (and consumption in) California is expected to be difficult as a practical matter.

AB32 has been delayed a year and will begin in 2013. California carbon allowances have been trading in the $15-$22/tonne for 2013-2014 compliance. The market is thinly traded and is expected to remain so at least until the California Air Resources Board (CARB) approves the final market rules in late October 2011. The allowance pricing in California is indicative of the specific policy design of AB32 and is not necessarily an indicator of the impact of future Federal policy.

AB32 incorporates a variety of flexibility mechanisms such as allowance trading, banking, 3-year compliance periods, and the use of offsets.

Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) is a regional GHG trading program covering the northeast states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont). Governor Chris Christie (R-NJ) has recently announced the withdrawal of NJ from the program (NJ will cease to be part of RGGI in January 2012). RGGI is scheduled to reduce CO_2 emissions from power plants by 10% by 2018 relative to the 2009-2014 stabilization level. The stabilization level is 188 million tons, which is about 4% higher than the 2000-2005 actual emissions levels.

In recent years, the RGGI prices have been at or near the minimum reserve price of $1.89 per short ton. With reduced load (in part due to the recession), dispatch economics that are more favorable to natural gas than expected, and banking provisions, allowance prices in RGGI have been at or near the price floor. By 2018, the RGGI cap is supposed to be cut by 10% (to about 169 million tons). Current emissions are well under this level, implying that the RGGI policy will not be binding without revisions to the policy design and/or caps. A stakeholder process for reviewing the current RGGI policy has recently begun.

With respect to RGGI allowance trading during 2010, the average daily volume of RGGI futures trading ranged from zero to 1.3 million. Average daily trading in 2010 was 0.21 million allowances, in comparison to 2.7 million during the prior year. The total volume of trading for all of 2010 was 52 million allowances, in comparison to the 143 million allowances that were auctioned or allocated in 2010.[3]

Exchange traded volumes have contracted greatly over the last 12 months (to September 30, 2011) on the NYMEX and the CCFE (Chicago Climate Futures Exchange). The CCFE will close at the end of the calendar year 2011, with existing contracts and related trading rolling over to an over-the-counter (OTC) platform on the Intercontinental Exchange (ICE).

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[3] "Annual Report on the Market for RGGI CO2 Allowances: 2010," Potomac Economics, April 2011.

International Climate Negotiation Outcomes[4]

Copenhagen Accord at COP15

Going into the Conference of the Parties 15 (COP15) to the UNFCCC held in Copenhagen in December 2009, expectations for progress in the international efforts to address climate change were high. The Copenhagen meeting was a capstone to a process that had begun with the Bali Action Plan two years before. A political accord was struck at COP15. The accord calls for emissions reductions from all the major economies – this includes large developing countries such as China for the first time. However, it remains unclear how a binding agreement will be reached.

The conference in Copenhagen was characterized by discord. There were public divisions and arguments. Notably, at the close of the conference multiple countries were trying to block the Accord because they were outside of the room while it was being negotiated. These countries included Venezuela, Sudan, Nicaragua, and Bolivia. In addition, throughout the conference, there were frequent disagreements on approach between the U.S. and China.

Notably, the Accord included the pledge by developed countries to provide $100B per year of transition assistance by 2020 to developing countries. The Copenhagen Accord did include broad agreement on emissions verification procedures.

Cancun Climate Change Conference at COP16

Going into the November/December 2010 Cancun Conference of the Parties 16 (COP16) to the UNFCCC, expectations were low (relative to sentiments prior to COP15). At the conclusion of COP16, there was still no clear path to binding commitments for emissions limitations among the participating countries. However, further progress was made with respect to finance and transparency.

COP16 was less acrimonious than COP15 and the negotiations produced small successes breathing some life back into the UN process.

Summary of Recent Legislative Developments

Since the Waxman-Markey and Kerry-Lieberman bills failed during the summer of 2010, the discussion of federal GHG legislation in Washington has largely faded. This stands in contrast to relatively consistent and vigorous debate over the prior several years. Climate change policy was overshadowed by the national Health Care debate. The Republican victory in the House and the narrowing of the Democratic majority in the Senate has suppressed the legislative debate about GHG legislation. With continued sluggish growth in the U.S. economy and high unemployment, action on climate change appears lower on the national agenda than it was just a few years ago. Considerable anti-

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[4] This section is based on summaries written by the Pew Center on Global Climate Change.

regulation sentiment has also developed as part of a broader discussion about the role of government in the U.S. economy. It is against this backdrop that a massive and complex GHG bill would have to advance – a difficult political proposition at this time.

It seems highly improbable that federal GHG legislation could pass before the next federal election. With this mind and with the assumption that it would take at least one year to pass complex GHG legislation after the election, the earliest feasible date for passage is early 2014. Most GHG legislation has a 3-year implementation period, thus the earliest feasible date for implementation would be early 2017.

Recent EPA Actions on GHG Regulation / Implications for Utilities

EPA has entered into a settlement agreement with environmental organizations and several States to issue rules that will address GHG emissions from electric generating units and refineries. For gas-, oil-, and coal-fired electric generators, EPA committed to proposing regulations by July 2011 and finalizing them by May 2012. The July deadline was extended and EPA recently announced that they would not meet the extended deadline of September 30, 2011. EPA will likely negotiate a new deadline with the other parties to the settlement agreement.

When proposed and finalized, the regulations will take the form of New Source Performance Standards (NSPS) for new and modified generators and State emissions guidelines for existing generators. The NSPS will apply to new and modified generators if their construction begins after EPA proposes the NSPS. The states are given significant discretion under the Clean Air Act with respect to the timelines and stringency of applying EPA's guidelines to existing facilities.

CO_2 Price Trajectories from Recent Public Analyses

CRA reviewed the public analyses of recent GHG legislation by the U.S. Environmental Protection Agency (EPA), U.S. Energy Information Administration (EIA), and the Massachusetts Institute of Technology (MIT). The reviewed legislation includes the Lieberman-Warner, Waxman-Markey, and Kerry-Lieberman bills. Results for EPA are reported for both its ADAGE and IGEM models.[5]

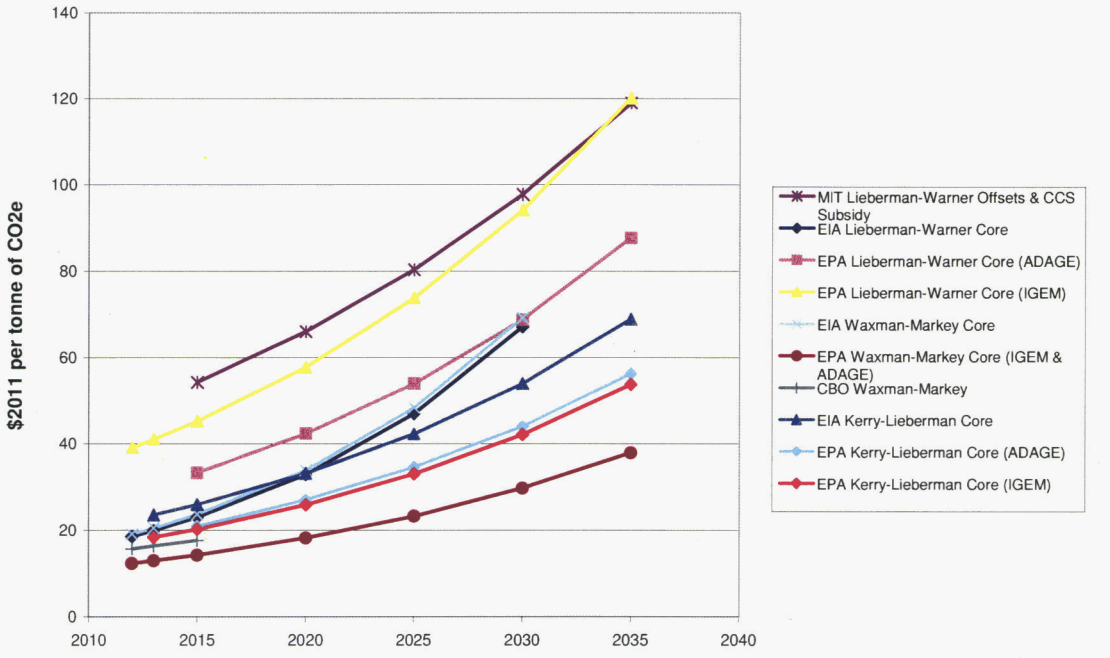
MIT did not evaluate all the bills, so we have only included MIT's Lieberman-Warner analysis. However, MIT did evaluate several GHG trajectories that were approximations

[5] The EPA models are the Applied Dynamic Analysis of the Global Economy (ADAGE) and Intertemporal General Equilibrium Model (IGEM).

of other bills[6] – from this analysis, we observe that MIT's projected allowance prices tend to be higher than those for EIA or EPA.

Exhibit 2 summarizes the "core" cases for the most recent legislation. We have put all of these trajectories into the same units (2011$ per tonne of $CO_{2\ Eq.}$).

Exhibit 2. CO2 Prices for Recent Proposals and Public Analyses



We note that with the exception of the MIT analysis and the EPA Lieberman-Warner (IGEM) analysis, the allowance prices tend to start in the range of $12 - $33 per tonne of $CO_{2\ Eq.}$. The two noted exceptions have higher allowance starting prices. Each price path exhibits the standard feature for a cap-and-trade policy that includes banking, namely the price rises at the model's discount rate (this price path prevents arbitrage across time).

We also note that these studies have a variety of sensitivity analyses associated with them (not shown) – key sensitivity variables include restriction on technology availability (e.g., carbon capture), energy efficiency deployment, and the availability of international and domestic offsets. We note that the availability of international offsets has a particularly large impact on the allowance price. For example, the EPA's analysis of Waxman-Markey has a starting allowance price that is 89% higher with zero availability of international offsets.

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[6] Paltsev, et al, *Assessment of U.S. Cap-and-Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change, Report No. 146.

Recommended CO_2 Allowance Price Projection

The future of global and U.S. GHG policy is uncertain. It is not known if federal legislation will ever pass, or if it does, when it will be implemented. The stringency of the caps and the resulting allowance prices are also not known. The co-evolution of climate science, macroeconomic conditions, and electoral politics will ultimately determine the U.S. GHG policy.

Based on our review of the most recent legislative proposals and the CA AB32 policy, we recommend the CO_2 price ranges below for the duration of APS's 15-year planning horizon. As was shown in Exhibit 2, most of the starting prices associated with public analyses of the most recent bills are clustered in the range of $12 - $33 per tonne of CO_2. However, this report has discussed the factors that lead us to recommend somewhat lower starting allowance prices. These mitigating factors include slowing of progress in international negotiations and the current U.S. political and macroeconomic conditions. These conditions suggest that future bills might be less strict/aggressive. We also suggested that early 2017 is the earliest feasible date for the implementation of federally legislated GHG policy – we feel it is prudent to expect implementation a year or more beyond 2017. Our recommendations are as follows:

Base Case. For the IRP's base case, we recommend using $12 (2011$) per metric tonne of $CO_{2\,Eq.}$ beginning in 2018-2020 and rising at 5% above inflation. This trajectory is highly plausible and represents a reasonable base case for planning.

Note that under cap-and-trade, CO_2 prices are typically projected to rise at the discount rate applicable to the business operations impacted by the CO_2 market. For example, if CO_2-emitters looked forward 3 years into the futures market and saw that the CO_2 price was higher than the discount rate would suggest, they would further cut emissions now and bank them to reduce compliance costs 3 years from now. The result, in aggregate, would be to push up current allowance prices and depress future prices. Given this type of calculation by market actors occurring over 40+ years, the price rise will tend to equilibrate at the discount rate. CRA assumes a 5% real discount rate applies to the cap-and-trade market, which is in line with other studies which typically are in the 4-7% range. A real discount rate reflects the rate over and above the general economy-wide inflation rate. In actual practice, changes in technology, fuel prices, energy demand, caps, and other parameters will yield actual prices for CO_2 that will vary over time.

Low Case. Given the current macroeconomic and political climate, we also believe it makes sense to consider a plausible scenario in which federal climate legislation is not enacted in the U.S. for decades.

High Case. We also believe it makes sense to evaluate a higher carbon price trajectory, for example $20 (2011$) per metric tonne of $CO_{2\,Eq.}$ beginning in 2018-2020 and rising at 5% above inflation. We do not believe this is the highest carbon price trajectory that is politically feasible, but it represents a reasonable upper bound to reflect probable policy over the next decade.

We also suggest to APS that it would be reasonable – depending on the horizon of the analysis - to assume a limit on the allowance price above which it could not rise any further (most relevant for the $20 high case). It seems likely that there is a price above which political support for a GHG policy (assuming one could pass) would deteriorate.

We also note that under GHG policy, natural gas prices will likely rise (relative to a business-as-usual forecast) in the short- to medium-term as the electric sector consumes more gas. In the long-term (after APS's 15-year planning horizon), the natural gas prices (exclusive of the CO_2 price) will likely fall (relative to a business-as-usual forecast) as advanced, low-carbon technologies enter the market in large-scale (e.g., carbon capture, new nuclear, etc.). With respect to the demand for electricity, a CO_2 price also will generally dampen the demand for power below a "business-as-usual" load forecast.

CO_2 Allocations to Utilities

The allocation of GHG allowances under a cap-and-trade program is one of the most contentious parts of climate change policy. The allocations represent the division and transfer of wealth. The government has the choice of 100% allowance auction, 100% free allocation, and all options in between. Moreover, the government can select the distribution of the free allocations, that is, the recipients of the transferred wealth. Because the possibilities for allocation design are limitless, potential recipients are put into the position of advocating for the most beneficial allocation. Allocation schemes are by nature contentious and arbitrary.[7]

Generally, the allocation scheme does not affect the compliance choices of energy producers and consumers. Exceptions to this generalization include: (1) the uses of auction revenue can alter decision-making (e.g., to reduce other taxes on capital and labor), (2) free allocations to cost-of-service utilities can lower electricity rates and therefore reduce the role of demand reduction in GHG compliance, and (3) the potential for market power (e.g., if all allowances were freely given to one party, market power would distort the production decisions).

The allocation that a particular generating unit would receive under a federal CO_2 policy in a particular year would be based on: (1) the cap itself, that is, the fractional reduction in emissions represented by the cap (e.g., if the cap were zero, then all units would receive zero allocation), (2) the fraction of total allocations distributed to the electric sector versus other sectors (and versus auctioned), and (3) the allocation among units within the electric sector, typically based on historic emissions. As the cap is tightened, the dollar value of each allowance increases.

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[7] In the non-carbon context, EPA's recently finalized Cross-State Air Pollution Rule (CSAPR) allocated units with SO_2 and NOx allowances primarily based on heat input. The final rule marked a significant departure from the proposed Clean Air Transport Rule (CATR) which allocated allowances based on historical emissions. The final CSAPR allocation benefits cleaner units at the expense of more heavily polluting units. This has been a contentious aspect of the CSAPR final rule.

The electric sector typically represents 35-40% of U.S. GHG emissions. The Lieberman-Warner proposal distributed 20% of total allowances to power plant owners and about 10% to load serving entities (LSEs) in 2012. Thus, the power sector was to receive allocations for roughly 80% of its emissions-based share ([10% + 20%] / 37.5%). By 2031, the power plant owners would have received none of the total allowances.

Under Kerry-Lieberman, about 74% of the allocations were to be freely distributed in 2013. By 2035, no allowances would have been freely allocated under Kerry-Lieberman. Of the freely allocated allowances, the Kerry-Lieberman bill would have freely allocated 51% of the allowances to the electric sector in 2013-2015 (before heavy industry is placed under the cap), 35% in 2016-2026, before tapering off to zero by 2030. Prior to 2027, the electric sector would have received slightly less than its emissions-based share.

As discussed above, the allocation of allowances is complex, arbitrary, and difficult to predict. One reasonable scenario would be to assume that the electric sector would receive 80-90% of the allowances that it needed during the first year of GHG policy implementation, and then reducing that quantity of allowances (tonnes) linearly to zero over the subsequent 20-year period. The value of these allowances ($) for the APS portfolio in any year would be equal to the number of allocated tonnes times the allowance price.

While the allocation of allowances to APS under any climate-change policy would be an important component in estimating the ultimate impact to APS electric rates, decisions related to future APS generation resources will be based on applicable CO_2 prices (along with demand growth, fuel prices, etc.). This is because allowances can be bought or sold at the prevailing market price. As such, any allowances provided to APS would not change the most economic resource expansion policy to pursue, notwithstanding impacts on demand growth.

Perspectives on Clean Energy Standards (CES)

Clean Energy Standards (CES) are similar to Renewable Portfolio Standards (RPS) except that natural gas-fired generation and nuclear power would be included in the mandated requirement. Typically, only a portion of the gas-fired generation would count toward the CES requirement.

The CES policy is a mandate for low-carbon power. The CES would result in a price for clean energy credits that power producers would consider in their generation decisions. For example, the CES credit price might encourage a generator to dispatch gas before coal, thereby creating a credit for CES compliance or sale. In contrast, a cap-and-trade policy or a carbon tax provides an economic disincentive to generate CO_2. While the two approaches are fundamentally different, a CES could conceivably be designed to roughly result in the same future generation mix as a cap-and-trade policy or a carbon tax. To achieve this comparability, one of the key choices in the CES policy design would be the treatment of gas-fired generation. If the objective of the policy is to reduce CO_2

emissions, a carbon tax (or cap-and-trade) would typically be a more direct and efficient means of doing so. In general, the CES would be a less direct method of reducing CO_2 emissions.

Appendix B

Water/Energy Nexus

Introduction

One of the symbiotic relationships that will challenge Arizona's quality of life in the next century is the relationship between power and water. Neither of these essential consumer needs can survive without the other. One of the greatest demands upon energy in a community is in the treatment, distribution, collection, and reclamation of water. One of the largest needs of a thermoelectric power plant is a predictable, reliable, and cost-effective supply of water used for cooling.

Water and energy have been closely aligned in Arizona for many years, an early success story being in the 1970s when the Palo Verde Nuclear Generating Station, soon to be largest nuclear power plant in the United States, searched for a location and a reliable cooling water supply to support generation. The planners embraced the largest water/energy project in Arizona's history, constructing the first nuclear power plant in the world that did not abut a lake, river, or ocean. In the 1970s, wastewater was often discharged with little or no beneficial use, but the plant's innovative use of approximately 70,000 acre-feet per year of wastewater allowed conservation of less sustainable or higher quality supplies, such as groundwater or surface water, to meet the needs of a rapidly growing state. For over 25 years, reclaimed water from the Sub-Regional Operating Group 91st Avenue Wastewater Treatment Plant has been delivered to the Palo Verde Nuclear Generating Station where it is further treated for use as cooling water. APS continues to explore use of reclaimed water and other renewable alternative water supplies for use as cooling water in pursuit of the "right water for the right use." As Arizona continues to grow, the beneficial use of available water supplies to generate the power needed for Arizona is being explored, and will include integrated planning between water and energy providers to improve the Company's ability to sustainably supply essential power to the communities served by APS.

Commission Decisions Related to Water/Energy Nexus

In Decision 72022 (December 10, 2010), the Commission directed the utilities to jointly procure or conduct a study of the water/energy nexus in Arizona. Subsequently, Decision 72174 (February 11, 2011) amended Decision 72022 and stipulated that "APS is welcome to address these issues when it files its integrated resource plan".

Development of the Water/Energy Nexus Project

APS is participating (along with Tucson Electric Power and the Salt River Project) in a project led by Sandia National Laboratories entitled, "Energy and Water in the Western and Texas Interconnects". In addition to this project representing the first comprehensive, regional analysis of the energy-water nexus, it is also the first coordinated analysis undertaken by federal and state agencies, the power industry, non-governmental organizations, and other interested stakeholders. One of the key deliverables from this project is an integrated Energy-Water Decision Support System that will enable planners in the Western and Texas Interconnection to analyze the potential implications of water stress for transmission and resource planning. Other supporting partners participating in this study include Argonne National Laboratory, Electric Power Research Institute, Idaho National Laboratory, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, and the University of Texas. For further information, please see attached Exhibit 1 for a project summary developed by Dr. Vincent Tidwell of Sandia National Laboratories.

Currently, this project is in its second year of three-year funding and should be completed sometime in 2013. Since its conception, APS has met with the principal investigator, Dr. Tidwell, on several occasions and has provided Sandia National Laboratories and Argonne National Laboratory technical support through the exchange of historical water use figures as well as drought contingency plans. On August 1, 2011, APS presented an overview of the project and the anticipated benefits and outcomes at its Integrated Resource Planning (IRP) Stakeholder meeting.

Exhibit 1

Project Summary

Project Title: Energy and Water in the Western and Texas Interconnects

Lead Laboratory: Sandia National Laboratories
Principal Investigator: Dr. Vincent Tidwell (email: vctidwe@sandia.gov)

Supporting Partners: Argonne National Laboratory
Electric Power Research Institute
Idaho National Laboratory
National Renewable Energy Laboratory
Pacific Northwest National Laboratory
University of Texas

Project Objectives: This proposal is in response to the Research Call to DOE/Federal Laboratories for "Technical Support for Interconnection-Level Electric Infrastructure Planning, RC-BM-20 10" Area of Interest 3: Water energy Nexus. According to the stated needs of the Research Call, three overarching objects are identified:

1. Develop an integrated Energy-Water Decision Support System (DSS) that will enable planners in the Western and Texas Interconnections to analyze the potential implications of water stress for transmission and resource planning.
2. Pursue the formulation and development of the Energy-Water DSS through a strongly collaborative process between members of this proposal team and the Western Electricity Coordinating Council (WECC), Western Governors' Association (WGA), the Electric Reliability Council of Texas (ERCOT) and their associated stakeholder teams.
3. Exercise the Energy-Water DSS to investigate water stress implications of the transmission planning scenarios put forward by WECC, WGA, and ERCOT.

Project Methods: Beyond efforts toward project management and reporting, eight additional project tasks are focused on the development of the Energy-Water DSS. The initial foundation for this tool is Sandia National Laboratories (Sandia) Energy-Power-Water Simulation (EPWSim) model. This existing framework provides an interactive environment for exploring trade-offs, and "best" alternatives among a broad list of energy/water options and objectives. The framework currently supports prototype modules for calculating thermoelectric power demand and related water use; water demand from competing use sectors; surface and groundwater availability, and; an energy for water calculator. Each of these modules will be updated and expanded, while additional process modules will be added.

Development of the DSS will be conducted in close cooperation with WECC, WGA, ERCOT and their stakeholder teams. To enhance transparency and consensus a Collaborative Modeling Team (CMT) will be assembled to oversee development of the Energy-Water DSS. Team membership will include a subgroup of our interconnection partners. The CMT will meet on a periodic basis with our project modelers to define: 1) key metrics and decision variable for inclusion in the DSS; 2) vet process models; 3) vet data, water use factors, etc; 4) jointly review the models and conduct calibration analyses; and 5) conduct desired scenario analyses.

The first module of the DSS calculates water withdrawals and consumption for current and projected thermoelectric power generation. Input to the model are WECC and ERCOT's transmission planning results. Water demands are calculated according to power plant capacity, production, type of plant, type of cooling,

and type of emissions control. Accompanying parasitic energy loads imposed by emission controls and water-conserving cooling technologies are also calculated. Using information on population growth, Gross State Product and historical water use trends, future water demands are calculated for competing water use sectors (municipal, industrial, agriculture, mining and livestock). The source of the withdrawal (surface water, groundwater, or non-potable water) is tracked as well as the return flows.

The DSS is also fitted with a water availability model that provides a regional measure of water supply for surface water, groundwater, and non-potable resources. The model has two principle components, "wet" and "paper" water. Wet water provides a measure of the physical water available in a basin for use, while paper water addresses the institutional controls (policies) that define access to the water. The model combines historical gauge data and other information to project surface and groundwater availability.

The water demand and availability modules are accompanied by additional process models to further resolve water availability. The first of these is an environmental controls model for identification and assessment **of** potential environmental risks associated with growing water use. A climate change calculator is included for estimating potential changes in water availability. This will include two components - a climate downscaling model to provide future climate forcing data for the watershed model and a dynamic large-scale watershed model to project related changes to water availability. Beyond the scarcity of water, information concerning the potential cost of water for a new withdrawal is calculated including water rights purchase, value of goods and their water intensity, and cost of treating non-potable water. Finally, an energy for water calculator is included to calculate electricity demand to pump, convey, treat (both primary and waste water), and distribute water.

The DSS is fitted with an interface that serves as the "dashboard" controlling scenario makeup, simulation operations, and the rendering of results. This dashboard provides an interactive, real-time environment comprised of slider bars, buttons and switches for changing key input variables, and real-time output graphs, tables, and geospatial maps for displaying results. The DSS operates on a laptop computer taking only few seconds to accomplish a simulation. The DSS can be distributed to users on CD or via download from the internet.

Project Benefits and Outcomes: A key deliverable from this project is an integrated Energy-Water DSS that will enable planners in the Western and Texas Interconnections to analyze the potential implications of water stress for transmission and resource planning. Working with WECC, WGA, and ERCOT and utilizing this Energy-Water DSS a wide range of transmission planning scenarios will be simulated and evaluated.

While timely accomplishment of these tasks is important and necessary, we are striving for broader impact. Currently there are no long-range, interconnection-wide transmission plans for the Western and Texas Interconnections. Consequently, the ability to assess how various infrastructure options balance reliability, cost, and the environment from an interconnection-wide perspective does not exist.

This project coordinated with the efforts of WECC, WGA, ERCOT and their partners will create a comprehensive package of stakeholder-vetted, regional planning models, data, and conclusions that are coordinated at the interconnection-wide level. Cumulatively, this information will substantially improve the quality and quantity of information available to industry planners, state and federal policymakers and regulators. Specifically, this project will supplement interconnection-wide transmission planning studies with information on water availability, which is critical in shaping electricity generation options. This proposed project represents the first comprehensive, regional analysis of the energy-water nexus. This is also the first coordinated analysis undertaken by federal and state agencies, the power industry, NGOs and other interested stakeholders. In this way, the data, models, scenario analyses, and insights derived from this effort will provide a significantly improved body of evidence for policy making at local, state and federal levels.