2017 INTEGRATED RESOURCE PLAN

APRIL 2017 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as “forecast,” “estimate,” “projection,” “may,” “believe,” “expect,” “plan,” “require,” “intend,” “assume,” and similar words. Because actual results may differ materially from expectations, APS cautions against placing 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 APS. A discussion of some of these risks and uncertainties is contained in APS’s Annual Report on Form 10-K filed with the Securities and Exchange Commission, available on APS corporate parent’s website at www.pinnaclewest.com, which should be carefully reviewed before placing any reliance on APS’s forward-looking statements, financial statements or disclosures. APS assumes no obligation to update any forward-looking statements, even if internal estimates change, except as may be required by applicable law.

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EXECUTIVE SUMMARY

Introduction

While the convergent forces of change in the power sector continue to redefine how electricity is generated, delivered and ultimately used by customers, APS's guiding vision remains resolute: to safely and efficiently generate and deliver reliable energy to meet the changing needs of our customers. The 2017 IRP establishes a 15-year blueprint to deliver on that vision by creating a portfolio of supply- and demand-side resources to manage the impacts of today's industry developments and to position the Company to successfully manage those that will arise in the future. Guided by the Company's planning principles of reliability, flexibility, affordability, sustainability and risk management, and informed by industry developments that are impacting utilities around the country, in particular the desert southwest, the 2017 IRP details the inputs and analytical framework used in the portfolio evaluation process and the conclusion that flexible resources continue to be key in maintaining power reliability while keeping costs low for customers. The 2017 Integrated Resource Plan leads to a cleaner sustainable energy mix that is anchored by the largest carbon-free electricity resource in the United States, the Palo Verde Nuclear Generating Station.

2017 IRP

Increase Flexible Generation to Manage Non-Curtailable Solar

Increase Grid Investment

Manage Increasing Market Impacts

Pursue Demand-Focused DSM

Continue to Utilize IRP as Primary Planning Vehicle

INDUSTRY BACKDROP

Regional mandates creating market challenges

Increased deployment of non-curtailable rooftop solar affecting resource needs.

Accelerating duck curve

The difference between minimum and peak loads is growing as demand continues to decline during midday hours.

Increasing customer interest in energy options

Customer awareness and interest in how best to optimize energy usage continues to increase.

Evolving load patterns

Minimum loads are getting lower, and peak loads are getting higher.

Gas price outlook continues to be low and stable

Long-term price projections for natural gas are low for the Planning Period and beyond.

APS PLANNING PRINCIPLES

Reliability

Ensuring that sufficient resources and the right types of resources are available to meet customer demand.

Flexibility

Having available a variety of solutions to meet the challenges of today's industry is key.

Affordability

APS's planning models are optimized toward a least-cost/best-fit solution.

Sustainability

The combination of Palo Verde's reliable carbon-free nuclear generation and the Company's solar leadership will continue to deliver a cleaner energy mix to APS customers.

Risk Management

The increasing penetration of non-curtailable solar is impacting resource diversity.

2017–2032 PORTFOLIO HIGHLIGHTS

The 2017 Integrated Resource Plan (2017 IRP) details how APS evaluates the most cost-effective and reliable means to meet the projected 13,000 MW resource requirement within its service territory through 2032. In the near-term, through 2021, the Action Plan details how resource needs will be met due to contract roll-offs and existing unit retirements. Over the longer-term, future decisions will be required to address the retirement of certain coal-fired units, contract rolloffs, and projected load growth. Over the course of the Planning Period, existing resource capacity will be reduced from 7,706 MW in 2017 to 5,703 MW in 2032, creating the need for 7,280 MW in additional resources to ensure reliability of service. Needs throughout the Planning Period may be met with existing resources in the region or new resources.

SUSTAINABLE PERFORMANCE UNDER HIGH GROWTH

↓23% Carbon Intensity

↓29% Water Intensity

↑50% Customer Demand

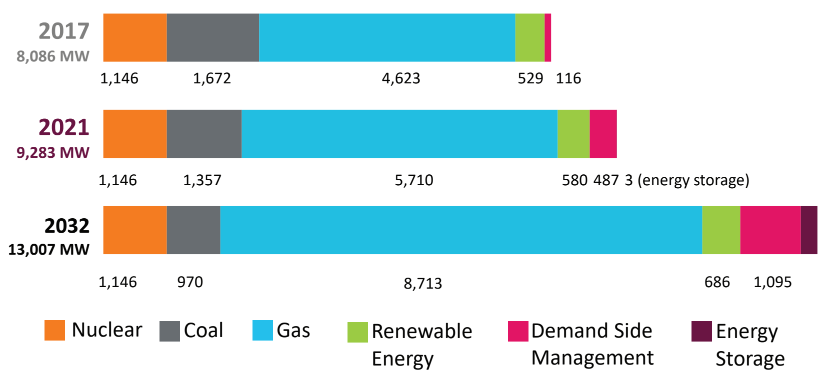
TABLE ES-1. PEAK CAPACITY: EXISTING AND FUTURE RESOURCES OF THE 2017 IRP SELECTED PLAN (FLEXIBLE RESOURCE PORTFOLIO)

	2017 RESOURCES	PPA EXPIRATIONS/ OCOTILLO STEAMERS	COAL REDUCTIONS	RESOURCE ADDITIONS	2032 RESOURCES
Nuclear	1,146 MW				1,146 MW
Coal	1,672 MW		-702 MW		970 MW
Natural Gas	4,623 MW	-1,297 MW		5,387 MW	8,713 MW
Renewable Energy	529 MW	-26 MW		183 MW	686 MW
Incremental DSM (EE + DR)	116 MW			979 MW	1,095 MW
Energy Storage	0 MW			397 MW	397 MW
TOTAL	**8,086 MW**	**-1,323 MW**	**-702 MW**	**6,946 MW**	**13,007 MW**
Renewable Energy with Existing Rooftop (Nameplate)	1,710 MW	-27 MW		3,315 MW	4,998 MW
Energy Storage (Nameplate)	4 MW			503 MW	507 MW

CAPACITY NEEDED TO MEET THE PEAK RESOURCE REQUIREMENT OF 13,000 MW

Capacity is the maximum amount of electricity a resource can produce and peak capacity is the maximum amount of electricity a resource can produce during peak demand. Table ES-1 and Figure ES-1 detail the peak capacity changes that will occur during the 2017-2032 Planning Period.

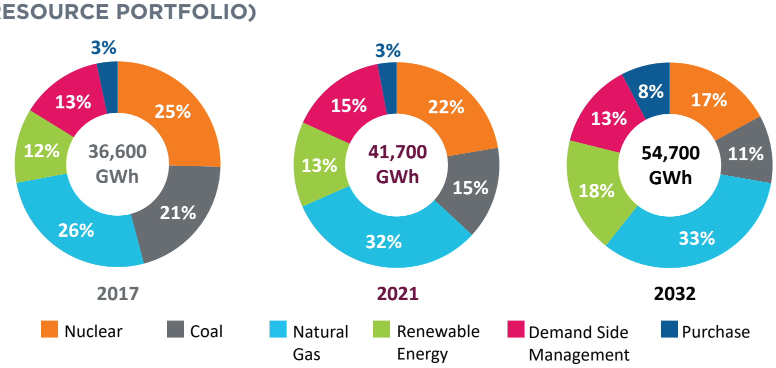
FIGURE ES-1. PEAK CAPACITY MIX OF THE 2017 IRP SELECTED PLAN (FLEXIBLE RESOURCE PORTFOLIO)



ENERGY MIX OF THE 2017 IRP SELECTED PLAN

Whereas capacity refers to the maximum amount of electricity a resource can produce in an instant of time, energy is the electricity that actually is produced and delivered to customers over a period of time. Figure ES-2 details the energy mix by resource for the beginning and ending years of the Action Plan Period (2017-2021) and the IRP Planning Period (2017-2032). While energy requirements are projected to grow over the Planning Period by over 50%, APS continues to reduce both CO2 and water consumption per unit of electricity consumed by 23% and 29% respectively.

FIGURE ES-2. ENERGY MIX OF THE 2017 IRP SELECTED PLAN (FLEXIBLE RESOURCE PORTFOLIO)



Future resources shown are for reference only. APS will make commitments to obtain specific resources through construction, acquisition, or market contracts at the appropriate time. Resources actually procured by APS may be different technologies than indicated.

Portfolio Selection

OVERVIEW OF IRP PROCESS AND PORTFOLIOS

The IRP was developed as a collaborative process that included a number of stakeholder workshops in which APS presented and took feedback from participants. As a result, APS considered seven portfolios in the development of the 2017 IRP – each offering different combinations of incremental or replacement natural gas generation, renewable energy, demand side management (DSM) programs, energy storage technologies, new configurations of nuclear-powered energy and declining amounts of baseload coal-fired generation. Four of the portfolios – Expanded Demand Side Management, Expanded Renewables, Energy Storage Systems and Small Modular Reactors – are included in accordance with Decision No. 75068.[1] Two additional portfolios, the Carbon Reduction and Resource Mandates Portfolios, were the result of stakeholder suggestions provided during the Stakeholder Forums held by APS in February and November 2016. Refer to Chapter 7 – Plan Selection for a further discussion of the Portfolios reviewed and to Attachment F.1 (a)(1) through F.1.(a)(7) for the Loads and Resources tables for each of the Portfolios summarized below.

PORTFOLIOS – BREAKDOWN BY CAPACITY AND ENERGY MIX CONTRIBUTIONS

TABLE ES-2. CAPACITY AND ENERGY MIX BY PORTFOLIO

	FLEXIBLE RESOURCE (2017 IRP SELECTED PLAN)	CARBON REDUCTION	EXPANDED DSM	EXPANDED RENEWABLES	ENERGY STORAGE SYSTEMS	RESOURCE MANDATES	SMALL MODULAR REACTORS
Description	Retire Cholla in 2024; demand reducing DSM; RE above compliance, flexible battery storage & gas generation	Retire Cholla in 2022, Four Corners in 2031; demand reducing DSM; RE above compliance, flexible battery storage & gas generation	Retire Cholla in 2024; energy reducing DSM; RE above compliance, flexible battery storage & gas generation	Retire Cholla in 2024; demand reducing DSM; RE well above compliance, flexible battery storage & gas generation	Retire Cholla in 2024; demand reducing DSM; RE above compliance, additional flexible battery storage & gas generation	Retire Cholla in 2024; plus expanded DSM, renewables and battery storage; gas generation	Retire Cholla in 2024; SMR; demand reducing DSM; RE above compliance, flexible battery storage & gas generation
Resource Contributions (2032 Namplate Capacity/% Energy Mix)							
Nuclear	1,146 MW / 17.1%	1,146 MW / 17.1%	1,146 MW / 17.0%	1,146 MW / 16.9%	1,146 MW / 17.0%	1,146 MW / 16.7%	1,716 MW / 22.3%
Coal	970 MW / 10.7%	0 MW / 0.0%	970 MW / 10.5%	970 MW / 10.5%	970 MW / 10.7%	970 MW / 10.3%	970 MW / 10.4%
Natural Gas	8,475 MW / 32.9%	9,616 MW / 42.6%	7,828 MW / 27.4%	8,259 MW / 30.4%	8,259 MW / 32.9%	7,181 MW / 26.4%	8,043 MW / 28.8%
Renewable Energy (RE & DE)	4,353 MW / 18.2%	4,353 MW / 18.3%	4,353 MW / 17.8%	5,052 MW / 21.7%	4,353 MW / 18.1%	4,697 MW / 19.6%	4,353 MW / 18.2%
Demand Side Management	922 MW / 13.4%	922 MW / 13.5%	1,547 MW / 20.8%	922 MW / 13.3%	922 MW / 13.4%	1,547 MW / 20.5%	922 MW / 13.4%
Demand Response & Microgrids*	420 MW	420 MW	420 MW	420 MW	420 MW	420 MW	420 MW
Energy Storage**	507 MW	507 MW	507 MW	507 MW	1,107 MW	1,107 MW	507 MW
Market Purchase	158 MW / 7.7%	158 MW / 8.5%	158 MW / 6.5%	158 MW / 7.1%	158 MW / 7.9%	158 MW / 6.5%	158 MW / 6.8%

*DR and microgrids are considered capacity resources and are not included in the energy mix.
**Energy storage does not create its own energy, so energy associated with it is reported under the source that provided the charging energy.

1 A.C.C. Docket No. E-00000V-13-0070 (May 8, 2015).

CHOOSING THE BEST PLAN: FLEXIBLE RESOURCE PORTFOLIO

BALANCED BLEND OF RESOURCES AND COST CONSIDERATIONS

The Flexible Resource Portfolio has a number of positive elements. It reduces carbon emissions through select coal reductions, continues to add more peak demand-reducing DSM, has a prudent level of energy storage, continues to add renewables and maintains operation of the Palo Verde Nuclear Generating Station. While the other Portfolios each have positive attributes, they compare less favorably than the Flexible Resource Portfolio to meet APS system needs during the Planning Period.

The Flexible Resource Portfolio rates very well in terms of cost measures, including both 15- and 30-year net present value (NPV), system cost, cost shift and capital expenditures. It has a balanced energy mix with natural gas contributing about one third of its mix. Carbon emissions and water usage continue to decline and its mix of flexible resources (natural gas and batteries) makes it a good fit for reliability and affordability. It also allows APS customers to benefit from market opportunities through its operation in the western wholesale energy market. Overall, of the seven Portfolios evaluated, this Portfolio best balances resource needs with cost considerations.[2]

FIGURE ES-3. COMPARATIVE REVENUE REQUIREMENTS (NPV) 2017-2046

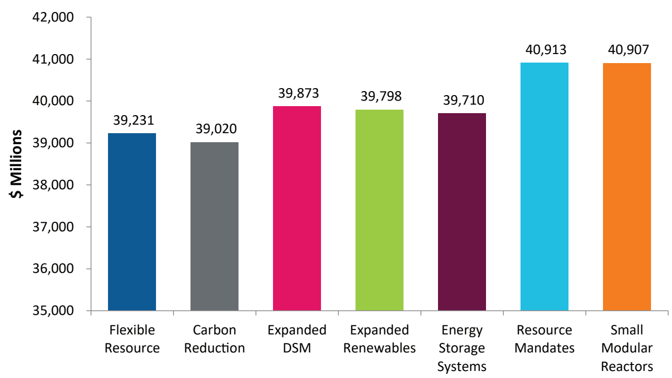


FIGURE ES-4. COMPARATIVE WHOLESALE MARKET PURCHASES IN 2032

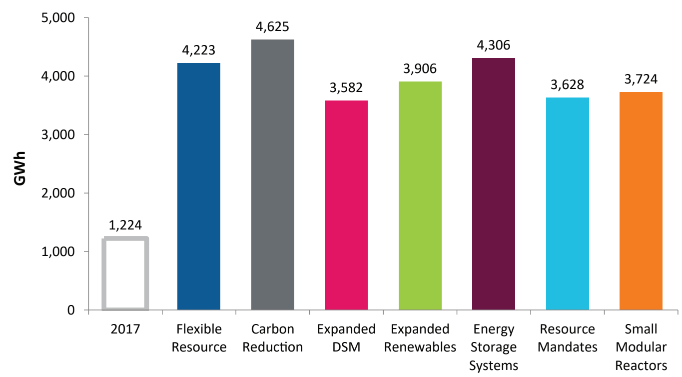


FIGURE ES-5. COMPARATIVE CAPITAL EXPENDITURES (2017-2032)

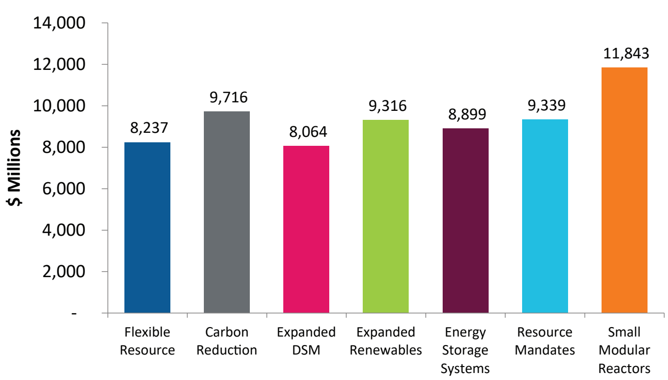
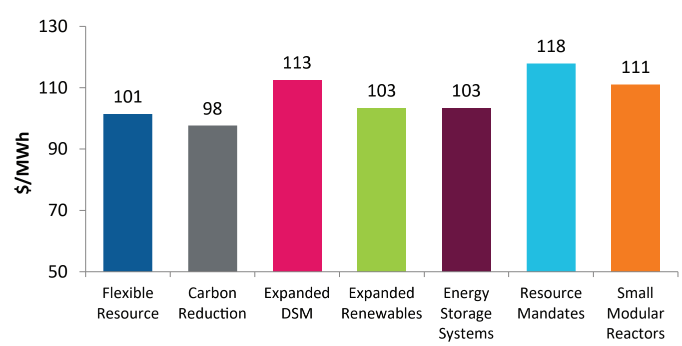


FIGURE ES-6. COMPARATIVE SYSTEM AVERAGE COST IN 2032



2 Moving through the Planning Period, circumstances governing current assumptions and forecasts will undoubtedly change and will be updated in future resource plans, potentially shifting the preferred Portfolio.

Planning Perspectives

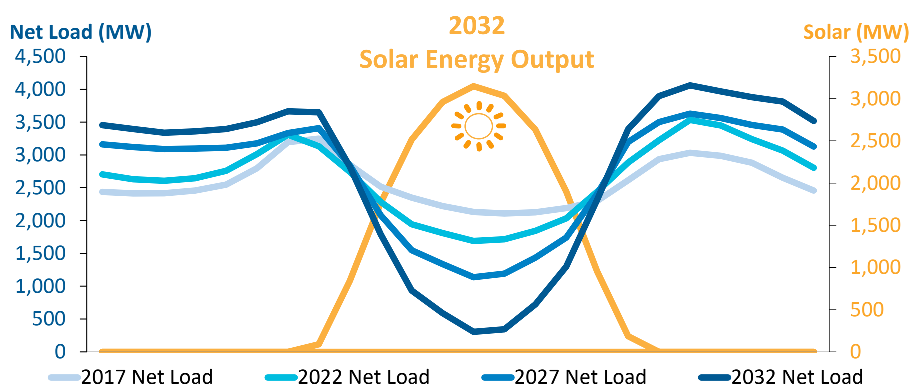
ENERGY TRENDS IN THE WEST

The electric industry continues to undergo significant change throughout the United States and particularly in the desert southwest. As a solar-rich state, Arizona has experienced a widespread deployment of non-curtailable rooftop solar and that trend is not expected to diminish. The reliability challenges inherent in integrating these resources include not only their level of deployment, but also the rate at which they have impacted seasonal and locational operations of the electric grid. By displacing other resources, even other renewable energy resources such as grid-scale solar, creating volatility in wholesale power prices and increasing the need for natural gas generation and local resources, non-curtailable rooftop solar resources have become one of the single most defining factors in western energy markets today. The other defining factor continues to be natural gas. By fueling flexible, dispatchable, low-emitting generation and its long-term, low-cost outlook, natural gas has become the resource of choice to manage an increasingly dynamic operating environment. Finally, the changes reshaping the industry also include significant developments on the customer side. Customers are becoming increasingly engaged in how they monitor and control energy usage, take advantage of more diverse rate options and embrace a more interactive role which will likely accelerate the pace of industry advancements going forward. This convergence of technology-powered resources and customer-driven views has set the stage for a refined power model to emerge. Regardless of the challenges imposed and associated impacts on both the bulk and local distribution grid, APS must maintain reliable operations for all of its customers in a cost-effective manner.

CHANGING SYSTEM CONDITIONS: ACCELERATING DUCK CURVE

With more than 300 days of sunshine annually, Arizona is a solar energy leader. APS drives that leadership with more than 1 GW of nameplate capacity on its system, including grid-scale and private rooftop solar. While this renewable energy source has some clear benefits, including no carbon emissions, it is also a variable resource which presents operational challenges when large quantities are added to the electric grid. For solar abundant regions like Arizona and the western United States, a particular challenge is the growing trend of declining minimum net loads in non-summer months and sharply changing patterns of maximum loads when solar energy resources stop producing. Commonly referred to as the "duck curve," these evolving net load shapes are projected to become more pronounced over time as non-curtailable rooftop generation continues to push system demand down during midday hours and rapidly ramp demand up when the sun sets. The progressively wider swings between the belly (trough) and the neck (peak) of the duck curve are boosting ramping requirements - the need for the system to quickly supply power to meet demand. APS currently projects ramping requirements by the end of the Planning Period to range from 4,000 MW to 5,000 MW daily.

FIGURE ES-7. INCREASING IMPACT OF NON-CURTAILABLE SOLAR ON APS NET LOAD SHAPES

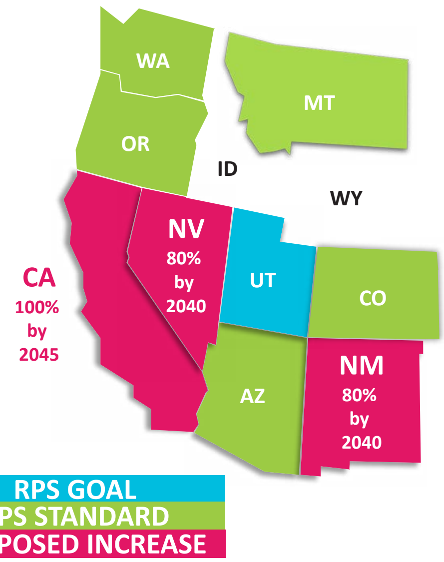


From a broader perspective, as Western states continue to raise the renewable energy contribution in their portfolios, in some cases due to increasing renewable mandates, the stress on the regional grid increases while planning options decrease.[3] Providing a platform to address these operating conditions and maintain system reliability requires an increase in flexibly dispatched resources to the portfolio mix. Rapidly responding units, critical in helping achieve a continuous equilibrium, can be ramped down or turned off when non-curtailable rooftop solar energy production is at its highest, and then ramped up to meet customer needs as the sun starts to set.

CHANGING REGIONAL CONDITIONS: MARKET IMPACTS ON BASELOAD RESOURCES

A combination of market, regulatory and policy decisions have coincided to pressure some baseload generation as well. Markets naturally seek out least-cost resources, yet policies and mandates are invalidating that natural order by artificially depressing wholesale market prices. While these policy-driven increases in non-curtailable rooftop solar deployment have also increased the need for flexible natural gas generation to maintain reliability on the system, they also have directly impacted diversity provided by baseload resources – including carbon-free nuclear generation. Nuclear generating resources such as Palo Verde Nuclear Generating Station may need to be curtailed to make room for must-take renewable energy and associated fast-ramping requirements made on the system by the duck curve. This has negative implications for a cleaner energy mix. Policy mandates that continue to increase variable and intermittent generation, such as solar and wind resources, add to the proliferation of these conditions, leaving less room for existing baseload resources to find their niche in the changing energy landscape. As several states have increased, or are exploring the potential to increase their renewable energy targets, the pressure on baseload resources builds further.

FIGURE ES-8. PROPOSED RENEWABLE PORTFOLIO STANDARD (RPS) INCREASES



Source: SNL – S&P Global Market Intelligence

CUSTOMIZE: ENERGY SOLUTIONS FOR CUSTOMERS

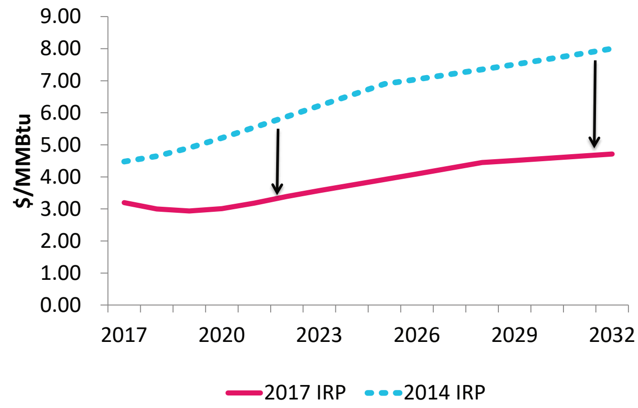
Empowered by access to greater information, more diverse rate structures, innovative cost-saving DSM programs and advanced grid technologies, customers are seeking more sophisticated solutions to manage their energy usage and goals. Whether the need comes from residential customers or larger commercial and industrial customers, a broad range of technology and program options are required to craft customized solutions while also improving system reliability and power quality issues at the local level.

3 S&P Global Platts, Megawatt Daily, CAL-ISO curtailments show renewables overload (March 10, 2017).

NATURAL GAS: RELIABLE, FLEXIBLE, LOW-COST ENABLER

Fueled by an abundant supply, low-cost natural gas generation provides the dispatch flexibility required to integrate the variable output of increasing levels of renewable resources on APS's system and regionally. With long-term price projections for this fuel remaining low over the course of the Planning Period and beyond, natural gas generation is a cost-effective, proven technology that provides much-needed summer peaking capacity, ramping capability and the dispatch flexibility needed to integrate renewable energy resources throughout the year. Natural gas is also a low emissions fuel and contributes to a cleaner energy mix.

FIGURE ES-9. GAS PRICE FORECAST (FORWARD MARKETS PLUS PIPELINE DELIVERY)



Planning Principles

In its 131-year history, APS has safely and reliably met customer needs, engaged in the communities it serves and mobilized its planning efforts to accommodate the next phase of energy growth and development for over 1.2 million households and businesses. New technologies and customer options have not changed those commitments; they have broadened the ways in which we can achieve a stronger grid and a cleaner energy mix. Customers are now expanding the many ways they can customize their energy experience and communities are exploring innovative energy solutions to support future economic development. APS's planning efforts are enlisting more resource types, both large- and small-scale (including distributed energy resources), to ensure APS continues its commitment to provide safe, reliable, and affordable electricity in the 21st century.

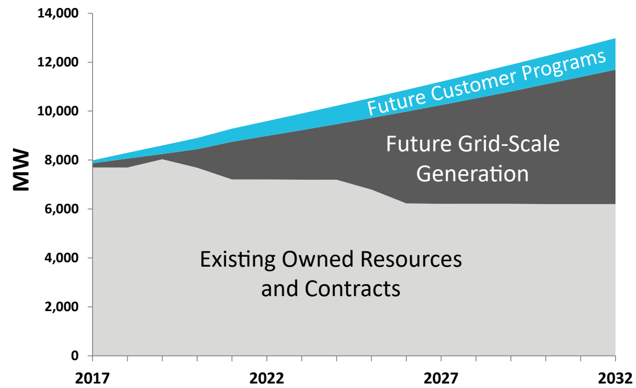
The Integrated Resource Plan process remains the best-suited platform to aggregate today's challenges with tomorrow's opportunities, ensure comprehensive planning efforts and pursue stakeholder engagement. To guide the creation and implementation of these strategic directions, the 2017 IRP is anchored on five planning principles: reliability, flexibility, affordability, sustainability and risk management.

RELIABILITY

Ensuring that sufficient resources and the right types of resources, including distributed resources and advanced grid technologies, are available to meet customer demand remains the cornerstone of resource planning.

Maintaining reliable service is at the forefront of APS's development of the 2017 IRP. By 2032, APS estimates that total electricity requirements will increase by over 50%. Additionally, capacity needs are expected to increase by 7,280 MW by the end of the Planning Period. In accordance with NERC reliability requirements and other criteria, APS maintains electric service under a variety of conditions including high summer temperatures and summer monsoons. Planning and operating reserves, along with robust transmission and distribution infrastructure, ensure electric service is provided under such conditions while maintaining least-cost, best-fit planning criteria. As market conditions continue to change, APS and other utilities are required to obtain resources that are both reliable and flexible because these two attributes have become inextricably linked with the introduction of significant levels of non-curtailable rooftop solar resources in the Southwest. These resources must not only meet a supply-demand gap, but also must maintain system reliability that is becoming increasingly variable.

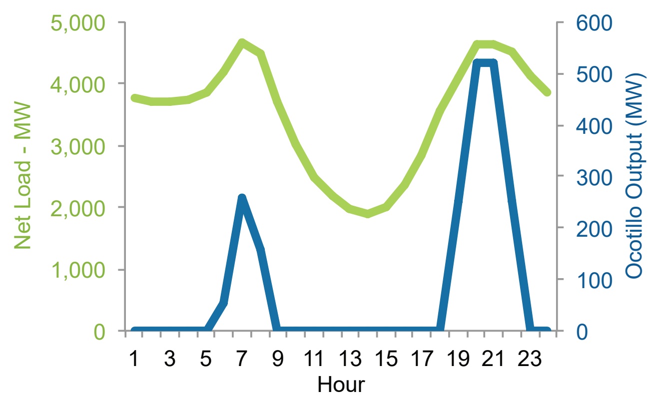
FIGURE ES-10. APS SUPPLY-DEMAND GAP (IN MW)



HOW APS IS RESPONDING TO CHANGING RESOURCE NEEDS

The Ocotillo Modernization Project (OMP), currently underway, is an example of how APS is responding to the need to maintain reliability by adding flexible resource capabilities on its system. The project, scheduled to be completed in 2019, consists of replacing two 1960s-era steam generators with five fast-starting, fast-ramping natural gas combustion turbine (CT) units with capacities of 102 MW each. By improving on an existing generation site located inside the Phoenix load pocket, the project provides power at an optimal location to maintain reliability for customers. Not only will Ocotillo meet summer capacity needs, it will also meet cycling and ramping requirements in the non-summer months. Figure ES-11 uses the net load graph for non-summer months and illustrates how OMP's operational characteristics may respond to the dual peaks created by non-curtailable rooftop solar penetration. To manage the challenges of meeting peak summer demand, APS plans to also add market combined cycle (CC) natural gas units to its system during the 2017-2032 Planning Period. In Arizona, having both types of natural gas-fired resources is important for a balanced natural gas fleet.

FIGURE ES-11. OMP CONTRIBUTION TO MEETING NET LOAD IN NON-SUMMER MONTHS



MICROGRIDS & BATTERIES

Microgrids are another example of resources that are particularly well-suited for the APS system. Not only do they provide needed backup power to customers, but also increase flexible capacity on the APS system to meet summer reliability requirements and provide additional services such as autonomous frequency response that make the grid stronger and more reliable.

FIGURE ES-12. MICROGRID

APS continues its leadership position in new technology development for customers by furthering its knowledge of storage through the Request for Proposal (RFP) process and through experience with two separate research and development projects which have this technology as a core component. The APS Solar Partner Program (SPP) incorporates two grid-scale battery storage systems that are interconnected to the distribution grid at strategic locations and seeks to evaluate storage as a local solution for power quality issues related to heavily penetrated solar feeders. The Solar Innovation Study (SIS) also incorporates storage systems, but only on the customer side. Through these small-scale projects, APS seeks to further understand the potential benefits of this technology and its synergies with other DSM-related technologies, and prepare for its wider-scale deployment once the cost and technology maturity outlooks improve.

ADVANCED GRID TECHNOLOGIES

APS is committed to success as a next generation energy company and recognizes that digitizing its grid is an essential step in achieving that goal. Operating under a more customer-centric platform, continuing advances in two-way communication technologies, grid health monitoring systems and state-of-the-art industry planning models that incorporate distributed energy resources are part of an intelligent network designed to increase reliability, system responsiveness and power quality.

FLEXIBILITY

From the fast-starting, fast-ramping capabilities of natural gas plants to transmission systems that give APS access to generation resources and market opportunities, the flexibility to seek out solutions from a variety of sources is key.

The energy challenges that have been growing in Arizona and other solar-rich regions of the U.S. are no longer a theoretical possibility; they are an operational reality. On one hand, as the state's economy recovers from the recession, the forecast for peak energy demand is on the rise. On the other hand, as Arizona boasts the #3 national ranking in total cumulative state solar PV installations,[4] the net demand for non-summer midday energy is declining. The divergent nature of these two trends requires utilities to not only re-examine how to balance supply with demand, but also how to plan for the future. Having sufficient resources, the right types of resources and a wide spectrum of customer options are key planning objectives and will become more so as solar energy continues to grow not only in APS's service territory, but regionally as well.

Ultimately, that is the key to flexibility: having an array of options to meet the challenge at hand. In addition to the dispatch flexibility of natural gas plants, such as the OMP, batteries and microgrid projects, generation resources are available in an increasing range of both type and scale. DSM programs are also offering customers greater diversity to fit their individual needs and markets are presenting new opportunities to reduce customer costs throughout the year. The more levers available for the Company to manage the impacts of external factors, such as changes in customer demand patterns, the more APS can reduce customers' exposure to various risks.

4 Solar Energy Industry Association, SEIA/GTM Research U.S. Solar Market Insight Report 2016 Year In Review (March 9, 2017), http://www.seia.org/research-resources/solar-market-insight-report-2016-year-review.

FOCUS: ENGAGE CUSTOMERS WITH OPTIONALITY

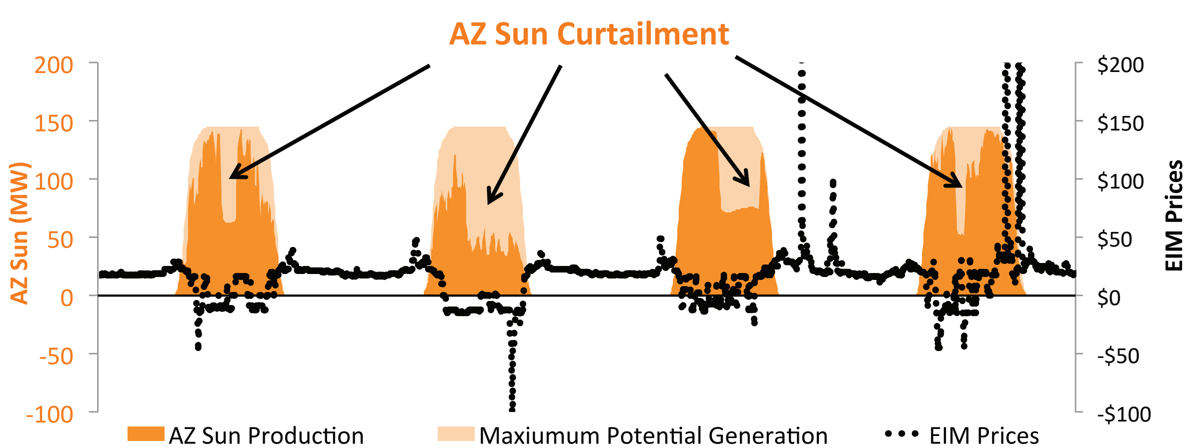
To achieve the right balance of resources at an affordable price, APS's least-cost, best-fit resource planning efforts account for changes in technologies, fuel prices, and growing customer demand for a wide range of technologies, devices and programs. Although the Renewable Energy Standard (RES) and Energy Efficient Standard (EES) have been useful in promoting some technologies, they were developed when renewable energy technology costs were high and customer awareness of energy-saving products and programs were low. Since then, renewable energy technology costs have come down and customer sophistication on energy optimization has increased significantly. Recalibrating planning efforts towards a greater support of evolving customer choices is needed to transition to the next phase of industry development. By giving customers the option to adopt new technologies and programs, should they so choose, a more cost-effective, customer-responsive approach to both APS portfolio needs and customer objectives can be achieved. This approach also supports APS's delivery of reliable, affordable service to customers when market conditions fluctuate.

CAPTURE: MARKET OPPORTUNITIES TO REDUCE CUSTOMER COSTS

Regional non-curtailable rooftop solar energy penetration, driven by falling photovoltaic (PV) panel prices and various state RPS programs to increase the contribution of renewable energy, have not only pushed down the belly of the duck (lowered the trough), but also have impacted regional wholesale market pricing during low load, non-summer months. Short-term market prices for electricity have at times fallen to zero and even gone negative – meaning the buyer gets paid to take electricity because there is too much energy on the system.

APS continuously looks at opportunities to lower customer costs through market opportunities such as curtailing its grid-scale solar resources (see Figure ES-13) and by turning down flexible generation to purchase surplus solar energy at the market's low/negative prices. These pricing opportunities, which APS customers continue to benefit from, could be diluted or even nullified going forward by policy initiatives that further expand renewable energy resources beyond current required levels. Should significant additional mandates occur in Arizona, APS may become a negative-price seller (paying others to take our energy) rather than a negative-price taker due to flexibility restrictions on non-curtailable rooftop solar and baseload generation.

FIGURE ES-13. NEGATIVE WHOLESALE POWER PRICING IN THE ENERGY IMBALANCE MARKET (EIM)



AFFORDABILITY

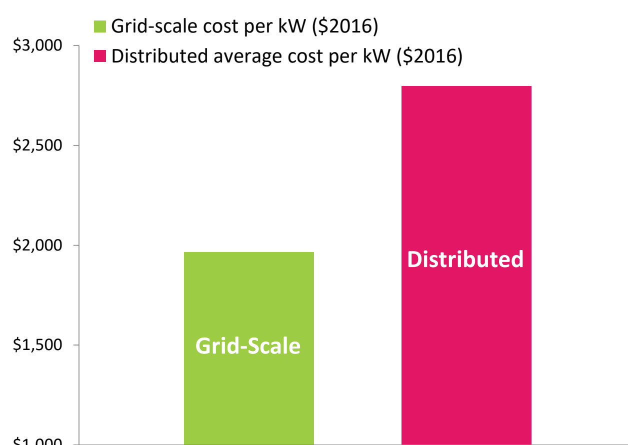
Recognizing that affordability is at the forefront of customer concerns, APS's planning models are optimized toward a least-cost/best-fit solution and its product line is expanding to offer customers more diverse options.

While delivering modernized energy choices to current and future APS customers is a key planning consideration, affordability is as well. To ensure that these considerations are approached in tandem, APS continues to improve its customer engagement efforts to include more diverse rate options and other advanced technologies to help customers select how best to manage their energy usage in their homes and businesses. Recognizing that while some customers are interested in adopting these latest technologies, other customers are more interested in keeping their energy bills within a budget. APS strives to give its customers choices to select from a wide range of options, depending on what best fits their needs, including sending the correct price signals that encourage sound customer decisions. APS remains cost-conscious and understands that low rates are an exceptional economic development tool as well. Finally, APS is exploring emerging technologies, such as energy storage, to better understand how a suite of advanced energy products and DSM programs can help customers achieve a "smarter" home. Through the totality of this process, APS's goals are to be prepared for technology, maximize value and promote long-term, sustainable solutions for customers.

ENERGY STORAGE: OUTLOOK FOR FUTURE USE

Emerging as a technology of interest, energy storage, in particular grid-scale battery storage, may become increasingly useful in helping manage evolving load shapes and providing system support. With 507 MW of grid-scale energy storage in the 2017 IRP Selected Plan (Flexible Resource Portfolio), APS recognized that this technology is more cost-competitive in large-scale applications than distributed storage (see Figure ES-14) and since it is utility-controlled, it provides more value to all customers. APS anticipates that the economics and technological maturity of grid-scale storage will improve over time, potentially warranting a greater contribution to the portfolio mix that could be even higher than the 1,100 MW in the Energy Storage Systems Portfolio. Such an increase in grid-scale storage could displace other resource additions and expand the Company's options in flexible capacity at an affordable price.

FIGURE ES-14. GRID-SCALE VS. BEHIND-THE-METER ENERGY STORAGE COST ESTIMATES ($/KW - 2016)



Data Source: IHS for grid-scale cost, manufacturers' estimate average for distributed -scale cost

Through the SPP and SIS, APS is exploring additional applications of battery storage including potential locational and power quality benefits of distributed storage capabilities. By increasing its expertise in this area, APS will be ready to deploy this resource on a wider-scale once costs become more competitive and technological performance is more certain under a variety of circumstances.

SUSTAINABILITY

The combination of Palo Verde's reliable carbon-free nuclear generation, the Company's solar leadership, flexible generation and installation of emissions controls at existing coal facilities will continue to deliver a cleaner energy mix to APS customers.

The sustainability activities of APS-operated power plants are founded on the principle that promoting Arizona's vibrant economy, protecting a healthy environment and supporting stable communities will strengthen our service territory for future generations. In 2017, APS expects to produce over 50% of its energy mix from carbon-free resources including renewable energy, energy efficiency and other DSM programs and, most importantly, the carbon-free nuclear generation from Palo Verde which in 2016 produced 32.2 million MWh – the only U.S. generating facility to produce more than 30 million MWh in a single year. Another milestone expected to be achieved in emissions control is a 90% reduction in NOx levels at Four Corners after the installation of selective catalytic reduction devices in 2018. During the course of the Planning Period, that commitment to clean energy will continue as APS evaluates further advances in water conservation, emissions control and waste management, in addition to supporting customers increasing interest in DSM solutions.

PALO VERDE: THE OTHER CARBON-FREE RESOURCE

Palo Verde provides carbon-free, reliable power that is essential to maintaining a clean energy mix. It is also the only nuclear plant in the world not located near a large body of water, using municipal reclaimed water for its cooling needs to preserve Arizona's most scarce resource. In 2016, 74% of APS's total water usage was effluent (reclaimed) water and that level is expected to increase to 77% over the next ten years. Across the APS-operated fleet, non-renewable groundwater usage is expected to be reduced by almost half from 13% in 2016 to only 7% during the same timeframe.

Under the 2017 IRP Selected Plan (Flexible Resource Portfolio), APS expects to meet increasing energy needs while reducing carbon and water intensity by 23% and 29%, respectively.

RISK MANAGEMENT

Changing market conditions are impacting operations and the economic viability of resources.

As the energy industry continues to deploy more non-curtailable rooftop solar energy resources, portfolio diversity is coming under increasing pressure at both the regional and local levels. To integrate the higher levels of variable and intermittent resources, a greater reliance on fast-acting natural gas generation is no longer just a low-cost choice, but also a necessity to maintain reliability. As costs continue to decline, the potential for energy storage to add value from both a bulk and local distribution management perspective does as well. Maintaining as much flexibility as possible, in not just the portfolio mix but also in how the portfolio can be adapted in a variety of market conditions, is essential to prudent management of market risks.

Increasing regional renewable portfolio standards are impacting regional baseload and combined cycle resources. Recently, the California Independent System Operator (CAISO) released a draft report that contemplates retirement of up to 10,000 MW of natural gas capacity resources. The study further notes potential reliability concerns and potential for load shedding events should significant natural gas resources retire.[5] A regional perspective must be utilized to evaluate resource diversity, allow for economic market opportunities, and maintain reliability. As such, the low-cost, best-fit model must incorporate resource diversity and dispatch flexibility to ensure that reliability, affordability and sustainability continue to be delivered to customers.

BEYOND THE PORTFOLIO MIX: ECONOMIC IMPACTS OF A CHANGING MARKET

The cumulative effect of these developments could potentially reduce portfolio diversity as some carbon-free resources may need to be curtailed or shut down for economic and/or operational reasons. This risk, should it occur, has implications beyond the fuel mix. Nuclear resources, although providing carbon-free, reliable power, are less flexible than natural gas energy sources. As more non-curtailable rooftop solar generation is added to the system, non-flexible assets lose their relative importance and risk being curtailed to make room for load-following natural gas energy production. Aside from decreasing diversity, one of the impacts of such a curtailment would be the increase in emissions and water usage as nuclear energy is completely emissions free and, in the case of Palo Verde, uses reclaimed municipal water for its cooling needs.

5 California Independent System Operator, 2016-2017 ISO Transmission Plan (March 8, 2017), https://www.caiso.com /Documents/Revised Draft_2016-2017TransmissionPlan.pdf.

Action Plan Highlights (2017-2021)

The 2017-2021 Action Plan highlights specific initiatives anticipated to occur in the near-term that support greater operational flexibility, increased market participation and enhanced customer engagement. Actual events during the 2017-2021 Action Plan Period will be based on conditions prevalent at the time of their undertaking. APS will file updates to its Action Plan whenever substantive changes occur, in compliance with Commission Decision No. 75068.

1. FUTURE RESOURCES

2016 ALL-SOURCE REQUEST FOR PROPOSAL

To help meet load requirements and maintain system reliability beginning in 2020, APS issued an All-Source RFP in March 2016. The RFP sought competitive proposals for capacity resources totaling approximately 400-600 MW for summer 2020 and beyond. Following a comprehensive review and analysis of the received bids, APS selected the 565 MW Arlington Valley, LLC Gas Tolling Agreement based on favorable economics and its ability to meet summertime peak load conditions. In 2017, APS will conduct another RFP to meet future summer season peak capacity needs for 2021 and beyond.

INITIAL PROJECT SITING ACTIVITIES

During the Action Plan Period, APS will continue to consider a wide range of opportunities for the next generation resource expansion to ensure customer needs are met reliably in future years. Through this ongoing process, APS will continue to screen for potential sites that could be development-ready and may take action to create options for additional development of resources should they be needed to maintain APS system reliability.

2. OCOTILLO MODERNIZATION PROJECT

Site work at the Ocotillo Power Plant has commenced, including the removal of the existing oil tanks. In addition, grading, foundation work and underground utility installation have begun and delivery of the first two of the five turbines is well under way. Additionally, in APS's Ten-Year Transmission System Plan, APS detailed the Ocotillo Modernization Project Interconnection Facilities project, which will include two onsite 230kV generation interconnection circuits for interconnection to the existing onsite Ocotillo 230kV Substation. The project is planned to be in service by summer 2019.

3. EVALUATE AND DECIDE ON REMAINING COAL FLEET

APS continues to execute its plans for the Four Corners Generating Station and evaluate its plans for the Cholla Power Plant. Cholla Unit 2 was retired on October 1, 2015, and APS plans to no longer burn coal in Units 1 and 3 beyond 2024.

Based on a February 2017 decision among current Navajo Generating Station (NGS) owners, APS will maintain its allocation of capacity from the plant through December 2019, provided an agreement can be reached with the Navajo Nation. As of the filing of this IRP, discussions regarding the future of NGS are occurring among a number of parties. APS will continue to participate in these discussions and update its Action Plan as decisions on this and other coal generation resources are made.

4. ADD TRANSMISSION RESOURCES

APS's 2017-2026 Ten-Year Transmission System Plan (filed January 31, 2017) includes 38 miles of 500kV transmission lines, 14 miles of 230kV transmission lines and five substations. The total investment for the projects is estimated at approximately $195 million.

TABLE ES-3. SELECT PROJECTS FROM APS'S 2017-2026 TEN-YEAR TRANSMISSION PLAN

PROJECT	DESCRIPTION	CONSTRUCTION START	CONSTRUCTION END
Mazatzal 345/69kV Substation	To provide the electric source and support to the subtransmission system in the area of Payson and the surrounding communities.	2015	2018
Ocotillo Modernization Project Interconnection Facilities	To interconnect new generators being constructed as part of the Ocotillo Modernization Project.	2016	2018
Morgan-Sun Valley 500kV Line	To increase import capability to the Phoenix metro area, as well as increase the export/scheduling capability from the Palo Verde Hub area.	2017	2018
North Gila- Orchard 230kV Line Circuit #l	To increase ability to import resources into the Yuma load pocket and improve reliability of the local system.	2019	2021

5. CONTINUE EXPANSION OF RENEWABLE RESOURCES

APS SOLAR PARTNER PROGRAM (SPP)

In 2015-16, APS designed and implemented the 10 MW APS Solar Partner Program, in part to better understand the ability of advanced inverters to help mitigate the power-quality issues that can arise with high photovoltaic penetration. In addition to the 10 MW of new photovoltaic capacity under the program, APS has deployed two battery storage systems, each rated at 2 MW/2 MWh for use in peak-shaving (flattening the net feeder demand) and distribution-system voltage management on two of the primary SPP research feeders.

SOLAR INNOVATION STUDY (SIS)

SIS is composed of two separate programs:

- A 75-customer APS-owned home energy management and rate research and development field program designed to examine the integration of customer-side advanced technologies – including rooftop solar, advanced inverters and home energy management systems – with demand-based rates. APS started recruiting for the 75-home pilot in February 2016, and technology installations continued through the fall.
- A similar market-facing program will examine the integration of rooftop solar with energy-related technologies like demand managers (such as load controllers). Participating customers will be placed on demand rates and will own all equipment in the study.

CUSTOMER SOLAR PROJECT (RED ROCK SOLAR GENERATING STATION)

In December 2016, Red Rock Generating Station, APS's new 40 MW solar PV plant, became fully operational. The facility is the result of a collaboration between APS with Arizona State University (ASU) and PayPal, the sole purchasers of the plant's green attributes. The Red Rock project, APS's largest grid-scale solar plant, combines economic development and the deployment of new renewable energy resources in a single, customer-driven endeavor that will benefit all APS customers through an incremental revenue contribution from ASU and PayPal.

INVESTMENT IN AZ SUN II

The purpose of the AZ Sun II program, which has been proposed in APS's general rate case settlement, is to expand access to rooftop solar for low and moderate income Arizonans throughout APS's service territory, including in rural Arizona. For this program, distributed generation would be defined as photovoltaic solar generation connected to the distribution system, and may include any multi-family housing (such as apartment buildings), Title I Schools, and rural government customers. APS will own all the generation, renewable energy credits and other attributes from this program to benefit all customers. APS will propose a program of not less than $10 million per year, and not more than $15 million per year, in direct capital costs for the program. All reasonable and prudent costs incurred by APS pursuant to this program will be recoverable through the Renewable Energy Adjustment Clause until the next rate case. This program is contingent upon Commission approval.

6. CONTINUE IMPLEMENTATION OF CUSTOMER-SIDE RESOURCES

DSM IMPLEMENTATION PLAN

On June 1, 2016, APS filed its Demand Side Management (DSM) Implementation Plan for 2017 and on January 27, 2017, filed a Modified 2017 DSM Implementation Plan. The modified proposed plan aims to achieve first-year energy savings of approximately 562,000 MWh in 2017 and makes progress toward compliance with the overall EES requirement of 22% by 2020.

The 2017 portfolio of DSM programs has been reshaped to greater emphasize load shifting and peak load reducing measures. In particular, the Plan proposes a new Demand Response, Energy Storage, Load Management (DRESLM) program designed to support the deployment of residential load management, demand response, and energy storage technologies that help APS residential customers shift energy use and manage peak demand.

MICROGRID PROJECTS

In December 2016, APS, with the U.S. Department of the Navy and U.S. Marine Corps, launched the nation's first utility-owned, fully-islandable microgrid located within the fence line of a DOD facility at Marine Corps Air Station (MCAS) in Yuma. This 21.6 MW project pioneered a new way to partner with a customer in which both parties make contributions to the project for the benefits of the direct (host) customer and APS customers. The MCAS Yuma microgrid can provide reliable power throughout the summer peaks to all APS customers by backfeeding the grid from within the base facility and, in the event of a grid outage, the facility can provide 100% backup power to MCAS Yuma, enhancing national security. Due to the ability of the microgrid to go from zero to full output in under 20 seconds, it also provides frequency response services to the grid, which will further enhance the economics and savings of this facility for all customers.

APS also worked with the Aligned Data Center to bring an 11 MW microgrid facility into service in the Phoenix metro area in December 2016. Similar to the MCAS Yuma microgrid, this facility can act as a peaking resource and provide frequency response to the broader grid as well as backup power in the event of a grid outage.

7. INVEST IN ADVANCED GRID TECHNOLOGIES

PROJECT ILLUMINATE

APS will continue to implement its state-of-the-art grid management system, Project Illuminate, which uses advanced technologies to improve internal visualization and diagnostic capabilities. The cornerstone of the project is an Advanced Distribution Management System (ADMS) that allows for automation of distribution field devices and significantly increases operators' visibility into real-time aspects of the APS system. The initial phase of the ADMS project went online January 25, 2017, and included the new Outage Management and Distribution Management Systems, along with the advanced engineering applications. The ADMS "phase two" initiative will strategically position APS at the forefront of distribution technology by providing the ability to remotely monitor and control the distribution system and associated devices.

8. CAISO ENERGY IMBALANCE MARKET

APS joined the CAISO EIM as a new participating Balancing Authority on October 1, 2016. With a smooth transition to the EIM platform, APS is seeing energy flows in every hour of every day which is resulting in customers savings. APS is working with other EIM entities and the CAISO to address some existing operational issues, including fine-tuning processes and modeling efforts.

Since APS joined the EIM, the CAISO has published the Fourth Quarter 2016 Western EIM Benefits Report. APS's gross benefits from EIM participation was approximately $6 million, with APS being a net exporter in both the 15-minute and 5-minute tranches in all three months of the quarter.

9. NATURAL GAS STORAGE

APS is exploring potential options to develop a natural gas storage facility to add capacity, enhance reliability and increase flexibility.

CHAPTER 1

LOAD FORECAST

Assessing Customer Needs

2017

LOAD FORECAST

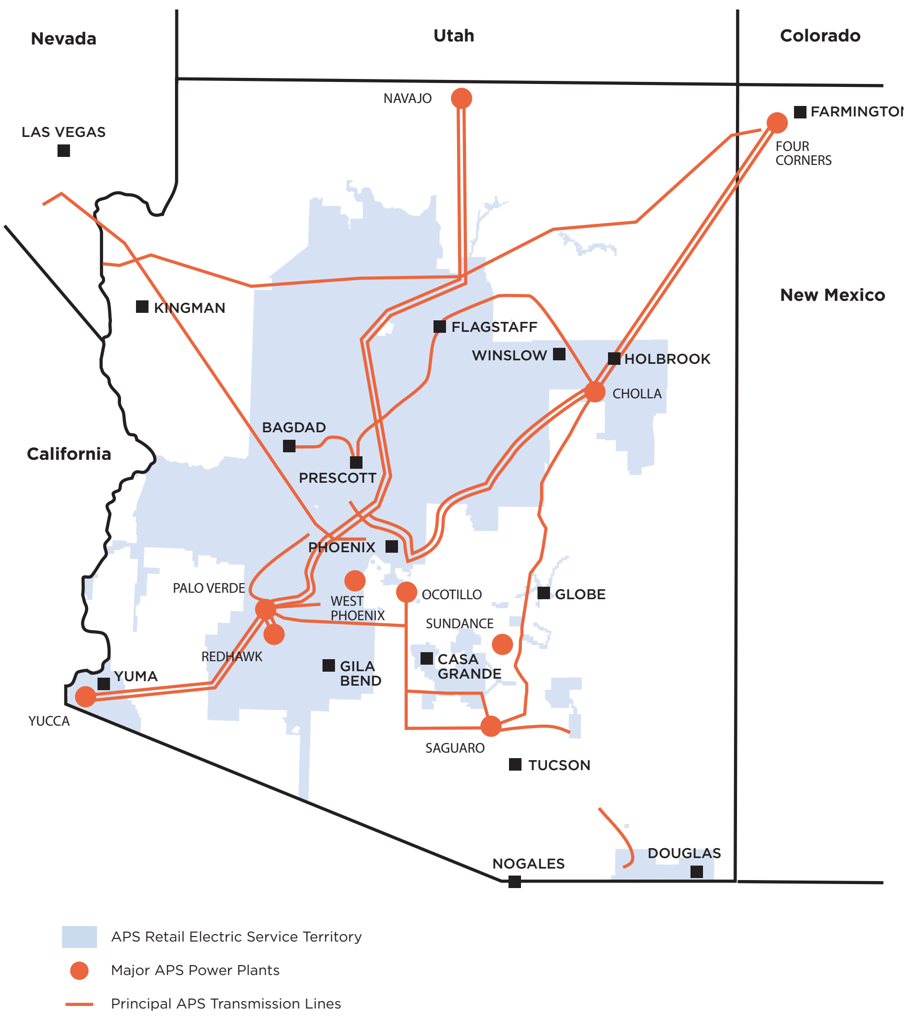
Overview

APS BACKGROUND

APS is both the largest and longest-serving electric utility in the state of Arizona with operations dating back to 1886. Today, APS provides electricity to 1.2 million customers in 11 of Arizona's 15 counties through a diverse energy portfolio of over 7,700 MW, including purchased power agreements but before customer-based resources, and transmission and distribution lines covering more than 35,000 miles.

The Company's 34,646-mile service territory spans most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. Wholly-owned by Pinnacle West Capital Corporation, APS is regulated by the Arizona Corporation Commission (ACC).

FIGURE 1-1. APS SERVICE TERRITORY MAP



APS'S ROLE IN ARIZONA'S ECONOMIC DEVELOPMENT

Economic growth in the state of Arizona is highly related to its relatively low cost of living and doing business while being situated next to a much larger region with a proportionately higher cost of living and doing business. APS believes that it has an important role to play in supporting robust economic development for the state of Arizona and further believes that the Company's contributions can best be made by providing reliable electricity at affordable prices, working directly with existing and prospective business customers to help them find solutions that meet their specific energy needs, and remaining open to the implementation of new and creative technologies which provide for the sustainable future many businesses are interested in today.

PROVIDE RELIABLE, AFFORDABLE ELECTRIC SERVICE

APS's primary contribution to supporting economic development is to keep the growth of overall energy costs for its customers at a manageable level. In its planning process, APS develops alternative resource portfolios which are then evaluated on the basis of:

- The overall cost to the customer
- The ability to reliably and dependably meet customers' current and future energy needs
- The degree to which each portfolio allows for a sustainable use of Arizona's resources
- The extent to which the Company, its customers – and by extension, the economy of the state of Arizona – are exposed to economic, technological, environmental and reliability risks

CUSTOMIZE SOLUTIONS TO MEET CUSTOMERS' UNIQUE NEEDS

APS remains committed to keeping Arizona a premier place to live and do business. Knowing that the Company's success is dependent on the success of its customers and the overall performance of the economy, the Company has several functions dedicated to helping customers optimize their energy usage for their individual needs:

- **Department of Economic Development –** Works directly with individual customers interested in locating a new site or expanding an existing site in Arizona
- **Solutions for Business Program –** Helps business customers find solutions meeting their energy needs in a more cost-effective manner
- **Department of Customer Technology –** Collaborates with new and existing customers to develop unique and creative opportunities to deploy technology that is both important to the customer – whether it be for backup power needs or sustainability goals – and that is also aligned with the cost and reliability goals of the Company in order to benefit all APS customers

UTILIZE IN-STATE FUEL SOURCES WHEN POSSIBLE

With respect to in-state versus out-of-state fuel sources, the state's resource endowment is somewhat limited. The state has no material amount of natural gas and no economic means of producing locally-originated nuclear fuel. Arizona does have coal supplies, but they are limited. Of the three coal-fired generating facilities partially owned by APS, one of the plants is served by a mine located in northern Arizona while the other two plants are served by mines in New Mexico. In terms of renewable energy options, Arizona is solar-abundant, but limited in other renewable energy resource types, including wind.

With that as an overall backdrop, APS strives to use locally provided fuel sources to the greatest extent possible, while considering cost and sustainability metrics. Other resources, such solar resources are available locally from an energy production perspective but components for their installations such as panels and inverters are often manufactured out of state and frequently in another country. Solar installation-related jobs are created through the deployment of these resources, but tend to be of shorter duration.

LOAD GROWTH FORECAST

Forecasting load is the foundation of resource planning, fundamental to analyzing not only how many resources the Company needs and when, but to an increasing degree, the type of resources needed. Weather, population growth, economic activity, and energy consumption patterns all play a role in determining future energy demand, and each is subject to variability, producing actual results that may vary from original projections. Also important is evaluating how those variables interact over the course of a 15-year period. Although future unknowns cannot be removed from the forecasting process, APS's robust forecasting methodologies are structured to address uncertainty over the Planning Period.

LOAD REQUIREMENTS EXPECTED TO EXCEED 13,000 MW BY 2032

By 2032, Arizona's population is projected to reach more than nine million. During that time, APS is projected to add 550,000 customers, increasing total electricity consumption by over 50%, or 3%, on a compounded annual growth rate basis, prior to the use customer resources, such energy efficiency, demand response and rooftop solar. This growth rate translates to a projected load that will require an additional 5,000 MW by the end of the Planning Period, prior to the effects of PPA expirations and coal capacity reductions. About a quarter of this increase is expected to be met with the use of customer resources, as discussed later in this section.

HOW THE NEED IS FORECASTED

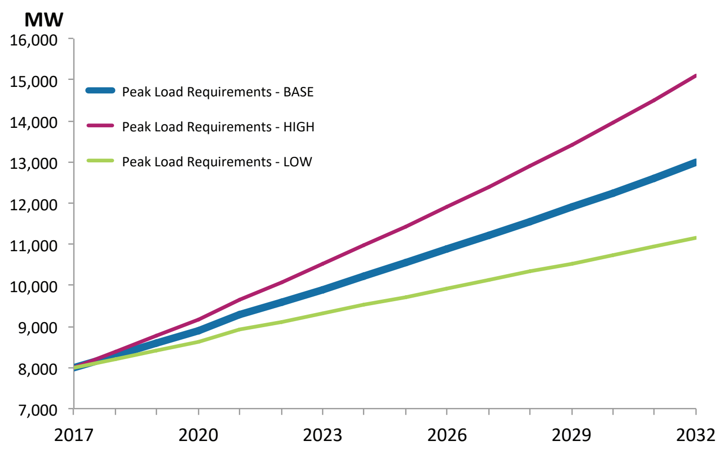
Future resource requirements are calculated based on a peak consumption hour growth rate under three scenarios – the Base Assumption, Low Load Growth and High Load Growth. The Base Assumption is that peak load growth, prior to customer resources, is expected to average approximately 3.3% annually over the next 15 years and result in a peak load of about 13,000 MW, including reserves. Under Low Load Growth conditions, the expectation within APS's service territory over the next 15 years is 2.3% average annual peak demand growth, which would result in a peak hour requirement in 2032 that is roughly 3,200 MW higher than that expected for 2017. Under High Load Growth conditions, the peak load annual average growth rate of 4.3% would result in over 7,100 MW of additional resource requirements by 2032.

FACTORS AFFECTING LOAD GROWTH

Population and Economic Growth

Economic growth rates are typically the single most influential factor when forecasting long-term changes in electricity demand. In Arizona, high population migration rates have historically contributed to the state's rapid growth in electricity demand and the need for greater supply. That demand has been bolstered by larger homes, more consumer electronics and greater commercial activity. Although the recent economic downturn paused that trajectory, APS expects that future growth will once again be driven by these factors as it has in the past.

FIGURE 1-2. APS LOAD FORECAST



Long-term economic growth in Arizona is primarily driven by growth in population. The Arizona economy has less heavy industry than the United States as a whole, with industries such as business services, health care, high-tech and aerospace manufacturing and tourism making up a larger share of the economy. The recent growth in health care is expected to continue in the long-term, and Arizona's regional position as a relatively low-cost state is expected to continue to drive population and business growth.

In the short term, the Arizona economy tends to move with the business cycle of the national economy. Among other national and state-level economic indicators, APS closely monitors housing permits and changes in construction employment when determining near-term patterns in customer growth.

NEW TECHNOLOGIES

The emergence of new technologies presents uncertainties to the pace of future electricity demand. New technologies can result in increased efficiency of existing appliances, transformational shifts in the use of electricity, such as electric vehicles replacing gasoline-powered vehicles or new uses like the increase of personal computers, cell phones, and tablets over the last two decades. The impact of new technologies on electricity consumption and peak demand is difficult to forecast not only due to the lack of historical data but also due to the uncertainty surrounding the scope of what technologies may arise over the course of the Planning Period.

ENERGY PRICES

Electricity usage has historically been only mildly responsive to price fluctuations. However, the current state of the industry's infrastructure may place inflationary pressures on electricity prices that, in some cases, may be more significant than in the past. Environmental regulation, the need for infrastructure development, the higher cost of emerging technologies and fuel cost trends will also likely influence the direction of power prices. The rising costs of generation may ultimately be reflected in the prices customers pay.

CUSTOMER RESOURCES

The three categories of customer resources, energy efficiency, demand response and rooftop solar are expected to contribute an increasing percentage to the APS resource mix over the course of the Planning Period. Energy efficiency resources are expected to increase by about 900 MW to meeting peak demand, demand response resources are projected to increase an additional 175 MW and rooftop solar is anticipated to increase to nearly 200 MW additional at peak. Achieving these levels will require significant participation by APS's customer base, which may be challenging depending on economic conditions and the economics of the specific measures. In addition, the costs associated with achieving these contributions over the next 15 years are uncertain. By comparison, these resources contributed over 850 MW over the last ten years.

PLANNING RESERVES

Planning reserves are required to maintain reliable electric system operations for APS customers. APS's capacity reserves provide at least a 15% planning reserve margin during APS's summer peak. The reserve margin level that is based upon a loss of load expectation (LOLE) of one event over a 10-year period (1 in 10) which is an industry standard metric for reliability. This metric is developed with a Loss of Load Probability (LOLP) calculation that is based upon historical and predicted reliability of APS generation units.

CHAPTER 2

MEETING FUTURE NEEDS

Existing and Future Resource Options

2017

MEETING FUTURE NEEDS

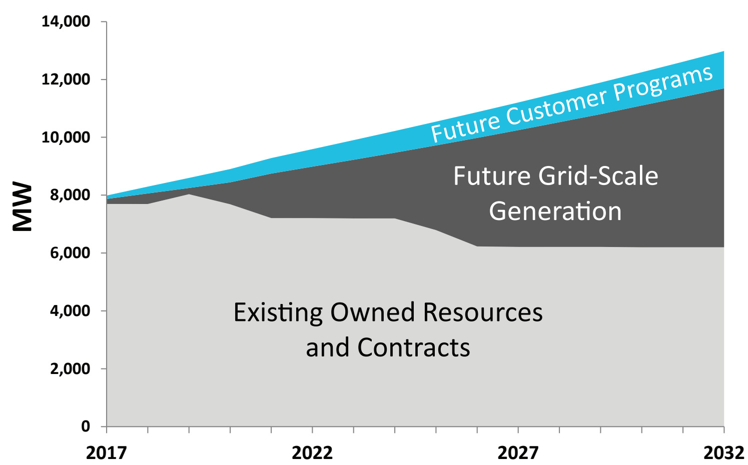
The difference between existing resources and the resources needed to meet customer needs is the supply-demand gap. With the resource requirement expected to grow to 13,000 MW over the course of the Planning Period and capacity available from existing resources decreasing by almost 2,000 MW due to expiring PPAs and unit retirements, the supply-demand gap is projected to total 7,280 MW by 2032.

To create a mix of existing and new, additional resources that will ensure reliability throughout the 2017-2032 time-frame, APS will rely on capacity from the following sources:

A. EXISTING APS RESOURCES

Palo Verde is the cornerstone of the APS fleet, providing reliable, carbon-free power to millions of customers. In addition, the Company's renewable energy portfolio includes over 1 GW of solar energy capacity, making APS the only utility outside of California to have surpassed that threshold. Needed to integrate variable solar resources, the natural gas portfolio provides low-cost, low-emitting and flexible capabilities. The DSM group of programs also contributes to affordability by giving customers a variety of options to manage their energy usage. Additional baseload power is provided by the Company's coal-fired generating units.

FIGURE 2-1. SUPPLY-DEMAND GAP (2017-2032)



B. FUTURE RESOURCE OPTIONS

New, additional capacity needed to close the supply-demand gap during the Planning Period will come from both generation resources and DSM programs and initiatives.

Generation Resources – In assessing generation resource options, APS considered conventional nuclear, small modular nuclear, coal, natural gas, grid-scale solar, rooftop solar, other renewable energy resources and storage.

DSM Programs and Initiatives – Regarding customer-based options, APS considered DSM programs ranging from those in current use to emerging concepts aimed at providing load shifting and integrative capabilities with advanced grid technologies.

Existing APS Resources

The map in Figure 2-2 details the location of APS's existing resource mix, with the exception of small-scale solar projects, utility-scale distributed resources (i.e., Bagdad), customer-side resources such as energy efficiency (EE), rooftop solar, demand response and conventional purchased power contracts. These resources are existing as shown in Attachment F.1(a)(1).

FIGURE 2-2. APS RESOURCE MAP

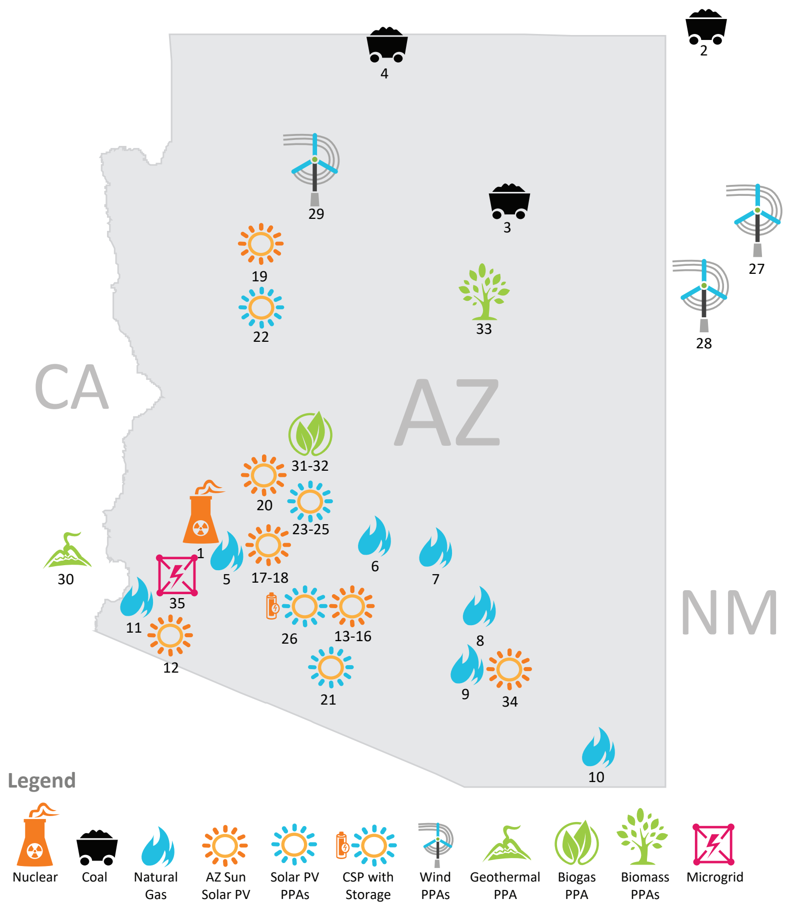


TABLE 2-1. APS EXISTING RESOURCES

TOTAL RESOURCES	9,327 MW
Nuclear	1,146 MW
Coal	1,672 MW
Natural Gas	4,183 MW
Owned Resources	3,106 MW
PPAs	1,077 MW
Microgrid	22 MW
Renewables	881 MW
Solar	562 MW
Owned Resources	237 MW
PPAs	325 MW
Wind (PPAs)	289 MW
Other (PPAs)	30 MW
Customer-Based	1,423 MW
Energy Efficiency	737 MW
Distributed Energy	660 MW
Demand Response	26 MW

TABLE 2-2. APS RESOURCE MAP NUMBER GUIDE

MAP #	PLANT	APS MW	IN SERVICE
1	Palo Verde	1,146	1986-88
2	Four Corners	970	1969-70
3	Cholla	387	1962-80
4	Navajo	315	1974-75
5	Redhawk	1,000	2002
6	West Phoenix	952	1972-2003
7	Ocotillo	320	1960-1970
8	Sundance	410	2002
9	Saguaro	176	1972-2002
10	Douglas	15	1972
11	Yucca	233	1971-2008
12	Foothills	35	2013
13	Paloma	17	2011
14	Cotton Center	17	2011
15	Gila Bend	32	2014
16	Desert Star	10	2015
17	Hyder	16	2011
18	Hyder II	14	2013

MAP #	PLANT	APS MW	IN SERVICE
19	Chino Valley	19	2012
20	Luke AFB	10	2015
21	Ajo Project	5	2011
22	Prescott Project	10	2011
23	Saddle Mountain	15	2012
24	Badger 1 Solar	15	2013
25	Gillespie	15	2013
26	Solana	250	2013
27	Aragonne	90	2006
28	High Lonesome	100	2009
29	Perrin Ranch	99	2012
30	Salton Sea	10	2006
31	Glendale	3	2010
32	NW Regional	3	2012
33	Snowflake	14	2008
34	Red Rock	40	2016
35	MCAS Yuma	22	2016

Existing Nuclear

POWER PLANT (APS MW ENTITLEMENT) – TOTAL: 1,146 MW

PALO VERDE NUCLEAR GENERATING STATION (1,146 MW)

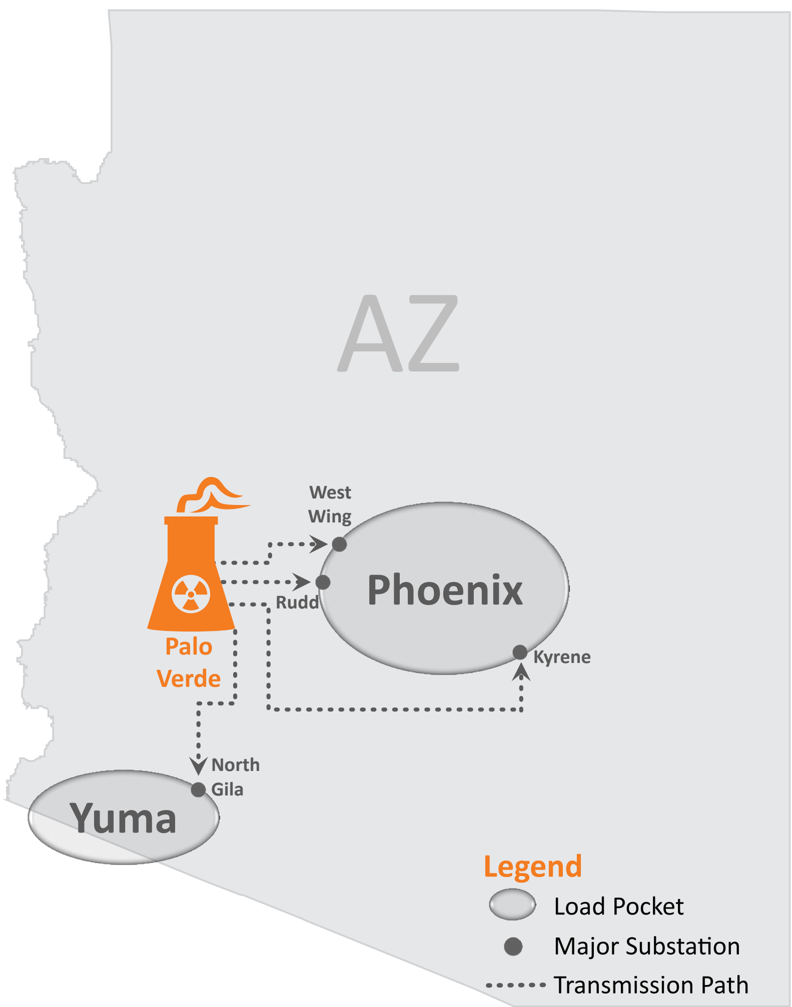
Palo Verde is a three-unit nuclear power plant located 50 miles west of Phoenix. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and has a combined ownership/leasehold interest of 29.1% in Unit 2. The NRC issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2 and 3 to June 2045, April 2046 and November 2047, respectively.

Palo Verde is the nation's largest power producer of any kind. In 2016, Palo Verde produced 32.2 million MWh of carbon-free energy – the only U.S. generating facility to produce more than 30 million MWh in a single year.

OTHER PLANT HIGHLIGHTS

- Total plant operating capacity: Over 4,000 MW (APS's share: 1,146 MW)
- Commercial operation of Units 1 and 2 began in 1986, and Unit 3 in 1988
- Provides electricity to 4 million people in Arizona, California, New Mexico and Texas
- Only nuclear power plant in the world not located near a large body of water
- Only nuclear power plant in the world that uses reclaimed municipal wastewater as its cooling water – on average, Palo Verde recycles 20 billion gallons of wastewater per year
- Has a $1.8 billion annual economic impact and is the largest single commercial taxpayer in Arizona
- Located at major trading hub in the West

FIGURE 2-3. HOW PALO VERDE MEETS CUSTOMER DEMAND



Existing Coal

POWER PLANTS (APS MW ENTITLEMENT) – TOTAL: 1,672 MW

FOUR CORNERS POWER PLANT (970 MW)

Four Corners Power Plant is comprised of two 770 MW units located near Farmington in the northwest corner of New Mexico. APS operates and owns 63% of the plant. Continued operation of Units 4 and 5 have large impacts on the region which benefit the Navajo Nation and local citizens significantly. The plant and the supporting mining operations have a $225 million annual impact on the Farmington and Navajo economies and provide more than $100 million per year in taxes, fees and royalties to the Navajo Nation and state, local and federal entities.

CHOLLA POWER PLANT (387 MW)

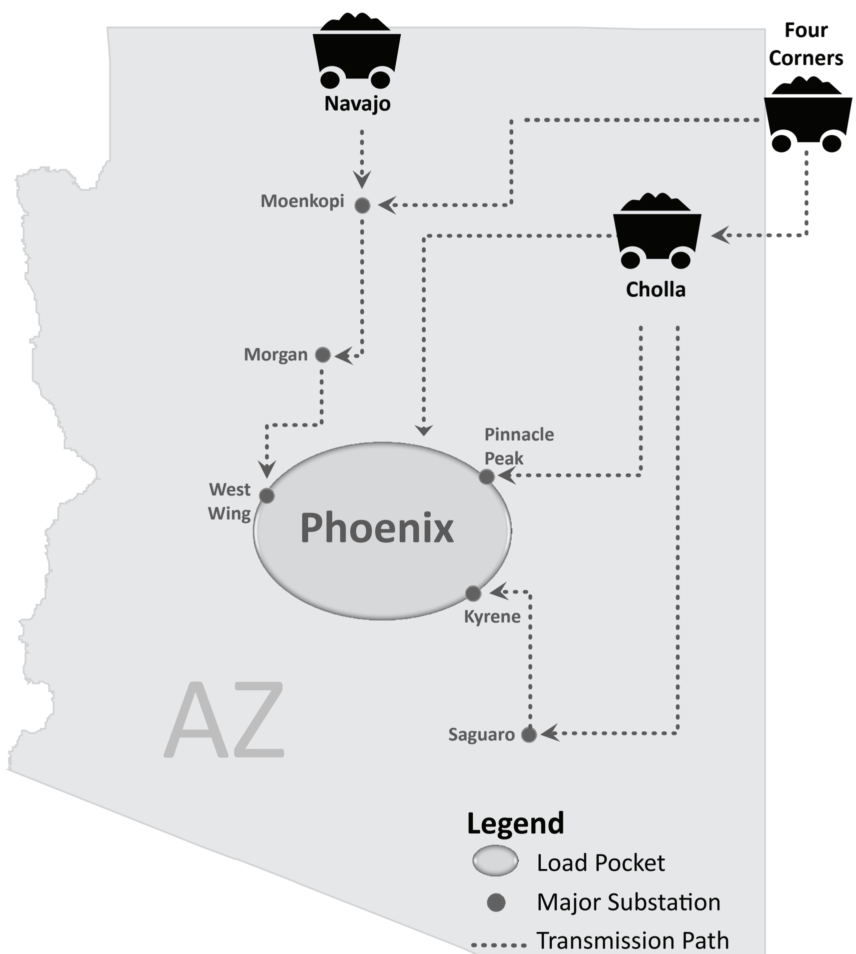
Cholla, originally a 4-unit coal-fired power plant, is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1 and 3. PacifiCorp owns the 380 MW Unit 4 – the largest unit at the plant. Unit 2 was closed on October 1, 2015 as part of an environmental agreement with the United States Environmental Protection Agency (EPA). Units 1 and 3 are projected to retire or no longer burn coal beyond 2024.

NAVAJO GENERATING STATION (315 MW)

The Navajo Generating Station (NGS) is located in northern Arizona on the Navajo Reservation near Page, and features three 750 MW coal-fired electric generating units. The plant is operated by Salt River Project, and is owned by a partnership of four utility companies and the U.S. Bureau of Reclamation. APS owns 14% of the plant.

On February 13, 2017, the joint owners decided to continue operation of NGS through December 2019, provided an agreement can be reached with the Navajo Nation.

FIGURE 2-4. HOW EXISTING COAL RESOURCES MEET CUSTOMER DEMAND



Existing Natural Gas

POWER PLANTS (APS MW ENTITLEMENT) – TOTAL: 3,106 MW

REDHAWK POWER STATION (1,000 MW)

Redhawk Power Station, which began operating in mid-2002, consists of two identical 500 MW natural gas-fueled combined-cycle units. Located 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. The plant is owned and operated by APS.

WEST PHOENIX POWER PLANT (952 MW)

West Phoenix Power Plant, located in southwest Phoenix, has seven natural gas-fueled generating units – two combustion turbine units and five units that employ combined-cycle technology. The plant is owned and operated by APS.

OCOTILLO POWER PLANT (320 MW)

Ocotillo Power Plant is currently a 4-unit gas plant. In early 2014, APS announced a $600-$700 million project to modernize the plant, which will involve retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 50 MW combustion turbines. In total, this will increase the capacity of the site by 290 MW, to 610 MW, with completion targeted for 2019. The plant is owned and operated by APS.

The OMP is critical to the Phoenix metro area and supports service reliability, improves the plant's appearance, offers environmental improvements, creates construction jobs and adds additional tax revenue to the local economy.

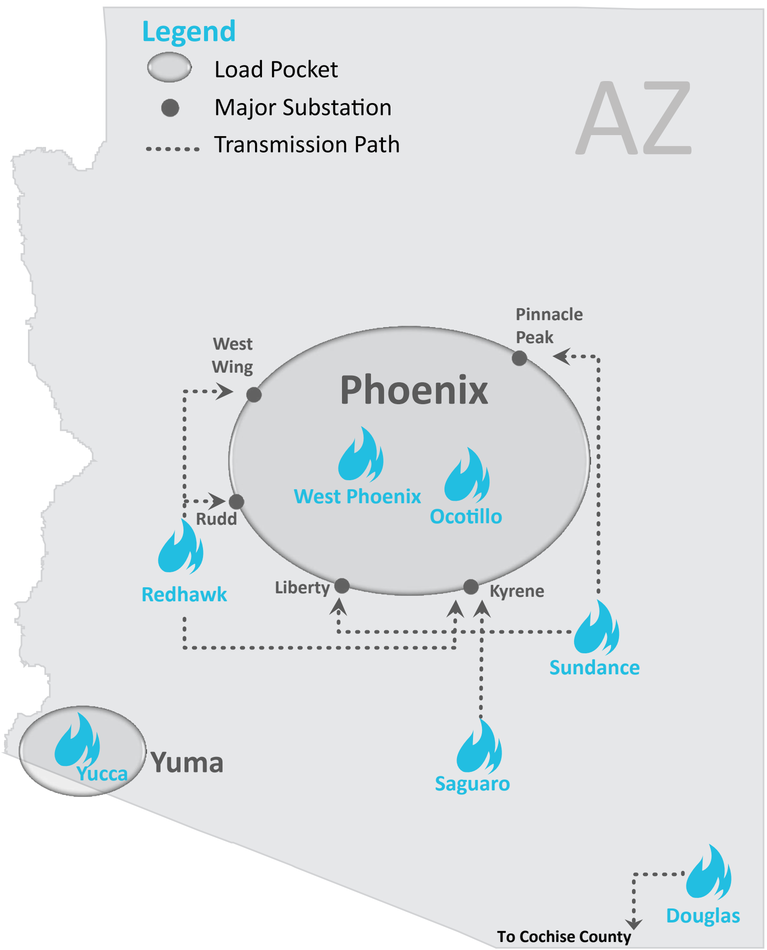
SUNDANCE GENERATING STATION (410 MW)

Sundance Generating Station in Coolidge, Arizona, is a natural gas-fueled combustion turbine plant that consists of 10 quick-start units. The plant is owned and operated by APS.

SAGUARO POWER PLANT (176 MW)

Saguaro Power Plant, a natural gas fueled facility located north of Tucson, Arizona, had two older steam units which retired in June 2013, and three combustion turbine units which are still in operation. The plant is owned and operated by APS.

FIGURE 2-5. HOW EXISTING NATURAL GAS RESOURCES MEET CUSTOMER DEMAND



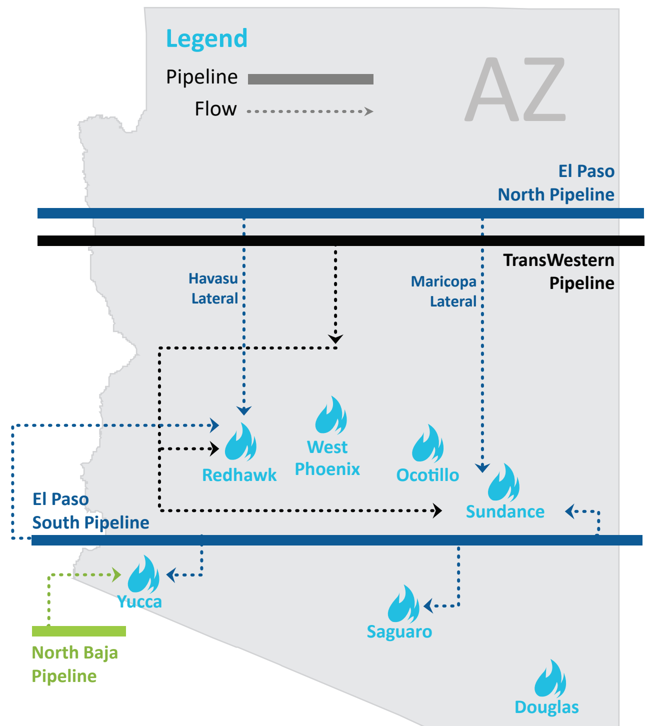
DOUGLAS POWER PLANT (15 MW)

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. The plant is owned and operated by APS.

YUCCA POWER PLANT (233 MW)

Yucca Power Plant, located near Yuma in southwestern Arizona, has (a) six combustion turbine units that produce 233 MW which are owned and operated by APS and (b) one 75 MW steam turbine and one 22 MW combustion turbine, both of which are owned by Imperial Irrigation District but operated by APS.

FIGURE 2-6. NATURAL GAS PIPELINE MAP



TOTAL NATURAL GAS PURCHASED POWER AGREEMENTS – TOTAL: 1,077 MW

Total Natural Gas Purchased Power Agreements at Beginning of 2014 IRP Planning Period	Total Natural Gas Purchased Power Agreements at Beginning of 2017 IRP Planning Period	Total Existing Natural Gas Purchased Power Agreements at End of 2017 IRP Planning Period
2,460 MW	1,077 MW	0 MW

Existing Renewable Energy (Grid-Scale)

Grid-Scale Renewable Energy (APS MW Entitlement) – Total: 881 MW

SOLAR – TOTAL: 562 MW

PALOMA SOLAR POWER PLANT (17 MW)

Paloma Solar Power Plant is a photovoltaic facility located in Gila Bend, AZ. The plant began serving customers in the third quarter of 2011, and is comprised of 280,000 thin-film fixed tilt modules. The plant is owned and operated by APS.

COTTON CENTER SOLAR PLANT (17 MW)

Cotton Center Solar Plant is a photovoltaic facility also located in Gila Bend, AZ. The plant began serving customers in the third quarter of 2011, and is comprised of about 93,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

HYDER SOLAR POWER PLANT (16 MW)

Hyder Solar Power Plant is a photovoltaic facility located in Hyder, AZ. The plant began serving customers in the fourth quarter of 2011, and is comprised of about 70,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

HYDER II SOLAR POWER PLANT (14 MW)

Hyder II Solar Power Plant is a photovoltaic facility located in Hyder, AZ. The plant began serving customers in the fourth quarter of 2013, and is comprised of more than 71,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

CHINO VALLEY SOLAR PLANT (19 MW)

Chino Valley Solar Plant is a photovoltaic facility located in Chino Valley near Prescott, AZ. The plant began serving customers in the fourth quarter of 2012, and is comprised of about 77,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

FOOTHILLS SOLAR PLANT (35 MW)

Foothills Solar Plant is a photovoltaic facility located near Yuma, AZ. Construction of the plant was completed in the fourth quarter of 2013. The plant is comprised of more than 182,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

GILA BEND SOLAR PLANT (32 MW)

Gila Bend Solar Plant, a photovoltaic facility located near Gila Bend, AZ, became fully operational in October 2014. Built on 400 acres, the plant is comprised of about 172,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

LUKE AIR FORCE BASE (AFB) SOLAR PLANT (10 MW)

Luke AFB Solar Plant is a 10 MW photovoltaic facility located on Luke AFB, seven miles west of the central business district of Glendale, AZ. Owned and operated by APS, the facility is comprised of 50,800 multicrystalline modules on a single-axis tracking system and became operational in the summer of 2015.

DESERT STAR SOLAR PLANT (10 MW)

Located on 100 acres in Buckeye, AZ, Desert Star became fully operational in June 2015. The plant, owned and operated by APS, is comprised of 50,800 multicrystalline modules on a single-axis tracking system.

AJO PROJECT (5 MW)

Ajo Project, a crystalline photovoltaic single-axis tracking system, is located near Ajo, AZ and reached commercial operation in September 2011. APS has a 25-year purchased power agreement for the entire project output.

PRESCOTT PROJECT (10 MW)

Prescott Project, located 2 miles north of Prescott Regional Airport, is a crystalline photovoltaic single-axis tracking system. APS purchases the generation output under a 30-year agreement, which began in November 2011.

SADDLE MOUNTAIN PROJECT (15 MW)

Saddle Mountain Project is a crystalline photovoltaic single-axis tracking system located near Tonopah, AZ. APS purchases the generation under a 30-year agreement, which began in December 2012.

BADGER 1 SOLAR FACILITY (15 MW)

Badger I Solar Facility, a crystalline photovoltaic single-axis tracking system located near Tonopah, AZ, reached commercial operation in November 2013. APS has a 30-year purchased power agreement for the entire output.

GILLESPIE (15 MW)

Gillespie, located near Arlington, AZ, is a crystalline photovoltaic single-axis tracking system. APS purchases the generation output from Recurrent Energy under a 30-year agreement, which began in December 2013.

SOLANA GENERATING STATION (250 MW)

Solana, located near Gila Bend, AZ, uses concentrated solar power (CSP) technology with a thermal energy storage system. APS purchases the generation output from Arizona Solar One (Abengoa) under a 30-year agreement, which began in October 2013.

RED ROCK (40 MW)

Red Rock is a 40 MW photovoltaic facility located in southern Pinal County, AZ and is comprised of 182,880 multicrystalline modules. The facility is an APS collaboration with PayPal and Arizona State University, the sole purchasers of the plant's green attributes. The plant is owned and operated by APS.

SCHOOLS & GOVERNMENT* (13 MW)

The solar installations for Schools & Government are fixed solar photovoltaic systems installed throughout the state of Arizona with a project completion at the end of 2012 and continuing through 2013. The program consists of 59 school installations which APS owns and operates.

LEGACY* (4 MW)

Legacy solar photovoltaic systems installed throughout the state of Arizona are a mix of fixed and single axis tracking systems. The fleet is comprised of 36 systems, representing the oldest of the APS-owned and operated solar facilities.

APS SOLAR PARTNER PROGRAM / FLAGSTAFF COMMUNITY PROJECT* (10 MW)

Approximately 1,600 rooftop solar systems installed on homes and completed at the end of 2016 in the Phoenix area, and 125 completed at the end of 2012 in Flagstaff. The solar photovoltaic systems are owned and operated by APS.

BAGDAD* (15 MW)

Bagdad is 15 MW crystalline photovoltaic single-axis tracking facility, under which a third-party contracts with APS to buy back the entire 15 MW under a 25-year agreement which began in December 2011.

*Diverse small-scale solar projects and utility-scale distributed resources are not shown on the APS Resource Map.

WIND – TOTAL: 289 MW

ARAGONNE MESA WIND PROJECT (90 MW)

Aragonne Mesa Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 20-year PPA to purchase the entire project output; the project began making energy deliveries to APS in December 2006.

HIGH LONESOME WIND PROJECT (100 MW)

High Lonesome Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 30-year PPA to purchase the entire project output; the project began making energy deliveries to APS in 2009.

PERRIN RANCH WIND PROJECT (99 MW)

Perrin Ranch Wind Project, located near Williams, AZ, reached commercial operation in June 2012. APS has 25-year PPA to purchase the entire project output.

OTHER RENEWABLE ENERGY – TOTAL: 30 MW

SALTON SEA GEOTHERMAL PROJECT (10 MW)

Salton Sea Geothermal Project, located in the Salton Sea area of southeastern California, delivers capacity to the APS system in Yuma. APS has a 23-year PPA to purchase the output that began delivering energy to APS in January 2006.

GLENDALE BIOGAS PROJECT (3 MW)

Glendale Biogas Project commenced operations in late January 2010 and sells all its energy to APS under a 20-year PPA.

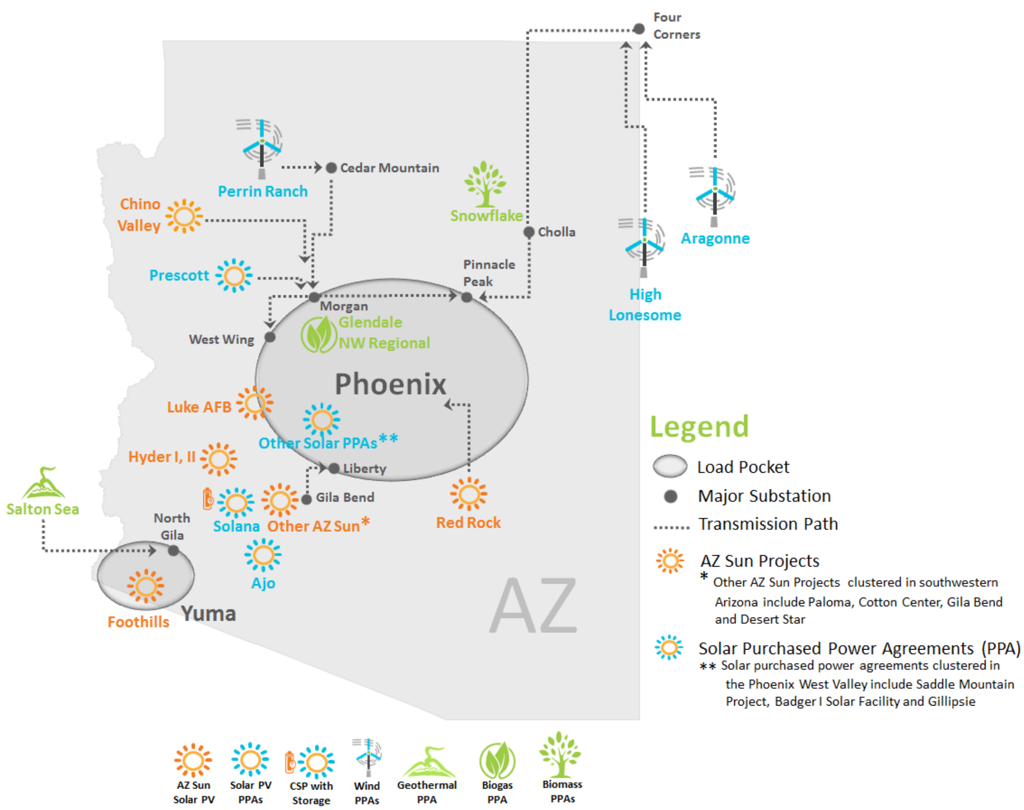
NORTHWEST REGIONAL BIOGAS PROJECT (3 MW)

NW Regional Biogas Project, located in Surprise, AZ, commenced operations in August 2012 and sells all its energy to APS under a 20-year PPA.

SNOWFLAKE BIOMASS PROJECT (14 MW)

Snowflake Biomass Project commenced commercial operations in June 2008 and sells part of its output to APS under a 15-year PPA.

FIGURE 2-7. HOW EXISTING RENEWABLE ENERGY RESOURCES MEET CUSTOMER DEMAND



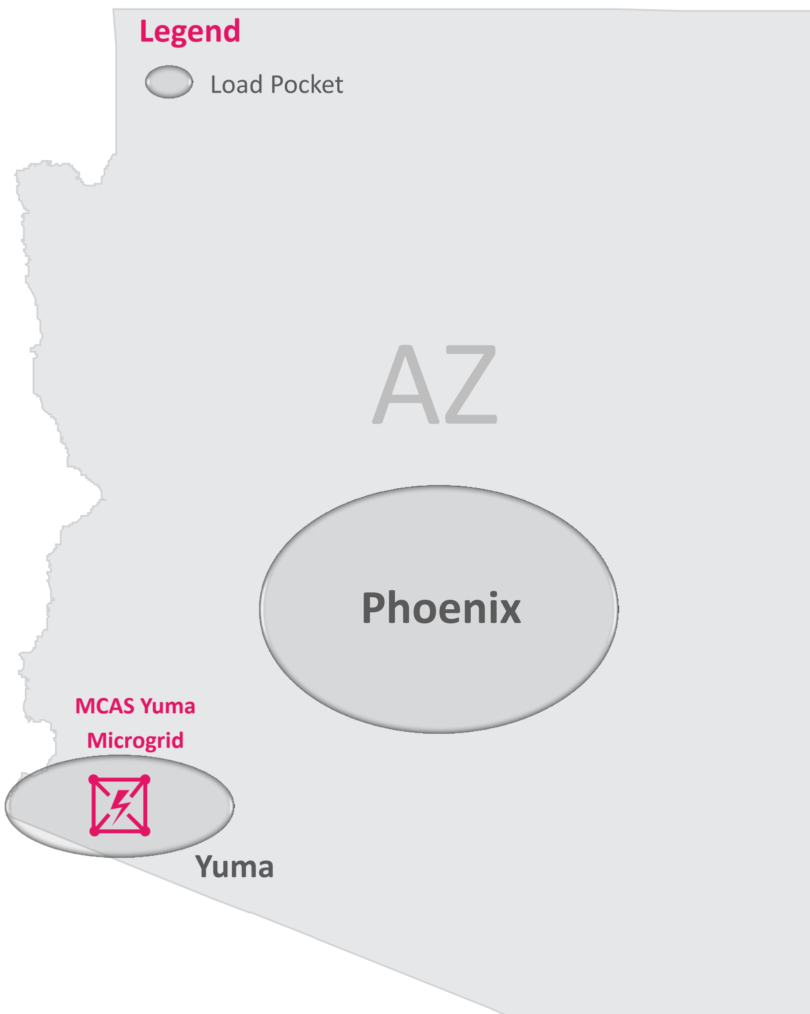
Existing Microgrid Resources

MICROGRID (APS MW ENTITLEMENT) – TOTAL: 22 MW

MARINE CORPS AIR STATION (MCAS) YUMA MICROGRID

The MCAS Yuma project provides the base 100% backup power in the event of a grid disruption and fast-starting, clean-burning diesel generation set (genset) power to the rest of the community under normal operating conditions. The benefits of the project also extend to adding needed flexible capacity to the system while delivering a customized solution to a key client.

FIGURE 2-8. HOW THE MCAS YUMA MICROGRID MEETS CUSTOMER DEMAND



Existing Customer-Based Resources

CUSTOMER-BASED RESOURCES – TOTAL: 1,423 MW

ENERGY EFFICIENCY (737 MW)

By rule, APS is expected to achieve cost-effective cumulative energy savings of 22% of its retail sales by 2020. APS's EE portfolio includes a balanced mix of programs that address APS's diverse customer base in both residential and non-residential categories. These programs include, but are not limited to, the following:

- Residential Existing Homes, Heating, Ventilation and Air Conditioning (HVAC) and Home Performance Programs, which support energy-efficient residential air conditioning and heating including HVAC diagnostics, HVAC system quality installation, air sealing, insulation and duct repair.
- Residential New Construction Program promotes high-efficiency construction practices for new homes.
- Consumer Products Program promotes the use of high-efficiency LEDs, pool pumps, and smart thermostats.
- Large Existing Facilities Program provides incentives to non-residential facilities for EE improvements in lighting, HVAC, motors and refrigeration appliances.
- Non-Residential New Construction and Major Renovations Program promotes an integrated and comprehensive approach to improve the efficiency of new non-residential construction facilities.
- Schools Program provides assistance in reducing energy used in schools, including public, private and charter schools (K-12).

DEMAND RESPONSE (26 MW)

APS's demand response programs include:

- APS Peak Solutions is a 25 MW commercial and industrial DR program for APS's Yuma and Phoenix metropolitan customers.
- Peak Event Pricing (or Critical Peak Pricing), for residential and business customers, is a rate rider that provides a high price signal over a small number of core summer peak days and hours.
- Behavioral Demand Response is a new element of the Home Energy Reports EE program that provides participating residential customers with day-ahead notice of peak demand events, and offers tips for saving energy during the peak. After the event, participants receive feedback on how well they did at reducing their peak demand.

ROOFTOP SOLAR (660 MW)

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. The required DE percentage is 30%.

DE resources include but are not limited to:

- Rooftop/Customer-Sited Solar PV consists of rooftop solar systems that convert the sun's energy into electricity. As of year-end 2016, APS had over 56,000 customer-owned/leased distributed PV systems, approximately 130 APS-owned distributed PV systems on residential customer premises as part of the Flagstaff Community Power Project and 1,600 APS-owned distributed PV systems on residential customer premises as part of the APS Solar Partner Program.
- Solar Water Heating uses thermal energy from the sun to heat the water used in both commercial and residential applications. APS has been providing rebates to encourage the installation of solar water heaters since 2002. As a result, there were 9,076 units installed as of the end of 2016, with 52 units installed that year.

Future Resource Options

APS ASSESSMENT OF FUTURE RESOURCES OPTIONS

Long-term planning presents unique challenges in all industries and energy is no exception. With technologies that are rapidly evolving on both sides of the meter, a fluid federal regulatory landscape and rising customer engagement, resource assessment has become more multi-faceted. The 2017 IRP incorporates that view in selecting technologies for review that will ensure APS meets its commitment to reliable, affordable and sustainable service for the future. Factors considered in the assessment of future resource options include:

RESOURCE RESILIENCE

The evaluation of future resource options, some in early phases of development, includes assessing the potential contribution of those resources to enterprise agility – meaning the ability of a company to adapt to changing operating conditions over time. Natural gas resources give today's energy companies this ability by not only providing stable, low-priced energy, but also by enabling the integration of variable resources and supporting advanced grid capabilities that require quicker response times. The unique ability of this resource to add value in both highly conventional portfolios and those that have varying degrees of newer technologies is what makes natural gas a resilient resource, one that can play an important role under several scenarios.

TECHNOLOGICAL DUE DILIGENCE

The technological due diligence process considers several factors, including (a) resource reliability – the ability to reliably produce energy for APS customers when they most need it; (b) technological maturity –sufficient confidence that the addition of a new resource type will not subject APS customers to costs associated with that resource's construction overruns, difficulties in graduating from test-scale to grid-scale, shortfalls in operational capabilities under a full range of conditions and limited integrative capability with resources already in place; and (c) environmental impact – the commitment to limit the impact of a resource on Arizona's water levels, noise levels, land use, soil quality and local habitat.

COST

At a time when investments in infrastructure upgrades and new technologies are key objectives, maintaining affordable cost of service to customers through the Company's planning and other processes is vital. A key consideration in the assessment of new technologies is not only their cost outlooks, but the reliability of those cost outlooks given the lack of track record in large-scale, operational settings. To ensure APS continues to deliver reasonably priced power as it expands its resource mix over the Planning Period and beyond, the Company's commitment to a comprehensive and proactive stance on cost issues remains. The most recent examples include (a) the March 2016 All-Source RFP which provided up-to-date information on a broad array of technologies and their cost of deployment and (b) the 2017 IRP which considers the costs of new technologies and programs to deliver reliable, affordable power to customers.

Generation Resources

In assessing generation resource options available, APS considered several technologies in nuclear, coal, natural gas, grid-scale solar, rooftop solar, energy storage and other renewable energy technologies.

TABLE 2-3. LIST OF FUTURE GENERATION RESOURCE OPTIONS AND ASSOCIATED COSTS

FUTURE GENERATION RESOURCE OPTIONS	CAPITAL COSTS ($/KW)
NUCLEAR	
AP1000 Hybrid	$6,065
Small Modular Reactor	$5,889
COAL	
Integrated Gasification Combined Cycle	$5,791
NATURAL GAS	
Large-Frame Combustion Turbine	$759
Aeroderivative Gas Turbine	$1,475
Combined Cycle	$1,236
GRID-SCALE SOLAR	
Thin Film Solar PV - Single Axis Utility	$1,439
Thin Film Solar PV - Fixed Utility	$1,344
Parabolic Trough, Gas Hybrid	$5,587
Parabolic Trough, Salt Storage	$5,481
Central Receiver (Power Tower), Salt Storage	$8,301
ROOFTOP SOLAR	
Thin Film Solar PV - Fixed Commercial	$2,090
Thin Film Solar PV - Fixed Residential	$2,825
ENERGY STORAGE	
Compressed Air Energy Storage (CAES)	$3,246
Pumped Storage Hydro	$3,139
Battery Energy Storage System (Li-ion)	$1,539
Flow Battery	$1,589
Battery Energy Storage System (NaS)	$1,740
Battery Energy Storage System (Lead Acid)	$941
Battery Energy Storage System (Zn-Air)	$1,214
Fly Wheels	$3,008
OTHER RENEWABLE ENERGY SOURCES	
Arizona / New Mexico Wind	$1,886
Geothermal	$4,505
Biomass	$4,260
Biogas	$9,456

Notes:
Numbers in Table 2-3 are $ per installed kilowatt.
Some generation resource options provide less output towards meeting system peak.
Overnight construction costs in 2020 dollars and do not include Allowance for Funds Used During Construction (AFUDC).

Nuclear

OVERVIEW AND RISK CONSIDERATIONS

In 2015, the 100 U.S. nuclear reactors accounted for more than 30% of worldwide nuclear generation and 19% of total U.S. power generation. The average capacity factor for these plants is in excess of 90%.[1] Currently, there are four large-scale reactors under construction - all Westinghouse AP1000s.

In determining whether to add new nuclear resources to a portfolio, several risks are considered. First, risks and costs related to construction delays and budget overruns have not been addressed by advanced designs of this technology. Another consideration is the ultimate disposal of spent nuclear fuel as the federal government has not succeeded in establishing a permanent repository. Spent nuclear fuel from existing nuclear power plants continues to be stored at the individual plant sites, either in spent fuel pools or in dry cask storage facilities.

To mitigate these considerations, small modular reactors (SMRs) are viewed as potential alternatives. According to the Department of Energy's Office of Nuclear Energy, SMRs offer reduced initial capital investment due to their modular, largely pre-fabricated design, greater scalability and siting flexibility due to their size (typically less than 300 MW),[2] and increased security as most will be built below grade (underground).[3] Challenges include the assessment of technological maturity and ultimate cost as none are currently in operation.

TECHNOLOGIES

PRESSURIZED WATER REACTORS (PWR)

In a PWR, the heat created by the core in the reactor vessel is transported to the steam generator where the water is vaporized, producing the steam needed to turn the turbine.[4] Palo Verde comprises three PWRs.

ADVANCED LARGE-SCALE REACTORS – WESTINGHOUSE AP1000

The Westinghouse AP1000 design is a two-loop pressurized water reactor. The primary loop cools the nuclear core and carries the thermal energy to the steam generator heat exchangers. The steam generators transfer the thermal energy to the secondary loop to produce steam that generates electricity through the turbine generator. The AP1000 incorporates a passive core cooling system in addition to many other safety systems in the design.

Note: In February 2017, Toshiba (the parent company of Westinghouse) announced the company's plan to write-off more than $6 billion of nuclear-related losses, and exit from the nuclear energy construction business.[5] The announcement was anticipated as a result of continued cost overruns and project management missteps in its nuclear business over the past several years, both in the U.S. and overseas.[6] Also, on March 29, 2017, Westinghouse Electric Co., filed for bankruptcy protection, increasing the uncertainty regarding completion of the four half-finished reactors in the U.S.[7]

1 World Nuclear Association, Nuclear Power in the USA, http://www.world-nuclear.org/information-library/country-profiles/countries-t-z/usa-nuclear-power.aspx.
2 International Atomic Energy Agency, Small and Medium Sized Reactors (SMR) Development, Assessment and Deployment, https://www.iaea.org/NuclearPower/SMR/.
3 U.S. Department of Energy, Office of Nuclear Energy, Benefits of Small Modular Reactors (SMRS), https://www.energy.gov/ne/benefits-small-modular-reactors-smrs.
4 U.S. Nuclear Regulatory Commission, Pressurized Water Reactors, https://www.nrc.gov/reactors/pwrs.html.
5 The New York Times, Toshiba's Chairman Resigns as Its Nuclear Power Losses Mount (February 14, 2017), https://www.nytimes.com/2017/02/14/business/toshiba-chairman-nuclear-loss.html.
6 Reuters, Nuclear write-down leaves Toshiba with $3.5-billion loss in third-quarter: Nikkei (February 11, 2017), http://www.reuters.com/article/us-toshiba-loss-idUSKBN15R01Z.
7 THE WALL STREET JOURNAL, Toshiba's Westinghouse Electric Files for Bankruptcy Protection (March 29, 2017), https://www.wsj.com/articles/toshibas-westinghouse-electric-files-for-bankruptcy-protection-1490771532.

SMALL MODULAR REACTORS

A. Light Water Reactors

NuScale SMR Design – In December 2013, the U.S. Department of Energy (DOE) awarded NuScale Power funding to develop innovative SMR technology. According to the DOE, the NuScale SMR design offers a mix of safety, scalability, transportability, and economics, as well as sufficient design maturity and is expected to achieve commercial operation in the 2025 timeframe.[8]

How the NuScale SMR Works

The NuScale SMR is an advanced light-water reactor comprised of self-contained NuScale Power Modules that operate independently within a multi-module configuration. Up to 12 modules are monitored and operated from a single control room. Components and workings of the design include:

1. The reactor and containment vessel operate inside a water-filled pool that is built below ground level. The reactor, using natural circulation, has no pumps and through a convection process, heats the water as it passes over the core.
2. As it heats up, the water rises and once it reaches the top, it is pulled by gravity back down to the bottom of the reactor where it is again drawn over the core. Water in the reactor system is kept separate from the water in the steam generator system to prevent contamination.
3. As the hot water in the reactor system passes over tubes in the steam generator, heat is transferred through the tube walls and turning the water to steam, which then turns the turbines.
4. After passing through the turbines, the steam is cooled back into liquid form in the condenser then pumped back to the steam generator where it begins the cycle again.[9]

Other Light Water Reactor Designs

- **Babcock & Wilcox Co. mPower Reactor –** The mPower reactor design is a 180 MW electric advanced light water reactor design that uses gravity, convection and conduction to cool the reactor in an emergency with a below-ground containment.
- **Holtec Inherently Safe Modular Underground Reactor (Hi-Smur) 160 –** The HI-SMUR 160, a 160 MW reactor, also has an underground core and a 42-month refueling cycle.
- **The Westinghouse SMR –** The Westinghouse SMR is a 200 MW reactor with primary components located below-ground level.[10]

B. Liquid Metal and Gas-Cooled Fast Reactors

According to the Nuclear Energy Institute (NEI), liquid metal or gas-cooled fast reactor technologies hold the promise of distributed nuclear applications for electricity, water purification and district heating in remote communities.[11] The unique characteristic of these units is the recycling of nuclear waste to generate electricity.

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8 U.S. Department of Energy, Office of Nuclear Energy, Small Modular Reactors, https://www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors.

9 NuScale Power, How NuScale Technology Works, http://www.nuscalepower.com/our-technology/technology-overview.

10 Forum on Energy, Types of SMRs, http://forumonenergy.com/2015/03/17/types-of-smrs/.

11 Nuclear Energy Institute, Small Reactor Development Advances Energy, Environmental Benefits in New Markets, https://www.nei.org/Prints?printpath=/Master-Document-Folder/Backgrounders/Policy-Briefs/Small-Reactor-Development-Advances-Energy,-Environ&classname=custom.document&pNm=PolicyBriefs.

Coal

OVERVIEW AND RISK CONSIDERATIONS

According to the Energy Information Administration (EIA), declining capital costs for solar photovoltaics (PV), environmental regulations and low natural gas prices are expected to contribute to a reduction in coal's share of total generation. The agency projects that, in the absence of the Clean Power Plan (CPP), the coal share of total electricity capacity will fall from 274 GW in 2015 to 217 GW in 2040 due to a combination of emission regulations, low natural gas prices and increased deployment of renewable generation. Under the EIA's Reference Case, which includes the CPP, coal generating capacity is projected to decrease to 167 GW in 2040.[12]

Given the importance of affordability in portfolio development, new pulverized coal plants are currently not an economically viable option due to the continued long-term outlook for low natural gas prices and increasing energy contributions from renewable energy resources.

Other risks related to pulverized coal plants include compliance cost risk related to potential environmental regulations. As discussed in Chapter 6 – Regulatory, the Environmental Protection Agency (EPA) has implemented air quality regulations governing new coal plants for certain emissions, and may promulgate additional regulations over the course of the Planning Period. National climate change policies pertaining to greenhouse gas (GHG) emissions may also occur during the 15-year period under review. It is uncertain how these programs would 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.

TECHNOLOGIES

SUBCRITICAL AND SUPERCRITICAL COAL STEAM BOILERS

Both subcritical and supercritical coal steam boiler technologies burn pulverized coal to produce steam in the boiler tubes at varying pressures, which then is expanded through a steam turbine which spins the generator to produce electricity. From there, the turbine exhaust steam is condensed back to water and returned to the boiler tubes for the cycle to start again. Supercritical boilers run at higher pressures and are more efficient than subcritical boilers. These and other generating technologies can be cooled by conventional wet cooling towers or dry air-to-air heat exchangers or a combination of both (hybrid).

TABLE 2-4. COAL STEAM BOILER TECHNOLOGIES

COAL STEAM BOILER TECHNOLOGY	OPERATING CHARACTERISTICS		APS PLANT
	Pressure	Temp.	
Subcritical	<3,208 psi	1,025°F	Cholla Units 1 and 3
Supercritical	>3,208 psi	1,000°F – 1,050°F	Four Corners Units 4 and 5 Navajo Units 1-3

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

IGCCs convert fuel to a synthetic mixture of hydrogen and carbon monoxide that is converted to electricity through gas turbine and steam turbine processes which includes a heat recovery steam generator (HRSG).[13]

12 U.S. Energy Information Administration, Annual Energy Outlook 2017, http://www.eia.gov/outlooks/aeo/.
13 Massachusetts Institute of Technology, Laboratory for Energy and the Environment – An Overview of Coal based Integrated Gasification Combined Cycle (IGCC) Technology, https://sequestration.mit.edu/pdf/LFEE_2005-002_WP.pdf.

Two Largest IGCC Projects in U.S.

1. Duke Energy's Edwardsport Generating Station, a 618 MW facility, was completed for $3.5 billion – $1.6 billion over the original $1.9 billion budget.[14] The facility currently does not include carbon capture and sequestration (CCS) technology.[15]
2. Southern Company's Kemper Project, a 583 MW facility that does include CCS technology designed to capture 65% of the project's CO2 emissions[16] is several years behind schedule and more than double the original estimate of $2.8 billion (latest project estimate: over $7 billion).[17]

Natural Gas

OVERVIEW AND RISK CONSIDERATIONS

In 2015, natural gas generation accounted for 33% of total U.S. electricity generation and the EIA projected in its 2017 Annual Energy Outlook that percentage would increase to 37% by 2040 under its Reference Case which assumes implementation of the CPP with U.S. states selecting mass-based limits on CO2 for CPP compliance.[18]

The primary risk associated with natural gas combined cycle technology is the price of natural gas that has a history of volatility, although that trend is not projected to re-emerge over the course of the Planning Period due to technology advancements in hydraulic fracturing (fracking) and resulting increase in available shale gas. In terms of price levels, the latest estimates from the EIA project natural gas spot prices at Henry Hub ($/MMBtu in 2016 dollars) showing modest and steady increases from $3.00/MMBtu in 2017 to $5.07/MMBtu in 2040 in the Reference Case which does include the CPP and $2.99/MMBtu and $5.01/MMBtu for those two years excluding the CPP.[19]

Potential future compliance costs with CO2 regulation is also a concern as natural gas combined cycle units emit CO2, albeit at a much lower rate than coal-fired generation plants. CO2 emissions are less of a concern with combustion turbines due to the limited run time of peaking units. Potential compliance liabilities related to fracking and increased demand for U.S. exports of this fuel are other risk considerations. A broader movement to regulate fracking at the state and/or federal level could have material effects on the future price of natural gas.

TECHNOLOGIES

STEAM GENERATION UNITS

These turbines operate similarly to coal steam turbines, but utilize gas instead of pulverized coal as their fuel source. In these units, compressed natural gas is burned within the boiler to produce subcritical steam in the boiler tubes at a typical pressure of 1,450 psi and temperature of 1,000F. The subcritical steam is expanded through a steam turbine to produce electricity. The turbine steam is exhausted into the condenser, is condensed back to water, and then pumped back into the boiler tubes to repeat the cycle. These basic steam generation units have moderate efficiency, typically 33% to 35%,[20] once they are running. The Ocotillo Power Plant has two units that are still in use but will be replaced by 2019 with five fast-ramping, highly flexibility combustion turbines with achievable efficiency rates of approximately 44%.[21]

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14 Indiana Public Media, State Regulators Approve Duke Energy Edwardsport Settlement (August 26, 2016), http://indianapublicmedia.org/news/state-regulators-approve-duke-energy-edwardsport-settlement-104185/.
15 Orkas Energy Endurance, Kemper, Big Bang or Black Hole for Clean Cole (July 7, 2014), http://www.orkas.com/kemper-big-bang-or-black-hole-for-clean-coal/.
16 Kallanish Energy, New delay in starting $7B carbon-capturing Mississippi plant (February 6, 2017), https://www.kallanishenergy.com/2017/02/06/another-delay-starting-7b-carbon-capturing-kemper-plant/.
17 UtilityDive, Southern Co. faces shareholder lawsuit for Kemper project delays and cost overruns (January 26, 2017), http://www.utilitydive.com/news/southern-co-faces-shareholder-lawsuit-for-kemper-project-delays-and-cost-o/434766/.
18 EIA Annual Energy Outlook 2017, available at http://www.eia.gov/outlooks/aeo/.
19 U.S. Energy Information Administration, Annual Energy Outlook 2017 (January 5, 2017), http://eia.gov/outlook/aeo/.
20 NaturalGas.org, Electrical Uses, http://naturalgas.org/overview/uses-electrical/.
21 GE Energy: LMS100 Flexible Power Brochure, www.cfaspower.com/LMS100_Brochure.pdf.

CONVENTIONAL AND ADVANCED COMBINED CYCLE (CC)

A CC generating unit consists of one or more combustion turbine (CT) generators equipped with HRSG to capture the otherwise wasted thermal energy remaining in the turbine exhaust gases. Steam produced in the HRSG powers a steam turbine generator to produce electric power, in addition to the power produced by the CT(s). This process significantly increases the efficiency of this electric generating unit, and additional capacity can be obtained with the use of power augmentation technologies, including turbine inlet cooling of the compressed air, duct firing at the inlet of the HRSG and steam injection.

APS installed three combined-cycle units at the West Phoenix Power Plant in 1976. Since then, APS has added two additional units at West Phoenix and two units at the Redhawk Power Plant.

SIMPLE CYCLE COMBUSTION TURBINES (CT)

A CT generating system consists of an inlet air filter, inlet cooling system, compressor, combustor, turbine, exhaust environmental controls, stack, generator and auxiliary systems needed to support the operation of the CT. Many of the newer units are now capable of a 10-minute quick start.

APS has owned and operated CTs since the first units were installed at the Yucca Power Plant in 1971. Currently, the Company has 24 CTs in operation positioned around its service territory to support the local grid. Yucca, Douglas, Saguaro, Ocotillo, West Phoenix and Sundance all have CTs on-site, with an additional five CTs being installed as part of the Ocotillo Modernization Project.

Aeroderivative Gas Turbine

One type of combustion turbine is the gas aeroderivative turbine, which is used as a compression device to take in air, compress the natural gas then apply heat to the mixture with a burner. The hot air produced from this process powers the turbine.[22]

Some of the benefits of aeroderivative turbines are fast-starting capabilities, the reduction in fuel consumption (about 10%) and improvement in operating duration (about 2%) as they avoid the long downtime maintenance cycles associated with other turbine types.[23]

APS employs these types of units at Sundance and Yucca (LM6000) and is implementing them as part of the Ocotillo Modernization Project (LM100).

RECIPROCATING ENGINES

Reciprocating engines operate by introducing a mixture of fuel and air into a combustion cylinder, which is then compressed as the piston within the cylinder moves upward. As it nears the top, a spark is produced that ignites the air-fuel mixture. The pressure of the resulting exploding gases drives the piston down. The moving piston produces rotational energy used to generate electricity or drive a piece of equipment or machinery. APS currently has many backup power generators at electrical critical sites, including the emergency electric power requirements at the Palo Verde Nuclear Generating Station.

These units can start and produce power within 20 seconds and are often used in microgrid applications, such as APS's Aligned Data Center Microgrid (in collaboration with Aligned Data Center, a subsidiary of Aligned Energy) and the Marine Corps Air Station Yuma Microgrid.[24]

22 Turbine TECHNICS, Understanding Aeroderivative Gas Turbines, http://www.turbinetechnics.com/about-us/understanding-aeroderivative-gas-turbines.

23 U.S. Department of Energy, Office of International Affairs, Understanding Natural Gas and LNG Options, https://energy.gov/ia/downloads/understanding-natural-gas-and-lng-options.

24 Microgrid Knowledge, How to Pay for Utility Microgrids? Arizona May Offer Answers (October 11, 2016), https://microgridknowledge.com/utility-microgrids-arizona/.

Solar: Grid-Scale

OVERVIEW AND RISK CONSIDERATIONS

Bloomberg New Energy Finance (BNEF) projects that U.S. installed grid-scale PV capacity will increase from 24 GW at the end of 2016 to almost 100 GW in 2025. Although a 19% reduction in new builds is projected for 2017 as the rush from pre-Investment Tax Credit (ITC) extension subsides, the market is expected to recover as a result of policy-driven demand and improving economics of grid-scale PV, especially in the Southwest, the Southeast and Texas.[25]

Deployment of grid-scale solar is subject to a variety of risks, including:

a. **Cost –** Although more cost-competitive than rooftop solar, this technology remains less competitive than other resource options, such as natural gas.

b. **Lack of alignment with customer demand –** Solar energy output peaks during non-peak hours and wanes when customers most need energy.

c. **Footprint –** Grid-scale solar installations require more acreage when compared to conventional generation.

d. **Renewable Energy Standard requirements –** These may be modified during the Planning Period.

e. **Uncertain tax and fiscal policies –** These may result in cost increases for this technology, specifically changes to tax incentives that could widen the competitiveness gap with other resource types.

f. **Intermittency –** Because solar is an intermittent resource, system integration costs and back-up capacity must be factored in when evaluating solar against other resource options.

INVESTMENT TAX CREDIT

Section 48 of the Internal Revenue Code provides an investment tax credit (ITC) for certain solar and other renewable energy property. The credit is subject to the following phase-down schedule:

- 30% ITC for projects that begin construction before 2020 and are placed in service before 2024
- 26% ITC for projects that begin construction in 2020 and are placed in service before 2024
- 22% ITC for projects that begin construction in 2021 and are placed in service before 2024
- 10% ITC for projects that begin construction before 2022 and are placed in service after 2024

The 2017 IRP portfolios are based on current law. Given the prospects for broad-based tax reform in the near future, it has been assumed that the PTC (see Wind section) and ITC will not be extended beyond their scheduled expiration dates. Furthermore, it is possible that the current phase-down provisions could be repealed as part of tax reform efforts.

TECHNOLOGIES

SOLAR PV FIXED AND SINGLE AXIS TRACKING (SAT)

Fixed systems are typically angled at latitude for optimum production while SAT systems rotate to follow the sun from east to west. Adding SAT increases the energy output from the system by approximately 25% in comparison to a fixed system.[26] It also increases the value of the energy delivered, as a portion of that additional output is in the late-afternoon hours when load is at its peak. In a grid-scale solar plant, thousands of solar modules are connected together to form large systems connected to the grid. Grid-scale inverters typically range in scale from 500kW to over 1 MW. Many of these inverters are combined together to form multi-MW solar power systems.

25 BNEF H2 2016 US PV Market Outlook, Question marks pile up, https://www.bnef.com/core/insight/15633/view.
26 Solar Power World, How does a new single-axis tracking process increase solar plant efficiency? (June 16, 2015), http://www.solarpowerworldonline.com/2015/06/how-does-a-new-single-axis-tracking-process-increase-solar-plant-efficiency/.

SOLAR THERMAL TROUGH TECHNOLOGY WITH SALT STORAGE

Parabolic troughs are the most mature concentrated solar power technology.[27] Parabolic mirrors focus solar energy onto a receiver tube that contains a heat transfer fluid, typically synthetic oil. The fluid then returns to a series of heat exchangers, where it is used to generate superheated steam at about 1,450 psia and 700°F. The steam is then used to run conventional steam turbines. Spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers as condensate via the feedwater pumps.

With the addition of molten salt thermal storage, such as APS's Solana Plant, or gas hybridization, these systems can extend the generation period up to six hours after sunset.

PARABOLIC TROUGH, GAS HYBRID

Parabolic trough gas hybrid systems inject solar steam into a common turbine, which is also supplied by the natural gas plant, giving the flexibility to generate electricity from either or both of the natural gas and solar facilities as needed.[28] The 75 MW Martin Next Generation Solar Energy Center was the first hybrid solar facility in the world to combine a solar thermal array of over 190,000 mirrors with a combined cycle natural gas power plant.

CENTRAL RECEIVER (POWER TOWER) – SALT STORAGE

In power tower concentrating solar power systems, flat, sun-tracking mirrors, known as heliostats, direct sunlight onto a receiver located at the top of a tall tower. A heat-transfer fluid is used to heat a working fluid, which, in turn, produces electricity in a conventional turbine generator.[29] Power towers can operate by heating water directly, such as the Ivanpah Generation Station in California, or they can heat molten salt directly for thermal storage and steam generation, such as the Crescent Dunes project in Nevada.

Of the 16 APS-owned and purchased grid-scale solar systems, 1 is fixed, 14 are SAT and 1 is solar thermal trough with storage.

27 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Parabolic Trough, https://energy.gov/eere/sunshot/parabolic-trough.

28 Solar Industry, FPL Generates Electricity And Experience at Martin Hybrid Solar Facility, http://solarindustrymag.com/online/issues/SI1502/FEAT_01_FPL-Generates-Electricity-And-Experience-At-Martin-Hybrid-Solar-Facility.html.

29 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Power Tower System Concentrating Solar Power Basics (August 20, 2013), https://energy.gov/eere/energybasics/articles/power-tower-system-concentrating-solar-power-basics.

Solar: Rooftop

OVERVIEW AND RISK CONSIDERATIONS

BNEF projects that U.S. installed commercial and industrial PV capacity will increase from 7 GW at the end of 2016 to 26 GW in 2025, while residential capacity will increase from 8 GW to 44 GW during the same time frame. Until the ITC is phased out in 2022 (down to 10% tax credit for commercial and 0% for residential), the urgency to install systems will drive demand in both customer segments. After that, the residential market is likely to grow at a reduced rate while the commercial and industrial segment will continue its growth pattern, yet will remain smaller than both the residential and utility-scale segments.[30]

Rooftop solar is not able to generate over the full period of peak demand. Also, as an intermittent resource, system integration costs and back-up capacity must be factored in when evaluating rooftop solar against other resource options. It carries the same ITC-related risks as grid-scale solar and increased planning reserve uncertainty regarding forecasted amounts of rooftop solar generation in Arizona and the Western Electricity Coordinating Council (WECC). Rooftop solar increases the need for fast-ramping, flexible generation to provide the backup power to meet demand when the solar energy output disappears at sundown. Perhaps most significantly, rooftop solar generation is still far from being cost effective compared to natural-gas resources due to the high cost to install this resource (more than 2X the levelized cost of energy [LCOE] of grid-scale solar).

TECHNOLOGIES

THIN FILM SOLAR PV: FIXED COMMERCIAL AND FIXED RESIDENTIAL

Thin-film solar cells, made by depositing one or more thin layers of non-crystalline PV material on a surface such as glass, metal or plastic, can be used as rooftop or solar shingles, roof tiles or building facades.[31] The type of thin film solar cells is categorized by the PV material used: amorphous silicon, cadmium telluride, copper indium gallium selenide or organic PV cells.[32] Cadmium telluride global market share was estimated at 7 GW in 2015 and on a revenue-basis is projected to increase over 17% by 2024, while amorphous silicon contributed over 13% to global thin film solar cell revenues in 2015.[33]

CRYSTALLINE SILICON ROOFTOP PV: FIXED COMMERCIAL AND FIXED RESIDENTIAL

Crystalline silicon is the dominant semiconducting material used in PV technology for the production of solar cells. These cells are assembled into solar panels as part of the PV system used to generate solar power from sunlight. The technology is mature, having arisen from decades of innovation in the semiconductor industry, although its deployment has in part been driven by regulatory and tax policy initiatives.

As of year-end 2016, APS had over 56,000 customer-owned/leased distributed PV systems, approximately 130 APS-owned distributed PV systems on residential customer premises as part of the Flagstaff Community Power Project, and almost 1,600 APS-owned distributed PV systems on residential customer premises as part of the APS Solar Partner Program.

30 BNEF H2 2016 US PV Market Outlook, Question marks pile up, https://www.bnef.com/core/insight/15633/view.
31 U.S. Department of Energy, Energy Saver, Small Solar Electric Systems, https://energy.gov/energysaver/small-solar-electric-systems.
32 Energy Informative, Which Solar Panel Type is Best? Mono- vs. Polycrystalline vs. Thin Film (May 18, 2015), http://energyinformative.org/best-solar-panel-monocrystalline-polycrystalline-thin-film/.
33 Global Market Insights, Inc., Thin Film Solar Cells Market Size By Component (Cadmium Telluride (CDTE), Amorphous Silicon (A-Si), Copper Indium Gallium Diselenide), By Connectivity (On-Grid, Off Grid), By Application (Residential, Commercial, Utility), Industry Analysis Report, Regional Outlook (U.S., Canada, Mexico, UK, Germany, Spain, France, China, India, Japan, Australia, UAE, South Africa, Brazil, Chile, Argentina), Price Trends, Competitive Market Share & Forecast, 2016 – 2024 (December 2016), https://www.gminsights.com/industry-analysis/thin-film-solar-cells-market?utm_source=prnewswire.com&utm_medium=referral&utm_campaign=Paid_prnewswire.

Energy Storage

OVERVIEW AND RISK CONSIDERATIONS

Energy storage, the capture of energy produced at one time for dispatch at a later time, is a growing technology that has the potential to increase the value of rooftop solar resources, as well as improve grid reliability and stability, although not at current cost levels. In renewable energy integration, the value of storage is its ability to align solar energy production with peak energy demand. Solar energy generation is highest during midday hours when many customers are at work and home energy usage is low. Conversely, when customers come home in the evening and increase their energy usage by turning on their air conditioners, washing machines, lights and TVs simultaneously, solar energy production has stopped because the sun has set – creating a mismatch between when rooftop solar installations produce energy and when customers need it. Storage addresses this misalignment by harvesting the solar energy that is produced during midday hours then dispatching it in the evening when it is most needed.

Globally, almost 900 MW of new energy storage capacity was announced in the second half of 2016, extending the sustained increase in activity that began in the fourth quarter of 2014. Over 500 MW of utility-scale projects were also commissioned in 2016 (as of December 20, 2016). Frequency regulation remains the single largest application for commissioned energy storage projects, accounting for 60% of total capacity in 2016.[34]

In the APS Solar Partner Program, APS is assessing risks associated with storage technologies including:

- **Resource risk –** Batteries do not produce energy so they are reliant on other resources – often variable resources – the deployment of which has been driven by tax policies that may not be extended.
- **Cost risk –** As with other resources, batteries will be considered for dispatch on a cost-competitive basis against other resources.
- **Integrative capabilities –** Pairing storage with other resources, namely solar or wind, has limited operational experience and requires more “live” projects before these pairings can be viewed as seamless and reliable.

Through this project, APS seeks to further understand the potential benefits of this technology and prepare for its possible wider-scale deployment once costs become more competitive, its reliability and safety are validated.

TECHNOLOGIES

COMPRESSED AIR ENERGY STORAGE (CAES)

Compressed Air Energy Storage (CAES) is a bulk energy storage technology that utilizes either a below ground cavern or above-ground storage tank to store energy as compressed air to later turn that energy into electricity through a natural gas combustion turbine. There are currently only two functional grid-scale CAES systems: one in Germany and one in Alabama. Second-generation CAES technology has been developed to use a natural gas fired combustion turbine to increase efficiency, yet this approach has never been deployed in the field.

PUMPED STORAGE HYDRO

Pumped hydro energy storage utilizes the pumping of water upwards against gravity during off-peak hours and then discharging the stored potential energy of the elevated water during peak times. This technology is mature. Pumped hydro plants have high efficiencies and a half-century of useful life. Water resource and environmental concerns have limited the growth of the technology past the 1980s.

34 BNEF H2 2016 Global Energy Storage Market Outlook (December 2016), https://www.bnef.com/core/insight/15649.

BATTERY ENERGY STORAGE SYSTEM – LITHIUM-ION (LI-ON)

Lithium-ion (LI-ON) battery systems are perhaps the fastest growing chemical storage technology in the marketplace today. The technology has already matured for cell phones and other stationary consumer electronics, and electric vehicles. There are approximately 150 GWh of lithium-ion batteries produced globally every year and the market is growing rapidly, although a significant amount of this production is used in the consumer electronics industry. Utilities around the country are also deploying the technology in grid-scale applications for power management, with over 200 MW of units installed. They are useful in capacity, arbitrage, and ancillary-service applications such as spinning reserve, frequency regulation, and Volt/VAr management.

APS has installed 4 MW/4 MWh of storage in its portfolio as part of the SPP. The units went operational in the first quarter of 2017 and are currently in an evaluation and testing phase.

FLOW BATTERY

Vanadium reduction and oxidation (redox) batteries are a type of flow battery in which both of the anode and cathode materials are in solution at all times. The batteries are able to ramp to full discharge capacity extremely rapidly and cell life is not reflected on depth of discharge. Flow batteries typically can have their electrolytes cycled almost indefinitely, but the components of the battery cells and pump systems can degrade over time. Cost challenges with this technology have limited its deployment to date.

BATTERY ENERGY STORAGE SYSTEM – SODIUM-SULFUR (NAS)

Sodium-sulfur (NaS) batteries are a chemical battery system that is unique for its long discharge properties for potential continuous peak load support. The battery systems use metallic sodium, which is combustible if exposed to water. The approximate life cycle of a NaS battery system is around 15 years at 4,500 cycles. There are around 221 sites around the USA and other countries that currently have NaS battery technologies deployed. Cost challenges with this technology have limited its deployment to date.

BATTERY ENERGY STORAGE SYSTEM – LEAD ACID

Lead acid battery systems are the oldest form of chemical storage dating back to the 1800s. Issues arise with depth of discharge issues and weight of batteries when applied in automotive EV applications. They are designed more for quick pulses of high power applications, but have issues with long sustained usage in utility storage applications. Advanced lead acid battery technologies and carbon composite lead materials have allowed for greater depth of discharge and utility storage applications, but are still maturing.

BATTERY ENERGY STORAGE SYSTEM – ZINC-AIR (ZN-AIR)

Zinc-Air (Zn-Air) batteries utilize an electropositive metal in an electrochemical couple with oxygen to generate electricity. Since they only require one electrode, the technology can have high energy densities compared with other chemical energy storage. There can be some issues with the electrolyte not deactivating in the recharging cycle which can reduce the number of times the battery can be recharged. The anode material is made from zinc oxide which is easily recyclable and obtainable, yet the characteristics of the battery reduce charging/discharging efficiencies to 50%. Energy density and maturity of this technology relative to Li-ion have limited the deployment of this technology.

FLYWHEELS

Flywheels are a type of mechanical storage in the form of angular momentum of a spinning mass. The flywheels are housed in a thick steel unit to prevent injury from failure of the spinning unit of the system; also the steel enclosure is used to eliminate friction through vacuum or low friction gas magnets. Most flywheel systems are DC coupled so would need an inverter to convert to AC power. Fly wheels have much greater life than chemical storage in excess of 100,000 full discharge cycles and a power density 5 to 10 times greater. Cost and technology maturity challenges have limited the deployment of this technology.

Wind

OVERVIEW AND RISK CONSIDERATIONS

The EIA projects that wind net summer capacity will increase from 71.9 GW in 2015 to 161.6 GW in 2040, in its Reference Case (includes the CPP) and to 142.7 GW without the CPP. The agency also projects that the scheduled expiration of the PTC will encourage an increase in wind capacity additions as developers rush to complete projects to take advantage of the incentive.[35]

PRODUCTION TAX CREDIT

Section 45 of the Internal Revenue Code provides a PTC, a federal financial incentive for the development of certain renewable energy facilities. The credit is based on kilowatt-hours produced and sold to an unrelated entity for electricity generated at qualified facilities and is currently on a phase-down schedule. For facilities which began construction prior to 2017 the credit is 2.3 cents/kWh for ten years. For facilities which begin construction after December 31, 2016, the following reductions to the 2.3 cent/kWh credit level generally apply:

- 20% reduction for projects beginning in 2017
- 40% reduction for projects beginning in 2018
- 60% reduction for projects beginning in 2019
- No credit for any facility that begins construction after December 31, 2019

In lieu of the PTC, taxpayers of certain wind projects may make an irrevocable election to claim the ITC. If such an election is made, the above PTC credit reductions also apply to the ITC, allowing for credits as follows:

- 24% ITC for projects beginning in 2017
- 18% ITC for projects beginning in 2018
- 12% ITC for projects beginning in 2019
- No credit for any facility that begins construction after December 31, 2019

Like other renewable energy resources, the primary risk of wind energy is its variable generation depending on the region. Wind energy production primarily occurs in the spring when APS's customer loads are at reduced levels, resulting in wind energy's contribution to meeting summer peak demand to be a fraction of the rated generation output. Because wind is an intermittent resource, system integration costs and back-up capacity must be factored in when evaluating wind against other resource options. Tax policy is also a key factor in the economics of this resource.

TECHNOLOGY

Wind systems convert the wind's energy into electricity by using rotating blades, typically made of fiberglass, to collect the wind's kinetic energy. The turbines are supported by a conical steel tower that is widest at the base and tapers in diameter to just below the nacelle. The nacelle is attached to the top of the tower and contains the primary mechanical components of a wind turbine. The blades are connected to a drive shaft that turns a generator to produce electricity.

APS has Power Purchase Agreements (PPAs) for three wind farms. Two are located outside of the state, in New Mexico.

35 U.S. Energy Information Administration, Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/data/browser/.

Geothermal

OVERVIEW AND RISK CONSIDERATIONS

The EIA projects that geothermal net summer capacity will increase from 2.5 GW in 2015 to 7.0 GW in 2040, in its Reference Case (includes the CPP) and to 7.1 GW without the CPP.[36]

Geothermal energy provides carbon-free baseload power, the need of which is already addressed in APS's service territory by Palo Verde. Other considerations include the location of geothermal resources as they are generally a significant distance from APS's 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.

TECHNOLOGY

To generate electricity, geothermal power uses heat from a variety of sources below the earth's surface to generate electricity including hot water or steam reservoirs deep in the earth, and geothermal reservoirs and shallow ground near the surface of the earth.[37]

APS has a 10 MW power purchase agreement for geothermal energy from the Salton Sea in California.

36 U.S. Energy Information Administration, Annual Energy Outlook 2017 (January 5, 2017), http://eia.gov/outlook/aeo/.
37 National Renewable Energy Laboratory, Geothermal Energy Basics, http://www.nrel.gov/workingwithus/re-geothermal.html.

Biomass and Biogas

OVERVIEW AND RISK CONSIDERATIONS

The EIA projects that biomass net summer capacity will increase from 3.6 GW in 2015 to 4.0 GW in 2040, in its Reference Case (includes the CPP) and to 3.7 GW without the CPP. For biogas net summer capacity, the agency projects an increase from 3.7 GW to 3.8 GW in both its Reference and No CPP Cases.[38]

Although biomass and biogas facilities utilize a combustion process that emits CO2, 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.

TECHNOLOGIES

BIOMASS

Biomass fuels are primarily wood or wood byproducts. However, they can include dried municipal solid wastes, feedlot and dairy manure, crop wastes, and sewage digester sludge. Biomass can be converted into electricity in one of several processes. The majority of biomass electricity is generated today using a steam cycle where the biomass is burned in a boiler to produce steam. The steam turns a turbine, which is connected to a generator that produces electricity.

APS has a PPA for approximately 50% of the Snowflake biomass power plant's output.

BIOGAS

Biogas is a low-BTU gas composed of methane (40-60%), carbon dioxide, water and miscellaneous contaminates that is produced through anaerobic digestion processes in landfills, and wastewater treatment at municipal water plants and concentrating animal feeding operation (CAFO) farms. The gas is produced, collected, and then typically flared and/or used for on-site thermal heating. If the amount of biogas produced is sufficient to warrant the development of a biogas-to-energy project, the biogas would be cleaned and dried, and/or thermally oxidized prior to combustion. The biogas can then be converted into electricity by combustion in specific reciprocating engines, microturbines, and fuel cells that have been designed and configured to utilize low-BTU fuels.

APS currently has a PPA with the Glendale Landfill, a 2.8 MW generation facility and the Surprise Landfill, a 3.2 MW generation facility.

38 U.S. Energy Information Administration, Annual Energy Outlook 2017 (January 5, 2017), http://eia.gov/outlook/aeo/.

DSM Programs and Initiatives

CURRENT DSM PROGRAMS	NEW DSM PROGRAMS
DSM programs that are currently being implemented	**Recently proposed DSM programs and pilots**
Consumer Products	T&D pilot
HVAC Existing Homes	
Home Performance	Load Management Technologies pilot
Residential New Construction	
Multi-Family EE	Energy and Demand Management Education
Limited Income Weatherization	Demand Response, Energy Storage and Load Management Program
Home Energy Reports	
Non-Residential Large Existing Facilities	**DSM PROGRAMS IN DEVELOPMENT**
Non-Residential New Construction	**DSM technologies and trends currently being assessed**
Small Business	Connected Devices
Schools	Load Monitoring and Management
Energy Information Service	Load Shifting
Codes and Standards	Energy Storage
APS System Savings	Automated Demand Response
Demand Response	Reverse Demand Response

Current DSM Programs

APS's current portfolio of DSM programs provides opportunities for customers to save energy and reduce peak demand within a wide range of customer segments and energy end uses. APS is currently on target to achieve cumulative DSM savings of 22% of expected annual retail energy sales by 2020.

While DSM provides a valuable resource, it also presents a number of unique risks and challenges. Energy efficiency measures typically require customers to make an upfront investment in exchange for savings that occur over the lifetime of the product. Because that investment decision is made by customers, there is uncertainty regarding the amount of energy efficiency that will be implemented. And once energy efficiency is implemented, it may not always perform as expected or be available during times of system peak demand, since most current DSM measures are not utility controlled or dispatched resources. Similar to energy efficiency, demand response initiatives are contingent upon customer participation. Factors such as comfort impact, usability of technology, load reduction (kW) per household, and incentives for participation will all influence the ultimate impact of such a program.

Another unique challenge is that energy efficiency measures reduce revenue necessary to recover APS's fixed costs. In its 2012 Settlement Agreement, APS agreed to a limited Lost Fixed Cost Recovery Mechanism; however, in the future, APS will need a more comprehensive ratemaking mechanism to address the recovery of the fixed cost investments. 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.

APS continuously strives to align DSM programs and energy efficiency resources with APS resource needs. During the planning process for each DSM Implementation Plan, APS reviews the cost effectiveness of all EE programs using updated avoided costs. Currently, avoided costs are low due to continuing low natural gas prices, making the EE programs less cost-effective. In addition, the continued penetration of distributed solar energy is causing changes to the system load shape (i.e., the "duck curve" shape) which further reduces avoided costs during midday hours, when there is an abundance of solar energy available. This makes avoided costs much more time dependent, further reducing cost effectiveness for programs and technologies that save energy during midday. To stay cost effective and focus program spending on the highest value savings, the DSM portfolio needs to evolve to better align with these changing resource needs by focusing programs on reducing the late afternoon and early evening peak demand with less focus on midday kWh savings. This can be done by carefully targeting EE savings to the best load profiles and integrating energy efficiency with load shifting and demand response opportunities.

The current APS DSM Portfolio includes the following Programs and Initiatives:

Consumer Products Program offers incentives towards the purchase of qualifying ENERGY STAR LED lighting, variable speed pool pumps, and HVAC system smart thermostat controls.

Existing Homes HVAC Program uses a combination of financial incentives, contractor training and consumer education to promote the proper installation and maintenance of energy-efficient HVAC systems. The Air Conditioner (AC) Rebate, Duct Test and Repair, Western Cooling Control and Residential Diagnostic measures support energy-efficient residential air conditioning and heating systems along with the proper installation, maintenance and repair of these systems.

Home Performance with ENERGY STAR (HPwES) Program promotes a whole-house approach to EE by offering incentives for improvements to the building envelope of existing residential homes within the APS service territory. HPwES includes measures that improve the EE of the home with air sealing, insulation, faucet aerators, and low-flow showerheads.

Residential New Construction Program promotes high-efficiency construction practices for new homes by offering incentives to builders that meet the program's EE standards. The program emphasizes the whole building approach to improving EE and includes field-testing of homes to ensure performance.

Limited Income Weatherization 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.

Conservation Behavior Program provides participating residential customers with periodic reports containing information designed to motivate them to adopt energy conservation behaviors.

Multi-Family Energy Efficiency Program aims to improve the efficiency of multi-family properties and dormitories by using a comprehensive approach designed to target existing and new construction multi-family buildings.

Large Existing Facilities Program provides prescriptive incentives to owners and operators of large Non-Residential facilities for EE improvements in lighting, HVAC, motors, building envelope, and refrigeration measures. Custom incentives are also provided for EE measures not covered by the prescriptive incentives.

New Construction and Renovation Program includes three components: 1) design assistance; 2) prescriptive measures; and 3) custom efficiency measures that are targeted to improve the energy efficiency of new large commercial and government buildings.

Small Business Program provides prescriptive incentives to small business owners for EE improvements in lighting, HVAC, motors, building envelope, and refrigeration applications through a simple and straightforward mechanism.

Schools Program is designed to set aside DSM funding for K-12 school buildings, including public schools, private schools, and charter schools.

Energy Information Services Program provides large non-residential customers with interval usage information that can be used to improve or monitor energy usage patterns, reduce energy use, reduce demand during on-peak periods, and to better manage their overall energy operations.

Codes and Standards Initiative encourages energy savings by supporting better compliance with energy codes and appliance standards in jurisdictions throughout the APS service area.

APS System Savings Initiative projects include but are not limited to APS generation, transmission, distribution, and facilities energy efficiency improvements, as well as conservation voltage reduction strategies.

Demand Response Programs include the Peak Solutions demand control program, Critical Peak Pricing rates, and Behavioral Demand Response.

New DSM Programs

While traditional EE programs provide customers a greater role in managing their energy use, the focus of DSM efforts needs to align with APS resource needs by emphasizing savings during high cost, high demand late afternoon and evening hours rather than midday hours when solar generation is abundant and wholesale energy market prices are lower.

APS continues to closely examine opportunities for peak demand reduction technologies and programs. Reviewing a broad range of DSM programs/measures, each one is assessed for its peak coincidence factor potential (likelihood that the DSM measure provides energy savings at the time of the utility system peak) and for its impact on 8,760 hourly annual load shapes, particularly with regard to its ability to improve duck curve issues. APS is already transitioning the current portfolio of EE measures toward peak demand management programs that will provide high value to customers and align better with system resource needs.

APS has recently proposed several new programs and pilots in the 2017 DSM Implementation Plan (filed June 1, 2016)[39] and the Modified 2017 DSM Implementation Plan (filed January 27, 2017) that leverage emerging distributed energy resource technologies to better align with changing APS resource needs, including:

T&D PILOT

The T&D pilot is intended to target both residential and non-residential customers who are served by substations that are facing future capacity constraints due to projected load growth or intermittency issues. It will deploy previously approved measures that have been found to be cost-effective by ACC Staff. The pilot will attempt to enhance the benefits that these measures provide by targeting them to areas where they have the most value in helping to reduce or defer T&D infrastructure costs. Therefore, the pilot was designed to produce incrementally higher cost effectiveness results as compared to the same DSM measures installed elsewhere on the system.

LOAD MANAGEMENT TECHNOLOGY PILOT

The Load Management Technology pilot is intended to deploy commercially available load control and load shifting technologies for residential and non-residential customers. The pilot will focus on understanding the potential benefits of these technologies in meeting APS's flexible resource needs. APS will field test the value of select utility-controlled and/or price-responsive load management technologies to gather data on energy and demand savings, reliability of load reductions, and system operation benefits.

ENERGY AND DEMAND EDUCATION PILOT

APS will pilot new energy information tools including web based energy and demand analyzers, personalized videos to guide customers through targeted savings opportunities that match their usage profiles, and an enhanced mobile phone application that can provide near real time feedback on a home's demand and energy use. These new energy information tools and resources provide customers enhanced feedback resulting in a more informed consumer who better understands how to manage their energy use and demand, improve efficiency, and save energy costs.

39 A.C.C. Docket No. E-01345A-16-0176.

DEMAND RESPONSE, ENERGY STORAGE AND LOAD MANAGEMENT PROGRAM (DRESLM)

The Residential Demand Response, Energy Storage and Load Management Program (filed in accordance with Decision No. 75679)[40] is designed to support the deployment of residential load management, demand response and energy storage technologies that help APS residential customers shift energy use and manage peak demand while also providing system peak reduction and other grid operational benefits. The program includes three elements: battery storage, thermal storage and demand response. The program will focus on optimizing the potential benefits of these technologies in helping customers manage peak demand while meeting APS's changing resource needs.

DSM Programs in Development

Increasingly, the future of DSM involves an integrated approach to Distributed Energy Resources (DERs) for managing energy demand and shifting load not only on the grid as a whole, but in specific locations to help defer the cost of distribution related upgrades. As connected devices become more economic and integrated with each other, these DERs will offer more instantaneous demand response capabilities – optimizing the operation of key appliances to save customers money while offering benefits for utility operations. APS is currently conducting the SIS to further explore integrated distributed energy resource solutions. In such a changing environment, it is important to maintain an open dialogue about how the EES can be revisited and applied in a way that more appropriately values the benefits of load management in meeting resource needs, while achieving credit toward EE goals.

DSM ECONOMIC CONSIDERATIONS[41]

The economics of DSM programs can be evaluated by using five cost-effectiveness tests defined in the California Standard Practice Manual. These cost-effectiveness tests include the Participant Cost (PC) test, Ratepayer Impact Measure (RIM) test, Program Administrator Cost (PAC) test, Total Resource Cost (TRC) test and Societal Cost (SC) test. The Arizona Corporation Commission currently uses the SC test as the sole test to evaluate energy efficiency programs. Although APS shares the Commission's view that the SC test can be a useful assessment tool, the Company recommends that additional tests be used to evaluate the economics of DSM programs because each test provides a distinct perspective on the costs and benefits of a particular DSM program. In this broader approach, the SC test could still be used in conjunction with any or all of the other four tests to evaluate additional considerations for a particular DSM program. The use of additional tests such as the RIM and PAC tests can assist in ranking similar programs when considering program implementation. In addition to program ranking, the RIM test also evaluates the average rate and/or shifting of revenue burden from DSM customers to non-DSM customers. Given the perspective the RIM test provides to all customers, both participants and non-participants, it is very useful in evaluating the cost shift or equity of particular DSM programs.

OVERVIEW OF COST-EFFECTIVENESS TESTS

- **PC Test –** Assesses the value of a program only from the potential participants' financial perspective: it compares a customer's bill savings with the capital investment in DSM measures.
- **RIM Test –** Evaluates a program's impact on non-participating customers; i.e., the shifting of revenues from participating customers' bill savings to non-participating customers.
- **PAC Test –** Compares the total costs of providing energy service or revenue requirements before and after the addition of DSM programs to the system.
- **TRC Test –** Evaluates the total costs of DSM programs including costs incurred by both the participating customers and the utility.
- **SC Test –** Provides an economic evaluation similar to the TRC test but also includes externalities such as health impacts.

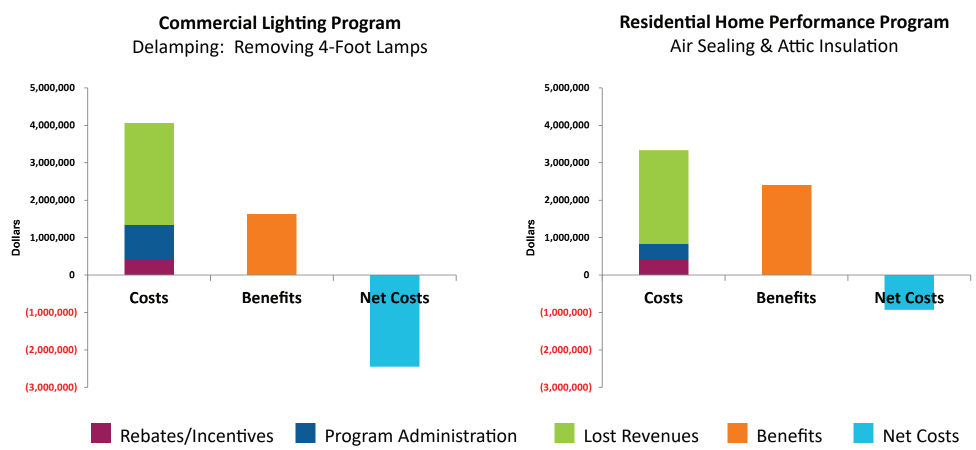
40 A.C.C. Docket No. E-01345A-15-0182.
41 The cost tests in this section can be utilized to determine the cost-effectiveness and cost shift related to rooftop solar as well.

Utilizing these cost-effectiveness tests in the evaluation of supply and demand side resources provides insight into resource selection from multiple perspectives. In particular, the RIM test can be used to rank programs that provide more value or that have lower cost/rate impacts on customers as a whole. The appropriate balance of programs with emphasis on costs as well as other factors is essential to obtaining a balanced resource mix. This approach to costs and benefits is related to the rapidly changing regional resources and the associated energy mix. The widespread deployment of rooftop solar, in particular, has contributed to wholesale market conditions that at times have produced low or negative avoided energy prices. The same phenomenon has created a need for additional peaking units to serve growing peak demands that exist after the sun goes down.

The RIM test includes system benefits such as avoided generation capacity, generation energy, transmission, and distribution costs, while system costs include the utility's DSM program costs such as rebate/incentive payments, program planning, staffing, marketing, administration and lost revenues due to reduction in participating customers' bills as a cost component. If costs are higher than benefits in the RIM test (i.e., there are net costs to the system), the utility would recover these net costs in the form of a rate increase in the next rate case. This would result in the shifting of costs from participating customers to non-participating customers.

The RIM test is particularly useful in evaluating and prioritizing energy efficiency programs that may be introduced by APS. The graphs below illustrate the results from the RIM test applied to two different EE measures. The first graph shows an example of a commercial lighting measure that reduces kWhs, but has very little impact on system peak (high load factor EE measure). It has a low RIM test benefit/cost ratio of approximately 0.40. The second graph shows a residential attic insulation program that has more significant coincident peak reduction but reduces relatively low kWh (low load factor EE measure). It has a relatively higher RIM benefit/cost ratio of approximately 0.72. The RIM test results suggest that the attic insulation measure should be a higher ranking priority because it indicates both a higher valued system savings and a relatively lower degree of cost shifting than the lighting measure.

FIGURE 2-9. DSM RIM TEST EXAMPLES



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U.S. DEPARTMENT OF ENERGY
https://www.energy.gov/

U.S. ENERGY INFORMATION ADMINISTRATION
http://www.eia.gov/

NATIONAL RENEWABLE ENERGY LABORATORY
http://www.nrel.gov/

WORLD NUCLEAR ASSOCIATION
http://www.world-nuclear.org/

CHAPTER 3

TRANSMISSION

Delivering Power to Customers

2017

TRANSMISSION

Approximately 1.2 million customers, in 11 of Arizona's 15 counties, depend on APS for reliable and affordable electric service. APS delivers such service to its customers by relying on its network of transmission and distribution lines that safely transmit power from multiple large-scale generators to customers. APS's transmission planning facilitates the development of such electric infrastructure while ensuring reliable service by employing a planning process that is timely, coordinated and transparent.

APS considers all technologies including generation, transmission, distribution resources and non-transmission alternatives to address the challenges of an increasing array of resource types and higher than national average population growth, while remaining committed to providing least-cost, best-fit solutions. Towards this end, APS's Resource Planning and Transmission Planning teams work together, along with stakeholders and counterparts across the state and throughout the Western region, to assure continued reliable and affordable power to customers.

In APS's 2017-2026 Ten-Year Transmission System Plan (Transmission Plan),[1] the Company detailed expansion of its transmission system for approximately 38 miles of 500kV transmission lines, 14 miles of 230kV transmission lines, and five transformers. These new transmission projects, coupled with additional distribution and subtransmission investments, will support continued reliable power delivery in APS's service territory and APS's increased participation in regional markets.

KEY ISSUES

INCREASED DEPLOYMENT OF SOLAR ENERGY RESOURCES

Increased deployment of intermittent resources, especially rooftop solar, requires greater flexible capacity to respond to net load shapes such as the duck curve. To achieve those objectives, resources that are capable of fast-ramping with the ability to quickly turn on and off are essential to maintain the instantaneous supply and demand balance that the electric grid requires. The transmission system is the link that allows flexible resources to meet changing customer demand.

PARTICIPATION IN REGIONAL MARKETS

Adequate transmission access to energy markets provides APS the ability to leverage its diverse generation fleet for the benefit of our customers. As such, APS's entry into the EIM in October 2016 has already provided $6 million of savings to customers as a result of improved dispatch efficiency and reduced flexibility reserve requirements.[2]

1 Arizona Public Service Company 2017-2026 Ten-Year Transmission System Plan, Docket No. E-00000D-17-0001.

2 California Independent System Operator, Western EIM Benefits Report Fourth Quarter 2016 (January 30, 2017), https://www.caiso.com/Documents/ISO-EIMBenefitsReportQ4_2016.pdf.

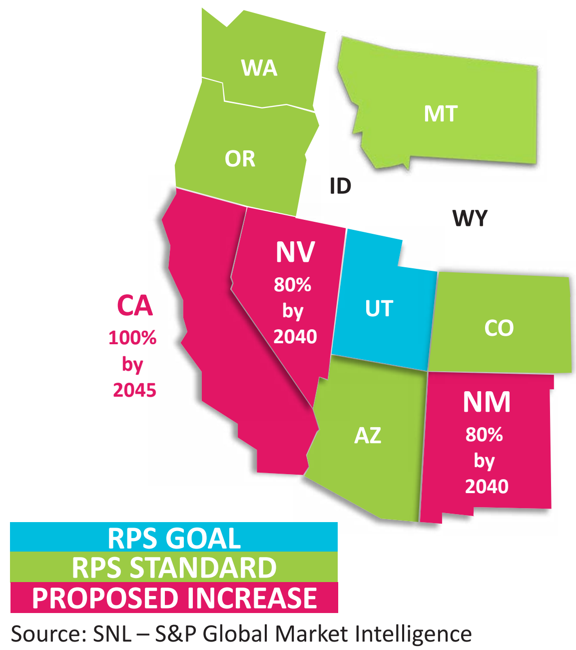
RELIABILITY

APS has a responsibility to provide reliable electric service to its customers. This is achieved through coordinated planning at all levels at APS to provide an integrated electric system capable of maintaining service under a variety of circumstances including adverse weather conditions (both extreme heat and cold) and highly variable load conditions. To ensure resources are available when needed, APS uses both probabilistic and deterministic approaches to assess not only the reliability of its generation and transmission systems, but also the interplay between these two components on the utility system holistically.

RESOURCE ADEQUACY

Resource adequacy assures sufficient capacity is available to the system to balance supply and demand for electricity. The portfolio of assets selected to best achieve those objectives is one that meets APS's planning principles and strikes the proper balance of anticipated needs for the Planning Period. However, the addition of customer-sited resources and regional policies to add significant renewable energy resources (see Figure 3-1) reduces resource diversity by displacing other resource types and requires APS to increase the flexibility of its fleet to be able to respond to the new two-way power flow phenomenon and new net load shapes such as the duck curve. Resources that are capable of turning on, ramping up and down and turning off as needed are vital to maintaining the instantaneous supply and demand balance that the electric grid requires. APS's transmission system is the key component required to achieve system reliability under continuously changing load and resource requirements.

FIGURE 3-1. PROPOSED RENEWABLE PORTFOLIO STANDARD (RPS) INCREASES



SYSTEM STABILITY & SECURITY

The electric gird is a physical system that requires thermal, voltage and frequency levels that do not exceed the limits of the transmission system under normal and contingency conditions. As such, grid-connected resources contribute to the overall reliability of the system by providing voltage support and frequency balancing in addition to providing capacity. Many resources provide these capabilities to varying degrees, and are increasingly important to offset less flexible and intermittent resources that are being quickly added to the electric grid. The result is a more complex system that still must maintain reliable operation for customers.

TRANSMISSION PLANNING

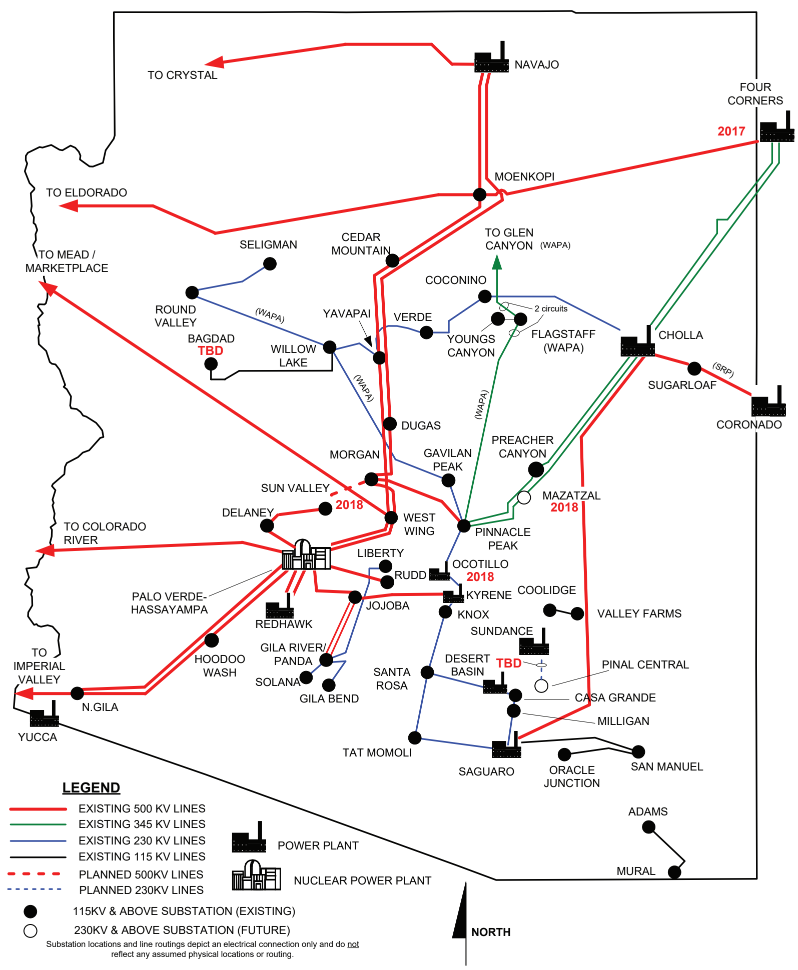
APS's electric transmission facilities consist of more than 6,000 miles of high voltage transmission lines, over 29,000 miles of distribution lines, 430 substations, 300,000 transformers and more than 550,000 power poles and structures.[3] APS owns all or a part of several major transmission paths in the states of Arizona, New Mexico and Nevada, which transport electricity from fossil, nuclear and renewable facilities as well as various long-term purchase agreements as shown in Figure 3-2.

Subtransmission systems carry voltages reduced from high voltage transmission lines to ultimately deliver electricity to the customer. APS annually conducts an analysis of its 69kV subtransmission where modifications may be needed to accommodate changes in load. Upgrades associated with these changes include increasing or decreasing capacity or additional construction projects. More specific information related to subtransmission and distribution resources can be found in Response to Rule D.1 (F).

Distribution systems are the subset of the grid that delivers power to customers. APS focuses its distribution system planning efforts on a five-year basis due to the challenges associated with the level and location of load growth beyond that timeframe.

Optimizing use of the existing transmission system is crucial to the resource planning process as it manages costs, increases line efficiency and is the first step to new generation siting initiatives. Additionally, new transmission infrastructure is being reviewed to enhance the existing system and improve reliability. As adequate transmission must either exist or be planned for construction in support of future generation resources, as well as potential contingencies, APS's resource plans and transmission planning departments coordinate to ensure continued reliability of service.

FIGURE 3-2. APS EXTRA HIGH VOLTAGE TRANSMISSION SYSTEM



3 See APS Witness Jacob Tetlow's Direct Testimony, ACC Docket Nos. E-01345A-16-0036 & E-01345A-16-0123.

LOCAL TRANSMISSION PLANNING PROCESS

APS's Transmission Plan, filed annually, identifies and evaluates future electric transmission system additions that may be required to serve the anticipated APS area load growth, associated generation additions and/or to accommodate interconnection requests. Figures 3-2 through 3-4 provide an overview of the major projects detailed in the APS Transmission Plan. In the formulation of its Transmission Plan, APS uses the reliability criteria established by the Western Electricity Coordinating Council (WECC) and North American Electric Reliability Corporation (NERC), in addition to select APS criteria, to ensure plan compliance. Also, included with the Transmission Plan are the Renewable Transmission Action Plan and the technical study on the effects of distributed generation (DG) and energy efficiency (EE) on the fifth year transmission according to ACC Decisions.[4] For the 2017-2026 planning cycle, the Transmission Plan did not show any additional need for Renewable Transmission Projects (RTP) beyond what was approved by the Commission in the previous order. Two of the three RTPs have been completed, with currently no need to progress on the third plan. Results of the DG/EE Study indicate that delayed or non-implemented DG and EE have no effect on APS's Bulk Electric System (BES) as currently planned in 2021.

FIGURE 3-3. PHOENIX METROPOLITAN AREA TRANSMISSION PLANS (2017-2026)

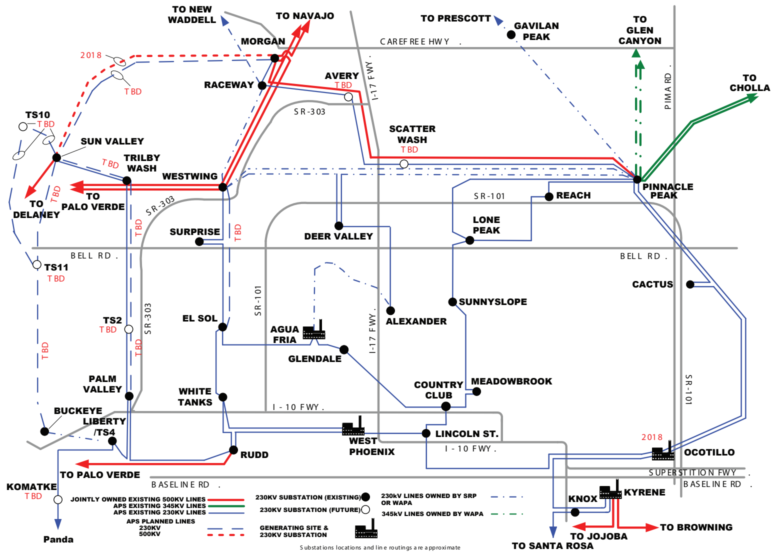
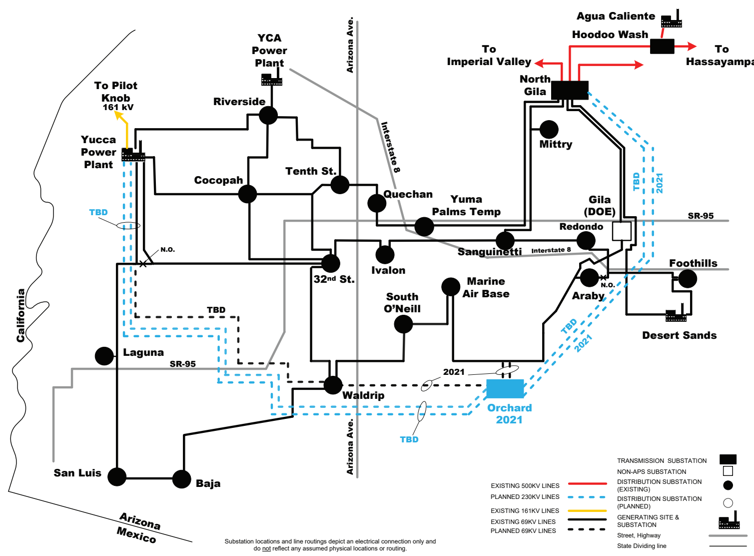


FIGURE 3-4. YUMA AREA TRANSMISSION PLANS (2017-2026)



4 ACC Decision Nos. 70635 (December 11, 2008), and 74785 (October 24, 2014), respectively.

REGIONAL TRANSMISSION PLANNING PROCESS

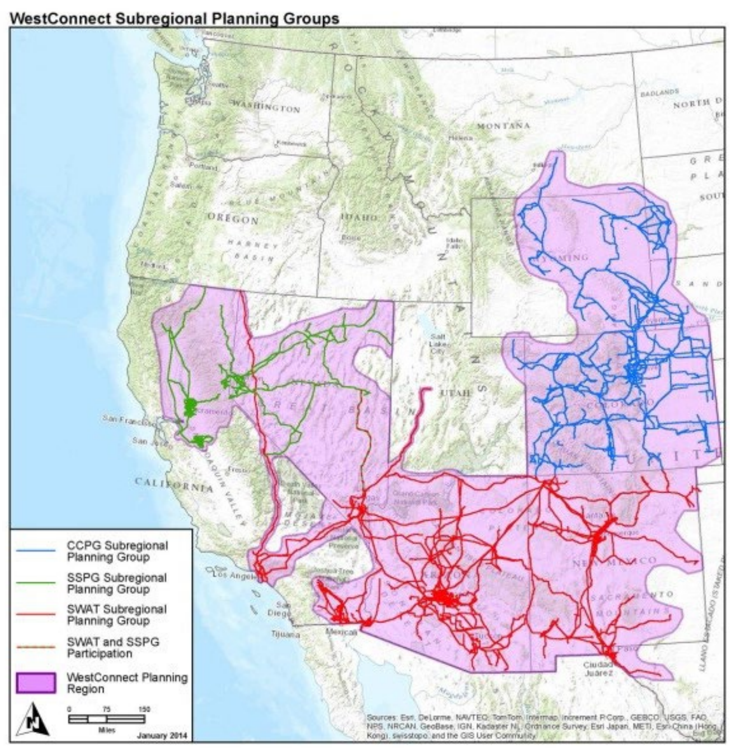
APS participates in numerous regional planning organizations in recognition that transmission planning has broad implications over the entire WECC region. Through membership and active engagement in these organizations, the needs of multiple entities and the region as a whole can be identified and studied, which maximizes the effectiveness and use of new projects. APS is a member of the following regional organizations which coordinate transmission and generation additions and retirements:

a. **Western Electricity Coordinating Council (WECC) –** WECC is a FERC-designated regional entity for the Western Interconnection and has delegated authority from NERC to create, monitor and enforce reliability standards.

b. **Southwest Area Transmission (SWAT) –** SWAT is a group of transmission regulators, transmission users, transmission owners, transmission operators and environmental entities that work collaboratively to encourage implementation of a robust transmission system in the southwestern United States (see Figure 3-5 for the SWAT footprint).

c. **WestConnect FERC Order 1000 Compliance –** WestConnect is comprised of transmission owners (TO) and various other parties that are signatories to the participation agreement in regional transmission planning activities for FERC Order No. 1000 compliance (see Figure 3-5 for the WestConnect footprint). This includes participation in a regional transmission planning process that satisfies the principles outlined in FERC Order No. 890 and results in a regional transmission plan. The goal of WestConnect planning forum is to coordinate transmission planning amongst multiple TOs in both an intraregional and interregional manner with the intention of identifying more efficient or cost-effective solutions to reliability, economic, public policy needs or any combination of such needs.

FIGURE 3-5. WESTCONNECT PLANNING REGION



Source: WestConnect, Regional Planning, Subregional Planning Groups, http://regplanning.westconnect.com/subregional_plng_groups.htm.

TO LEARN MORE

ARIZONA CORPORATION COMMISSION
http://www.azcc.gov/Default.htm

BIENNIAL TRANSMISSION ASSESSMENT (BTA)
http://www.azcc.gov/divisions/utilities/electric/biennial.asp

OPEN ACCESS SAME-TIME INFORMATION SYSTEM (OASIS)
http://www.oasis.oati.com/azps/index.html

FEDERAL ENERGY REGULATORY COMMISSION (FERC)
https://www.ferc.gov/

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC)
http://www.nerc.com/Pages/default.aspx

WESTERN ELECTRICITY COORDINATING COUNCIL (WECC)
https://www.wecc.biz/Pages/home.aspx

SOUTHWEST AREA TRANSMISSION
http://regplanning.westconnect.com/swat.htm

WESTCONNECT
http://www.westconnect.com/

NORTHERN TIER TRANSMISSION GROUP (NTTG)
http://www.nttg.biz/site/index.php?option=com_docman&view=list&Itemid=31

CALIFORNIA ISO
http://www.caiso.com/

CHAPTER 4

MODERNIZING THE GRID

Optimizing Grid Performance and Customer Engagement

2017

MODERNIZING THE GRID

While electric grids have been around for more than a century, until recently, they transmitted power in only one direction: from large-scale power plants to customers through a network of long-distance and local transmission systems. With the introduction of new technologies, the operation of the grid is being revolutionized. Customers are increasingly engaging in the management of their energy usage, including when and how much they use, and what type of resource best meets their needs. The proliferation of hand-held technologies and associated software developments are further facilitating this trend by giving customers more tools to interact remotely and instantaneously with their home energy management systems while other technologies, such as rooftop solar, have paved the way for customers to not only receive power from the grid but to sell it back as well. Over the course of the Planning Period, APS anticipates further developments in customer-based energy production, storage and management, adding to the complexity of integrating new technologies while ensuring seamless reliability of service throughout the day.

The path to incorporate these developments into a grid that traces its roots back over a century is one that requires greater flexibility, responsiveness and resilience. By optimizing grid operations and resources, system operators can rapidly detect and address power disturbances, integrate an increasingly diverse set of resource options and empower customers to maximize the benefits from the technologies that are now available.[1] As much of this progress is driven by greater granularity in data collection and analysis and accessibility, cybersecurity is playing a larger role in our operations to ensure that the modernization of the grid is conducted to safeguard the security and reliability required of APS systems and the privacy of APS customers.

KEY OBJECTIVES

The continued deployment of variable and distributed energy resources in and around APS's footprint has driven the need for an increased ability to ramp and cycle other resources to maintain the active power balance and assist potential bi-directional flows while maintaining power quality and reliability to customers. These capabilities, facilitated by the integration of advanced grid technologies, address the following objectives:

MAINTAIN RELIABILITY

As distributed generation and other forms of renewable energy grow to meet customer energy needs, monitoring and maintaining stable system operating conditions, including voltage, is becoming more important to ensure a balanced grid.

EMPOWER CUSTOMERS

The two-way flow of electricity between customers and utilities is opening doors to real-time operations unprecedented in this industry's history. Smart grid systems increase situational awareness, letting utilities know about changes in localized customer demand, enabling quicker response and minimizing impacts on other customers in the area.

INTEGRATE RESOURCES

While the cost to operate renewable energy assets is less variable than conventional generation, the energy output of these resources is more variable and often not coincident with customer usage patterns. High degrees of fluctuation can and do occur – daily, hourly and in a matter of seconds – and real-time communication between conventional and renewable energy resources is needed to dynamically manage voltage, maintain power quality and ensure overall system reliability and improve operating efficiencies.

1 U.S. Department of Energy, Quadrennial Technology Review (September 2015), https://energy.gov/sites/prod/files/2015/09/f26/QTR2015-03-Grid.pdf.

DISTRIBUTED ENERGY RESOURCE INTEGRATION

The backbone of a modernized grid is a network management system that includes several technologies aimed at optimizing grid performance, reducing customer interruptions and enhancing system efficiencies. Since 2008, APS's rooftop solar customer base has grown from less than 200 to 56,000, requiring new technologies that can accommodate the operational challenges these resources bring. Grid modernization efforts will not only facilitate the integration of these resources, but also provide system operators with greater visibility and customers with real-time information so that they can customize their energy experience. As customers increase their level of interaction with the grid through new technologies available to them, a more distributed, agile and real-time grid will continue to emerge.

DISTRIBUTED ENERGY RESOURCE INTEGRATION ENGINEERING

Distributed energy resources (DER) are comprised of energy generation, energy usage and energy storage technologies which are generally connected to the medium-voltage distribution grid and include, but are not limited to, rooftop solar PV, battery energy storage systems (BESS), demand response or load management devices and other potential technologies. APS has dedicated a team of DER engineers to assess DER impacts and facilitate DER as a component of grid and resource planning. Equipped with simulation and analysis tools, the DER team studies the impacts of DER integration, identifies opportunities for DER deployment and evaluates reliability management with existing grid control tools. In addition, the Advanced Metering Infrastructure (AMI) Program described in CUSTOMER RESOURCES and suite of distribution tools described in DISTRIBUTION PROGRAMS provide APS the data and visibility on system performance to effectively manage a modern grid, with integrated DER, through the Advanced Distribution Management System (ADMS) applications described.

ROOFTOP SOLAR

The ever-increasing adoption of residential rooftop solar photovoltaic (PV) systems throughout APS's service territory is evidence of the shift towards a future characterized by highly distributed, variable, and intermittent resources. At the end of 2016, APS had approximately 56,000 solar PV sites in total, over 16,000 of which were installed in 2016. These distributed generators are quickly becoming an integral part of grid operation. Interconnection processing and feeder level reliability assessments must be streamlined to accomplish multiple, but often conflicting objectives; for example, creating a quick and seamless process for customers and installers given the large volume of interconnection requests, all while maintaining grid reliability for both solar and non-solar customers who share the grid infrastructure.

BATTERY ENERGY STORAGE SYSTEMS

Though still an emerging technology for grid management, APS has initiated projects to test the efficacy of grid batteries as a DER. Two large battery installations at different substations are being operated in conjunction with high penetrations of rooftop solar PV as part of the APS Solar Partner Program (SPP). Residential-scale BESS projects are also exploring the potential of this technology to help customers manage energy and demand through the Solar Innovation Study (SIS).

In September 2016, APS filed its report Spotlight on Energy Storage,[2] which detailed several considerations related to battery storage technology including:

- Cost, technological maturity for widescale deployment and performance, particularly given the high summer temperatures in Arizona, are primary factors in assessing this technology's portfolio value.
- Scale matters. The limited size and relatively high cost of residential batteries makes residential applications a matter for further study, particularly related to their cost-effectiveness or range of benefits as larger, grid-scale connected (12kV+) batteries.
- As energy storage interconnections operate as both load and generator, operating requirements need to be developed, and control and mitigation strategies need to be clearly identified. Proper coordination with larger grid operations is necessary to enable energy storage to modify load shapes and reduce peak demand and avoid this technology's potential impact on congestion and system peak.

FIGURE 4-1. BATTERY ENERGY STORAGE SYSTEM

As the technology matures and cost-effective applications are identified, batteries are likely to become a tool available to both customers and utilities to help balance grid resources with customer demand. APS's resource plans, designed with the flexibility to adapt to these changes, will be able to capitalize on future developments in this technology and increase the level of battery storage to further resource diversification and flexibility in the Company's portfolio. To assess the impacts of increasing energy storage's contribution, APS evaluated an Energy Storage Systems Portfolio detailed in Chapter 7 – Plan Selection.

ADVANCED GRID TECHNOLOGIES

APS is committed to success as a next generation energy company and recognizes that digitizing its grid is an essential step in achieving that goal. Operating under a more customer-centric platform, continuing advances in two-way communication technologies, grid health monitoring systems and hosting capacity information that can pinpoint optimal locations for rooftop solar interconnection are part of an intelligent network designed to increase power quality and system responsiveness.

As advanced grid technologies represent a growing suite of responses to the operational challenges associated with increasing levels of rooftop solar, they offer protective measures to the wider energy system. By containing outages through the re-routing of power flows and locating where repairs are needed so that crews can restore power to customers as quickly as possible, these technologies are projected to increase utility responsiveness and reduce costs. These efficiency improvements also improve asset utilization, reduce line losses, enable advanced data management and analytics and support sustainability efforts by reducing the use of inefficient resources to meet system needs.

By 2025, APS plans to invest in grid modernization technologies, system upgrades and related management systems through a number of project initiatives. Over the past three years, more than 2,000 advanced grid devices have been installed at APS. Going forward, these technologies will be integrated into our new ADMS, providing our operators with a single view to operate the distribution grid. A description of these initiatives and their benefits is provided below.

2 Arizona Public Service Company Spotlight on Energy Storage (September 30, 2016), ACC Docket No. E-01345A-16-0238.

TRANSMISSION PROGRAMS

APS is conducting a number of efforts to maintain and improve transmission reliability from an operational perspective as well. These include:

Energy Management System (EMS) Upgrade Program – EMS is the main operational platform used to monitor, control and optimize the performance of the transmission system. EMS upgrades are expected to provide operators with an enhanced user interface and advanced analytical tools.

State Estimation/Real-Time Contingency Analysis – This tool allows the transmission operator the ability to run "what-if scenarios" and provides greater situational awareness of grid conditions through enhanced network models.

Advanced Visualization Tools – Providing visual analytics and robust reporting for improved operator risk management, these tools allow the operator to assess system conditions more rapidly without having to process a great deal of information or data.

Transmission Substation Health Monitoring (SHM) Program – This program is a family of transmission substation equipment monitoring technologies. Transmission SHM mitigates catastrophic transformer failures and increases system visibility for improved operator risk management.

Phasor Measurement Units (PMUs) – PMUs provide sub-second information about the operating characteristics of the transmission system which, in turn, provide the operator greater situational awareness of system conditions.

Uses include:

- Reducing the risk of major outages through the use of real-time data for improved operator risk management
- Post-event diagnostic capability through the analysis of disturbances and protection scheme performance

DISTRIBUTION PROGRAMS

Substation Health Monitoring (SHM) Program – SHM is a family of distribution substation equipment monitoring technologies that remotely monitor the health of transformer oil, transformer bushings and other substation equipment. Use of distribution SHM technology mitigates catastrophic transformer failures and increases visibility for improved operator risk management.

Distribution Automation (DA) Program – Integrated Volt/VAR Control (IVVC), Two-Way Capacitor Bank Controllers, and Automated Switching are subcomponents of the DA Program. IVVC mitigates low power quality and lowers the need for peak generation, transmission and distribution systems by continuously controlling regulators and capacitor banks to manage power quality such as power factor and voltage at the feeder level. Two-Way Capacitor Bank Controllers provide two-way communication and automation to capacitor banks to manage power quality and voltage. The Automated Switching subcomponent includes several hardware upgrades that automate the detection of problems along the distribution system and allows for remote operation and faster restoration of power.

Distribution Asset Monitoring (DAM) Program – DAM consists of two technology deployments:

- **Communicating Fault Indicators (CFI) –** CFIs installed on distribution lines can be used to detect whether current is flowing on the line and then communicate that status via communications or visual indicators. CFIs provide near real-time voltage, current and fault information, which improve outage restoration times and limit equipment damage risk.
- **Network Protections (NP) –** NP deployment involves the installation of improved breakers, sensors, and relays at existing NPs. These devices provide greater visibility of status, voltage and current in real-time, in addition to increasing safety for field personnel. Historically, this data was obtained manually. Additionally, the Distribution Operations Center will be able to control the NPs in supervisory mode for enhanced operations.

Fire Mitigation (FM) Program – FM technologies mitigate the risk of fire caused by normal operation of the grid located in a forested area. They also have the potential to help APS rapidly determine when equipment has failed and is in need of immediate attention in high fire-risk areas, and they limit the scope of potential hazards when equipment failures do occur.

Advanced Distribution Management System (ADMS) Program – ADMS is an advanced operational platform that manages the operations of the distribution system. It is comprised of three applications: Distribution Supervisory Control and Data Acquisition (DSCADA), Distribution Management System (DMS) and Outage Management System (OMS). Together, they provide an electric grid and individual asset health index, improve outage management (return-to-service), optimize trouble call management and enable condition-based maintenance programs for resource optimization.

Communication Infrastructure Program – Components include the installation of new optical fiber, expansion of AMI network, cell phone networks, microwave communication devices and data management systems required to serve the overall needs of the enterprise in a secure and reliable manner.

ADVANCED ANALYTICS, DATA MANAGEMENT AND CYBERSECURITY

Advanced Analytics – Advanced Analytics analyzes the data being collected through grid technology and leverages this information to assess the performance of the technology to make decisions regarding what further investments are needed, if any. Advanced Analytics also promote a better understanding of customer usage through AMI meters and of how the new grid technology is performing. Areas of focus in this space have been Integrated IVCC, CFIs and Advanced Visualization.

Data Management – Data Management is the collection, storage, protection, and deletion of new data that is being created through grid technologies. APS is enforcing governance and establishing stewardship of the data to ensure and protect its value so that it may be used in the future to allow informed decisions based on facts and data and to be eventually transformed in actions.

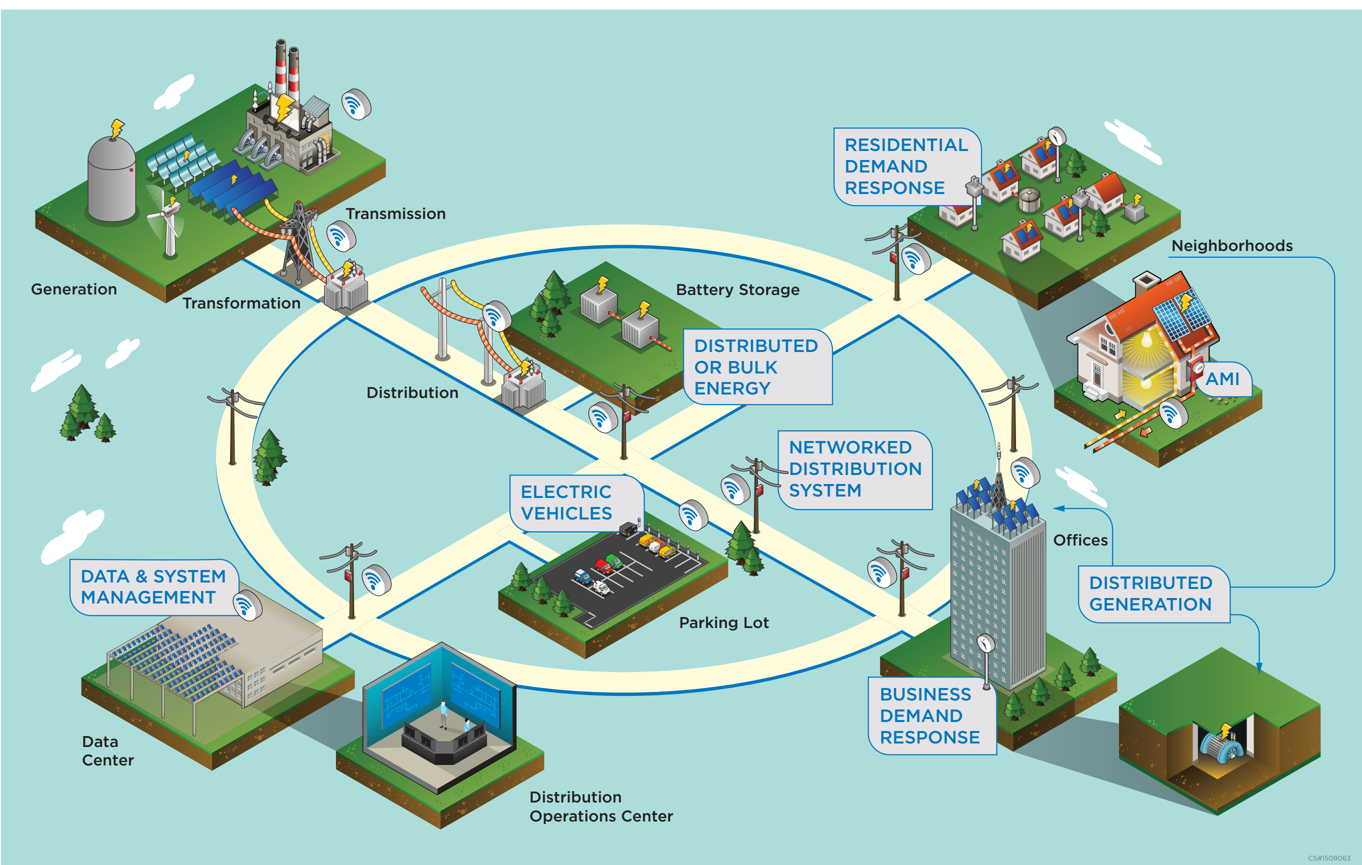
Cybersecurity – As cybersecurity attacks are more frequent and sophisticated across numerous industries, safeguarding the technology that delivers power to APS customers becomes increasingly important. Also, APS recognizes that there are a growing number of vendors, suppliers and businesses that have responsibility for managing the electric grid. Over time, as these third-parties have become more interdependent on each other, a cybersecurity attack on one or more of these third-parties could affect an electric utility's ability to manage grid activities. To protect our customers against such risks, our comprehensive cybersecurity program is designed to prepare our people, programs and technologies for emerging threats. The program is built on three essential elements: awareness, defensive posture and resiliency. Awareness includes employees taking an active part in the cybersecurity program. The cornerstone of the program is providing employees with the tools to recognize attacks using multiple delivery mechanisms, including tracking how employees respond and react to customized phishing emails we send to them throughout the year. Part of the Company's defensive posture is to deploy controls to prevent unauthorized use of removable media and the stealing of credentials that can be used to compromise or damage systems. In 2016, the Company established the APS Cyber Defense Center (ACDC) to enable faster and more efficient responses to cybersecurity threats. Our resiliency includes conducting quarterly exercises to simulate emergent threats and scenarios that could arise from potential cybersecurity attacks and data breaches, ensuring that incident response and business-restoration procedures are up-to-date and effective.

CUSTOMER RESOURCES

Advanced Metering Infrastructure (AMI) Program – AMI is the collection of advanced billing meters, communicating devices and data management systems required to provide wireless electric metering and two-way communications between utilities and their customers. Benefits include:

- Enables customers to manage costs by providing monitoring tools for energy usage, change service plans or connect and disconnect service from their computer.
- Enables APS to offer a host of programs to give customers more choices, such as the Company's Preferred Due Date option, which allows customers to choose the payment date that best fits their lifestyle, including varying the due date by a few days from one bill to the next.
- Enables APS to monitor voltage levels and power quality to help ensure reliable service and effectively plan for future energy needs.
- Provides safety and environmental benefits by avoiding millions of driving miles by APS employees to remotely perform customer read-ins, read-outs, rate changes, disconnects and reconnects.
- Produces substantial amounts of new data that can be transformed into actions such as reducing the number of unplanned transformer failures, identification of power outages and optimize placement of future grid modernization technologies for even more enhanced performance, monitoring, and control.
- New AMI technologies being deployed have the capability to support DA devices on the same communications network as the meters providing added grid monitoring and control at a reduced installation and operations cost.

FIGURE 4-2. ADVANCED GRID ILLUSTRATION



CUSTOMER TECHNOLOGY PROGRAMS

As energy technologies become more sophisticated, customers are increasingly exploring ways in which these technologies can be optimized to fit their individual needs. While some customers pursue energy solutions on a resource-by-resource or program-by-program basis, others prefer a more comprehensive approach and seek a robust spectrum of technologies customized to their objectives. Whether the need for these solutions comes from residential customers who seek to better manage their energy usage through advanced devices and appliances, or from commercial and industrial customers which seek to reduce costs, increase reliability and meet sustainability goals, APS recruits from its broad range of technology and program options to create solutions that work. From these initiatives, APS is expanding its expertise in individual technologies and, more importantly, in how these technologies and DSM programs work together as a cohesive whole.

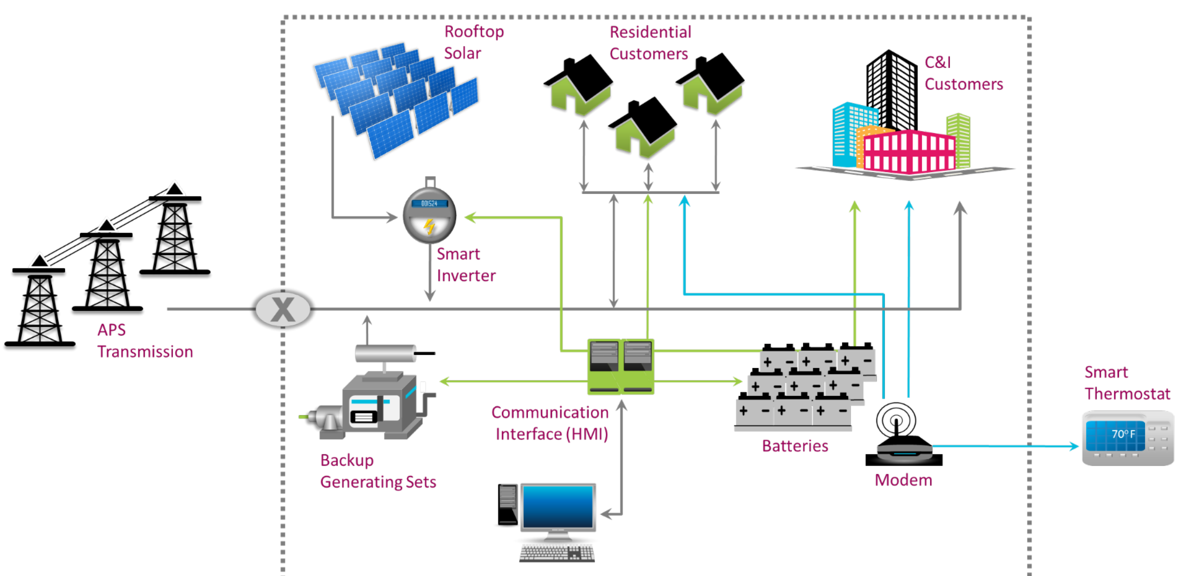
To help customers engage more in their use of energy, last year APS launched a number of customer service improvements including an upgraded mobile-friendly outage map and a new mobile application that gives customers the ability to view usage and pay bills from their smartphones.

MICROGRIDS

A microgrid is a part of the distribution grid that can separate (island) from the grid, continue operation, and reconnect with the grid at a later point in time without customer disruption. Local generation within the microgrid is key to a successful project in order for the microgrid to continue providing power to meet local load needs. Ongoing industry cost reductions in DER and low-cost communication platforms that provide the real-time command and management of local loads and resources has made the application of utility-led microgrids increasingly possible and cost-effective for customers.

APS expects microgrids to play an increased role in how the Company supports business customers and economic development. Microgrids are beneficial for APS's system and its customers as they increase reliability of the distribution grid, especially in the local area, by preventing localized power outages from continuing down the line and affecting the rest of APS's system. In addition, due to their fast-acting characteristics, microgrids provide ancillary services, such as frequency response, in the event of a grid disturbance. By providing customers with needed backup power and APS with increased flexible capacity on its system, microgrids are beneficial to both participating and non-participating parties and may defer future capacity needs on the APS system.

FIGURE 4-3. MICROGRID ILLUSTRATION



Examples of suitable settings for microgrid projects include hospitals, military installations, data centers and other customers with sensitive loads that cannot sustain loss of power. These customers traditionally procure their own back-up power systems to ensure continuous operation in the unlikely event of a power outage. APS partners with these customers to share in the cost and use of these resources, which have reliable and flexible operating characteristics to respond to their needs.

In many of these applications, microgrid-capable DER installed at customer sites can act in a dual-use mode; in their first mode of operation, they provide peaking power to the grid in a grid-connected mode, benefiting all customers by acting as another peaking resource on the system and meeting APS planned resource requirements (plus reserve margin). In their second mode of operation, they can provide backup power to the host customer in the event of a power outage.

Microgrid Projects

In December 2016, APS, with the U.S. Department of the Navy and U.S. Marine Corps, launched the nation's first utility-owned, fully-islandable microgrid located within the fence line of a DOD facility at Marine Corps Air Station (MCAS) in Yuma. This 21.6 MW project pioneered a new way to partner with a customer in which both parties make contributions to the project for the benefits of the direct (host) customer and APS customers. The MCAS Yuma microgrid can provide reliable power throughout the summer peaks to all APS customers by backfeeding the grid from within the base facility and, in the event of a grid outage, the facility can provide 100% backup power to MCAS Yuma, enhancing national security. Due to the ability of the microgrid to go from zero to full output in under 20 seconds, it also provides frequency response services to the grid, which will further enhance the economics and savings of this facility for all customers.

FIGURE 4-4. MCAS YUMA MICROGRID

APS also worked with the Aligned Data Center to bring an 11 MW microgrid facility into service in the Phoenix metro area in December 2016. Similar to the MCAS Yuma microgrid, this facility can act as a peaking resource and provide frequency response to the broader grid as well as backup power in the event of a grid outage.

ROOFTOP SOLAR, ADVANCED INVERTERS, LOAD MANAGEMENT AND ENERGY STORAGE

APS Solar Partner Program (SPP) – In 2015-2016, APS designed and implemented the 10 MW APS Solar Partner Program. The program involves approximately 1,600 utility-owned residential PV systems with advanced inverters wirelessly connected to a central control system in the APS operations center. Each installation includes advanced inverters certified to the latest UL-1741SA standard and centrally controlled wireless communications for all advanced functions. This is the first time in the industry that an advanced-inverter project has been implemented at this scale and breadth. West- or southwest-facing rooftops were specified to better align solar output with peak system demand on six primary research feeders.

In addition to the 10 MW of new photovoltaic capacity under the program, APS deployed two battery storage systems, each rated at 2 MW/2 MWh for use in peak-shaving (flattening the net feeder demand) and distribution system voltage management on two of the primary SPP research feeders. APS, in continued cooperation with EPRI, will conduct research on the battery systems in 2017 with the goal of understanding whether batteries do a better job of voltage rise on high-PV-penetration feeders versus advanced inverters (or whether both are useful and necessary). Findings from this portion of APS activities will be available in early 2018.

The SPP initiative was named 2017 Project of the Year for Renewables Integration by the industry organization DistribuTECH.[3]

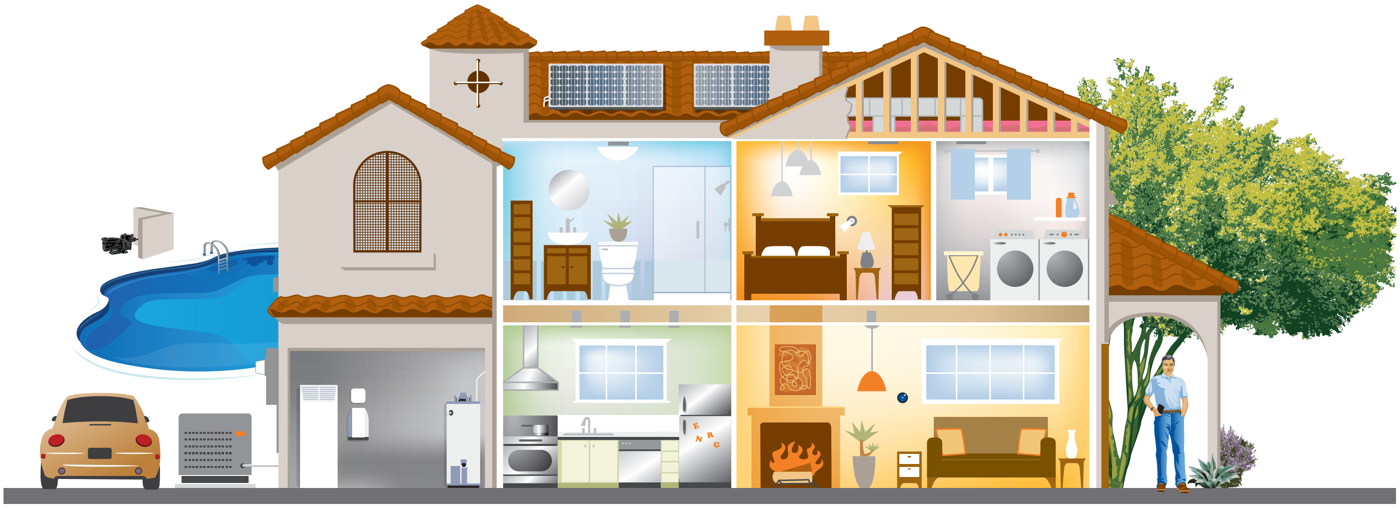
Solar Innovation Study (SIS) – SIS is comprised of two separate programs:

- A 75-customer home energy management and rate research and development field program designed to examine the integration of customer-side advanced technologies, including battery storage
- A similar, market-facing program will examine the integration of rooftop solar with energy-related technologies like demand managers (such as load controllers). Participating customers will be placed on demand rates and will own all equipment in the study

Demand Response Energy Storage Load Management (DRESLM) Program – APS has filed for approval of an APS-owned residential energy storage program within the Demand Response Energy Storage Load Management (DRESLM) program,[4] designed to support the deployment of residential load management, demand response, and energy storage technologies that help APS residential customers shift energy use and manage peak demand. The initiative comprises an estimated 13.25 MWs of peak demand reduction, and includes residential and intermediate scale batteries, thermal storage in the form of grid interactive water heaters, and a demand response component facilitated through smart thermostats.

3 Electric Light & Power, POWERGRID International names Project of the Year Award winners (January 31, 2017), http://www.elp.com/articles/2017/01/powergrid-international-names-project-of-the-year-award-winners.html.

4 In the Matter of the Application of APS for a Ruling Relating to Its 2016 DSM Implementation Plan, Docket No. E-01345A-15-0182; see also Docket No. E-01345A-16-0176.



SMART HOMES

Customer interest in optimizing energy usage is on the rise. Driven not only by an evolving expectation of what is possible through the use of several home devices and hand-held technologies, but also by advanced grid technologies that allow customers and utilities to see usage details like never before, homes are being adapted with energy management in mind.

KEY SMART HOME COMPONENTS

Smart Meters – Smart meters are the digital interface between utilities and their customers. Through the automatic transfer of information – from the customer to the utility and vice versa – smart meters have opened up a vast landscape of previously unavailable energy data that utilities use to offer increasingly customized and targeted energy products, and customers use to better manage their energy consumption.

Smart Thermostats – More than just a device to adjust the temperature, smart thermostats monitor how customers use energy then automatically adjust temperature settings according to the behaviors it records. Features include self-adjustment when no one is home to save energy, self-programming based on customers' preferred temperature settings, control from mobile devices via Wi-Fi and energy reports showing energy usage details and energy savings provided by having the smart thermostat installed.

Smart Appliances – Smart appliances use digital processing and communications technology to make functions faster, more energy-efficient and more interactive. Smart refrigerators can automatically adjust humidity settings to preserve food longer, smart dishwashers can self-diagnose maintenance issues and send an alert to mobile devices and smart washer/dryers can be started or paused remotely. More importantly, these smart appliances (including major home energy users such as pool pumps and electric water heaters) can be coordinated to manage energy demand and linked with smart thermostats to become part of the household energy behavior patterns that the thermostat will adjust to optimize energy usage.

Home Energy Management Systems – A smart home can include more than smart meters, thermostats and appliances. It can also include smart plugs, switches, outlets, lights, windows, sensors and more. Home energy management systems bring these Wi-Fi-enabled devices under the control of a single application for a comprehensive home automation approach.

TO LEARN MORE

U.S. DEPARTMENT OF ENERGY – SMART GRID

https://energy.gov/oe/services/technology-development/smart-grid

CHAPTER 5

SUSTAINABILITY

Water Conservation, Emissions Control and Waste Management

2017

SUSTAINABILITY

Sustainability has many different definitions. At APS, it means doing the work we do every day to strike a balance between providing reliable, affordable energy and being responsible stewards of the environment. The sustainability activities of APS-operated power plants are founded on the principle that promoting Arizona's vibrant economy, protecting a healthy environment and supporting stable communities will strengthen our service territory for future generations. In 2017, APS expects to produce over 50% of its energy mix from carbon-free resources including renewable energy, energy efficiency and other DSM programs and, most importantly, the carbon-free nuclear generation from Palo Verde which in 2016 produced 32.2 million MWh – the only U.S. generating facility to produce more than 30 million MWh in a single year. Over the course of the Planning Period, that commitment to clean energy will continue as APS evaluates further advances in water conservation, emissions control and waste management programs and technologies, in addition to supporting customers' increasing interest in DSM solutions.

WATER CONSERVATION

Arizona's water challenges are balanced between two realities: increasing demand for water due to high growth rates and limited supply of water given the arid conditions of the desert southwest. The state's electric utility industry has long recognized these challenges and continuously engages in water conservation efforts that have resulted in Arizona power plants consuming less than 3% of the state's water supply. APS's achievements in this effort include the largest water/energy project in Arizona's history: Palo Verde became the first nuclear power plant in the world not bordering a large body of water to use reclaimed water. APS continues to explore innovative solutions in pursuit of the "right water for the right use." Towards that end, each APS power plant has a unique water strategy, which is developed to promote efficient and sustainable use of water and reliability of water supplies. In addition, other efforts such as retiring or upgrading water-intensive power plants, increasing the use of renewable energy and implementing DSM programs, add to APS's overall water conservation.

EMISSIONS CONTROL

APS strives to cost-effectively reduce the impact of its operations on the environment and communities of which we are a part. During the Action Plan Period, APS will complete (a) the installation of state-of-the-art air pollution controls at the Four Corners Power Plant in 2018, and (b) the replacement of older gas-fired turbines with new, modern turbines and modernized air pollution controls as part of the Ocotillo Modernization Project expected to be completed in 2019.

WASTE MANAGEMENT

APS's waste management efforts encompass the responsible handling of discharges of wastewater and streams originating from fly ash and bottom ash handling facilities, solid waste, hazardous waste, and coal combustion products, which consist of bottom ash, fly ash, and air pollution control wastes. APS currently disposes of coal combustion residuals in ash ponds and dry storage areas at Cholla and Four Corners, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete production.

Approximately 40% of the non-hazardous waste tracked through the Company's Investment Recovery group is recycled. In terms of hazardous waste, APS has achieved reductions since 2002, and each year since 2006, APS has successfully generated 88% - 97% less hazardous waste than what was produced in 2001.

High-level nuclear waste (i.e., spent fuel) continues to be stored on-site at Palo Verde Generating Station. APS has identified and implemented the safest, lowest maintenance and effective interim storage options pending a permanent solution from the U.S. Department of Energy. Low-level nuclear waste is safely shipped off-site for disposal.

Water Conservation

Water is growing in importance as a factor in assessing the viability of new energy projects for all utilities. Utilities operating in water constrained areas – such as APS's service territory – face greater challenges. To meet those challenges while maximizing the use of renewable water resources and minimizing the use of non-renewable resources, it is important to consistently monitor water use, both in terms of the amount of water used and the water intensity (gallons per MWh).

As power plants get older and are eventually retired, APS plans to replace these more water-intensive units with newer, more water-efficient technologies, such as the hybrid cooling systems that APS will use at Ocotillo. These types of upgrades, as well as conducting water efficiency audits of power plants, implementing leak reduction programs, and ensuring equipment is functioning as designed, will help the Company achieve conservation of groundwater resources. Additional groundwater conservation measures were implemented in 2016 with development of APS's well and pumping equipment reliability initiative. Under this initiative, 46 production wells were evaluated and prioritized for replacement or renovation, new wells have been drilled and more efficient pumping equipment has been installed. The result was increased reliability, more efficient water use, and improvement in water quality, resulting in reduced water consumption.

FIGURE 5-1. WATER SOURCE BY FACILITY (APS-OPERATED)

To bolster water efficiency efforts and improve communication with other water stakeholders, APS has participated 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. More recent efforts include participating on the Governor's Blue Ribbon Panel on Water, supporting development and activities of the Kyl Center for Water Policy at the Morrison Institute, participating in the Groundwater Users Advisory Council, the Governor's Water Augmentation Council, the Colorado River Water Users Association, the Water Reuse Association and assisting ADWR on the development of the 4th (Groundwater) Management Plan.

OUTLOOK FOR WATER INTENSITY IN APS OPERATIONS

Over the 2017-2032 Planning Period, water intensity is expected to decrease due to:

- Increased penetration of renewable energy resources
- Increased penetration of energy efficiency
- Retirement of older, water-intensive units
- Technological advancements in new power plants that use efficient water cooling strategies such as hybrid cooling systems
- Implementing water conservation measures at existing plants

WATER OVERVIEW BY FACILITY

APS manages the water use at nine APS-owned/operated facilities. In 2016, APS developed and implemented a groundwater conservation strategy designed to reduce fleetwide consumption of groundwater by 8% compared to the reference year 2014. Goals of 10% and 12% were established for 2017 and 2018 respectively. This strategy supports an APS Tier I metric entitled Conservation of Non-Renewable Water Supplies, which will be achieved by (a) retiring older water-intensive units and replacing them with more efficient units and (b) implementing water conservation measures at APS plants.

The focus is on non-renewable water (i.e. groundwater) because this supply is at the greatest risk of depletion and is a significant source of supply at seven of nine APS power plants.

NUCLEAR

PALO VERDE

Source: Treated effluent (reclaimed) water.

With operating licenses in place for Units 1, 2 and 3 out to June 2045, April 2046 and November 2047, respectively, the current water supply contract ensures a reliable supply will be available through 2050. However, it is likely that a second license renewal request will be made for an additional 20 years. Opportunities include working with state and federal agencies as well as West Valley communities to develop alternative water supplies, which can be used directly or indirectly through recharge and recovery.

Palo Verde uses treated effluent for cooling water and a comparatively small quantity of groundwater for drinking water and industrial process water. Avoidance of groundwater use as cooling water is very important because two adjacent power plants, Mesquite and Arlington Valley, rely upon groundwater from the same aquifer. APS (for Palo Verde and Redhawk), Mesquite, and Arlington Valley send a report every five years to the ACC, ADWR, and U.S. Geological Survey (USGS) concerning subsidence and land fissure development around the four power plants. Effluent use by Palo Verde and Redhawk instead of groundwater reduces the probability of subsidence in the area.

In 2016, Palo Verde's Water Reclamation Facility built a seventh treatment train that will provide redundancy and allow rehabilitation of existing equipment with no loss of treatment capacity. This provides greater reliability of treated effluent for use at Palo Verde and Redhawk.

COAL

FOUR CORNERS

Source: Surface water from the San Juan River.

Following a drought in 2000, a shortage sharing agreement was executed between the Bureau of Reclamation (BOR) and the parties utilizing San Juan surface water as their water supply. Although the current agreement expired in January, 2017, a renewal until the end of 2020 has been executed by APS and is pending signature of the remaining parties. In 2016, APS worked with the United States Bureau of Reclamation (USBR) and other major water users on the San Juan River to develop a new management strategy for Navajo Reservoir. The reservoir will be held at a higher level than in previous years to ensure that all of the water needs, including environmental needs, are met while minimizing the potential of future water shortages. In 2017, APS will begin implementing a water pumping plan at Four Corners to better protect endangered species in the San Juan River.

CHOLLA

Source: Groundwater from 18 production wells located on both sides of the Little Colorado River.

To mitigate concerns of the wells' close proximity to the Little Colorado River, a Cholla groundwater flow model was developed in 2014 and a groundwater monitoring program has been conducted since 2012. Further development of this model is ongoing and is expected to minimize possible adverse impacts on groundwater levels, water quality and surface water flows. Cholla's groundwater modeling and water quality sampling has enabled development of a Cholla Wellfield Operations Plan that has identified variable water quality in wells and directs plant staff to use higher quality water first. This optimizes the water quality available for use as cooling water, drinking water, and industrial process water and results in reduced overall water consumption.

NATURAL GAS

OCOTILLO

Source: Groundwater in the Phoenix Active Management Area.

As part of the Ocotillo Modernization Project, APS has begun the process of replacing the two existing 1960s-era steam units with five new quick-start combustion turbines (CTs), which will incorporate hybrid (wet/dry) cooling towers into the design. The new CTs will use approximately 140 gallons/MWh compared to the steam unit consumption of 900 gallon/MWh. Water conservation surveys were conducted in 2016 at all APS plants that use groundwater and Ocotillo was found to employ the best cooling tower water management strategy. An automated water quality monitoring system monitors make-up and blowdown of cooling water, resulting in maximum efficiency and water savings compared to manual systems. Results of the water conservation survey and recommendations were provided to all APS plants.

WEST PHOENIX

Source: Groundwater in the Phoenix Active Management Area.

The West Phoenix Power Plant utilizes a zero liquid discharge (ZLD) brine concentrator and evaporator that allows reclamation and reuse of treated water, reducing reliance on groundwater. In 2016, West Phoenix upgraded equipment, provided operator training, and optimized water management to reduce groundwater consumption.

REDHAWK

Source: Treated municipal effluent (reclaimed water) provided by the Palo Verde Water Reclamation Facility (PVWRF) as the primary cooling water supply plus groundwater.

The effluent is delivered to the Redhawk reservoir with a minimum 20-day supply at 100% capacity factor and is ready for use. In 2016, Palo Verde's Water Reclamation Facility built a seventh treatment train that will provide redundancy and allow rehabilitation of existing equipment with no loss of treatment capacity. This provides greater reliability of treated effluent for use at Redhawk and Palo Verde.

SAGUARO

Source: Groundwater from four on-site wells.

Decommissioning of the two steam turbines has significantly reduced the need for water to support generation. However smaller quantity water needs persist for the plant's combustion turbines.

SUNDANCE

Source: Surface water.

In addition to its rights for excess Central Arizona Project (CAP) water, APS has purchased as an alternative 5,000 AF of water from the Gila River Indian Community (GRIC) and entered into a recovery and exchange agreement with the GRIC for the next 45 years, continuing its reliance on renewable surface water.

YUCCA

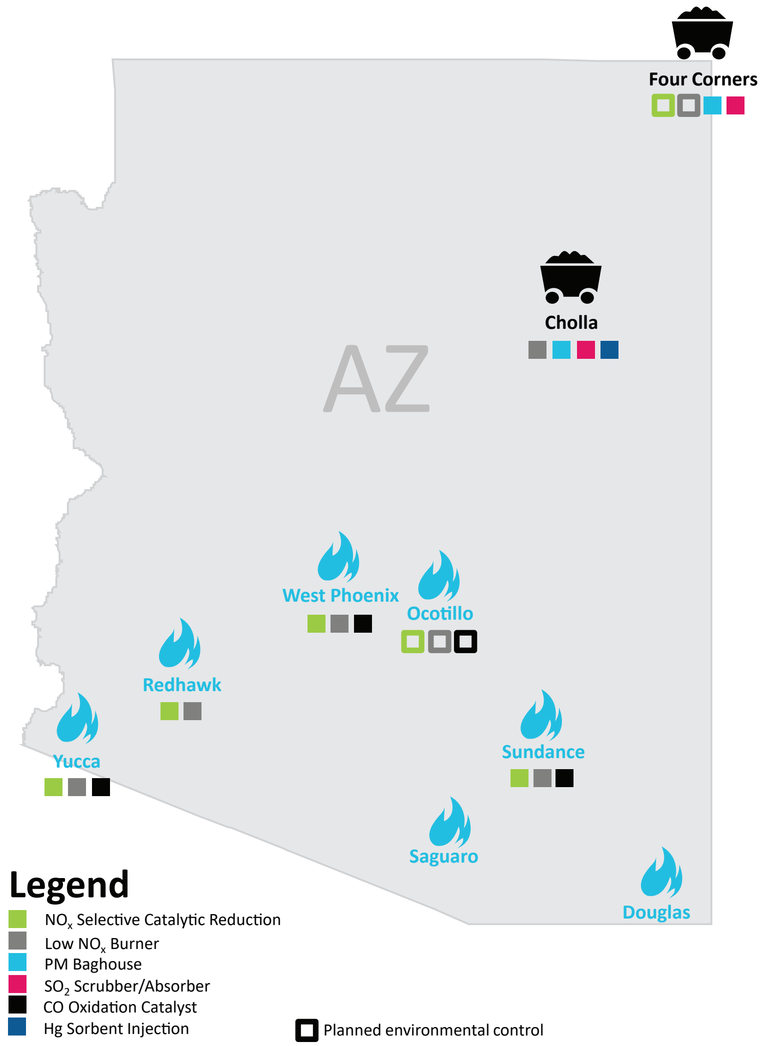
Source: Surface water from the Colorado River and groundwater from three on-site wells.

A new well was drilled in 2014 and placed into service in 2015. This well is out of the Colorado River accounting surface, pumps groundwater, and will meet the needs of the plant in the event of a Colorado River shortage. APS entered into an agreement with the CAP and USBR to forego use of 5th - 6th priority surface water rights and instead use groundwater whenever possible, conserving the surface water in Lake Mead as a hedge against future shortage.

EMISSIONS CONTROL

APS is reducing its carbon footprint through the Company's commitment to add only low- and zero-emitting resources to its portfolio mix. See Chapter 7 – Plan Selection for a carbon analysis of the seven portfolios reviewed in the 2017 IRP. Reduction in other pollutants, such as mercury (Hg), nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter (PM) and carbon monoxide (CO) is managed through the installation of various environmental controls and other efforts. Since 2007, overall Company-wide emissions have been reduced as a result of the retirement of generating units at some facilities, the installation of new air pollution controls at existing units and investments in state-of-the-art air pollution control technology at new and modernized facilities. A recent example is the Ocotillo Modernization Project, expected to be in operation in 2019, which will replace two existing 1960s-era natural gas-fired steam generating units with five new gas-fired turbines that will be equipped with state-of-the-art air pollution control technology. As a result, the energy generation capacity at the site will more than double while the NOx and CO emissions from the facility will be cut in half. Figure 5-2 provides a visual overview of the air pollution controls that exist or are planned for the facilities within the Company's fossil fuel-fired fleet of generating facilities.

FIGURE 5-2. AIR POLLUTION CONTROLS BY POWER PLANT (APS-OPERATED)



NITROGEN OXIDES (NOx)

Nitrogen oxides are a family of highly reactive gasses that form when fuel is burned at high temperatures. The pollutant appears as a brownish gas and is known to react with Volatile Organic Compounds (VOC) and heat to form ground-level ozone, often referred to as smog. In 2016, APS reported a total of approximately 21,300 tons of NOx emissions for all APS operated facilities. That number is expected to decrease to approximately 10,500 tons per year by the end of 2019. All of APS's coal-fired facilities and many of its natural gas-fired facilities, especially those that impact or are impacted by nearby ozone non-attainment areas, have installed at least one of the air pollution controls detailed below.

LOW NOx BURNERS (LNB)

By volume, dry air from the earth's atmosphere contains approximately 78% nitrogen in the form of N2. At high temperatures, the naturally occurring nitrogen molecules break apart and react with oxygen to form NOx. LNBs effectively control this reaction by changing the characteristics and location of fuel combustion as well as the peak flame temperature. LNBs are one of the better values in air pollution control, providing a high level of removal efficiency of NOx at a lower overall cost than other NOx control options.

APS-operated facilities that currently employ LNB technology:

- Cholla
- Redhawk
- Sundance
- West Phoenix
- Yucca

APS-operated facilities that are planning to employ LNB technology:

- Four Corners (2018)
- Ocotillo (2019)

In 2007, APS reported more than 15,200 tons of NOx emissions from the Cholla Generating Station alone. As a result of the retirement of Unit 2 at the end of 2015, the use of LNB on the remaining units and lower load demands, total NOx emissions from the facility were reduced to 2,736 tons in 2016. Total NOx emissions from the facility are expected to remain at or below 5,500 tons per year in future years.

SELECTIVE CATALYTIC REDUCTION (SCR)

SCR is a post-combustion control device that utilizes a catalyst and a chemical reaction with ammonia to reduce emissions of NOx by turning it into water, oxygen and nitrogen. In the United States, SCR has been applied to both coal- and natural gas-fired electrical utility boilers and turbines, effectively reducing overall emissions by 70% to 90%. SCR also results in the emission of small concentrations of ammonia, often referred to as ammonia slip, as the chemical reaction performs best in the presence of excess ammonia. SCR is the most expensive of all NOx air pollution control strategies.

> Completion of the installation of SCRs at the Four Corners Power Plant is expected to result in a 90% reduction of NOx emissions from 2007 levels.

APS-operated facilities that currently employ SCR technology:

- Redhawk
- Sundance
- West Phoenix
- Yucca

APS-operated facilities that are planned to employ SCR technology:

- Four Corners (2018)
- Ocotillo (2019)

In 2007, APS reported more than 41,000 tons of NOx emissions from its Four Corners Power Plant. In 2013, APS permanently retired Units 1, 2 and 3, reducing NOx emissions by approximately 12,000 tons. Total NOx emissions from the facility continued to decline to approximately 17,300 tons in 2016. In early 2018, APS anticipates completing the installation of SCR on the remaining Units 4 and 5. By 2019, the first full year of operation with the new SCRs, the total NOx emissions from the facility is expected to decline to approximately 3,700 tons per year, an overall reduction of more than 90%.

SULFUR DIOXIDE (SO2)

Sulfur dioxide is part of a larger family of reactive gasses that form as a result of burning fuels that contain sulfur. Because natural gas is inherently low in sulfur, coal- and oil-fired facilities are the most likely to generate SO2 emissions. SO2 in the atmosphere contributes to the formation of acid rain and can react with other compounds in the atmosphere to form fine particles that create visibility impairment, or haze, throughout the United States. In

2016, APS reported a total of 5,766 tons of SO_2 for all APS operated facilities. Only 21 tons (less than 0.5%) were emitted by the natural gas fleet.

SO2 SCRUBBER/ABSORBER

SO2 scrubbers and absorbers, sometimes referred to as Flue Gas Desulfurization, typically use aqueous limestone slurries to create a chemical reaction that eliminates the gaseous SO2. This acid-base reaction forms Calcium Sulfide which is absorbed by the liquid in the scrubber, resulting in significant control of the SO2 acid gases that form as part of combustion. Because natural gas is inherently low in sulfur content, SO2 scrubbers and absorbers are only used on coal-fired generating stations in the APS fleet. Scrubbers also provide an additional benefit by reducing particulate matter emissions.

Both APS-operated coal facilities, Four Corners Power Plant and Cholla Generating Station, include SO2 Scrubber or Absorber technology.

Improvement in pollution control at APS's coal facilities have resulted in significant reductions of SO2 throughout the fleet. In 2007, prior to its voluntary emissions reduction program, the Cholla Generating Station reported more than 23,500 tons of SO2 emissions. As a result of the retirement of Unit 2 at the end of 2015, the use of SO2 scrubbers and absorbers on the remaining units and load demands, total SO2 emissions from the facility were reduced to approximately 1,334 tons in 2016. Total SO2 emissions from the facility are expected to remain at or below 3,000 tons per year in future years, an 87% overall reduction.

PARTICULATE MATTER (PM)

Particulate matter, also known as particle pollution, is a term that describes the mixture of solid particles and liquid droplets that are found in the air. Unlike gaseous pollutants, particulate matter is regulated by size. Larger particles, called PM10, are often associated with activities that break up the earth's crust or generate dust. Smaller particles, called PM2.5, are often associated with the burning of fuel and are commonly referred to as soot. Both forms of particulate matter have been a focus of the Clean Air Act since its inception. Combustion of natural gas produces almost no PM emissions. Coal-fired facilities are the primary contributor to PM stack emissions. In 2016, APS reported a total of approximately 824 tons of PM10 emissions for all owned and operated facilities. The most common control device is a baghouse.

BAGHOUSE

A baghouse is an air pollution control device that is specifically designed to remove particulate matter by passing the exhaust gas from a process through a fabric filter or series of fabric filters that resemble a large sock or bag. These socks or bags physically collect the particulates in the folds or on the surface of the fabric. Self-cleaning mechanisms are used to periodically remove the dust cake from the surface of the fabric to ensure optimal removal efficiency.

APS-operated facilities that currently employ baghouse technology:

- Cholla Generating Station
- Four Corners Power Plant

CARBON MONOXIDE (CO)

Carbon monoxide is a colorless, odorless gas formed through the incomplete combustion of fuel. Problems with concentrations of CO in the atmosphere have largely been resolved through the proliferation of modern air pollution controls.

CO OXIDATION CATALYST

CO oxidation catalyst is a post-combustion control device that utilizes a precious metal catalyst (typically platinum) and heat to achieve the maximum conversion of carbon-based compounds, including carbon monoxide gas, to carbon dioxide.

APS-operated facilities that currently employ CO Oxidation Catalyst technology:

- Sundance
- West Phoenix
- Yucca

APS-operated facilities that are planning to employ CO Oxidation Catalyst technology:

- Ocotillo (2019)

MERCURY (HG)

Mercury is a naturally-occurring chemical element that is found in rock and other materials in the earth's crust, including deposits of coal. Because mercury does not degrade in the environment, most mercury emitted into the atmosphere eventually deposits into land or water bodies.

TABLE 5-1. MERCURY EMISSIONS

APS-OPERATED FACILITY	2016 MERCURY EMISSIONS
Cholla	48 pounds
Four Corners	43 pounds
TOTAL	91 pounds

Arizona utilities have been working collaboratively with the Arizona Department of Environmental Quality to reduce mercury emissions since 2007, when they agreed to a state mercury emissions reduction program that set a long term goal of complying with EPA's final Mercury Air Toxics Standard or a 90% emissions control by the end of 2016. APS also selected an interim goal of achieving a 50% control for the Cholla Generating Station by 2011, which it accomplished. In 2016, total emissions of mercury from APS operated coal-fired electricity generating units was approximately 91 pounds.

ACTIVATED CARBON INJECTION

Activated carbon injection is a post-combustion control technology that typically introduces activated carbon into a gas stream in an effort to reduce emissions of mercury. The activated carbon is injected into the gas stream upstream of the particulate matter control device to absorb mercury before being captured and removed by the particulate matter control device.

The Cholla Generating Station is the only APS-operated facility that currently employs activated carbon injection for mercury control. The Four Corners Power Plant has been able to achieve significant mercury emissions reductions and comply with EPA's Mercury Air Toxics Standard without the need of additional controls. APS achieved these emissions reductions by improving the method in which coal is combusted in the boiler, introducing electrostatic chemistry in the baghouse, and utilizing the SO2 scrubber's ability to remove all but the remaining elemental mercury.

WASTE MANAGEMENT

Sustainability is about being a good steward of resources, using only what is needed today and keeping the balance to meet similar needs in the future. For APS, this translates into efficiently extracting the value from those resources that are necessary to deliver safe and reliable energy to meet customer demand. Towards that end, APS maximizes the use of its fuels and supplies and works to not only minimize or eliminate waste where possible but also to responsibly manage waste that is generated by the Company's processes (e.g., waste management).

COMMON WASTE MANAGEMENT

APS's Investment Recovery group is a leader in corporate recycling and landfill use reduction. Waste materials are recycled through specialized streams (such as scrap metal and E-waste) as well as comingled, which is a single-stream recycling of common waste materials. APS continues its efforts to understand and limit its impact on the environment by tracking wastes diverted through the APS forestry program and by capturing the quantities of vegetation that are removed and able to be mulched.

HAZARDOUS WASTE MANAGEMENT

APS has been proactively reducing its hazardous waste for a number of years. Since 2006, APS's annual hazardous waste reduction efforts achieved between 88% to 97% reductions from 2001 levels. APS's rolling, three-year average hazardous waste reduction efforts have also achieved between 93% and 96% reduction every year since 2008.

> APS is one of the first U.S. utilities to recycle solar panels without generating any hazardous waste materials.

This commitment was underscored in the summer of 2016 when several of APS's solar facilities experienced heavy damage due to high winds and hail from a monsoon storm. Samples revealed that approximately 200 tons of damaged solar panels would qualify as hazardous waste if they were simply to be disposed. APS's review of its fleet of solar assets indicates that as many as half of its solar panels could also qualify as hazardous waste if not recycled in the event of disposal. Through exhaustive research, APS identified a single recycling company in the United States capable of handling and completely recycling the solar panels without generating any hazardous waste. This breakthrough ensures APS's continued success in reducing the amount of hazardous waste ending up in landfills each year.

NUCLEAR WASTE MANAGEMENT

Like all nuclear power plants, Palo Verde produces nuclear waste in the form of spent fuel - commonly referred to as high-level waste - along with low-level waste such as used protective clothing, filters and other contaminated items. There are currently no options for disposal or reprocessing of high-level waste. As a result, Palo Verde continues to move spent fuel from its spent fuel pools to dry cask storage. Dry cask storage is a safe, low maintenance and effective interim, on-site storage option for nuclear waste that the Company will continue to use until the U.S. Department of Energy meets its obligation to provide a permanent nuclear waste storage facility. Low-level waste, including low-level water waste, is packaged in proper containers and shipped for disposal in permitted disposal facilities.

POLYCHLORINATED BIPHENYLS (PCB) MANAGEMENT

APS has been implementing a PCB management program in an effort to manage and reduce the amount of PCB and PCB-contaminated equipment. APS has been successful in reducing the use of PCBs in electrical equipment by targeting suspected equipment based on manufacturer information and the serial numbers. Since 2000, APS removed 17,374 pieces of equipment from its distribution and substation systems, resulting in the disposal and replacement of more than 3.9 million pounds of PCB-containing material. APS expects to continue its program by proactively identifying and managing PCB-containing equipment as it works to eliminate the use of PCBs through the Planning Period.

TO LEARN MORE

U.S. BUREAU OF RECLAMATION

https://www.usbr.gov/

U.S. ENVIRONMENTAL PROTECTION AGENCY

https://www.epa.gov/

ARIZONA DEPARTMENT OF WATER RESOURCES

http://www.azwater.gov/azdwr/

CHAPTER 6

REGULATORY

Regulations and Oversight

2017

REGULATORY

Although the Company's operations are governed by a wide range of regulations at the federal, state and local levels, the regulatory environment from a resource planning perspective is focused on four key areas: planning and standard-setting, environmental, licensing and permitting. Regulation of other issues, such as transmission, are covered in the Company's other regulatory filings.

KEY LEGISLATIVE & REGULATORY AUTHORITIES GOVERNING APS RESOURCE PLANNING ISSUES

U.S. CONGRESS

Passes energy-related legislation from which federal agencies promulgate regulations.

U.S. ENVIRONMENTAL PROTECTION AGENCY (EPA)

Regulates water use and certain emissions of power-generating facilities.

NUCLEAR REGULATORY COMMISSION (NRC)

Oversees the safety and licensing of nuclear power plants.

ARIZONA CORPORATION COMMISSION (ACC)

Sets utility rates, governs resource and transmission planning activities and sets standards to achieve state-wide energy objectives.

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY (ADEQ)

Administers Arizona's environmental laws and delegated federal programs to prevent air, water and land pollution and ensure cleanup.

LOCAL AIR QUALITY DEPARTMENTS

Issues pre-construction and operating permits.

KEY REGULATORY AND PERMITTING REQUIREMENTS

RULES & STANDARDS

ARIZONA CORPORATION COMMISSION

- Integrated Resource Planning Rules
- Ten-Year Transmission System Plan
- Certificate of Environmental Compatibility
- Renewable Energy Standard
- Energy Efficiency Standard

ENVIRONMENTAL LEGISLATION

CONGRESS

- Clean Air Act (CAA)
- Clean Water Act (CWA)
- Resource Conservation Act (as amended by the Water Infrastructure Improvements for the Nation Act of 2016)
- Water Infrastructure Improvements for the Nation
- Other

ENVIRONMENTAL REGULATION

ENVIRONMENTAL PROTECTION AGENCY

- Regional Haze Program
- Mercury and Air Toxic Standard
- National Ambient Air Quality Standards
- Carbon Pollution Standards for Fossil-Fired Electric Generating Units
- Cooling Water Intake Structure Regulations
- Revised Effluent Limitation Guidelines
- Coal Combustion Residual Regulations

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

- Arizona laws and delegated federal programs governing air quality, water quality and waste programs

ENVIRONMENTAL PERMITTING FOR NEW CONSTRUCTION

FEDERAL

- National Environmental Policy Act Review
- Endangered Species Act Consultation and Permitting
- Clean Water Act Section 404 Permitting
- Right-of-Way for Use of Tribal Lands
- NRC Nuclear Generation Licensing Process

STATE

- Certificate of Environmental Compatibility
- Delegated Clean Air Act Permitting
- Aquifer Permit
- Title V Quality Permit

LOCAL

- Maricopa County Air Quality Department – CAA preconstruction and Title V operating permits for facilities located in Maricopa County
- Pinal County Air Quality Control Department – CAA preconstruction and Title V operating permits for facilities located in Pinal County

ARIZONA CORPORATION COMMISSION

INTEGRATED RESOURCE PLANNING

The ACC's IRP Rules[1] require regulated electric utilities to file an IRP detailing how customer needs are projected to be met over a 15-year period. The IRP Rules require load-serving entities in Arizona, including APS, to submit to the Commission the following filings:

Historical Filing (every year by April 1) – The Historical Filing details demand- and supply-side data for the previous calendar year, except for coincident peak demand and number of customers by customer class which are reported for the previous 10 years.

Work Plan (every odd year by April 1) – The Work Plan outlines the contents of the upcoming IRP.

IRP (every even year by April 1) – The IRP details how a load-serving entity intends to meet peak load over a 15-year Planning Period and includes:

- A coincident peak load forecast for each month and year
- A comparison of a wide set of resource options, taking into consideration fuel and technology diversity
- The selection of a portfolio based on a wide range of considerations of demand- and supply-side options
- Documentation of assumptions, models and methods used in forecasting
- Analysis of the integration costs of renewables
- Expected reductions in environmental impacts
- Comprehensive risk assessments of the IRP components
- A three-year action plan

In Decision No. 75269 (September 16, 2015), the Commission ordered Arizona's regulated electric utilities, for the 2016 IRP cycle, to file a Preliminary IRP on March 1, 2016, and a Preliminary IRP Update on October 1, 2016, with the Final IRP to be filed April 3, 2017. The requirement of the Preliminary IRP filings and the one-year extension of the Final IRPs were undertaken to allow the filing entities to discuss and assess the impacts of EPA's Clean Power Plan.

In Decision No. 75068 (May 8, 2015), the Commission also ordered Arizona's load-serving entities, with the exception of Arizona Electric Power Cooperative, to file updates to the 3-Year Action Plans contained in their respective IRPs whenever a substantive change occurs in the near term resource plan.

TEN-YEAR TRANSMISSION SYSTEM PLAN

In compliance with A.R.S. § 40-360.02, the ACC requires Arizona regulated electric utilities to file a Ten-Year Transmission System Plan (Ten-Year Plan) for major transmission facilities. Arizona regulated electric utilities are also required to file a Renewable Transmission Action Plan in accordance with ACC Decision No. 70635 (December 11, 2008), a Technical Study on the Effects of DG/EE on Fifth Year Transmission in accordance with ACC Decision No. 74785 (October 24, 2014), and internal planning criteria and system ratings in accordance with ACC Decision No. 63876 (July 25, 2001).

1 A.A.C. R14-2-703.

ACC STANDARDS

Renewable Energy and Energy Efficiency Standards – The ACC Renewable Energy Standard (RES)[2] requires 15% of retail sales be met by renewable energy by 2025. As part of the RES, APS must also meet a portion of the renewable energy requirement with distributed energy resources – namely, rooftop solar installations. The ACC Energy Efficiency Standard (EES)[3] requires a 22% cumulative energy savings requirement by 2020.

From a planning perspective, the degree to which customers engage in these programs represents a significant uncertainty and has a direct impact on projected customer demand levels. If customer participation is lower than projected, then demand for energy could exceed forecasted levels as would the need for resources to supply that demand. Conversely, higher than anticipated participation in these programs would lower customer demand for energy resulting in reduced resource needs. Over the 15-year Planning Period, penetration of these programs may be higher or lower than originally forecast, depending on many factors such as customer preferences, general economic conditions and availability of affordable technology (which can include subsidies such as the Solar Investment Tax Credit).

RENEWABLE ENERGY STANDARD

The ACC's RES requires electric utilities under its jurisdiction to supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement is 7% of retail electric sales in 2017 and is set to increase annually until it reaches 15% in 2025. The RES also includes a carve-out for distributed energy systems of 30% of the overall RES requirement per year.

ENERGY EFFICIENCY STANDARD

The ACC's Energy Efficiency (EE) rules went into effect in 2010 and increase yearly up to an EES of 22% of cumulative annual energy savings by 2020. The requirement is a percent of prior year's retail sales.

TABLE 6-1. RES % REQUIREMENTS

YEAR	RES REQUIREMENT*
2017	7.00%
2018	8.00%
2019	9.00%
2020	10.00%
2021	11.00%
2022	12.00%
2023	13.00%
2024	14.00%
2025	15.00%

*The requirement is calculated each calendar year by applying the applicable annual percentage to the retail kWh sold. See A.A.C. R14-2-1804(B).

TABLE 6-2. EES % REQUIREMENTS

YEAR	EES REQUIREMENT**
2017	14.50%
2018	17.00%
2019	19.50%
2020	22.00%

**The requirement is a percent of prior year's retail sales. See A.A.C. R14-2-2404(B).

2 A.A.C. R14-2-1801 et seq.
3 A.A.C. R14-2-2401 et seq.

ENVIRONMENTAL LEGISLATION

CONGRESS

The only significant environmental legislation affecting APS during the 114th Congress was the Water Infrastructure Improvements for the Nation (WIIN) Act, which was signed into law by President Obama on December 16, 2016. This Act contains a number of provisions that require EPA to modify the self-implementing provisions of the Agency's current Coal Combustion Residual (CCR) rules, which were intended to regulate the way steam-electric generating units manage the solid and liquid waste by-products of coal combustion and associated air emission controls. Specifically, EPA is provided with the authority to directly enforce the CCR rules through the use of administrative orders and, pending congressional appropriation, the obligation to develop a federal permitting program. EPA was also provided the authority to delegate permitting authority to the States through the approval of a state-proposed permitting program. Because EPA has yet to undertake implementation of the CCR provisions of the WIIN Act, and Arizona has yet to determine whether it will develop a state-specific permitting program, it is unclear what effects, if any, the CCR provisions of the WIIN Act will have on APS's management of CCR.

With respect to the 115th Congress, it remains unclear at this time what environmental legislation, if any, will be proposed for consideration and passage. While it is anticipated that several environmental regulations promulgated by the U.S. EPA towards the end of President Obama's second term will be subject to elimination through Congressional Review Act (CRA) resolutions (e.g., the Office of Surface Mining Reclamation and Enforcement's "Stream Protection Rule"), substantial changes to federal environmental statutes through congressional action are not expected.

ENVIRONMENTAL REGULATIONS

Environmental regulations are promulgated on the federal (EPA), state (ADEQ), and county (Maricopa, Pinal, and Pima) levels.[4] EPA, specifically, has promulgated multiple regulations that have an impact on APS's operations.

CLEAN AIR ACT

The CAA regulates air emissions from stationary and mobile sources. Numerous programs have been established to protect public health and welfare by controlling emissions of air pollutants.

REGIONAL HAZE (VISIBILITY)

Best Available Retrofit Technology (BART) – The Four Corners, Cholla, and Navajo power plants are subject to the CAA's Regional Haze rule, which requires an analysis of the impacts of air emissions from certain industrial facilities and the installation of "best available retrofit technology" to control emissions from those facilities to improve visibility in affected national parks and wilderness areas. The focus of the regulations is to reduce emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2), and particulate matter (PM), which contribute to visibility impairment in these federal areas. Congress enacted the visibility statutes to address the aesthetic effects of air pollution in national parks and wilderness areas, not to protect public health. To secure "reasonable progress" with statutory goals, the Regional Haze rule envisions a long period, covered by several planning phases, to meet the congressionally established national visibility goal targeted to be met in 2064. The state of Arizona is required to develop a Regional Haze State Implementation Plan (SIP) for each period, the first of which extends from 2005 through 2018. Each subsequent planning period will run for 10 years. Arizona's first Regional Haze SIP covered the initial planning period extending from 2005 through 2018 and included a BART determination for each BART-eligible source in the state. APS's Four Corners and Navajo plants were subject to BART determinations made by EPA, as these facilities are located on the Navajo Nation. Though the status of these initial BART determinations for APS's plants evolved, both through litigation and additional regulatory proceedings between ADEQ and EPA, each facility is now subject to a finalized BART determination. During the next (i.e. second) planning period, which will run from 2019 through 2028, the state of Arizona must consider man-made sources of visibility-impairing pollutants for potential Reasonable Progress controls. Sources not subject to BART in the first planning period

4 Additional information regarding environmental regulations can be found in Response to Rule D.17.

could potentially be subject to additional emission control requirements in the second and subsequent planning periods of the Regional Haze program.

MERCURY AND AIR TOXICS STANDARD (MATS)

EPA proposed a rule regulating hazardous air pollutants (HAPs) on May 3, 2011, and finalized the regulations on December 16, 2011. The rule establishes standards and requirements for reducing mercury and other HAP emissions from certain electric generating units. APS has met all of its regulatory obligations for installing activated carbon injection on Units 1, 3 and 4 at Cholla. Four Corners Units 4 and 5 were able to meet the mercury limit with existing equipment. Both facilities are fully compliant with the applicable emissions limitations.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

For the purpose of protecting public health and welfare, the CAA established NAAQS for six pollutants: ozone, NOx, SO2, PM10, carbon monoxide, and lead. On October 26, 2015, the EPA adopted a new ozone NAAQS and set it at 70 parts per billion. This decision was legally challenged by various industry organizations, yet supported by various states and environmental groups. The lawsuit is currently on-going. During this time, both the 2008 and the 2015 ozone NAAQS remain in effect. EPA is presently engaged in a rulemaking effort to direct implementation of the 2015 NAAQS for ozone.

CARBON POLLUTION STANDARDS FOR FOSSIL-FIRED ELECTRIC GENERATING UNITS

Clean Power Plan (CPP) – On August 3, 2015, EPA finalized the CPP to reduce emissions of carbon dioxide (CO2) from existing electricity generating units by setting a CO2 emissions reduction goal for each State or Tribe's electricity generating facilities. These goals could be met through a combination of the following emission mitigation measures: more efficiently producing electricity, voluntarily shifting power production from high (coal and oil) to low (natural gas) or zero (nuclear, renewable) sources of CO2, improving end user energy efficiency, and increasing electricity generation from renewable sources. EPA's final rule was appealed to the U.S. Court of Appeals for the District of Columbia Circuit, who initially denied motions to stay the effectiveness of the rules. After an appeal of that court's stay decision, on February 9, 2016, the U.S. Supreme Court ordered an immediate halt to federal efforts implementing the CPP until the judicial proceedings challenging the regulations are fully completed. The State of Arizona has stopped all work on the CPP and will restart proceedings after the legal uncertainty has been resolved. Adding to the uncertainty is the Trump administration's expressed intent to roll-back the Obama Administration's Climate Action Plan, which includes the CPP. The exact scope and extent of the Trump Administration's regulatory roll-back effort remains unclear at this time. The D.C. Circuit of Appeals is expected to make a decision regarding the first round of appeals of the CPP in the first half of 2017.

New Source Performance Standard (NSPS) – On August 3, 2015, the EPA also finalized a New Source Performance Standard (NSPS) to limit emissions of CO2 for new coal plants and natural gas combustion turbines. The rules for new coal-fired units would require the installation and operation of Carbon Capture and Sequestration (CCS) technology, which at this time is cost prohibitive. The rules for new natural gas units are based on high efficiency combined cycle units. Low capacity factor combustion turbines, including simple cycle units, are exempt.

CLEAN WATER ACT

The CWA establishes the basic structure for regulating discharges of pollutants into 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 – EPA issued its final cooling water intake structures rule on August 15, 2014, which provides national standards applicable to certain cooling water intake structures at existing power plants and other facilities pursuant to Section 316(b) of the CWA. The rule is intended to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). These standards are intended to comply with section 316(b)'s standard that such cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

Effluent Limitation Guidelines (ELG) – On September 30, 2015, EPA finalized its revisions to the effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil fuel-fired Electric Generating Units (EGUs). The final regulation is intended to reduce metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and leached wastewaters collected from coal ash disposal units. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero-discharge" from fly ash and bottom ash handling, and impoundments for leached wastewaters collected from coal ash disposal units. Compliance with these limitations will be required as a part of the National Pollution Discharge Elimination System (NPDES) permit renewals, which arise over the course of five year intervals.

RESOURCE CONSERVATION AND RECOVERY ACT

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

Coal Combustion Residuals – On December 19, 2014, EPA issued its final regulations governing the handling and disposal of Coal Combustion Residuals (CCR), such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit the pond with a liner, or close. All CCR landfills or surface impoundments that cannot meet the applicable performance criteria for location restrictions or structural integrity are required to close. The provisions of this rule are self-implementing and currently rely upon citizens lawsuits for enforcement of its requirements. To the extent ADEQ takes action to implement the CCR permitting provisions of the recently passed WIIN Act, though, utility company exposure to citizen lawsuits pursuant to these CCR regulations is expected to be reduced.

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

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

Similar to EPA delegation authority, ADEQ may delegate some permitting and enforcement responsibilities to counties within the state. ADEQ has delegated CAA permitting and enforcement authority to Pima, Pinal, and Maricopa counties.

ENVIRONMENTAL PERMITTING FOR NEW CONSTRUCTION

Construction of new electric facilities – whether for electric generation or for transmission – requires compliance with extensive permitting and environmental impact review processes. Depending on the specifications of the facility and its location, the permitting and review process may take up to 24 months or more to complete before construction is authorized. The major permits and environmental review obligations required by federal, state, and local authorities are described below.

FEDERAL

National Environmental Policy Act Review – The National Environmental Policy Act (NEPA) requires federal agencies to prepare an Environmental Impact Statement (EIS) on proposals for major federal actions (including authorizations or approvals) significantly affecting the quality of the human environment. The EIS describes the environmental impacts of a proposed action and alternative actions that may be taken instead of the one proposed. An EIS may be required when a development is proposed for a site on undisturbed, environmentally-sensitive or federally-protected land, or for projects subject to federal funding or approval. For those projects that are not expected to result in significant environmental impacts, federal decision or action agencies are authorized to prepare an Environmental Assessment (EA) along with a Finding of No Significant Impact (FONSI). An EA/FONSI is typically a more concise document than an EIS and requires significantly less environmental review to complete.

Endangered Species Act Consultation And Permitting – With respect to projects that may result in harm to species federally designated as threatened or endangered, compliance with the species impact review procedures under the federal Endangered Species Act (ESA) is required. For projects with a federal nexus, such as those involving land under federal jurisdiction or federal funding or authorizations, the federal action or decision agency must consult with the U.S. Fish and Wildlife Service under Section 7 of the ESA, which can result in certain species protection conditions being placed on federal acts of discretionary authority. As for those projects without a federal nexus, Section 9 of the ESA provides for incidental "take" permitting, which authorizes purely private activity that may otherwise harm protected species subject to certain species protection conditions.

Clean Water Act Section 404 Permitting – For projects that cross or otherwise result in the discharge of dredge or fill material within certain surface water resources under federal jurisdiction (or "Waters of the U.S."), permitting under Section 404 of the CWA from the U.S. Army Corps of Engineers is required. The current scope and extent of what qualifies as a surface water resource under federal jurisdiction is subject to controversy and dispute. Nonetheless, the definition can include a number of low-lying washes subject to routine flooding or surface water flow during heavy rain conditions.

Right-of-Way for Use of Tribal Lands – When constructing generation facilities or installing transmission lines on tribal lands, a right-of-way easement granted by the tribe and approved by the Secretary of the Interior is required.

NRC Nuclear Generation Licensing Process – Despite the recent increase in federal support for nuclear power projects, including loan guarantees and the NRC improved licensing process, the period from design to commissioning is double that for other technologies while costs are considerably higher. New nuclear generator units often have a lead time of over nine years because: (1) new reactor licenses must be approved by the NRC, which can take between two and a half to five years, and (2) after the review process is complete, construction can take roughly five to eight additional years.[5]

STATE

Certificate of Environmental Compatibility – Utilities, with proposed power plants or transmission lines subject to the jurisdiction of the ACC and the Arizona Power Plant and Line Siting Committee (Committee), are required to make an application with the ACC for a Certificate of Environmental Compatibility (CEC).[6] The Committee considers, during public evidentiary hearings, the application relative to a series of factors[7] including, among other things, the status of all, applicable permits. Following these deliberations, the Committee makes a recommendation to the Commission regarding the CEC. The Commission then makes a final determination on the CEC application complying with A.R.S. § 40-360.06 and balancing, in the public interest, the need for an adequate, economical and reliable supply of electric power with minimizing environmental impact.[8]

5 International Atomic Energy Agency, Nuclear Power - Small and Medium Sized Reactors (SMRs) Development, Assessment and Deployment, available at https://www.iaea.org/NuclearPower/SMR/.

6 Applies to construction of a new thermal electric, nuclear, or hydroelectric facility of 100 MW or more or a transmission lines of 115kV or greater.

7 Specified in A.R.S. § 40-360.06.

8 A.R.S. § 40-360.07.

Delegated Clean Air Act Permitting – The state of Arizona has full approval to implement the federal CAA preconstruction permit program, and is the local permitting authority for all of Arizona, except Maricopa County, Pima County, Pinal County, and tribal lands. The EPA administers this program for sources on tribal lands, where the tribe does not have its own approved program or has agreed not to exert regulatory jurisdiction over a source. The CAA preconstruction permits, commonly known as “Prevention of Significant Deterioration” (PSD) permits in geographical locations that meet or exceed the National Ambient Air Quality Standards (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 construction of a new major source of air emissions, and prior to making a major modification to an existing source of air emissions. PSD and NNSR 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 Rate” (LAER) for nonattainment areas. These limits are then rolled into the eventual 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, the ADEQ delegated this authority to three of the 15 counties within the state – Maricopa, Pima, and Pinal – with the remaining 12 counties continuing under ADEQ jurisdiction. The EPA administers the Title V operating permit program on tribal lands 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 stationary 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) – MCAQD issues CAA preconstruction and Title V operating permits for facilities located within Maricopa County, which include APS’s Redhawk, West Phoenix, and Ocotillo power plants. As with ADEQ, MCAQD requires a Title V permit for any major stationary source of air emissions. MCAQD also requires a CAA preconstruction 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 power plants are located in Pinal County. Therefore, these plants are under the jurisdiction of the Pinal County Air Quality Control Department, which issues CAA preconstruction and Title V operating permits for facilities located within Pinal County.

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ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
http://www.azdeq.gov/

MARICOPA COUNTY, AIR QUALITY DEPARTMENT
http://www.maricopa.gov/1244/Air-Quality

PINAL COUNTY, AIR QUALITY
http://www.pinalcountyaz.gov/AirQuality/Pages/home.aspx

CHAPTER 7

PLAN SELECTION

Portfolio Analytics

2017

PLAN SELECTION

The IRP process culminates in the evaluation and comparison of a number of alternative resource plans to meet future electricity needs and identifies the most favorable plan. This chapter discusses the development and analytical evaluation of alternative resource plans and their associated potential risks. Based upon the needs and opportunities assessment identified in Chapters 1 and 2, a set of responsive Portfolios were developed and measured against our future challenges. This chapter includes the major assumptions affecting our resource choices, description of the resource plans, future uncertainties and Sensitivities, along with a comprehensive set of results. Consideration is given to all of these factors to determine which plan best fits with our customers' long-term needs of reliable, cost-effective and environmentally responsible electricity. The result is APS's 2017 IRP.

Development of Resource Portfolios

The term "Resource Portfolio" refers to the entire set of resources over the Planning Period designed to meet customer demand for electric energy. Each Portfolio includes the existing generation fleet and power contracts as well as potential future conventional, energy storage, renewable, and DSM programs. Portfolio analysis includes dispatch simulations and 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 beyond the 15-year window. In this filing, revenue requirements are calculated through 2046.

Resource Portfolios were developed using Ventyx's resource expansion plan optimizing software, Strategist. Existing generation and contracts were input into the model as fixed assets, and the program was allowed to choose from a list of future resource options to meet load growth and reliability constraints. Future resource options included natural gas combined cycles, combustion turbines, energy storage, solar photovoltaic, wind, geothermal, and nuclear technologies. Strategist used dynamic programming to evaluate thousands of resource combinations to meet load growth and reliability constraints. Resource plans are ranked based on least-cost, best-fit criteria for further detailed analysis in PROMOD IV and subject to Sensitivity Analysis.

"Sensitivity Analysis" refers to running the Portfolios and varying the assumptions related to key uncertain variables. The goal of Sensitivity Analysis is to illustrate the impact to each Portfolio's key variables being stressed in a plausible manner. Results of these studies provide information on diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.

INPUTS AND ASSUMPTIONS

Each of the Resource Portfolios assessed incorporate 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 2016, 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 approximately 3% energy growth year-over-year for a net 57% increase in load requirements prior to energy efficiency (EE) and distributed energy (DE).

Distributed Energy – DE (rooftop solar) has grown dramatically over the last few years and is projected to continue to grow at approximately 200 MW per year through 2032. This amounts to over 3,400 MW and 6,300 GWH of new DE added in APS service territory between 2017 and 2032. Despite the large nameplate capacity of this resource, it only contributes 196 MW toward meeting the summer peak load due to the high penetration and production not aligning well with peak demand. The DE forecast, including existing DE, is provided in response to Rule D.4.

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

Inflation – APS assumes a future inflation rate 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 meet the state's Energy Efficiency Standard (EES) and exceed compliance with the state's Renewable Energy Standard (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 2016, and includes delivery charges.

Carbon Costs – APS is incorporating assumed carbon costs based on the actual trading price of CO2 allowances in the California market. Although the resolution of the Clean Power Plan (CPP) remains uncertain pending final legal review and the expressed intent of the Trump administration to rollback several climate initiatives of the previous administration, including the CPP, other climate change regulations may be promulgated over the course of the Planning Period. The 2017 IRP analysis assumes a one year delay in the implementation of carbon legislation with carbon prices beginning in 2023, escalating at the assumed rate of inflation.

Wholesale Market Prices – Hourly wholesale market prices for the Palo Verde Hub were developed for APS by Energy and Environmental Economics, Inc. The prices, based on regional electric market fundamentals, include the gas price forecast used in this IRP, and reflect California's mandate of 50% renewables by 2030. Note that the CAISO is already experiencing negative priced energy with increasing frequency in the midday non-summer months due to the surplus non-curtailable renewable generation in California. The model allows APS to purchase from the wholesale market to offset its own fossil generation or curtail APS grid-scale solar for the benefit of APS's customers. Incidences of negative market pricing are expected to increase as California and other neighboring states move toward higher renewable energy mandates.

FIGURE 7-1. NATURAL GAS PRICE CURVE

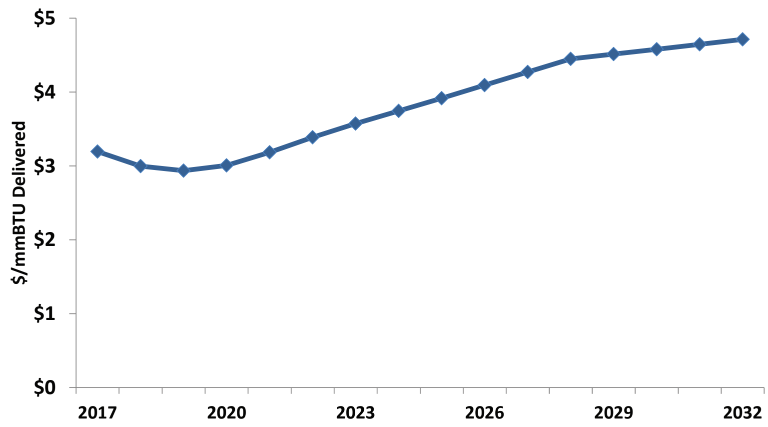


FIGURE 7-2. CARBON PRICE CURVE

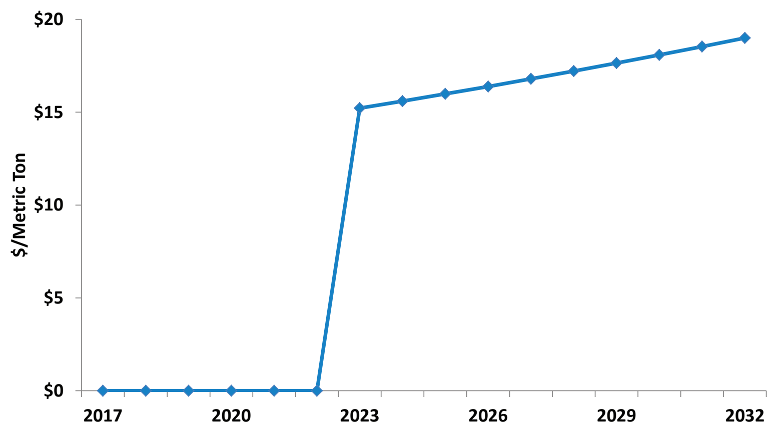
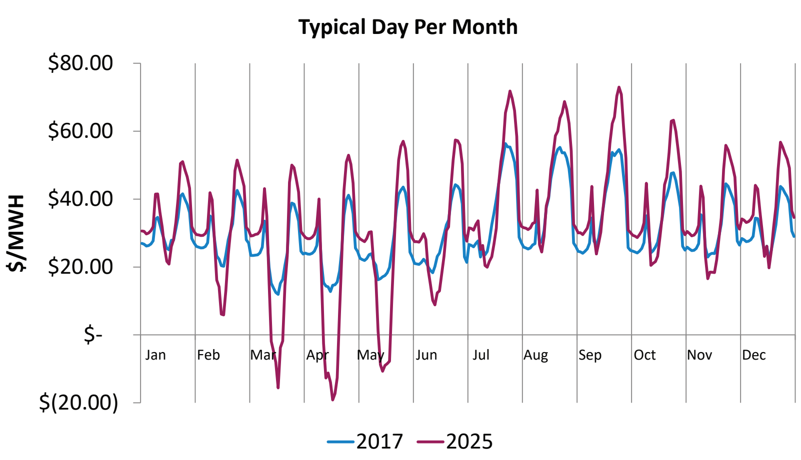


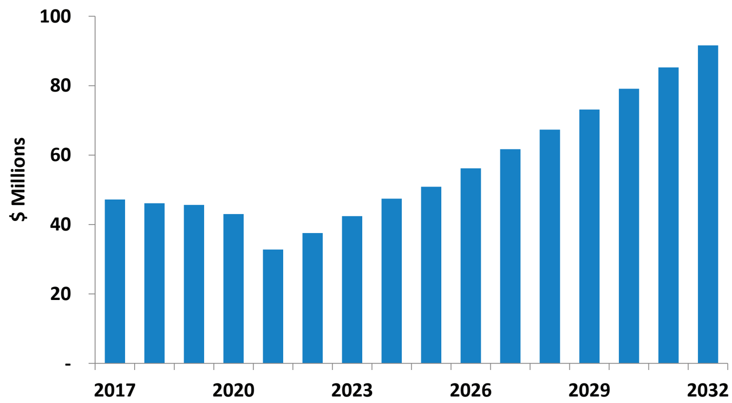
FIGURE 7-3. PALO VERDE HUB MARKET PRICES



Source: H:\ResPlanCommon\Pat\Price Shaping\E3 Model\November Update\E3-APS November 23rd 2016 Final Curves.xlsx

DSM Costs – DSM program costs, including EE programs and demand response, are relatively well known in the near-term and are based on the cost of programs employed by APS over the past few years. Over the 2017 – 2020 period, APS assumes that existing programs will continue to contribute towards the EE goals and will be replaced and/or expanded upon to meet the overall EES requirement of 22% by 2020. Post-2020, DSM costs are assumed to continue to be incurred as APS focuses more on peak load reduction programs and load shifting rather than meeting MWh requirements with EE programs. It is important to note that these costs are projections based upon current programs; actual future costs of DSM programs are unknown at this time, and are likely significantly more expensive than those currently in place.

FIGURE 7-4. DEMAND SIDE MANAGEMENT COSTS



Technology Costs – Capital cost of technologies are based on information obtained from vendors or industry publications. Costs of established technologies shown in Chapter 2 are assumed to escalate at the rate of inflation while costs of emerging technologies such as batteries are assumed to decline. Strategist and PROMOD IV are essential to this part of the planning process because these models offer detailed cost estimates of how new resources integrate with the existing resource mix and meet changing load and reliability requirements rather than on a stand-alone levelized cost basis.

PTC/ITC – APS assumes that the current tax provisions related to production tax credits and investment tax credits expire as detailed in Chapter 2.

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(a) and F.1(b) for all Portfolios modeled using base assumptions.

Fuel Diversity – A more diverse Portfolio relies on a greater number of energy sources, thereby mitigating risks associated with any one particular source. Fuel diversity is quantified by the energy mix by the end of the Planning Period (2032).

Portfolio Costs[1] – Portfolio costs are 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 Planning Period.[2] Portfolio costs are also quantified in terms of cost shift. Some customer programs create savings for participating customers and shift fixed costs to non-participating customers. Those costs are also quantified in terms of 15- and 30-year NPV.

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.

Natural Gas Burn – Natural gas burn provides an indication of the amount of natural gas cost risk inherent in each Portfolio.

CO2 Emissions – Total emissions of CO2 give an indication of the 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 in analyzing Portfolios and is quantified in terms of acre-feet per year.

1 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.). For Portfolios with higher levels of DSM, customer costs are included for a more equitable comparison.

2 Average system generation cost, represented in $/MWh, is not intended to directly equate 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.

Portfolios

The following seven Portfolios were developed either to meet requirements of the 2014 IRP order or from input by stakeholders and the ACC, and then optimizing the remaining resources in Strategist. Four of the Portfolios – Expanded Demand Side Management, Expanded Renewables, Energy Storage Systems and Small Modular Reactors – are included in accordance with Decision No. 75068.[3] The Portfolios were further studied through the more detailed PROMOD IV simulation model, and subjected to Sensitivity Analysis. Strategist results were reviewed to ensure that the ACC's RES and EES were met in all Portfolios. In general, Strategist optimized the Portfolios with a mix of combined cycles, combustion turbines and some battery storage later in the Planning Period. It did not find either new renewables or SMR nuclear to be economic resources.

PORTFOLIOS – BREAKDOWN BY CAPACITY AND ENERGY MIX CONTRIBUTIONS

TABLE 7-1. CAPACITY AND ENERGY MIX BY PORTFOLIO

	FLEXIBLE RESOURCE (SELECTED)	CARBON REDUCTION	EXPANDED DSM	EXPANDED RENEWABLES	ENERGY STORAGE SYSTEMS	RESOURCE MANDATES	SMALL MODULAR REACTORS
Description	Retire Cholla in 2024; demand reducing DSM; RE above compliance, flexible battery storage & gas generation	Retire Cholla in 2022, Four Corners in 2031; demand reducing DSM; RE above compliance, flexible battery storage & gas generation	Retire Cholla in 2024; energy reducing DSM; RE above compliance, flexible battery storage & gas generation	Retire Cholla in 2024; demand reducing DSM; RE well above compliance, flexible battery storage & gas generation	Retire Cholla in 2024; demand reducing DSM; RE above compliance, additional flexible battery storage & gas generation	Retire Cholla in 2024; plus expanded DSM, renewables and battery storage; gas generation	Retire Cholla in 2024; SMR; demand reducing DSM; RE above compliance, flexible battery storage & gas generation
Resource Contributions (2032 Namplate Capacity/% Energy Mix)							
Nuclear	1,146 MW / 17.1%	1,146 MW / 17.1%	1,146 MW / 17.0%	1,146 MW / 16.9%	1,146 MW / 17.0%	1,146 MW / 16.7%	1,716 MW / 22.3%
Coal	970 MW / 10.7%	0 MW / 0.0%	970 MW / 10.5%	970 MW / 10.5%	970 MW / 10.7%	970 MW / 10.3%	970 MW / 10.4%
Natural Gas	8,475 MW / 32.9%	9,616 MW / 42.6%	7,828 MW / 27.4%	8,259 MW / 30.4%	8,259 MW / 32.9%	7,181 MW / 26.4%	8,043 MW / 28.8%
Renewable Energy (RE & DE)	4,353 MW / 18.2%	4,353 MW / 18.3%	4,353 MW / 17.8%	5,052 MW / 21.7%	4,353 MW / 18.1%	4,697 MW / 19.6%	4,353 MW / 18.2%
Demand Side Management	922 MW / 13.4%	922 MW / 13.5%	1,547 MW / 20.8%	922 MW / 13.3%	922 MW / 13.4%	1,547 MW / 20.5%	922 MW / 13.4%
Demand Response & Microgrids*	420 MW	420 MW	420 MW	420 MW	420 MW	420 MW	420 MW
Energy Storage**	507 MW	507 MW	507 MW	507 MW	1,107 MW	1,107 MW	507 MW
Market Purchase	158 MW / 7.7%	158 MW / 8.5%	158 MW / 6.5%	158 MW / 7.1%	158 MW / 7.9%	158 MW / 6.5%	158 MW / 6.8%

*DR and microgrids are considered capacity resources and are not included in the energy mix.
**Energy storage does not create its own energy, so energy associated with it is reported under the source that provided the charging energy.

3 A.C.C. Docket No. E-00000V-13-0070 (May 8, 2015).

FLEXIBLE RESOURCE PORTFOLIO

The Flexible Resource Portfolio is designed to deliver an increasingly flexible set of resources that does not overly rely on one specific fuel source during the 15-year Planning Period. It incorporates a significant level of rooftop solar generation expected to be installed by APS customers, adds approximately 50 MW per year of peak demand reducing DSM programs, over 500 MW of energy storage systems, microgrids, demand response and flexible gas generation. It recognizes the economically and operationally challenging environment for coal power plants and accordingly assumes that APS will no longer receive coal-fired generation from the Navajo Generating Station after 2019, and no longer burn coal at Cholla Units 1 and 3 beyond 2024. The reduced coal capacity along with the increase in flexible energy storage and natural gas generation allows APS customers to benefit from the low wholesale market prices being created by neighboring states with high renewable mandates. The Loads & Resources table for this Portfolio can be found in Attachment F.1(a)(1).

FIGURE 7-5. FLEXIBLE RESOURCE PORTFOLIO – ENERGY MIX

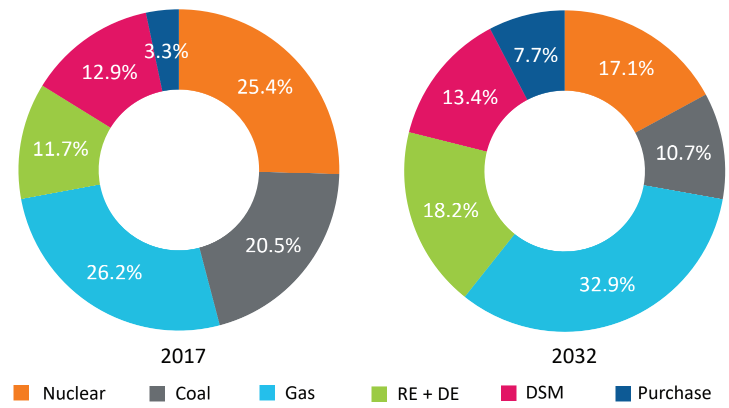
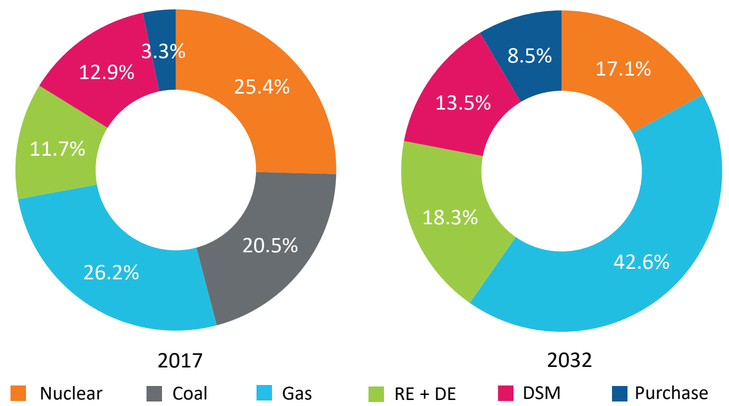


FIGURE 7-6. CARBON REDUCTION PORTFOLIO – ENERGY MIX



CARBON REDUCTION PORTFOLIO

The Carbon Reduction Portfolio was designed to reduce the level of carbon emissions in tons, not just the intensity, in order to evaluate the impacts of a mass-based carbon reduction goal that could potentially be mandated by the Environmental Protection Agency. One effective way to reduce carbon emissions is by reducing coal generation. In this Portfolio, that was accomplished by advancing the assumed retirement date of Cholla Units 1 and 3 from 2024 to 2022, and advancing the retirement date of Four Corners Units 4 and 5 to 2031 to coincide with the expiration of its current coal contract. Due to the operational challenges created by the amount of distributed generation in the resource mix, the lost generation was replaced with natural gas rather than additional renewable or base load nuclear generation. The Loads and Resources table for this Portfolio can be found in Attachment F.1(a)(2).

EXPANDED DEMAND SIDE MANAGEMENT PORTFOLIO

This Portfolio continues to implement the same types of EE programs currently used to meet the EES up to 2020 when the standard expires throughout the 15-year Planning Period. It assumes about 100 MW per year reduction in peak load and 434,000 MWH per year energy reduction from 2020 to 2032. These programs are more focused on meeting MWH reduction goals rather than meeting peak demand reductions modeled in the Flexible Resource Portfolio. It should be noted that the current standard is one of the most aggressive in the nation, and will have been in effect for 10 years by 2020. APS is not certain that it can continue the high levels of energy reductions for such an extended period of time, and acknowledges that there is a great amount of uncertainty in the cost estimate used herein. The Loads and Resources table for this Portfolio can be found in Attachment F.1(a)(3).

EXPANDED RENEWABLES PORTFOLIO

The Expanded Renewables Portfolio is designed to show the impacts of increasing the contribution of renewable energy to 30% of retail sales by 2030.[4] In this Portfolio, 700 MW of renewables were added between 2027 and 2030, approximately evenly split between single axis tracking solar photovoltaic and wind. Due to the high levels of renewable penetration on the system, the additional solar and wind only contribute about 250 MW of on-peak capacity, and thus replace about that amount of natural gas generation. The Loads and Resources table for this Portfolio can be found at Attachment F.1(a)(4).

ENERGY STORAGE SYSTEMS PORTFOLIO

This Portfolio increases the amount of energy storage from 507 MW in the Flexible Resource Portfolio to 1,107 MW. It assumes four hours of storage capability for battery energy storage systems. Because of its limited use per day, the 1,107 MWs of nameplate capacity contribute 718 MW toward meeting peak requirements on load on the resource plan. The battery discharge energy is not directly shown in the energy mix chart below, but rather is represented in the energy source that provided the charging for the battery. The Loads and Resources table for this Portfolio can be found in Attachment F.1(a)(5).

FIGURE 7-7. EXPANDED DEMAND SIDE MANAGEMENT PORTFOLIO – ENERGY MIX

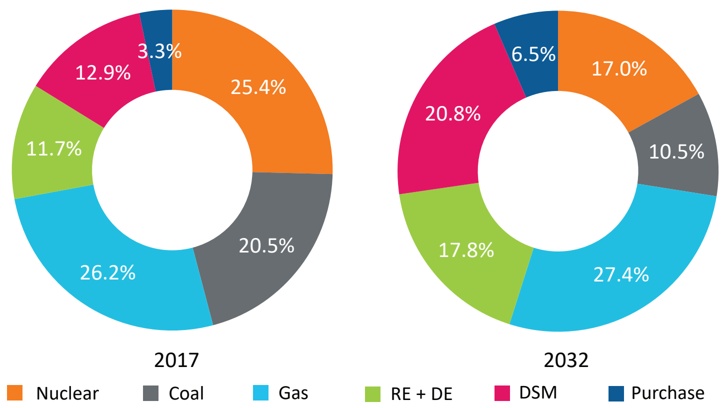


FIGURE 7-8. EXPANDED RENEWABLES PORTFOLIO – ENERGY MIX

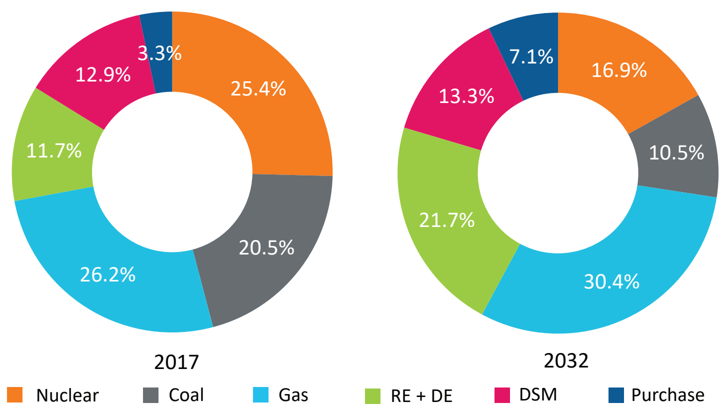
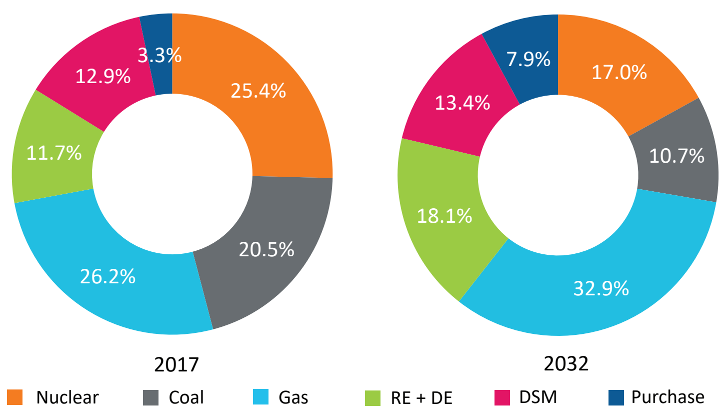


FIGURE 7-9. ENERGY STORAGE SYSTEMS PORTFOLIO – ENERGY MIX



4 After the effects of EE and DE, assuming no curtailment of renewables. There likely would be curtailments, and more renewables would have to be added to achieve 30% after curtailments.

RESOURCE MANDATES PORTFOLIO

The Resource Mandates Portfolio combines elements of the Expanded DSM, Expanded Renewables and Energy Storage Systems Portfolios described above. It represents a number of resources that, based on the current outlook, would not be implemented due to economics, but rather to satisfy a hypothetical policy mandate. Over the 15-year Planning Period, this Portfolio increases DSM by 625 MW, renewables by 344 MW, and energy storage by 600 MW over the Flexible Resource Portfolio, and reduces natural gas generation by about 1,300 MW. The Loads & Resources table for this Portfolio can be found at Attachment F.1(a)(6).

SMALL MODULAR REACTORS PORTFOLIO

In this Portfolio, 285 MWs of SMRs was added to the Portfolio in 2028 and another 285 MW in 2032 for a total of 570 MW during the 15-year Planning Period. It replaces gas generation in the Flexible Resource Portfolio. This technology is not yet commercially available, and further development is needed for it to be viable by the late 2020s. SMRs have more operational flexibility than today's large-scale plants, but may not have enough flexibility to operate in systems with high penetrations of non-dispatchable generation. Their capital costs are not known with certainty at this time, but they are expected to be relatively high and SMRs could be difficult to finance. Nonetheless, new nuclear may be an option to potentially help manage carbon emissions in the future for utilities that need base load generation. The Loads & Resources table for this Portfolio can be found at Attachment F.1(a)(7).

FIGURE 7-10. RESOURCE MANDATES PORTFOLIO – ENERGY MIX

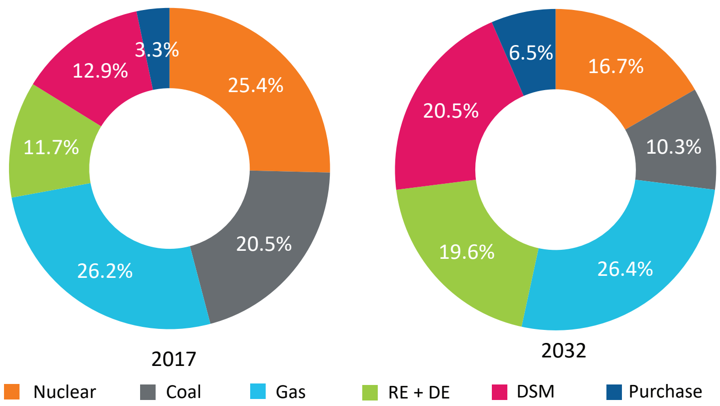
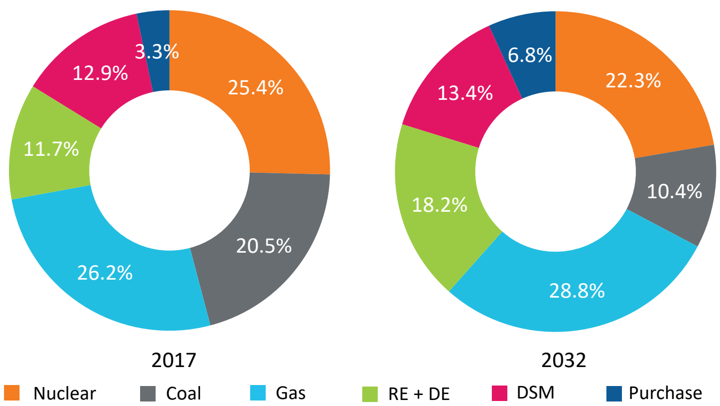


FIGURE 7-11. SMALL MODULAR REACTORS PORTFOLIO – ENERGY MIX



SENSITIVITIES

Eight Sensitivities were developed to help assess the economic risk associated with each of the seven Portfolios. The most sensitive and impactful variables are natural gas prices, carbon costs, load forecast and capital costs. Each of the base assumptions were stressed as described below.

Natural Gas Prices – Natural gas prices were flexed 30% above and below the baseline forecast.

Carbon Prices – Carbon prices range from a low of zero, representing a situation in which carbon legislation is not enacted or does not apply to APS's generating units, to a high of $15/ton escalating at 7.5% per year.

Technology Capital Costs – A Low and High Capital Cost Sensitivity analysis was performed for battery energy storage as indicated below and for SMRs. Combustion turbine capital cost is known with more certainty than new technologies, and is shown below for reference. SMRs are assumed to be available for commercial service in 2028, and are assumed to cost $7,175/kW in that year plus or minus 25%. Costs shown on the chart do not include AFUDC, and are based on the technology capacity rating, not the contribution to on-peak capacity represented in the resource plan.

Load Growth – Load growth before DE and DSM is 3.3% per year in the base. Load growth in the Sensitivity cases are 2.3% for the low, and 4.3% for the high-growth cases.

FIGURE 7-12. NATURAL GAS PRICE SENSITIVITY

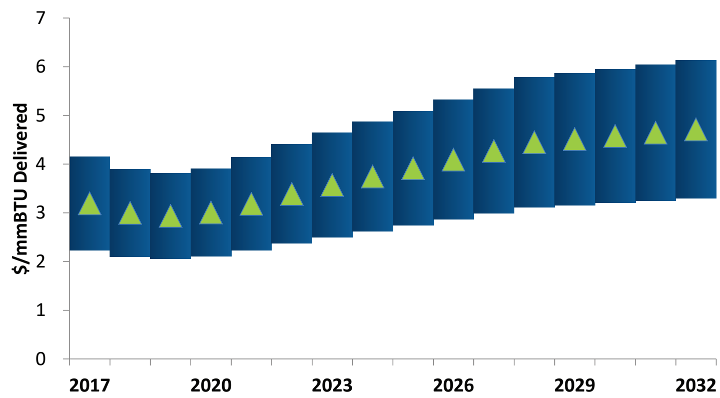


FIGURE 7-13. CARBON PRICE SENSITIVITY

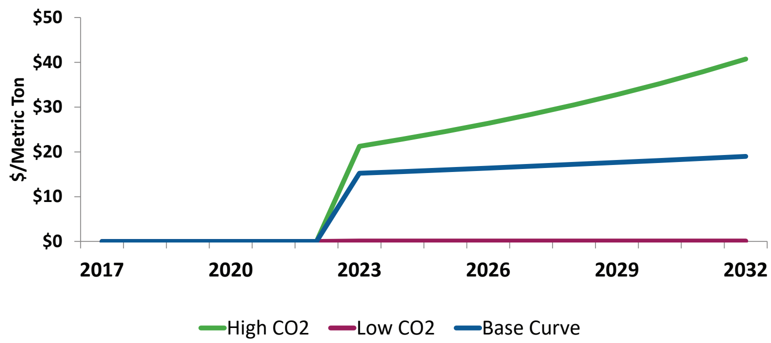


FIGURE 7-14. TECHNOLOGY CAPITAL COST SENSITIVITY

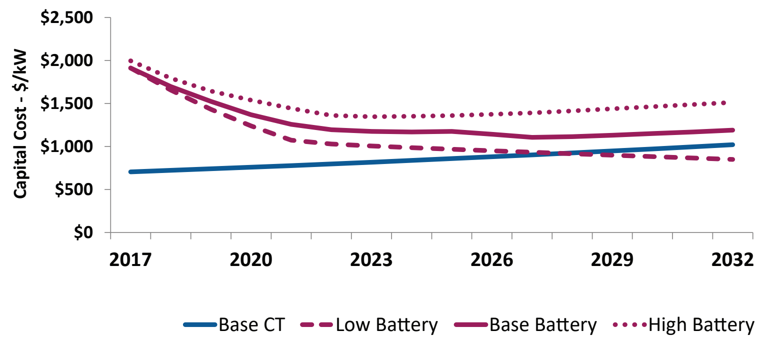
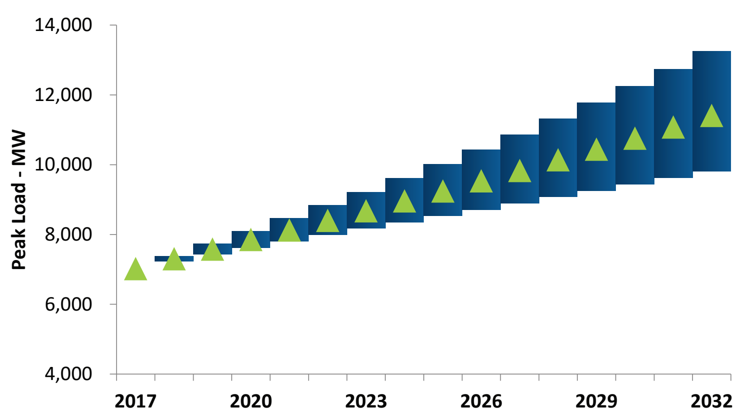


FIGURE 7-15. LOAD FORECAST SENSITIVITY



Results of Portfolio Analysis

This section provides a summary and discussion of results for the seven Portfolios under the base assumptions. Detailed information is provided in the attachments including annual resource plans, energy mix (GWH and %), revenue requirements, system average costs, cumulative capital expenditures, gas burn, carbon emissions and water use. Please see Attachment F.1(b) through Attachment F.1(b)(5).

SUMMARY OF PORTFOLIO ANALYTICS

TABLE 7-2. SUMMARY OF PORTFOLIO RESULTS

	FLEXIBLE RESOURCE	CARBON REDUCTION	EXPANDED DSM	EXPANDED RENEWABLES	ENERGY STORAGE SYSTEMS	RESOURCE MANDATES	SMALL MODULAR REACTORS
Revenue Reqmt NPV 2017-2032 $Billions*	26.0	26.1	26.0	26.2	26.3	26.5	26.4
Revenue Reqmt NPV 2017-2046 $Billions	39.2	39.0	39.9	39.8	39.7	41.0	40.9
Cost Shift NPV 2017-2032 $Billions	0.1	0.1	0.8	0.1	0.1	0.8	0.1
Cost Shift NPV 2017-2046 $Billions	0.3	0.3	2.8	0.3	0.3	2.8	0.3
System Cost in 2032 $/ MWH	101.4	97.6	112.5	104.3	103.4	117.9	111.1
Cumulative Capital Exp 2017-2032 $Billions	8.2	9.7	8.1	9.3	8.9	9.3	11.8
Gas Burn in 2032 - BCF	140.9	178.3	117.9	131.3	140.9	115.0	122.6
CO2 Emissions in 2032 - Million Metric Tons	13.5	10.6	12.1	12.9	13.5	11.9	12.3
Water Use in 2032 Thousand Acre-Feet	52.7	43.3	49.9	51.5	52.8	49.6	55.3

*Revenue requirements and capital expenditures include customer costs for DSM measures included in the Expanded DSM and Resource Mandates Portfolios for comparability to other Portfolios consistent with the Total Resource Cost (TRC) Test.

KEY METRIC COMPARISON

Annual revenue requirements steadily rise over the course of the Planning Period, regardless of the Portfolio. Costs are driven by increasing fuel prices, inclusion of assumed carbon tax, increased operation and maintenance costs, and increased capital investment to meet load growth (see Figure 7-16).

In the 15-year NPV of revenue requirements, the Flexible Resource Portfolio has the lowest NPV while the Energy Storage Systems, Resource Mandates and Small Modular Reactors Portfolios have the highest costs, with NPVs of $300 million to $500 million higher than the Flexible Resource Portfolio. In this 15-year Planning Period, the Expanded DSM Portfolio is slightly higher, and the Carbon Reduction Portfolio is $150 million higher (see Figure 7-17).

The 30-year NPV of revenue requirements is shown in Figure 7-18. The Flexible Resource and Carbon Reduction Portfolios have the lowest NPV while the Resource Mandates and Small Modular Reactors Portfolios have the highest costs, with NPV of $700 million higher than the Flexible Resource Portfolio. Expanded DSM, Expanded Renewables and Energy Storage Systems Portfolios were $400 to $600 million higher.

FIGURE 7-16. ANNUAL REVENUE REQUIREMENTS

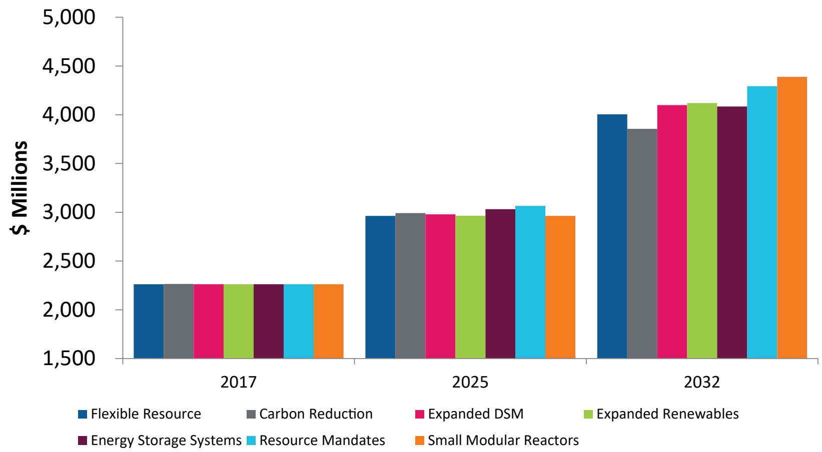


FIGURE 7-17. NPV OF REVENUE REQUIREMENTS 2017-2032

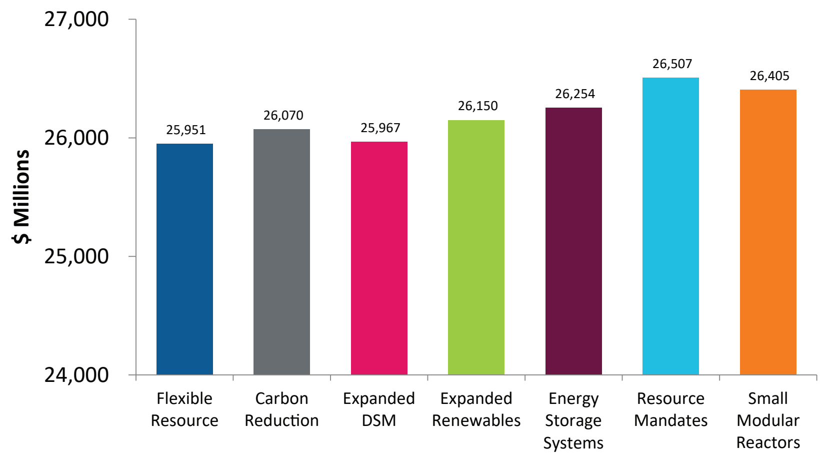


FIGURE 7-18. NPV OF REVENUE REQUIREMENTS 2017-2046

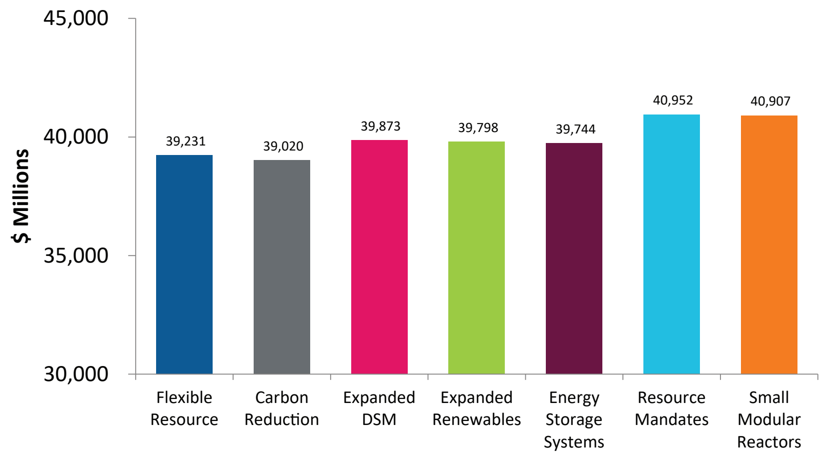


FIGURE 7-19. SYSTEM AVERAGE COST IN 2032

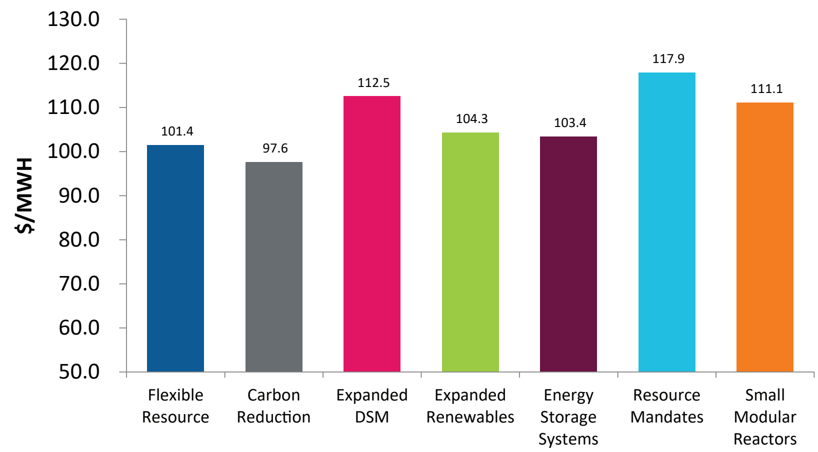


FIGURE 7-20. NPV OF COST SHIFT 2017-2032

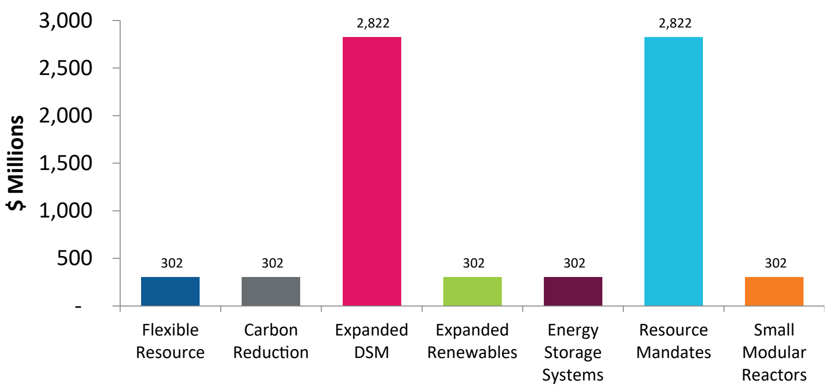
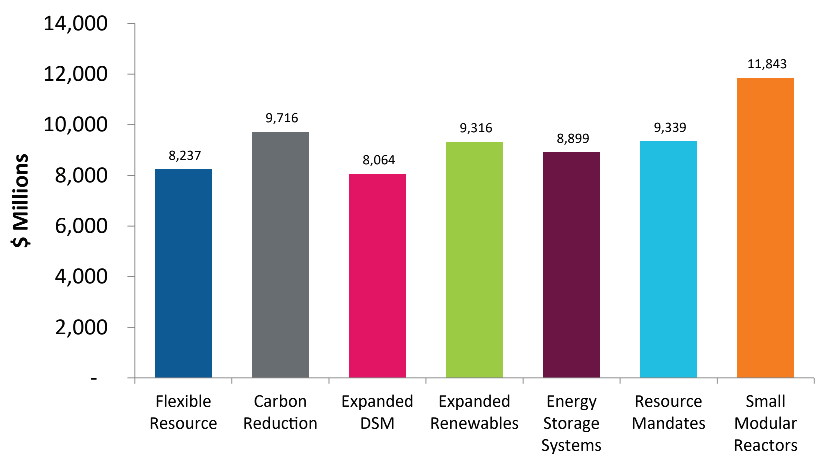


FIGURE 7-21. CAPITAL EXPENDITURES 2017-2032



The system average costs in 2032 show a similar trend with the Expanded Renewables, Resource Mandates and Small Modular Reactors Portfolios being significantly higher than the others. Although these are not projected customer rates, they do reflect that the cents per kWh will be higher under those Portfolios. This is what gives rise to the high cost shift in two of the Portfolios as indicated in Figure 7-19.

Cost shift in the two Portfolios with higher levels of EE is approximately $2.5 billion more than the Portfolios with the peak demand reducing DSM as shown in Figure 7-20.

The cumulative capital expenditures required to support the Flexible Portfolio are $8.2 billion over the Planning Period, as illustrated in Figure 7-21. It has the lowest capital requirements for APS of all of the Portfolios except the Expanded DSM.[5] All other Portfolios have higher capital requirements, with the Small Modular Reactors Portfolio requiring an additional $3.5 billion, or over 40% more than the Flexible Resource Portfolio. This is primarily due to the comparatively low cost of conventional peaking capacity included in the plans.

5 The customer cost of DSM totals about $600 million from 2017-2032 and is included in the capital expenditures for the Expanded DSM and Resource Mandates Portfolios shown on the chart.

Water consumption is expected to grow from 49,900 acre-feet in 2017 to 52,700 acre-feet in 2032 in the Flexible Resource Portfolio, an increase of 6%. This is a modest increase in absolute terms considering that load is expected to grow by 54%, and is actually a 29% reduction in water intensity, or water use per MWH. The Carbon Reduction Portfolio uses the least amount of water, or 18% less than the Flexible Resource Portfolio while the Small Modular Reactors Portfolio uses the most water at 5% more (see Figure 7-22).

In the Flexible Resource Portfolio, CO2 emissions increase by 15% from 2017 to 2032, while load increases by 54%, as shown in Figure 7-23. Therefore, CO2 intensity is actually reduced by 23% over the Planning Period. The Carbon Reduction Portfolio is the only Portfolio of the seven that reduces carbon emissions below 2017 levels by the end of the Planning Period.

In the Flexible Resource Portfolio, APS expects to burn more natural gas in 2032 than in 2017. The Carbon Reduction Portfolio burns the most natural gas in 2032 while the Resource Mandates Portfolio burns the least. Gas burn increases in all Portfolios due to load growth and coal plant retirements, and is partially offset by DSM and renewable generation. As shown in Figure 7-24, although gas burn is higher in the future, it still only represents about a third of APS's overall energy mix, and is a low-cost option.

The Flexible Resource Portfolio provides flexibility needed to purchase low-cost or negatively priced energy in the wholesale energy market. As shown in Figure 7-25, in 2032 the model estimates 4,200 GWH of purchases. The Carbon Reduction Portfolio allows the highest levels of such purchases, and the Energy Storage Systems Portfolio allows an extra 80 GWH in that year. Figure 7-25 also indicates that additional DSM/Renewables/Nuclear generation would reduce the amount of those purchases by between 300,000 MWH and 650,000 MWH per year, depending on the Portfolio.

FIGURE 7-22. WATER USE IN 2032

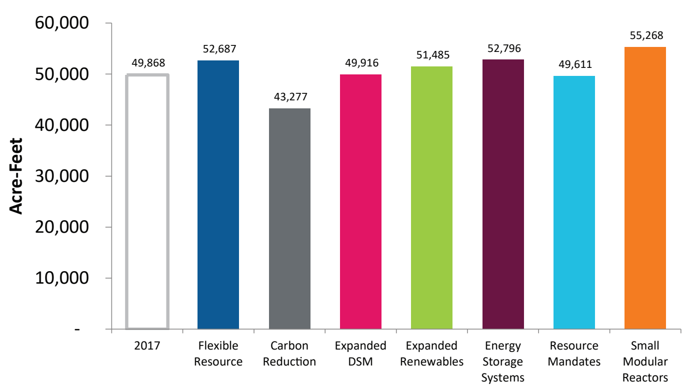


FIGURE 7-23. CO2 EMISSIONS IN 2032

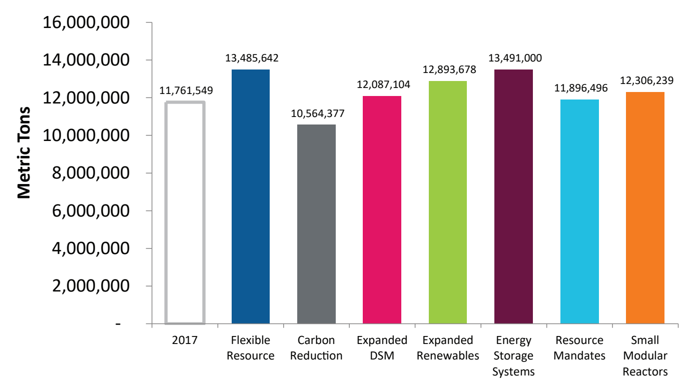


FIGURE 7-24. NATURAL GAS BURN IN 2032

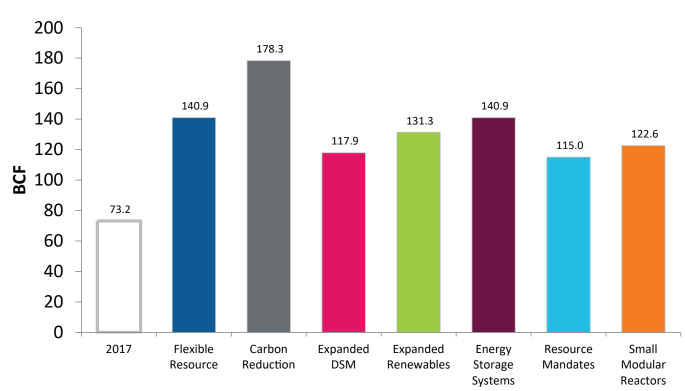
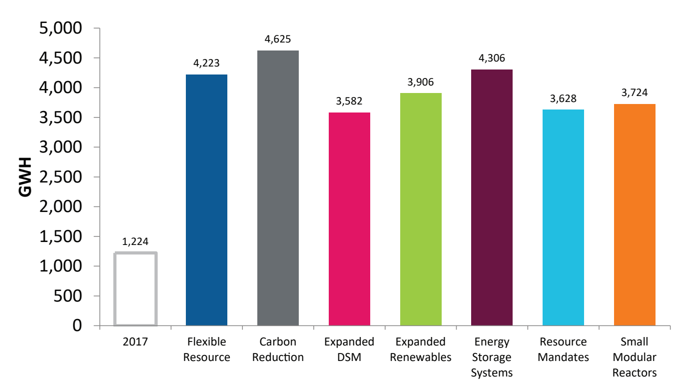


FIGURE 7-25. WHOLESALE MARKET PURCHASES IN 2032



DISCUSSION OF RESULTS

The results presented above illustrate the trade-offs in key metrics between the seven Portfolios under the base assumptions and are synopsized below.

The **Flexible Resource Portfolio** rates very well in terms of cost measures – both 15- and 30-year NPV, system cost, cost shift and capital expenditures. It has a reasonable energy mix with natural gas contributing about one third of its mix. Although it has slightly higher carbon emissions and uses slightly more water than some of the other Portfolios, its higher mix of flexible resources (natural gas and batteries) makes it a good fit for reliability, affordability and allows APS customers to benefit from market opportunities through its operation in the western wholesale energy market. Overall, this Portfolio is least-cost, best-fitting Portfolio of the seven evaluated.

The **Carbon Reduction Portfolio** has slightly higher costs than the Flexible Resource Portfolio in the 15-year NPV, and slightly lower in the 30-year NPV. It emits less carbon and uses less water than the other Portfolios; however, it also has significantly higher capital expenditure requirements and gas burn, with natural gas approaching 50% of the energy mix. APS will continue to evaluate operation of its coal resources and update future IRPs as appropriate.

The **Expanded DSM Portfolio** slightly reduces gas burn, carbon emissions and water use relative to the Flexible Resource Portfolio. However, the Portfolio does not compare well in terms of the economic analysis, especially when considering the size of the potential cost shift to non-participating customers and system average cost is 10% higher in this Portfolio than it is in the Flexible Resource Portfolio. The analysis confirms that the peak demand focused DSM represented in the Flexible Resource Portfolio is a more cost-effective option for all customers than continuation of today's GWH-focused EE programs.

The **Expanded Renewables Portfolio** reduces gas burn, carbon emissions and water use relative to the Flexible Resource Portfolio, but the Portfolio does not compare well to many of the other Portfolios in terms of the economic analysis. It is $100 million and $500 million more expensive than the Flexible Resource Portfolio in 15- and 30-year NPV of revenue requirements. Although the cost of renewable resources declines over the Planning Period, they do not provide enough value to offset their cost. Renewable resources provide limited summer peak capacity, so natural gas generation is still needed to meet the peak demand. Additionally, renewable resources provide a significant amount of energy in low-value, non-summer midday hours.

The **Energy Storage Systems Portfolio** is $300 million and $500 million more costly in 15- and 30-year NPV of revenue requirements, respectively, than the Flexible Resource Portfolio. Because of the limited number of hours per day that the storage systems can be used, increasing the amount of storage capacity results in reduced capacity value. In other words, the first 500 MW achieves approximately 80% capacity value, and the next 600 MW only achieves 60%. In this Portfolio, the addition of the extra 600 MW increases the amount of energy APS could purchase from the wholesale market, but the resources are also more costly and see diminishing returns on arbitrage opportunities. Gas burn, carbon emissions and water use were minimally impacted by the Energy Storage Systems Portfolio.

The **Resource Mandates Portfolio** combines elements of Expanded DSM, Expanded Renewables and Energy Storage Systems Portfolios. This Portfolio is extremely costly and is $500 million and $1.7 billion more expensive than the 15- and 30-year NPV values for the Flexible Resource Portfolio. It furthermore results in a cost shift of $2.8 billion to customers not participating in the EE programs embodied in the Portfolio. It raises system average costs more than 15% compared to the Flexible Resource Portfolio.

The **Small Modular Reactors Portfolio** is also a very costly Portfolio with 15- and 30-year NPV of revenue requirements $400 million and $1.7 billion higher than the Flexible Resource Portfolio. Due to the base load nature of the SMRs, the amount of energy that APS could purchase from the wholesale market in 2032, for example, is reduced by about 500 GWHs. Although it reduces gas burn and carbon emissions, both gas prices and carbon prices would have to be dramatically higher to make this a cost-effective option.

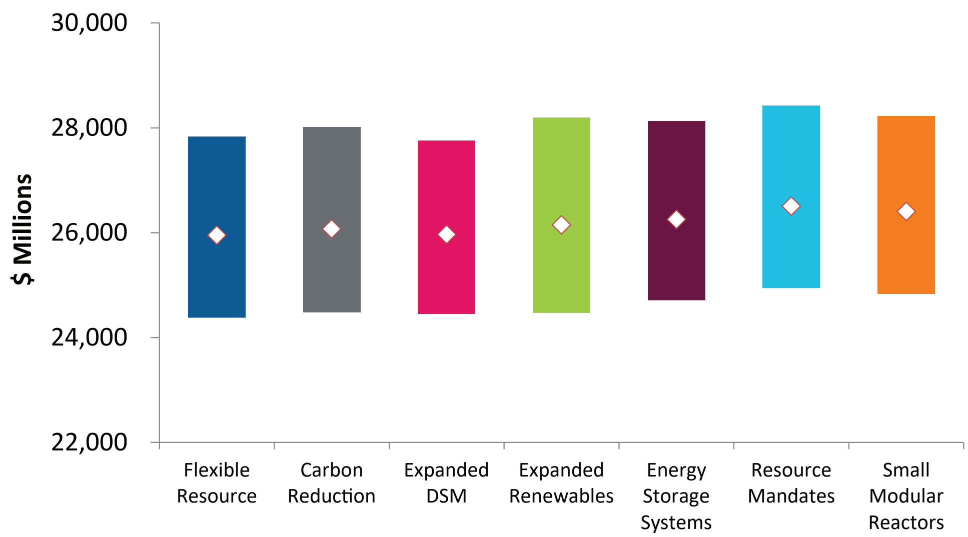
RESULTS OF SENSITIVITY ANALYSIS

While the values of the metrics associated with the base assumptions are most useful in making resource decisions, key variables are also stressed both upward and downward to evaluate the robustness of each Portfolio. Robust Portfolios are relatively less sensitive to changes in the assumptions and perform better over a wide range of assumptions. This section summarizes the base assumption results and the ranges of results in the key metrics for the eight Sensitivities and seven Portfolios. For each of the metrics, a figure is presented indicating the values using the base assumptions for each Portfolio (represented by a diamond), and the highest and lowest values for each Portfolio across the Sensitivities (represented by a bar). A table follows each figure indicating the base assumption value for each Portfolio and the ranges of results as a percentage of the base assumption for that Portfolio.

REVENUE REQUIREMENTS NPV (15 YEAR)

The 15-year NPVs of revenue requirements are bounded by the Low Load Forecast Sensitivity on the low end of the range and by the High Load Forecast Sensitivity on the high end. The range of revenue requirements is very similar for all four Portfolios indicating that none of the Portfolios is significantly more or less susceptible to the uncertainties considered, and that the cost of electricity over the next 15 years is more dependent on future load conditions than it is the selection of resources (Portfolios) considered.

FIGURE 7-26. RANGE OF REVENUE REQUIREMENTS 2017-2032 NPV

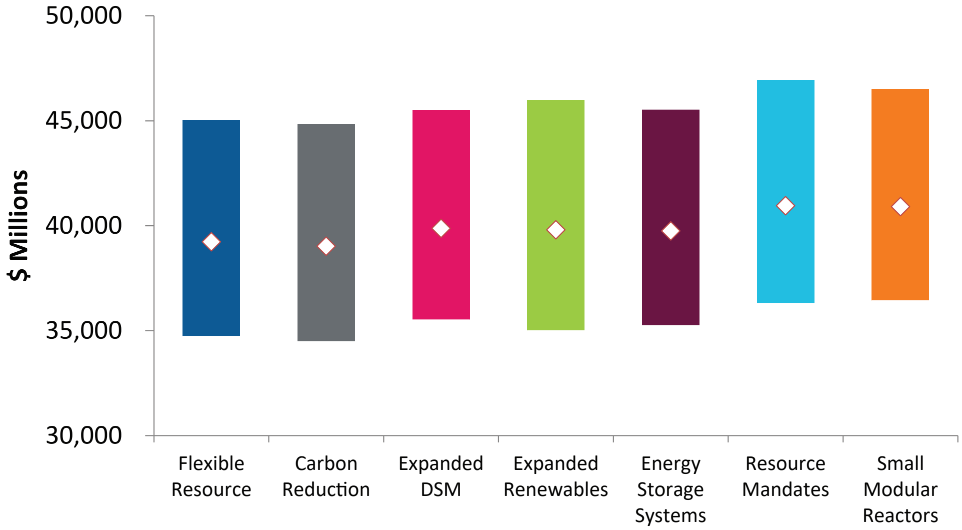


Flexible Resource Portfolio	$26.0 billion (-6.2% to +6.9%)
Carbon Reduction Portfolio	$26.1 billion (-6.1% to +7.3%)
Expanded DSM Portfolio	$26.0 billion (-6.2% to +6.9%)
Expanded Renewables Portfolio	$26.1 billion (-6.1% to +8.0%)
Energy Storage Systems Portfolio	$26.3 billion (-6.1% to +6.8%)
Resource Mandates Portfolio	$26.5 billion (-6.0% to +7.2%)
Small Modular Reactors Portfolio	$26.4 billion (-6.1% to +6.8%)
RANGE OF REVENUE REQUIREMENTS 2017-2032 NPV	

REVENUE REQUIREMENTS NPV (30 YEAR)

The 30-year NPVs of revenue requirements are also bounded by the Low Load Forecast Sensitivity on the low end of the range and by the High Load Forecast Sensitivity on the high end. The range of revenue requirements is very similar for all four Portfolios indicating that none of the Portfolios is significantly more or less susceptible to the uncertainties considered, and that the cost of electricity over the next 30 years is more dependent on future load conditions than it is on the selection of resources (Portfolios) considered.

FIGURE 7-27. RANGE OF REVENUE REQUIREMENTS 2017-2046 NPV

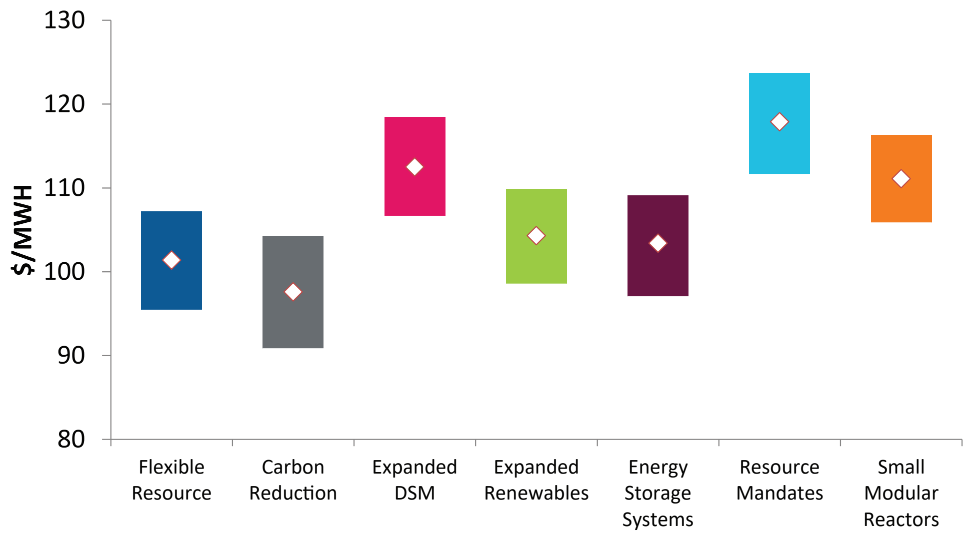


Flexible Resource Portfolio	$39.2 billion (-11.5% to +14.8%)
Carbon Reduction Portfolio	$39.0 billion (-11.5% to +14.9%)
Expanded DSM Portfolio	$39.9 billion (-11.0% to +14.0%)
Expanded Renewables Portfolio	$39.7 billion (-11.8% to +15.9%)
Energy Storage Systems Portfolio	$39.7 billion (-11.3% to +14.6%)
Resource Mandates Portfolio	$41.0 billion (-11.5% to +14.4%)
Small Modular Reactors Portfolio	$40.9 billion (-11.0% to +13.7%)
RANGE OF REVENUE REQUIREMENTS 2017-2046 NPV	

SYSTEM AVERAGE COST IN 2032

In this case, the low and high end of the cost range is associated with the Low and High Carbon Price Sensitivities for all Portfolios except for the Carbon Reduction Portfolio, which is bound by the Low and High Gas Price Sensitivity. The notable observation on this chart is that the low end of the cost ranges for the Expanded DSM, Resource Mandates, and Small Modular Reactors Portfolios are above, or almost above, the high end of the range for the Flexible Resource Portfolio. So, in this case, the choice of the Portfolio has a bigger impact on system average cost than carbon or natural gas prices themselves have the average cost to serve customers.

FIGURE 7-28. RANGE OF SYSTEM AVERAGE COST IN 2032

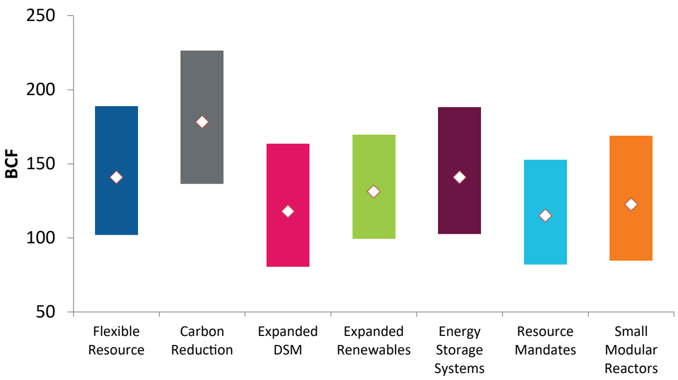


Flexible Resource Portfolio	101.4 $/MWH (-6.0% to +5.7%)
Carbon Reduction Portfolio	97.6 $/MWH (-7.0% to +6.9%)
Expanded DSM Portfolio	112.5 $/MWH (-5.2% to +5.3%)
Expanded Renewables Portfolio	104.3 $/MWH (-5.6% to +6.4%)
Energy Storage Systems Portfolio	103.4 $/MWH (-6.2% to +5.5%)
Resource Mandates Portfolio	117.9 $/MWH (-5.3% to +4.9%)
Small Modular Reactors Portfolio	111.1 $/MWH (-4.8% to +4.7%)
RANGE OF SYSTEM AVERAGE COST IN 2032	

NATURAL GAS BURN

The low end and the high end of the ranges are again defined by the Low and High Load Growth Sensitivities, respectively, rather than selection of resources.

FIGURE 7-29. RANGE OF NATURAL GAS BURN IN 2032



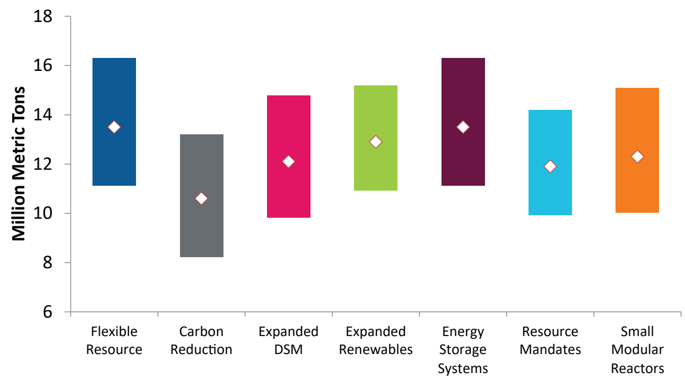
Flexible Resource Portfolio	140.9 BCF (-27.8% to +33.9%)
Carbon Reduction Portfolio	178.3 BCF (-23.7% to +26.9%)
Expanded DSM Portfolio	117.9 BCF (-32.0% to +38.6%)
Expanded Renewables Portfolio	131.3 BCF (-24.6% to +29.2%)
Energy Storage Systems Portfolio	140.9 BCF (-27.4% to +33.4%)
Resource Mandates Portfolio	115.0 BCF (-29.0% to +32.6%)
Small Modular Reactors Portfolio	122.6 BCF (-31.2% to +37.6%)

RANGE OF NATURAL GAS BURN IN 2032

CARBON EMISSIONS

The low end and the high end of the ranges are again defined by the Low and High Load Forecast Sensitivities, respectively.

FIGURE 7-30. RANGE OF CARBON EMISSIONS IN 2032



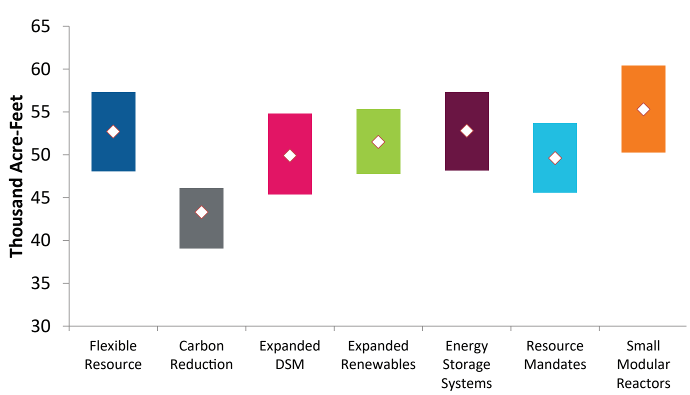
Flexible Resource Portfolio	13.5 MT (-17.8% to +20.7%)
Carbon Reduction Portfolio	10.6 MT (-22.6% to +24.5%)
Expanded DSM Portfolio	12.1 MT (-19.0% to +22.3%)
Expanded Renewables Portfolio	12.9 MT (-15.5% to +17.8%)
Energy Storage Systems Portfolio	13.5 MT (-17.8% to +20.7%)
Resource Mandates Portfolio	11.9 MT (-16.8% to +19.3%)
Small Modular Reactors Portfolio	12.3 MT (-18.7% to +22.8%)

RANGE OF CARBON EMISSIONS IN 2032

WATER USE

While the low end and the high end of the ranges are again defined by the Low and High Load Forecast Sensitivities, respectively, the range of water use across the Portfolios and Sensitivities is much narrower than the ranges of the other metrics discussed. This is reflective of the expectation that whatever new technology APS employs, whether it be renewable or natural gas, water consumption will be minimized.

FIGURE 7-31. ANNUAL WATER USE RANGE IN 2032



Flexible Resource Portfolio	52.7 KAF (-8.9% to +8.7%)
Carbon Reduction Portfolio	43.3 KAF (-9.9% to +6.5%)
Expanded DSM Portfolio	49.9 KAF (-9.2% to +9.8%)
Expanded Renewables Portfolio	51.5 KAF (-7.4% to +7.4%)
Energy Storage Systems Portfolio	52.8 KAF (-8.9% to +8.5%)
Resource Mandates Portfolio	49.6 KAF (-8.3% to +8.3%)
Small Modular Reactors Portfolio	55.3 KAF (-9.2% to +9.2%)

ANNUAL WATER USE RANGE IN 2032

DISCUSSION OF SENSITIVITY RESULTS

Each of the seven Portfolios was run through Sensitivities in order to determine how each Portfolio would perform relative to changes in key assumptions. The purpose is to identify a Portfolio that performs well across many high and low cost assumptions and, further, to indicate how resource plans might change if/when it is recognized that one of the alternative futures is becoming the new reality. While summarizing all of the key metrics, the following discussions focus on the economics of the Portfolios.

Summary tables are provided below for the Gas Price, Carbon Price, Load Forecast and Capital Cost Sensitivity studies. The tables are organized such that each cell contains three values: the top cell corresponds to the low assumption, the middle value corresponds to the base assumption, and the bottom value corresponds to the high assumption as defined earlier in this chapter. If the different Sensitivity assumptions do not cause different results than the base, only the one value is included in the table. For example, the High and Low Capital Cost Sensitivities do not cause the system to dispatch differently, so only one value is provided for each Portfolio for outputs such as gas burn, carbon emissions, and water use.

GAS PRICE SENSITIVITY

Overall, the +/- 30% change in the natural gas price assumption impacts revenue requirements by approximately +/- 5%. The Flexible Resource Portfolio ranks first and second best across Base/Low/High Gas Sensitivities in terms of the economic metrics (15- and 30-year NPV and system cost). The Carbon Reduction Portfolio ranks well in the 30-year NPV, but not so well in the 15-year NPV, capital expenditures or in terms of gas burn. The Resource Mandates and Small Modular Reactors Portfolios are very costly in all cases.

TABLE 7-3. SUMMARY OF GAS PRICE SENSITIVITY RESULTS*, **

	FLEXIBLE RESOURCE	CARBON REDUCTION	EXPANDED DSM	EXPANDED RENEWABLES	ENERGY STORAGE SYSTEMS	RESOURCE MANDATES	SMALL MODULAR REACTORS
Revenue Reqmt NPV 2017-2032 $Billions	25.0	25.1	25.1	25.2	25.3	25.6	25.5
	26.0	26.1	26.0	26.1	26.3	26.5	26.4
	26.9	27.0	26.8	27.1	27.1	27.3	27.3
Revenue Reqmt NPV 2017-2046 $Billions	37.3	37.1	38.2	38.0	37.8	39.2	39.2
	39.2	39.0	39.9	39.7	39.7	41.0	40.9
	41.1	41.0	41.5	41.5	41.5	42.3	42.6
System Cost in 2032 $/MWH	95.6	90.8	107.2	98.8	97.3	112.2	106.5
	101.4	97.6	112.5	104.3	103.4	117.9	111.1
	106.5	104.3	117.3	108.7	108.0	121.6	115.3
Cumulative Capital Exp 2017-2032 $Billions	8.2	9.7	8.1	9.3	8.9	9.3	11.8
Gas Burn in 2032 - BCF	150.3	179.8	126.6	140.4	149.0	121.1	132.0
	140.9	178.3	117.9	131.3	140.9	115.0	122.6
	139.4	177.0	115.8	129.4	137.7	110.3	119.2
CO2 Emissions in 2032 - Million Metric Tons	13.3	10.6	11.8	12.7	13.1	11.5	12.1
	13.5	10.6	12.1	12.9	13.5	11.9	12.3
	13.8	10.5	12.3	13.2	13.6	12.0	12.5
Water Use in 2032 Thousand Acre-Feet	52.1	43.4	49.4	50.9	52.0	48.9	54.7
	52.7	43.3	49.9	51.5	52.8	49.6	55.3
	53.2	43.2	50.4	52.0	53.1	49.8	55.9

*Revenue requirements and capital expenditures include customer costs for DSM measures included in the Expanded DSM and Resource Mandates Portfolios for comparability to other Portfolios consistent with the Total Resource Cost (TRC) Test.

** Low/Base/High Sensitivities except for Cumulative Capital Expenditures 2017-2032 $B.

CARBON PRICE SENSITIVITY

Overall, the high and low carbon price assumptions impacted the 30-year NPV of revenue requirements by about +/-3% from base assumption results. Just as in the Natural Gas Price Sensitivity, the Flexible Resource Portfolio ranks first and second best out of the seven Portfolios in terms of the economic metrics. And likewise, the Carbon Reduction Portfolio ranks well in the 30-year NPV, but not in the 15-year NPV, capital expenditures or natural gas burn. Resource Mandates and Small Modular Reactors Portfolios remain high cost compared to the rest.

TABLE 7-4. SUMMARY OF CARBON PRICE SENSITIVITY RESULTS*, **

	FLEXIBLE RESOURCE	CARBON REDUCTION	EXPANDED DSM	EXPANDED RENEWABLES	ENERGY STORAGE SYSTEMS	RESOURCE MANDATES	SMALL MODULAR REACTORS
Revenue Reqmt NPV 2017-2032 $Billions	25.5	25.7	25.6	25.7	25.8	26.1	26.0
	26.0	26.1	26.0	26.1	26.3	26.5	26.4
	26.3	26.4	26.3	26.5	26.6	26.8	26.7
Revenue Reqmt NPV 2017-2046 $Billions	38.0	37.9	38.8	38.6	38.5	39.8	39.8
	39.2	39.0	39.9	39.7	39.7	41.0	40.9
	40.4	40.1	40.9	40.9	40.9	41.9	42.0
System Cost in 2032 $/MWH	95.3	93.0	106.6	98.5	97.0	111.6	105.8
	101.4	97.6	112.5	104.3	103.4	117.9	111.1
	107.2	102.1	118.5	109.9	109.1	123.7	116.3
Cumulative Capital Exp 2017-2032 $Billions	8.2	9.7	8.1	9.3	8.9	9.3	11.8
Gas Burn in 2032 - BCF	147.4	187.9	121.9	137.0	146.4	117.0	127.5
	140.9	178.3	117.9	131.3	140.9	115.0	122.6
	132.7	165.5	113.3	124.8	131.0	108.3	115.3
CO2 Emissions in 2032 - Million Metric Tons	14.3	11.0	12.7	13.7	14.1	12.4	12.9
	13.5	10.6	12.1	12.9	13.5	11.9	12.3
	12.5	9.9	11.4	12.5	12.5	11.2	11.5
Water Use in 2032 Thousand Acre-Feet	54.3	44.1	51.4	53.1	54.3	50.9	56.8
	52.7	43.3	49.9	51.5	52.8	49.6	55.3
	50.7	42.1	48.4	49.8	50.8	48.0	53.5

*Revenue requirements and capital expenditures include customer costs for DSM measures included in the Expanded DSM and Resource Mandates Portfolios for comparability to other Portfolios consistent with the Total Resource Cost (TRC) Test.

** Low/Base/High Sensitivities except for Cumulative Capital Expenditures 2017-2032 $B.

LOAD FORECAST SENSITIVITY

The Load Forecast Sensitivities have the largest impact on the revenue requirements of all of the Sensitivities, with the 1% per year lower growth rate reducing 30-year NPV revenue requirements by about 11.5%, and the 1% per year higher growth rate increasing revenue requirements by about 15%. This Sensitivity also has the largest impact on capital expenditures, gas burn, carbon emissions, and water use in terms of absolute values. Individual customer cost impact is much less though, as evidenced by the system average cost in 2032 of only 0% to 2% in the Flexible Resource Portfolio. As in the previous two Sensitivities, the Flexible Resource Portfolio ranks first and second best out of the seven Portfolios in terms of the economic metrics. And likewise, the Carbon Reduction Portfolio ranks well in the 30-year NPV, but not in the 15-year NPV, capital expenditures or natural gas burn. Resource Mandates and Small Modular Reactors Portfolios remain high cost compared to the rest.

TABLE 7-5. SUMMARY OF LOAD FORECAST SENSITIVITY RESULTS*, **

	FLEXIBLE RESOURCE	CARBON REDUCTION	EXPANDED DSM	EXPANDED RENEWABLES	ENERGY STORAGE SYSTEMS	RESOURCE MANDATES	SMALL MODULAR REACTORS
Revenue Reqmt NPV 2017-2032 $Billions	24.4	24.5	24.4	24.5	24.7	24.9	24.8
	26.0	26.1	26.0	26.1	26.3	26.5	26.4
	27.8	28.0	27.8	28.2	28.1	28.4	28.2
Revenue Reqmt NPV 2017-2046 $Billions	34.7	34.5	35.5	35.0	35.2	36.3	36.4
	39.2	39.0	39.9	39.7	39.7	41.0	40.9
	45.0	44.8	45.5	46.0	45.5	46.9	46.5
System Cost in 2032 $/MWH	103.2	97.4	118.1	104.7	105.3	122.8	115.2
	101.4	97.6	112.5	104.3	103.4	117.9	111.1
	101.4	100.5	110.3	104.8	102.3	115.5	108.8
Cumulative Capital Exp 2017-2032 $Billions	6.3	7.6	6.4	6.6	6.9	7.1	10.1
	8.2	9.7	8.1	9.3	8.9	9.3	11.8
	10.7	12.6	10.6	12.5	11.2	11.1	14.2
Gas Burn in 2032 - BCF	101.7	136.1	80.2	99.0	102.3	81.7	84.3
	140.9	178.3	117.9	131.3	140.9	115.0	122.6
	188.7	226.2	163.4	169.6	188.0	152.5	168.7
CO2 Emissions in 2032 - Million Metric Tons	11.1	8.2	9.8	10.9	11.1	9.9	10.0
	13.5	10.6	12.1	12.9	13.5	11.9	12.3
	16.3	13.2	14.8	15.2	16.3	14.2	15.1
Water Use in 2032 Thousand Acre-Feet	48.0	39.0	45.3	47.7	48.1	45.5	50.2
	52.7	43.3	49.9	51.5	52.8	49.6	55.3
	57.3	46.1	54.8	55.3	57.3	53.7	60.4

*Revenue requirements and capital expenditures include customer costs for DSM measures included in the Expanded DSM and Resource Mandates Portfolios for comparability to other Portfolios consistent with the Total Resource Cost (TRC) Test.

** Low/Base/High Sensitivities.

CAPITAL COST SENSITIVITY

The Capital Cost Sensitivity has the lowest impact on 30-year NPV revenue requirements of all of the Sensitivities, only changing the values by less than plus or minus 1%. Because this Sensitivity focused on the most uncertain capital costs of battery storage and nuclear, it has little impact on many of the Portfolios. The significant observation in the results of this Sensitivity is that even if the low cost Sensitivity assumptions are realized, the Energy Storage Systems, Resource Mandates and Small Modular Reactor Portfolios are still high cost Portfolios. Note that there is not a change in system dispatch due to the Capital Cost Sensitivity assumptions, so natural gas use, carbon emissions and water use are not impacted.

TABLE 7-6. SUMMARY OF CAPITAL COST SENSITIVITY RESULTS*, **

	FLEXIBLE RESOURCE	CARBON REDUCTION	EXPANDED DSM	EXPANDED RENEWABLES	ENERGY STORAGE SYSTEMS	RESOURCE MANDATES	SMALL MODULAR REACTORS
Revenue Reqmt NPV 2017-2032 $Billions	25.9	26.1	25.9	26.1	26.2	26.4	26.3
	26.0	26.1	26.0	26.2	26.3	26.5	26.4
	26.0	26.1	26.0	26.2	26.4	26.7	26.6
Revenue Reqmt NPV 2017-2046 $Billions	39.2	39.0	39.8	39.8	39.6	40.7	40.3
	39.2	39.0	39.9	39.8	39.7	41.0	40.9
	39.4	39.2	40.1	40.0	40.2	41.5	41.7
System Cost in 2032 $/MWH	101.2	97.4	112.0	104.1	102.9	117.1	107.8
	101.4	97.6	112.5	104.3	103.4	117.9	111.1
	102.4	98.6	113.7	105.3	105.5	120.7	115.2
Cumulative Capital Exp 2017-2032 $Billions	8.2	9.7	8.0	9.3	8.7	9.1	10.8
	8.2	9.7	8.1	9.3	8.9	9.3	11.8
	8.5	9.9	8.3	9.5	9.4	9.9	13.1
Gas Burn in 2032 - BCF	140.9	178.3	117.9	131.3	140.9	115.0	122.6
CO2 Emissions in 2032 - Million Metric Tons	13.5	10.6	12.1	12.9	13.5	11.9	12.3
Water Use in 2032 Thousand Acre-Feet	52.7	43.3	49.9	51.5	52.8	49.6	55.3

*Revenue requirements and capital expenditures include customer costs for DSM measures included in the Expanded DSM and Resource Mandates Portfolios for comparability to other Portfolios consistent with the Total Resource Cost (TRC) Test.

** Low/Base/High Sensitivities except for Gas Burn in 2032 - BCF, CO2 Emissions in 2032 - Million Metric Tons and Water Use in 2032 Thousand Acre-Feet.

2017 IRP

Based upon the foregoing Portfolio and Sensitivity analyses, the following observations are made:

FLEXIBLE RESOURCE PORTFOLIO (2017 IRP SELECTED PLAN)

- Performs very well in terms of revenue requirements and system average cost across all Sensitivities
- Second lowest capital expenditure requirement across all Sensitivities
- Reasonable natural gas burn, CO2 emissions and water use and is viewed to employ a balanced and sufficiently diverse fuel mix with the ability to update as appropriate

CARBON REDUCTION PORTFOLIO

- Performs very well in terms of 30-year NPV revenue requirements and system average cost across all Sensitivities, not as well in terms of 15-year NPV revenue requirements
- Highest natural gas burn, least diverse of all Portfolios
- Lowest carbon emissions and water use of all Portfolios

EXPANDED DSM PORTFOLIO

- Significant uncertainty as to whether this Portfolio is achievable
- Performs well in terms of 15-year NPV revenue requirements (total resource costs), not well in terms of 30-year NPV
- Slightly lower capital expenditure requirement including customer costs
- Results in higher system average costs (higher rates) and large cost shift to non-participating customers
- Second lowest gas burn, and third lowest carbon emissions and water use of the Portfolios

EXPANDED RENEWABLES PORTFOLIO

- Performance is average in terms of economic metrics, but well above the costs of the Flexible Resources Portfolio
- Higher capital expenditure requirements, and does not avoid much capital expenditure in conventional resources due to the high renewable penetration and corresponding low capacity value for this Portfolio
- Small reduction in gas burn, carbon emissions and water use compared to the Flexible Resource Portfolio
- Reduced ability to capture market opportunities

ENERGY STORAGE SYSTEMS PORTFOLIO

- Performance is average in terms of economic metrics, similar to the Expanded Renewables Portfolio, but well above the costs of the Flexible Resources Portfolio
- Reduced capacity credit for additional amounts of storage
- Minimal change in gas burn, carbon emissions and water use compared to the Flexible Resource Portfolio
- Allows for a minimal increase in ability to purchase low or negatively priced power in the wholesale market

RESOURCE MANDATES PORTFOLIO

- Does not perform well in terms of economic metrics, creating high revenue requirements, system average and customer costs
- Largest reduction in gas burn of all Portfolios, approximately 20% less natural gas than the Flexible Resource Portfolio
- Moderate reductions in carbon emissions and water use compared to the Flexible Resource Portfolio
- Provides least flexibility in future resource decisions under changing circumstances

SMALL MODULAR REACTORS (SMR) PORTFOLIO

- Significant uncertainty as to whether this Portfolio is achievable since the technology is not commercially available at this time
- Does not perform well in terms of economic metrics, creating high revenue requirements, system average and customer costs
- Highest capital expenditure requirements, approximately 44% higher than the Flexible Resource Portfolio
- Reduces carbon emissions and gas burn by 10-15% relative to the Flexible Resource Portfolio
- Only Portfolio to increase water use up to 5% above the Flexible Resource Portfolio

Conclusion

As can be seen from the observations discussed in this chapter, each Portfolio has benefits under certain conditions. There are many economic, environmental and risk trade-offs to be considered in the selection of APS's 2017 resource plan. At this time, APS is selecting the Flexible Resource Portfolio as its 2017 resource plan. This plan exhibits a balanced blend of attributes when compared to the other Portfolios. With the changing energy landscape as well as the evolving energy markets, it provides the flexibility needed to operate the system efficiently and economically for our customers. Based upon the above analysis, APS chose the Flexible Resource Portfolio as its 2017 Resource Plan. The resulting resource plan, associated revenue requirements and other details can be found in Attachments F.1(a)(1) and F.1(b), respectively. In addition to this analysis, the Flexible Resource Portfolio has the following characteristics:

- Maintains diversity of APS energy mix from 2017 to 2032, increasing parts of the mix while decreasing others
- Complies with the ACC's RES and EES
- Reduces intensity of CO_2 emissions and water use
- Plans natural gas additions that provide flexibility in generation dispatch that will be required due to increased penetration of customer-sited solar photovoltaic resources and allows the opportunity to take advantage of market conditions

Should circumstances significantly change over the course of the Planning Period, the Selected Plan may be modified to better fit the conditions prevalent at the time such a decision is made. APS will monitor key variables such as carbon legislation and gas prices which influence the economics and will continue to evaluate its options.

CHAPTER 8

ACTION PLAN

2017–2021

2017

ACTION PLAN

As discussed in Chapters 1 through 7, APS determined the Flexible Resource Portfolio represented the most reasonable mix of resources to meet customer needs for the Planning Period at this time. Based on that determination, the 2017-2021 Action Plan[1] lays out the specific activities anticipated to occur during the first five years of the 2017 IRP. Note that this five-year Action Plan extends beyond the ACC Resource Planning and Procurement requirement of a three-year Action Plan in order to highlight activities APS expects to undertake during that time-frame.

As with other components of the 2017 IRP, the 2017-2021 Action Plan is based on current information available at the time of this writing and forecasts that have been derived from information gathered in the third quarter of 2016. Actual activities during the Action Plan Period will be based on conditions prevalent at the time of their undertaking, including compliance with current regulatory rules and orders, and may differ from what is delineated here.

1. FUTURE RESOURCES

2016 ALL-SOURCE REQUEST FOR PROPOSAL (RFP)

To help meet load requirements and maintain system reliability beginning in 2020, APS issued an All-Source RFP in March 2016. The RFP sought competitive proposals for capacity resources totaling approximately 400-600 MW for summer 2020 and beyond. Following a comprehensive review and analysis of the received bids, APS selected the 565 MW Arlington Valley, LLC Gas Tolling Agreement based on favorable economics and its ability to meet summertime peak load conditions. The term of the gas tolling agreement covers the six-year period 2020-2025 for the months of June through September only. The entire RFP process was observed and reviewed by a third-party, ACC-approved independent monitor. The independent monitor concluded that the process was conducted in a clear, transparent and fair manner. In 2017, APS will conduct another RFP to meet future summer season peak capacity needs for 2021 and beyond.

INITIAL PROJECT SITING ACTIVITIES

During the Action Plan Period, APS will continue to consider a wide range of opportunities for next generation resource expansion to ensure customer needs are met reliably in future years. As energy resources become more complex, the process for screening potential sites requires additional phases of preliminary assessments before formal siting activities can be undertaken. Through this ongoing process, APS will continue to screen for potential sites that could be development-ready and may take action to create options for additional development of resources should they be needed to maintain APS system reliability.

2. OCOTILLO MODERNIZATION PROJECT

Site work at the Ocotillo Power Plant has commenced, including the removal of the existing oil tanks. In addition, grading, foundation work and underground utility installation have begun and delivery of the first two of the five turbines is well under way. Additionally, in APS's Ten-Year Transmission System Plan, APS detailed the Ocotillo Modernization Project Interconnection Facilities project, which will include two onsite 230kV generation interconnection circuits for interconnection to the existing onsite Ocotillo 230kV Substation. The project is planned to be in service by summer 2019.

1 As required by A.A.C. R14-2-703(H).

3. EVALUATE AND DECIDE ON REMAINING COAL FLEET

APS continues to execute its plans for the Four Corners Generating Station and evaluate its plans for the Cholla Power Plant. Cholla Unit 2 was retired on October 1, 2015, and APS plans to no longer burn coal in Units 1 and 3 beyond 2024.

Based on a February 2017 decision among current NGS owners, APS will maintain its allocation of capacity from the plant through December 2019, provided an agreement can be reached with the Navajo Nation. As of the filing of this IRP, discussions regarding the future of NGS are occurring among a number of parties. APS will continue to participate in these discussions and update its Action Plan as decisions on this and other coal generation resources are made.

4. ADD TRANSMISSION RESOURCES

APS's 2017-2026 Ten-Year Transmission System Plan (filed January 31, 2017)[2] includes 38 miles of 500kV transmission lines, 14 miles of 230kV transmission lines and five substations. The total investment for the APS projects is estimated at approximately $195 million.

TABLE 8-1. SELECT PROJECTS FROM APS'S 2017-2026 TEN-YEAR TRANSMISSION PLAN

PROJECT	DESCRIPTION	CONSTRUCTION START DATE	CONSTRUCTION END DATE
Mazatzal 345/69kV Substation	To provide the electric source and support to the subtransmission system in the area of Payson and the surrounding communities.	2015	2018
Ocotillo Modernization Project Interconnection Facilities	To interconnect new generators being constructed as part of the Ocotillo Modernization Project.	2016	2018
Morgan- Sun Valley 500kV Line	To increase import capability to the Phoenix metro area, as well as increase the export/scheduling capability from the Palo Verde Hub area.	2017	2018
North Gila-Orchard 230kV Line Circuit #I	To increase ability to import resources into the Yuma load pocket and improve reliability of the local system.	2019	2021

5. CONTINUE EXPANSION OF RENEWABLE RESOURCES

APS SOLAR PARTNER PROGRAM (SPP)

In 2015-16, APS designed and implemented the 10 MW SPP, in part to better understand the ability of advanced inverters to help mitigate the power-quality issues that can arise with high-photovoltaic penetration.

The program involves approximately 1,600 utility-owned residential PV systems with advanced inverters wirelessly connected to a central control system in the APS operations center. West- or southwest-facing rooftops were specified to better align solar output with peak system demand on six primary research feeders. The program's central control system was provided by Siemens and enhanced according to APS's specifications to allow the controller to remotely issue commands to groups of PV systems on individual feeders.

APS developed a year-long test plan involving 21 research questions in partnership with the Electric Power Research Institute (EPRI) to evaluate the multiple functions and capabilities of advanced-inverters. Predictive mathematical models were developed to allow measured results to be extrapolated to even higher levels of future penetration. Preliminary results of the SPP were included in EPRI's January 2017 report: APS Solar Partner Program Research Highlights.[3] The final report will be available in the second quarter of 2017.

2 Arizona Public Service Company 2017-2026 Ten-Year Transmission System Plan, Docket No. E-00000D-17-0001.
3 Electric Power Research Institute, APS Solar Partner Program: Research Highlights (January 31, 2017), http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002009779.

In addition to the 10 MW of new photovoltaic capacity under the program, APS has deployed two battery storage systems, each rated at 2 MW/2 MWh for use in peak-shaving (flattening the net feeder demand) and distribution-system voltage management on two of the primary SPP research feeders. APS – in continued cooperation with EPRI – will conduct research on the battery systems in 2017 with the goal of understanding whether batteries do a better job of voltage rise on high-PV-penetration feeders vs. advanced inverters (or whether both are useful and necessary). Findings from this portion of APS activities will be available in early 2018.

SOLAR INNOVATION STUDY (SIS)

SIS is composed of two separate programs:

- A 75-customer APS-owned home energy management and rate research and development field program designed to examine the integration of customer-side advanced technologies – including rooftop solar, advanced inverters and home energy management systems – with demand-based rates. APS started recruiting for the 75-home pilot in February 2016 and technology installations continued through the fall.
- A similar market-facing program will examine the integration of rooftop solar with energy-related technologies like demand managers (such as load controllers). Participating customers will be placed on demand rates and will own all equipment in the study.

CUSTOMER SOLAR PROJECT (RED ROCK SOLAR GENERATING STATION)

In December 2016, Red Rock Generating Station, APS's new 40 MW solar PV plant, became fully operational. The facility is the result of a collaboration between APS with Arizona State University (ASU) and PayPal, the sole purchasers of the plant's green attributes. The Red Rock project, APS's largest grid-scale solar plant, combines economic development and the deployment of new renewable energy resources in a single, customer-driven endeavor that will benefit all APS customers through an incremental revenue contribution from ASU and PayPal.

INVESTMENT IN AZ SUN II

The purpose of this program, which has been proposed in APS's general rate case settlement, is to expand access to rooftop solar for low and moderate income Arizonans, and will be available throughout APS's service territory, including rural Arizona. For this program, distributed generation would be defined as photovoltaic solar generation connected to the distribution system, and may include any multi-family housing (such as apartment buildings), Title I Schools, and rural government customers. APS will own all the generation, renewable energy credits and other attributes from this program to benefit all customers. APS will propose a program of not less than $10 million per year, and not more than $15 million per year, in direct capital costs for the program. All reasonable and prudent costs incurred by APS pursuant to this program will be recoverable through the Renewable Energy Adjustment Clause until the next rate case. This program is contingent upon Commission approval.

6. CONTINUE IMPLEMENTATION OF CUSTOMER-SIDE RESOURCES

DSM IMPLEMENTATION PLAN

On June 1, 2016, APS filed its Demand Side Management (DSM) Implementation Plan for 2017 and on January 27, 2017 filed a Modified 2017 DSM Implementation Plan.[4] The modified proposed plan aims to achieve first-year energy savings of approximately 562,000 MWh in 2017 and makes progress toward compliance with the overall Energy Efficiency Standard (EES) requirement of 22% by 2020.

The 2017 portfolio of DSM programs has been reshaped to greater emphasize load shifting and peak load reducing measures. In particular, the Plan proposes a new Demand Response, Energy Storage, Load Management (DRESLM) program designed to support the deployment of residential load management, demand response and energy storage technologies that help APS residential customers shift energy use and manage peak demand. The total program includes residential and intermediate scale batteries, thermal storage in the form of grid interactive water heaters, and a demand response component facilitated through smart thermostats.

In addition, the Plan proposes several new pilot programs, including: (a) Energy and Demand Management Education Pilot, allowing APS to explore strategies to help customers adapt to three-part rates while at the same time addressing system needs; (b) Load Management Technologies Pilot, which will deploy load control and load shifting technologies to assist customers shift energy usage to off-peak and/or lower demand periods; and (c) Transmission and Distribution Pilot, which will target energy saving and load shifting strategies specifically to customers located on constrained distribution feeders.

Beyond these new additions, the Plan requests that residential EE programs continue with its existing portfolio of programs, with the following modifications: discontinuation of CFL rebates and incentives, expansion of funding for LED incentives in anticipation of higher customer demand, and modification of the Residential New Construction program to keep pace with evolving codes. Non-Residential Programs (Solutions for Business) will be enhanced with three new measures: expansion of incentives of LED lighting, expansion of Conservation Behavior program and increase in the incentive level for the Energy Information Services program to 100% of first-year incremental cost.

APS Systems Saving Initiatives will continue operation of its Conservation Voltage Reduction systems, implement energy efficiency upgrades at select APS facilities and upgrade certain APS–owned streetlights with LED technologies.

When approved, this Plan will allow APS to meet the 2017 target for the EES and will also continue the transformation of the DSM programs to emphasize peak load reduction and time differentiated energy savings.

MICROGRID PROJECTS

In December 2016, APS, with the U.S. Department of the Navy and U.S. Marine Corps, launched the nation's first utility-owned, fully-islandable microgrid located within the fence line of a DOD facility at Marine Corps Air Station (MCAS) in Yuma. This 21.6 MW project pioneered a new way to partner with a customer in which both parties make contributions to the project for the benefits of the direct (host) customer and APS customers. The MCAS Yuma microgrid can provide reliable power throughout the summer peaks to all APS customers by backfeeding the grid from within the base facility and, in the event of a grid outage, the facility can provide 100% backup power to MCAS Yuma, enhancing national security. Due to the ability of the microgrid to go from zero to full output in less than 20 seconds, it also provides frequency response services to the grid, which will further enhance the economics and savings of this facility for all customers.

APS also worked with the Aligned Data Center to bring an 11 MW microgrid facility into service in the Phoenix metro area in December 2016. Similar to the MCAS Yuma microgrid, this facility can act as a peaking resource and provide frequency response to the broader grid as well as backup power in the event of a grid outage.

4 A.C.C. Docket No. E-01345A-16-0176.

7. INVEST IN ADVANCED GRID TECHNOLOGIES

PROJECT ILLUMINATE

APS will continue to implement its state-of-the-art grid management system, Project Illuminate, which uses advanced technologies to improve internal visualization and diagnostic capabilities. The cornerstone of the project is an Advanced Distribution Management System (ADMS) that allows for automation of distribution field devices and significantly increases operators' visibility into real-time aspects of the APS system. The initial phase of the ADMS project went online January 25, 2017 and includes the new Outage Management and Distribution Management Systems, along with the advanced engineering applications. Within the Outage Management System is a new mobility platform for APS field crews to respond to outages with the same real-time operating system map view in their trucks as the operators in the distribution operations center, enabling more efficient communications, which will lead to more efficient outage management.

The ADMS "phase two" initiative will strategically position APS at the forefront of distribution technology by providing the ability to remotely monitor and control the distribution system and associated devices.

8. CAISO ENERGY IMBALANCE MARKET

APS joined the CAISO EIM as a new participating Balancing Authority on October 1, 2016. With a smooth transition to the EIM platform, APS is seeing energy flows in every hour of every day, which is resulting in customers savings. APS is working with other EIM entities and the CAISO to address some existing operational issues, including fine tuning processes and modeling efforts.

Since APS joined the EIM, the CAISO has published the Fourth Quarter 2016 Western EIM Benefits Report. APS's gross benefits from EIM participation was approximately $6 million, with APS being a net exporter in both the 15-minute and 5-minute tranches in all three months of the quarter. APS's largest export volumes went to CAISO while its largest import volumes came from PacifiCorp. CAISO's new flexible ramping products, which facilitate the procurement of both upward and downward flexible ramping capacity to address variability in real-time dispatch, were used by APS for net upward flexible ramping capacity in October and December and net downward flexible ramping capacity in November.

9. NATURAL GAS STORAGE

APS is exploring potential options to develop a natural gas storage facility to add capacity, enhance reliability and increase flexibility.

RESPONSE TO RULES

SECTION C

Demand

2017

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 or equal to 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.

The line labeled "Own Load Peak – After DE Before EE/DR" in Attachment C.2 provides a disaggregation of the load forecast by month and year into a component in which no additional demand management measures are assumed. Within the same exhibit, a disaggregation of the load forecast assuming the change in load due to additional 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.

Time of use (TOU) rates may also be considered demand management measures. TOU energy 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 energy rates have reduced summer peak loads by over 100 MW since their inception. APS has proposed to eliminate inclining block rates, phase out flat energy rates, increase adoption of TOU energy and demand rates, and align peak rate hours with system peak hours (3-8pm) in its current rate case. These changes are expected to provide additional demand reduction in the future.

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 from several different class-level analyses, which account for differences in the way customers use electricity. These analyses 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.

The U.S. Census Bureau reports historical population and household data. 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. APS uses statistical models of net migration developed by the Economic and Business Research Center at the University of Arizona as the foundation for the net migration forecast. These models capture in-migration and out-migration flows separately and control for differences in the age of migrants as well as the regions from which they are arriving or to which they are moving.

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. These publicly available sources include the Arizona Department of Administration 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 (PPH). 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 that 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 percent of Maricopa County, but has been receiving about 50 percent 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 by melding together an historical end-use model with more recent historical trends/outcomes, coupled with short-run forecast dynamics that are expected to occur along with the business cycle.

The end-use-model disaggregates historical annual residential electricity usage into the five largest 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.

Electricity use for each of these applications is projected based on the most recent CDA estimates, an assumption of normal weather, an assumption of efficiency improvements 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.

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 developed with 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 autoregressive regression model which estimates the historical relationship between total commercial and industrial electricity demand and overall economic growth in the APS Metro Phoenix 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 load greater than 3 MW is subtracted from the total.

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 and other similar sources. 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 two 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.

Line Losses – Transmission and distribution line losses coupled with company use 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 about 6.5 percent.

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 within the range of 68 percent to 63 percent for those summer months with some downward trend embedded. 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. Typically, peak regression models (due to their inherent statistical approach) have a tendency to under forecast peak conditions and thus suffer forecast bias. Class-based hourly load models may be another option, but currently they would require a longer data history than is presently available.

RESPONSE TO RULES

SECTION D

Supply

2017

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 D-1.

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.

TABLE D-1. LIST OF D.1(A) ATTACHMENTS

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 attachment	D.1(a)(4)
B.1(h) Other variable O&M attachment	D.1(a)(1)
B.1(i) Purchased power energy costs for 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 – CO2	D.1(a)(8)
B.1(p) Environmental impacts – CO	D.1(a)(8)
B.1(p) Environmental impacts – NOx	D.1(a)(8)
B.1(p) Environmental impacts – SO2	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)

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 take forward into the intraday markets. 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 intraday 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.

Within the sub-hourly window, the real-time traders proceed to further refine our generation plan by interacting with the CAISO Energy Imbalance Market (EIM) to transfer energy when economically beneficial. Through calculated cost curves of each unit, the real-time traders determine which generators may be incremented, decremented, committed (start) and de-committed (shutdown) as part of a greater EIM footprint solution. While considering available transmission resources, fuel supplies, and reliability needs, APS participates in both the 5-minute and 15-minute markets while maintaining the required reserves and system stability requirements for our system. Each of these markets utilize dynamic meter and load data as well as 5-minute renewable forecasting to dispatch all participating units with the goal of reducing the production cost of the greater EIM footprint.

As the final step in this process, the real-time traders issue the commitment and de-commitment instructions to generating units as needed to meet load and sales commitments. Additionally they update the plan as needed for generating unit or transmission outages; continuously optimizing usage 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.

A new operational and financial risk is developing due to the increase of solar resources on the APS system and in the southwest region. During non-summer months the percentage of APS load served by solar is increasing to the point where there is insufficient load for base load generation resources to operate. Additionally, policies in the region that encourage solar development are moving market electric prices during the middle of the day in the non-summer months to negative values. Strategies have been developed and implemented to manage both an over generation problem and to curtail APS's grid-scale solar resources to take advantage of market opportunities for our customers. These operational strategies seek to minimize costs to accommodate the solar resources, take advantage of negatively priced power while maintaining system reliability. As more solar resources are added onto the grid, these challenges are expected to amplify over time.

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 D2. "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 SO2 and CO2 emissions. "Purchases" includes the variable O&M and commodity portion of fuel costs for tolled generating units, costs for existing PPAs, and short-term market purchases represented in response to Rule D.1(b) – B.2(f).

TABLE D-2. TOTAL PRODUCTION COSTS FOR 2017 RESOURCE PLAN ($MILLIONS)

	Generation		Emissions	Purchases		Sales	Total
	FUEL	VARIABLE O&M	SO2 & CO2	DEMAND	ENERGY		$MILLIONS
2017	486.1	67.4	(0.1)	102.4	297.9	0.0	953.7
2018	517.8	72.6	(0.1)	71.0	252.3	0.0	913.6
2019	518.5	77.6	(0.1)	70.3	254.1	0.1	920.5
2020	541.1	86.1	(0.1)	49.3	242.2	0.3	918.8
2021	590.5	98.1	(0.1)	39.8	243.7	0.6	972.7
2022	631.5	104.2	(0.1)	39.9	250.9	0.7	1,027.2
2023	620.5	108.5	22.5	40.3	273.2	1.7	1,066.7
2024	657.8	112.0	26.5	40.8	283.7	2.0	1,122.8
2025	674.7	119.8	25.4	41.3	276.2	2.0	1,139.5
2026	740.4	131.7	46.5	6.2	250.2	4.0	1,178.9
2027	785.0	137.8	89.0	6.8	267.3	6.8	1,292.8
2028	831.5	140.1	125.3	7.6	286.6	11.1	1,402.2
2029	844.5	146.5	173.8	8.4	296.8	17.7	1,487.8
2030	896.1	151.2	215.0	9.3	302.8	19.1	1,593.5
2031	932.0	159.1	228.5	10.3	308.4	20.9	1,659.2
2032	959.9	162.2	241.6	11.5	321.7	35.2	1,732.2

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 2017 Resource Plan are provided in Attachment F.9(b) on line 3 and in Table D-4 for Rule D.1(b)-B.2(e).

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).[1] Individual members' spinning reserve requirements are calculated using a formula that takes into account factors such as each member's forecasted hourly loads, online generation and joint ownership percentages. 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 D-3. Up to half of these requirements can be met with units designed to start within 10 minutes.

1 Additional information regarding SRSG can be found at www.srsg.org.

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 expectation (LOLE). APS's reserve criterion is based on LOLE of one outage in ten years, which currently translates to a 15% reserve requirement. To ensure a reliable generation system, reserves should be greater than or equal to 15%. Table D-4 shows the annual reserve requirement amounts based on the 15% requirement (also shown on Attachment F.9(b), line 3).

TRANSMISSION AND DISTRIBUTION RELIABILITY

APS follows the Institute of Electrical and Electronics Engineers (IEEE) 1366 – 2012, "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). 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 flat trend in transmission reliability during the 15-year Planning Period with improvement over current reliability.

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 improvement in APS's reliability. The improving effectiveness of current Reliability Programs with proactive and strategic approaches suggests slight improvements to reliability year over year. Forecast vs. actual data may vary depending upon weather patterns and unusual events.

TABLE D-3. FORECAST SPINNING RESERVE REQUIREMENT

YEAR	SPINNING RESERVE REQUIREMENT
2017	218
2018	219
2019	219
2020	220
2021	221
2022	221
2023	223
2024	224
2025	226
2026	227
2027	230
2028	231
2029	233
2030	236
2031	238
2032	242

TABLE D-4. FORECAST RESERVE REQUIREMENTS

YEAR	RESERVE REQUIREMENT
2017	961
2018	989
2019	1015
2020	1047
2021	1152
2022	1187
2023	1222
2024	1258
2025	1294
2026	1331
2027	1369
2028	1409
2029	1448
2030	1489
2031	1530
2032	1573

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 during the first five years as depicted in Attachment F.9(b) at line 33. These are assumed to be four-month summer purchases (June to September) with capacity and energy prices based on anticipated available market generation costs as indicated in Table D-5. 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.

TABLE D-5. COSTS OF FORECASTED SHORT-TERM MARKET PURCHASES

YEAR	CAPACITY (MW)	DEMAND COST ($/KW-YR)	ENERGY COST ($/MWH)
2017	0	N/A	N/A
2018	90	$11.59	$24.68
2019	0	N/A	N/A
2020	0	N/A	N/A
2021	13	$17.65	$28.11

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 short-term market prices.

The energy costs are based on fuel and O&M costs for a merchant CC.

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) new technology capital costs, which are expected to decline 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:

Four Corners 1-2-3 were retired December 31, 2013, Saguaro Steam 1-2 were retired June 30, 2013, and Ocotillo Steam 1-2 are expected to be retired in 2018. Cholla 2 was retired October 1, 2015. Cholla 1&3 could potentially be retired in the 15-year Planning Period.

(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 $55 million in 2016 dollars. APS finished dismantling Units 1-3 in November 2016 and is not planning to fully decommission the site until after the retirement of Units 4-5, which is beyond the time frame of the Planning Period.

The estimated cost to decommission the Saguaro Steam units is approximately $9.0 M.

The estimated cost to decommission the Ocotillo Steam units is approximately $8.4 M.

The estimated cost to decommission the Cholla 2 Steam unit is approximately $8.2 M.

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

The retirement of Four Corners Units 1-3 was part of a plan that included APS purchasing Southern California Edison's (SCE) share of Four Corners 4-5. Details of that transaction are provided in Decision No. 73130.[2] Four Corners Units 1-3 were retired 1) so that APS ownership in coal would not increase appreciably as a result of the transaction, 2) to satisfy BART provisions with the EPA, and 3) because APS does not have enough transmission to deliver its new share of Units 4-5 plus Units 1-3.

The Saguaro Steam units were constructed in 1954 and 1955 and have reached the end of their useful life. The units are old, inefficient technology that had become increasingly difficult to maintain. APS anticipates preserving the site for remaining generation and for potential new generation in the future.

The Ocotillo Steam units were installed in 1960, and have also reached the end of their useful lives. It is becoming increasingly difficult to maintain and to acquire necessary parts for repair. Due to the importance of the location of the power plant in the Valley and its impact on ability to serve Valley load, five fast start combustion turbines generating units will be built on the site. The units are currently under construction and are scheduled to be in service in 2019.

Cholla 2 Steam Unit was retired 1) due to the age of the unit, reaching the end of its useful life 2) potential capital cost associated with environment compliance 3) the additional generation associated with the purchase of SCE's share of Four Corner Units 4-5 and 4) the agreement with the EPA regarding the Regional Haze Rules. For more information about the Regional Haze Rules see Rule D.17 and Rule E.1(d).

Though Cholla 1&3 are currently shown in the resource plan throughout the Planning Period, the plant is facing expensive environmental upgrade costs as described in D.17. APS is continuing to evaluate its options related to Cholla, and will inform the Commission upon making any decisions in this matter.

2 ACC Decision No. 73130 (April 24, 2012)

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). 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 D-6. 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.

TABLE D-6. O&M COSTS FOR NEW OR REFURBISHED TRANSMISSION

YEAR	O&M ($000)
2017	[redacted]
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	

SUBTRANSMISSION

APS annually conducts an analysis of its 69kV subtransmission. 69kV system changes are necessitated due to electric load changes. Load changes require elements to have increased capacity or additional elements to be constructed. 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 a very small geographic location 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 the Table D-7 were developed based upon APS's past expenditures and its system coincident peak load forecast for 2017 to 2032. O&M costs are not assigned to individual projects and are planned as a 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.

TABLE D-7. DISTIBUTION PLANNED IMPROVEMENT EXPENDITURES

YEAR	CAPITAL ($000)	O&M ($000)
2017	[redacted]	
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		

ADVANCED GRID TECHNOLOGY

APS is likely to invest $341M in new grid technologies through 2025 to support reliability, integrate distributed energy and emerging technologies. A list of technologies includes but is not limited to, Advanced Operational Platforms, Automated Switches, Communicating Fault Indicators, Advanced Analytics, Substation Health Monitors, Communication Infrastructure, Downed Conductor Detection, Advanced Metering Infrastructure, Phasor Measurement Units, and Network Protectors. These technologies are described in Chapter 4 – Modernizing the Grid.

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 Attachment D.1(f). 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 2017 Resource Plan are provided in Attachment D.10. The cost of existing and expected environmental regulations is embedded within the capital, O&M and emissions 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.

As an initial step, APS used Ventyx's PROVIEW resource optimizer to develop the portfolios as described in Chapter 7. PROVIEW developed and evaluated thousands of resource expansion plans designed to meet APS's forecasted load growth while meeting or exceeding reserve margin constraints. As part of the optimization process, the model calculated revenue requirements for each of the plans developed, including estimated power production and production costs for the Planning Period. Portfolios with the lowest NPV of revenue requirements were selected for further study using the much more detailed and accurate production model, PROMOD IV. 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).

TABLE D-8. COST OF CAPITAL

	CAPITAL RATIO	COST RATE	WEIGHTED COST OF CAPITAL	AFTER-TAX WEIGHTED COST OF CAPITAL
Debt	46.06%	7.50%	3.45%	2.11%
Equity	53.94%	10.00%	5.39%	5.39%
Totals	100%		8.84%	7.50%
AFUDC Rate	7.51%			
Composite Income Tax Rate	38.90%			

TABLE D-9. DEPRECIATION

	BOOK LIFE	TAX LIFE
Coal	32 Years	20 Years
Advanced Nuclear	60 Years	15 Years
Nuclear - SMR	40 Years	15 Years
Combined Cycle	32 Years	20 Years
Combustion Turbine	32 Years	15 Years
Transmission	50 Years	20 Years
Solar	25-35 Years	5 Years
Wind	20 Years	5 Years
Biomass	25 Years	5 Years
Geothermal	25 Years	5 Years

TABLE D-10. INVESTMENT TAX CREDITS

	2017	2018	2019	2020	2021	FUTURE YEARS
Solar	30%	30%	30%	26%	22%	10%[1]
Wind	24%	18%	12%	N/A	N/A	N/A
Geothermal	10%	10%	10%	10%	10%	10%
Biomass	N/A	N/A	N/A	N/A	N/A	N/A

(1) In 2022 and beyond, the ITC is 10% for commercial projects and 0% for residential projects.

TABLE D-11. CARBON DIOXIDE COSTS

YEAR	CO2 COST ($/METRIC TON)[1]
2017	$0.0
2018	$0.0
2019	$0.0
2020	$0.0
2021	$0.0
2022	$0.0
2023	$15.2
2024	$15.6
2025	$16.0
2026	$16.4
2027	$16.8
2028	$17.2
2029	$17.6
2030	$18.1
2031	$18.5
2032	$19.0

(1) Updated CO_2 numbers based on CA 2016 CO2 cost ($12.80) escalated at 2.5% (begin in 2023)

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 sales in the interchange market, which can change 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 and maintain reliability. However, increasing levels of solar in the region are driving non-summer mid-day electric market prices lower with negative values already seen on a regular basis. These downward price trends are included as an interchange purchase option and expected to accelerate as regional renewable mandates are achieved.

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 2017 Resource Plan are included in Table D-8, Table D-9, Table D-10 and Table D-11.

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 costs of potential future generating resources including baseload, intermediate, peaking, and energy storage as well as renewable resources such as solar, wind, geothermal, and biomass/biogas. The 2017 Integrated Resource Plan was based on economics, need, and operational characteristics. Attachment D.3 includes the resource type, associated capital costs, O&M costs, and performance characteristics for selected and non-selected technologies.

The power procurement process is utilized to acquire resources. Procurement is governed by the ACC rule R14-2-705. The actual procured resources may differ from the 2017 Integrated Resource Plan depending on the technology profiles prevalent at the time the procurement process is initiated.

Reasons why specific resources were not in the 2017 Integrated Resource Plan include:

- APS plans to meet or exceed the existing RES using a diverse set of renewable resources such as solar photovoltaic, parabolic trough with storage, wind, geothermal, and biomass/biogas. Economics constrain the feasibility of acquiring resources such as a solar thermal tower with storage.
- APS does not plan to construct new coal or large, traditional nuclear resources. The resources were modeled in PROVIEW, a resource optimization program, but were infeasible due to economics and other considerations.
- Energy storage technologies were considered and included battery storage, compressed air energy storage, pumped hydro storage, and flywheels. Battery storage is included in the 2017 Integrated Resource Plan. Although prices for this technology have declined in recent years, there remains considerable uncertainty related to its future cost outlook and pace of technological maturity. APS continues to monitor price trends of this technology and its potential for greater contribution to the APS portfolio mix. Other energy storage technologies were not included in the 2017 Integrated Resource Plan due to economics, commercial availability, technological maturity, and other considerations.

Flexible resources such as peaking combustion turbines were included in the 2017 Integrated Resource Plan. Continued increases in renewable penetration will require additional highly flexible resources on the APS system to ensure their integration and to maintain operational and reliability requirements. Operating characteristics such as low minimal loading, multiple daily dispatch potential, fast ramping capability, and others are essential to maintain balance in the APS system. In addition to their operating characteristics, combustion turbines are favored over other resources due to economics and projected fuel prices. The power procurement process will be utilized to acquire specific natural gas resources.

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 25 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."

TABLE D-12. RENEWABLE ENERGY CAPACITY AND PRODUCTION FOR SELECTED PLAN

YEAR	NAMEPLATE CAPACITY (MW)	ENERGY PRODUCTION (MWH)
2017	863	1,587,798
2018	1,043	1,919,247
2019	1,223	2,250,696
2020	1,403	2,582,042
2021	1,583	2,913,595
2022	1,810	3,321,828
2023	2,060	3,768,190
2024	2,322	4,233,264
2025	2,580	4,693,241
2026	2,840	5,152,858
2027	3,096	5,607,473
2028	3,341	6,040,240
2029	3,570	6,441,422
2030	3,782	6,811,015
2031	3,990	7,171,049
2032	4,199	7,530,195

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.

At this time, APS does not offer an up-front cash incentive for self-generation. The response provided in Rule D.4 depicts the current outlook for adoption of self-generation. The future of DE penetration is impacted by many factors, and is therefore highly uncertain. See Table D-12 for the renewable energy capacity and production for the selected plan.

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).

Table D-13 shows the forecast of total annual customer costs that may potentially be incurred by customer investments[3] in self-generation for the select plan during the 15-year Planning Period.[4]

RULE D.7

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

The 2017 Resource Plan reflects the estimation of the energy output reflected in this case. The D5 Response Scenario estimates the projected level of self-generation in 2017 through 2032. The development of the D5

3 $/Watt represents the average cost between residential and commercial

4 Capital costs represent new installations per year. O&M costs include costs incurred for installations that occurred in previous years. All costs are in nomial dollars.

Response Scenario was based upon the best information available to APS at the time; however, the future of DE penetration is highly uncertain.

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.

TABLE D-13.FORECAST OF ANNUAL SELF-GENERATION COST INCURRED BY APS CUSTOMERS FOR THE SELECTED PLAN

Base Case				
	CAPITAL		O&M	
Year	$M	$/Watt (ac)	$M	$/kW-yr (ac)
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				

RULE D.8

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

The APS 2017 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 and wind; 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. For more details about the plans considered and the plan selected see Chapter 7 – Plan Selection.

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 D-14.

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 2017 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. 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 non-dispatchable resources such as wind or solar due to their variable nature. Additional operating reserves may be needed to meet system reliability requirements. System integration costs depend upon many factors, including the accuracy of forecasted system loads and variable resource generation at sub-hourly level, penetration level of variable resources, resource mix, and fuel prices. APS commissioned the Northern Arizona University to conduct the APS Wind Integration Cost Study in 2007 and Black & Veach to perform the Solar Photovoltaic (PV) Integration Cost Study in November 2012. APS has updated the integration costs to reflect increased penetration levels of wind and solar in the APS systems and current fuel prices.

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.

TABLE D-14. RENEWABLE ENERGY BENEFITS

TOTAL RENEWABLE				AVOIDED EMISSIONS						
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO2 (Metric Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (lbs)	Avoided Water Usage (Acre-feet)
2017	899	4,272	32	1,729,792	10	219	197	53	8	3,868
2018	916	4,590	34	1,858,673	10	235	211	57	9	4,156
2019	928	4,917	36	1,991,009	11	252	226	62	9	4,452
2020	938	5,251	39	2,126,213	12	269	242	66	10	4,754
2021	950	5,571	41	2,255,710	13	285	256	70	11	5,043
2022	963	5,975	44	2,419,165	13	306	275	75	11	5,409
2023	964	6,358	47	2,574,227	14	326	293	80	12	5,756
2024	977	6,781	50	2,745,534	15	347	312	85	13	6,139
2025	990	7,229	53	2,927,201	16	370	333	90	14	6,545
2026	1,003	7,684	57	3,111,470	17	394	354	96	15	6,957
2027	1,013	8,134	60	3,293,577	18	417	374	102	15	7,364
2028	1,024	8,568	63	3,469,200	19	439	394	107	16	7,757
2029	1,035	8,957	66	3,626,709	20	459	412	112	17	8,109
2030	1,033	9,240	68	3,741,393	21	473	425	116	17	8,365
2031	1,044	9,593	71	3,884,161	22	491	441	120	18	8,684
2032	1,055	9,941	74	4,025,226	22	509	457	124	19	9,000
		Total	**835**	**45,779,260**	**253**	**5,791**	**5,202**	**1415**	**214**	**102,358**

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. As APS adds new natural gas generation to its system, it considers adding generation that is more efficient than previous models. For example, the existing Ocotillo Steam units have full load heat rates of about 10,500 Btu/kWh, and in the modernization project, they will be replaced with state-of-the-art LMS100 combustion turbines expected to have heat rates of approximately 9,100 Btu/kWh. This will significantly increase the efficiency of the site and of APS generation portfolio in general. As APS installs or acquires or contracts for natural gas generation represented in the 2017 Resource Plan, APS will continue to consider high efficiency power plants. Actual models and efficiencies will be determined through a competitive procurement process, and will be selected based on cost efficiency amongst other things (see water below). 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 during the planning period, the new units will likely utilize hybrid wet-dry cooling systems. The goal is to reduce water use without sacrificing needed efficiency or increasing costs. Wet cooling is more cost effective as well as more efficient for electricity production while dry cooling does not use water but is more costly and decreases plant efficiency. Generally, more wet cooling is used in the summer when loads are higher and more dry cooling is used in the other seasons, when loads are lower.

A forecast of the reduction in water intensity measured as gallons per MWh for the Resource Plan is included in the response to Rule D.17. Many of the new technologies represented in the 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

There are currently thirteen EE programs and twenty-two DR programs (including eighteen rates). This included nineteen residential programs and sixteen non-residential programs. These programs are detailed in Attachment D.14(a).

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, APS may request approval of new programs, measures, or pilots 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. APS has currently proposed a number of new technology pilots and programs including the Demand Response, Energy Storage and Load Management program, the Load Management Technology pilot, the Energy and Demand Education program and the DSM T&D pilot.

In planning for the future, APS applies the concepts described in Chapter 2 to develop its long-term DSM plans for the 2021-2032 period. It was assumed that APS would stay in compliance with the Energy Efficiency Standard (EES) with a goal of reducing system energy by 562,000 MWh a year during the next 4 years (2017–2020). Starting in 2021, APS developed long-term DSM goals while balancing the benefits and costs of DSM under various perspectives reflected in the context of the SC and RIM test.

Energy efficiency (EE) technologies similar to those included in the APS 2016 and 2017 DSM Implementation Plans were screened by using the SC test, and only those with load factors in the 0%-30% range, typically summer peak programs, were selected for inclusion in the Base DSM Case. A High DSM Case was also developed with the assumption that high load factor measures included in the 2017 DSM Plan would be maintained for the next 12 years (2021-2032). However, considering that APS expects to have already met the State's aggressive EES of 22% by 2020, it is not known whether APS could continue to achieve such high levels of DSM for an extended period of time. Details of the two DSM cases are provided in Tables D15 and D16 below.

The Base DSM Case includes approximately 50 MW and 91,700 MWh of peak-focused savings a year. The High DSM Case results in approximately 100 MW and 434,300 MWh of savings per year. There is a large disparity between these two DSM plans: whereas the annual MW demand savings differ by a factor of 2 to 1, the annual MWh energy savings differ by a factor of almost 5 to 1 with much of the energy in the Base DSM Case coming only from summer peak periods.

In addition to EE measures accounting for the MW and MWh savings cited above for the two alternate DSM cases, each case has a demand response (DR) program that starts with 25 MW/year in 2021 and amounts to 300 MW in 2032.

The Base DSM Case also has a load shifting program targeting residential loads in the non-summer months. The objective is to shifting 10% of residential loads from on-peak hours to off-peak hours (i.e., clipping the peak and filling the valley). This program will help mitigate impacts of rooftop solar on the system load shapes by reducing the high ramp rates caused by the "duck curve" effects. Both the DR and load shifting programs are expected to result in net zero energy changes.

TABLE D-15. BASE DSM PLAN: DEMAND AND ENERGY REDUCTION/SHIFTING

	Peak Demand Reduction (MW)			Energy Reduction/Shifting (MWh)		
YEAR	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING
2021	50	25	82	91,713	2,000	59,061
2022	100	50	94	183,426	4,000	67,747
2023	150	75	107	275,140	6,000	77,712
2024	200	100	122	367,494	8,000	89,142
2025	250	125	141	458,566	10,000	102,254
2026	300	150	162	550,279	12,000	117,293
2027	350	175	186	641,992	14,000	134,545
2028	400	200	190	734,988	16,000	138,221
2029	450	225	197	825,419	18,000	142,381
2030	500	250	203	917,132	20,000	147,135
2031	550	275	210	1,008,845	22,000	152,291
2032	600	300	216	1,102,482	24,000	157,245

TABLE D-16. HIGH DSM PLAN: DEMAND AND ENERGY REDUCTION/SHIFTING

	Peak Demand Reduction (MW)			Energy Reduction/Shifting (MWh)		
YEAR	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING
2021	100	25	0	434,296	2,000	0
2022	200	50	0	868,591	4,000	0
2023	300	75	0	1,302,887	6,000	0
2024	400	100	0	1,741,284	8,000	0
2025	500	125	0	2,171,478	10,000	0
2026	600	150	0	2,605,773	12,000	0
2027	700	175	0	3,040,069	14,000	0
2028	800	200	0	3,482,569	16,000	0
2029	900	225	0	3,908,660	18,000	0
2030	1,000	250	0	4,342,955	20,000	0
2031	1,100	275	0	4,777,251	22,000	0
2032	1,200	300	0	5,223,853	24,000	0

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) and Light Emitting Diode (LED) bulbs (where APS has sold over 26 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 installed needed to be undertaken to meet its goal for each year on a going-forward basis in the DSM Implementation Plan. Actual 2016 participation on a measure level is provided at Attachment D.14(b).

Projected demand response and time-of-use program participation is forecast in Table D-17 and Table D-18.

TABLE D-17. EXPECTED RESIDENTIAL DR PROGRAM PARTICIPATION

2017 RESIDENTIAL DR PROGRAMS		
Time-Differentiated Rates	Expected Participants	
	2017	15-Year Horizon
1. ET-SP Time Advantage Super Peak[1]	2,427	0
2. ET-1 Time Advantage (9am–9pm)[2]	122,315	7614
3. ECT-1R Combined Advantage (9am–9pm)[2]	23,457	473
4. ET-2 Time Advantage (Noon–7pm)[2]	333,598	24,420
5. ECT-2 Combined Advantage (Noon–7pm)[2]	98,195	1,868
6. ET-EV Experimental Electric Vehicle Charging Rate Schedule1	333	0
7. Peak Event Pricing[3]	414	Unknown
8. Demand Response, Energy Storage, Load Management Program (Proposed)	6,450	Unknown

Notes:

1. APS has filed a request to cancel this rate effective July 1, 2017 in ACC Docket E-01345A-16-0036.
2. APS has filed a request to freeze and limit this rate to only existing customers on the rate with distributed generation effective July 1, 2017 in ACC Docket E-01345A-16-0036.
3. Customers are included in the parent rate schedule.

APS has proposed rates R-1, R-2, and R-3 in ACC Docket E-01345A-16-0036 to replace APS's current TOU offerings.

TABLE D-18. EXPECTED NON-RESIDENTIAL DR PROGRAM PARTICIPATION

2017 NON-RESIDENTIAL DR PROGRAMS		
Time-Differentiated Rates	Expected Participants	
	2017*	15-Year Horizon
1. E-20	400	400
2. E-221-8T	60	59
3. E-32 XS TOU	527	726
4. E-32 S TOU		
5. E-32 M TOU		
6. E-32 L TOU		
7. E-35	37	37
8. GS-Schools M	134	184
9. GS-Schools L		
10. Interruptible Rate	0	Unknown
11. Peak Solutions[1]	769	N/A

Notes:

1. The underlying contract that supports this program expires at the end of 2024.

*Total participants as of December, 2016.

As more cost-effective DSM measures and technologies are identified and new programs such as standby generation, direct-load control, and thermal energy storage pilots are evaluated and deployed, additional customer participation over time is likely. All new programs and/or pilots will estimate identifying long-term customer participation and revised customer offsets per event. As more information becomes available, estimated participation numbers will be included in the APS DSM Implementation Plan filings.

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 D-19 are the capacity and annual energy savings for 2016 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 D-20. The savings represented in the 2017 Resource Plan reflect the 2016 EE and DR program results.

TABLE D-19. ENERGY EFFICIENCY CAPACITY AND ENERGY CONTRIBUTIONS

2016 Residential and Non-Residential EE Programs[1]		
PROGRAM NAME	**CAPACITY SAVINGS (MW)**	**ANNUAL ENERGY SAVINGS (MWH)**
Residential		
Consumer Products	16.3	120,447
Existing Homes HVAC	15.8	21,397
Existing Homes - Home Performance	3.4	6,042
New Construction	4.9	10,220
Appliance Recycling	0	0
Conservation Behavior	12.3	60,433
Multi-Family	1.1	9,567
Prepaid Energy Conservation	0.2	1,243
Limited Income	0.2	996
Residential Sub-Total	**54.2**	**230,345**
Non-Residential		
Large Existing Facilities	33.4	172,672
New Construction	4.4	33,376
Small Business	2.8	15,387
Energy Information Services	2.2	33
Schools	4.1	18,451
Non-Residential Sub-Total	**46.9**	**239,919**
Codes & Standards	10.7	41,539
System Savings	0	4,752
DR Contribution	-	56,213
TOTAL	**111.80**	**572,768**

Notes:
1. Numbers represent peak demand and energy reduction goals, with DR contribution, for 2016 as reported in the APS DSM Annual Progress Report filed with the ACC on March 1, 2017.

TABLE D-20. EXPECTED DR PROGRAM ENERGY AND DEMAND CONTRIBUTIONS

2017 Residential and Non-Residential DR Programs				
PROGRAM NAME	2017		15-YEAR HORIZON	
	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)[1]	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)
Residential				
Future Direct Load Control	N/A	N/A	50	2250[2]
Non-Residential				
Peak Solutions[3]	26	N/A	N/A	N/A
Standby Generation	N/A	N/A	75	N/A[4]
Future Programs	N/A	N/A	N/A	N/A
Unspecified Future Programs	N/A	N/A	125	N/A
Time-of-Use Rates[5]	117	75	N/A	N/A

Notes:

1. Assumes 90 hours of events and 50% snapback; 50 MW x 90 hrs x 0.5 = 2250 MWh
2. Per ACC Decision No. 71436, the credit for demand response and load management peak reductions shall not exceed 10% of the EE standard for any year. Calculation for energy savings shall be calculated at Energy Savings (MWh) = Load reduction MW x 8,760 x 50% load factor.
3. Expires prior to the end of the Planning Period.
4. Standby generation, while it reduces the utility's peak load observed on the system, does not result in less energy consumed by the Customer.
5. Demand reductions are estimated for all current residential rates, and energy reduction is estimated only for ET-SP, CPP-RES and PTR. 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.

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 D-21 provides estimates of 2016 energy efficiency environmental impacts.

The estimated impacts on air emissions for the experimental residential peak event pricing and super peak programs are shown in Table D-22.

TABLE D-21. EE ESTIMATED ENVIRONMENTAL IMPACT

2016 Residential and Non-Residential EE Programs Reduction of Environmental Impact					
	WATER (MIL GAL)	SOX (LBS)	NOX (LBS)	CO2 (MIL LBS)	PM10 (LBS)
Residential					
Consumer Products	381	5,345	101,551	1,080	29,667
Existing Homes - HVAC	88	1,240	23,559	251	6,883
Existing Homes - HPwES	25	353	6,699	71	1,957
New Construction	65	910	17,283	184	5,049
Appliance Recycling	0	0	0	0	0
Conservation Behavior	19	269	5,110	54	1,493
Multi Family	47	655	12,453	132	3,638
Prepaid Energy Conservation	0	6	105	1	31
Limited Income	6	78	1,473	16	430
TOTAL – Residential	**631**	**8,854**	**168,234**	**1,789**	**49,147**
Non-Residential					
Large Existing Facilities	685	9,622	182,823	1,944	53,409
New Construction	160	2,250	42,743	454	12,487
Small Business	56	783	14,879	158	4,347
Energy Information Systems	0	1	14	0	4
Schools	84	1,186	22,530	240	6,582
TOTAL – Non-Residential	**986**	**13,841**	**262,988**	**2,796**	**76,828**

TABLE D-22. ESTIMATED ENVIRONMENTAL IMPACT FROM SELECT RATES AND PEAK SOLUTIONS

2017 Residential Peak Event Pricing and Super Peak Pricing Programs Estimated Reduction in Air Emissions					
	WATER (MIL GAL)	SOX (LBS)	NOX (LBS)	CO2 (MIL LBS)	PM10 (LBS)
Peak Event Pricing	0.21	0.30	56.7	0.60	16.6
Time Advantage Super Peak	0.85	1.19	227.0	2.41	66.3
Peak Solutions	0.31	0.43	82.1	0.87	24.0
TOTAL	**1.37**	**1.93**	**366**	**4**	**106.9**

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).

In Decision No. 73089, APS was ordered "that in all future DSM Implementation Plans, the Company use the same input values and methodology as Staff for calculating the present value benefits and costs to determine benefit-cost ratios."

Table D-23 provides details on the societal benefits, societal costs, and cost-effectiveness of the existing DSM programs.

TABLE D-23. BENEFIT-COST RATIOS FOR EE PROGRAMS

2016 Residential and Non-Residential EE Programs Societal Costs, Benefits and Cost-Effectiveness				
	SOCIETAL BENEFITS ($1,000S)	SOCIETAL COSTS ($1,000S)	NET BENEFITS ($1,000S)	BENEFIT-COST RATIO
Residential				
Consumer Products	$43,924	$21,973	$21,951	2.00
Existing Homes - HVAC	$14,678	$11,682	$2,996	1.26
Existing Homes - HPwES	$3,933	$3,841	$92	1.02
New Construction	$8,688	$7,577	$1,111	1.15
Appliance Recycling	$0	-$78	$78	-
Conservation Behavior	$1,578	$1,524	$54	1.04
Multi Family	4,551	$3,283	$1,268	1.39
Prepaid Energy Conservation	$38	$65	-$27	0.58
Limited Income	$2,521	$2,521	$0	1.00
TOTAL – Residential	**$79,911**	**$52,388**	**$27,523**	**1.53**
Non-Residential				
Large Existing Facilities	$70,717	$50,067	$20,650	1.41
New Construction	$20,370	$8,481	$11,889	2.40
Small Business	$5,703	$3,782	$1,921	1.51
Energy Information Systems	$185	$154	$31	1.20
Schools	$8,653	$8,410	$243	1.03
TOTAL – Non-Residential	**$105,628**	**$70,894**	**34,734**	**1.49**

TABLE D-24. APS PEAK SOLUTIONS BENEFIT-COST RATIO

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 D-25. EXPECTED LIFE OF EE PROGRAMS

2016 Residential and Non-Residential EE Programs Program and Measure Life	
PROGRAM	**YEARS**
Residential	
1. Consumer Products	10.0
2. Existing Homes - HVAC	13.0
3. Existing Homes - HPwES	13.1
4. New Construction	20.0
5. Conservation Behavior	1.0
6. Multi Family	15.4
7. Prepaid Energy Conservation	1.0
8. Limited Income	17.5
Non-Residential	
1. Large Existing Facilities	12.5
2. New Construction	15.1
3. Small Business	11.4
4. Energy Information Systems	4.9
5. Schools	14.4

TABLE D-26. EE PROGRAM COSTS

2016 Residential and Non-Residential EE Programs[1] | Program Costs	
PROGRAM	**COST ($1,000S)**
Residential	
1. Consumer Products	8,395
2. Existing Homes - HVAC	8,710
3. Existing Homes - HPwES	2,064
4. New Construction	5,107
5. Appliance Recycling	(78)
6. Conservation Behavior	1,634
7. Multi Family	2,196
8. Prepaid Energy Conservation	69
9. Limited Income	2,521
TOTAL:	**30,618**
Non-Residential	
1. Large Existing Facilities	20,230
2. New Construction	3,704
3. Small Business	2,169
4. Energy Information Systems	110
5. Schools	5,745
TOTAL:	**31,958**

Notes:

1. MER costs are an additional $1,924,665; the EE Performance Incentive is an additional $4,223,188.

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 D-24.

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 D-25 presents the estimated measure life (in years) by EE program.

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 Table D-26.

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 D-27. In 2016, only 90% of the capacity reduction contracted for was achieved, and the contractor payment is performance based.

TABLE D-27. FORECASTED COSTS FOR APS PEAK SOLUTIONS

Peak Solutions Program Costs	
YEAR	**COSTS ($1,000S)**
2016	[redacted]
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	

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.

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.

As required by the EE Rules, the societal cost test was applied to all measures submitted for approval by APS. If the benefit-cost ratio was not greater than 1.0, the measure was rejected. Table D-28 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 measures listed were not approved due to their not passing the SCT requirement. APS will continue to reevaluate beneficial measures and propose those that improve the DSM portfolio in subsequent DSM filings.

DEMAND RESPONSE PROGRAMS

To date, no specific DR program has been rejected.

TABLE D-28. REJECTED EE MEASURES AND PROGRAMS

Residential and Non-Residential EE Programs –Rejected Measures and Programs				
RULE D.15(A)	RULE D.15(B)		RULE D.15(C)	RULE D.15(D)
DESCRIPTION	PEAK DEMAND SAVINGS (KW/ UNIT)	ENERGY SAVINGS	ESTIMATED COST-EFFECTIVENESS (SCT RESULT)	INCREMENTAL COST ($/UNIT)
Residential				
Clothes Washer Tier 1 (existing)[1]	0.02	163	0.20	$301.20
Clothes Washer Tier 2 (existing)	0.03	202	0.40	$364.46
Clothes Washer Tier 3 (existing)	0.03	232	0.50	$427.72
Clothes Washer Advanced (proposed)[2]	0.04	280	0.70	$467.33
Dishwashers	0.07	13	0.04	$99.66
Energy Star Refrigerators	0.06	243	0.90	$131
Window Film	0.28	527	0.80	$537
Solar Water Heaters	0.40	2,950	0.25	$4,000.00
Smart Strips	0.04	208	0.95	$22.49
In-Unit Linear Fluorescents	0.03	17	0.27	$23.95
Non-Residential				
T12 to Premium T8 ad Electronic Ballast - 8 foot	-	16	0.68	$10.24
HID to 2-lamp T5HO	0.11	359	0.82	$195.69
HID to 3-lamp T5HO	0.15	466	0.94	$223.69
HID to 6-lamp T5HO	0.14	448	0.80	$251.33
Single Phase AC & HP Units	0.01	22	0.94	$13.73
Outside Air Economizer	-	274	0.97	$80.00
Motor Rewind	-	19	0.89	$305.00
Night Covers	-	235	0.72	$40.52
High-Efficiency Ice Makers	0.24	1787	0.83	$665.88
T8 to Premium T8	0.01	67	0.53	$58.31
T12 to T8	0.04	210	0.92	$57.36
Evaporative Fan Motor Controls	-	493	0.53	$245.83
ECM+Control	0.10	1496	0.97	$475.83
Smart Strips	0.06	182	0.56	$79.00
LED Channel Signs	0.01	26	0.60	$10.10
Bid for Efficiency	-	1	0.78	$0.33
LED - Pedestrian Signs	0.10	705	0.88	$238.66
LED Troffers	0.08	299	0.59	$296.03
Coolerado	0.07	137	0.08	$1,100.00
Solar Water Heaters	0.42	3069	0.26	$4,000.00

Notes:
(1) Existing clothes washer refers to clothes washers that are currently available on the market.
(2) Proposed clothes washer refers to the next generation of clothes washers that are not commercially-available today.

RULE D.16

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

In 2016, Concentric Energy Advisors completed a study for APS that analyzed the supply outlook for natural gas and gas infrastructure. As part of this study, coal generation outlook, gas and renewables generation, regulations and cost competitiveness were analyzed for the Southwestern U.S. (including Mexico), and on a national level. The study period was 2016-2025 and this effort informed the preparation of the 2017 Integrated Resource Plan filing. Concentric's supply and demand outlook for the North American gas and energy infrastructure covered the technological, environmental, and economic factors driving the expectations for fuels and infrastructure of significant interest to APS: natural gas, gas pipelines, renewables, and impacts to coal generation. In addition to the report providing an outlook for North America (48 states and Mexico) 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) sub-region.

Natural gas supply includes existing contract capacity, future extension of existing contracts, additional seasonal and annual contracts as well as short term contracts. All APS natural gas contracts are firm fixed delivery to assure adequate gas supply for peak seasonal demands. The natural gas supply and demand analysis was used to assess the APS gas use projection and gas infrastructure portfolio to ensure that current and future generation needs are fully met. This analysis was an input to APS resource planning effort. This assessment is designed to project peak seasonal natural gas use and identify the supply of gas for each of these seasonal peaks during the Planning Period. An example of this analysis can be found in Attachment D.16.

Based on these studies, APS reaffirms that the ongoing practice of procuring firm fixed gas fuel delivery contracts is appropriate and adequately addresses potential fuel supply and delivery during the Planning Period. See Rule E(f) for more information about future fuel supplies.

RULE D.17

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

Plans to reduce environmental impacts related to air emissions and solid waste are provided in Figure D-1. Regulations impacting water and a plan for reducing impacts are included in Figure D-2.

FIGURE D-1. PLAN FOR REDUCING AIR AND SOLID WASTE ENVIRONMENTAL IMPACTS

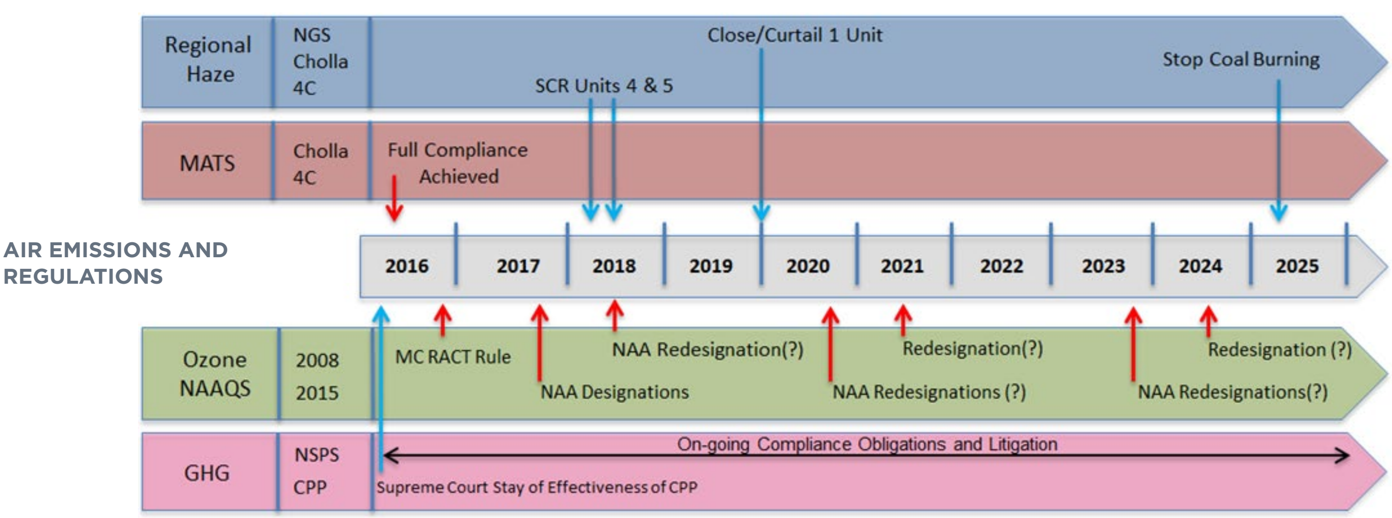
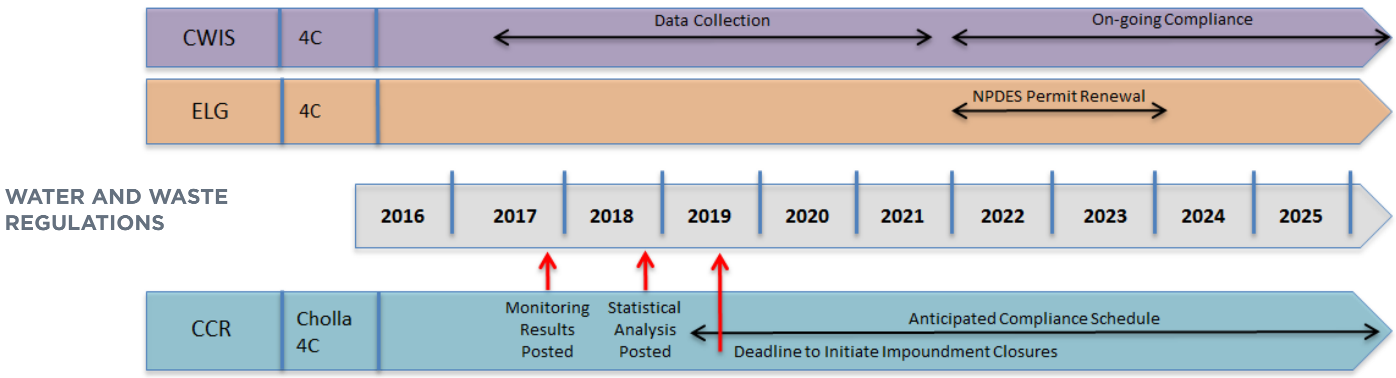


FIGURE D-2. REDUCTION OF ENVIRONMENTAL IMPACTS TO WATER



COMPANY RESPONSE TO CLIMATE CHANGE INITIATIVES

APS has undertaken a number of initiatives to address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency.

APS prepares an inventory of GHG emissions from its operations. This inventory is reported to EPA under the EPA GHG Reporting Program and is voluntarily communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on the Pinnacle West website (www.pinnaclewest.com). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance.

EPA ENVIRONMENTAL REGULATIONS

REGIONAL HAZE RULES

In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal lands, EPA) to develop plans to achieve natural visibility conditions by 2064. The first planning period during which the regional haze rules were required to be implemented occurs between 2008 and 2018. The most impactful provisions of the rules was the requirement to determine what pollution control technologies constitute the Best Available Retrofit Technology (BART) for certain older major stationary sources. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis. The second planning period begins in 2018, but the plans that will demonstrate continued progress toward the goal of natural visibility conditions will not be submitted to EPA until July 31, 2021. It is possible that additional air pollution control technologies will be required to further reduce visibility impairing air pollution.

Cholla BART

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA partially approved and partially disapproved the State's BART determinations, and imposed its own sulfur dioxide (SO2) removal efficiency requirement and oxides of nitrogen (NOx) emissions limitations within a Federal Implementation Plan (FIP). In order to comply with the new limits, APS would have been required to upgrade the SO2 scrubbing efficiency and install selective catalytic reduction (SCR) technology on Units 2 and 3. The state of Arizona, APS, and others sued EPA over this determination, along with other related-BART determinations. Concurrent to the litigation, APS offered an alternative BART Reassessment, which was premised on a commitment by APS shut down Unit 2 in 2016 and either shutdown the other units by April of 2025 or convert them to natural gas while operating at no more than a 20% capacity factor. In exchange for this commitment, Unit 3 could continue operation without SCR.

On October 22, 2015, the state of Arizona submitted a State Implementation Plan Revision to EPA for approval that contained this alternative BART Reassessment. Public comment on EPA's proposed approval of the alternative BART Reassessment closed on September 1, 2016, and a final action was signed by former EPA Administrator Gina McCarthy on January 13, 2017. On March 27, 2017, the final rule containing the Cholla BART Reassessment was published in the Federal Register and took effect.

Four Corners BART

On August 6, 2012, EPA issued its final BART determination for Four Corners. On December 30, 2013, on behalf of itself and the Four Corners co-owners, APS notified EPA that the co-owners selected the BART alternative, which required APS to permanently shut down Four Corners Units 1-3, and install and operate SCR control technology on Units 4 and 5 by July 31, 2018. EPA also required a 95% SO2 removal rate, which requires some upgrades and restorations to the Flue Gas Desulfurization (FGD) systems. Consistent with this alternative, APS retired Units 1-3 on December 30, 2013, and permanent decommissioning of those facilities is complete. The addition of SCRs necessitated the addition of a Dry Sorbent Injection system to remove sulfuric acid mist created in the SCRs. Upgrades and restorations to the FGD systems and installation of the SCR control technology are underway and on schedule.

Navajo BART

EPA accepted SRP's proposal for an alternative to BART, which provides the Navajo Plant with additional time to install the SCR technology. Under this "better-than-BART" alternative, the Navajo Generating Station participants are required to shut down one unit or curtail the equivalent of one unit by January 1, 2020 and install SCR technology on the two remaining units by December 31, 2030.

MERCURY AND OTHER HAZARDOUS AIR POLLUTANTS

On December 16, 2011, EPA issued the final Mercury and Air Toxics Standard (MATS) rule, which established maximum achievable control technology (MACT) standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired power plants. APS has met all of its regulatory obligations for installing activated carbon injection on Units 1 and 3 at Cholla. Four Corners Units 4 and 5 were able to meet the mercury limit with existing equipment. Both facilities are fully compliant with the applicable emissions limitations.

COOLING WATER INTAKE STRUCTURES

EPA issued its final cooling water intake structures rule on August 15, 2014, which provides national standards applicable to certain cooling water intake structures at existing power plants and other facilities pursuant to Section 316(b) of the Clean Water Act. The rule is intended to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). The rule requires existing facilities such as Four Corners and Navajo Generating Station that use surface water to comply with the impingement mortality requirements as soon as possible, but in no event later than eight years after the effective date of the rule. Cholla is not impacted because its cooling water is supplied from well water. Existing facilities subject to the rule are required to comply with the entrainment requirements as soon as possible under a schedule of compliance established by the permitting authority.

COAL COMBUSTION RESIDUALS (CCR)

On December 19, 2014, EPA issued its final regulations governing the handling and disposal of Coal Combustion Residuals (CCR), such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit the pond with a liner, or close. All CCR landfills or surface impoundments that cannot meet the applicable performance criteria for location restrictions or structural integrity are required to close. The provisions of this rule are self-implementing and currently rely upon citizens lawsuits for enforcement of its requirements.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete production. The known impacts of the rule are to initiate closure of two impoundments at Four Corners on or before June 17, 2019. In compliance with the requirements of the rule, APS is conducting on-going groundwater monitoring at both locations. All monitoring results are required to be made publicly available through a company controlled website on or before October 17, 2017 and must update this information annually until 30 years after the closure of the ash ponds or dry storage areas. A statistical analysis of the collected data and an analysis of any required remedial actions must be completed and posted to the same website on or before October 17, 2018.

On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation (WIIN) Act into law. This act contains a number of provisions that require EPA to modify the self-implementing provisions of the Agency's current CCR rules. Specifically EPA is provided with the authority to directly enforce the CCR rules through the use of administrative orders and, pending congressional appropriation, the obligation to develop a federal permitting program. EPA was also provided the authority to delegate permitting authority to the States through the approval of a state-proposed permitting program. Because EPA has yet to undertake implementation of the CCR provisions of the WIIN Act, and Arizona has yet to determine whether it will develop a state-specific permitting program, it is unclear what effects the CCR provisions of the WIIN Act will have on APS's management of CCR.

EFFLUENT LIMITATION GUIDELINES

On September 30, 2015, EPA finalized its revisions to the effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil fuel-fired Electric Generating Units (EGUs). The final regulation is intended to reduce metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero-discharge" from fly ash and bottom ash handling, and impoundments for coal ash disposal leachate. Compliance with these limitations will be required as a part of the plant's National Pollution Discharge Elimination System (NPDES) permit which renews in five year intervals. The NPDES program only impacts the Four Corners power plant. APS anticipates renewing the NPDES permit for the Four Corners plant between 2018 and 2023. Until a draft NPDES permit for Four Corners is proposed, APS is uncertain about what additional controls, if any, might be required to ensure that discharges from the facility are in compliance with the finalized effluent limitation guidelines.

OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

On October 26, 2015, EPA adopted a new ozone NAAQS and set it at 70 parts per billion. This decision was legally challenged by various industry organizations, yet supported by various states and environmental groups. The lawsuit is currently on-going. During this time, both the 2008 and the 2015 ozone NAAQS remain in effect.

In accordance with Clean Air Act requirements, on September 27, 2016, the state of Arizona made an initial recommendation that EPA classify the air quality in portions of Gila, Maricopa, and Pinal counties (e.g., Phoenix area) as a single non-attainment area, and a portion of Yuma County as a separate non-attainment area. The recommendation also suggested three other data-contingent alternatives for the Phoenix area. EPA is required to make a final decision regarding the classification of air quality in Arizona by October 1, 2017.

In order to meet the Clean Air Act requirements for implementing the 2008 ozone standard, the Phoenix area was reclassified as moderate nonattainment, compelling the Maricopa County Air Quality Department to adopt new Reasonably Available Control Measures to reduce air pollution that leads to the formation of ozone. On November 2, 2016, County Rule 322 was revised to reduce emissions of nitrogen oxides and volatile organic compounds from fossil generation units. APS anticipates that it will need to install Dry Low NOx burners on West Phoenix CC 1 & 2 in order to comply with the provisions of this rule.

Given the Clean Air Act's requirements and the legal challenges to the 2015 ozone standard, APS will not know whether similar rules will be required for the Yucca Generating Station in Yuma County until 2020.

In addition to requiring existing sources of nitrogen oxides and volatile organic compounds to improve their air pollution controls, the process for obtaining new air quality permits in these areas is likely to become more stringent. New and modified major sources of these pollutants will be required to install the most stringent air pollution controls available and remove (offset) more air pollution than the facility is allowed to emit. Both requirements will increase the cost of potential future projects at APS facilities located within these non-attainment areas.

FOUR CORNERS CONSENT DECREE

In August 2009, APS responded to a request from EPA seeking detailed information regarding projects at and operations of Four Corners pursuant to Section 114 of the Clean Air Act. This request was part of an enforcement initiative that EPA had undertaken under the New Source Review (NSR) provisions of the Clean Air Act. APS denied and continues to deny the allegations brought by EPA and other environmental groups, but did agree that settlement of the action was in the best interest of all of the Parties and the public interest. On August 17, 2015, APS entered into a Consent Decree that supplemented measures Four Corners had planned to implement for compliance with the 2012 BART determination. In addition to agreeing to the BART emission reduction requirements for nitrogen oxides and SO2, APS agreed to particulate matter emissions reductions requirements, the installation and certification of a particulate matter continuous emissions monitors, and three environmental mitigation projects within the Navajo Nation. The provisions of the Consent Decree do not terminate until at least December 31, 2021.

WATER SUPPLY

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's plan for reducing water consumption includes the following actions:

- Employment of alternative cooling technologies for new generating resources
- Improving the efficiency of water use during the planning period
- New power plant construction, water saving alternatives
- Retirement of existing power plant generating units, associated water savings
- Reduce quantity of non-renewable groundwater consumed
- Improve the efficiency of water utilization at APS's existing facilities
- Increase 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 O&M 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. APS has a commitment to maximize use of renewable effluent and surface water and minimize use of non-renewable groundwater. Between 2016 and 2026, our goal is to reduce our groundwater use from about 13% to 6.5%. More information on water use can be found in Chapter 5.

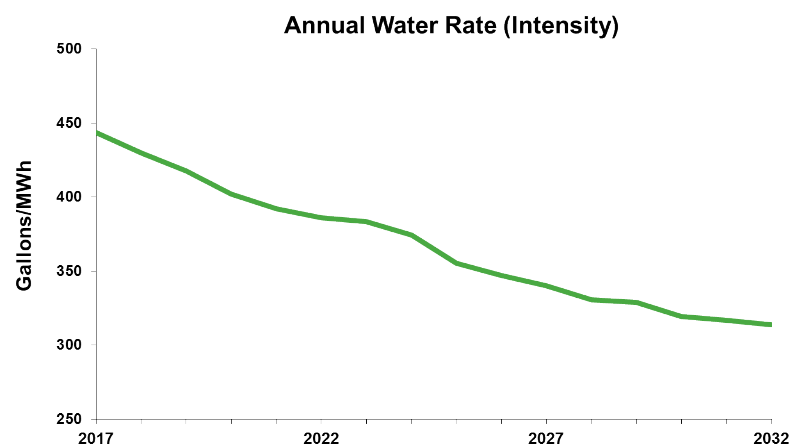
IMPROVING THE EFFICIENCY OF WATER USE DURING THE PLANNING PERIOD

Even though energy consumption is forecast to significantly increase during the Planning Period, water consumption will only see a minimal increase and due to the energy efficiency and renewable energy resources envisioned in the 2017 Resource Plan, the rate of water usage declines dramatically over the course of the Planning Period. This can be seen in Figure D3, which shows a decline in water intensity from 444 gallons/MWh in 2017 to 314 gallons/MWh in 2032.

NEW POWER PLANT CONSTRUCTION, WATER SAVING ALTERNATIVES

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 20 gallons/MWh as compared to wet-cooled combined cycle plants such as Redhawk, which use approximately 295 gallons/MWh.

FIGURE D-3. ANNUAL WATER RATE (GALLONS/MWH)



APS, in conjunction with SRP and Tucson Electric Power Company performed a detailed estimate of the equipment cost for an air-cooled condenser and determined the cost difference to be about $60 million based on a nominal 600 MW combined cycle power plant constructed in the Arizona desert.

RETIREMENT OF EXISTING POWER PLANT GENERATING UNITS, ASSOCIATED WATER SAVINGS

RETIREMENT OF FOUR CORNERS UNITS 1-3

In addition to evaluating alternative cooling technologies, further reductions in regional water consumption were achieved through the retirement of Four Corners Units 1-3, effective December 30, 2013. Retirement of these three units saves approximately 4,000 – 6,000 acre-feet of water annually.

RETIREMENT OF CHOLLA UNIT 2

Cholla Unit 2 was retired effective October 1, 2015 resulting in a decrease of approximately 3,000 – 4,000 acre-feet annually. Cholla remains the largest user of non-renewable groundwater in the APS fleet; however, APS has committed to cease coal generation at that site in 2025.

REDUCE QUANTITY OF NON-RENEWABLE GROUNDWATER CONSUMED

In 2016, APS developed and implemented a new Tier 1 metric designed to reduce consumption of non-renewable groundwater by 8%, compared to the reference year of 2014, which exceeded our 2016 target. Further reductions are planned in 2017 (10%) and in 2018 (12%). This metric will be achieved by retiring older water-intensive units and replacing them with more efficient units, by implementing water conservation measures at APS plants, and increasing reliance on RE and DE.

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 Palo Verde Nuclear Generating Station, which not only uses reclaimed wastewater effluent as its cooling water source, but has focused on continual improvement in water treatment and operations to achieve over 23 cycles of concentration (on average) through the cooling water system. Redhawk also operates its cooling system using reclaimed water. In 2016, 74% 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 its Water Resource Planning 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 Resource Planning 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 assess the impacts of various decisions and scenarios.

APS has performed modeling of groundwater withdrawals and evaluated potential impacts of the withdrawals, and has developed wellfield management plans at the largest water consuming plants to enable more efficient use of the resource.

APS has also become more integrated into the Arizona water community. Participation in the U.S. Bureau of Reclamation's Colorado River Basin Study Group, the Joint Legislative Committee on Water Salinity Issues, the Arizona Department of Water Resources' (ADWR) Water Resources Development Commission, the governor's Blue Ribbon Panel on Water, and the Central Arizona Project's Acquisition, Development and Delivery Water program are five examples of activities where involvement is enabling improved communication with other water stakeholders, including regulators, municipalities, agricultural users, and other industries. APS is 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 is the primary mechanism for public comment and review during ADWR's development of the Phoenix AMA's Fourth Management Plan. APS is a supporter of the Kyl Center for Water Policy, a research analysis and collaboration entity at the Morrison Institute for Public Policy at Arizona State University, promoting sound water policy and stewardship in Arizona. This integration into the broader water community has opened communication and facilitated partnering opportunities for the future.

ENERGY EFFICIENCY AND RENEWABLE ENERGY RESOURCES

Demand-side management programs and renewable energy resources generally consume little or no water. The expansion of these programs in the 2017 Resource Plan contributes to a reduction in water consumption per MWh over the Planning Period.

RESPONSE TO RULES

SECTION E

Risk

2017

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 E-1 illustrates the results of a probabilistic approach.

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

TABLE E-1. PROBABILISTIC ANALYSIS OF PEAK DEMAND FORECAST

APS System Peak Demand Forecase (Probabilistic Analysis)								
PERCENTILE	2017	2018	2019	2020	2021	2022	2023	2024
10th	6,620	6,673	6,801	6,902	7,080	7,302	7,404	7,627
20th	6,709	6,787	6,912	7,057	7,228	7,457	7,606	7,827
30th	6,782	6,868	6,998	7,141	7,344	7,569	7,742	7,964
40th	6,840	6,937	7,075	7,225	7,421	7,676	7,857	8,094
Forecast	6,873	7,003	7,127	7,290	7,499	7,749	7,980	8,198
60th	6,948	7,055	7,216	7,390	7,593	7,862	8,086	8,305
70th	6,999	7,128	7,292	7,478	7,702	7,962	8,210	8,440
80th	7,077	7,212	7,381	7,584	7,789	8,067	8,330	8,560
90th	7,188	7,331	7,517	7,684	7,940	8,234	8,515	8,811

APS System Peak Demand Forecase (Probabilistic Analysis)								
PERCENTILE	2025	2026	2027	2028	2029	2030	2031	2032
10th	7,788	7,984	8,154	8,446	8,540	8,742	8,952	9,209
20th	8,049	8,229	8,440	8,693	8,858	9,044	9,255	9,533
30th	8,195	8,412	8,646	8,877	9,078	9,277	9,510	9,786
40th	8,297	8,552	8,788	9,051	9,275	9,472	9,739	9,983
Forecast	8,449	8,695	8,941	9,197	9,447	9,666	9,965	10,239
60th	8,550	8,841	9,098	9,364	9,605	9,864	10,154	10,420
70th	8,682	8,985	9,259	9,507	9,800	10,043	10,355	10,634
80th	8,850	9,153	9,411	9,712	10,015	10,288	10,636	10,920
90th	9,090	9,410	9,654	10,030	10,345	10,613	11,000	11,317

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 exceed 110°F. In the last ten years, the temperature on peak day has been as high as 118°F and as low as 113°F. The 90th percentile is 116°F. Temperatures 2°F above the 10 year average of 114°F can add nearly 200 MW to peak.

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 and deployment 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 2.5%.

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 in several ways. The Company has the ability to add short-lead-time resources, including battery storage 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 do 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 is able to buy and sell capacity and electricity 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. 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 financial, 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. 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 dispatch 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 construction cost- and fuel cost-related risks and uncertainties are addressed in subsequent sections.

Other risks associated with costs of power supply involve surplus or shortfalls in meeting reserve requirements. APS manages three types of reserves at three different time intervals: planning reserves – these are the reserve requirements calculated at annual timescales and encapsulated in Attachment F.9(b) line 3; contingency reserves – these are made up of spin- and non-spin reserves and are managed on an hourly basis, and; frequency response reserves – these are managed at a sub-minute level and help to maintain frequency on the regional transmission system after contingencies. Surplus and shortfalls in any of these categories can bring about financial risk in terms of surplus variable or capacity costs, if reserves are in surplus, or risk of overpaying during states of emergency or from paying fines for failing to meet requirements, if reserves are too low. Surpluses and shortfalls are also affected by regional availability of capacity resources.

Though APS has always had cost risk related to surplus or shortfalls in reserve requirements, solar penetration has increased the magnitude of risk related to contingency and frequency reserve requirements and distributed generation has added an element of uncertainty when developing planning reserves. Descriptions of these three risks follow:

Frequency Reserves –Cost risk can occur when frequency reserves are in surplus (but reliability is higher) or below minimum requirement levels. APS strives to balance reserve costs and reliability. Operations disruptions from unplanned generation or transmission line outages – have historically posed the greatest challenges. However, more recently, intermittency related to solar generation adds an additional level of cost risk as generation output can vary at short time intervals due to cloud movement.

Contingency Reserves – Likewise, power supply cost risk may result from forecast error. APS utilizes various forecasting tools to minimize risks to over- or under-generation. These forecasts include demand, weather and load- and utility-side renewable production. The potential magnitude of load- and utility-side renewable production forecast error is expected to increase with additions of wind and/or solar to the APS system.

Planning Reserves – APS targets a 15% planning reserve margin in order to have the available capacity to cover needed frequency and contingency reserves for our balancing area.

RULE E.2(B)

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

DEMAND MANAGEMENT MEASURES

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. The results of the most current analyses are provided in Rule D.14.

POWER SUPPLY

Specific methods to manage construction cost and fuel cost-related risks and uncertainties of the costs of power supply are addressed in subsequent sections.

Real-time operations power supply cost risks have traditionally been managed through NERC reliability requirements. Many compliance costs associated with these NERC requirements have been managed through APS's participation in regional reserve sharing groups, such as the Southwest Reserve Sharing Group. Continued increases in the amount of intermittent generation, such as wind and solar, on the electric grid are expected to increase frequency and contingency reserve-related costs. APS employed Black and Veatch to analyze solar integration costs and Northern Arizona University to analyze wind integration costs in order to quantify cost impacts related to carrying additional operations reserves. These analyses are discussed in more detail in response to Rule D.11. As a general rule, integration costs increase with increased levels of solar and/or wind penetration. Integration costs increase because the magnitude of potential power supply disruptions increase with more MW of solar and/or wind.

Power supply cost impacts related to forecast error is often situation dependent and are expected to increase with increasing additions of solar and wind generation. APS analyzes weather, load and renewable forecasts on a daily basis and analyzes patterns so that forecasts can be improved. Renewable production forecasting is a relatively new practice and therefore renewable production forecast practices throughout the industry are expected to advance during the Planning Period.

Planning reserve cost impacts depend upon the magnitude and direction of the difference in annual forecasted distributed energy additions and actual.

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 a 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. APS uses cost tests to rank DSM programs in order of effectiveness in reducing peak. Annually, APS seeks to manage EE program costs by exploring innovative incentive models, creating additional technology options, and conducting Measurement and Evaluation Research (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.

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

Risk mitigation plans for construction cost- and fuel cost-related risks and uncertainties are addressed in subsequent sections.

To mitigate the risks associated with forecast error-related 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, load-side renewable production, and utility-side renewable production 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.

To mitigate risks associated with renewable forecast error, APS actively assesses forecast error, scans relevant available industry sources, consults renewable forecast providers, and participates in various renewable energy forecasting forums in order to improve its methodologies.

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. Additionally, planning reserve margins and distributed energy MW additions are assessed several times a year.

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 (surplus reserve 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 to 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 Rule E.3(a), APS plans to carry a minimum 15% planning capacity reserve requirement that helps ensure sufficient power sources are available. APS's capacity reserve requirement for 2017 is 961 MW, as shown on line 3 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 2017 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 2017 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 2017 Resource Plan, APS could choose to contract with or purchase available market generation, or construct new combustion turbines or combined cycle units. There are currently four market generators located near the Palo Verde Hub with a total of over 3,000 MW of capacity. This market capacity could potentially fill some of the natural gas generation needs identified in the 2017 Resource Plan by 2032. 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:

- Capital and O&M costs pertaining to existing regulations are subject to cost increases triggered by inflation 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 UNCERTAINTY PERTAINING TO REGIONAL HAZE REGULATIONS (BART)

EPA published a rule regarding regional haze, which includes decreasing NOx, SO2, and PM emissions at the Four Corners and Cholla Power Plants. Low NOx Burners and Over-fired Air were installed in 2007-2009. As an alternative to the SCR's EPA demanded, APS offered to shut down Unit 2 by October 2015 and either shut-down or convert the other units to natural gas by April 1, 2025 if EPA agrees to Low NOx Burners and Over-fired Air. EPA has reviewed and accepted the revised state implementation plan (SIP).

On December 30, 2013, APS, on behalf of itself and the other co-owners, notified EPA that they had selected the alternative BART compliance strategy for the Four Corners facility, which required the closure of Units 1-3 by January 1, 2014 and installation of SCR controls on Units 4 and 5 by July 31, 2018. The risk for additional costs from BART at Four Corners lies mainly in the cost estimate for economizer bypasses and reagent usage. If the economizer bypass costs are at the high end of the range, capital costs could increase by $12M. Increased reagent usage could increase O&M by $5.4M per year to $6.5M per year. Also, there is a potential of high volatility in the urea market. APS is negotiating a long-term contract that would stabilize the price, but it has not been finalized.

On September 25, 2013, EPA issued a supplemental rule proposing additional alternatives to BART at the Navajo Generating Station (NGS). Under the rule, installation of BART controls at NGS are delayed until December 31, 2030. This alternative would require the permanent closure of one of the units or curtailment of generation by a similar amount at the Navajo Plant by January 1, 2020 and installation of SCR's on the remaining two units by December 31, 2030. The cost to APS for SCR's and Fabric Filters is $161M. The biggest risk to increases in BART compliance costs at Navajo would be if future regulations accelerated this schedule.

ANALYSIS OF UNCERTAINTY PERTAINING TO MERCURY AND AIR TOXICS STANDARDS (MATS) REGULATIONS

In 2012, EPA finalized new regulations to control mercury and other hazardous air pollutants (HAPS). Coal units are most affected by this rule. Activated Carbon Injection was installed on Units 1 and 3 at Cholla in 2014. The addition of SCR controls at Cholla would complicate matters as they can convert SO2 to SO3, which can interfere with the effectiveness of activated carbon for mercury control. Reagent usage at Cholla could increase from $0.7M per year to $1.1M per year.

It appears that reagent will not be required at Four Corners to control mercury emissions. APS is in the process of upgrading flue gas desulfurization (FGD) systems to improve mercury and SO2 control. Mercury excursions at start-up could prompt the addition of a re-emission chemical to the FGD's. If it turns out that a re-emission chemical is required, APS's share of total capital costs to comply with the MATS rule at Units 4 and 5 could increase by $1.2M and re-emission chemical usage could be $1.7M per year.

ANALYSIS OF RESOURCE CONSERVATION RECOVERY ACT (RCRA) SUBTITLE D

EPA proposed to regulate for RCRA under Subtitle D (non-hazardous), but with some very stringent requirements. The RCRA's hazardous waste regulations would result in the regulation of many aspects of power plant operations at Four Corners, Cholla, and the Navajo Plant, not just the coal combustion residual (CCR) disposal operations. Under the Subtitle C 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 CCR) and convert all CCR handling systems to dry handling and dispose of CCR in engineered, lined landfills at both APS operated plants (Four Corners and Cholla).

APS is in the process of closing several impoundments and will have to build several new ones. This regulation includes monitoring and reporting requirements. The uncertainty of the cost of compliance is mainly related to additional impoundments that may have to be closed in a very short time period if monitoring results indicate seepage of certain substances.

The plants would also be required to obtain federal permits for the handling and disposal of CCR, and all CCR handling operations would be required to meet hazardous waste requirements. The current estimate for closure of fly ash and bottom ash ponds at Cholla is $16.2M. If there are difficulties, or the schedule has to be accelerated for any reason, or the plant shuts down early (being unable to use reclaim from the ponds), this cost could increase significantly.

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 RCRA, it is possible that APS may not be able to continue to market fly ash for beneficial reuse. In such an event, APS would have to dispose of the material in permitted landfills.

If certain wells test high in regulated chemicals, APS's share of the capital costs at Cholla could increase. The largest portion of the O&M cost increase at Cholla could arise from the inability to sell fly ash due to the risk of future hazardous categorization and the subsequent need to dispose of that ash.

Similarly, if certain wells test high in regulated chemicals, APS's share of the capital and O&M costs at Four Corners could increase. Again, the largest portion of this O&M cost increase would result from the inability to sell fly ash due to the need to dispose of that ash as a hazardous waste.

ANALYSIS OF UNCERTAINTY PERTAINING TO NATIONAL AMBIENT AIR QUALITY STANDARD (NAAQS) REGULATIONS

EPA has established a new NAAQS for ozone. Arizona and Maricopa County now have to establish SIPs to get air quality down to the new standard. It is difficult to estimate the impact of new standards on APS's system until the State and County finalize their plans. With respect to coal plants on which SCR controls are required under BART, it is unlikely that any additional NOx controls will be required during the first regional haze planning period, which will end in 2018. However, there is a possibility that SCR or Dry Low NOx controls may be required on some of the natural gas combustion turbines in Maricopa County. Capacity factor will likely be a significant factor in deciding which units would require the installation of new controls. Because APS's higher capacity factor combustion turbines already have SCR controls, there are only a few existing units that might be at risk. The risks are that Maricopa County might require controls on more combustion turbines than anticipated or might require a higher level of control than anticipated.

ANALYSIS OF UNCERTAINTY PERTAINING TO NEW SOURCE REVIEW (NSR) REGULATIONS

Under the NSR rules, a project at an existing unit triggers pre-construction permitting and additional control requirements if it is a physical or operational change that would result in a significant net emission increase. Projects considered to be "routine maintenance, repair, and replacement" are categorically excluded. In the late 1990s, EPA started an NSR "enforcement initiative" against the utility industry. The enforcement actions are based on a theory of universal liability, under which every utility in the nation has violated NSR repeatedly in the past three decades, in virtually every outage that involved major repairs and replacements. EPA asserts in the enforcement cases that "routine" must be judged by reference to activities commonly undertaken at the specific unit in question, so any boiler component replacement project of substantial size is not "routine," because it occurs only once or twice in the life of any unit. On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners co-owners alleging NSR violations. In conjunction with BART, APS reached an agreement with EPA to put SCR's on Units 4&5 and shut down Units 1-3, and resolve all NSR issues. There is still the possibility of new alleged NSR violations at Four Corners. Because of the breadth of controls already installed at these two plants, it is likely that the impact will be minimal.

ANALYSIS OF UNCERTAINTY PERTAINING TO GREENHOUSE GAS (GHG) NEW SOURCE PERFORMANCE STANDARDS (NSPS) REGULATIONS

On September 20, 2013, EPA proposed an NSPS for emissions of CO2 for new affected fossil fuel-fired electric utility generating units. On August 3, 2015, EPA proposed standards of performance for GHG emissions from existing power plants. Among other things, EPA proposed GHG regulations that dictate which units in a utility system will run. Several states, utilities, and other organizations have sued EPA over this rule arguing that it is outside EPA's authority under the law they are regulating under. There is a risk that a court would agree with EPA and allow them to enforce this system approach to GHG's.

ANALYSIS OF UNCERTAINTY RELATED TO EFFLUENT LIMITATION GUIDELINES (ELG)

The Clean Water Act (CWA) regulates discharges to "waters of the U.S." through water quality standards and technology-based standards. Effluent Limitation Guidelines (ELG) are technology-based standards developed by EPA on an industry-by-industry basis. The CWA requires EPA to review periodically and revise these standards as appropriate. On November 3, 2015, EPA finalized revised ELG wastewater discharge limitations for fossil-fired electric generating units. ELG targets metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and non-chemical metal cleaning wastes operations.

The ELG will impact the 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. West Phoenix and Ocotillo are permitted to discharge into municipal sewer systems, which are in turn permitted to discharge directly into a water of the U.S. In addition, West Phoenix is permitted to discharge directly into an adjacent irrigation canal, but as a normal practice does not use this discharge point.

Revisions to the ELG could impact the discharge limits at APS Four Corners, West Phoenix, and Ocotillo power plants. Accordingly, these plants may be faced with increased capital and O&M expenses to achieve and maintain compliance. APS's share of the ELG compliance costs at Four Corners is currently estimated to be approximately $6-20M for capital and $0-2.7M per year for O&M. ELG requirements are to be rolled up into a plant's National Pollution Discharge Elimination System (NPDES) permit. Four Corners currently has a permit being processed. If that permit is issued as scheduled, changes for ELG will not have to be incorporated for another five years. ELG impacts at West Phoenix and Ocotillo are expected to be minor.

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 and 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. A key component is flexibility which is supported by our participation in the California ISO EIM and with the Ocotillo Modernization Project.

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 and state agencies and third-party consulting firms to maintain awareness of proposed changes and to evaluate commercially-viable options for technology:**

For example, APS used Black & Veatch, a global engineering consulting firm, to provide the initial evaluation and subsequent updates for commercially-viable technology required for SCR controls installation at the Four Corners Power Plant, 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 the Utility Air Regulatory Group are two organizations in which APS participates as members of committees involved with environmental control technologies. Membership in these committees also provides contacts at other utilities who can share their experiences with us.

- **Negotiate solutions with government agencies that balance cost and compliance:**

APS worked with the EPA to develop a solution for controlling NOx and SO2 emissions at the Cholla and Four Corners Power Plant, which balanced 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 2017 Resource Plan, APS is managing the risk of environmental regulations by 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.

- **Analyze portfolio cost risks related to existing and expected environmental regulations:**

APS includes the Flexible Resources, Carbon Reduction and Resource Mandates Portfolios in order to measure cost impacts of various levels of compliance with MATS, BART and potential CO2 legislation. Results from these analyses will help APS evaluate future emission control investment strategies.

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 in the response to Rules D.17 and E(d). In addition, an implementation plan was included in response D.17 which identified the potential technology and time frame for design and installation based on the most current information available as of February 2017. As previously discussed, 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 of which APS is currently aware, there are potential new regulations, such as another round of regional haze rules (a new EPA long-term strategy planning period starts in 2019) and GHG regulations, which 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 CO2 CAPTURE AND SEQUESTRATION (CCS) REGULATIONS

On August 3, 2015, EPA finalized a New Source Performance Standard (NSPS) to limit emissions of carbon dioxide (CO2) for new coal plants and natural gas combustion turbines. The rules for new coal-fired units would require the installation and operation of Carbon Capture and Sequestration (CCS) technology and are cost prohibitive. The rules for new natural gas units are based on high efficiency combined cycle units. Low capacity factor combustion turbines, including simple cycle units, are exempt. APS anticipates constructing simple cycle natural gas combustion turbines during the planning period, but they are expected to have a low capacity factor and thus not be affected by the NSPS.

On August 3, 2015, EPA also finalized the Clean Power Plan (CPP) to reduce emissions of CO2 from existing electricity generating units by setting a carbon dioxide emissions reduction goal for each State or Tribe's electricity generating facilities. These goals could be met through a combination of the following emission mitigation measures: more efficiently producing electricity, voluntarily shifting power production from high (coal and oil) to low (natural gas) or zero (nuclear, renewable) sources of carbon dioxide, improving end user energy efficiency, and increasing electricity generation from renewable sources. EPA's final rule was appealed to the U.S. Court of Appeals for the District of Columbia Circuit, who initially denied motions to stay the effectiveness of the rules. After an appeal of that court's stay decision, though, on February 9, 2016 the U.S. Supreme Court granted an immediate halt federal efforts to implement the CPP until the judicial proceedings challenging the regulations are fully completed. The State of Arizona has stopped all work on the CPP and will restart proceedings after the legal uncertainty has been resolved. Adding to the uncertainty is the Trump administration's expressed intent to roll-back the Obama Administration's Climate Action Plan, which includes the CPP. The exact scope and extent of the Trump Administration's regulatory roll-back effort remains unclear at this time. The D.C. Circuit of Appeals is expected to make a decision regarding the first round of appeals of the CPP in the first half of 2017.

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 and state agencies, industry publications, market research, and third-party consulting organizations, to maintain awareness of proposed changes to existing and expected regulations that will impact technology choices and cost
- Evaluate commercially viable options for technologies that will enable environmental compliance
- Serve on environmental control committees within industry organizations
- Negotiate solutions with government agencies that balance cost and environmental impact
- Update costs of technology needed for compliance as better information becomes available
- Monitor executive, legislative and judicial activities related to CO2 and develop cost sensitivities to evaluate the potential impact
- 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
- Implement the formal regulatory review process to ensure review of, identification of impacts from, and when necessary, provision of comment on, all new and revised environmental regulations
- Implement the existing Environmental Management Information System to ensure all required activities are completed and recorded
- Continued implementation of the ISO 14001 Certified Environmental Management System

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 and judicial 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. APS also comments, both through industry groups and independently, on regulations when they are proposed in order to help influence the final form of the regulation. The hypothetical cost of CO2 is included in Table D-11 in Rule D.2. That cost based upon the current California market Cap and Trade prices, because Congress has not yet taken action on this issue. 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 has access to renewables; however the deployment is based on economics and public policy. Renewable energy resources help diversify the APS portfolio and mitigate the dependency on fossil-fueled generation. In addition, the retirement of Four Corners Units 1-3, coupled with APS's acquisition of SCE's 48% share of Units 4 and 5 may help mitigate the uncertain costs associated with the implementation of CO2 emission reduction measures within the Navajo Nation, such as the CPP should it eventually be implemented.

Should the CPP be allowed to take effect in its current form, Arizona has the potential to comply with the provisions of a rate-based program with its existing mix of electricity generation and by continuing compliance with the existing end-user energy efficiency programs and renewable energy portfolio standards.

RULE E.1(F)

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

Coal for APS power plants is currently purchased under long-term contracts with fixed prices and inflation-related escalators. Should APS have the need to decrease coal deliveries to a level below coal contract terms, APS would likely be subject to liquidated damages for the amount of the coal that was contracted, but not taken. Risks for coal supply to power plants include rail service interruptions and mine permit extensions.

Current natural gas supplies in North America are projected to last over 100 years at the current levels of consumption. The primary reliability risk for natural gas supplies would be a disruption in natural gas pipeline transportation between the gas production basins and APS power plants. A disruption could involve extreme weather events and subsequent well-head freeze-off, pipeline rupture or lack of pipeline compression needed to move fuel through pipelines.

Natural gas pipeline capacity presents the greatest fuel risk to APS. While natural gas prices have dropped due to the abundant supply attributed to the shale revolution, available natural gas transportation in the Southwest is rapidly decreasing as domestic and Mexican demand for natural gas grows. Since 2013, Mexico has continually added substantial incremental subscriptions for long term gas capacity with pipeline networks in the Southwest and Texas. APS monitors future demand growth and current pipeline infrastructure to determine any shortfalls in the 3-5 year timeframe.

In order to identify how natural gas transportation availability will affect future demand growth, APS performed a Natural Gas Infrastructure Strategy assessment in 2016. APS utilizes information from a study performed by Concentric and analyzes this against various growth models developed by APS. The information compares current pipeline contracts with total pipeline capacity and forecasts future transportation availability in the 5-10 year period. In order to quantify how natural gas price fluctuation risk would impact the portfolios, APS performs gas price sensitivity analyses. APS evaluates natural gas generation assuming 30% higher and lower natural gas prices in order to evaluate changes in relative position of natural gas units to other technologies.

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.

Natural gas supply is typically contracted for under shorter-term fuel supply 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.

Natural gas transportation is typically contracted for using fixed rates under longer-term arrangements. Additional gas transport capabilities are developed as necessary based on as-needed firm contract requests. The sequence of pipeline infrastructure build-out follows this general sequence:

- Gas customer recognizes a need for additional transport need. An APS example may be due to the construction of a new natural gas generation facility.
- The gas customer makes a decision on whether this new gas capability should be a firm delivery or interruptible based on a variety of factors including economics, reliability requirements, appetite for volatility of prices or delivery. APS contracts for only firm transport based on APS business model and reliability responsibilities.
- The gas customer negotiates with gas transportation supplier(s) for the appropriate services based on each suppliers list of services and customer needs. These services differ based on carrier.
- When a firm transport contract is requested that is beyond the existing natural gas infrastructure capabilities, it triggers an infrastructure build-out study and balance of cost, capability, type, etc. Typical examples include adding additional horsepower to existing compressor stations, adding compressor stations or adding new transport pipeline.
- The lead time and cost of additions is dependent on the stated need (firm contract request), availability of options to satisfy the need, and securing needed regulatory permits or approvals.
- Given this general process, and recognizing that APS projected additional firm contract needs begin to require additional capacity in the summer of 2019, APS will begin to start discussions with gas providers in the 2016-2017 timeframe to balance the timing of contract additions and associated costs. APS and the gas pipeline need to allow enough time to enhance the pipeline if necessary, while minimizing over-conservative and early construction costs that would be unnecessary.

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 SRP).

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 SRP.

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. An example of this planning can be found in Attachment D.16. In addition, APS benefits from dual pipeline supply capability at the following power plants: Redhawk, Yucca, 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.

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, productivity risks;
- Federal, state or municipality permitting process;,
- 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 due to industry shift in technology selection; 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. Vendor selection is key; contracting with an experienced EPC that take responsibility for and have a proven track record with the total design including equipment integration mitigates risks that all of the process system components will fit and work together when the project is commissioned. The risks of long term reliability and maintainability are also mitigated by ensuring that personnel with power plant engineering and operations are integrated in the design review process.

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. Typically this risk is mitigated through purchasing of insurance for compensation of loss. It is also 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 processes include the review of Environmental and Critical Infrastructure Protection regulations in order to ensure technology choices are meet or exceed regulatory requirements.

When the need to retire, expand or build new generating assets is the planned course of action, external stakeholder analysis is an integral part of the planning process. 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.
- **Permitting delays –** May result from the need to satisfy local aesthetic or other preferences in order to obtain municipal construction permits; address concerns of non-governmental organizations or other interveners in order to obtain environmental permits. To mitigate this risk, APS is a an active participant in Federal, state, local community and regulatory forums which enables a project team to identify external stakeholders concerns early and incorporate into project timelines and budgets.
- **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 are mitigated by the regular review and updating of project plans and 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.

Several risks, uncertainties and errors have been discussed independently in Rules E(a) through E(g) above. APS has chosen to consider these and other parameters in tandem with each other by creating seven portfolios and eight sensitivities. These portfolios try to capture potential correlation between variables as described in Chapter 7 – Plan Selection. Assumptions were varied around the following parameters: load forecast, natural gas prices, CO2 prices and technology capital costs.

In addition to the risk identification outlined in Rules E(a) through E(g), APS is constantly working to identify new risks that may need to be addressed.

RULE E.2(H)

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

Seven resource portfolios were each evaluated under all eight sensitivities in order to assess their robustness, or ability to perform under different circumstances. They were evaluated in terms of their fuel diversity, capital expenditure requirements, gas burn, revenue requirements, carbon emissions and water consumption. Please see Chapter 7 for results of the risk analysis.

New risks are analyzed on an ongoing basis.

RULE E.3(H)

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

The risks inherent in future scenarios may be mitigated by the choosing the appropriate resource portfolio. APS's Flexible Resources Plan performed well in most scenarios, potentially mitigating a wide range of risks. Risks can be further mitigated by altering the resource portfolio in the future as the APS gains clarity around the uncertain variables and gains recognition of which scenario may be becoming reality. For a full discussion about the portfolios, scenarios or risks, APS analysis and results, please refer to Chapter 7.

There are companywide policies, processes and procedures that help APS to identify, analyze and mitigate new and ongoing risks.

RESPONSE TO RULES

SECTION F

2017 IRP

2017

RESPONSE TO RULES SECTION F – 2017 IRP

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 2017 Resource Plan, APS analyzed seven 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; net present value (NPV) of revenue requirements; average system cost; cumulative capital expenditures; carbon emissions; and water use. APS then created sensitivities and stressed several key input variables including natural gas prices, carbon costs, load growth, and technology capital costs, to determine the robustness of each portfolio. The results of the analytics can be found at:

- Attachment F.1(a) – Analysis of Seven Portfolios (Loads and Resources Tables and Energy Mixes)
- Attachment F.1(b) – Continued Analysis of Seven Portfolios (Revenue Requirements and Key Metrics)

Description of portfolios and sensitivities can be found in Chapter 7.

RULE F.2

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

The APS 2017 Resource Plan is designed to provide reliable power to its customers with the required planning 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 LOLE reliability criterion that targets a one event in ten years measure to provide the desired level of reliability. While there is not a standard prescribed by the WECC or NERC, a 1-in-10 LOLE is a common standard in the industry. APS's 2017 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 metrics discussed above, as part of the ACC's Biennial Transmission Assessment (BTA) APS may be required to perform a Reliability Must Run (RMR) study of its Phoenix and Yuma load pockets. The BTA is conducted every two years and if conditions are sufficiently different in the load pocket compared to the previous RMR a new RMR is triggered. The RMR specifically looks at transmission-constrained load pockets, and is done in conjunction with Southwest Area Transmission and other Arizona utilities. The last RMR, 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 LOLE for the years studied. Because conditions have not changed appreciably since the 2012 filing, a new RMR study has not been required.

RULE F.3

Will address the adverse environmental impacts of power production.

As described in response to Rule D.17, APS has planned for power plant emissions upgrades (example Four Corners SCRs) over the next decade to ensure full compliance with known environmental regulations. Additionally, this IRP includes in its base assumptions a hypothetical cost for carbon emissions implemented in 2023. The Resource Plan also includes a significant amount of energy efficiency and renewable energy – resources that provide energy to APS with limited adverse environmental impacts. This allows for a 50% increase in customer load sales prior to energy efficiency and distributed energy, while CO2 emission intensity and annual water use intensity decreases 23% and 29%, respectively, over the 15-year Planning Period. For more details about the quantified rates for multiple emissions for the reference plan see 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 F-1 below, the 2017 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 was required to achieve 1,700,000 MWh of incremental renewable generation by December 31, 2015, per ACC Decision No. 71448.

The percentages for renewable energy production presented in Table F-1 do not include market purchases of renewable energy. Given the current trend, we are anticipating the opportunity to continue to take advantage of the regional excess supply of solar through the market.

TABLE F-1. RENEWABLE GENERATION INCLUDED IN 2017 RESOURCE PLAN

CALENDAR YEAR	ACC RES REQUIREMENT (PERCENT OF RETAIL SALES DURING CALENDAR YEAR)	RENEWABLE GENERATION IN APS 2017 RESOURCE PLAN
2017	7.0%	14.3%
2018	8.0%	15.2%
2019	9.0%	16.0%
2020	10.0%	17.0%
2021	11.0%	17.7%
2022	12.0%	18.6%
2023	13.0%	19.4%
2024	14.0%	20.3%
2025	15.0%	21.3%
2026	15.0%	22.2%
2027	15.0%	23.1%
2028	15.0%	23.9%
2029	15.0%	24.5%
2030	15.0%	24.8%
2031	15.0%	25.2%
2032	15.0%	25.6%

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:

The Distributed Renewable Energy Requirement in R14-2-1805 and the annual percentages in the Resource Planning Rules are the same and have been set at 30% since 2011. As indicated in Table F-2 the distributed energy represented in the 2017 Resource Plan meets or exceeds the requirements in all years of the Planning Period.

TABLE F-2. DISTRIBUTED RENEWABLE ENERGY INCLUDED IN THE 2017 RESOURCE PLAN

CALENDAR YEAR	DISTRIBUTED GENERATION REQUIREMENT (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)	DISTRIBUTED GENERATION IN APS 2017 RESOURCE PLAN (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)
2017	30%	75%
2018	30%	78%
2019	30%	81%
2020	30%	83%
2021	30%	83%
2022	30%	85%
2023	30%	87%
2024	30%	90%
2025	30%	91%
2026	30%	98%
2027	30%	105%
2028	30%	111%
2029	30%	116%
2030	30%	120%
2031	30%	124%
2032	30%	127%

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.

ACC Decision No. 71819 set forth Energy Efficiency Requirements, which became effective January 1, 2011. As indicated in Table F3, Energy Efficiency represented in the 2017 Resource Plan meets the 2020 EE Standard and yearly targets set in Decision #75679.

TABLE F-3. CUMULATIVE ENERGY EFFICIENCY BY YEAR % OF RETAIL SALES

Cumulative Energy Efficiency		
CALENDAR YEAR	ACC DECISION NO. 71819 EE STANDARD (PERCENTAGE OF RETAIL SALES)	EE INCLUDED IN APS 2017 RESOURCE PLAN
2017	14.50%	14.18%
2018	17.00%	16.74%
2019	19.50%	19.34%
2020	22.00%	22.00%

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 2017 Resource Plan accomplishes both of these criteria. 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. Regardless of fuel price outcomes, APS relies on the output of Palo Verde Nuclear Generation Station to maintain a reliable and diverse low carbon mix of resources. APS also manages future cost and environmental risks by either assuming compliance or exceeding 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 existing generation resources in the region, market purchase opportunities for energy, 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 2017 Resource Plan, as outlined in Attachment F.9(b), meets the objectives set forth in Rules F.2 through 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 fuel- and technology-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 2017 Resource Plan are contained in Attachment D.10.
- **Discount Rate –** APS uses 7.50%, 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

2017

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.

This response is included in Chapter 8.

RESPONSE TO RULES

SECTION I

Other Factors

2017

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 the utility to provide additional information related to environmental impacts for the Commission's considerations.

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 2017 Resource Plan in multiple locations within this document. Environmental issues and water usage are discussed in Chapter 5. 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). A table of emissions for each generator is found at Attachment D.1(a)(8). Attachment F.1(b) contains information for model runs performed in support of this resource plan.

RESPONSE TO RULES

OTHER COMPLIANCE REQUIREMENTS

2017

RESPONSE TO RULES OTHER COMPLIANCE REQUIREMENTS

The ACC included compliance requirements in APS's 2014 IRP Decision ACC Docket Number E-00000V-13-0070 Decision No. 75068 (May 8, 2015), as well as suggestions listed in correspondence from Commissioner Bob Stump and Commissioner Andy Tobin in ACC Docket Number E-00000V-15-0094 (September 19, 2016 and December 6, 2016, respectively). APS Responses are included below.

APS'S 2014 IRP DECISION

IT IS FURTHER ORDERED that Arizona Public Service Company, shall address the issues identified in the 2014 Integrated Resource Planning Assessment and incorporate the appropriate responses in the 2017 Integrated Resource Plans:

I. LOAD FORECASTING TECHNIQUE

ORDER: Re-examine load forecasting techniques prior to filing the IRP to ensure that the resource plans are not forecasting high load growth that is unlikely to occur and include a report on the results of the re-examination of load forecasting techniques on or before October 31, 2015.

In response, APS filed Re-examination of APS Load Forecasting Techniques report in ACC Docket Number E-00000V-15-0094 (October 30, 2015). A description of the load forecasting methodology used in the development of the 2017 IRP can be found in Chapter 1 – Load Forecast and Response to Rules – Section C – Demand. Results of high and low load sensitivity analysis are described in Chapter 7, Results of Sensitivity Analysis.

II. EIM MARKET PARTICIPATION

ORDER: Load Serving Entities shall include a discussion of the status of their EIM market participation deliberations in the update to their respective IRP and 3-Year Action Plans.

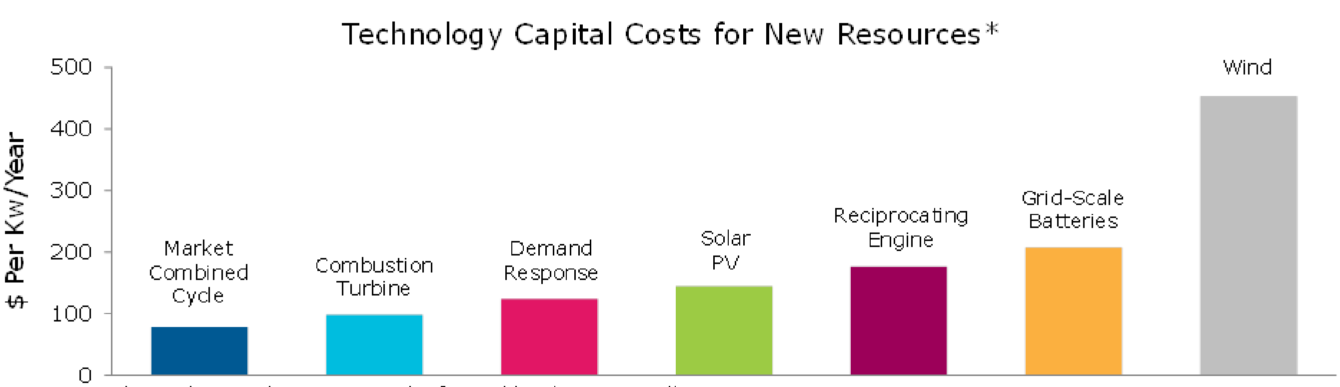
APS joined the California Independent System Operator (CAISO) EIM as a new participating Balancing Authority on October 1, 2016. See the Action Plan in Chapter 8 for additional details.

III. NEW TECHNOLOGIES

ORDER: Include a discussion of the development status and associated costs and benefits of new technologies considered in the IRP and associated 3-Year Action Plan.

APS considered a wide variety of new technologies as described in Chapter 2, Future Resource Options and Chapter 4 – Modernizing the Grid. A list of resource options that were considered in the 2017 IRP is included

FIGURE OCR-1. TECHNOLOGY CAPITAL COSTS FOR NEW RESOURCES



*Based on peak capacity and informed by the recent All-Source RFP
Annual levelized capital costs for Demand Response and Batteries assume a 10-year life; all others assume a 20-year life
Solar PV assumes inclusion of Investment Tax Credit (ITC)

in Response to Rules Attachment D.3, Table - Generation Technology. The Action Plan in Chapter 8 lays out specific activities, which are anticipated to occur during the first five years of the 2017 IRP that will advance new technology understanding and development.

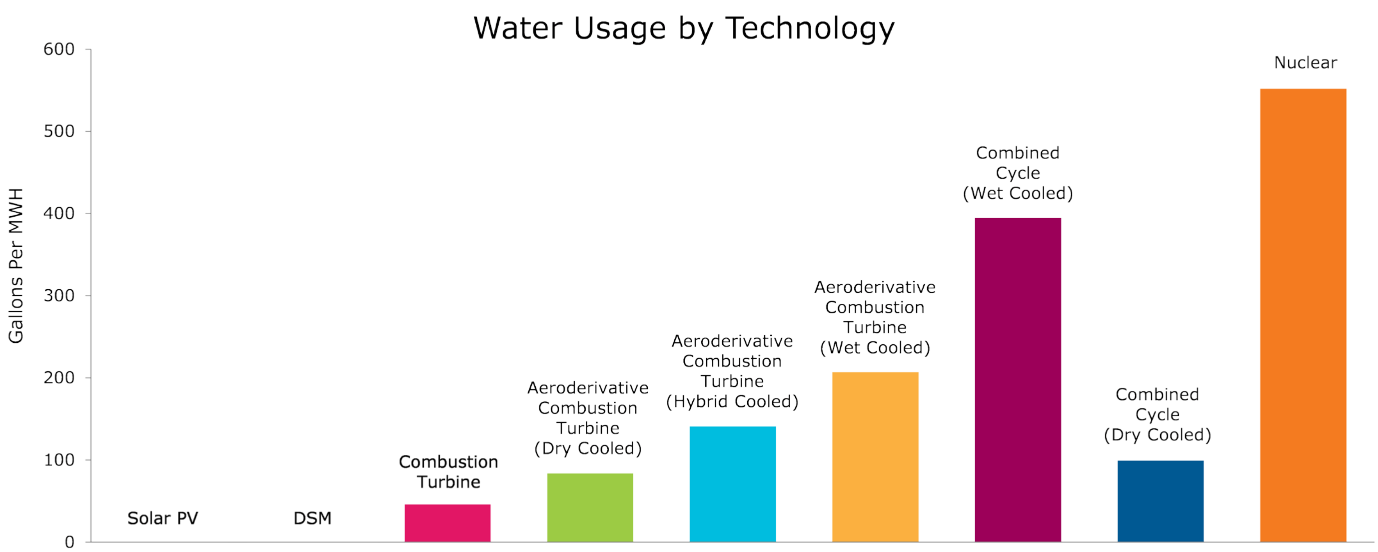
Additionally, APS has provided the results from the 2016 All-Source RFP as shown in Figure OCR-1. APS utilizes both internal estimates of new construction as well as RFP results to develop accurate estimates of new technology costs.

Additional insight can be gained about relative resource costs and system reliability contributions when resources are viewed through a comparable measure such as contribution to peak. See for example, the Incremental Peak Contribution chart (Figure 24) included in the Updated Preliminary 2017 Integrated Resource Plan, Docket No. E-00000V-15-0094 (September 30, 2016). This reinforces the need to make resource comparisons on a per unit of reliability measure ($/kW) rather than a unit of energy measure ($/kWh) or levelized energy comparison. The difference in value associated with each resource is substantial and related to resource dispatchability or call-ability when the electric grid needs reliability most, on-peak.

WATER USAGE BY TECHNOLOGY

Regardless of location, water is an important factor in assessing the viability of new energy projects for all utilities. However, those operating in water constrained areas – such as the Desert-Southwest - face greater challenges which can be further exacerbated when coupled with anticipated load growth. Although APS currently has sufficient water supplies, deployment of low water use technologies and greater integration of energy and water policies will be needed and are an integral part of the planning process. Figure OCR-2 below shows water usage levels by technology modeled in the 2017 IRP.

FIGURE OCR-2. WATER USAGE BY TECHNOLOGY



IV. PORTFOLIOS

ORDER: Consider the following portfolios in the Integrated Resource Plans (1) energy storage; (2) small nuclear reactors; (3) expanded renewables (including distributed resources): biogas, solar, wind, geothermal, etc.; and (4) expanded energy efficiency/demand response/integrate demand side management (which shall include the effect of microgrids and combined heat and power). If these portfolios are not included in the Integrated Resource Plans, the reason(s) why they were excluded must be provided.

APS evaluated the following four portfolios – Expanded Demand Side Management, Expanded Renewables, Energy Storage Systems and Nuclear Small Modular Reactor – in the 2017 Integrated Resource Plan in accordance with Decision No. 75068.

V. PLANS FOR AGING GENERATION

ORDER: Provide a thorough discussion regarding plans for aging generation plants in the IRP. If a Load Serving Entity intends to perform a major upgrade, excluding normal maintenance or repairs, or retire an existing generation plant, this information should be included in its 3-Year Plan, IRP and any updates thereto, prior to the utility taking action.

APS considered seven portfolios in the development of the 2017 IRP, all of which included planned major upgrades and plant retirements. Portfolio inputs and analysis results can be found in Chapter 7, in the Portfolios section.

COMMISSIONER BOB STUMP CORRESPONDENCE

Commissioner Bob Stump correspondence in Docket No. E-00000V-15-0094, dated September 19, 2016:

I. FORECAST IMPACT ON CUSTOMER BILLING METRICS

Chapter 7, Results of Portfolio Analysis and Attachment F.1(B) show average cost in $/MWh for the revenue requirements of each portfolio.

II. ROOFTOP SOLAR COST SHIFT

Current residential rooftop solar customers shift $50 million per year of unrecovered fixed cost to non-solar customers. Over the next 20 years these rooftop solar customers will shift $1 billion in fixed cost to non-participants. APS presents this topic at length in the APS 2016 Rate Case Application and Attachment 1, Docket No. E-01345A-16-0036.

III. RESOURCE COST COMPARISON

Costs and benefits of future resources are discussed in Chapter 2, Future Resource Options. Costs are shown in Response to Rules Attachment D.3, Table - Lifetime Levelized Costs in $/MWh of Generation Technologies and Table - Generation Technology. As described in Chapter 7, Technology Costs section, Strategist and PROMOD IV provide more robust resource cost comparison because these models offer detailed cost estimates of how new resources integrate with the existing resource mix and meet changing load and reliability requirements rather than on a stand-alone levelized cost basis.

IV. ASSESS HISTORICAL LOAD FORECASTING PERFORMANCE

As part of good business practice, APS periodically re-examines its load forecasting techniques in an effort to continuously improve forecast accuracy. APS included a detailed response to this topic in the Updated Preliminary 2017 Integrated Resource Plan, Docket No. E-00000V-15-0094 (September 30, 2016), Historical Load Forecasting Performance. A description of the load forecasting methodology used in the 2017 IRP can be found in Chapter 1, Load Forecast and Response to Rules Section C, Demand.

V. PEAK DEMAND REDUCTION

APS incorporated demand reduction programs in the IRP evaluation process, details of which can be found in Response to Rules Section D.14. A detailed description of Current DSM Programs, New DSM Programs, and DSM Programs in Development also can be found in Chapter 2, DSM Programs and Initiatives.

COMMISSIONER ANDY TOBIN CORRESPONDENCE

Commissioner Andy Tobin correspondence in Docket No. E-00000V-15-0094, dated December 6, 2016:

I. MORE ROBUST LEVELIZED RESOURCE COST COMPARISONS

Levelized cost comparisons are shown in Response to Rules Attachment D.3, Table - Lifetime Levelized Costs in $/MWh of Generation Technologies. As described in Chapter 7, Technology Costs section, Strategist and PROMOD IV provide more robust resource cost comparison because these models offer detailed cost estimates of how new resources integrate with the existing resource mix and meet changing load and reliability requirements rather than on a stand-alone levelized cost basis. Discussion of changes in technology costs and impact on resource planning forecasts can be found in Chapter 2, APS Assessment of Future Resource Options. See Chapter 7, Results of Portfolio Analysis for more detailed information on revenue requirements, system average costs, cumulative capital expenditures, gas burn, carbon emissions and water use. Chapter 7, Results of Sensitivity Analysis includes sensitivity studies for the gas price, carbon price, load forecast and capital cost. See Response to Rules Attachments F.1(A) and F.1(B) for additional analysis results.

II. ECONOMIC DEVELOPMENT

See Chapter 1, APS's Role in Arizona's Economic Development for how APS is supporting economic growth in Arizona. The Action Plan in Chapter 8 contains specific activities, which are anticipated to occur during the first five years of the 2017 IRP that will positively impact in-state economic development.

In particular APS views three resource expansion streams as being significant contributors to the Arizona economy over the course of the Planning Period: increased natural gas-fired generation, advanced grid technologies and solar energy. Recent examples of these projects and their economic impact to Arizona include:

Ocotillo Modernization Project (OMP) - In addition to the more than 100 jobs created during the construction phase, the project will increase total property tax revenue for the state from $600,000 to $8 million by its fifth year in operation.

Marine Corp Air Station Yuma Microgrid (MCAS Yuma) - APS expects microgrids to play an increasing role in how the company supports business customers and economic development. The 22-MW MCAS Yuma project provides the base 100% backup power needed in the event of a grid disruption and fast-starting, clean-burning diesel generation set (genset) power to the rest of the community under normal operating conditions. With a $21.6 million contribution to the Arizona economy during the construction phase, the benefits of the project also extend to adding needed flexible capacity to the system, delivering a customized solution to a key client and providing expertise in an area that APS views as a growing component of the energy mix.

Red Rock Solar Generating Station (Red Rock) - APS built a 40-MW new solar PV power plant, with Arizona State University (ASU) and PayPal the sole purchasers of the plant's output. The project marks an important milestone as it combines economic development, load retention and the deployment of new renewable energy resources in a single, customer-driven endeavor that will benefit all APS customers.

III. MORE ILLUSTRATIVE RISK/REWARD TRADEOFFS

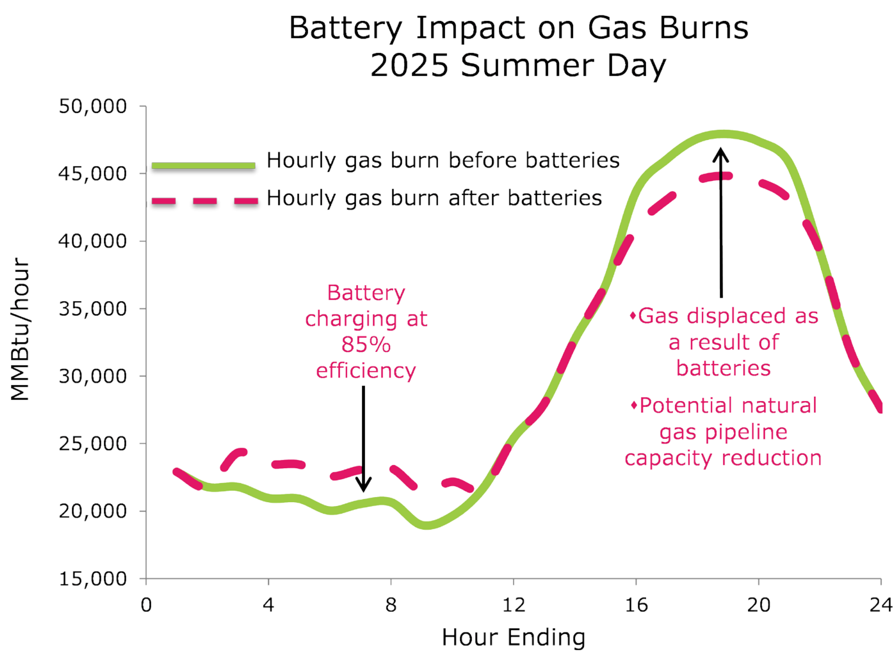
The 2017 IRP, which incorporates risk/reward tradeoffs in selecting technologies for review, can be found in Chapter 2, Future Resource Options. See Chapter 7, Sensitivities and Results of Sensitivity Analysis for a description of cost and potential volatility of the different portfolios. Risk analysis and mitigation are described in detail in Response to Rules Section E, Risk.

IV. MORE STRATEGIES TO TAKE ADVANTAGE OF LOW DAYTIME PRICING

Natural gas combustion turbines are a cost-effective, proven technology that provides much-needed summer peaking capacity, ramping capability and the dispatch flexibility needed to integrate renewable energy resources throughout the year. The Ocotillo Modernization Project (OMP), currently underway, is an example of how APS is responding to the need to maintain reliability by adding flexible resource capabilities on its system. See the Executive Summary, Ocotillo Modernization Project section for additional details.

Battery storage is anticipated to play a role in APS's future resource fleet to take advantage of low daytime pricing during non-summer months providing that costs come down as expected and the technology is sufficiently mature. Assuming technology cost declines occur as rapidly as projected, battery storage may be feasible in within the next 10 years.

FIGURE OCR-3. BATTERY IMPACT ON GAS BURNS FOR A SUMMER DAY IN 2025



Batteries have a number of new and interesting characteristics such as instantaneous switching from charge to discharge and quick ramps, but also have challenges associated with cost and discharge duration. In addition to helping mitigate the duck curve in the non-summer months, APS is also exploring their future contribution to resource diversity in the summer. While batteries have minimal impact on summer fuel savings and therefore fuel mix, batteries can have effects on infrastructure requirements. As depicted in Figure OCR-3, batteries in the summer are charged with combined cycle energy and discharged to replace combustion turbine energy. When the efficiency losses associated with battery charge and discharge are accounted for, the fuel burn is relatively unchanged. However, as shown in Figure OCR-3, potential natural gas pipeline capacity needed will be reduced resulting in a more efficient usage of existing gas infrastructure. Additionally, the potential to site batteries near load may have implications for reductions of transmission and distribution infrastructure in the future.

V. MORE COVERAGE OF THE DISTRIBUTION SYSTEM

See Chapter 4 – Modernizing the Grid for a discussion of how the grid is changing, as well as grid challenges and opportunities that were considered in the 2017 IRP.

TABLE OCR-1. ISSUES IDENTIFIED IN THE 2014 IRP ASSESSMENT AND ASSOCIATED REFERENCES

ISSUE	REFERENCE
I. Load Forecasting Technique	• **2017 IRP, Chapter 1 –** Load Forecast • **2017 IRP, Chapter 7 –** Plan Selection, "Results of Sensitivity Analysis" • **Response to Rules –** Section C – Demand • **Re-examination of APS Load Forecasting Techniques –** Docket No. E-00000V-15-0094
II. EIM Market Participation	• **2017 IRP, Chapter 8 –** Action Plan
III. New Technologies	• **2017 IRP, Chapter 2 –** Meeting Future Needs, "Future Resource Options" • **2017 IRP, Chapter 4 –** Modernizing the Grid • **2017 IRP, Chapter 8 –** Action Plan • **Response to Rules –** Section D.3 – Table: Generation Technology • **Updated Preliminary 2017 Integrated Resource Plan –** Docket No. E-00000V-15-0094, Figure 24 - Incremental Peak Contribution
IV. Portfolios	• **2017 IRP, Chapter 7 –** Plan Selection
V. Plans for Aging Generation	• **2017 IRP, Chapter 7 –** Plan Selection

TABLE OCR-2. ISSUES HIGHLIGHTED BY COMMISSIONER BOB STUMP IN DOCKET NO. E-00000V-15-0094, DATED SEPTEMBER 19, 2016 AND ASSOCIATED REFERENCES

ISSUE	REFERENCE
I. Forecast Impact on Customer Billing Metrics	• **2017 IRP, Chapter 7 –** Plan Selection, "Results of Portfolio Analysis " • **Response to Rules –** Section F, Attachment F.1(B)
II. Rooftop Solar Cost Shift	• **APS 2016 Rate Case Application and Attachment 1 –** Docket No. E-01345A-16-0036
III. Resource Cost Comparison	• **2017 IRP, Chapter 2 –** Meeting Future Needs, "Future Resource Options" • **2017 IRP, Chapter 7 –** Plan Selection, "Technology Costs" • **Response to Rules –** Section D – Attachment D.3, Table: Lifetime Levelized Costs in $/MWh of Generation Technologies and Table: Generation Technology
IV. Assess Historical Load Forecasting Performance	• **2017 IRP, Chapter 1 –** Load Forecast • **Response to Rules –** Section C – Demand • **Updated Preliminary 2017 Integrated Resource Plan –** Docket No. E-00000V-15-0094, Historical Load Forecasting Performance
V. Peak Demand Reduction	• **2017 IRP, Chapter 2 –** Meeting Future Needs, "DSM Programs and Initiatives" • **Response to Rules –** Section D.14

TABLE OCR-3. ISSUES HIGHLIGHTED BY COMMISSIONER ANDY TOBIN IN DOCKET NO. E-00000V-15-0094, DATED DECEMBER 6, 2016 AND ASSOCIATED REFERENCES

ISSUE	REFERENCE
I. More Robust Levelized Resource Cost Comparisons	• **2017 IRP, Chapter 2 –** Meeting Future Needs, "APS Assessment of Future Resource Options" • **2017 IRP, Chapter 7 –** Plan Selection, "Technology Costs," "Results of Portfolio Analysis" and "Results of Sensitivity Analysis" • **Response to Rules –** Section D.3, Table: Lifetime Levelized Costs in $/MWh of Generation Technologies • **Response to Rules –** Section F, Attachments F.1(A) and F.1(B)
II. Economic Development	• **2017 IRP, Chapter 1 –** Load Forecast, "APS's Role in Arizona's Economic Development" • **2017 IRP, Chapter 8 –** Action Plan
III. More Illustrative Risk/Reward Tradeoffs	• **2017 IRP, Chapter 2 –** Meeting Future Needs, "Future Resource Options" • **2017 IRP, Chapter 7 –** Plan Selection, "Sensitivities and Results of Sensitivity Analysis" • **Response to Rules –** Section E – Risk
IV. More Strategies to Take Advantage of Low Daytime Pricing	• **2017 IRP, Executive Summary –** Ocotillo Modernization Project
V. More Coverage of the Distribution System	• **2017 IRP, Chapter 4 –** Modernizing the Grid

ATTACHMENTS

2017

TABLE OF ATTACHMENTS

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS

PEAK DEMAND (MW)													
YEAR: 2017	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,136	1,896	1,636	2,010	2,846	3,586	3,742	3,919	3,250	2,426	1,584	2,184	3,919
Comm+Ind <3 MW	1,388	1,411	1,388	1,557	1,594	1,778	2,026	1,857	1,992	1,759	1,411	1,369	1,857
Comm+Ind >3 MW	331	381	371	375	383	397	435	411	426	408	380	340	411
Irrigation	1	0	1	1	1	2	2	1	1	1	1	1	1
Streetlights	6	3	11	0	0	0	0	0	0	0	25	18	0
Resale (x/off-system sales)	4	6	5	16	2	2	9	5	19	4	6	7	5
System Peak Prior to Losses	3,865	3,698	3,413	3,960	4,826	5,764	6,214	6,193	5,688	4,598	3,406	3,918	6,193
Losses On Peak	416	386	338	383	565	757	810	830	719	528	361	432	830
Total Own Load Peak	4,281	4,084	3,751	4,343	5,391	6,521	7,023	7,023	6,407	5,126	3,767	4,350	7,023
Energy Efficiency Programs	(54)	(53)	(59)	(71)	(81)	(108)	(113)	(113)	(97)	(80)	(55)	(54)	(113)
Distributed Energy Programs	(0)	(0)	(1)	(43)	(44)	(42)	(37)	(37)	(38)	(35)	(0)	(0)	(37)
Own Load After EE/DE	4,227	4,031	3,692	4,228	5,266	6,371	6,873	6,873	6,271	5,012	3,712	4,296	6,873

PEAK DEMAND (MW)													
YEAR: 2018	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,240	1,974	1,698	2,088	2,942	3,716	3,898	4,081	3,379	2,518	1,638	2,260	4,081
Comm+Ind <3 MW	1,455	1,469	1,441	1,617	1,648	1,843	2,111	1,933	2,070	1,825	1,459	1,417	1,933
Comm+Ind >3 MW	347	396	385	390	396	412	453	428	443	423	393	352	428
Irrigation	1	0	1	1	1	2	2	1	1	1	1	1	1
Streetlights	6	3	12	0	0	0	0	0	0	0	25	18	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,049	3,843	3,537	4,097	4,988	5,972	6,464	6,443	5,894	4,769	3,517	4,047	6,443
Losses On Peak	436	401	350	396	584	784	842	864	745	548	373	447	864
Total Own Load Peak	4,485	4,244	3,887	4,493	5,572	6,757	7,307	7,307	6,639	5,316	3,890	4,493	7,307
Energy Efficiency Programs	(110)	(107)	(119)	(141)	(159)	(214)	(229)	(229)	(197)	(162)	(114)	(109)	(229)
Distributed Energy Programs	(0)	(0)	(1)	(49)	(70)	(61)	(75)	(75)	(77)	(69)	(1)	(0)	(75)
Own Load After EE/DE	4,374	4,137	3,767	4,303	5,342	6,482	7,003	7,003	6,365	5,085	3,775	4,385	7,003

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2019	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,323	2,042	1,752	2,174	3,056	3,847	4,045	4,234	3,517	2,624	1,700	2,340	4,045
Comm+Ind <3 MW	1,509	1,520	1,486	1,684	1,712	1,908	2,190	2,006	2,155	1,902	1,515	1,467	2,190
Comm+Ind >3 MW	360	410	397	406	411	426	470	444	461	441	408	364	470
Irrigation	1	0	1	1	1	2	2	1	1	1	1	1	2
Streetlights	6	3	12	0	0	0	0	0	0	0	26	19	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,199	3,975	3,649	4,265	5,181	6,183	6,707	6,685	6,135	4,968	3,651	4,191	6,707
Losses On Peak	452	415	361	413	607	812	874	896	776	570	387	463	874
Total Own Load Peak	4,651	4,390	4,010	4,678	5,787	6,995	7,581	7,581	6,911	5,539	4,038	4,653	7,581
Energy Efficiency Programs	(168)	(163)	(170)	(214)	(241)	(322)	(337)	(345)	(298)	(244)	(163)	(165)	(337)
Distributed Energy Programs	(0)	(0)	(2)	(42)	(75)	(65)	(117)	(126)	(115)	(104)	(1)	(0)	(117)
Own Load After EE/DE	4,483	4,227	3,838	4,422	5,472	6,608	7,127	7,110	6,498	5,191	3,874	4,488	7,127

PEAK DEMAND (MW)													
YEAR: 2020	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,400	2,069	1,784	2,247	3,160	4,003	4,191	4,387	3,629	2,710	1,762	2,421	4,387
Comm+Ind <3 MW	1,559	1,540	1,514	1,740	1,770	1,985	2,269	2,078	2,224	1,965	1,570	1,518	2,078
Comm+Ind >3 MW	372	416	405	420	425	444	487	460	476	456	423	377	460
Irrigation	1	0	1	1	2	2	2	1	1	2	1	1	1
Streetlights	7	3	12	0	0	0	0	0	0	0	27	20	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,338	4,029	3,716	4,408	5,357	6,434	6,949	6,927	6,330	5,132	3,783	4,336	6,927
Losses On Peak	467	421	368	426	627	845	906	929	800	589	401	479	929
Total Own Load Peak	4,805	4,449	4,084	4,835	5,984	7,279	7,855	7,855	7,130	5,722	4,184	4,815	7,855
Energy Efficiency Programs	(224)	(218)	(235)	(286)	(321)	(430)	(450)	(450)	(397)	(326)	(221)	(220)	(450)
Distributed Energy Programs	(0)	(0)	(0)	(8)	(81)	(71)	(123)	(115)	(150)	(141)	(0)	(0)	(115)
Own Load After EE/DE	4,581	4,232	3,849	4,541	5,582	6,778	7,282	7,290	6,582	5,254	3,963	4,595	7,290

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2021	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,466	2,175	1,874	2,311	3,263	4,134	4,338	4,541	3,758	2,800	1,813	2,495	4,541
Comm+Ind <3 MW	1,602	1,619	1,590	1,790	1,827	2,050	2,349	2,151	2,303	2,030	1,615	1,565	2,151
Comm+Ind >3 MW	382	437	425	431	439	458	504	476	493	471	435	388	476
Irrigation	1	1	1	1	2	2	2	1	1	2	1	1	1
Streetlights	7	4	13	0	0	0	0	0	0	0	28	20	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,457	4,235	3,904	4,534	5,530	6,644	7,193	7,169	6,555	5,302	3,892	4,469	7,169
Losses On Peak	480	442	387	439	648	872	937	961	829	609	412	493	961
Total Own Load Peak	4,937	4,677	4,291	4,972	6,178	7,517	8,130	8,130	7,384	5,910	4,304	4,962	8,130
Energy Efficiency Programs	(311)	(308)	(300)	(393)	(345)	(475)	(496)	(494)	(416)	(329)	(309)	(308)	(494)
Distributed Energy Programs	(0)	(0)	(3)	(57)	(85)	(76)	(133)	(123)	(186)	(142)	(1)	(0)	(123)
Own Load After EE/DE	4,626	4,369	3,987	4,522	5,748	6,966	7,501	7,514	6,782	5,440	3,995	4,655	7,514

PEAK DEMAND (MW)													
YEAR: 2022	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,546	2,239	1,931	2,386	3,373	4,271	4,484	4,694	3,881	2,883	1,869	2,569	4,694
Comm+Ind <3 MW	1,654	1,667	1,638	1,848	1,889	2,118	2,428	2,224	2,378	2,090	1,665	1,611	2,224
Comm+Ind >3 MW	394	450	438	446	454	473	521	492	509	485	449	400	492
Irrigation	1	1	1	1	2	2	2	1	1	2	1	1	1
Streetlights	7	4	13	0	0	0	0	0	0	0	29	21	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,601	4,360	4,022	4,681	5,717	6,865	7,436	7,411	6,769	5,460	4,012	4,601	7,411
Losses On Peak	495	455	398	453	669	901	969	993	856	627	425	508	993
Total Own Load Peak	5,097	4,815	4,420	5,134	6,386	7,766	8,405	8,405	7,625	6,087	4,437	5,109	8,405
Energy Efficiency Programs	(327)	(328)	(314)	(430)	(367)	(519)	(534)	(536)	(443)	(347)	(327)	(325)	(536)
Distributed Energy Programs	(0)	(0)	(7)	(74)	(100)	(93)	(148)	(136)	(247)	(155)	(0)	(0)	(136)
Own Load After EE/DE	4,769	4,487	4,100	4,630	5,919	7,155	7,722	7,733	6,935	5,586	4,110	4,783	7,733

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,619	2,305	1,989	2,457	3,481	4,403	4,632	4,848	3,988	2,959	1,928	2,644	4,848
Comm+Ind <3 MW	1,702	1,716	1,688	1,903	1,950	2,183	2,508	2,297	2,443	2,145	1,718	1,658	2,297
Comm+Ind >3 MW	405	463	451	459	468	488	538	509	523	498	463	412	509
Irrigation	1	1	1	2	2	2	2	1	1	2	1	1	1
Streetlights	7	4	14	0	0	0	0	0	0	0	30	21	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,734	4,488	4,143	4,819	5,901	7,076	7,680	7,655	6,956	5,603	4,140	4,735	7,655
Losses On Peak	510	469	410	466	691	929	1,001	1,026	880	643	439	523	1,026
Total Own Load Peak	5,244	4,957	4,554	5,286	6,592	8,005	8,681	8,681	7,835	6,246	4,578	5,258	8,681
Energy Efficiency Programs	(341)	(342)	(332)	(470)	(390)	(570)	(576)	(578)	(449)	(378)	(349)	(347)	(578)
Distributed Energy Programs	(0)	(1)	(12)	(88)	(118)	(115)	(172)	(156)	(211)	(160)	(0)	(0)	(156)
Own Load After EE/DE	4,903	4,614	4,210	4,728	6,083	7,320	7,934	7,947	7,176	5,708	4,229	4,911	7,947

PEAK DEMAND (MW)													
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,699	2,334	2,008	2,534	3,576	4,518	4,781	5,005	4,116	3,060	1,979	2,718	4,781
Comm+Ind <3 MW	1,753	1,738	1,704	1,962	2,003	2,240	2,589	2,371	2,522	2,218	1,763	1,704	2,589
Comm+Ind >3 MW	418	469	455	473	481	501	556	525	540	515	475	423	556
Irrigation	1	1	1	2	2	2	2	1	1	2	1	1	2
Streetlights	7	4	14	0	0	0	0	0	0	0	31	22	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,878	4,545	4,182	4,970	6,061	7,261	7,928	7,902	7,180	5,794	4,249	4,869	7,928
Losses On Peak	525	475	414	481	710	954	1,033	1,059	908	665	450	537	1,033
Total Own Load Peak	5,403	5,020	4,596	5,451	6,771	8,215	8,961	8,961	8,088	6,459	4,700	5,406	8,961
Energy Efficiency Programs	(359)	(360)	(373)	(488)	(406)	(599)	(585)	(622)	(523)	(405)	(354)	(359)	(585)
Distributed Energy Programs	(0)	(1)	(0)	(98)	(129)	(138)	(194)	(271)	(224)	(166)	(0)	(0)	(194)
Own Load After EE/DE	5,045	4,659	4,223	4,865	6,236	7,477	8,182	8,067	7,340	5,888	4,345	5,046	8,182

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,782	2,442	2,095	2,612	3,681	4,666	4,934	5,165	4,231	3,149	2,038	2,798	4,934
Comm+Ind <3 MW	1,807	1,818	1,778	2,022	2,062	2,313	2,672	2,447	2,593	2,282	1,816	1,754	2,672
Comm+Ind >3 MW	431	490	475	488	495	517	574	542	555	529	489	435	574
Irrigation	1	1	1	2	2	2	2	2	1	2	1	1	2
Streetlights	8	4	15	0	0	0	0	0	0	0	32	23	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,028	4,755	4,364	5,123	6,239	7,498	8,182	8,155	7,380	5,962	4,376	5,010	8,182
Losses On Peak	541	496	432	496	731	985	1,066	1,093	933	685	464	553	1,066
Total Own Load Peak	5,570	5,252	4,796	5,619	6,970	8,483	9,248	9,248	8,314	6,647	4,840	5,563	9,248
Energy Efficiency Programs	(391)	(388)	(349)	(528)	(482)	(643)	(620)	(647)	(561)	(414)	(380)	(383)	(620)
Distributed Energy Programs	(0)	(1)	(27)	(76)	(147)	(163)	(219)	(204)	(238)	(172)	(0)	(0)	(219)
Own Load After EE/DE	5,179	4,862	4,420	5,015	6,340	7,677	8,409	8,397	7,516	6,061	4,460	5,180	8,409

PEAK DEMAND (MW)													
YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,851	2,511	2,158	2,677	3,786	4,819	5,089	5,327	4,353	3,235	2,098	2,880	5,327
Comm+Ind <3 MW	1,853	1,869	1,831	2,073	2,120	2,389	2,756	2,524	2,667	2,345	1,869	1,806	2,524
Comm+Ind >3 MW	441	504	489	500	509	534	592	559	571	544	504	448	559
Irrigation	1	1	1	2	2	3	2	2	2	2	1	1	2
Streetlights	8	4	15	0	0	0	0	0	0	0	32	23	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,154	4,889	4,496	5,252	6,417	7,744	8,439	8,411	7,593	6,126	4,505	5,158	8,411
Losses On Peak	555	510	445	508	751	1,017	1,100	1,128	960	703	477	569	1,128
Total Own Load Peak	5,709	5,400	4,941	5,760	7,168	8,761	9,539	9,539	8,553	6,830	4,982	5,727	9,539
Energy Efficiency Programs	(424)	(429)	(390)	(568)	(514)	(685)	(727)	(686)	(584)	(406)	(420)	(402)	(686)
Distributed Energy Programs	(0)	(1)	(5)	(83)	(166)	(188)	(245)	(225)	(360)	(264)	(0)	(0)	(225)
Own Load After EE/DE	5,285	4,969	4,545	5,108	6,488	7,887	8,567	8,627	7,609	6,159	4,562	5,325	8,627

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,928	2,577	2,220	2,744	3,892	4,956	5,247	5,493	4,490	3,329	2,150	2,958	5,493
Comm+Ind <3 MW	1,902	1,918	1,884	2,125	2,180	2,457	2,842	2,602	2,751	2,413	1,915	1,855	2,602
Comm+Ind >3 MW	453	518	503	512	523	549	610	576	589	560	516	460	576
Irrigation	1	1	1	2	2	3	2	2	2	2	1	1	2
Streetlights	8	4	15	0	0	0	0	0	0	0	33	24	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,292	5,017	4,624	5,383	6,598	7,965	8,701	8,673	7,832	6,303	4,616	5,298	8,673
Losses On Peak	570	524	458	521	773	1,046	1,134	1,163	991	724	489	585	1,163
Total Own Load Peak	5,861	5,541	5,082	5,903	7,370	9,011	9,835	9,835	8,823	7,027	5,105	5,883	9,835
Energy Efficiency Programs	(443)	(461)	(367)	(649)	(481)	(739)	(766)	(747)	(639)	(476)	(449)	(443)	(747)
Distributed Energy Programs	(0)	(2)	(40)	(157)	(185)	(214)	(275)	(251)	(267)	(181)	(0)	(0)	(251)
Own Load After EE/DE	5,419	5,078	4,675	5,097	6,705	8,058	8,794	8,837	7,917	6,369	4,656	5,440	8,837

PEAK DEMAND (MW)													
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,014	2,596	2,243	2,824	4,018	5,104	5,411	5,664	4,610	3,405	2,215	3,037	5,664
Comm+Ind <3 MW	1,958	1,933	1,903	2,187	2,250	2,530	2,930	2,683	2,824	2,469	1,973	1,904	2,683
Comm+Ind >3 MW	467	521	509	527	540	565	629	594	605	573	532	473	594
Irrigation	1	1	1	2	2	3	2	2	2	2	1	1	2
Streetlights	8	4	16	0	0	0	0	0	0	0	34	25	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,448	5,055	4,673	5,540	6,810	8,202	8,972	8,942	8,040	6,449	4,755	5,439	8,942
Losses On Peak	587	528	463	536	797	1,077	1,169	1,199	1,017	740	504	600	1,199
Total Own Load Peak	6,035	5,583	5,135	6,075	7,608	9,279	10,141	10,141	9,057	7,189	5,259	6,040	10,141
Energy Efficiency Programs	(451)	(473)	(443)	(629)	(503)	(780)	(782)	(788)	(564)	(516)	(465)	(461)	(788)
Distributed Energy Programs	(0)	(2)	(0)	(188)	(214)	(240)	(308)	(277)	(275)	(188)	(0)	(0)	(277)
Own Load After EE/DE	5,584	5,108	4,692	5,258	6,891	8,259	9,051	9,076	8,218	6,485	4,795	5,579	9,076

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,097	2,718	2,340	2,897	4,121	5,237	5,573	5,834	4,735	3,509	2,273	3,118	5,573
Comm+Ind <3 MW	2,012	2,023	1,985	2,244	2,308	2,596	3,018	2,764	2,901	2,544	2,025	1,955	3,018
Comm+Ind >3 MW	479	546	531	541	554	580	648	612	621	590	546	485	648
Irrigation	1	1	1	2	2	3	3	2	2	2	1	1	3
Streetlights	8	4	16	0	0	0	0	0	0	0	35	25	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,597	5,293	4,873	5,684	6,986	8,416	9,241	9,211	8,259	6,645	4,879	5,583	9,241
Losses On Peak	603	553	482	550	818	1,105	1,204	1,235	1,045	763	517	616	1,204
Total Own Load Peak	6,200	5,845	5,356	6,234	7,804	9,521	10,446	10,446	9,304	7,408	5,396	6,200	10,446
Energy Efficiency Programs	(448)	(460)	(416)	(642)	(513)	(812)	(755)	(867)	(589)	(544)	(502)	(450)	(755)
Distributed Energy Programs	(0)	(2)	(58)	(210)	(236)	(256)	(339)	(303)	(290)	(194)	(4)	(0)	(339)
Own Load After EE/DE	5,752	5,383	4,881	5,381	7,056	8,453	9,352	9,276	8,426	6,669	4,891	5,749	9,352

PEAK DEMAND (MW)													
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,188	2,791	2,395	2,984	4,233	5,376	5,741	6,010	4,881	3,610	2,330	3,201	5,741
Comm+Ind <3 MW	2,071	2,078	2,032	2,311	2,371	2,665	3,109	2,847	2,991	2,617	2,076	2,007	3,109
Comm+Ind >3 MW	494	561	543	557	569	596	667	630	640	607	560	498	667
Irrigation	1	1	2	2	2	3	3	2	2	2	1	1	3
Streetlights	9	5	17	0	0	0	0	0	0	0	36	26	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,762	5,435	4,988	5,854	7,175	8,640	9,520	9,489	8,513	6,836	5,003	5,732	9,520
Losses On Peak	620	567	494	566	840	1,135	1,241	1,272	1,077	785	530	633	1,241
Total Own Load Peak	6,382	6,002	5,481	6,421	8,015	9,774	10,761	10,761	9,590	7,621	5,533	6,365	10,761
Energy Efficiency Programs	(457)	(480)	(424)	(690)	(534)	(855)	(789)	(882)	(743)	(572)	(475)	(466)	(789)
Distributed Energy Programs	(0)	(1)	(8)	(224)	(258)	(298)	(370)	(417)	(306)	(200)	(0)	(1)	(370)
Own Load After EE/DE	5,925	5,521	5,049	5,507	7,223	8,621	9,602	9,462	8,541	6,848	5,058	5,898	9,602

ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,272	2,866	2,458	3,068	4,348	5,539	5,912	6,189	5,007	3,707	2,395	3,288	5,912
Comm+Ind <3 MW	2,126	2,133	2,086	2,376	2,435	2,747	3,202	2,932	3,068	2,688	2,134	2,062	3,202
Comm+Ind >3 MW	507	576	558	573	585	614	687	649	657	623	575	512	687
Irrigation	1	1	2	2	2	3	3	2	2	2	1	1	3
Streetlights	9	5	17	0	0	0	0	0	0	0	37	27	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,914	5,580	5,120	6,019	7,370	8,903	9,804	9,772	8,734	7,021	5,142	5,889	9,804
Losses On Peak	637	583	507	582	863	1,169	1,278	1,310	1,105	806	545	650	1,278
Total Own Load Peak	6,551	6,163	5,627	6,601	8,233	10,072	11,081	11,081	9,838	7,827	5,687	6,539	11,081
Energy Efficiency Programs	(489)	(493)	(405)	(710)	(674)	(898)	(822)	(882)	(779)	(556)	(488)	(477)	(822)
Distributed Energy Programs	(0)	(1)	(44)	(191)	(283)	(329)	(404)	(362)	(321)	(207)	(0)	(1)	(404)
Own Load After EE/DE	6,062	5,669	5,177	5,700	7,276	8,845	9,855	9,838	8,738	7,064	5,199	6,061	9,855

PEAK DEMAND (MW)													
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,349	2,886	2,491	3,134	4,463	5,706	6,087	6,372	5,156	3,807	2,455	3,379	6,372
Comm+Ind <3 MW	2,176	2,148	2,113	2,427	2,500	2,829	3,296	3,019	3,159	2,760	2,187	2,118	3,019
Comm+Ind >3 MW	518	580	565	585	600	632	708	668	676	640	590	526	668
Irrigation	1	1	2	2	2	3	3	2	2	2	1	1	2
Streetlights	9	5	17	0	0	0	0	0	0	0	38	27	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	6,053	5,620	5,188	6,147	7,565	9,170	10,094	10,061	8,993	7,209	5,271	6,051	10,061
Losses On Peak	652	587	514	595	886	1,204	1,316	1,349	1,137	828	559	668	1,349
Total Own Load Peak	6,705	6,207	5,701	6,742	8,451	10,375	11,410	11,410	10,130	8,037	5,829	6,719	11,410
Energy Efficiency Programs	(515)	(532)	(480)	(756)	(593)	(958)	(990)	(957)	(824)	(605)	(509)	(499)	(957)
Distributed Energy Programs	(0)	(1)	(0)	(279)	(330)	(363)	(443)	(386)	(323)	(209)	(0)	(1)	(386)
Own Load After EE/DE	6,190	5,674	5,221	5,707	7,528	9,053	9,977	10,066	8,984	7,223	5,321	6,220	10,066

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS

ENERGY DEMAND (MWH)													
YEAR: 2017	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,066,547	813,044	826,700	822,769	1,015,845	1,460,128	1,914,496	1,787,920	1,479,224	956,824	799,601	1,034,223	13,977,321
Comm+Ind <3 MW	789,731	821,702	865,466	866,630	1,056,912	1,036,137	1,118,535	1,202,477	1,032,227	948,375	876,695	846,080	11,460,967
Comm+Ind >3 MW	276,419	257,732	272,348	265,665	273,711	294,570	318,288	318,582	330,313	315,871	294,823	279,613	3,497,935
Irrigation	532	545	869	1,080	1,444	1,339	1,299	1,118	982	876	676	491	11,251
Streetlights	11,674	12,802	14,217	12,630	13,879	10,971	11,391	12,406	11,425	12,986	13,418	13,321	151,120
Resale (x/off-system sales)	3,489	2,888	2,744	2,669	2,666	2,853	3,375	3,132	2,707	2,964	2,998	3,798	36,283
Sales Prior to EE/DE	2,148,392	1,908,713	1,982,344	1,971,443	2,364,457	2,805,998	3,367,384	3,325,635	2,856,878	2,237,896	1,988,211	2,177,526	29,134,877
Energy Efficiency Programs	(41,295)	(26,229)	(34,652)	(35,267)	(43,895)	(51,296)	(54,681)	(54,944)	(33,180)	(33,455)	(27,514)	(28,032)	(464,440)
Distributed Energy Programs	(28,446)	(20,348)	(32,414)	(32,480)	(38,635)	(28,903)	(27,749)	(29,672)	(22,884)	(24,575)	(19,250)	(14,386)	(319,742)
Total Sales	2,078,651	1,862,136	1,915,278	1,903,696	2,281,927	2,725,799	3,284,954	3,241,019	2,800,814	2,179,866	1,941,447	2,135,108	28,350,695
Energy Losses	170,872	104,423	143,486	127,657	170,604	206,924	215,648	214,680	169,103	138,908	96,813	195,707	1,954,825
Total Own Load Energy	2,249,523	1,966,559	2,058,764	2,031,353	2,452,531	2,932,723	3,500,602	3,455,699	2,969,917	2,318,774	2,038,260	2,330,815	30,305,520

ENERGY DEMAND (MWH)													
YEAR: 2018	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,129,962	852,335	867,223	860,489	1,051,545	1,521,610	2,007,228	1,863,025	1,549,803	989,068	827,650	1,075,949	14,595,887
Comm+Ind <3 MW	833,309	859,477	904,179	905,231	1,103,207	1,084,340	1,171,023	1,256,178	1,080,604	991,732	916,425	885,834	11,991,539
Comm+Ind >3 MW	275,509	256,592	271,557	264,062	271,624	292,624	317,680	315,965	327,899	313,303	292,615	278,632	3,478,062
Irrigation	486	510	876	1,062	1,329	1,338	1,243	1,117	991	881	674	491	10,998
Streetlights	11,940	13,017	14,505	12,824	14,112	11,156	11,580	12,646	11,619	13,213	13,669	13,548	153,829
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,251,206	1,981,931	2,058,340	2,043,668	2,441,817	2,911,068	3,508,754	3,448,931	2,970,916	2,308,197	2,051,033	2,254,454	30,230,315
Energy Efficiency Programs	(70,011)	(53,126)	(69,825)	(72,334)	(88,857)	(103,155)	(111,035)	(111,211)	(66,897)	(68,592)	(55,733)	(56,943)	(927,719)
Distributed Energy Programs	(48,267)	(40,473)	(65,509)	(64,682)	(77,347)	(57,499)	(55,683)	(59,552)	(45,517)	(49,072)	(38,631)	(28,726)	(630,958)
Total Sales	2,132,928	1,888,332	1,923,006	1,906,652	2,275,613	2,750,414	3,342,036	3,278,168	2,858,502	2,190,533	1,956,669	2,168,785	28,671,638
Energy Losses	174,396	106,158	149,430	129,459	186,138	204,091	211,110	227,464	146,096	150,281	97,311	191,616	1,973,550
Total Own Load Energy	2,307,324	1,994,490	2,072,436	2,036,111	2,461,751	2,954,505	3,553,146	3,505,632	3,004,598	2,340,814	2,053,980	2,360,401	30,645,188

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2019	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,168,074	881,945	897,739	895,065	1,104,518	1,587,546	2,078,133	1,940,826	1,605,741	1,040,510	867,676	1,118,633	15,186,406
Comm+Ind <3 MW	869,927	896,865	942,204	943,940	1,149,491	1,131,417	1,221,472	1,311,341	1,128,260	1,034,397	955,749	924,430	12,509,493
Comm+Ind >3 MW	276,636	257,740	272,379	265,015	272,483	293,309	317,448	317,936	330,837	315,551	294,829	280,860	3,495,023
Irrigation	488	513	875	1,062	1,324	1,340	1,231	1,109	990	886	680	495	10,993
Streetlights	12,164	13,237	14,742	13,069	14,368	11,358	11,776	12,865	11,835	13,466	13,926	13,789	156,595
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,327,289	2,050,300	2,127,939	2,118,151	2,542,184	3,024,970	3,630,060	3,584,077	3,077,663	2,404,810	2,132,860	2,338,207	31,358,510
Energy Efficiency Programs	(99,126)	(80,728)	(105,283)	(110,837)	(134,274)	(154,468)	(167,939)	(166,987)	(102,201)	(103,953)	(84,044)	(87,646)	(1,397,486)
Distributed Energy Programs	(67,690)	(62,493)	(96,743)	(97,370)	(115,882)	(86,566)	(83,276)	(89,591)	(68,257)	(73,370)	(58,307)	(42,457)	(942,002)
Total Sales	2,160,473	1,907,079	1,925,913	1,909,944	2,292,028	2,783,936	3,378,845	3,327,499	2,907,205	2,227,487	1,990,509	2,208,104	29,019,022
Energy Losses	184,208	106,565	153,234	146,298	194,846	193,710	218,505	215,478	149,676	150,308	91,261	189,882	1,993,971
Total Own Load Energy	2,344,681	2,013,644	2,079,147	2,056,242	2,486,874	2,977,646	3,597,350	3,542,977	3,056,881	2,377,795	2,081,770	2,397,986	31,012,993

ENERGY DEMAND (MWH)													
YEAR: 2020	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,210,862	915,636	932,649	930,353	1,148,480	1,650,822	2,160,601	2,018,084	1,669,460	1,081,739	901,435	1,160,642	15,780,763
Comm+Ind <3 MW	898,306	929,127	975,497	977,798	1,189,770	1,172,322	1,264,949	1,358,090	1,168,833	1,071,984	989,966	957,955	12,954,597
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	486	513	875	1,057	1,326	1,340	1,231	1,109	990	886	680	495	10,988
Streetlights	12,420	13,503	15,003	13,326	14,647	11,577	12,016	13,077	12,071	13,692	14,186	14,074	159,592
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,401,094	2,118,588	2,198,700	2,190,356	2,629,299	3,132,312	3,758,313	3,710,150	3,183,198	2,485,692	2,203,185	2,416,276	32,427,163
Energy Efficiency Programs	(126,862)	(112,842)	(140,343)	(147,660)	(176,993)	(209,759)	(223,037)	(221,810)	(137,627)	(137,494)	(112,631)	(118,160)	(1,865,218)
Distributed Energy Programs	(89,346)	(85,070)	(129,752)	(128,660)	(154,362)	(114,280)	(111,055)	(116,962)	(91,876)	(96,868)	(74,305)	(62,146)	(1,254,682)
Total Sales	2,184,886	1,920,676	1,928,605	1,914,036	2,297,944	2,808,273	3,424,221	3,371,378	2,953,695	2,251,330	2,016,249	2,235,970	29,307,263
Energy Losses	189,993	143,503	127,857	143,119	207,275	212,559	216,152	212,629	130,870	146,818	95,912	197,513	2,024,200
Total Own Load Energy	2,374,879	2,064,179	2,056,462	2,057,155	2,505,219	3,020,832	3,640,373	3,584,007	3,084,565	2,398,148	2,112,161	2,433,483	31,331,463

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2021	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,256,583	950,162	968,426	966,656	1,193,485	1,715,821	2,245,167	2,097,345	1,734,649	1,124,096	936,030	1,204,009	16,392,429
Comm+Ind <3 MW	927,494	961,001	1,007,995	1,010,706	1,229,189	1,212,633	1,308,414	1,404,164	1,209,274	1,108,575	1,023,390	990,875	13,393,710
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	489	513	878	1,061	1,329	1,330	1,234	1,104	986	884	677	493	10,978
Streetlights	12,528	13,689	15,257	13,504	14,856	11,724	12,193	13,249	12,234	13,906	14,384	14,272	161,796
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,476,114	2,185,174	2,267,232	2,259,749	2,713,935	3,237,759	3,886,524	3,835,652	3,288,987	2,564,852	2,271,399	2,492,759	33,480,136
Energy Efficiency Programs	(113,526)	(111,258)	(146,958)	(153,511)	(186,224)	(226,654)	(240,511)	(237,294)	(144,551)	(140,748)	(115,945)	(119,414)	(1,936,594)
Distributed Energy Programs	(105,883)	(103,639)	(163,932)	(162,017)	(193,104)	(142,498)	(139,465)	(146,443)	(117,086)	(120,432)	(95,530)	(73,933)	(1,563,962)
Total Sales	2,256,705	1,970,277	1,956,342	1,944,221	2,334,607	2,868,607	3,506,548	3,451,915	3,027,350	2,303,672	2,059,924	2,299,412	29,979,580
Energy Losses	169,137	108,834	182,345	148,569	218,434	213,066	211,724	217,954	136,120	150,105	92,339	196,356	2,044,983
Total Own Load Energy	2,425,842	2,079,111	2,138,687	2,092,790	2,553,041	3,081,673	3,718,272	3,669,869	3,163,470	2,453,777	2,152,263	2,495,768	32,024,563

ENERGY DEMAND (MWH)													
YEAR: 2022	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,301,943	984,906	1,004,258	1,003,097	1,238,840	1,780,972	2,329,965	2,176,838	1,800,314	1,166,544	970,716	1,247,731	17,006,124
Comm+Ind <3 MW	957,160	992,247	1,039,850	1,042,963	1,267,828	1,252,147	1,351,019	1,449,328	1,248,915	1,144,443	1,056,150	1,023,144	13,825,194
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	487	513	875	1,057	1,331	1,330	1,227	1,106	986	879	679	493	10,963
Streetlights	12,723	13,894	15,451	13,701	15,067	11,890	12,364	13,452	12,401	14,103	14,587	14,472	164,105
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,551,333	2,251,369	2,335,110	2,328,640	2,798,142	3,342,590	4,014,091	3,960,514	3,394,460	2,643,360	2,339,050	2,568,950	34,527,609
Energy Efficiency Programs	(117,189)	(113,341)	(150,485)	(158,159)	(196,460)	(242,455)	(257,318)	(252,104)	(151,027)	(144,683)	(117,522)	(121,746)	(2,022,489)
Distributed Energy Programs	(135,487)	(123,935)	(208,374)	(200,784)	(240,957)	(179,161)	(171,437)	(184,302)	(144,043)	(150,746)	(118,956)	(91,644)	(1,949,826)
Total Sales	2,298,657	2,014,093	1,976,251	1,969,697	2,360,725	2,920,974	3,585,336	3,524,108	3,099,390	2,347,931	2,102,572	2,355,560	30,555,294
Energy Losses	183,963	106,946	194,217	157,975	238,986	218,592	203,401	213,051	132,955	149,346	94,622	196,188	2,090,242
Total Own Load Energy	2,482,620	2,121,039	2,170,468	2,127,672	2,599,711	3,139,566	3,788,737	3,737,159	3,232,345	2,497,277	2,197,194	2,551,748	32,645,536

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,348,425	1,020,349	1,040,930	1,040,231	1,284,991	1,847,210	2,416,676	2,258,014	1,867,134	1,209,891	1,006,143	1,291,966	17,631,960
Comm+Ind <3 MW	986,110	1,022,788	1,070,988	1,074,492	1,305,597	1,290,771	1,392,663	1,493,471	1,287,662	1,179,503	1,088,173	1,054,685	14,246,903
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	485	510	876	1,062	1,329	1,324	1,223	1,102	984	876	677	491	10,939
Streetlights	12,887	14,063	15,695	13,871	15,302	12,068	12,529	13,657	12,584	14,296	14,790	14,693	166,435
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,626,927	2,317,519	2,403,165	2,397,478	2,882,295	3,447,624	4,142,607	4,086,034	3,500,208	2,721,957	2,406,701	2,644,945	35,577,460
Energy Efficiency Programs	(119,753)	(115,867)	(154,128)	(162,980)	(206,861)	(258,434)	(274,572)	(266,030)	(157,184)	(150,095)	(118,875)	(123,119)	(2,107,898)
Distributed Energy Programs	(164,351)	(150,745)	(252,814)	(244,286)	(292,852)	(217,626)	(209,944)	(224,924)	(170,288)	(187,435)	(144,601)	(109,682)	(2,369,548)
Total Sales	2,342,823	2,050,907	1,996,223	1,990,212	2,382,582	2,971,564	3,658,091	3,595,080	3,172,736	2,384,427	2,143,225	2,412,144	31,100,014
Energy Losses	189,024	108,616	206,339	163,479	258,259	218,081	204,907	226,598	113,882	142,187	100,111	196,333	2,127,816
Total Own Load Energy	2,531,847	2,159,523	2,202,562	2,153,691	2,640,841	3,189,645	3,862,998	3,821,678	3,286,618	2,526,614	2,243,336	2,608,477	33,227,830

ENERGY DEMAND (MWH)													
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,396,165	1,056,375	1,078,421	1,078,335	1,332,121	1,915,419	2,505,245	2,341,037	1,935,620	1,254,079	1,042,324	1,337,281	18,272,422
Comm+Ind <3 MW	1,014,585	1,052,759	1,101,544	1,105,434	1,342,659	1,328,674	1,433,530	1,536,793	1,325,686	1,213,907	1,119,598	1,085,637	14,660,806
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	483	508	880	1,061	1,324	1,326	1,229	1,106	986	879	673	492	10,947
Streetlights	13,077	14,269	15,893	14,073	15,496	12,243	12,736	13,838	12,744	14,513	15,008	14,858	168,748
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,703,330	2,383,720	2,471,414	2,466,725	2,966,676	3,553,913	4,272,256	4,212,564	3,606,880	2,800,769	2,474,521	2,721,378	36,634,146
Energy Efficiency Programs	(123,298)	(124,690)	(153,042)	(171,570)	(214,422)	(271,614)	(292,683)	(278,186)	(164,116)	(154,920)	(118,898)	(126,642)	(2,194,081)
Distributed Energy Programs	(193,413)	(197,213)	(288,870)	(290,930)	(347,134)	(255,226)	(250,894)	(262,248)	(205,677)	(217,223)	(170,014)	(126,952)	(2,805,794)
Total Sales	2,386,619	2,061,817	2,029,502	2,004,225	2,405,120	3,027,073	3,728,679	3,672,130	3,237,087	2,428,626	2,185,609	2,467,784	31,634,271
Energy Losses	199,889	164,537	157,571	178,699	263,935	200,855	214,338	223,750	117,184	156,226	95,008	196,568	2,168,560
Total Own Load Energy	2,586,508	2,226,354	2,187,073	2,182,924	2,669,055	3,227,928	3,943,017	3,895,880	3,354,271	2,584,852	2,280,617	2,664,352	33,802,831

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,445,622	1,093,581	1,117,017	1,117,615	1,380,868	1,985,497	2,596,696	2,426,539	2,006,239	1,299,846	1,079,523	1,383,787	18,932,830
Comm+Ind <3 MW	1,043,577	1,082,874	1,132,248	1,136,525	1,379,902	1,366,759	1,474,595	1,580,322	1,363,893	1,248,480	1,151,174	1,116,738	15,077,087
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	483	508	880	1,061	1,324	1,326	1,229	1,106	986	879	673	492	10,947
Streetlights	13,255	14,456	16,118	14,268	15,730	12,371	12,894	14,038	12,937	14,707	15,198	15,085	171,057
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,781,957	2,451,228	2,540,939	2,537,291	3,052,900	3,662,204	4,404,930	4,341,795	3,715,899	2,881,303	2,543,486	2,799,212	37,713,144
Energy Efficiency Programs	(125,963)	(120,557)	(159,105)	(177,834)	(222,526)	(290,400)	(310,003)	(291,643)	(172,565)	(159,038)	(119,757)	(130,662)	(2,280,053)
Distributed Energy Programs	(230,871)	(210,847)	(341,899)	(334,539)	(399,651)	(294,999)	(288,114)	(303,041)	(236,880)	(251,543)	(191,690)	(157,943)	(3,242,017)
Total Sales	2,425,123	2,119,824	2,039,935	2,024,918	2,430,723	3,076,805	3,806,813	3,747,111	3,306,454	2,470,722	2,232,039	2,510,607	32,191,074
Energy Losses	214,423	115,432	212,871	184,606	276,523	211,960	211,975	221,689	104,103	157,896	97,550	205,157	2,214,185
Total Own Load Energy	2,639,546	2,235,256	2,252,806	2,209,524	2,707,246	3,288,765	4,018,788	3,968,800	3,410,557	2,628,618	2,329,589	2,715,764	34,405,259

ENERGY DEMAND (MWH)													
YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,496,521	1,131,931	1,156,644	1,157,962	1,431,130	2,057,637	2,690,787	2,514,719	2,079,016	1,346,858	1,117,845	1,431,987	19,613,037
Comm+Ind <3 MW	1,071,509	1,112,329	1,162,278	1,166,933	1,416,329	1,404,010	1,514,758	1,622,898	1,401,263	1,282,292	1,182,060	1,147,157	15,483,816
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	478	503	868	1,052	1,310	1,307	1,219	1,095	976	867	670	489	10,834
Streetlights	13,463	14,661	16,336	14,482	15,940	12,593	13,083	14,221	13,114	14,894	15,427	15,320	173,534
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,860,991	2,519,233	2,610,802	2,608,251	3,139,785	3,771,798	4,539,363	4,472,723	3,826,213	2,962,302	2,612,920	2,878,063	38,802,444
Energy Efficiency Programs	(126,932)	(123,352)	(163,852)	(183,319)	(230,142)	(308,629)	(326,679)	(305,493)	(179,471)	(161,948)	(122,781)	(132,684)	(2,365,282)
Distributed Energy Programs	(249,470)	(241,006)	(388,593)	(378,435)	(454,649)	(336,067)	(324,712)	(344,859)	(268,655)	(285,085)	(216,805)	(183,939)	(3,672,275)
Total Sales	2,484,589	2,154,875	2,058,357	2,046,497	2,454,994	3,127,102	3,887,972	3,822,371	3,378,087	2,515,269	2,273,334	2,561,440	32,764,887
Energy Losses	205,006	120,847	230,060	180,262	289,607	226,102	209,492	225,380	95,387	156,600	102,744	212,984	2,254,471
Total Own Load Energy	2,689,595	2,275,722	2,288,417	2,226,759	2,744,601	3,353,204	4,097,464	4,047,751	3,473,474	2,671,869	2,376,078	2,774,424	35,019,358

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,548,269	1,171,326	1,197,484	1,199,321	1,482,506	2,131,857	2,787,294	2,605,159	2,153,528	1,395,222	1,157,133	1,481,210	20,310,309
Comm+Ind <3 MW	1,099,570	1,141,636	1,192,158	1,197,189	1,452,572	1,441,072	1,554,721	1,665,260	1,438,444	1,315,936	1,212,789	1,177,425	15,888,772
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	480	503	868	1,052	1,310	1,307	1,219	1,095	976	867	670	489	10,836
Streetlights	13,604	14,887	16,572	14,673	16,158	12,732	13,242	14,458	13,297	15,124	15,643	15,487	175,877
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,940,943	2,588,161	2,681,758	2,680,057	3,227,622	3,883,219	4,675,992	4,605,762	3,938,089	3,044,540	2,683,153	2,957,721	39,907,017
Energy Efficiency Programs	(128,397)	(126,160)	(168,632)	(188,837)	(238,966)	(325,040)	(343,651)	(320,471)	(186,087)	(164,884)	(125,854)	(133,678)	(2,450,657)
Distributed Energy Programs	(271,064)	(270,891)	(434,413)	(424,409)	(507,402)	(371,235)	(367,365)	(382,009)	(307,039)	(314,935)	(246,295)	(198,745)	(4,095,802)
Total Sales	2,541,482	2,191,110	2,078,713	2,066,811	2,481,254	3,186,944	3,964,976	3,903,282	3,444,963	2,564,721	2,311,004	2,625,298	33,360,558
Energy Losses	204,001	121,544	244,184	186,175	302,548	223,138	204,071	229,050	101,763	158,392	98,689	211,393	2,284,948
Total Own Load Energy	2,745,483	2,312,654	2,322,897	2,252,986	2,783,802	3,410,082	4,169,047	4,132,332	3,546,726	2,723,113	2,409,693	2,836,691	35,645,506

ENERGY DEMAND (MWH)													
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,602,309	1,211,998	1,239,633	1,242,192	1,535,805	2,208,653	2,887,444	2,698,979	2,230,791	1,445,070	1,197,812	1,532,480	21,033,166
Comm+Ind <3 MW	1,128,110	1,171,212	1,222,310	1,227,723	1,489,145	1,478,475	1,595,050	1,708,008	1,475,967	1,349,887	1,243,799	1,207,968	16,297,654
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	480	503	868	1,052	1,310	1,307	1,219	1,095	976	867	670	489	10,836
Streetlights	13,834	15,079	16,814	14,884	16,390	12,929	13,457	14,638	13,476	15,313	15,860	15,749	178,423
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,023,753	2,658,601	2,754,301	2,753,673	3,317,726	3,997,615	4,816,686	4,742,510	4,053,054	3,128,528	2,755,059	3,039,796	41,041,302
Energy Efficiency Programs	(131,836)	(135,792)	(169,516)	(192,075)	(250,385)	(339,957)	(360,003)	(334,825)	(191,469)	(169,880)	(126,855)	(134,729)	(2,537,322)
Distributed Energy Programs	(302,704)	(307,012)	(480,527)	(463,885)	(557,214)	(408,173)	(401,407)	(424,050)	(320,143)	(355,114)	(265,518)	(216,248)	(4,501,995)
Total Sales	2,589,213	2,215,797	2,104,258	2,097,713	2,510,127	3,249,485	4,055,276	3,983,635	3,541,442	2,603,534	2,362,686	2,688,819	34,001,985
Energy Losses	217,060	171,656	202,649	194,210	331,535	226,365	197,995	237,313	81,304	151,343	105,400	210,959	2,327,789
Total Own Load Energy	2,806,273	2,387,453	2,306,907	2,291,923	2,841,662	3,475,850	4,253,271	4,220,948	3,622,746	2,754,877	2,468,086	2,899,778	36,329,774

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,655,222	1,252,754	1,281,765	1,284,896	1,588,969	2,285,106	2,987,124	2,792,398	2,307,778	1,494,835	1,238,547	1,583,151	21,752,545
Comm+Ind <3 MW	1,156,626	1,200,868	1,252,546	1,258,340	1,525,819	1,515,979	1,635,487	1,750,875	1,513,591	1,383,929	1,274,893	1,238,596	16,707,549
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	480	503	868	1,052	1,310	1,307	1,219	1,095	976	867	670	489	10,836
Streetlights	14,019	15,293	17,019	15,107	16,623	13,131	13,623	14,853	13,683	15,525	16,085	15,970	180,931
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,105,367	2,729,227	2,826,874	2,827,217	3,407,797	4,111,774	4,956,969	4,879,011	4,167,872	3,212,547	2,827,113	3,121,316	42,173,084
Energy Efficiency Programs	(136,243)	(130,439)	(174,627)	(199,808)	(259,171)	(355,445)	(378,435)	(349,098)	(197,874)	(175,555)	(128,415)	(137,360)	(2,622,470)
Distributed Energy Programs	(335,579)	(310,189)	(533,144)	(501,960)	(605,324)	(442,265)	(436,870)	(459,347)	(353,025)	(383,024)	(285,785)	(231,186)	(4,877,698)
Total Sales	2,633,545	2,288,599	2,119,103	2,125,449	2,543,302	3,314,064	4,141,664	4,070,566	3,616,973	2,653,968	2,412,913	2,752,770	34,672,916
Energy Losses	227,916	120,547	268,786	197,351	339,193	218,115	207,411	246,553	73,664	163,067	104,221	212,718	2,379,542
Total Own Load Energy	2,861,461	2,409,146	2,387,889	2,322,800	2,882,495	3,532,179	4,349,075	4,317,119	3,690,637	2,817,035	2,517,134	2,965,488	37,052,458

ENERGY DEMAND (MWH)													
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,711,551	1,295,040	1,325,625	1,329,297	1,644,373	2,364,797	3,090,944	2,889,513	2,388,000	1,546,683	1,280,781	1,636,164	22,502,768
Comm+Ind <3 MW	1,185,467	1,230,769	1,283,032	1,289,209	1,562,798	1,553,794	1,676,261	1,794,096	1,551,528	1,418,255	1,306,247	1,269,477	17,120,933
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	480	503	868	1,052	1,310	1,307	1,219	1,095	976	867	670	489	10,836
Streetlights	14,202	15,514	17,275	15,315	16,856	13,299	13,837	15,040	13,866	15,763	16,304	16,195	183,466
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,190,720	2,801,635	2,901,476	2,902,695	3,500,413	4,229,448	5,101,777	5,019,534	4,286,214	3,298,959	2,900,920	3,205,435	43,339,226
Energy Efficiency Programs	(138,685)	(132,967)	(177,145)	(207,271)	(267,632)	(370,612)	(396,481)	(361,989)	(206,017)	(179,382)	(129,071)	(141,174)	(2,708,426)
Distributed Energy Programs	(360,869)	(349,561)	(553,934)	(539,950)	(648,844)	(472,579)	(470,814)	(483,419)	(385,169)	(403,405)	(310,318)	(245,996)	(5,224,858)
Total Sales	2,691,166	2,319,107	2,170,397	2,155,474	2,583,937	3,386,257	4,234,482	4,174,126	3,695,028	2,716,172	2,461,531	2,818,265	35,405,942
Energy Losses	241,645	127,825	260,522	217,375	351,283	212,262	210,148	235,760	85,115	168,468	104,186	215,184	2,429,773
Total Own Load Energy	2,932,811	2,446,932	2,430,919	2,372,849	2,935,220	3,598,519	4,444,630	4,409,886	3,780,143	2,884,640	2,565,717	3,033,449	37,835,715

ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

	ENERGY DEMAND (MWH)												
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,768,413	1,338,074	1,370,097	1,374,793	1,700,701	2,445,963	3,196,585	2,988,743	2,469,532	1,599,580	1,323,896	1,690,257	23,266,634
Comm+Ind <3 MW	1,214,902	1,261,158	1,314,014	1,320,582	1,600,376	1,592,226	1,717,696	1,838,021	1,590,081	1,453,140	1,338,109	1,300,859	17,541,164
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	480	503	868	1,052	1,310	1,307	1,219	1,095	976	867	670	489	10,836
Streetlights	14,386	15,736	17,500	15,536	17,093	13,499	14,009	15,271	14,069	15,961	16,554	16,414	186,028
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,277,201	2,875,280	2,977,155	2,979,785	3,594,556	4,349,246	5,249,025	5,162,920	4,406,502	3,386,939	2,976,147	3,291,129	44,525,885
Energy Efficiency Programs	(140,803)	(135,446)	(180,750)	(213,159)	(275,265)	(388,829)	(413,174)	(374,853)	(214,100)	(183,165)	(129,643)	(144,915)	(2,794,102)
Distributed Energy Programs	(389,994)	(356,916)	(601,801)	(572,588)	(690,833)	(504,316)	(496,648)	(519,390)	(409,014)	(430,785)	(325,760)	(265,668)	(5,563,713)
Total Sales	2,746,404	2,382,918	2,194,604	2,194,038	2,628,458	3,456,101	4,339,203	4,268,677	3,783,388	2,772,989	2,520,744	2,880,546	36,168,070
Energy Losses	247,491	126,618	277,282	222,200	364,269	227,011	208,618	235,938	72,185	171,822	108,723	224,023	2,486,180
Total Own Load Energy	2,993,895	2,509,536	2,471,886	2,416,238	2,992,727	3,683,112	4,547,821	4,504,615	3,855,573	2,944,811	2,629,467	3,104,569	38,654,250

	ENERGY DEMAND (MWH)												
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,826,664	1,382,100	1,415,907	1,421,323	1,758,559	2,529,076	3,305,026	3,090,364	2,553,490	1,653,898	1,367,986	1,745,626	24,050,019
Comm+Ind <3 MW	1,244,831	1,292,049	1,345,509	1,352,475	1,638,579	1,631,292	1,759,820	1,882,673	1,629,274	1,488,603	1,370,500	1,332,763	17,968,368
Comm+Ind >3 MW	279,020	259,809	274,676	267,822	275,076	296,251	319,516	319,790	331,844	317,391	296,918	283,110	3,521,223
Irrigation	480	503	868	1,052	1,310	1,307	1,219	1,095	976	867	670	489	10,836
Streetlights	14,602	15,950	17,762	15,729	17,319	13,678	14,226	15,478	14,265	16,215	16,774	16,641	188,639
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,365,597	2,950,411	3,054,722	3,058,401	3,690,843	4,471,604	5,399,807	5,309,400	4,529,849	3,476,974	3,052,848	3,378,629	45,739,085
Energy Efficiency Programs	(141,496)	(145,561)	(184,017)	(217,924)	(282,498)	(406,596)	(429,158)	(389,324)	(220,368)	(184,679)	(133,808)	(145,277)	(2,880,706)
Distributed Energy Programs	(408,920)	(401,500)	(635,115)	(605,032)	(730,622)	(530,525)	(524,452)	(542,280)	(435,560)	(452,368)	(342,225)	(295,729)	(5,904,328)
Total Sales	2,815,181	2,403,350	2,235,590	2,235,445	2,677,723	3,534,483	4,446,197	4,377,796	3,873,921	2,839,927	2,576,815	2,937,623	36,954,051
Energy Losses	239,767	189,550	238,432	214,460	374,709	240,665	203,172	242,583	80,216	173,664	108,539	235,943	2,541,700
Total Own Load Energy	3,054,948	2,592,900	2,474,022	2,449,905	3,052,432	3,775,148	4,649,369	4,620,379	3,954,137	3,013,591	2,685,354	3,173,566	39,495,751

ATTACHMENT C.2 – COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM

PEAK DEMAND (MW)													
YEAR: 2017	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	4,281	4,084	3,751	4,343	5,391	6,521	7,023	7,023	6,407	5,126	3,767	4,350	7,023
Distributed Energy Programs	(0)	(0)	(1)	(43)	(44)	(42)	(37)	(37)	(38)	(35)	(0)	(0)	(37)
Own Load Peak - After DE Before EE/DR	4,281	4,084	3,750	4,300	5,347	6,479	6,986	6,986	6,369	5,091	3,767	4,350	6,986
Energy Efficiency Programs	(54)	(53)	(59)	(71)	(81)	(108)	(113)	(113)	(97)	(80)	(55)	(54)	(113)
Distributed Energy Programs	0	0	0	0	0	(39)	(39)	(39)	(39)	0	0	0	(39)
Own Load After EE/ DE	4,227	4,031	3,692	4,228	5,266	6,332	6,834	6,834	6,232	5,012	3,712	4,296	6,834

PEAK DEMAND (MW)													
YEAR: 2018	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	4,485	4,244	3,887	4,493	5,572	6,757	7,307	7,307	6,639	5,316	3,890	4,493	7,307
Distributed Energy Programs	(0)	(0)	(1)	(49)	(70)	(61)	(75)	(75)	(77)	(69)	(1)	(0)	(75)
Own Load Peak - After DE Before EE/DR	4,485	4,244	3,886	4,444	5,501	6,696	7,232	7,232	6,563	5,247	3,889	4,493	7,232
Energy Efficiency Programs	(110)	(107)	(119)	(141)	(159)	(214)	(229)	(229)	(197)	(162)	(114)	(109)	(229)
Distributed Energy Programs	0	0	0	0	0	(39)	(39)	(39)	(39)	0	0	0	(39)
Own Load After EE/ DE	4,374	4,137	3,767	4,303	5,342	6,443	6,964	6,964	6,326	5,085	3,775	4,385	6,964

PEAK DEMAND (MW)													
YEAR: 2019	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	4,651	4,390	4,010	4,678	5,787	6,995	7,581	7,581	6,911	5,539	4,038	4,653	7,581
Distributed Energy Programs	(0)	(0)	(2)	(42)	(75)	(65)	(117)	(126)	(115)	(104)	(1)	(0)	(117)
Own Load Peak - After DE Before EE/DR	4,651	4,390	4,008	4,636	5,712	6,930	7,464	7,455	6,796	5,435	4,037	4,653	7,464
Energy Efficiency Programs	(168)	(163)	(170)	(214)	(241)	(322)	(337)	(345)	(298)	(244)	(163)	(165)	(337)
Distributed Energy Programs	0	0	0	0	0	(39)	(39)	(39)	(39)	0	0	0	(39)
Own Load After EE/ DE	4,483	4,227	3,838	4,422	5,472	6,569	7,088	7,071	6,459	5,191	3,874	4,488	7,088

ATTACHMENT C.2 – COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2020	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	4,805	4,449	4,084	4,835	5,984	7,279	7,855	7,855	7,130	5,722	4,184	4,815	7,855
Distributed Energy Programs	(0)	(0)	(0)	(8)	(81)	(71)	(123)	(115)	(150)	(141)	(0)	(0)	(115)
Own Load Peak - After DE Before EE/DR	4,805	4,449	4,084	4,827	5,903	7,208	7,732	7,740	6,980	5,580	4,184	4,815	7,740
Energy Efficiency Programs	(224)	(218)	(235)	(286)	(321)	(430)	(450)	(450)	(397)	(326)	(221)	(220)	(450)
Distributed Energy Programs	0	0	0	0	0	(39)	(39)	(39)	(39)	0	0	0	(39)
Own Load After EE/DE	4,581	4,232	3,849	4,541	5,582	6,739	7,243	7,251	6,543	5,254	3,963	4,595	7,251

PEAK DEMAND (MW)													
YEAR: 2021	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	4,937	4,677	4,291	4,972	6,178	7,517	8,130	8,130	7,384	5,910	4,304	4,962	8,130
Distributed Energy Programs	(0)	(0)	(3)	(57)	(85)	(76)	(133)	(123)	(186)	(142)	(1)	(0)	(123)
Own Load Peak - After DE Before EE/DR	4,937	4,677	4,288	4,916	6,093	7,441	7,997	8,007	7,198	5,768	4,303	4,962	8,007
Energy Efficiency Programs	(311)	(308)	(300)	(393)	(345)	(475)	(496)	(494)	(416)	(329)	(309)	(308)	(494)
Distributed Energy Programs	0	0	0	0	0	(64)	(64)	(64)	(64)	0	0	0	(64)
Own Load After EE/DE	4,626	4,369	3,987	4,522	5,748	6,902	7,437	7,450	6,718	5,440	3,995	4,655	7,450

PEAK DEMAND (MW)													
YEAR: 2022	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	5,097	4,815	4,420	5,134	6,386	7,766	8,405	8,405	7,625	6,087	4,437	5,109	8,405
Distributed Energy Programs	(0)	(0)	(7)	(74)	(100)	(93)	(148)	(136)	(247)	(155)	(0)	(0)	(136)
Own Load Peak - After DE Before EE/DR	5,097	4,815	4,414	5,061	6,287	7,674	8,256	8,269	7,378	5,932	4,437	5,109	8,269
Energy Efficiency Programs	(327)	(328)	(314)	(430)	(367)	(519)	(534)	(536)	(443)	(347)	(327)	(325)	(536)
Distributed Energy Programs	0	0	0	0	0	(89)	(89)	(89)	(89)	0	0	0	(89)
Own Load After EE/DE	4,769	4,487	4,100	4,630	5,919	7,066	7,633	7,644	6,846	5,586	4,110	4,783	7,644

ATTACHMENT C.2 – COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	5,244	4,957	4,554	5,286	6,592	8,005	8,681	8,681	7,835	6,246	4,578	5,258	8,681
Distributed Energy Programs	(0)	(1)	(12)	(88)	(118)	(115)	(172)	(156)	(211)	(160)	(0)	(0)	(156)
Own Load Peak - After DE Before EE/DR	5,244	4,956	4,542	5,198	6,473	7,891	8,509	8,525	7,625	6,086	4,578	5,258	8,525
Energy Efficiency Programs	(341)	(342)	(332)	(470)	(390)	(570)	(576)	(578)	(449)	(378)	(349)	(347)	(578)
Distributed Energy Programs	0	0	0	0	0	(114)	(114)	(114)	(114)	0	0	0	(114)
Own Load After EE/ DE	4,903	4,614	4,210	4,728	6,083	7,206	7,820	7,833	7,062	5,708	4,229	4,911	7,833

PEAK DEMAND (MW)													
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	5,403	5,020	4,596	5,451	6,771	8,215	8,961	8,961	8,088	6,459	4,700	5,406	8,961
Distributed Energy Programs	(0)	(1)	(0)	(98)	(129)	(138)	(194)	(271)	(224)	(166)	(0)	(0)	(194)
Own Load Peak - After DE Before EE/DR	5,403	5,019	4,596	5,354	6,642	8,076	8,768	8,690	7,863	6,293	4,700	5,406	8,768
Energy Efficiency Programs	(359)	(360)	(373)	(488)	(406)	(599)	(585)	(622)	(523)	(405)	(354)	(359)	(585)
Distributed Energy Programs	0	0	0	0	0	(139)	(139)	(139)	(139)	0	0	0	(139)
Own Load After EE/ DE	5,045	4,659	4,223	4,865	6,236	7,338	8,043	7,928	7,201	5,888	4,345	5,046	8,043

PEAK DEMAND (MW)													
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	5,570	5,252	4,796	5,619	6,970	8,483	9,248	9,248	8,314	6,647	4,840	5,563	9,248
Distributed Energy Programs	(0)	(1)	(27)	(76)	(147)	(163)	(219)	(204)	(238)	(172)	(0)	(0)	(219)
Own Load Peak - After DE Before EE/DR	5,570	5,251	4,769	5,542	6,822	8,320	9,029	9,044	8,076	6,475	4,840	5,563	9,029
Energy Efficiency Programs	(391)	(388)	(349)	(528)	(482)	(643)	(620)	(647)	(561)	(414)	(380)	(383)	(620)
Distributed Energy Programs	0	0	0	0	0	(138)	(138)	(138)	(138)	0	0	0	(138)
Own Load After EE/ DE	5,179	4,862	4,420	5,015	6,340	7,539	8,271	8,259	7,378	6,061	4,460	5,180	8,271

ATTACHMENT C.2 – COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	5,709	5,400	4,941	5,760	7,168	8,761	9,539	9,539	8,553	6,830	4,982	5,727	9,539
Distributed Energy Programs	(0)	(1)	(5)	(83)	(166)	(188)	(245)	(225)	(360)	(264)	(0)	(0)	(225)
Own Load Peak - After DE Before EE/DR	5,709	5,398	4,935	5,677	7,002	8,573	9,294	9,314	8,193	6,566	4,982	5,727	9,314
Energy Efficiency Programs	(424)	(429)	(390)	(568)	(514)	(685)	(727)	(686)	(584)	(406)	(420)	(402)	(686)
Distributed Energy Programs	0	0	0	0	0	(163)	(163)	(163)	(163)	0	0	0	(163)
Own Load After EE/ DE	5,285	4,969	4,545	5,108	6,488	7,724	8,404	8,464	7,446	6,159	4,562	5,325	8,464

PEAK DEMAND (MW)													
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	5,861	5,541	5,082	5,903	7,370	9,011	9,835	9,835	8,823	7,027	5,105	5,883	9,835
Distributed Energy Programs	(0)	(2)	(40)	(157)	(185)	(214)	(275)	(251)	(267)	(181)	(0)	(0)	(251)
Own Load Peak - After DE Before EE/DR	5,861	5,539	5,042	5,747	7,186	8,797	9,560	9,584	8,556	6,846	5,105	5,883	9,584
Energy Efficiency Programs	(443)	(461)	(367)	(649)	(481)	(739)	(766)	(747)	(639)	(476)	(449)	(443)	(747)
Distributed Energy Programs	0	0	0	0	0	(188)	(188)	(188)	(188)	0	0	0	(188)
Own Load After EE/ DE	5,419	5,078	4,675	5,097	6,705	7,870	8,606	8,649	7,729	6,369	4,656	5,440	8,649

PEAK DEMAND (MW)													
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	6,035	5,583	5,135	6,075	7,608	9,279	10,141	10,141	9,057	7,189	5,259	6,040	10,141
Distributed Energy Programs	(0)	(2)	(0)	(188)	(214)	(240)	(308)	(277)	(275)	(188)	(0)	(0)	(277)
Own Load Peak - After DE Before EE/DR	6,035	5,581	5,135	5,887	7,394	9,039	9,833	9,864	8,782	7,001	5,259	6,039	9,864
Energy Efficiency Programs	(451)	(473)	(443)	(629)	(503)	(780)	(782)	(788)	(564)	(516)	(465)	(461)	(788)
Distributed Energy Programs	0	0	0	0	0	(213)	(213)	(213)	(213)	0	0	0	(213)
Own Load After EE/ DE	5,584	5,108	4,692	5,258	6,891	8,046	8,838	8,863	8,005	6,485	4,795	5,579	8,863

ATTACHMENT C.2 – COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	6,200	5,845	5,356	6,234	7,804	9,521	10,446	10,446	9,304	7,408	5,396	6,200	10,446
Distributed Energy Programs	(0)	(2)	(58)	(210)	(236)	(256)	(339)	(303)	(290)	(194)	(4)	(0)	(339)
Own Load Peak - After DE Before EE/DR	6,200	5,843	5,297	6,024	7,568	9,265	10,107	10,143	9,014	7,214	5,393	6,199	10,107
Energy Efficiency Programs	(448)	(460)	(416)	(642)	(513)	(812)	(755)	(867)	(589)	(544)	(502)	(450)	(755)
Distributed Energy Programs	0	0	0	0	0	(238)	(238)	(238)	(238)	0	0	0	(238)
Own Load After EE/DE	5,752	5,383	4,881	5,381	7,056	8,215	9,114	9,038	8,188	6,669	4,891	5,749	9,114

PEAK DEMAND (MW)													
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	6,382	6,002	5,481	6,421	8,015	9,774	10,761	10,761	9,590	7,621	5,533	6,365	10,761
Distributed Energy Programs	(0)	(1)	(8)	(224)	(258)	(298)	(370)	(417)	(306)	(200)	(0)	(1)	(370)
Own Load Peak - After DE Before EE/DR	6,382	6,001	5,473	6,197	7,757	9,476	10,390	10,344	9,284	7,421	5,533	6,364	10,390
Energy Efficiency Programs	(457)	(480)	(424)	(690)	(534)	(855)	(789)	(882)	(743)	(572)	(475)	(466)	(789)
Distributed Energy Programs	0	0	0	0	0	(263)	(263)	(263)	(263)	0	0	0	(263)
Own Load After EE/DE	5,925	5,521	5,049	5,507	7,223	8,358	9,339	9,199	8,278	6,848	5,058	5,898	9,339

ATTACHMENT C.2 – COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	6,551	6,163	5,627	6,601	8,233	10,072	11,081	11,081	9,838	7,827	5,687	6,539	11,081
Distributed Energy Programs	(0)	(1)	(44)	(191)	(283)	(329)	(404)	(362)	(321)	(207)	(0)	(1)	(404)
Own Load Peak - After DE Before EE/DR	6,551	6,162	5,583	6,410	7,950	9,742	10,678	10,720	9,517	7,620	5,687	6,538	10,678
Energy Efficiency Programs	(489)	(493)	(405)	(710)	(674)	(898)	(822)	(882)	(779)	(556)	(488)	(477)	(822)
Distributed Energy Programs	0	0	0	0	0	(288)	(288)	(288)	(288)	0	0	0	(288)
Own Load After EE/DE	6,062	5,669	5,177	5,700	7,276	8,557	9,567	9,550	8,450	7,064	5,199	6,061	9,567

PEAK DEMAND (MW)													
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak	6,705	6,207	5,701	6,742	8,451	10,375	11,410	11,410	10,130	8,037	5,829	6,719	11,410
Distributed Energy Programs	(0)	(1)	(0)	(279)	(330)	(363)	(443)	(386)	(323)	(209)	(0)	(1)	(386)
Own Load Peak - After DE Before EE/DR	6,705	6,205	5,701	6,463	8,121	10,011	10,967	11,024	9,808	7,828	5,829	6,718	11,024
Energy Efficiency Programs	(515)	(532)	(480)	(756)	(593)	(958)	(990)	(957)	(824)	(605)	(509)	(499)	(957)
Distributed Energy Programs	0	0	0	0	0	(313)	(313)	(313)	(313)	0	0	0	(313)
Own Load After EE/DE	6,190	5,674	5,221	5,707	7,528	8,740	9,664	9,753	8,671	7,223	5,321	6,220	9,753

D.1(A)(1) – POWER SUPPLY

POWER SUPPLY – ESTIMATES FOR 2017-2032															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Palo Verde															
Unit 1	1986	2047	Steam	382	1,311	382	382					Uranium	382	Must Run	Baseload
Unit 2	1986	2047	Steam	382	1,314	382	382					Uranium	382	Must Run	Baseload
Unit 3	1988	2047	Steam	382	1,312	382	382					Uranium	382	Must Run	Baseload
Four Corners															
Unit 4	1969	2038	Steam	485	770	485	485					Coal	315	Must Run	Baseload
Unit 5	1970	2038	Steam	485	770	485	485					Coal	315	Must Run	Baseload
Navajo Generating Station (NGS)															
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	2025	Steam	116	116	116	116					Coal	30	No	Baseload
Unit 3	1980	2025	Steam	271	271	271	271					Coal	150	No	Baseload
Ocotillo															
Unit 1 ST	1960	2018	Steam	110	110	110	110					Gas	20	No	Peaking
Unit 2 ST	1960	2018	Steam	110	110	110	110					Gas	20	No	Peaking
Unit 1 CT	1972	2030	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2030	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 3-7 CT	2019	2049	Combustion Turbine	530	540	540	524					Gas	133	No	Peaking
Saguaro															
Unit 1 CT	1972	2030	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2030	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

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(9) 2016$

D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032														
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) 1,9	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking 8
West Phoenix															
Unit 1 CC	1976	2030	Combined Cycle	88	92	92	85					Gas	20	No	Intermediate
Unit 2 CC	1976	2030	Combined Cycle	88	92	92	85					Gas	20	No	Intermediate
Unit 3 CC	1976	2030	Combined Cycle	88	92	92	85					Gas	50	No	Intermediate
Unit 4 CC	2001	2036	Combined Cycle	117	123	123	110					Gas	77	No	Intermediate
Unit 5 CC	2003	2038	Combined Cycle	506	568	568	487					Gas	270	No	Intermediate
Unit 1 CT	1972	2030	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 2 CT	1973	2030	Combustion Turbine	55	62	62	50					Gas	4	No	Peaking
Unit 3	1988	2047	Steam	382	1,312	382	382					Uranium	382	Must Run	Baseload
Redhawk															
Unit 1 CC	2002	2037	Combined Cycle	492	532	532	500					Gas	250	No	Intermediate
Unit 2 CC	2002	2037	Combined Cycle	492	532	532	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

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(9) 2016$

D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Sundance (continued)															
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	2030	Combustion Turbine	19	22	22	18					Gas	2	No	Peaking
Unit 2 CT	1971	2030	Combustion Turbine	19	22	22	18					Gas	2	No	Peaking
Unit 3 CT	1973	2030	Combustion Turbine	55	62	62	52					Gas	5	No	Peaking
Unit 4 CT	1974	2030	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	2030	Combustion Turbine	16	19	19	15					Oil	2	No	Peaking
Microgrid															
Marine Corp Air Station Yuma (MCASY)	2016	2036	Diesel Gen Set	22	22	22	22					Oil	2.2	No	Peaking

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D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units															
Unit 1 CC	2021	2052	Combined Cycle	541	541	541	500					Gas	230	No	Intermediate
Unit 2 CC	2020	2051	Combined Cycle	541	541	541	500					Gas	230	No	Intermediate
Unit 3 CC	2021	2052	Combined Cycle	541	541	541	500					Gas	230	No	Intermediate
Unit 4 CC	2026	2057	Combined Cycle	541	541	541	500					Gas	230	No	Intermediate
Unit 1-2 Large Frame CT [2]	2022	2052	Combustion Turbine	446	454	454	431					Gas	200	No	Peaking
Unit 3-5 Large Frame CT [3]	2025	2055	Combustion Turbine	669	681	681	647					Gas	300	No	Peaking
Unit 6-7 Large Frame CT [2]	2026	2056	Combustion Turbine	446	454	454	431					Gas	200	No	Peaking
Unit 8 Large Frame CT	2027	2057	Combustion Turbine	223	227	227	216					Gas	100	No	Peaking
Unit 9 Large Frame CT	2028	2058	Combustion Turbine	223	227	227	216					Gas	100	No	Peaking
Unit 10 Large Frame CT	2029	2059	Combustion Turbine	223	227	227	216					Gas	100	No	Peaking
Unit 11 Large Frame CT	2030	2060	Combustion Turbine	223	227	227	216					Gas	100	No	Peaking
Unit 12 Large Frame CT	2031	2061	Combustion Turbine	223	227	227	216					Gas	100	No	Peaking
Unit 13-14 CT [4]	2024	2054	Combustion Turbine	212	216	216	209					Gas	53	No	Peaking
Unit 15-16 CT [4]	2032	2062	Combustion Turbine	212	216	216	209					Gas	53	No	Peaking

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D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units (continued)															
Microgrid 1	2017	2037	Diesel Gen Set	11	11	11	11					Oil	1.1	No	Peaking
Microgrid 2	2022	2042	Diesel Gen Set	25	25	25	25					Oil	2.5	No	Peaking
Microgrid 3	2023	2043	Diesel Gen Set	50	50	50	50					Oil	5.0	No	Peaking
Energy Storage System 1	2018	2038	Battery ESS	1	1	1	1					N/A	N/A	No	Peaking
Energy Storage System 2	2019	2039	Battery ESS	2	2	2	2					N/A	N/A	No	Peaking
Energy Storage System 3	2024	2044	Battery ESS	100	100	79	79					N/A	N/A	No	Peaking
Energy Storage System 4	2028	2048	Battery ESS	100	100	79	79					N/A	N/A	No	Peaking
Energy Storage System 5	2029	2049	Battery ESS	100	100	79	79					N/A	N/A	No	Peaking
Energy Storage System 6	2030	2050	Battery ESS	100	100	79	79					N/A	N/A	No	Peaking
Energy Storage System 7	2032	2052	Battery ESS	100	100	79	79					N/A	N/A	No	Peaking
Renewables															
APS Existing Solar [5]	1997-2006	2013-2023	Renewable	4	4	2	2					Solar	N/A	No	Intermittent
Aragonne Mesa Wind, NM	2006	2026	Renewable	87	90	18	18					Wind	N/A	No	Intermittent

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D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032																
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Renewables (continued)															
Salton Sea CE Turbo	2006	2029	Renewable	10	10	10	10					Geothermal	N/A	No	Baseload
SWMP Biomass (Snowflake Abitibi)	2008	2023	Renewable	14	14	13	13					Biomass	N/A	No	Baseload
High Lonesome Wind, New Mexico	2009	2039	Renewable	97	100	17	17					Wind	N/A	No	Intermittent
Sexton - City of Glendale Landfill	2010	2029	Renewable	3	3	3	3					Biogas	N/A	No	Baseload
Perrin Ranch Wind	2012	2036	Renewable	99	99	20	20					Wind	N/A	No	Intermittent
New Wind	2027	2047	Renewable	87	87	16	16					Wind	N/A	No	Intermittent
Solana CSP	2013	2043	Renewable	250	250	250	250					Solar	N/A	No	Intermittent
AZ Sun: Hyder II	2013	2038	Renewable	14	14	0	12					Solar	N/A	No	Intermittent
AZ Sun: Cotton Center	2011	2036	Renewable	17	17	0	10					Solar	N/A	No	Intermittent
AZ Sun: Hyder	2011	2036	Renewable	16	16	0	9					Solar	N/A	No	Intermittent
AZ Sun: Chino Valley	2012	2037	Renewable	19	19	0	8					Solar	N/A	No	Intermittent
AZ Sun: Paloma	2011	2036	Renewable	17	17	0	6					Solar	N/A	No	Intermittent
AZ Sun: Yuma Foothills	2013	2038	Renewable	35	35	0	25					Solar	N/A	No	Intermittent

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D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032																
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) 1,9	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking 8
Renewables (continued)															
AZ Sun: Luke AFB	2015	2040	Renewable	10	10	0	7					Solar	N/A	No	Intermittent
AZ Sun: Desert Star	2015	2040	Renewable	10	10	0	7					Solar	N/A	No	Intermittent
Red Rock Solar	2016	2041	Renewable	40	40	0	25					Solar	N/A	No	Intermittent
Small Gen RFP (Ajo)	2011	2036	Renewable	5	5	0	2					Solar	N/A	No	Intermittent
Small Gen RFP (Prescott)	2011	2041	Renewable	10	10	0	4					Solar	N/A	No	Intermittent
Small Gen RFP (Saddle Mt Tonopah)	2012	2042	Renewable	15	15	0	8					Solar	N/A	No	Intermittent
Small Gen RFP (WM Landfill)	2012	2032	Renewable	3	3	3	3					Biogas	N/A	No	Baseload
Badger-Desert Sky	2013	2042	Renewable	15	15	0	9					Solar	N/A	No	Intermittent
Recurrent Gillespie	2013	2042	Renewable	15	15	0	9					Solar	N/A	No	Intermittent
Utility Scale DE															
Bagdad	2011	2036	Renewable	15	15	0	6					Solar	N/A	No	Intermittent
Schools and Gov't DE	2012-2016	2036	Renewable	23	23	0	8					Solar	N/A	No	Intermittent

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D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Contracts															
SRP - Firm / Eastern Mining Load	1955	2020	Contract	38	38	38	37					N/A	N/A	No	Baseload
PACIFICORP Div Exch	1990	2020	Contract	480	480	(480)	480					N/A	N/A	No	Intermediate
AGX Load	2017	2032	Contract	158	158	158	158					N/A	N/A	No	Baseload
DR Contract (on-peak) # 1	2010	2025	Contract	25	26	0	12					N/A	N/A	No	Peaking
DR Contract (on-peak) # 2	2017	2032	Contract	13	13	0	7					N/A	N/A	No	Peaking
DR Contract (on-peak) # 3	2021	2032	Contract	300	300	0	165					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 [6]	2010	2019	Tolling	250	250	0	250					Gas	150	No	Intermediate
CC Tolling # 2 2A [6]	2010	2019	Tolling	250	250	0	250					Gas	150	No	Intermediate
CC Tolling # 2 3A [6]	2010	2019	Tolling	75	75	0	75					Gas	75	No	Intermediate

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D.1(A)(1) – POWER SUPPLY (CONTINUED)

POWER SUPPLY – ESTIMATES FOR 2017-2032																
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(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) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Contracts (continued)															
CC Tolling # 3 [7]	2017	2020	Tolling	271	271	0	250					Gas	115	No	Intermediate
CC Tolling # 4 1A [7]	2020	2025	Tolling	250	250	0	250					Gas	125	No	Intermediate
CC Tolling # 4 2A [7]	2020	2025	Tolling	250	250	0	250					Gas	125	No	Intermediate
CC Tolling # 4 3A [7]	2020	2025	Tolling	65	65	0	65					Gas	65	No	Intermediate

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ATTACHMENT D.1(A)(2) – ANNUAL CAPACITY FACTOR

	Annual Capacity Factor – B.1(e)															
UNIT	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Palo Verde																
Unit 1	[redacted]															
Unit 2	[redacted]															
Unit 3	[redacted]															
Four Corners																
Unit 4	[redacted]															
Unit 5	[redacted]															
NGS																
Unit 1	[redacted]															
Unit 2	[redacted]															
Unit 3	[redacted]															
Cholla																
Unit 1	[redacted]															
Unit 3	[redacted]															
Ocotillo																
Unit 1 ST	[redacted]															
Unit 2 ST	[redacted]															
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Saguaro																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
West Phoenix																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Unit 3 CC	[redacted]															
Unit 4 CC	[redacted]															
Unit 5 CC	[redacted]															
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															

ATTACHMENT D.1(A)(2) – ANNUAL CAPACITY FACTOR (CONTINUED)

	Annual Capacity Factor – B.1(e)															
UNIT	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
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																
Unit 1 CC																
Unit 2 CC																
Unit 3 CC																
Unit 4 CC																
Unit 1 CT																
Unit 2 CT																
Unit 3 CT																
Unit 4 CT																
Unit 5 CT																

ATTACHMENT D.1(A)(2) – ANNUAL CAPACITY FACTOR (CONTINUED)

	Annual Capacity Factor – B.1(e)															
UNIT	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Future Units (continued)																
Unit 6 CT																
Unit 7 CT																
Unit 8 CT																
Unit 9 CT																
Unit 10 CT																
Unit 11 CT																
Unit 12 CT																
Unit 13 CT																
Unit 14 CT																
Unit 15 CT																
Unit 16 CT																
Renewables																
APS existing solar																
Aragonne Mesa Wind, New Mexico																
Salton Sea CE Turbo #1																
SWMP Biomass (Abitibi)																
High Lonesome Wind, New Mexico																
Sexton - City of Glendale Landfill																
Solana CSP																
Redrock																
New Wind																
Perrin Ranch Wind																
AZSun Desert Star																
AZSun Luke																
AZSun Solon																
AZSun Chino																
AZSun Hyder																
AZSun Hyder II																
AZSun Paloma																
AZSun Foothills																
AZSun Gila Bend																

ATTACHMENT D.1(A)(2) – ANNUAL CAPACITY FACTOR (CONTINUED)

	Annual Capacity Factor – B.1(e)															
UNIT	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Renewables (continued)																
Small Gen RFP (Ajo S)	[redacted]															
Small Gen RFP (Prescott S)	[redacted]															
Small Gen RFP (Saddle Mountain)	[redacted]															
Small Gen RFP (WM Landfil)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillepie (SAT PV)	[redacted]															
Recurrent Bagdad (SAT PV)	[redacted]															
Contracts																
SRP - Firm / Eastern Mining Load	[redacted]															
PACIFICORP Diversity Exchange	[redacted]															
Schools and Gov't DE	[redacted]															
	[redacted]															
CC Tolling # 1	[redacted]															
CC Tolling # 2	[redacted]															
CC Tolling # 3	[redacted]															
CC Tolling # 4	[redacted]															
	[redacted]															
Short term Purchases	[redacted]															

ATTACHMENT D.1(A)(3) – AVERAGE HEAT RATE

Average Heat Rate – B.1(f)(b) (Btu/kWh)																
UNIT	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
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 4	9,833	9,798	9,845	9,815	9,840	9,828	9,833	9,806	9,822	9,841	9,834	9,799	9,794	9,835	9,847	9,824
Unit 5	9,796	9,808	9,851	9,842	9,847	9,836	9,837	9,856	9,840	9,818	9,850	9,817	9,846	9,821	9,839	9,827
NGS																
Unit 1	10,103	10,110	10,091													
Unit 2	10,090	10,080	10,091													
Unit 3	10,091	10,120	10,110													
Cholla																
Unit 1	10,697	11,111	11,273	11,492	11,478	11,279	10,865	10,848	11,654							
Unit 3	10,678	10,792	10,824	10,870	10,845	10,818	10,789	10,768	11,024							
Ocotillo																
Unit 1 ST	14,424															
Unit 2 ST	14,770															
Unit 1 CT	15,789	15,243	-	16,349	15,757	-	16,011	-	-	-	15,010	-	-	-	-	-
Unit 2 CT	16,111	15,466	15,259	15,972	16,254	-	16,376	-	-	-	15,259	-	-	-	44,735	-
Unit 3 CT		9,758	9,450	9,656	9,420	9,441	10,881	10,010	9,927	9,879	9,820	9,848	9,870	9,905	9,901	9,741
Unit 4 CT		10,231	9,419	9,589	9,508	9,490	11,038	10,205	9,916	10,011	9,773	9,977	9,870	9,938	9,911	9,752
Unit 5 CT		-	9,380	9,605	9,493	9,497	11,039	10,562	10,093	10,088	9,812	10,035	9,888	9,877	9,860	9,771
Unit 6 CT		-	9,490	9,705	9,688	9,733	11,347	10,761	10,298	10,109	9,921	10,037	9,853	9,934	9,855	9,736
Unit 7 CT		-	9,681	10,095	10,117	10,101	11,762	11,118	10,453	10,410	10,100	10,149	9,870	9,939	9,857	9,755
Saguaro																
Unit 1 CT	16,801	15,529	15,401	15,908	-	-	-	-	-	-	15,259	-	-	-	-	-
Unit 2 CT	16,543	15,067	15,259	15,722	15,757	-	-	-	-	-	15,010	-	-	-	-	-
Unit 3 CT	13,297	13,162	12,870	12,853	13,751	14,892	14,104	15,266	14,837	15,225	14,095	14,443	15,641	13,663	14,307	13,083
West Phoenix																
Unit 1 CC	11,519	10,761	10,995	10,733	10,624	10,785	10,892	10,577	10,446	10,299	10,117	10,099	10,020	9,967	9,880	9,980
Unit 2 CC	11,861	11,615	11,925	11,683	11,872	11,648	12,425	12,022	11,353	11,237	10,782	10,654	10,581	10,310	10,255	10,277
Unit 3 CC	10,440	10,570	10,546	10,326	10,744	10,742	10,906	10,942	10,632	10,531	10,329	10,228	10,180	9,984	9,974	9,972
Unit 4 CC	8,726	8,603	8,658	8,808	8,699	8,704	8,700	8,663	8,667	8,658	8,637	8,589	8,595	8,538	8,552	8,490
Unit 5 CC	8,881	8,837	8,154	8,189	8,227	8,223	8,291	8,281	8,259	8,270	8,269	8,242	8,232	8,216	8,216	8,184
Unit 1 CT	16,047	17,117	15,856	16,257	-	-	15,776	-	-	-	15,259	-	-	-	-	-
Unit 2 CT	16,171	14,864	15,458	16,040	-	-	17,714	-	-	-	15,010	-	-	-	-	-

ATTACHMENT D.1(A)(3) – AVERAGE HEAT RATE (CONTINUED)

	Average Heat Rate – B.1(f)(b) (Btu/kWh)															
UNIT	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Redhawk																
Unit 1 CC	8,421	8,402	8,395	8,381	8,413	8,395	8,437	8,433	8,348	8,372	8,379	8,379	8,383	8,378	8,379	8,378
Unit 2 CC	8,438	8,408	8,401	8,385	8,400	8,373	8,462	8,459	8,358	8,390	8,379	8,389	8,381	8,384	8,392	8,388
Sundance																
Unit 1 CT	12,219	12,731	12,176	12,563	12,865	14,490	12,690	13,126	13,157	12,990	12,927	12,923	-	14,490	12,501	-
Unit 2 CT	12,273	12,764	12,952	12,596	13,019	12,824	12,780	13,776	13,354	13,240	12,823	13,490	-	-	11,532	-
Unit 3 CT	12,410	12,714	12,938	12,625	13,062	13,240	12,615	13,776	13,776	14,490	12,490	13,240	-	-	11,531	-
Unit 4 CT	12,505	12,728	12,766	12,621	13,240	13,240	12,648	13,657	13,490	-	12,490	13,062	-	-	11,532	-
Unit 5 CT	12,507	12,789	12,539	12,743	13,379	14,490	12,685	13,657	13,657	-	12,615	14,490	-	-	11,532	-
Unit 6 CT	12,506	12,783	12,823	12,717	13,314	14,490	12,615	14,490	14,490	-	12,615	14,490	-	-	12,586	-
Unit 7 CT	12,567	12,514	12,823	12,666	12,874	14,490	12,615	14,490	-	-	12,615	-	-	-	12,824	-
Unit 8 CT	12,366	11,516	12,990	12,547	13,240	-	12,759	-	-	-	12,615	14,490	-	-	13,240	-
Unit 9 CT	11,337	11,631	10,429	10,958	11,078	-	11,162	-	14,490	-	10,170	14,490	14,490	-	13,240	-
Unit 10 CT	11,571	11,677	10,360	11,197	11,467	-	12,121	-	14,490	-	10,170	14,490	14,490	-	13,240	-
Yucca																
Unit 1 CT	15,407	14,419	14,582	14,517	-	-	18,398	-	-	-	14,485	-	-	-	-	-
Unit 2 CT	15,922	14,245	14,582	14,543	-	-	18,771	-	-	-	14,485	-	-	-	-	-
Unit 3 CT	14,220	13,818	13,788	14,243	13,839	-	14,891	-	-	-	13,796	-	-	-	-	-
Unit 4 CT	57,661	-	58,315	57,975	-	-	-	-	-	-	57,465	-	-	-	-	-
Unit 5 CT	12,178	12,115	12,347	11,768	12,367	13,995	13,323	13,845	13,676	13,891	13,511	13,657	15,141	14,232	12,844	12,486
Unit 6 CT	12,343	12,180	12,138	12,345	12,851	13,667	13,346	13,655	13,528	13,957	13,579	13,332	14,208	12,896	12,667	11,740
Douglas																
Unit 1 CT	53,526	52,169	55,435	54,035	-	-	-	-	-	-	51,935	-	-	-	-	-
Future Units																
Unit 1 CC					8,016	8,016	8,075	8,076	8,059	8,064	8,070	8,040	8,057	8,039	8,038	8,050
Unit 2 CC				7,975	8,042	8,039	8,073	8,103	8,097	8,099	8,115	8,096	8,081	8,076	8,081	8,067
Unit 3 CC					7,994	8,006	8,082	8,087	8,092	8,081	8,077	8,057	8,063	8,051	8,049	8,046
Unit 4 CC										8,049	8,125	8,102	8,086	8,083	8,079	8,059
Unit 1 CT						11,190	11,937	12,044	11,420	11,400	11,246	11,132	10,889	10,806	10,797	10,775
Unit 2 CT						11,916	12,590	12,222	11,662	11,419	11,238	11,006	10,858	10,755	10,719	10,773
Unit 3 CT									11,554	11,588	11,020	11,006	10,819	10,747	10,698	10,679
Unit 4 CT									11,266	11,442	11,007	10,968	10,874	10,616	10,732	10,509
Unit 5 CT									12,188	10,964	11,105	10,665	10,905	10,825	10,634	10,607
Unit 6 CT										10,792	11,156	10,848	10,835	10,771	10,640	10,584

ATTACHMENT D.1(A)(3) – AVERAGE HEAT RATE (CONTINUED)

Average Heat Rate – B.1(f)(b) (Btu/kWh)																
UNIT	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																
Unit 7 CT										11,735	11,466	10,923	11,224	10,962	10,641	10,830
Unit 8 CT											11,208	11,330	11,419	10,509	10,826	11,046
Unit 9 CT												11,690	12,153	11,041	11,010	11,182
Unit 10 CT													12,701	11,461	11,083	11,422
Unit 11 CT														11,666	11,758	11,020
Unit 12 CT															12,272	11,683
Unit 13 CT								10,784	10,622	10,554	10,441	10,382	10,160	10,074	10,263	9,940
Unit 14 CT								11,277	10,668	10,711	10,484	10,367	10,211	10,152	10,234	9,913
Unit 15 CT																9,887
Unit 16 CT																9,916

ATTACHMENT D.1(A)(4) – AVERAGE FUEL COST

Average Fuel Cost – B.1(g) ($/MMBtu)																
FUEL	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Uranium																
Coal – Four Corners																
Coal – NGS																
Coal – Cholla																
Gas																

ATTACHMENT D.1(A)(5) – PURCHASED POWER ENERGY COSTS FOR LONG-TERM CONTRACTS

	Energy Cost for Long Term Contract B.1(i) ($/MWh)															
UNIT	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo #1	[redacted]															
SWMP Biomass (Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
New Wind	[redacted]															
Sexton - City of Glendale Landfill	[redacted]															
Solana CSP	[redacted]															
Perrin Ranch Wind	[redacted]															
Small Gen RFP (Ajo S)	[redacted]															
Small Gen RFP (Prescott S)	[redacted]															
Small Gen RFP (Saddle Mountain)	[redacted]															
Small Gen RFP (WM Landfil)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillepie (SAT PV)	[redacted]															
Recurrent Bagdad (SAT PV)	[redacted]															
Contracts																
SRP - Firm / Eastern Mining Load[1]	[redacted]															
CC Tolling # 1	[redacted]															
CC Tolling # 2	[redacted]															
CC Tolling # 3	[redacted]															
CC Tolling # 4	[redacted]															
	[redacted]															
AGX Load	[redacted]															

Notes:
(1) Based on Palo Verde Day-Ahead Index

ATTACHMENT D.1(A)(6) – FIXED O&M

Fixed Operating and Maintenance – B.1(j) ($/MW)																
PLANT	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Palo Verde 1, 2, 3	[redacted]															
Four Corners 4, 5	[redacted]															
NGS 1, 2, 3	[redacted]															
Cholla	[redacted]															
Ocotillo CT 1,2	[redacted]															
Douglas CT	[redacted]															
Saguaro CT	[redacted]															
West Phoenix CC 1, 2, 3	[redacted]															
West Phoenix CC 4	[redacted]															
West Phoenix CC 5	[redacted]															
West Phoenix CT 1, 2	[redacted]															
Redhawk	[redacted]															
Sundance	[redacted]															
Yucca CT 1, 2, 3, 4	[redacted]															
Yucca CT 5, 6	[redacted]															
Redrock	[redacted]															
AZ Sun: Hyder II	[redacted]															
AZ Sun: Cotton Center	[redacted]															
AZ Sun: Hyder I	[redacted]															
AZ Sun: Chino Valley	[redacted]															
AZ Sun: Paloma	[redacted]															
AZ Sun: Yuma Foothills	[redacted]															
AZ Sun: Gila Bend	[redacted]															
AZ Sun: Luke	[redacted]															
AZ Sun: Desert Star	[redacted]															
Future Units																
Future Unit 1 CC	[redacted]															
Future Unit 2 CC	[redacted]															
Future Unit 3 CC	[redacted]															
Future Unit 4 CC	[redacted]															
Future Unit 1-12 CT	[redacted]															
Future Unit 13-16 CT	[redacted]															

ATTACHMENT D.1(A)(7) – DEMAND CHARGES FOR PURCHASED POWER

Demand Charges for Purchased Power – B.1(k) ($/kW-Yr)																
CONTRACT	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CC Tolling # 1	[redacted]															
CC Tolling # 2[1]	[redacted]															
CC Tolling # 3[2]	[redacted]															
CC Tolling # 4[2]	[redacted]															

[redacted]

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS

		CO_2 Emissions – B.1(p) (Metric Tons)															
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
W. Phx. CC 5																	
Unit 1 CT																	
Unit 2 CT																	
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO_2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Sundance																	
Unit 1	[redacted]																
Unit 2	[redacted]																
Unit 3	[redacted]																
Unit 1	[redacted]																
Unit 3	[redacted]																
Unit 1 ST	[redacted]																
Unit 2 ST	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Yucca																	
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Douglas																	
Unit 1 CC	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

		CO_2 Emissions – B.1(p) (Metric Tons)															
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
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																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
Unit 16 CT																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO_2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																	
CC Tolling # 1																	
CC Tolling # 2																	
CC Tolling # 3																	
CC Tolling # 4																	
Short term Purchases																	
Other Contracts[2]																	
Total		12,964,956	13,149,091	13,185,145	12,498,413	12,779,030	12,906,868	13,526,403	13,588,020	13,074,566	13,199,842	13,432,975	13,313,355	13,860,792	13,885,458	14,394,356	14,865,453

Notes:
(1) Emission rates are as of 2016

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

		CO Emissions – B.1(p) (Metric Tons)															
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
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																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																	
Unit 11 CT	[redacted]																
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
Unit 16 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
CC Tolling # 3																	
CC Tolling # 4																	
Short term Purchases																	
Other Contracts [2]																	
Total		**1,573**	**1,596**	**1,621**	**1,563**	**1,575**	**1,576**	**1,681**	**1,677**	**1,663**	**1,688**	**1,713**	**1,690**	**1,764**	**1,746**	**1,814**	**1,887**

Notes:
(1) Emission rates are as of 2016
[redacted]

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

VOC Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

VOC Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																
Future Units																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

VOC Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
Unit 16 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
CC Tolling # 3																	
CC Tolling # 4																	
Short term Purchases																	
Other Contracts [2]																	
Total		**104**	**104**	**98**	**81**	**78**	**83**	**80**	**83**	**64**	**61**	**64**	**66**	**66**	**70**	**73**	**75**

Notes:
(1) Emission rates are as of 2016

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

NO$_x$ Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4[2]																	
Unit 5[2]																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

NO$_x$ Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
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																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

NO$_x$ Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
Unit 16 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
CC Tolling # 3																	
CC Tolling # 4																	
Short term Purchases																	
Other Contracts [3]																	
Total		**13,652**	**6,772**	**6,126**	**4,389**	**4,155**	**4,277**	**4,903**	**4,928**	**3,379**	**3,077**	**3,100**	**2,981**	**3,187**	**3,051**	**3,198**	**3,303**

Notes:
(1) Emission rates are as of 2016

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

SO_2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4[2]																	
Unit 5[2]																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
		SO_2 Emissions – B.1(p) (Metric Tons)															
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																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

SO_2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																	
Unit 11 CT	[redacted]																
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
Unit 16 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
CC Tolling # 3																	
CC Tolling # 4																	
Short term Purchases																	
Other Contracts [3]																	
Total		**5,185**	**3,603**	**3,580**	**3,239**	**3,111**	**3,092**	**3,720**	**3,641**	**2,746**	**2,589**	**2,561**	**2,373**	**2,618**	**2,388**	**2,496**	**2,606**

Notes:
(1) Emission rates are as of 2016

[redacted]

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Hg Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ Tril Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Hg Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ Tril Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
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																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Hg Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ Tril Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
Unit 16 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
CC Tolling # 3																	
CC Tolling # 4																	
Short term Purchases																	
Other Contracts [2]																	
Total		**0.056**	**0.057**	**0.057**	**0.052**	**0.052**	**0.052**	**0.058**	**0.057**	**0.053**	**0.054**	**0.054**	**0.052**	**0.055**	**0.053**	**0.055**	**0.057**

Notes:
(1) Emission rates are as of 2016

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

PM10 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 ST																	
Unit 2 ST																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

PM10 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
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																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
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																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

PM10 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Future Units (continued)																	
Unit 11 CT																	
Unit 12 CT																	
Unit 13 CT																	
Unit 14 CT																	
Unit 15 CT																	
Unit 16 CT																	
CC Tolling # 1																	
CC Tolling # 2																	
CC Tolling # 3																	
CC Tolling # 4																	
Short term Purchases																	
Other Contracts [2]																	
Total		**622**	**612**	**586**	**424**	**426**	**431**	**476**	**480**	**411**	**404**	**412**	**403**	**424**	**421**	**436**	**450**

Notes:
(1) Emission rates are as of 2016

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
Plant	Rates (Gal/ MWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Palo Verde Units 1, 2, 3																	
Four Corners Units 4, 5																	
Navajo Generating Station Units 1, 2, 3																	
Cholla Units 1, 3																	
Ocotillo Units 1, 2 ST																	
Ocotillo Units 1, 2 CT																	
Ocotillo New Units 3-7 CT																	
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 5, 6 CT																	
Yucca 4																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

	Water Consumption – B.1(q) (Acre-Feet)																
Plant	Rates (Gal/ MWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Douglas	[redacted]																
Future Unit 1 CC																	
Future Unit 2 CC																	
Future Unit 3 CC																	
Future Unit 4 CC																	
Future Unit 1-12 CT																	
Future Unit 13-16 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																	
CC Tolling # 3																	
CC Tolling # 4																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
Plant	Rates (Gal/ MWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Economic Purchases																	
Small GEN WM LANDFILL																	
AGX Load																	
Total		49,868	49,954	50,290	49,449	50,107	50,450	51,214	51,254	49,979	50,090	50,356	50,206	51,194	50,889	51,763	52,687

Note:
Water consumption rates are based on plant actual.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

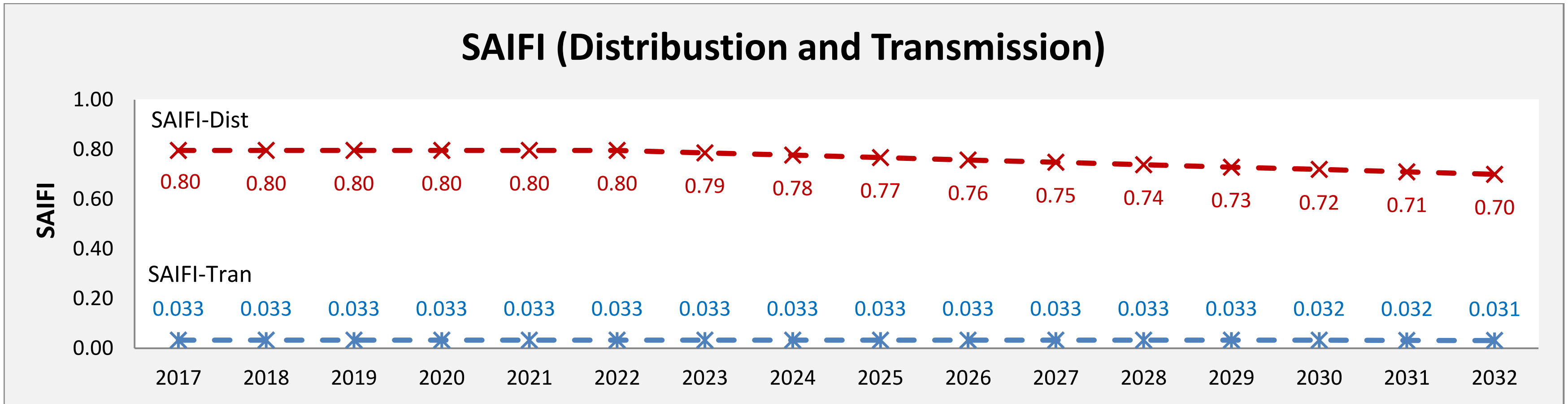
Coal Fly Ash Collected – B.1(r) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Total		609,176	619,309	630,739	595,130	574,397	553,947	671,344	643,480	576,963	574,145	567,330	525,268	580,184	527,642	551,462	576,122

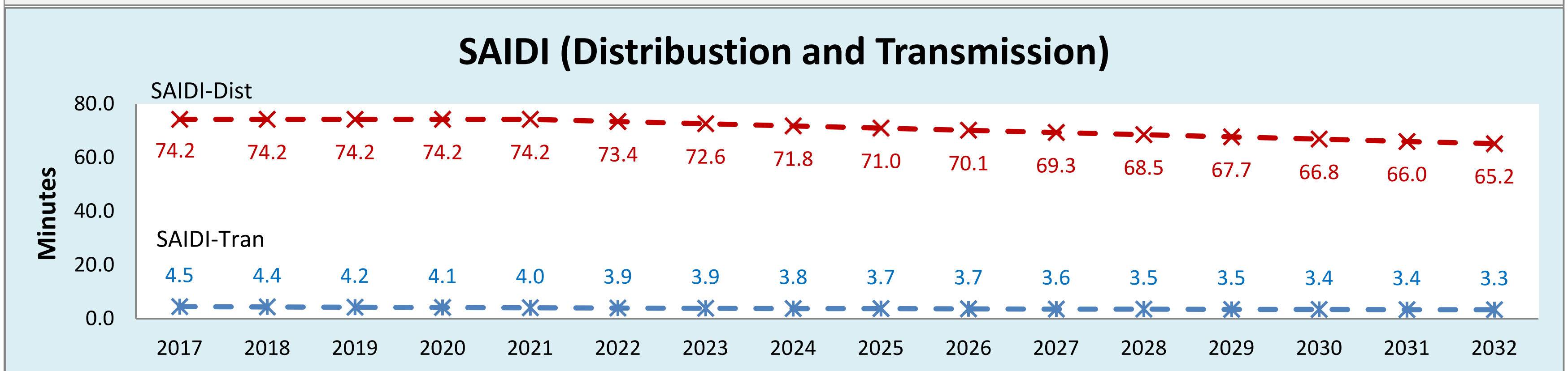
Note:
(1) Emission rates are as of 2016

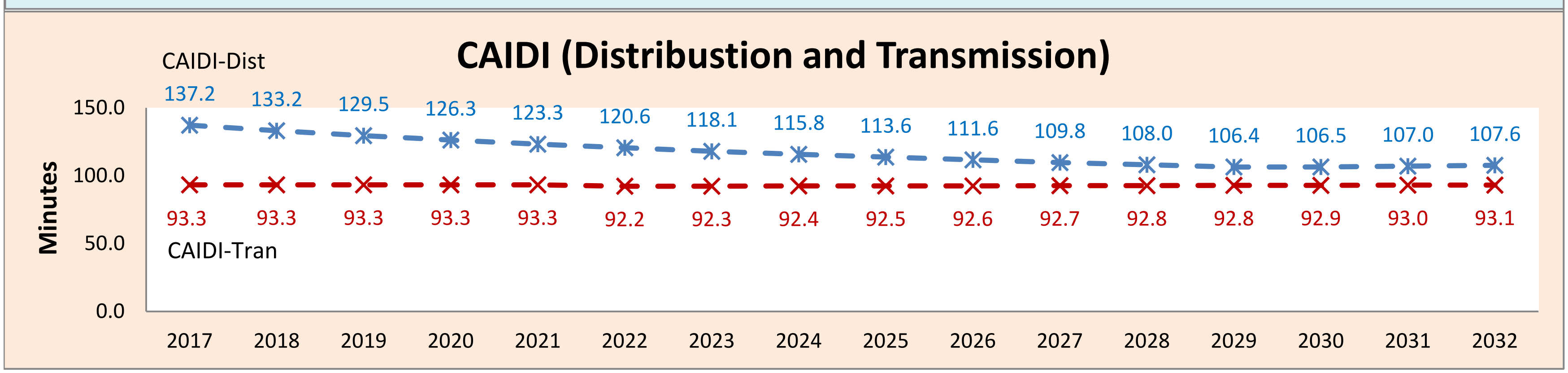
ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Coal Ash Bottom Collected – B.1(r) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners																	
Unit 4																	
Unit 5																	
NGS																	
Unit 1																	
Unit 2																	
Unit 3																	
Cholla																	
Unit 1																	
Unit 3																	
Total		152,286	154,820	157,677	148,775	143,592	138,479	167,827	160,861	144,234	143,529	141,825	131,311	145,039	131,904	137,859	144,023

Note:
(1) Emission rates are as of 2016


SAIFI (Distribustion and Transmission)
SAIFI
1.00
0.80
0.60
0.40
0.20
0.00
SAIFI-Dist
0.80 0.80 0.80 0.80 0.80 0.80 0.79 0.78 0.77 0.76 0.75 0.74 0.73 0.72 0.71 0.70
SAIFI-Tran
0.033 0.033 0.033 0.033 0.033 0.033 0.033 0.033 0.033 0.033 0.033 0.033 0.033 0.032 0.032 0.031
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032


SAIDI (Distribustion and Transmission)
Minutes
80.0
60.0
40.0
20.0
0.0
SAIDI-Dist
74.2 74.2 74.2 74.2 74.2 73.4 72.6 71.8 71.0 70.1 69.3 68.5 67.7 66.8 66.0 65.2
SAIDI-Tran
4.5 4.4 4.2 4.1 4.0 3.9 3.9 3.8 3.7 3.7 3.6 3.5 3.5 3.4 3.4 3.3
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032


CAIDI (Distribution and Transmission)
Minutes
150.0
100.0
50.0
0.0
CAIDI-Dist
137.2 133.2 129.5 126.3 123.3 120.6 118.1 115.8 113.6 111.6 109.8 108.0 106.4 106.5 107.0 107.6
93.3 93.3 93.3 93.3 93.3 92.2 92.3 92.4 92.5 92.6 92.7 92.8 92.8 92.9 93.0 93.1
CAIDI-Tran
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032

ATTACHMENT D.1(C) CAPITAL COST AND CONSTRUCTION SPENDING SCHEDULE

2017 Resource Plan – Capital Costs
Generation Construction Cash Flow without AFUDC
In Millions of Dollars

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Capital Costs through 2032 TOTAL
1 Peaking Generation																		
2	Future CT																	
3	Future CT																	
2	Future CT																	
1	Future CT																	
1	Future CT																	
1	Future CT																	
1	Future CT																	
1	Future CT																	
1	Future CT																	
1	Future CT																	
2	Future CT																	
2	Future CT																	
Subtotal																		
2 Combined Cycle Generation																		
1	Combined Cycle																	
1	Combined Cycle																	
1	Combined Cycle																	
1	Combined Cycle																	
Subtotal																		
3 Energy Storage and Microgrid Systems																		
5	ESS																	
2	Microgrid																	
Subtotal																		
4 Grand Total																		
5 Cumulative Total																		

Note: Capital Cost includes APS-owned construction of generation.

ATTACHMENT D.1(F) – TRANSMISSION PROJECTS

PROJECT DESCRIPTION	I/S	PARTICIPANTS	KV	RATING (MVA)	TOTAL COST ($MILLIONS)	LENGTH (MILES)	PURPOSE
Four Corners 500/345kV Transformer #2	2017	None	500/345	1025	[redacted]	0	Increase Total Transfer Capability of Path 23 to satisfy Transmission Service Requests.
Mazatzal substation	2018	None	345/69	150	[redacted]	1	Provide the electric source and support to the subtransmission system in the area of Payson and the surrounding communities.
Ocotillo Modernization Project Interconnection Facilities	2018	None	230	1195	[redacted]	1	To interconnect new generators being constructed as part of the Ocotillo Modernization Project. These circuits will connect the new units to the existing Ocotillo 230kV Substation.
Morgan-Sun Valley line	2018	APS (90%) CAWCD(10%)	500	TBD	[redacted]	38	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.
North Gila-Orchard line	2021	None	230	1195	[redacted]	13	Serves the need for electric energy, improved reliability and continuity of service for the greater Yuma area.
Scatter Wash substation	2023	None	230/69	188	[redacted]	1	Provide electric energy in the northern portions of the Phoenix Metropolitan area; increase the reliability and continuity of service for these areas.
CT Connect Costs	2022-2032	TBD	230-500	TBD	[redacted]	TBD	Connect new resources
CC Connect Costs	N/A	TBD	230-500	TBD	[redacted]	TBD	Connect new resources

Source: 2017-2026 Transmission Ten-Year Plan dated January 2017

ATTACHMENT D.3 – GENERATION TECHNOLOGIES

Conventional Generation Technologies Assumptions													
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 (yrs)	Capacity Factor %	CO_2 Emission (lbs/ MWh)	Water Consumption (gal/MWh)
Coal													
Cholla 5 490MW IGCC	Cholla	490	455	518	2,635	5,791	23.51	3.83	10,000	9	86%	2,050	491
Gas Greenfield													
One 7F.05, Evap Inlet	Maricopa	222	216	227	171.9	797	10.08	2.28	9,959	3	10%	1,215	15
Two 7F.05, Evap Inlet	Maricopa	443	431	454	327.2	759	10.08	2.28	9,959	3	10%	1,215	15
Four 7E.03, Evap Inlet	Maricopa	340	320	360	359.0	1,122	8.43	2.83	10,434	3	10%	1,273	22
Six LM6000PC Sprint, Chilled Inlet	Maricopa	282	276	294	415.4	1,505	9.72	2.28	9,723	3	10%	1,186	111
3X0 LMS100PA+ Chilled Inlet, Wet Cooled	Maricopa	319	306	324	451.3	1,475	13.53	2.73	9,125	3	10%	1,113	207
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled	Maricopa	318	306	324	454.0	1,484	13.53	2.73	9,138	3	10%	1,115	141
3X0 LMS100PA+ Chilled Inlet, Dry Cooled	Maricopa	289	258	312	465.6	1,805	13.53	2.73	9,566	3	10%	1,167	84
5X0 LMS100PA+ Chilled Inlet, Wet Cooled	Maricopa	531	510	540	692.2	1,357	8.51	2.70	9,125	3	10%	1,113	207
5X0 LMS100PA+ Chilled Inlet, Hybrid Cooled	Maricopa	531	510	540	698.1	1,369	8.51	2.70	9,138	3	10%	1,115	141
5X0 LMS100PA+ Chilled Inlet, Dry Cooled	Maricopa	482	430	520	709.4	1,650	8.51	2.70	9,566	3	10%	1,167	84
2X1 CC 7F.05, Evap Inlet, DB on, CT (Wet)	Maricopa	783	729	841	824.9	1,132	6.37	2.21	6,964	4	50%	850	395
2x1 CC 7F.05, Evap Inlet, DB On, ACC	Maricopa	802	710	869	877.3	1,236	6.53	1.82	7,149	4	50%	872	20
Gas Brownfield													
One Redhawk 7F.05, Evap Inlet	Redhawk	222	216	227	160.6	745	10.08	2.28	9,959	3	10%	1,215	15
Two Redhawk 7F.05, Evap Inlet	Redhawk	443	431	454	312.5	725	10.08	2.28	9,959	3	10%	1,215	15
Two Redhawk 7E.03, Evap Inlet	Redhawk	170	160	180	193.8	1,211	16.86	2.83	10,434	3	10%	1,273	22
Two Sundance LM6000PC Sprint, Chilled Inlet	Sundance	94	92	98	168.3	1,830	29.16	2.28	9,723	3	10%	1,186	111
Two Yucca LM6000PC Sprint, Chilled Inlet	Yuma	94	92	98	168.3	1,830	29.16	2.28	9,723	3	10%	1,186	111
5X0 LMS100PA+ Chilled Inlet, Wet Cooled	Maricopa	531	510	540	586.2	1,149	8.51	2.70	9,125	3	10%	1,113	207
5X0 LMS100PA+ Chilled Inlet, Hybrid Cooled	Maricopa	531	510	540	615.9	1,208	8.51	2.70	9,138	3	10%	1,115	141

ATTACHMENT D.3 – GENERATION TECHNOLOGIES (CONTINUED)

Conventional Generation Technologies Assumptions													
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 (yrs)	Capacity Factor %	CO_2 Emission (lbs/MWh)	Water Consumption (gal/MWh)
Gas Brownfield (continued)													
5X0 LMS100PA+ Chilled Inlet, Dry Cooled	Maricopa	482	430	520	613.5	1,427	8.51	2.70	9,566	3	10%	1,167	84
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled, Redhawk	Redhawk	312	306	321	432.3	1,413	13.53	2.73	9,138	3	10%	1,115	141
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled, Sundance	Sundance	312	306	318	441.1	1,442	13.53	2.73	9,138	3	10%	1,115	141
3X0 LMS100PA+ Chilled Inlet, Hybrid Cooled, Cholla	Cholla	312	306	318	500.6	1,636	13.53	2.73	9,138	3	10%	1,115	141
Six Unit Wartsila 18V50	Maricopa	110	110	111	205.6	1,869	24.47	2.85	8,421	3	10%	985	0
2X0 P&W SP60 FT8-3 Mech Chillers	Maricopa	116	92	124	139.9	1,521	29.46	3.05	10,662	3	10%	1,301	140
Inlet Chilling RH (existing 4 GTs) versus Existing Evap Inlet	Redhawk	23	43	0	77.2	1,796	0.00	3.50	6,975	2	10%	851	80
Inlet Chilling WP5 (existing 2 GTs) versus Existing Evap Inlet	Maricopa	16	30	0	43.5	1,451	0.00	3.17	7,290	2	10%	889	40
Energy Storage													
CAES, Compressed Air Energy Storage	Maricopa	100	100	100	324.6	3,246	21.51	2.64	4,390	3	10%	1	0
Pumped Storage Hydro	Maricopa	100	100	100	313.9	3,139	78.48	3.49	*75%	5	10%	0	0
Battery Energy Storage System (Li-ion)	Maricopa	25	25	25	30.0	1,539	23.98	0.00	*88%	1	10%	0	0
Flow Battery	Maricopa	25	25	25	39.7	1,589	31.78	0	*65%	1	10%	0	0
Battery Energy Storage System (NaS)	Maricopa	25	25	25	43.5	1,740	34.80	0	*80%	1	10%	0	0
Battery Energy Storage System (Lead Acid)	Maricopa	25	25	25	23.5	941	18.82	0	*80%	1	10%	0	0
Battery Energy Storage System (Zn-Air)	Maricopa	25	25	25	30.4	1,214	24.28	0	*65%	1	10%	0	0
Fly Wheels	Maricopa	20	20	20	60.2	3,008	60.16	0	*95%	2	10%	0	0
Nuclear													
Nuclear AP 1000 Hybrid	Palo Verde	2,234	2,234	2,234	13549.2	6,065	111.00	2.55	10,449	10	92%	0	767
Small Modular Reactor	Palo Verde	570	570	570	3356.7	5,889	74.85	10.09	10,710	10	95%	0	767

* Efficiency
1 Costs are in year-2020 dollars.
2 Capital costs are overnight construction costs; $/kW is based on summer capacity rating.
3 Capital cost for IGCC does not include CO2 capture.
4 ACC- Air Cooled Condenser

ATTACHMENT D.3 – GENERATION TECHNOLOGIES (CONTINUED)

Renewable Generation Technologies Assumptions										
Plant	Capacity	Capital Costs	Capital Costs ($/kW)	Fixed O&M ($/kW-Yr)	Var O&M ($/MWh)	Water Use (Gal/MWh)	Capacity Factor	Capacity Value	UsefulLife Years	Fuel Cost ($/MWh)
Distributed Solar										
Residential Solar PV - Fixed	6.10 kW	$17,233	2,825	22.0	0	0	22%	**	25	0
Commercial & Industrial Solar PV	151.00 kW	$315,590	2,090	22.0	0	0	20%	**	25	0
Grid-Scale Solar										
Thin Film Solar PV - Fixed	20 MW	$27 M	1,344	17	0	0	27%	**	25	0
Thin Film Solar PV - Single Axis	20 MW	$29 M	1,439	17	0	0	31%	**	25	0
Parabolic Trough, Gas Hybrid	75 MW	$419 M	5,587	75	5	139	24%	100%	30	0
Parabolic Trough, Salt Storage	100 MW	$548 M	5,481	75	5	134	40%	100%	35	0
Central Receiver (Power Tower), Salt Storage	110 MW	$913 M	8,301	91	0	134	41%	100%	35	0
Other Grid-Scale Renewables										
Southwest Wind	100 MW	$189 M	1,886	52	0	0	33%	18% - 20%	20	0
Geothermal	50 MW	$225 M	4,505	131	0	221	80%	100%	25	0
Biomass	50 MW	$213 M	4,260	123	6	553	85%	100%	25	35
Biogas	50 MW	$473 M	9,456	457	10	235	71%	100%	25	31

Costs are in 2020 dollars.
Capital costs ($/kW) are overnight construction costs in 2020 dollars.
PV prices are in 2020 dollars.
**Capacity values are subject to change and vary with existing levels of penetration.
Distributed solar and grid-scale fixed solar PV capacity value range is 10% - 50%.
Grid-scale single axis solar PV capacity value range is 40% - 73%.

ATTACHMENT D.3 – GENERATION TECHNOLOGIES (CONTINUED)

Lifetime Levelized Costs in $/MWh of Generation Technologies (2020 Installation)										
Generation Technology	Capacity In MW	Useful Life in Years	Capacity Factor	Fixed Charges	Fuel	O&M	Water	Emissions (CO2 and SO2)	Transmission & Losses	Total
GE 7F.05 Combustion Turbine	216	32	10%	109.70	68.16	17.96	0.07	8.41	25.85	230.16
GE LMS100 Combustion Turbine	306	32	10%	204.12	62.54	23.66	0.67	7.72	27.07	325.78
GE LM6000 Combustion Turbine	276	32	10%	209.57	66.54	17.42	0.53	8.21	27.25	329.53
Combined Cycle	710	32	50%	35.99	38.62	4.31	0.09	6.04	6.44	91.50
Nuclear (SMR)	570	40	95%	94.31	9.52	25.79	3.81	0.00	3.83	137.26
SAT Solar	25	25	31%	45.42	0.00	8.12	0.00	0.00	4.53	58.07
Arizona Wind	200	20	24%	97.61	0.00	21.76	0.00	0.00	38.63	158.00
Energy Storage Battery	25	10	10%	291.95	(16.49)	30.20	0.00	0.00	9.64	315.29

ATTACHMENT D.10– 2017 RESOURCE PLAN – TOTAL REVENUE REQUIREMENTS

Total Revenue Requirements: Selected Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES	TOTAL					
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	653.0	486.1	67.4	386.3	76.4	1669.1	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2262.3	74.6
2018	748.8	517.8	72.6	431.6	76.8	1847.6	71.0	252.3	323.3	0.0	96.9	9.2	(0.1)	96.7	2373.6	77.5
2019	814.1	518.5	77.6	407.5	74.7	1892.5	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2395.3	77.2
2020	873.2	541.1	86.1	371.6	72.7	1944.7	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2432.6	77.6
2021	912.8	590.5	98.1	392.8	70.8	2065.0	39.8	243.7	283.6	0.6	103.0	15.4	(0.1)	82.1	2549.5	79.6
2022	942.1	631.5	104.2	411.1	73.0	2161.9	39.9	250.9	290.8	0.7	105.8	14.0	(0.1)	84.9	2658.0	81.4
2023	1021.4	620.5	108.5	399.7	74.9	2225.0	40.3	273.2	313.5	1.7	104.7	12.4	22.5	89.4	2769.3	83.3
2024	1060.7	657.8	112.0	412.1	74.0	2316.7	40.8	283.7	324.5	2.0	110.7	17.9	26.5	94.1	2892.4	85.6
2025	1088.9	674.7	119.8	390.3	76.4	2350.1	41.3	276.2	317.5	2.0	149.9	19.9	25.4	97.7	2962.6	86.1
2026	1108.8	740.4	131.7	411.1	88.6	2480.6	6.2	250.2	256.4	4.0	145.1	29.1	46.5	103.4	3064.9	87.5
2027	1125.5	785.0	137.8	428.9	99.5	2576.8	6.8	267.3	274.1	6.8	172.0	27.4	89.0	108.6	3254.7	91.3
2028	1164.5	831.5	140.1	443.6	102.8	2682.5	7.6	286.6	294.1	11.1	176.6	27.6	125.3	113.2	3430.5	94.4
2029	1186.3	844.5	146.5	458.8	101.1	2737.3	8.4	296.8	305.1	17.7	184.9	24.3	173.8	116.7	3559.9	96.1
2030	1220.2	896.1	151.2	474.3	110.6	2852.5	9.3	302.8	312.1	19.1	205.5	33.4	215.0	122.3	3759.8	99.4
2031	1184.0	932.0	159.1	490.1	121.0	2886.2	10.3	308.4	318.7	20.9	221.0	34.6	228.5	126.4	3836.3	99.2
2032	1253.7	959.9	162.2	506.4	124.2	3006.5	11.5	321.7	333.2	35.2	230.1	34.0	241.6	124.1	4004.7	101.4
CPW@ 7.50%																
(2017-2032)	8825.1	5972.9	980.8	3810.3	765.9	20355.0	395.5	2475.0	2870.6	46.0	1153.6	160.6	455.9	909.1	25950.7	84.9
(2017-2046)	12516.3	9461.9	1512.9	5311.3	1286.6	30089.0	462.5	3347.6	3810.1	96.7	2298.3	227.6	1296.4	1412.5	39230.6	91.6

ATTACHMENT D.14(A) – EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT

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. Light emitting diodes (LEDs), variable-speed pool pumps with high efficiency motors, and HVAC smart thermostats are measures incented through this program.
Residential EE	2. Existing Homes HVAC	On-going	The Existing Homes program provides incentives for heating ventilation, and air conditioning (HVAC) measures. The HVAC programs include the AC Rebate, Duct Test and Repair, Western Cooling Controls and HVAC diagnostics for tuning-up existing HVAC units. The AC Rebate offers financial incentives to homeowners for buying EE equipment (≥14 SEER/11 EER) that is installed in accordance with the program requirement for air flow, refrigerant charge, and sizing.
Residential EE	3. Home Performance with Energy Star	On-going	The HPwES program offers home owners a $99 comprehensive home energy checkup to help identify ways to improve EE and comfort throughout the home. This program element offers a direct install feature that includes up to 10 light emitting diodes (“LEDs”), and one low-flow showerhead that are installed at the time of the checkup. Additional financial incentives are available for duct sealing, air sealing, and insulation, once a home owner has completed an HPwES checkup.
Residential EE	4. 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.
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	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. Beginning in July of 2016, some home energy report (HER) customers were randomly selected and assigned to recieve behavioral demand response (BDR) in addition to the HER reports. Through the BDR component, when an event is called during the peak summer usage days, particiipants are requested to curb their energy use during particular periods of time. This reduces peak load and customers receive feedback on their demand reduction performance relative to other BDR participants.
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 LEDs, 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 three Builder Option Packages.1
Residential & Non-Residential EE	8. Codes & Standards	On-going	APS may count toward meeting the standard up to one third of the energy savings, resulting from energy efficiency building codes and appliance standards, that are quantified and reported through a measurement and evaluation study.

ATTACHMENT D.14(A) – EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

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. APS has filed a request to cancel this rate effective July 1, 2017 in ACC Docket E-01345A-16-0036.
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 has filed a request to limit this rate to only existing customers on the rate with distributed generation effective July 1, 2017 in ACC Docket E-01345A-16-0036.
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 three years and transitioning any remaining customers to the ET-2 or ECT-2 rates. APS has filed a request to limit this rate to only existing customers on the rate with distributed generation effective July 1, 2017 in ACC Docket E-01345A-16-0036.
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. APS has filed a request to freeze and limit this rate to only existing customers on the rate with distributed generation effective July 1, 2017 in ACC Docket E-01345A-16-0036.
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. APS has filed a request to freeze and limit this rate to only existing customers on the rate with distributed generation effective July 1, 2017 in ACC Docket E-01345A-16-0036.
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. APS has filed a request to cancel this rate effective July 1, 2017 in ACC Docket E-01345A-16-0036.
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 $0.25 per kWh for consumption during the hours 2 p.m. to 7pm. The customer also receives a discount of approximately $0.012143 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.

ATTACHMENT D.14(A) – EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL DR PROGRAM DESCRIPTION
Residential & Non-Residential DR	8. Energy & Demand Management Education Pilot	Proposed	This pilot focuses on energy information tools, including web based energy and demand analyzers, personalized videos to guide customers through targeted savings opportunities that match their usage profiles, and enhance mobile phone apps that can provide near real time feedback on a home's demand and energy use. A key objective of the pilot is to measure the EE savings resulting from behavioral changes in energy use that occur when the customer receives the enhanced energy information.
Residential & Non-Residential DR	9. Load Management Technology Pilot	Proposed	The Load Management Technology pilot is intended to deploy commercially available load control and load shifting technologies for residential and non-residential customers. The pilot will be focused on understanding the potential benefits of these technologies in meeting APS' flexible resource needs. APS will field tested the value of select utility controlled and/or price responsive load management technologies including HVAC thermal storage and connected appliances to gather data on energy and demand savings, reliability of load reductions, and systems operations benefits.
Residential & Non-Residential DR	10. Demand Response, Energy Storage and Load Management Program	Proposed	In 2016, APS filed for the Residential Demand Response, Energy Storage and Load Management (DRESLM) program which will deploy commercially available load management and load shifting technologies. The program is designed to support the deployment of residential load management, demand response and energy storage technologies that help APS residential customers shift energy use and manage peak demand while also providing system peak reduction and other grid operational benefits. The program includes three elements: battery storage, thermal storage and demand response.
Residential & Non-Residential DR	11. Transmission & Distribution Pilot	Proposed	The T&D pilot is intended to target both residential and non-residential customers who are served by substations that are facing future capacity constraints due to projected load growth. It seeks to deploy previously approved measures that have been found to be cost effective by ACC Staff. The pilot will attempt to enhance the benefits that these measures provide by targeting them to areas where they have the most value in helping to reduce or defer T&D infrastructure costs. Therefore, the pilot was designed to produce incrementally higher cost effectiveness results as compared to the same DSM measures installed elsewhere on the system.

ATTACHMENT D.14(A) – EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

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) custom 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.

ATTACHMENT D.14(A) – EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

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 July 1, 2013.
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	On-going	The rate rider IRR was approved for July 1st 2012. IRR 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. Customers in Metro Phoenix and Yuma area are not eligible for this rate until January 1st 2015.
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 1:00 p.m. and 7:00 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.

ATTACHMENT D.14(B) – EXPECTED EE PARTICIPATION[1]

RESIDENTIAL PROGRAM NAME	MEASURE OR UNIT	ACTUAL PARTICIPATION IN 2016
Consumer Products	CFL & LED Bulbs	2,056,367
	Variable Speed Pumps	4,299
	Smart Thermostats	245
Energy Star Homes	Version 3	3,284
	Second Tier – HERS 60	1,479
Home Performance with Energy Star	Audits	3,087
	On-line Energy Audits	15,523
	Western cooling control	46
	Low Flow Shower Heads	3,087
	LED Bulbs	23,405
	Insulation (only)	890
	Duct Test & Repair	1,542
	Insulation & Air Sealing	35
Residential HVAC	Equipment Rebates	12,115
	Duct Test & Repair	7,643
	AC Diagnostic	284
	Western cooling control	10
Multi-Family	Low Flow Shower Heads	2,819
	Low Flow Aerators	5,142
	CFL & LED Bulbs	93,485
	Builder Option Package 1	717
	Builder Option Package 2	501
	Builder Option Package 3	654
Low Income Weatherization	Homes Weatherized	410
Behavioral	Reports Generated	270,164
Prepaid Energy Conservation – Behavioral	Behavioral Billing	983
NON-RESIDENTIAL PROGRAM NAME	**MEASURE OR UNIT**	**ACTUAL PARTICIPATION IN 2016**
Large Existing	No. of Applications Paid	1,588
Large New Construction	No. of Applications Paid	134
Small Business	No. of Applications Paid	653
Schools	No. of Applications Paid	242
Energy Information System	No. of Meters	294

[1] Additional details pertaining to EE programs were provided in the 2016 APS Annual DSM Progress Report filed with the ACC on March 1, 2017.

ATTACHMENT D.16 – GAS TRANSPORT ANALYSIS

YEAR	2017		2018		2019		2020		2021	
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**436,559**	**258,700**	**494,560**	**255,523**	**518,640**	**250,234**	**543,751**	**237,726**	**582,259**	**240,283**
Current firm fuel contracts										
El Paso - FT24T000	99,994	36,888	99,994	36,888	99,994	36,888				
El Paso - FT39D000	108,266	56,145	108,266	56,145	108,266	56,145				
El Paso - FT39E000	33,473	11,250	33,473	11,250	33,473	11,250				
El Paso - FT39H000	31,500	19,000	31,500	19,000	31,500	19,000	31,500	19,000	31,500	19,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500	28,000	25,500	28,000	25,500
Transwestern - FT-5	220,000	140,000	220,000	140,000	220,000	140,000	220,000	140,000	220,000	140,000
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750
Total Current firm contracts[1]	**523,733**	**288,783**	**523,733**	**288,783**	**523,733**	**288,783**	**279,500**	**184,500**	**279,500**	**184,500**
Rollover ROFR firm fuel contracts										
El Paso - FT24T000							99,994	36,888	99,994	36,888
El Paso - FT39D000							108,266	56,145	108,266	56,145
El Paso - FT39E000							33,473	11,250	33,473	11,250
El Paso - FT39H000										
El Paso - H822E000										
Transwestern - FT-5										
North Baja - A027F1 (Yuma Only)										
North Baja - YA027F1 (Yuma Only)										
Total ROFR firm contracts[1]	0	0	0	0	0	0	**241,733**	**104,283**	**241,733**	**104,283**
Future fuel contracts[2]										
Long Term Seasonal Firm Purchases										
Short Term Purchases[3]					64,751		64,751		94,751	
Total future contracts	0	0	0	0	**64,751**	0	**64,751**	0	**94,751**	0
Total contract rights	523,733	288,783	523,733	288,783	588,484	288,783	585,984	288,783	615,984	288,783
LONG/(SHORT) CONTRACT RIGHTS	**87,174**	**30,083**	**29,173**	**33,260**	**69,844**	**38,549**	**42,233**	**51,057**	**33,725**	**48,500**

[1] North Baja capacity serving only Yuma is not included in total current firm contracts.
[2] Based upon hourly optimization analysis.
[3] Short Term Purchases include capacity for the Ocotillo Modernization Project (currently in negotiations) and future potential gas transportation contracts.
[4] Short Term Purchases include future potential gas transportation contracts.

ATTACHMENT D.16 – GAS TRANSPORT ANALYSIS (CONTINUED)

YEAR	2022		2023		2024		2025		2026	
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**629,187**	**259,285**	**652,661**	**289,456**	**675,397**	**293,178**	**722,594**	**316,216**	**727,902**	**331,356**
Current firm fuel contracts										
El Paso - FT24T000										
El Paso - FT39D000										
El Paso - FT39E000										
El Paso - FT39H000	31,500	19,000	31,500	19,000	31,500	19,000				
El Paso - H822E000	30,500	25,500	30,500	25,500						
Transwestern - FT-5	220,000	140,000	220,000	140,000						
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000				
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750				
Total Current firm contracts[1]	**282,000**	**184,500**	**282,000**	**184,500**	**31,500**	**19,000**	**0**	**0**	**0**	**0**
Rollover ROFR firm fuel contracts										
El Paso - FT24T000	99,994	36,888	99,994	36,888	99,994	36,888	99,994	36,888	99,994	36,888
El Paso - FT39D000	108,266	56,145	108,266	56,145	108,266	56,145	108,266	56,145	108,266	56,145
El Paso - FT39E000	33,473	11,250	33,473	11,250	33,473	11,250	33,473	11,250	33,473	11,250
El Paso - FT39H000							31,500	19,000	31,500	19,000
El Paso - H822E000					30,500	25,500	30,500	25,500	30,500	25,500
Transwestern - FT-5					220,000	140,000	220,000	140,000	220,000	140,000
North Baja - A027F1 (Yuma Only)							11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)							62,750	62,750	62,750	62,750
Total ROFR firm contracts[1]	**241,733**	**104,283**	**241,733**	**104,283**	**492,233**	**269,783**	**523,733**	**288,783**	**523,733**	**288,783**
Future fuel contracts[2]										
Long Term Seasonal Firm Purchases										
Short Term Purchases[4]	110,000		140,000		140,000					
Total future contracts	**110,000**	**0**	**140,000**	**0**	**140,000**	**0**	**0**	**0**	**0**	**0**
Total contract rights	**633,733**	**288,783**	**663,733**	**288,783**	**663,733**	**288,783**	**523,733**	**288,783**	**523,733**	**288,783**
LONG/(SHORT) CONTRACT RIGHTS	**4,546**	**29,498**	**11,072**	**(673)**	**(11,664)**	**(4,395)**	**(198,861)**	**(27,433)**	**(204,169)**	**(42,573)**

[1] North Baja capacity serving only Yuma is not included in total current firm contracts.
[2] Based upon hourly optimization analysis.
[3] Short Term Purchases include capacity for the Ocotillo Modernization Project (currently in negotiations) and future potential gas transportation contracts.
[4] Short Term Purchases include future potential gas transportation contracts.

ATTACHMENT D.16 – GAS TRANSPORT ANALYSIS (CONTINUED)

YEAR	2027		2028		2029	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**753,888**	**358,965**	**775,174**	**384,180**	**795,066**	**353,311**
Current firm fuel contracts						
El Paso - FT24T000						
El Paso - FT39D000						
El Paso - FT39E000						
El Paso - FT39H000						
El Paso - H822E000						
Transwestern - FT-5						
North Baja - A027F1 (Yuma Only)						
North Baja - YA027F1 (Yuma Only)						
Total Current firm contracts[1]	**0**	**0**	**0**	**0**	**0**	**0**
Rollover ROFR firm fuel contracts						
El Paso - FT24T000	99,994	36,888	99,994	36,888	99,994	36,888
El Paso - FT39D000	108,266	56,145	108,266	56,145	108,266	56,145
El Paso - FT39E000	33,473	11,250	33,473	11,250	33,473	11,250
El Paso - FT39H000	31,500	19,000	31,500	19,000	31,500	19,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500
Transwestern - FT-5	220,000	140,000	220,000	140,000	220,000	140,000
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750
Total ROFR firm contracts[1]	**523,733**	**288,783**	**523,733**	**288,783**	**523,733**	**288,783**
Future fuel contracts[2]						
Long Term Seasonal Firm Purchases						
Short Term Purchases[4]						
Total future contracts	**0**	**0**	**0**	**0**	**0**	**0**
Total contract rights	**523,733**	**288,783**	**523,733**	**288,783**	**523,733**	**288,783**
LONG/(SHORT) CONTRACT RIGHTS	**(230,155)**	**(70,182)**	**(251,441)**	**(95,397)**	**(271,333)**	**(64,528)**

[1] North Baja capacity serving only Yuma is not included in total current firm contracts.
[2] Based upon hourly optimization analysis.
[3] Short Term Purchases include capacity for the Ocotillo Modernization Project (currently in negotiations) and future potential gas transportation contracts.
[4] Short Term Purchases include future potential gas transportation contracts.

ATTACHMENT D.16 – GAS TRANSPORT ANALYSIS (CONTINUED)

YEAR	2030		2031		2032	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**821,626**	**407,548**	**909,260**	**416,911**	**896,082**	**428,946**
Current firm fuel contracts						
El Paso - FT24T000						
El Paso - FT39D000						
El Paso - FT39E000						
El Paso - FT39H000						
El Paso - H822E000						
Transwestern - FT-5						
North Baja - A027F1 (Yuma Only)						
North Baja - YA027F1 (Yuma Only)						
Total Current firm contracts[1]	**0**	**0**	**0**	**0**	**0**	**0**
Rollover ROFR firm fuel contracts						
El Paso - FT24T000	99,994	36,888	99,994	36,888	99,994	36,888
El Paso - FT39D000	108,266	56,145	108,266	56,145	108,266	56,145
El Paso - FT39E000	33,473	11,250	33,473	11,250	33,473	11,250
El Paso - FT39H000	31,500	19,000	31,500	19,000	31,500	19,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500
Transwestern - FT-5	220,000	140,000	220,000	140,000	220,000	140,000
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750
Total ROFR firm contracts[1]	**523,733**	**288,783**	**523,733**	**288,783**	**523,733**	**288,783**
Future fuel contracts[2]						
Long Term Seasonal Firm Purchases						
Short Term Purchases[4]						
Total future contracts	**0**	**0**	**0**	**0**	**0**	**0**
Total contract rights	**523,733**	**288,783**	**523,733**	**288,783**	**523,733**	**288,783**
LONG/(SHORT) CONTRACT RIGHTS	**(297,893)**	**(118,765)**	**(385,527)**	**(128,128)**	**(372,349)**	**(140,163)**

[1] North Baja capacity serving only Yuma is not included in total current firm contracts.
[2] Based upon hourly optimization analysis.
[3] Short Term Purchases include capacity for the Ocotillo Modernization Project (currently in negotiations) and future potential gas transportation contracts.
[4] Short Term Purchases include future potential gas transportation contracts.

ATTACHMENT F.1(A)(1) – FLEXIBLE RESOURCE (SELECTED) PORTFOLIO L&R AND ENERGY MIX

	Flexible Resource Portfolio (Selected) – Loads and Resources – MW Energy Contribution at Peak																
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	961	989	1,015	1,047	1,152	1,187	1,222	1,258	1,294	1,331	1,369	1,409	1,448	1,489	1,530	1,573
4	**Total Load Requirements**	**7,985**	**8,296**	**8,596**	**8,902**	**9,283**	**9,592**	**9,903**	**10,219**	**10,542**	**10,870**	**11,205**	**11,550**	**11,894**	**12,250**	**12,612**	**12,983**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	970
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	514	514	515	515	516	516	504	504	505	505	487	488	488	476	476	476
15	Distributed Energy	13	13	13	13	13	14	14	14	14	14	14	14	14	14	14	14
16	Solar	417	418	418	418	419	419	420	420	420	420	421	421	421	421	421	421
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,694**	**7,695**	**7,521**	**7,175**	**6,695**	**6,696**	**6,683**	**6,684**	**6,297**	**5,732**	**5,715**	**5,715**	**5,715**	**5,703**	**5,703**	**5,703**
23	**Customer Resources**																
24	Future Demand Side Management	98	198	298	397	448	491	534	577	620	664	707	750	793	836	879	922
25	Future Distributed Energy	15	32	43	54	64	77	90	103	116	129	140	151	162	173	183	195
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**131**	**249**	**363**	**473**	**551**	**620**	**695**	**766**	**821**	**890**	**957**	**1,026**	**1,092**	**1,149**	**1,219**	**1,289**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	250	340	760	1,260	2,023	2,441	2,441	2,651	3,297	4,228	4,444	4,659	4,875	5,091	5,306	5,516
31	Combined Cycle	250	250	250	750	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000
32	Combustion Turbines	0	0	510	510	510	941	941	1,151	1,797	2,228	2,444	2,659	2,875	3,091	3,306	3,516
33	Short-Term Market Purchases	0	90	0	0	13	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
35	Wind	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
36	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Storage	0	1	3	3	3	3	3	86	86	85	84	165	244	323	320	397
39	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
40	**Total Future Resources**	**261**	**352**	**773**	**1,273**	**2,036**	**2,479**	**2,529**	**2,823**	**3,469**	**4,399**	**4,630**	**4,926**	**5,221**	**5,515**	**5,728**	**6,014**
41	**TOTAL RESOURCES**	**8,086**	**8,296**	**8,658**	**8,921**	**9,283**	**9,795**	**9,908**	**10,273**	**10,587**	**11,022**	**11,301**	**11,666**	**12,028**	**12,367**	**12,650**	**13,006**

ATTACHMENT F.1(A)(1) – FLEXIBLE RESOURCE (SELECTED) PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix – Flexible Resource Portfolio (Selected)

ENERGY (GWH) – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	9,296	7,497	9,614	4,272	4,728	1,224	36,631
2018	9,171	7,450	10,183	4,590	5,223	1,249	37,866
2019	9,171	7,441	10,740	4,917	5,725	1,239	39,234
2020	9,199	6,332	11,805	5,251	6,226	1,270	40,081
2021	9,296	6,088	13,118	5,571	6,317	1,263	41,653
2022	9,297	5,930	13,615	5,975	6,409	1,373	42,600
2023	9,297	7,201	11,826	6,358	6,501	2,346	43,528
2024	9,324	6,946	12,253	6,781	6,592	2,732	44,628
2025	9,297	5,928	14,493	7,229	6,684	2,180	45,811
2026	9,297	5,838	15,113	7,684	6,776	2,325	47,034
2027	9,297	5,764	15,579	8,134	6,868	2,601	48,243
2028	9,325	5,349	16,154	8,568	6,960	3,091	49,448
2029	9,297	5,904	16,143	8,957	7,051	3,371	50,722
2030	9,287	5,366	17,105	9,240	7,143	3,783	51,924
2031	9,297	5,602	17,614	9,593	7,234	3,879	53,220
2032	9,325	5,860	18,006	9,941	7,328	4,223	54,683

ENERGY MIX % – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	25.4%	20.5%	26.2%	11.7%	12.9%	3.3%	100.0%
2018	24.2%	19.7%	26.9%	12.1%	13.8%	3.3%	100.0%
2019	23.4%	19.0%	27.4%	12.5%	14.6%	3.2%	100.0%
2020	22.9%	15.8%	29.5%	13.1%	15.5%	3.2%	100.0%
2021	22.3%	14.6%	31.5%	13.4%	15.2%	3.0%	100.0%
2022	21.8%	13.9%	32.0%	14.0%	15.0%	3.2%	100.0%
2023	21.4%	16.5%	27.2%	14.6%	14.9%	5.4%	100.0%
2024	20.9%	15.6%	27.5%	15.2%	14.8%	6.1%	100.0%
2025	20.3%	12.9%	31.6%	15.8%	14.6%	4.8%	100.0%
2026	19.8%	12.4%	32.1%	16.3%	14.4%	4.9%	100.0%
2027	19.3%	11.9%	32.3%	16.9%	14.2%	5.4%	100.0%
2028	18.9%	10.8%	32.7%	17.3%	14.1%	6.3%	100.0%
2029	18.3%	11.6%	31.8%	17.7%	13.9%	6.6%	100.0%
2030	17.9%	10.3%	32.9%	17.8%	13.8%	7.3%	100.0%
2031	17.5%	10.5%	33.1%	18.0%	13.6%	7.3%	100.0%
2032	17.1%	10.7%	32.9%	18.2%	13.4%	7.7%	100.0%

(1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.
(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.

ATTACHMENT F.1(A)(2) – CARBON REDUCTION PORTFOLIO L&R AND ENERGY MIX

	Carbon Reduction Portfolio – Loads and Resources – MW Energy Contribution at Peak																
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	961	989	1,015	1,047	1,152	1,187	1,222	1,258	1,294	1,331	1,369	1,409	1,448	1,489	1,530	1,573
4	**Total Load Requirements**	**7,985**	**8,296**	**8,596**	**8,902**	**9,283**	**9,592**	**9,903**	**10,219**	**10,542**	**10,870**	**11,205**	**11,550**	**11,894**	**12,250**	**12,612**	**12,983**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	970	970	970	970	970	970	970	970	970	0
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	514	514	515	515	516	516	504	504	505	505	487	488	488	476	476	476
15	Distributed Energy	13	13	13	13	13	14	14	14	14	14	14	14	14	14	14	14
16	Solar	417	418	418	418	419	419	420	420	420	420	421	421	421	421	421	421
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,694**	**7,695**	**7,521**	**7,175**	**6,695**	**6,696**	**6,296**	**6,297**	**6,297**	**5,732**	**5,715**	**5,715**	**5,715**	**5,703**	**5,703**	**4,733**
23	**Customer Resources**																
24	Future Demand Side Management	98	198	298	397	448	491	534	577	620	664	707	750	793	836	879	922
25	Future Distributed Energy	15	32	43	54	64	77	90	103	116	129	140	151	162	173	183	195
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**131**	**249**	**363**	**473**	**551**	**620**	**695**	**766**	**821**	**890**	**957**	**1,026**	**1,092**	**1,149**	**1,219**	**1,289**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	250	340	760	1,260	2,023	2,441	2,872	3,082	3,297	4,228	4,444	4,659	4,875	5,091	5,306	6,657
31	Combined Cycle	250	250	250	750	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,710
32	Combustion Turbines	0	0	510	510	510	941	1,372	1,582	1,797	2,228	2,444	2,659	2,875	3,091	3,306	3,947
33	Short-Term Market Purchases	0	90	0	0	13	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
35	Wind	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
36	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Storage	0	1	3	3	3	3	3	86	86	85	84	165	244	323	320	397
39	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
40	**Total Future Resources**	**261**	**352**	**773**	**1,273**	**2,036**	**2,479**	**2,961**	**3,254**	**3,469**	**4,399**	**4,630**	**4,926**	**5,221**	**5,515**	**5,728**	**7,155**
41	**TOTAL RESOURCES**	**8,086**	**8,296**	**8,658**	**8,921**	**9,283**	**9,795**	**9,952**	**10,317**	**10,587**	**11,022**	**11,301**	**11,666**	**12,028**	**12,367**	**12,650**	**13,177**

ATTACHMENT F.1(A)(2) – CARBON REDUCTION PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix – Carbon Reduction Portfolio

ENERGY (GWH) – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	9,296	7,497	9,614	4,272	4,728	1,224	36,631
2018	9,171	7,450	10,183	4,590	5,223	1,249	37,866
2019	9,171	7,441	10,740	4,917	5,725	1,239	39,234
2020	9,199	6,332	11,805	5,251	6,226	1,270	40,081
2021	9,296	6,088	13,118	5,571	6,317	1,263	41,653
2022	9,297	5,983	13,561	5,975	6,409	1,373	42,598
2023	9,297	5,392	13,569	6,358	6,501	2,394	43,510
2024	9,324	5,037	14,142	6,781	6,592	2,743	44,617
2025	9,297	5,559	14,890	7,229	6,684	2,147	45,806
2026	9,297	5,839	15,113	7,684	6,776	2,325	47,034
2027	9,297	5,764	15,579	8,134	6,868	2,601	48,243
2028	9,325	5,349	16,154	8,568	6,960	3,091	49,448
2029	9,297	5,904	16,134	8,957	7,051	3,378	50,722
2030	9,287	5,912	16,710	9,240	7,143	3,687	51,979
2031	9,297	4,374	18,779	9,593	7,234	3,956	53,234
2032	9,325	0	23,172	9,941	7,328	4,625	54,390

ENERGY MIX % – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	25.4%	20.5%	26.2%	11.7%	12.9%	3.3%	100.0%
2018	24.2%	19.7%	26.9%	12.1%	13.8%	3.3%	100.0%
2019	23.4%	19.0%	27.4%	12.5%	14.6%	3.2%	100.0%
2020	22.9%	15.8%	29.5%	13.1%	15.5%	3.2%	100.0%
2021	22.3%	14.6%	31.5%	13.4%	15.2%	3.0%	100.0%
2022	21.8%	14.0%	31.8%	14.0%	15.0%	3.2%	100.0%
2023	21.4%	12.4%	31.2%	14.6%	14.9%	5.5%	100.0%
2024	20.9%	11.3%	31.7%	15.2%	14.8%	6.1%	100.0%
2025	20.3%	12.1%	32.5%	15.8%	14.6%	4.7%	100.0%
2026	19.8%	12.4%	32.1%	16.3%	14.4%	4.9%	100.0%
2027	19.3%	11.9%	32.3%	16.9%	14.2%	5.4%	100.0%
2028	18.9%	10.8%	32.7%	17.3%	14.1%	6.3%	100.0%
2029	18.3%	11.6%	31.8%	17.7%	13.9%	6.7%	100.0%
2030	17.9%	11.4%	32.1%	17.8%	13.7%	7.1%	100.0%
2031	17.5%	8.2%	35.3%	18.0%	13.6%	7.4%	100.0%
2032	17.1%	0.0%	42.6%	18.3%	13.5%	8.5%	100.0%

(1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.
(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.

ATTACHMENT F.1(A)(3) – EXPANDED DEMAND SIDE MANAGEMENT PORTFOLIO L&R AND ENERGY MIX

	Expanded Demand Side Management Portfolio – Loads and Resources – MW Energy Contribution at Peak																
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	960	986	1,011	1,042	1,141	1,168	1,196	1,224	1,253	1,283	1,313	1,345	1,377	1,410	1,444	1,479
4	**Total Load Requirements**	**7,984**	**8,293**	**8,593**	**8,897**	**9,271**	**9,573**	**9,877**	**10,185**	**10,501**	**10,821**	**11,149**	**11,486**	**11,823**	**12,171**	**12,526**	**12,889**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	970
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	514	514	515	515	515	516	503	503	503	504	486	486	486	474	474	474
15	Distributed Energy	13	13	13	13	13	13	14	14	14	14	14	14	14	14	14	14
16	Solar	417	417	418	418	418	419	419	419	419	419	419	419	419	419	419	419
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,694**	**7,695**	**7,521**	**7,174**	**6,695**	**6,695**	**6,682**	**6,682**	**6,296**	**5,731**	**5,713**	**5,713**	**5,713**	**5,701**	**5,701**	**5,701**
23	**Customer Resources**																
24	Future Demand Side Management	106	213	321	429	523	616	709	802	895	988	1,081	1,174	1,267	1,360	1,453	1,547
25	Future Distributed Energy	15	32	43	53	63	75	87	99	111	122	134	144	154	163	172	182
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**139**	**265**	**387**	**505**	**625**	**742**	**867**	**987**	**1,091**	**1,209**	**1,325**	**1,443**	**1,558**	**1,664**	**1,782**	**1,901**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	250	322	760	1,260	2,010	2,226	2,441	2,651	3,082	3,797	4,013	4,228	4,228	4,444	4,659	4,869
31	Combined Cycle	250	250	250	750	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000
32	Combustion Turbines	0	0	510	510	510	726	941	1,151	1,582	1,797	2,013	2,228	2,228	2,444	2,659	2,869
33	Short-Term Market Purchases	0	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
35	Wind	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
36	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Storage	0	1	3	3	3	3	3	86	86	85	84	165	244	323	320	397
39	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
40	**Total Future Resources**	**261**	**334**	**773**	**1,273**	**2,023**	**2,264**	**2,529**	**2,823**	**3,253**	**3,968**	**4,198**	**4,495**	**4,574**	**4,868**	**5,081**	**5,367**
41	**TOTAL RESOURCES**	**8,094**	**8,293**	**8,681**	**8,952**	**9,343**	**9,701**	**10,079**	**10,492**	**10,639**	**10,907**	**11,236**	**11,651**	**11,846**	**12,233**	**12,564**	**12,969**

ATTACHMENT F.1(A)(3) – EXPANDED DEMAND SIDE MANAGEMENT PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix – Expanded Demand Side Management Portfolio

ENERGY (GWH) – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	9,296	7,497	9,614	4,272	4,728	1,224	36,631
2018	9,171	7,450	10,183	4,590	5,223	1,249	37,866
2019	9,171	7,441	10,740	4,917	5,725	1,239	39,234
2020	9,199	6,332	11,805	5,251	6,226	1,270	40,081
2021	9,296	6,065	12,841	5,571	6,660	1,258	41,692
2022	9,297	5,866	13,031	5,975	7,094	1,388	42,651
2023	9,297	7,108	11,045	6,358	7,528	2,289	43,625
2024	9,324	6,766	11,392	6,781	7,967	2,511	44,740
2025	9,297	5,843	13,108	7,228	8,397	2,099	45,972
2026	9,297	5,794	13,380	7,678	8,831	2,262	47,242
2027	9,297	5,718	13,655	8,114	9,266	2,466	48,516
2028	9,325	5,295	14,082	8,520	9,708	2,754	49,685
2029	9,297	5,836	13,860	8,893	10,134	3,003	51,023
2030	9,287	5,290	14,647	9,156	10,569	3,281	52,229
2031	9,297	5,528	14,812	9,487	11,003	3,413	53,539
2032	9,325	5,756	15,081	9,807	11,449	3,582	55,000

ENERGY MIX % – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	25.4%	20.5%	26.2%	11.7%	12.9%	3.3%	100.0%
2018	24.2%	19.7%	26.9%	12.1%	13.8%	3.3%	100.0%
2019	23.4%	19.0%	27.4%	12.5%	14.6%	3.2%	100.0%
2020	22.9%	15.8%	29.5%	13.1%	15.5%	3.2%	100.0%
2021	22.3%	14.5%	30.8%	13.4%	16.0%	3.0%	100.0%
2022	21.8%	13.8%	30.6%	14.0%	16.6%	3.3%	100.0%
2023	21.3%	16.3%	25.3%	14.6%	17.3%	5.2%	100.0%
2024	20.8%	15.1%	25.5%	15.2%	17.8%	5.6%	100.0%
2025	20.2%	12.7%	28.5%	15.7%	18.3%	4.6%	100.0%
2026	19.7%	12.3%	28.3%	16.3%	18.7%	4.8%	100.0%
2027	19.2%	11.8%	28.1%	16.7%	19.1%	5.1%	100.0%
2028	18.8%	10.7%	28.3%	17.1%	19.5%	5.5%	100.0%
2029	18.2%	11.4%	27.2%	17.4%	19.9%	5.9%	100.0%
2030	17.8%	10.1%	28.0%	17.5%	20.2%	6.3%	100.0%
2031	17.4%	10.3%	27.7%	17.7%	20.6%	6.4%	100.0%
2032	17.0%	10.5%	27.4%	17.8%	20.8%	6.5%	100.0%

(1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.
(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.

ATTACHMENT F.1(A)(4) – EXPANDED RENEWABLES PORTFOLIO L&R AND ENERGY MIX

	Expanded Renewables Portfolio – Loads and Resources – MW Energy Contribution at Peak																
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	961	989	1,015	1,047	1,152	1,187	1,222	1,258	1,294	1,331	1,369	1,409	1,448	1,489	1,530	1,573
4	**Total Load Requirements**	**7,985**	**8,296**	**8,596**	**8,902**	**9,283**	**9,592**	**9,903**	**10,219**	**10,542**	**10,870**	**11,205**	**11,550**	**11,894**	**12,250**	**12,612**	**12,983**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	970
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	517	518	518	519	519	520	507	508	508	508	477	466	455	434	435	436
15	Distributed Energy	13	13	13	13	14	14	14	14	14	14	14	13	13	13	13	13
16	Solar	420	421	421	422	422	423	423	423	424	424	411	400	390	381	382	383
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,698**	**7,698**	**7,525**	**7,178**	**6,699**	**6,699**	**6,687**	**6,687**	**6,300**	**5,736**	**5,704**	**5,693**	**5,683**	**5,661**	**5,662**	**5,664**
23	**Customer Resources**																
24	Future Demand Side Management	98	198	298	397	448	491	534	577	620	664	707	750	793	836	879	922
25	Future Distributed Energy	15	32	43	54	64	77	90	103	116	129	140	151	162	173	183	195
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**131**	**249**	**363**	**473**	**551**	**620**	**695**	**766**	**821**	**890**	**957**	**1,026**	**1,092**	**1,149**	**1,219**	**1,289**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	250	337	760	1,260	2,019	2,441	2,441	2,651	3,297	4,228	4,444	4,444	4,659	4,875	5,091	5,300
31	Combined Cycle	250	250	250	750	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000
32	Combustion Turbines	0	0	510	510	510	941	941	1,151	1,797	2,228	2,444	2,444	2,659	2,875	3,091	3,300
33	Short-Term Market Purchases	0	87	0	0	9	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	0	0	0	0	0	0	0	0	0	0	88	153	211	263	266	269
35	Wind	0	0	0	0	0	0	0	0	0	0	31	46	61	76	76	76
36	Solar	0	0	0	0	0	0	0	0	0	0	58	107	150	187	190	193
37	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Storage	0	1	3	3	3	3	3	86	86	85	84	165	244	323	320	397
39	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
40	**Total Future Resources**	**261**	**349**	**773**	**1,273**	**2,033**	**2,479**	**2,529**	**2,823**	**3,469**	**4,399**	**4,702**	**4,848**	**5,201**	**5,546**	**5,762**	**6,051**
41	**TOTAL RESOURCES**	**8,090**	**8,296**	**8,661**	**8,924**	**9,283**	**9,798**	**9,911**	**10,276**	**10,590**	**11,025**	**11,364**	**11,566**	**11,976**	**12,357**	**12,644**	**13,004**

ATTACHMENT F.1(A)(4) – EXPANDED RENEWABLES PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix – Expanded Renewables Portfolio

ENERGY (GWH) – RE + DE

	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	9,296	7,497	9,614	4,272	4,728	1,224	36,631
2018	9,171	7,450	10,183	4,590	5,223	1,249	37,866
2019	9,171	7,441	10,740	4,917	5,725	1,239	39,234
2020	9,199	6,332	11,805	5,251	6,226	1,270	40,081
2021	9,296	6,088	13,118	5,571	6,317	1,263	41,653
2022	9,297	5,930	13,615	5,975	6,409	1,373	42,600
2023	9,297	7,201	11,826	6,358	6,501	2,346	43,528
2024	9,324	6,946	12,253	6,781	6,592	2,732	44,628
2025	9,297	5,931	14,494	7,229	6,684	2,198	45,832
2026	9,297	5,837	15,139	7,684	6,776	2,313	47,046
2027	9,297	5,748	15,235	8,640	6,868	2,522	48,309
2028	9,325	5,329	15,529	9,583	6,960	2,887	49,614
2029	9,297	5,867	15,151	10,477	7,051	3,164	51,006
2030	9,287	5,328	15,702	11,264	7,143	3,594	52,318
2031	9,297	5,568	16,144	11,620	7,234	3,738	53,601
2032	9,325	5,811	16,761	11,978	7,328	3,906	55,108

ENERGY MIX % – RE + DE

	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	25.4%	20.5%	26.2%	11.7%	12.9%	3.3%	100.0%
2018	24.2%	19.7%	26.9%	12.1%	13.8%	3.3%	100.0%
2019	23.4%	19.0%	27.4%	12.5%	14.6%	3.2%	100.0%
2020	22.9%	15.8%	29.5%	13.1%	15.5%	3.2%	100.0%
2021	22.3%	14.6%	31.5%	13.4%	15.2%	3.0%	100.0%
2022	21.8%	13.9%	32.0%	14.0%	15.0%	3.2%	100.0%
2023	21.4%	16.5%	27.2%	14.6%	14.9%	5.4%	100.0%
2024	20.9%	15.6%	27.5%	15.2%	14.8%	6.1%	100.0%
2025	20.3%	12.9%	31.6%	15.8%	14.6%	4.8%	100.0%
2026	19.8%	12.4%	32.2%	16.3%	14.4%	4.9%	100.0%
2027	19.2%	11.9%	31.5%	17.9%	14.2%	5.2%	100.0%
2028	18.8%	10.7%	31.3%	19.3%	14.0%	5.8%	100.0%
2029	18.2%	11.5%	29.7%	20.5%	13.8%	6.2%	100.0%
2030	17.8%	10.2%	30.0%	21.5%	13.7%	6.9%	100.0%
2031	17.3%	10.4%	30.1%	21.7%	13.5%	7.0%	100.0%
2032	16.9%	10.5%	30.4%	21.7%	13.3%	7.1%	100.0%

(1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.
(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.

ATTACHMENT F.1(A)(5) – ENERGY STORAGE SYSTEMS PORTFOLIO L&R AND ENERGY MIX

	Energy Storage Systems Portfolio – Loads and Resources – MW Energy Contribution at Peak																
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	961	989	1,015	1,047	1,152	1,187	1,222	1,258	1,294	1,331	1,369	1,409	1,448	1,489	1,530	1,573
4	**Total Load Requirements**	**7,985**	**8,296**	**8,596**	**8,902**	**9,283**	**9,592**	**9,903**	**10,219**	**10,542**	**10,870**	**11,205**	**11,550**	**11,894**	**12,250**	**12,612**	**12,983**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	970
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	514	514	515	515	516	516	504	504	505	505	487	488	488	476	476	476
15	Distributed Energy	13	13	13	13	13	14	14	14	14	14	14	14	14	14	14	14
16	Solar	417	418	418	418	419	419	420	420	420	420	421	421	421	421	421	421
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,694**	**7,695**	**7,521**	**7,175**	**6,695**	**6,696**	**6,683**	**6,684**	**6,297**	**5,732**	**5,715**	**5,715**	**5,715**	**5,703**	**5,703**	**5,703**
23	**Customer Resources**																
24	Future Demand Side Management	98	198	298	397	448	491	534	577	620	664	707	750	793	836	879	922
25	Future Distributed Energy	15	32	43	54	64	77	90	103	116	129	140	151	162	173	183	195
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**131**	**249**	**363**	**473**	**551**	**620**	**695**	**766**	**821**	**890**	**957**	**1,026**	**1,092**	**1,149**	**1,219**	**1,289**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	250	340	760	1,260	2,010	2,226	2,226	2,435	3,082	4,013	4,013	4,228	4,444	4,875	4,875	5,300
31	Combined Cycle	250	250	250	750	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000
32	Combustion Turbines	0	0	510	510	510	726	726	935	1,582	2,013	2,013	2,228	2,444	2,875	2,875	3,300
33	Short-Term Market Purchases	0	90	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
35	Wind	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
36	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Storage	0	1	3	3	86	155	227	297	365	360	495	487	616	606	729	718
39	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
40	**Total Future Resources**	**261**	**352**	**773**	**1,273**	**2,106**	**2,416**	**2,538**	**2,818**	**3,533**	**4,458**	**4,609**	**4,817**	**5,161**	**5,583**	**5,705**	**6,119**
41	**TOTAL RESOURCES**	**8,086**	**8,296**	**8,658**	**8,921**	**9,353**	**9,731**	**9,917**	**10,268**	**10,651**	**11,081**	**11,280**	**11,558**	**11,969**	**12,435**	**12,627**	**13,111**

ATTACHMENT F.1(A)(5) – ENERGY STORAGE SYSTEMS PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix – Energy Storage Systems Portfolio

ENERGY (GWH) – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	9,296	7,497	9,614	4,272	4,728	1,224	36,631
2018	9,171	7,450	10,183	4,590	5,223	1,249	37,866
2019	9,171	7,441	10,740	4,917	5,725	1,239	39,234
2020	9,199	6,331	11,804	5,251	6,226	1,270	40,081
2021	9,296	6,094	13,079	5,571	6,317	1,262	41,619
2022	9,297	5,962	13,492	5,975	6,409	1,401	42,535
2023	9,297	7,297	11,444	6,358	6,501	2,613	43,509
2024	9,324	7,045	11,869	6,781	6,592	3,031	44,642
2025	9,297	5,985	14,217	7,229	6,684	2,493	45,905
2026	9,297	5,865	14,808	7,684	6,776	2,641	47,070
2027	9,297	5,815	15,285	8,134	6,868	2,932	48,331
2028	9,325	5,378	15,854	8,568	6,960	3,462	49,547
2029	9,297	5,909	16,161	8,957	7,051	3,486	50,860
2030	9,287	5,369	17,228	9,240	7,143	3,846	52,113
2031	9,297	5,599	17,675	9,593	7,234	4,037	53,435
2032	9,325	5,860	18,027	9,941	7,328	4,306	54,786

ENERGY MIX % – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	25.4%	20.5%	26.2%	11.7%	12.9%	3.3%	100.0%
2018	24.2%	19.7%	26.9%	12.1%	13.8%	3.3%	100.0%
2019	23.4%	19.0%	27.4%	12.5%	14.6%	3.2%	100.0%
2020	22.9%	15.8%	29.5%	13.1%	15.5%	3.2%	100.0%
2021	22.3%	14.6%	31.4%	13.4%	15.2%	3.0%	100.0%
2022	21.9%	14.0%	31.7%	14.0%	15.1%	3.3%	100.0%
2023	21.4%	16.8%	26.3%	14.6%	14.9%	6.0%	100.0%
2024	20.9%	15.8%	26.6%	15.2%	14.8%	6.8%	100.0%
2025	20.3%	13.0%	31.0%	15.7%	14.6%	5.4%	100.0%
2026	19.8%	12.5%	31.5%	16.3%	14.4%	5.6%	100.0%
2027	19.2%	12.0%	31.6%	16.8%	14.2%	6.1%	100.0%
2028	18.8%	10.9%	32.0%	17.3%	14.0%	7.0%	100.0%
2029	18.3%	11.6%	31.8%	17.6%	13.9%	6.9%	100.0%
2030	17.8%	10.3%	33.1%	17.7%	13.7%	7.4%	100.0%
2031	17.4%	10.5%	33.1%	18.0%	13.5%	7.6%	100.0%
2032	17.0%	10.7%	32.9%	18.1%	13.4%	7.9%	100.0%

(1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.
(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.

ATTACHMENT F.1(A)(6) – RESOURCE MANDATES PORTFOLIO L&R AND ENERGY MIX

	Resource Mandates Portfolio – Loads and Resources – MW Energy Contribution at Peak																
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	960	986	1,011	1,042	1,141	1,168	1,196	1,224	1,253	1,283	1,313	1,345	1,377	1,410	1,444	1,479
4	**Total Load Requirements**	**7,984**	**8,293**	**8,593**	**8,897**	**9,271**	**9,573**	**9,877**	**10,185**	**10,501**	**10,821**	**11,149**	**11,486**	**11,823**	**12,171**	**12,526**	**12,889**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	970
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	516	517	517	517	518	518	505	506	506	506	488	488	474	451	452	453
15	Distributed Energy	13	13	13	13	13	14	14	14	14	14	14	14	13	13	13	13
16	Solar	419	420	420	420	421	421	421	421	421	422	422	422	407	398	399	399
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,696**	**7,697**	**7,523**	**7,177**	**6,697**	**6,697**	**6,685**	**6,685**	**6,298**	**5,733**	**5,715**	**5,716**	**5,701**	**5,679**	**5,679**	**5,680**
23	**Customer Resources**																
24	Future Demand Side Management	106	213	321	429	523	616	709	802	895	988	1,081	1,174	1,267	1,360	1,453	1,547
25	Future Distributed Energy	15	32	43	53	63	75	87	99	111	122	134	144	154	163	172	182
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**139**	**265**	**387**	**505**	**625**	**742**	**867**	**987**	**1,091**	**1,209**	**1,325**	**1,443**	**1,558**	**1,664**	**1,782**	**1,901**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	250	320	760	1,260	2,010	2,010	2,226	2,435	2,866	3,582	3,582	3,797	3,797	4,013	4,228	4,438
31	Combined Cycle	250	250	250	750	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000
32	Combustion Turbines	0	0	510	510	510	510	726	935	1,366	1,582	1,582	1,797	1,797	2,013	2,228	2,438
33	Short-Term Market Purchases	0	70	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	0	0	0	0	0	0	0	0	0	0	16	16	96	151	151	152
35	Wind	0	0	0	0	0	0	0	0	0	0	16	16	33	45	45	45
36	Solar	0	0	0	0	0	0	0	0	0	0	0	0	63	105	106	107
37	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Storage	0	1	3	3	86	155	227	297	365	360	495	487	616	606	729	718
39	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
40	**Total Future Resources**	**261**	**332**	**773**	**1,273**	**2,106**	**2,200**	**2,538**	**2,818**	**3,317**	**4,027**	**4,178**	**4,386**	**4,595**	**4,855**	**5,195**	**5,393**
41	**TOTAL RESOURCES**	**8,096**	**8,293**	**8,683**	**8,955**	**9,428**	**9,640**	**10,090**	**10,490**	**10,706**	**10,969**	**11,218**	**11,544**	**11,854**	**12,198**	**12,656**	**12,974**

ATTACHMENT F.1(A)(6) – RESOURCE MANDATES PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix – Resource Mandates Portfolio

ENERGY (GWH) – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	9,296	7,497	9,614	4,272	4,728	1,224	36,631
2018	9,171	7,450	10,183	4,590	5,223	1,249	37,866
2019	9,171	7,441	10,740	4,917	5,725	1,239	39,234
2020	9,199	6,331	11,804	5,251	6,226	1,270	40,081
2021	9,296	6,071	12,794	5,571	6,660	1,259	41,651
2022	9,297	5,893	12,951	5,975	7,094	1,375	42,585
2023	9,297	7,218	10,620	6,358	7,528	2,566	43,587
2024	9,324	6,955	10,822	6,781	7,967	2,913	44,761
2025	9,297	5,945	13,051	7,229	8,397	2,327	46,246
2026	9,297	5,812	13,363	7,684	8,831	2,492	47,481
2027	9,297	5,759	13,623	8,135	9,266	2,712	48,792
2028	9,325	5,314	14,058	8,569	9,708	3,096	50,071
2029	9,297	5,817	13,751	9,538	10,134	3,057	51,594
2030	9,287	5,252	14,228	10,238	10,569	3,416	52,990
2031	9,297	5,487	14,507	10,594	11,003	3,472	54,359
2032	9,325	5,724	14,726	10,950	11,449	3,628	55,801

ENERGY MIX % – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	25.4%	20.5%	26.2%	11.7%	12.9%	3.3%	100.0%
2018	24.2%	19.7%	26.9%	12.1%	13.8%	3.3%	100.0%
2019	23.4%	19.0%	27.4%	12.5%	14.6%	3.2%	100.0%
2020	22.9%	15.8%	29.5%	13.1%	15.5%	3.2%	100.0%
2021	22.3%	14.6%	30.7%	13.4%	16.0%	3.0%	100.0%
2022	21.8%	13.8%	30.4%	14.0%	16.7%	3.2%	100.0%
2023	21.3%	16.6%	24.4%	14.6%	17.3%	5.9%	100.0%
2024	20.8%	15.5%	24.2%	15.1%	17.8%	6.5%	100.0%
2025	20.1%	12.9%	28.2%	15.6%	18.2%	5.0%	100.0%
2026	19.6%	12.2%	28.1%	16.2%	18.6%	5.2%	100.0%
2027	19.1%	11.8%	27.9%	16.7%	19.0%	5.6%	100.0%
2028	18.6%	10.6%	28.1%	17.1%	19.4%	6.2%	100.0%
2029	18.0%	11.3%	26.7%	18.5%	19.6%	5.9%	100.0%
2030	17.5%	9.9%	26.9%	19.3%	19.9%	6.4%	100.0%
2031	17.1%	10.1%	26.7%	19.5%	20.2%	6.4%	100.0%
2032	16.7%	10.3%	26.4%	19.6%	20.5%	6.5%	100.0%

(1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.
(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.

ATTACHMENT F.1(A)(7) – NUCLEAR SMALL MODULAR REACTORS PORTFOLIO L&R AND ENERGY MIX

	Nuclear Small Modular Reactors Portfolio – Loads and Resources – MW Energy Contribution at Peak																
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	961	989	1,015	1,047	1,152	1,187	1,222	1,258	1,294	1,331	1,369	1,409	1,448	1,489	1,530	1,573
4	**Total Load Requirements**	**7,985**	**8,296**	**8,596**	**8,902**	**9,283**	**9,592**	**9,903**	**10,219**	**10,542**	**10,870**	**11,205**	**11,550**	**11,894**	**12,250**	**12,612**	**12,983**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	970
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	514	514	515	515	516	516	504	504	505	505	487	488	488	476	476	476
15	Distributed Energy	13	13	13	13	13	14	14	14	14	14	14	14	14	14	14	14
16	Solar	417	418	418	418	419	419	420	420	420	420	421	421	421	421	421	421
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,694**	**7,695**	**7,521**	**7,175**	**6,695**	**6,696**	**6,683**	**6,684**	**6,297**	**5,732**	**5,715**	**5,715**	**5,715**	**5,703**	**5,703**	**5,703**
23	**Customer Resources**																
24	Future Demand Side Management	98	198	298	397	448	491	534	577	620	664	707	750	793	836	879	922
25	Future Distributed Energy	15	32	43	54	64	77	90	103	116	129	140	151	162	173	183	195
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**131**	**249**	**363**	**473**	**551**	**620**	**695**	**766**	**821**	**890**	**957**	**1,026**	**1,092**	**1,149**	**1,219**	**1,289**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	285	285	285	285	570
30	Natural Gas	250	340	760	1,260	2,023	2,441	2,441	2,651	3,297	4,228	4,444	4,444	4,659	4,875	5,084	5,084
31	Combined Cycle	250	250	250	750	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000
32	Combustion Turbines	0	0	510	510	510	941	941	1,151	1,797	2,228	2,444	2,444	2,659	2,875	3,084	3,084
33	Short-Term Market Purchases	0	90	0	0	13	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
35	Wind	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
36	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Energy Storage	0	1	3	3	3	3	3	86	86	85	84	165	244	323	320	397
39	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
40	**Total Future Resources**	**261**	**352**	**773**	**1,273**	**2,036**	**2,479**	**2,529**	**2,823**	**3,469**	**4,399**	**4,630**	**4,710**	**5,005**	**5,299**	**5,506**	**5,582**
41	**TOTAL RESOURCES**	**8,086**	**8,296**	**8,658**	**8,921**	**9,283**	**9,795**	**9,908**	**10,273**	**10,587**	**11,022**	**11,301**	**11,451**	**11,813**	**12,151**	**12,428**	**12,575**

ATTACHMENT F.1(A)(7) – NUCLEAR SMALL MODULAR REACTORS PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix – Nuclear Small Modular Reactors Portfolio

ENERGY (GWH) – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	9,296	7,497	9,614	4,272	4,728	1,224	36,631
2018	9,171	7,450	10,183	4,590	5,223	1,249	37,866
2019	9,171	7,441	10,740	4,917	5,725	1,239	39,234
2020	9,199	6,332	11,805	5,251	6,226	1,270	40,081
2021	9,296	6,088	13,118	5,571	6,317	1,263	41,653
2022	9,297	5,930	13,615	5,975	6,409	1,373	42,600
2023	9,297	7,201	11,826	6,358	6,501	2,346	43,528
2024	9,324	6,946	12,253	6,781	6,592	2,732	44,628
2025	9,297	5,928	14,493	7,229	6,684	2,180	45,811
2026	9,297	5,838	15,113	7,684	6,776	2,325	47,034
2027	9,297	5,764	15,579	8,134	6,868	2,601	48,243
2028	10,483	5,272	15,248	8,568	6,960	2,899	49,431
2029	11,140	5,796	14,791	8,957	7,051	2,973	50,707
2030	11,112	5,278	15,681	9,240	7,143	3,450	51,903
2031	11,123	5,517	16,158	9,593	7,234	3,565	53,189
2032	12,172	5,703	15,713	9,941	7,328	3,724	54,580

ENERGY MIX % – RE + DE							
	Nuclear	Coal	Gas + Oil	Renew	DSM	Purchase	TOT
2017	25.4%	20.5%	26.2%	11.7%	12.9%	3.3%	100.0%
2018	24.2%	19.7%	26.9%	12.1%	13.8%	3.3%	100.0%
2019	23.4%	19.0%	27.4%	12.5%	14.6%	3.2%	100.0%
2020	22.9%	15.8%	29.5%	13.1%	15.5%	3.2%	100.0%
2021	22.3%	14.6%	31.5%	13.4%	15.2%	3.0%	100.0%
2022	21.8%	13.9%	32.0%	14.0%	15.0%	3.2%	100.0%
2023	21.4%	16.5%	27.2%	14.6%	14.9%	5.4%	100.0%
2024	20.9%	15.6%	27.5%	15.2%	14.8%	6.1%	100.0%
2025	20.3%	12.9%	31.6%	15.8%	14.6%	4.8%	100.0%
2026	19.8%	12.4%	32.1%	16.3%	14.4%	4.9%	100.0%
2027	19.3%	11.9%	32.3%	16.9%	14.2%	5.4%	100.0%
2028	21.2%	10.7%	30.8%	17.3%	14.1%	5.9%	100.0%
2029	22.0%	11.4%	29.2%	17.7%	13.9%	5.9%	100.0%
2030	21.4%	10.2%	30.2%	17.8%	13.8%	6.6%	100.0%
2031	20.9%	10.4%	30.4%	18.0%	13.6%	6.7%	100.0%
2032	22.3%	10.4%	28.8%	18.2%	13.4%	6.8%	100.0%

(1) RE + DE Renew include DE installed since 2008. EE includes energy beginning in 2005.
(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.

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS

Total Revenue Requirements ($Millions)							
	FLEXIBLE RESOURCE PORTFOLIO (SELECTED)	CARBON REDUCTION PORTFOLIO	ENERGY STORAGE SYSTEMS PORTFOLIO	EXPANDED RENEWABLES PORTFOLIO	EXPANDED DEMAND SIDE MANAGEMENT PORTFOLIO*	RESOURCE MANDATES PORTFOLIO*	NUCLEAR SMALL MODULAR REACTORS PORTFOLIO
2017	2,262.3	2,265.2	2,262.3	2,262.3	2,262.3	2,262.3	2,262.3
2018	2,373.6	2,388.7	2,373.6	2,373.5	2,373.4	2,373.3	2,373.6
2019	2,395.3	2,410.6	2,395.3	2,395.3	2,395.3	2,395.3	2,395.3
2020	2,432.6	2,447.4	2,432.6	2,432.6	2,432.6	2,432.6	2,432.6
2021	2,549.5	2,564.1	2,582.2	2,549.4	2,615.7	2,648.7	2,549.5
2022	2,658.0	2,670.5	2,702.3	2,658.0	2,704.4	2,749.7	2,658.0
2023	2,769.3	2,757.7	2,816.8	2,769.3	2,807.0	2,860.8	2,769.3
2024	2,892.4	2,906.4	2,939.5	2,892.4	2,940.7	2,993.3	2,892.4
2025	2,962.6	2,991.7	3,031.6	2,963.6	2,979.0	3,064.5	2,962.6
2026	3,064.9	3,072.2	3,112.0	3,065.5	3,035.0	3,113.0	3,064.9
2027	3,254.7	3,266.4	3,309.7	3,291.4	3,195.4	3,310.5	3,254.7
2028	3,430.5	3,446.5	3,451.2	3,488.7	3,372.0	3,449.8	3,586.0
2029	3,559.9	3,583.2	3,629.9	3,657.9	3,499.3	3,662.7	3,822.3
2030	3,759.8	3,790.0	3,821.0	3,889.4	3,687.4	3,850.6	3,998.6
2031	3,836.3	4,005.6	3,923.5	3,944.1	3,740.5	3,962.5	4,068.9
2032	4,004.7	3,854.9	4,085.0	4,120.0	4,099.4	4,291.6	4,388.9
CPW@7.50%							
(2017-2032)	25,950.7	26,069.8	26,253.8	26,150.4	25,966.6	26,506.5	26,404.7
(2017-2046)	39,230.6	39,020.4	39,743.5	39,797.5	39,873.1	40,952.3	40,906.8

*indicate the costs shown are equal to the total revenue requirements and the incremental customer cost for DSM

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Revenue Requirements – Flexible Resource Portfolio (Selected) ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	653.0	486.1	67.4	386.3	76.4	1,669.1	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2,262.3	74.6
2018	748.8	517.8	72.6	431.6	76.8	1,847.6	71.0	252.3	323.3	0.0	96.9	9.2	(0.1)	96.7	2,373.6	77.5
2019	814.1	518.5	77.6	407.5	74.7	1,892.5	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2,395.3	77.2
2020	873.2	541.1	86.1	371.6	72.7	1,944.7	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2,432.6	77.6
2021	912.8	590.5	98.1	392.8	70.8	2,065.0	39.8	243.7	283.6	0.6	103.0	15.4	(0.1)	82.1	2,549.5	79.6
2022	942.1	631.5	104.2	411.1	73.0	2,161.9	39.9	250.9	290.8	0.7	105.8	14.0	(0.1)	84.9	2,658.0	81.4
2023	1,021.4	620.5	108.5	399.7	74.9	2,225.0	40.3	273.2	313.5	1.7	104.7	12.4	22.5	89.4	2,769.3	83.3
2024	1,060.7	657.8	112.0	412.1	74.0	2,316.7	40.8	283.7	324.5	2.0	110.7	17.9	26.5	94.1	2,892.4	85.6
2025	1,088.9	674.7	119.8	390.3	76.4	2,350.1	41.3	276.2	317.5	2.0	149.9	19.9	25.4	97.7	2,962.6	86.1
2026	1,108.8	740.4	131.7	411.1	88.6	2,480.6	6.2	250.2	256.4	4.0	145.1	29.1	46.5	103.4	3,064.9	87.5
2027	1,125.5	785.0	137.8	428.9	99.5	2,576.8	6.8	267.3	274.1	6.8	172.0	27.4	89.0	108.6	3,254.7	91.3
2028	1,164.5	831.5	140.1	443.6	102.8	2,682.5	7.6	286.6	294.1	11.1	176.6	27.6	125.3	113.2	3,430.5	94.4
2029	1,186.3	844.5	146.5	458.8	101.1	2,737.3	8.4	296.8	305.1	17.7	184.9	24.3	173.8	116.7	3,559.9	96.1
2030	1,220.2	896.1	151.2	474.3	110.6	2,852.5	9.3	302.8	312.1	19.1	205.5	33.4	215.0	122.3	3,759.8	99.4
2031	1,184.0	932.0	159.1	490.1	121.0	2,886.2	10.3	308.4	318.7	20.9	221.0	34.6	228.5	126.4	3,836.3	99.2
2032	1,253.7	959.9	162.2	506.4	124.2	3,006.5	11.5	321.7	333.2	35.2	230.1	34.0	241.6	124.1	4,004.7	101.4
CPW@ 7.50%																
(2017-2032)	8,825.1	5972.9	980.8	3810.3	765.9	20355.0	395.5	2475.0	2870.6	46.0	1153.6	160.6	455.9	909.1	25950.7	84.9
(2017-2046)	12,516.3	9461.9	1512.9	5311.3	1286.6	30089.0	462.5	3347.6	3810.1	96.7	2298.3	227.6	1296.4	1412.5	39230.6	91.6

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Revenue Requirements – Carbon Reduction Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES	TOTAL					
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	655.8	486.1	67.4	386.3	76.4	1,672.0	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2,265.2	74.7
2018	764.0	517.8	72.6	431.6	76.8	1,862.8	71.0	252.3	323.3	0.0	96.9	9.2	(0.1)	96.7	2,388.7	77.9
2019	829.4	518.5	77.6	407.5	74.7	1,907.8	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2,410.6	77.7
2020	888.0	541.1	86.1	371.6	72.7	1,959.5	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2,447.4	78.1
2021	927.4	590.5	98.1	392.8	70.8	2,079.6	39.8	243.7	283.6	0.6	102.9	15.4	(0.1)	82.1	2,564.1	80.1
2022	957.9	631.4	104.3	411.1	73.0	2,177.8	39.9	250.8	290.8	0.8	102.5	14.0	(0.1)	84.9	2,670.5	81.8
2023	1,063.2	605.3	105.4	366.0	74.9	2,214.8	40.3	275.5	315.8	1.5	122.6	12.4	1.2	89.4	2,757.7	83.0
2024	1,123.6	643.6	108.5	379.4	78.1	2,333.2	40.8	285.2	326.0	1.8	129.6	17.9	3.8	94.1	2,906.4	86.0
2025	1,119.2	674.7	119.6	391.9	79.0	2,384.5	41.3	275.4	316.7	2.0	149.9	19.9	21.1	97.7	2,991.7	87.0
2026	1,115.4	740.4	131.7	411.1	89.2	2,487.8	6.2	250.2	256.4	4.0	145.1	29.1	46.5	103.4	3,072.2	87.7
2027	1,137.6	785.0	137.8	428.9	99.1	2,588.4	6.8	267.3	274.1	6.8	172.0	27.4	89.0	108.6	3,266.4	91.6
2028	1,180.0	831.5	140.1	443.6	102.4	2,697.6	7.6	286.6	294.1	11.1	177.5	27.6	125.4	113.2	3,446.5	94.9
2029	1,210.1	844.2	146.5	458.8	100.7	2,760.4	8.4	297.1	305.4	17.7	184.9	24.3	173.8	116.7	3,583.2	96.7
2030	1,245.3	881.5	152.2	474.3	110.3	2,863.6	9.3	299.5	308.8	23.7	217.9	33.4	220.2	122.3	3,790.0	100.2
2031	1,299.8	970.6	153.6	494.6	121.2	3,039.8	10.3	310.4	320.7	23.8	243.0	34.6	217.4	126.4	4,005.6	103.6
2032	1,290.8	919.8	139.1	397.0	137.9	2,884.5	11.5	330.0	341.5	12.9	272.3	34.0	185.6	124.1	3,854.9	97.6
CPW@ 7.50%																
(2017-2032)	9,045.3	5,950.8	968.2	3,739.6	773.6	20,477.4	395.5	2,479.0	2,874.5	41.4	1,198.2	160.6	408.6	909.1	26,069.8	85.3
(2017-2046)	12,683.0	9,376.7	1,465.4	5,067.7	1,331.7	29,924.5	464.3	3,358.4	3,822.7	65.9	2,398.9	227.6	1,168.4	1,412.5	39,020.4	91.1

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Revenue Requirements – Expanded Demand Side Management Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	653.0	486.1	67.4	386.3	76.4	1,669.1	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2,262.3	74.6
2018	748.8	517.8	72.6	431.6	76.8	1,847.6	70.8	252.3	323.1	0.0	96.9	9.2	(0.1)	96.7	2,373.4	77.4
2019	814.1	518.5	77.6	407.5	74.7	1,892.5	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2,395.3	77.2
2020	873.2	541.1	86.1	371.6	72.7	1,944.7	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2,432.6	77.6
2021	912.8	583.6	98.3	392.8	70.8	2,058.4	39.6	243.5	283.1	0.6	100.5	15.4	(0.1)	122.2	2,580.2	81.4
2022	929.9	615.9	104.0	410.0	73.0	2,132.7	39.9	251.2	291.1	0.9	101.1	14.0	(0.1)	128.3	2,668.1	83.5
2023	1,014.3	598.5	107.8	398.9	74.9	2,194.4	40.3	271.6	311.9	2.5	96.1	12.4	16.2	136.4	2,770.0	86.0
2024	1,068.5	630.8	111.2	412.6	74.0	2,297.2	40.8	277.2	318.0	3.4	103.8	17.9	18.0	144.9	2,903.1	89.5
2025	1,083.0	632.8	117.0	389.7	76.4	2,298.9	41.3	273.8	315.1	3.9	135.8	19.9	14.8	152.6	2,940.8	90.0
2026	1,075.5	686.7	128.2	407.9	77.3	2,375.7	6.2	249.2	255.4	7.4	129.5	29.1	34.1	163.9	2,995.1	90.9
2027	1,081.9	722.6	133.0	424.6	76.4	2,438.4	6.8	264.3	271.1	13.3	153.5	27.4	74.8	175.5	3,153.9	94.9
2028	1,129.0	761.2	135.5	439.7	86.1	2,551.6	7.6	276.1	283.7	19.5	150.0	27.6	109.5	187.0	3,328.9	99.1
2029	1,138.3	765.9	140.9	453.6	92.0	2,590.7	8.4	286.0	294.4	31.9	159.5	24.3	155.8	198.1	3,454.8	101.7
2030	1,165.0	809.0	144.3	468.4	97.3	2,683.9	9.3	289.7	299.0	38.8	179.6	33.4	194.8	212.0	3,641.6	105.8
2031	1,130.2	830.8	150.4	484.0	97.8	2,693.2	10.3	296.4	306.7	40.8	186.1	34.6	205.0	226.4	3,692.8	105.8
2032	1,205.1	848.9	153.9	500.6	96.2	2,804.7	11.5	303.9	315.4	53.2	189.9	34.0	216.1	367.8	3,981.1	112.5
CPW@ 7.50%																
(2017-2032)	8,691.1	5,692.6	962.4	3,795.9	717.9	19,860.0	395.2	2,444.3	2,839.5	81.6	1,061.5	160.6	392.4	1,316.0	25,711.6	87.4
(2017-2046)	12,135.0	8,644.1	1,456.0	5,265.6	1,158.9	28,659.6	467.0	3,251.7	3,718.7	184.0	1,994.6	227.6	1,102.0	3,410.3	39,296.9	98.0

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Resource Cost – Expanded Demand Side Management Portfolio ($Millions)			
YEAR	TOTAL REV REQ	INCREMENTAL CUSTOMER COST FOR DSM	TOTAL RESOURCE COST
2017	2,262.3	0.0	2,262.3
2018	2,373.4	0.0	2,373.4
2019	2,395.3	0.0	2,395.3
2020	2,432.6	0.0	2,432.6
2021	2,580.2	35.5	2,615.7
2022	2,668.1	36.2	2,704.4
2023	2,770.0	37.0	2,807.0
2024	2,903.1	37.6	2,940.7
2025	2,940.8	38.2	2,979.0
2026	2,995.1	39.9	3,035.0
2027	3,153.9	41.5	3,195.4
2028	3,328.9	43.0	3,372.0
2029	3,454.8	44.5	3,499.3
2030	3,641.6	45.9	3,687.4
2031	3,692.8	47.7	3,740.5
2032	3,981.1	118.4	4,099.4
CPW@7.50%			
(2017-2032)	25,711.6	255.0	25,966.6
(2017-2046)	39,296.9	576.2	39,873.1

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Revenue Requirements – Expanded Renewables Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES	TOTAL					
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	653.0	486.1	67.4	386.3	76.4	1,669.1	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2,262.3	74.6
2018	748.8	517.8	72.6	431.6	76.8	1,847.6	71.0	252.3	323.2	0.0	96.9	9.2	(0.1)	96.7	2,373.5	77.5
2019	814.1	518.5	77.6	407.5	74.7	1,892.5	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2,395.3	77.2
2020	873.2	541.1	86.1	371.6	72.7	1,944.7	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2,432.6	77.6
2021	912.8	590.5	98.1	392.8	70.8	2,065.0	39.8	243.7	283.5	0.6	103.0	15.4	(0.1)	82.1	2,549.4	79.6
2022	942.1	631.5	104.2	411.1	73.0	2,161.9	39.9	250.9	290.8	0.7	105.8	14.0	(0.1)	84.9	2,658.0	81.4
2023	1,021.4	620.5	108.5	399.7	74.9	2,225.0	40.3	273.2	313.5	1.7	104.7	12.4	22.5	89.4	2,769.3	83.3
2024	1,060.7	657.8	112.0	412.1	74.0	2,316.7	40.8	283.7	324.5	2.0	110.7	17.9	26.5	94.1	2,892.4	85.6
2025	1,088.9	674.8	119.5	390.3	76.4	2,349.8	41.3	277.1	318.4	2.4	149.9	19.9	25.4	97.7	2,963.6	86.1
2026	1,108.8	741.1	131.5	411.1	88.6	2,481.1	6.2	249.9	256.1	4.1	145.1	29.1	46.6	103.4	3,065.5	87.5
2027	1,171.7	773.9	136.7	436.0	99.5	2,617.8	9.1	265.3	274.4	8.7	168.1	27.4	86.4	108.6	3,291.4	92.3
2028	1,236.8	810.5	138.5	456.6	102.8	2,745.2	12.6	280.7	293.3	17.8	171.1	27.6	120.6	113.2	3,488.7	96.0
2029	1,286.6	811.0	144.5	478.4	113.2	2,833.6	16.7	291.9	308.6	34.0	174.6	24.3	166.0	116.7	3,657.9	98.7
2030	1,357.7	846.7	146.8	502.0	118.5	2,971.7	21.6	300.1	321.7	47.3	189.3	33.4	203.7	122.3	3,889.4	102.8
2031	1,309.0	879.8	154.7	518.5	118.3	2,980.3	24.1	306.5	330.6	49.3	206.5	34.6	216.5	126.4	3,944.1	102.0
2032	1,367.3	913.0	158.3	535.5	132.8	3,107.0	27.0	314.4	341.5	66.9	215.8	34.0	230.8	124.1	4,120.0	104.3
CPW@ 7.50%																
(2017-2032)	9,043.3	5,896.0	974.3	3,855.4	775.3	20,544.2	415.8	2,466.1	2,882.0	86.2	1,130.2	160.6	438.2	909.1	26,150.4	85.6
(2017-2046)	13,167.3	9,143.4	1,488.2	5,502.7	1,336.7	30,638.3	560.3	3,312.6	3,872.9	233.3	2,193.5	227.6	1,219.4	1,412.5	39,797.5	92.9

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Revenue Requirements – Energy Storage Systems Portfolio ($Millions)

YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	653.0	486.1	67.4	386.3	76.4	1,669.1	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2,262.3	74.6
2018	748.8	517.8	72.6	431.6	76.8	1,847.6	71.0	252.3	323.3	0.0	96.9	9.2	(0.1)	96.7	2,373.6	77.5
2019	814.1	518.5	77.6	407.5	74.7	1,892.5	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2,395.3	77.2
2020	873.2	541.1	86.1	371.6	72.7	1,944.7	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2,432.6	77.6
2021	946.2	588.9	97.1	395.8	70.8	2,098.8	39.6	243.8	283.5	0.6	102.0	15.4	(0.1)	82.1	2,582.2	80.6
2022	988.2	627.3	102.7	415.6	73.0	2,206.7	39.9	251.6	291.5	0.6	104.8	14.0	(0.1)	84.9	2,702.3	82.8
2023	1,079.3	608.2	104.6	405.8	74.9	2,272.8	40.3	280.2	320.5	1.3	99.5	12.4	20.9	89.4	2,816.8	84.8
2024	1,112.5	645.3	108.4	418.2	74.0	2,358.5	40.8	292.0	332.8	2.0	109.1	17.9	25.0	94.1	2,939.5	87.0
2025	1,157.2	663.9	114.3	398.7	76.4	2,410.6	41.3	286.0	327.3	2.5	149.9	19.9	23.7	97.7	3,031.6	88.1
2026	1,170.6	726.7	126.6	419.7	77.3	2,520.8	6.2	259.9	266.1	4.3	144.3	29.1	43.9	103.4	3,112.0	88.9
2027	1,208.7	769.9	132.0	440.6	76.4	2,627.5	6.8	277.9	284.7	8.0	166.9	27.4	86.5	108.6	3,309.7	92.8
2028	1,206.4	817.1	134.0	452.3	86.1	2,695.9	7.6	297.2	304.8	13.3	173.6	27.6	122.8	113.2	3,451.2	95.0
2029	1,245.3	842.5	142.5	469.8	96.6	2,796.7	8.4	299.0	307.3	22.0	189.4	24.3	173.5	116.7	3,629.9	98.0
2030	1,269.6	898.8	147.5	485.1	100.3	2,901.3	9.3	304.2	313.4	28.7	206.3	33.4	215.6	122.3	3,821.0	101.0
2031	1,273.5	932.3	154.7	503.2	98.6	2,962.3	10.3	312.0	322.3	30.3	219.1	34.6	228.5	126.4	3,923.5	101.5
2032	1,327.6	960.0	161.5	516.9	113.7	3,079.7	11.5	322.5	334.0	38.9	232.6	34.0	241.7	124.1	4,085.0	103.4
CPW@ 7.50%																
(2017-2032)	9,157.4	5,929.8	959.6	3,855.7	726.6	20,629.1	395.4	2,506.3	2,901.7	57.1	1,146.4	160.6	449.8	909.1	26,253.8	85.9
(2017-2046)	13,038.5	9,415.8	1,488.3	5,383.7	1,232.0	30,558.3	463.4	3,385.5	3,849.0	120.1	2,286.2	227.6	1,289.8	1,412.5	39,743.5	92.8

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Revenue Requirements – Resource Mandates Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	653.0	486.1	67.4	386.3	76.4	1,669.1	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2,262.3	74.6
2018	748.8	517.8	72.6	431.6	76.8	1,847.6	70.8	252.3	323.1	0.0	96.9	9.2	(0.1)	96.7	2,373.3	77.4
2019	814.1	518.5	77.6	407.5	74.7	1,892.5	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2,395.3	77.2
2020	873.2	541.1	86.1	371.6	72.7	1,944.7	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2,432.6	77.6
2021	946.2	582.1	97.6	395.8	70.8	2,092.5	39.6	243.6	283.2	0.7	99.3	15.4	(0.1)	122.2	2,613.2	82.5
2022	979.2	612.9	102.7	414.9	69.1	2,178.7	39.9	250.9	290.8	0.7	100.9	14.0	(0.1)	128.3	2,713.4	84.9
2023	1,080.1	584.8	103.7	405.8	72.4	2,246.7	40.3	279.2	319.5	2.1	92.3	12.4	14.4	136.4	2,823.9	87.7
2024	1,127.4	614.8	106.3	419.7	73.4	2,341.5	40.8	289.2	329.9	3.4	101.3	17.9	16.8	144.9	2,955.7	91.1
2025	1,159.0	631.3	110.9	399.3	72.6	2,373.1	41.3	280.9	322.2	5.9	137.0	19.9	15.5	152.6	3,026.3	92.6
2026	1,144.2	681.7	121.4	417.8	75.0	2,440.1	6.2	257.5	263.7	10.1	132.9	29.1	33.3	163.9	3,073.1	93.2
2027	1,179.0	715.9	126.2	438.3	87.6	2,546.9	6.8	272.4	279.3	17.9	148.0	27.4	74.0	175.5	3,269.0	98.3
2028	1,176.9	755.8	127.6	450.0	94.4	2,604.8	7.6	287.5	295.1	30.8	152.6	27.6	108.7	187.0	3,406.8	101.4
2029	1,260.7	759.5	134.1	475.4	94.8	2,724.5	11.5	288.1	299.6	55.5	162.0	24.3	154.2	198.1	3,618.2	106.5
2030	1,289.6	793.2	136.2	494.2	92.1	2,805.3	15.3	293.9	309.2	82.1	171.7	33.4	190.8	212.0	3,804.7	110.6
2031	1,300.8	819.1	143.2	513.8	89.5	2,866.3	17.1	296.8	313.9	89.8	182.0	34.6	201.8	226.4	3,914.8	112.2
2032	1,343.7	833.9	148.5	527.0	91.8	2,944.9	19.2	305.5	324.7	105.4	183.9	34.0	212.5	367.8	4,173.2	117.9
CPW@ 7.50%																
(2017-2032)	9,150.2	5,646.9	933.3	3,865.8	714.0	20,310.2	403.3	2,474.8	2,878.1	148.4	1,052.6	160.6	385.7	1,316.0	26,251.5	89.2
(2017-2046)	13,026.2	8,504.1	1,409.6	5,437.8	1,151.7	29,529.4	504.7	3,284.2	3,788.9	403.2	1,944.5	227.6	1,072.2	3,410.3	40,376.1	100.7

ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Resource Cost – Resource Mandates Portfolio ($Millions)			
YEAR	TOTAL REV REQ	INCREMENTAL CUSTOMER COST FOR DSM	TOTAL RESOURCE COST
2017	2,262.3	0.0	2,262.3
2018	2,373.3	0.0	2,373.3
2019	2,395.3	0.0	2,395.3
2020	2,432.6	0.0	2,432.6
2021	2,613.2	35.5	2,648.7
2022	2,713.4	36.2	2,749.7
2023	2,823.9	37.0	2,860.8
2024	2,955.7	37.6	2,993.3
2025	3,026.3	38.2	3,064.5
2026	3,073.1	39.9	3,113.0
2027	3,269.0	41.5	3,310.5
2028	3,406.8	43.0	3,449.8
2029	3,618.2	44.5	3,662.7
2030	3,804.7	45.9	3,850.6
2031	3,914.8	47.7	3,962.5
2032	4,173.2	118.4	4,291.6
CPW@7.50%			
(2017-2032)	26,251.5	255.0	26,506.5
(2017-2046)	40,376.1	576.2	40,952.3

ATTACHMENT F.1(B)– REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS (CONTINUED)

Total Revenue Requirements – Nuclear Small Modular Reactors Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var. O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2017	653.0	486.1	67.4	386.3	76.4	1,669.1	102.4	297.9	400.3	0.0	84.2	11.0	(0.1)	97.6	2,262.3	74.6
2018	748.8	517.8	72.6	431.6	76.8	1,847.6	71.0	252.3	323.3	0.0	96.9	9.2	(0.1)	96.7	2,373.6	77.5
2019	814.1	518.5	77.6	407.5	74.7	1,892.5	70.3	254.1	324.3	0.1	75.4	7.5	(0.1)	95.5	2,395.3	77.2
2020	873.2	541.1	86.1	371.6	72.7	1,944.7	49.3	242.2	291.4	0.3	94.6	8.8	(0.1)	92.8	2,432.6	77.6
2021	912.8	590.5	98.1	392.8	70.8	2,065.0	39.8	243.7	283.6	0.6	103.0	15.4	(0.1)	82.1	2,549.5	79.6
2022	942.1	631.5	104.2	411.1	73.0	2,161.9	39.9	250.9	290.8	0.7	105.8	14.0	(0.1)	84.9	2,658.0	81.4
2023	1,021.4	620.5	108.5	399.7	74.9	2,225.0	40.3	273.2	313.5	1.7	104.7	12.4	22.5	89.4	2,769.3	83.3
2024	1,060.7	657.8	112.0	412.1	74.0	2,316.7	40.8	283.7	324.5	2.0	110.7	17.9	26.5	94.1	2,892.4	85.6
2025	1,088.9	674.7	119.8	390.3	76.4	2,350.1	41.3	276.2	317.5	2.0	149.9	19.9	25.4	97.7	2,962.6	86.1
2026	1,108.8	740.4	131.7	411.1	88.6	2,480.6	6.2	250.2	256.4	4.0	145.1	29.1	46.5	103.4	3,064.9	87.5
2027	1,125.5	785.0	137.8	428.9	99.5	2,576.8	6.8	267.3	274.1	6.8	172.0	27.4	89.0	108.6	3,254.7	91.3
2028	1,335.9	810.2	148.9	468.2	103.4	2,866.7	7.6	279.4	287.0	10.7	163.4	27.6	117.5	113.2	3,586.0	98.7
2029	1,471.8	813.4	161.3	482.9	114.2	3,043.6	8.4	280.8	289.2	17.7	169.0	24.3	161.9	116.7	3,822.3	103.2
2030	1,494.1	861.2	165.5	499.1	119.5	3,139.4	9.3	288.9	298.2	17.4	185.5	33.4	202.4	122.3	3,998.6	105.7
2031	1,463.5	894.9	174.1	515.3	119.3	3,167.2	10.3	294.8	305.1	18.5	201.9	34.6	215.3	126.4	4,068.9	105.3
2032	1,706.9	895.8	188.9	559.3	129.5	3,480.5	11.5	299.4	310.9	27.1	192.3	34.0	220.1	124.1	4,388.9	111.1
CPW@ 7.50%																
(2017-2032)	9,345.0	5,906.5	1,008.9	3,864.2	775.5	20,900.1	395.5	2,449.2	2,844.7	41.9	1,116.2	160.6	432.1	909.1	26,404.7	86.4
(2017-2046)	14,570.2	9,096.0	1,681.7	5,564.5	1,329.0	32,241.4	464.4	3,216.9	3,681.4	76.3	2,099.1	227.6	1,168.5	1,412.5	40,906.8	95.5

ATTACHMENT F.1(B)(1) – ANNUAL AVERAGE SYSTEM COST

Annual Average System Cost ($/MWh)							
	FLEXIBLE RESOURCE (SELECTED PORTFOLIO)	CARBON REDUCTION	ENERGY STORAGE SYSTEMS	EXPANDED RENEWABLES	EXPANDED DEMAND SIDE MANAGEMENT (DSM)	RESOURCE MANDATES	NUCLEAR SMALL MODULAR REACTORS (SMR)
2017	74.6	74.7	74.6	74.6	74.6	74.6	74.6
2018	77.5	77.9	77.5	77.5	77.4	77.4	77.5
2019	77.2	77.7	77.2	77.2	77.2	77.2	77.2
2020	77.6	78.1	77.6	77.6	77.6	77.6	77.6
2021	79.6	80.1	80.6	79.6	81.4	82.5	79.6
2022	81.4	81.8	82.8	81.4	83.5	84.9	81.4
2023	83.3	83.0	84.8	83.3	86.0	87.7	83.3
2024	85.6	86.0	87.0	85.6	89.5	91.1	85.6
2025	86.1	87.0	88.1	86.1	90.0	92.6	86.1
2026	87.5	87.7	88.9	87.5	90.9	93.2	87.5
2027	91.3	91.6	92.8	92.3	94.9	98.3	91.3
2028	94.4	94.9	95.0	96.0	99.1	101.4	98.7
2029	96.1	96.7	98.0	98.7	101.7	106.5	103.2
2030	99.4	100.2	101.0	102.8	105.8	110.6	105.7
2031	99.2	103.6	101.5	102.0	105.8	112.2	105.3
2032	101.4	97.6	103.4	104.3	112.5	117.9	111.1

ATTACHMENT F.1(B)(2) – CUMULATIVE CAPITAL SPENDING

Cumulative Capital Spending – Existing and New Generation Plus Incremental Transmission ($Millions)							
	FLEXIBLE RESOURCE (SELECTED PORTFOLIO)	CARBON REDUCTION	ENERGY STORAGE SYSTEMS	EXPANDED RENEWABLES	EXPANDED DEMAND SIDE MANAGEMENT (DSM)	RESOURCE MANDATES	NUCLEAR SMALL MODULAR REACTORS (SMR)
2017	574.5	574.5	574.5	574.5	574.5	574.5	574.5
2018	1,021.7	1,021.7	1,021.7	1,021.7	1,021.7	1,021.7	1,021.7
2019	1,233.7	1,233.7	1,233.7	1,233.7	1,233.7	1,233.7	1,233.7
2020	1,555.0	1,555.0	1,568.4	1,555.0	1,538.6	1,552.0	1,555.0
2021	2,154.1	2,187.6	2,229.4	2,154.1	2,070.6	2,151.0	2,212.4
2022	2,570.0	2,774.0	2,705.7	2,570.0	2,502.6	2,622.7	2,747.3
2023	3,005.9	3,313.7	3,227.4	3,005.9	2,985.6	3,267.1	3,417.3
2024	3,729.9	3,905.7	3,934.9	3,729.9	3,578.9	3,894.0	4,446.6
2025	4,382.7	4,360.7	4,621.7	4,383.9	4,032.7	4,409.7	5,480.8
2026	4,955.7	4,933.7	5,149.9	5,075.7	4,537.5	4,923.1	6,501.4
2027	5,409.6	5,387.6	5,656.0	5,757.7	4,957.5	5,428.2	7,465.7
2028	6,007.3	6,040.0	6,202.1	6,574.8	5,464.8	5,982.2	8,558.6
2029	6,556.5	6,875.5	6,915.5	7,420.3	5,905.4	6,789.7	9,473.2
2030	7,093.3	8,083.3	7,439.6	8,129.7	6,487.8	7,413.6	10,432.0
2031	7,616.6	9,051.3	8,196.5	8,634.4	6,970.3	8,142.9	11,139.7
2032	8,237.4	9,715.8	8,898.9	9,315.9	7,498.7	8,774.0	11,842.6

(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.
(3) Capital spending includes ongoing capital investment for existing owned generation.

ATTACHMENT F.1(B)(3) – ANNUAL NATURAL GAS BURNS

Annual Natural Gas Burns (BCF)							
	FLEXIBLE RESOURCE (SELECTED PORTFOLIO)	CARBON REDUCTION	ENERGY STORAGE SYSTEMS	EXPANDED RENEWABLES	EXPANDED DEMAND SIDE MANAGEMENT (DSM)	RESOURCE MANDATES	NUCLEAR SMALL MODULAR REACTORS (SMR)
2017	73.2	73.2	73.2	73.2	73.2	73.2	73.2
2018	78.0	78.0	78.0	78.0	78.0	78.0	78.0
2019	80.2	80.2	80.2	80.2	80.2	80.2	80.2
2020	89.6	89.6	89.6	89.6	89.6	89.6	89.6
2021	99.5	99.5	99.0	99.5	97.5	97.0	99.5
2022	103.3	102.8	101.9	103.3	99.0	98.0	103.3
2023	90.8	104.5	87.2	90.8	85.0	81.0	90.8
2024	94.2	109.1	90.7	94.2	87.8	82.8	94.2
2025	111.3	114.5	108.4	111.3	100.8	99.7	111.3
2026	116.9	116.9	113.7	117.1	103.8	102.7	116.9
2027	121.1	121.1	117.7	118.5	106.4	104.9	121.1
2028	125.6	125.6	122.5	120.9	109.7	108.6	118.5
2029	125.4	125.3	124.9	117.8	107.7	106.3	114.7
2030	133.1	130.1	133.7	122.3	113.9	110.5	121.8
2031	137.6	145.8	137.8	126.3	115.7	113.1	125.9
2032	140.9	178.3	140.9	131.3	117.9	115.0	122.6

ATTACHMENT F.1(B)(4) – ANNUAL CO_2 EMISSIONS

Annual CO_2 Emissions (Metric Tons)							
	FLEXIBLE RESOURCE (SELECTED PORTFOLIO)	CARBON REDUCTION	ENERGY STORAGE SYSTEMS	EXPANDED RENEWABLES	EXPANDED DEMAND SIDE MANAGEMENT (DSM)	RESOURCE MANDATES	NUCLEAR SMALL MODULAR REACTORS (SMR)
2017	11,761,549	11,761,549	11,761,549	11,761,549	11,761,549	11,761,549	11,761,549
2018	11,928,592	11,928,592	11,928,592	11,928,592	11,928,592	11,928,592	11,928,592
2019	11,961,300	11,961,300	11,961,300	11,961,300	11,961,300	11,961,300	11,961,300
2020	11,338,310	11,338,310	11,338,305	11,338,310	11,338,310	11,338,305	11,338,310
2021	11,592,881	11,592,881	11,568,626	11,592,881	11,453,923	11,431,039	11,592,881
2022	11,708,852	11,746,641	11,663,779	11,708,852	11,400,020	11,370,814	11,708,852
2023	12,270,882	10,890,938	12,174,119	12,270,882	11,851,345	11,744,122	12,270,882
2024	12,326,780	10,889,073	12,237,518	12,326,780	11,770,352	11,705,352	12,326,780
2025	11,860,985	11,591,216	11,758,997	11,863,108	11,189,323	11,223,100	11,860,985
2026	11,974,633	11,974,869	11,822,196	11,983,685	11,208,161	11,150,454	11,974,633
2027	12,186,126	12,186,159	12,051,141	12,020,975	11,330,515	11,275,004	12,186,126
2028	12,077,609	12,077,914	11,941,436	11,792,775	11,142,461	11,081,449	11,590,090
2029	12,574,233	12,570,989	12,561,768	12,119,461	11,530,869	11,420,857	11,871,556
2030	12,596,610	12,885,602	12,637,674	11,953,600	11,442,813	11,212,799	11,875,044
2031	13,058,272	12,470,684	13,065,653	12,394,036	11,761,614	11,572,004	12,322,025
2032	13,485,642	10,564,377	13,491,000	12,893,678	12,087,104	11,896,496	12,306,239

ATTACHMENT F.1(B)(5) – ANNUAL WATER USE

	Annual Water Use (Acre-Feet)						
	FLEXIBLE RESOURCE (SELECTED PORTFOLIO)	CARBON REDUCTION	ENERGY STORAGE SYSTEMS	EXPANDED RENEWABLES	EXPANDED DEMAND SIDE MANAGEMENT (DSM)	RESOURCE MANDATES	NUCLEAR SMALL MODULAR REACTORS (SMR)
2017	49,868	49,868	49,868	49,868	49,868	49,868	49,868
2018	49,954	49,954	49,954	49,954	49,954	49,954	49,954
2019	50,290	50,290	50,290	50,290	50,290	50,290	50,290
2020	49,449	49,449	49,449	49,449	49,449	49,449	49,449
2021	50,107	50,107	50,094	50,107	49,788	49,769	50,107
2022	50,450	50,538	50,440	50,450	49,759	49,766	50,450
2023	51,214	48,072	51,122	51,214	50,260	50,143	51,214
2024	51,254	47,949	51,169	51,254	49,993	49,971	51,254
2025	49,979	49,398	49,935	49,987	48,508	48,771	49,979
2026	50,090	50,090	49,931	50,109	48,448	48,505	50,090
2027	50,356	50,356	50,345	49,991	48,552	48,708	50,356
2028	50,206	50,207	50,137	49,605	48,271	48,361	51,219
2029	51,194	51,187	51,360	50,240	49,034	48,969	52,906
2030	50,889	51,499	51,107	49,545	48,542	48,179	52,548
2031	51,763	49,713	51,933	50,391	49,167	48,891	53,447
2032	52,687	43,277	52,796	51,485	49,916	49,611	55,268

ATTACHMENT F.9(B) – 2017 RESOURCE PLAN – LOADS & RESOURCES FORECAST

	LOADS AND RESOURCES – MW ENERGY CONTRIBUTION AT PEAK																
	Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
1	**Load Requirements**																
2	APS Peak Demand	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
3	Reserve Requirements	961	989	1,015	1,047	1,152	1,187	1,222	1,258	1,294	1,331	1,369	1,409	1,448	1,489	1,530	1,573
4	**Total Load Requirements**	**7,985**	**8,296**	**8,596**	**8,902**	**9,283**	**9,592**	**9,903**	**10,219**	**10,542**	**10,870**	**11,205**	**11,550**	**11,894**	**12,250**	**12,612**	**12,983**
5	**Existing Resources**																
6	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
7	Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	970
8	Natural Gas	4,341	4,341	4,167	4,135	3,655	3,655	3,655	3,655	3,655	3,090	3,090	3,090	3,090	3,090	3,090	3,090
9	Combined Cycle	1,852	1,852	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
10	Combustion / Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
11	PacifiCorp Seasonal Exchange	480	480	480	480	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	560	560	560	565	565	565	565	565	565	0	0	0	0	0	0	0
13	Market/Call Options/ Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
14	Renewable Energy	514	514	515	515	516	516	504	504	505	505	487	488	488	476	476	476
15	Distributed Energy	13	13	13	13	13	14	14	14	14	14	14	14	14	14	14	14
16	Solar	417	418	418	418	419	419	420	420	420	420	421	421	421	421	421	421
17	Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
19	Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
22	**Total Existing Resources**	**7,694**	**7,695**	**7,521**	**7,175**	**6,695**	**6,696**	**6,683**	**6,684**	**6,297**	**5,732**	**5,715**	**5,715**	**5,715**	**5,703**	**5,703**	**5,703**
23	**Customer Resources**																
24	Future Demand Side Management	98	198	298	397	448	491	534	577	620	664	707	750	793	836	879	922
25	Future Distributed Energy	15	32	43	54	64	77	90	103	116	129	140	151	162	173	183	195
26	Demand Response (Future & Existing)	18	19	22	23	39	51	71	86	85	98	110	125	137	141	157	173
27	**Total Customer Resources**	**131**	**249**	**363**	**473**	**551**	**620**	**695**	**766**	**821**	**890**	**957**	**1,026**	**1,092**	**1,149**	**1,219**	**1,289**
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	250	340	760	1,260	2,023	2,441	2,441	2,651	3,297	4,228	4,444	4,659	4,875	5,091	5,306	5,516
31	Short-Term Market Purchases	0	90	0	0	13	0	0	0	0	0	0	0	0	0	0	0
32	Renewable Energy	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
33	Wind	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16
34	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Energy Storage	0	1	3	3	3	3	3	86	86	85	84	165	244	323	320	397
37	Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
38	**Total Future Resources**	**261**	**352**	**773**	**1,273**	**2,036**	**2,479**	**2,529**	**2,823**	**3,469**	**4,399**	**4,630**	**4,926**	**5,221**	**5,515**	**5,728**	**6,014**
39	**TOTAL RESOURCES**	**8,086**	**8,296**	**8,658**	**8,921**	**9,283**	**9,795**	**9,908**	**10,273**	**10,587**	**11,022**	**11,301**	**11,666**	**12,028**	**12,367**	**12,650**	**13,006**

ACRONYMS AND GLOSSARY

2017

TABLE OF ACRONYMS AND ABBREVIATIONS

AAC	Arizona Administrative Code
AC	Air Conditioner
ACC	Arizona Corporation Commission
ACI	Activated Carbon Injection
ADEQ	Arizona Department of Environmental Quality
ADMS	Advanced Distribution Management System
ADWR	Arizona Department of Water Resources
AEO	Annual Energy Outlook
AF	Acre-Feet
AFB	Air Force Base
AFUDC	Allowance for Funds Used During Construction
AMA	Active Management Area
AMI	Advanced Metering Infrastructure
APP	Aquifer Protection Permit
APS	Arizona Public Service
ASU	Arizona State University
AZNMNV	Arizona-New Mexico-Nevada
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BCF	Billion Cubic Feet
BESS	Battery Energy Storage System
BNEF	Bloomberg New Energy Finance
BTA	Biennial Transmission Assessment
Btu	British Thermal Unit
CAA	Clean Air Act
CAES	Compressed Air Energy Storage
CAFO	Concentrating Animal Feeding Operation
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAP	Central Arizona Project
CC	Combined Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture & Sequestration
CDA	Conditional Demand Analysis
CEC	Certificate of Environmental Compatibility
CFI	Communicating Fault Indicators
CFL	Compact Fluorescent Lamp
CO	Carbon Monoxide
CO2	Carbon Dioxide
Commission	Arizona Corporation Commission
Company	Arizona Public Service
CPP	Clean Power Plan
CPP-RES	Critical Peak Pricing for Residential Customers
CRA	Congressional Review Act
CSP	Concentrating Solar Power
CT	Combustion Turbine

CWA	Clean Water Act
DA	Distribution Automation
DAM	Distribution Asset Monitoring
DE	Distributed Energy
DER	Distributed Energy Resources
DG	Distributed Generation
DMS	Distribution Management System
DR	Demand Response
DRESLM	Demand Response, Energy Storage and Load Management Program
DSCADA	Distribution Supervisory Control and Data Acquisition
DSM	Demand Side Management
EE	Energy Efficiency
EES	Energy Efficiency Standard
EGU	Electric Generating Units
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIS	Environmental Impact Statement
ELG	Effluent Limitations Guidelines
EMS	Energy Management System
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPRI	Electric Power Research Institute
ESA	Endangered Species Act
ESS	Energy Storage System
ECT-1R	Combined Advantage (9 am – 9 pm)
ECT-2	Combined Advantage (Noon – 7 pm)
ET-1	Time Advantage (9 am – 9 pm)
ET-2	Time Advantage (Noon – 7 pm)
ET-EV	Experimental Electric Vehicle Charging Rate Schedule
ET-SP	Time Advantage Super Peak
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FGD	Flue Gas Desulfurization
FM	Fire Mitigation
FONSI	Finding of No Significant Impact
GHG	Greenhouse Gas
GRIC	Gila River Indian Community
GUAC	Groundwater Users Advisory Council
GWh	Gigawatt-Hours
HAPS	Hazardous Air Pollutants
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning

TABLE OF ACRONYMS AND ABBREVIATIONS (CONTINUED)

IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IVVC	Integrated Volt/VAR Control
kW	Kilowatt
kWh	Kilowatt-Hour
LAER	Lowest Achievable Emission Rate
LED	Light-emitting Diode
Li-on	Lithium-ion
LNB	Low NOx Burners
LOLE	Loss of Load Expectation
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MCAQD	Maricopa County Air Quality Department
MCAS	Marine Corps Air Station
MER	Measurement and Evaluation Research
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NAAQS	National Ambient Air Quality Standards
NaS	Sodium-sulfur
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NGS	Navajo Generating Station
NNSR	Nonattainment New Source Review
NOx	Nitrogen Oxide
NP	Network Protector
NPDES	National Pollution Discharge Elimination System
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation & Maintenance
OMP	Ocotillo Modernization Project
OMS	Outage Management System
PAC	Program Administrator Costs Test
PC	Participant Cost Test
PCB	Polychlorinated Biphenyls
PM	Particulate Matter
PMUs	Phasor Measurement Units
PPA	Purchased Power Agreement
PPH	People Per Household
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit

PTR	Peak Time Rebate
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
PVWRF	Palo Verde Water Reclamation Facility
PWR	Pressurized Water Reactors
RCRA	Resource Conservation & Recovery Act
RE	Renewable Energy
RES	Renewable Energy Standard
RFP	Request for Proposal
RIM	Rate Impact Measure Test
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAT	Single Axis Tracking
SCE	Southern California Edison Company
SCR	Selective Catalytic Reduction
SC or SCT	Societal Benefit-Cost Test
SHM	Substation Health Monitoring
SIP	State Implementation Plan
SIS	Solar Innovation Study
SMR	Small Modular Reactors
SO2	Sulfur Dioxide
SPP	Solar Partner Program
SRP	Salt River Project Agricultural Improvement and Power District
SRSG	Southwest Reserve Sharing Group
SWAT	Southwest Area Transmission
T&D	Transmission and Distribution
TRC or TRCT	Total Resource Cost Test
TOU	Time of Use
USBR	United States Bureau of Reclamation
VAR	Volt-Ampere Reactive
VOC	Volatile Organic Compounds
WECC	Western Electricity Coordinating Council
WIIN	Water Infrastructure Improvements for the Nation
ZLD	Zero liquid discharge
Zn-Air	Zinc-Air

GLOSSARY

2017 Resource Plan (or 2017 Integrated Resource Plan or IRP)	Represents the documented process APS undertakes to select an energy resource portfolio for the 2017-2032 period based upon a wide range of supply- and demand-side options.
Acre-Foot	The volume of water that will cover an area of one acre to a depth of one foot. One acre foot equals approximately 325,851 gallons.
Action Plan	Material actions anticipated to occur during the Action Plan Period.
Action Plan Period	For the purposes of this filing, the timeframe of 2017-2021.
Activated Carbon Injection	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.[1]
Aquifer Protection Permit 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.
Auxiliary Load	The load that serves the power plant itself. Under normal circumstances, the auxiliary load is served by the production at the plant. If the plant is not producing power, then it is necessary for the grid to server the auxiliary load.
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.
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.
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).
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 emission allowances must buy credits 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 required.

1 http://www.adaes.com/mercury/acis/

GLOSSARY (CONTINUED)

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 the top 90 load hours of the year. APS calculates capacity value 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 and Sequestration (CCS)	A technology under development to limit emissions of carbon by capturing and storing it away from the atmosphere.
Carbon Dioxide (CO2)	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.
Carbon Intensity	The amount of carbon dioxide produced for every unit of energy. For the purposes of this IRP, carbon intensity will be measured in metric tons of carbon dioxide per megawatt-hour.
Carrying Costs	Annual costs associated with investment in assets including depreciation, debt interest, equity return, income taxes, and property taxes.
Class-Based Hourly Load Models	Methods for identifying the hourly pattern of electricity demand for groups of customers with similar characteristics.
Cholla Generating Station	This coal generating facility, located in northeastern Arizona, is capable of producing 387 MW of electricity for APS. PacifiCorp owns the 380 MW Unit 4.
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.
Coincident Peak	An individual customer's peak coincides with the system peak, meaning they are contributing to that peak hour.
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	The date when an operating utility formally declares a new generation resource to be available for the regular production of electricity.
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.

GLOSSARY (CONTINUED)

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 (CSP)	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, measured in megawatt-hours. 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. Generally, conventional resources are dispatchable.
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 (or customer-sited 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 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, measured in megawatts. 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.

GLOSSARY (CONTINUED)

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.
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. In this IRP, it specifically refers to the reduction that is result of participation in energy efficiency programs and load management programs.
Energy Mix	The percentage of each type of energy generated in a scenario or profile. Together, the percentages for each scenario add up to 100%.
Environmental Protection Agency (EPA)	A governmental agency established in 1970 to research, monitor, and establish standards that protect human health and the environment. The EPA also has the authority to enforce regulations when necessary, although normally the states implement them.
Federal Energy Regulatory Commission (FERC)	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.
Flexible Resource	Dispatchable generation resource capable of reaching full capacity in under an hour from cold start.
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.
Fuel Cell	A device that converts chemical energy into electrical energy using a fuel. Fuel cells require a constant supply of fuel and oxygen for its chemical reaction unlike batteries where the chemicals react with each other to provide the electricity.
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.
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.

GLOSSARY (CONTINUED)

(Power or electric) 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.
Groundwater	Water that is held in soil or in rocks underground. Groundwater is distinct from surface water, which is water held in lakes and rivers.
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.
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 CO2 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 (or Variable [Energy]) 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 the reduction 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.

GLOSSARY (CONTINUED)

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.
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 Expectation (LOLE)	The expectation that generation resources will fall short of the resource need. The LOLE is usually set as 1 day in 10 years.
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 (N2) 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 N2.
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 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	Term used to determine applicability of permitting regulation to stationary sources. For Title V of the Clean Air Act, refers to sources of air pollution that emit or have the potential to emit 100 tons per year or more of any criteria air pollutant.
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.
Must Take Generation	Electricity production that must be taken when it is produced by the utility. Generally refers to qualifying facilities under the Public Utility Regulatory Policies Act (PURPA).
Nameplate Capacity	A rating for each generating unit that specifies the maximum expected output of the generating unit.
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 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.

GLOSSARY (CONTINUED)

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-Spin Reserves	A generating reserve not connected to the system but capable of serving demand within a specified time, usually ten minutes.
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.
Operating Reserves (or reserves or Contingency Reserves)	A combination of spinning and non-spinning reserves. Operating reserve is the portion of all reserves APS is required to carry over and above firm system demand to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. APS carries a 15% reserve margin.
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.
Ozone	Ozone, the triatomic form of oxygen (O3), 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.
Particulate Matter	Particle pollution in the air that includes a mixture of solid particles and liquid droplets.
Peak Demand (or Peak Load or Peak)	The greatest demand that occurred or is expected to occur during a prescribed time period.
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.
Planning Period	For the purpose of this filing, the timeframe of 2017-2032.
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.

GLOSSARY (CONTINUED)

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.
PROVIEW	A modeling program created by Ventyx.
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.
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 (RCRA)	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 SO2 and CO2. 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.
Scenario Analysis	Refers to the grouping together of a set of assumptions of key uncertain variables that could potentially all occur in tandem. The goal of scenario analysis is to illustrate the impact to the portfolios of multiple key variables being stressed in a plausible manner. Results of these studies provide information on diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.
Selected Portfolio	The best-fitting plan chosen by APS that comprehensively considers a wide range of supply- and demand-side options.
Selective Catalytic Reduction (SCR) Controls	A post-combustion pollution control technology that removes NOx emissions from an air stream. Ammonia (NH3) is injected into the flue gas downstream from the combustion process and upstream from a catalyst bed. The NH3 reacts with the NOx on the catalyst surface to form nitrogen (N2) and water vapor (H2O).

GLOSSARY (CONTINUED)

Self-Dispatching	Resources that generate based on an outside stimulus, for example solar when the sun is shining on the panels. It also refers to generation that the utility cannot start or curtail at will.
(Retail) Service Territory	The area where a utility provides power.
Simple Cycle	See Combustion Turbine
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.
Start-up Costs	The costs associated with starting a power plant. These costs have become more of a consideration as more variable energy resources have been added to the electricity system and start-ups have become more frequent for some types of generation.
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 (SO2)	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.
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.
Variable (Intermittent) Resource (Energy)	Generating resources that have some degree of variability in the production pattern, typically due to weather conditions. An example would be wind energy. The power output from the wind project is entirely dependent upon the wind conditions and will fluctuate with changes in wind conditions.
Ventyx	The company that produces the modeling tools, PROMOD, PROVIEW and Strategist, used for this IRP.
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.

GLOSSARY (CONTINUED)

Water Intensity	The amount of water needed to produce a unit of electricity. In general this document will give water intensity as acre-feet per megawatt-hour.
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.
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, including Arizona.
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.