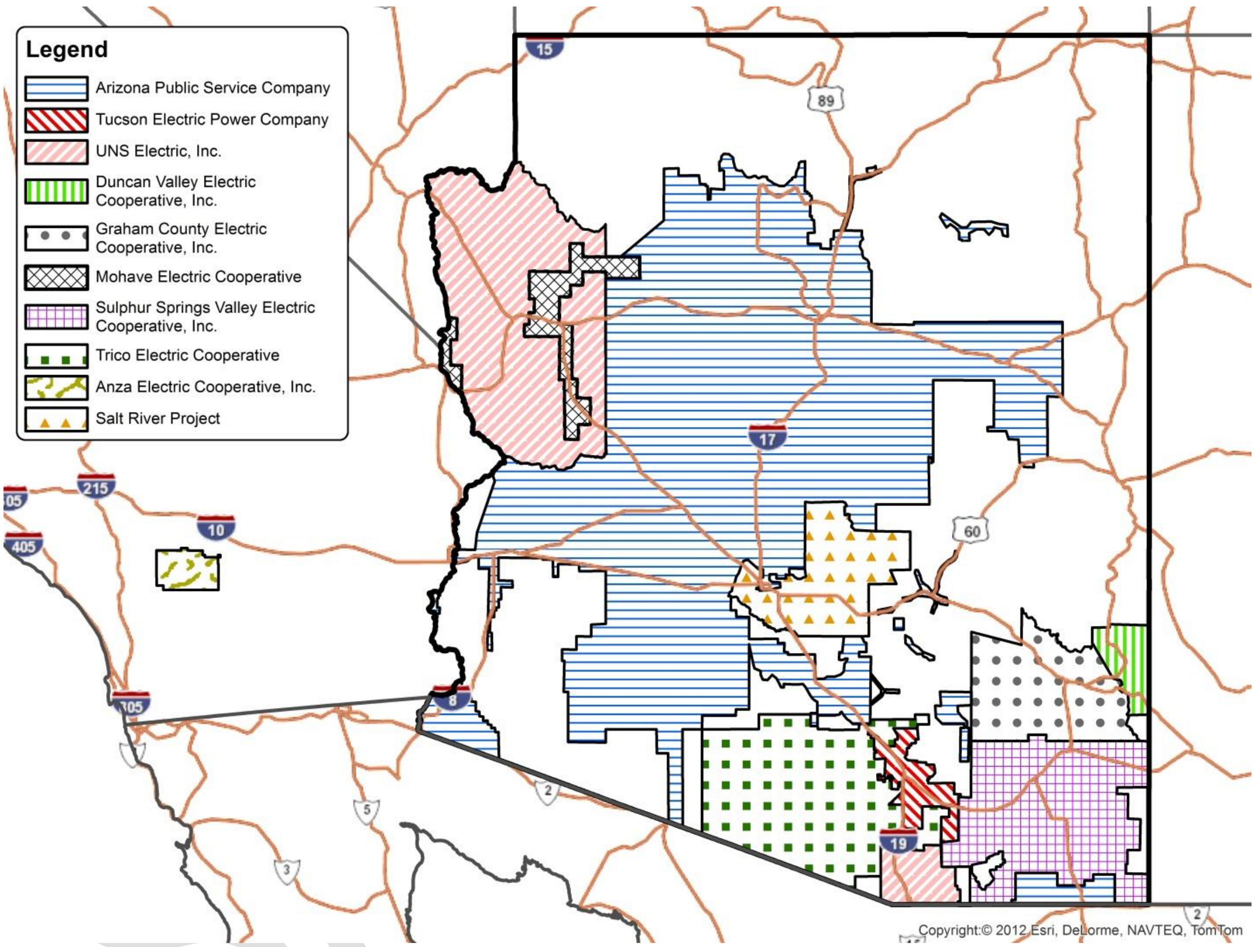
ASSESSMENT OF THE 2014 INTEGRATED RESOURCE PLANS OF THE ARIZONA ELECTRIC UTILITIES

ACC DOCKET NO. E-00000V-13-0070

DECEMBER 19, 2014



PREPARED ON BEHALF OF THE STAFF OF THE ARIZONA CORPORATION COMMISSION BY

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I. Executive Summary

A. Introduction

The purpose of this report is to satisfy the requirements of the Arizona Corporation Commission's ("Commission") Resource Planning and Procurement rules requiring the Commission's Utilities Division ("Staff") to file a report containing Staff's analysis and conclusions concerning Staff's statewide review and assessments of the Integrated Resource Plans ("IRPs") filed with the Commission. Four load-serving entities – (Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNSE") and Arizona Electric Power Cooperative, Inc. ("AEPCo")) are required to submit 15-year IRPs to the Commission in each evenly numbered year. The initial IRPs were filed with the Commission on April 1, 2012, and were reviewed by Staff, the Commission, and other parties in Docket No. E-00000A-11-0113. In Decision No. 73884 (May 8, 2013), the Commission acknowledged all four of the 2012 IRPs and ordered that certain improvements and modifications be made to the 2014 IRPs. Decision No. 73884 also modified the filing requirements for AEPCo. The load-serving entities filed their 2014 IRPs on April 1, 2014. These IRPs are the subject of this report.

A load-serving entity is defined in the Commission's rules as "a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with capacity of at least 50 megawatts combined."[1] APS, UNSE and TEP are investor-owned electric utilities subject to the rules and regulations of the Commission, each owning and operating generating facilities in excess of 50 megawatts. AEPCo owns and operates, on behalf of its distribution cooperatives, the Apache generating station, which has a total capacity of 555 megawatts. AEPCo's distribution cooperatives do not currently own or operate generating facilities. The second largest electric utility in Arizona, Salt River Project ("SRP"), is not subject to these rules and regulations of the Commission and is not required to file an IRP. However, certain publicly available information and additional information voluntarily supplied by SRP is included in this report.

An IRP is essentially the utility's plan to meet the future electric needs of its customers in a way that considers environmental impacts along with the concerns of customers, regulators, stockholders and all other stakeholders. Within the IRP, the selection of ways to reduce, or shift electric usage (demand-side resources) are weighed in an equitable fashion against ways to increase the production of electricity (supply-side resources). The bottom line of an IRP is a schedule of demand-side and supply-side resources that will provide for the continued reliable delivery of electricity to all customers in Arizona.

[1] Arizona Administrative Code ("A.A.C.") R14-2-701(26).

The Commission's rules include certain filing requirements and require the Commission to determine whether each IRP complies with the requirements of the rules and is reasonable and in the public interest based on the information available to the Commission at the time, considering the following factors[2,3]:

1. The total cost of electric energy services;
2. The degree to which the factors that affect demand, including demand management, have been taken into account;
3. The degree to which supply alternatives, such as self generation, have been taken into account;
4. Uncertainty in demand and supply analyses, forecasts, and whether plans are sufficiently flexible to enable the utility to respond to unforeseen changes in supply and demand factors;
5. The reliability of power supplies, including fuel diversity and non-cost considerations;
6. The reliability of the transmission grid;
7. The environmental impacts of resource choices and alternatives;
8. The degree to which the load-serving entity considered all relevant resources, risks, and uncertainties;
9. The degree to which the load-serving entity's plan for future resources is in the best interest of its customers;
10. The best combination of expected costs and associated risks for the load-serving entity and its customers; and
11. The degree to which the load-serving entity's resource plan allows for coordinated efforts with other load-serving entities.[4]

In addition, each load-serving entity (other than AEPCo) must meet the requirements of the Annual Renewable Energy Requirement,[5] the Distributed Renewable Energy Requirement,[6] and the Energy Efficiency Standard.[7]

Under the Renewable Energy Requirement, each load-serving entity (excluding AEPCo) must supply energy from eligible renewable energy resources (or obtain renewable energy credits) sufficient to supply the following annual percentages of retail energy sold by the load-serving entity during that calendar year[8]:

[2] A.A.C. R-14-2-704(B).

[3] The Staff Report and the Commission's acknowledgement are in no way intended to replace the normal prudency review that the Commission undertakes during ratemaking proceedings.

[4] A.A.C. R14-2-704.

[5] A.A.C. R14-2-1804.

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

[7] A.A.C. R14-2-2404.

[8] A.A.C. R14-2-1804.

2012	3.50%
2013	4.00%
2014	4.50%
2015	5.00%
2016	6.00%
2017	7.00%
2018	8.00%
2019	9.00%
2020	10.00%
2021	11.00%
2022	12.00%
2023	13.00%
2024	14.00%
After 2024	15.00%

The Distributed Renewable Energy Requirement essentially requires that at least 30% of the load-serving entity's Renewable Energy Requirement must be supplied by distributed (or customer-owned) renewable energy resources[9].

Under the Energy Efficiency Standard, each load-serving entity (excluding AEPCo) must achieve the cumulative annual energy savings from cost-effective demand-side energy efficiency programs, as a percentage of the retail energy sales in the previous calendar year, shown in the following table[10]:

2012	3.00%
2013	5.00%
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	19.50%
2020	22.00%

The Commission's decision in the initial IRP docket (Decision No. 73884) acknowledged the IRP's of all four load-serving entities, and required that APS, TEP and UNSE address the issues identified in the 2012 Integrated Resource Planning Assessment in their 2014 IRPs. The decision also ordered that TEP include a coal fleet retirement scenario in its 2014 IRP. Concerning AEPCO, the Commission acknowledged the special circumstances concerning AEPCO, namely that AEPCO does not serve any retail load, and its wholesale, supply-only role has shrunken dramatically since 2001. Therefore, the Commission ordered that AEPCO shall

[9] A.A.C. R14-2-1805.
[10] A.A.C. R14-2-2404.

file whatever information, data, criteria and studies it has used in its 15-year planning studies, and future AEPCO IRPs need not be acknowledged by the Commission.

Finally, Decision No. 73884 requires that each load-serving entity with possible extra capacity resulting in a reserve margin beyond 20% over a period of two years must include an alternative scenario in its IRP, in which any incremental additions of capacity, mandated or not, that contribute to the possible extra capacity, are delayed until such additions no longer contribute to the additional capacity. The costs of this alternative scenario, including projected revenue requirements, must be included in the IRP.

A. Major Findings

We have found that, for the most part, the 2014 Integrated Resource Plans filed by APS, TEP and UNSE are reasonable and in the public interest, based upon the information available to Staff when it prepared its report, and comply with the Commission's requirements, and thus recommend that the Commission acknowledge the APS, TEP and UNSE IRPs. However, Staff has identified the following issues concerning the 2014 IRPs:

<u>APS:</u>

- In Staff's Draft Assessment of the 2014 Integrated Resource plans (docketed November 3, 2014), Staff expressed concerns regarding the additional 290 MWs of additional capacity that is included in APS's proposed Ocotillo Modernization Project ("OMP"). Staff concluded with a recommendation to the Commission that APS should be directed to conduct an all-resource Request for Proposal ("RFP") process prior to initiating the construction of the proposed additional capacity so as to be certain that the proposed capacity addition was the most cost-effective option.

- Since docketing the Draft Assessment, Staff has reviewed the testimony from the OMP Certificate of Environmental Compatibility hearing before the Commission's Line Siting Committee (Docket #E-00000V-13-0070). Based on this review, Staff believes that the OMP may offer a unique opportunity to add capacity at a strategic location within the Phoenix Load Pocket. In addition, existing Ocotillo site attributes such as the availability of water, natural gas, and transmission infrastructure support the redevelopment activities proposed in the OMP. Further, Staff recognizes that APS conducted a variety of economic feasibility studies which point to the economic viability of the OMP.

- In making its earlier recommendation regarding the all-resources RFP, Staff partially relied on its interpretation of the R14-2-705 "Procurement" section of the Resource Planning and Procurement Rules ("Rules"). Staff initially believes that these Rules could be interpreted to require Load Serving Entities to procure new capacity through an RFP process. Based on discussions with APS, Staff concludes that there may be ambiguity in the rules as to when the RFP process is required. Exclusion to the RFP process contained in R14-2-705B(5) may apply to the OMP.

- Staff notes that APS has volunteered to conduct an all-resources RFP process prior to adding the additional 290 MW of capacity. Staff commends APS for making this voluntary commitment and believes that the information derived through the RFP process may provide useful information at such time that APS seeks cost recovery of the OMP.

- Staff recommends that if APS believes such information would be useful in demonstrating the prudency of the OMP, APS may conduct all-resources RFP prior to initiating construction, as it has volunteered to do.

- APS has requested that the Commission specifically approve the proposed retirement of Cholla Unit 2 in April of 2016. APS cites the provisions of R 14-2-704(E) as the basis for this specific approval. Subsequent to the receipt of this request for specific approval, Staff issued a set of Data Requests to APS inquiring, among other things, whether APS would seek recovery of stranded costs associated with the Unit 2 retirement, and if APS understands that any Commission approval of the Cholla Unit 2 retirement under this IRP proceeding would not be considered an approval of the prudency and cost of the retirement. APS responded affirmatively to both questions.

- Based on APS's recognition that the specific approval under this IRP proceeding of the Cholla Unit 2 retirement in April 2016 is not an approval of the prudency or costs associated with the retirement, Staff recommends that the Commission grant approval of said retirement. However, this approval would not imply a specific treatment or recommendation for rate base or rate making purposes in APS's future rate filings.

<u>TEP and APS:</u>

- The TEP and APS load forecasts appear to be somewhat optimistic, in that both assume a rapid return to historical load growth. Staff recommends that TEP and APS re-examine their load forecasting techniques prior to the filing of the 2016 IRPs to ensure that TEP and APS are not forecasting high load growth that is unlikely to occur.

<u>AEPCO:</u>

- Concerning AEPCo, Staff finds that the information supplied by AEPCo satisfies the requirements established in Decision No. 73884.

I. Integrated Resource Planning

A. General Overview & History

The Integrated Resource Planning process was developed with three primary purposes in mind: (a) to provide an opportunity for public input and participation in the long-term planning processes of the utilities; (b) to cause utilities to evaluate demand-side management ("DSM") resources and supply-side resources on an equal footing; and (c) to allow for the evaluation and consideration of the environmental and societal impacts of the actions of the utilities.

Prior to the implementation of Integrated Resource Planning in the 1980's, electric utilities performed long-term planning in a vacuum – with little or no input from the public or regulatory bodies. During this period, the model for electric utilities was to capitalize on the economies of scale derived by building large central station plants. These large plants contributed to the falling real price of electricity that had been evolving for years since the Second World War. Because of the low prices for electricity, the public was encouraged to consume as much power as they cared to use, with little or no consideration for making efficient use of the energy. Utilities responded by initiating large power plant construction programs.

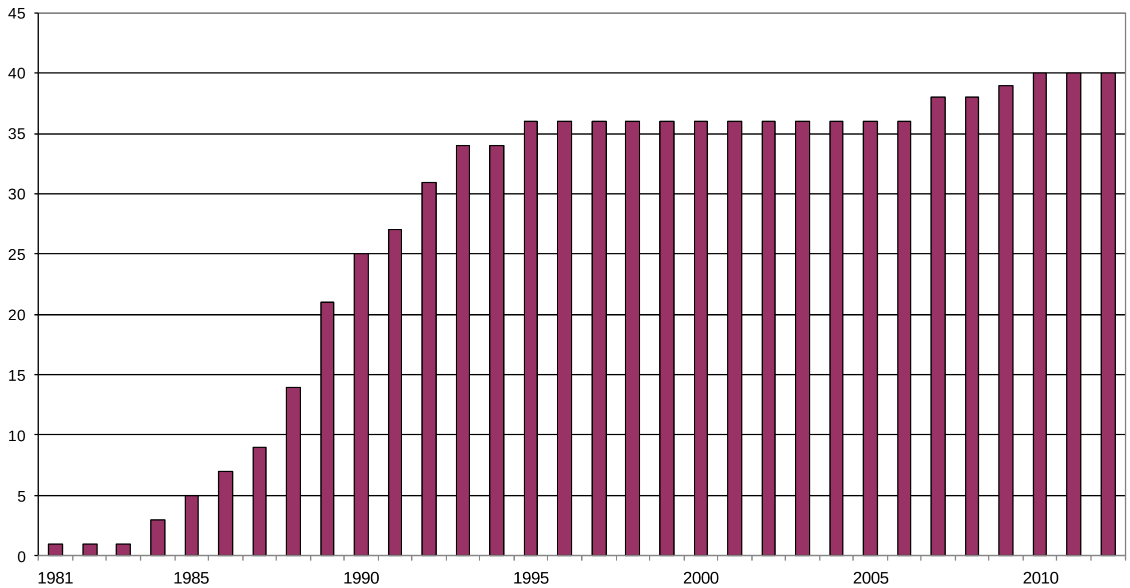
As a result of the boom in power plant construction, with very little public or regulatory oversight, the certification of new resources (generating plant) was often made after-the-fact, that is, after the construction of the generating plant was underway or even complete. This did not cause a major problem prior to the regulatory disallowance of the excessive costs of some nuclear generating plants. These nuclear disallowances were a major factor in the move to Integrated Resource Planning. With IRP, rather than planning in a vacuum, all stakeholders, including the utility's customers, the Commission and others participate in the decision-making process.

The high cost of imported oil and the resulting uncertainty of the future price of oil in the 1970's, as a result of the Middle East Oil Embargo, also played a major role in the move to IRP. Rates for electricity were moving upward and regulators wanted to ensure that all options to meet the growing demand for electricity were fairly considered. Energy efficiency improvements were seen as a way to help lower costs and preserve precious energy resources. Although it is counter to the natural tendencies of electric utilities, the IRP process requires utilities to fairly consider demand side management ("DSM") as a way to meet growing electric requirements. A DSM resource is a program that modifies the customer's need for electricity. An example is a program that encourages (through cash incentives) residential homeowners to add insulation to their homes. The added insulation reduces the use of air conditioning in the summer and electric heat in the winter, thus reducing the utility's need to generate electricity, and results in a more efficient use of electricity in the home.

The final major factor that resulted in the IRP process was the concern with the impact of generating plants on the environment. During the 1980's people became much more aware and concerned about the environmental impacts of pollution. Fossil fueled plants produce large emissions of sulfur dioxide (SO2), nitrous oxides (NOx), particulates, heavy metals, carbon dioxide (CO2), and other greenhouse gases. The Clean Air Act Amendments of 1990 resulted in national restrictions on the production of SO2 and NOx. Water is a scarce and valuable resource, so the consumption of water by generating facilities must also be a consideration. Through the IRP process, the levels of likely future emissions and water consumption can be estimated and alternative plans that result in reduced emissions and water consumption can be considered.

As shown in the following chart, the number of states that require electric utilities to file IRPs has grown steadily since 1981. Today, forty states require IRPs.

Number of States Requiring IRPs



Sources - NARUC Compilation of Utility Regulatory Policy 1995-1996 and
A Brief Survey of State Integrated Resource Planning Rules and Requirements - Synapse

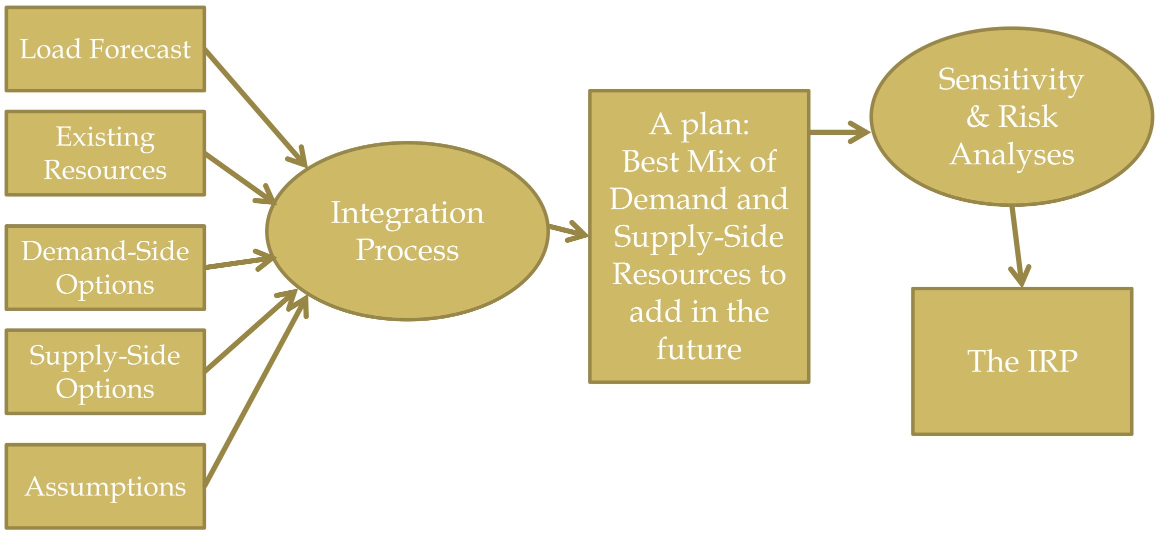
B. Overview & History of IRP in Arizona

The Commission originally adopted the Resource Planning and Procurement Rules ("IRP Rules") on February 3, 1989. The IRP Rules required all electric utilities owning generation facilities to file 10-year resource plans every three years. Plans were filed and reviewed by the Commission in the 1990-1991 period and also in the 1992-1993 period. In 1995, resource plans were filed, but no hearings were held and in 1997, some of the IRP Rules were suspended for one year. Then in 1999, a procedural order suspended the IRP Rules until further order of the Commission. However, that portion of the IRP Rules that required the filing of historical data remained in effect.

The 2005 APS settlement agreement (approved in Decision No. 67744 (April 7, 2005)) required Staff to schedule workshops on resource planning issues which would focus on developing needed infrastructure and a flexible, timely and fair competitive procurement process. In addition, the workshops were to consider whether and to what extent the competitive procurement process should include consideration of a diverse portfolio of short, medium and long-term purchased power; renewables; demand-side management; and distributed generation. The workshops were to be open to all stakeholders and the public and, if necessary, were to be followed with a rulemaking.

Workshops initiated by the 2005 APS settlement agreement were held in 2005, 2006, 2007 and 2008. Written comments were filed and Staff developed draft rule modifications which were distributed to all stakeholders. Written comments on the draft rule modifications were submitted and hearings were held in February 2010. The Commission, by final rulemaking, amended the IRP Rules, effective December 20, 2010. The IRP Rules are found in the Arizona Administrative Code ("AAC") at Title 14, Chapter 2, Article 7 "Resource Planning and Procurement", *et seq*. The AAC is available on the Commission's Home website found at www.azcc.gov under "Laws and Rules Governing the Commission".

C. *Basic Elements of an IRP*



An IRP is the utility's long-term plan to meet the future electric needs of its customers. While each utility may perform an IRP study using different approaches, all IRP studies generally contain the following basic elements:

Load Forecast
Examination of Existing Resources
Development of Potential DSM Options
Development of Potential Supply-Side Options
Assumptions
Integration Process
Sensitivity & Risk Analysis
IRP Selection

The **Load Forecast** is the utility's estimate of the future electric requirements of its customers. Commission rules require utilities to forecast for at least 15 years into the future. It includes a forecast of the annual peak demand (the single highest hourly electric usage during the year) and a forecast of the annual energy requirements (the total annual production of electricity required to meet the needs of all customers).

The next step in the IRP process is the **Development of Potential DSM Options**. In this step, the utility identifies all potential demand-side options that could be utilized to meet the future needs of its customers. Several qualitative and quantitative screenings are applied to the original list of options to produce a reasonable number of remaining options for inclusion in the Integration step. The screenings are usually based on a viability test and application of the standard ratios – the Total Resource Cost (TRC) test, the Utility Cost Test, the Participant Test and the Rate Impact Measure (RIM) test. Arizona jurisdictional utilities are required to use the Societal Test, which is similar to the TRC test, but includes societal benefits and costs.

The next step is the **Development of Potential Supply-Side Options**. Here, just as in the previous step, a comprehensive catalog of potential supply-side options is developed and then screened for viability and cost-effectiveness. The normal screening process is a comparison of the total busbar costs of each of the viable options at various operating levels. Busbar costs are construction costs, fixed and variable operating and maintenance costs, and fuel costs expressed as an average cost per unit of electricity produced ($/MWh). Those options that have the best busbar costs are passed on to the **Integration Process**.

Certain base **Assumptions** must be made, such as the assumed planning reserve margin, inflation, wind and solar integration costs, and future costs of natural gas, coal and other fuels.

The **Integration Process** selects the "best" mix of DSM and supply-side options to meet the load forecast. "Best" may mean lowest total revenue requirements, least environmental impact, lowest customer bills, and/or some other measures selected by the utility. If environmental impacts are monetized in this step, then the resulting plan will minimize total costs that include capital, fuel, Operating & Maintenance expense (O&M), and environmental costs. It is generally accepted that the IRP should include several potential plans; for example, a plan that minimizes total revenue requirements, a plan that includes monetized environmental impacts and a plan that minimizes customer bills. This will allow customers and regulators to more fully understand how the costs, benefits, rates, environmental impacts, etc. are affected by different resource plans.

Environmental consequences of each plan developed in the Integration Process should be included in the IRP. The annual production of all harmful emissions in each possible plan should be reported to provide customers and regulators information necessary for the proper evaluation of each plan. An assessment of environmental impacts should be performed even if environmental costs are not monetized as part of the Integration Process. Consideration should also be given to the impact of potential environmental legislation, such as the taxing of CO2 emissions, that is under consideration by the Environmental Protection Agency.

A **Sensitivity and Risk Analysis** is normally utilized to ensure that the selected plan will perform well should assumptions change. For example, a risk analysis will identify the potential dollar risk inherent in the plan if actual fuel prices turn out to be dramatically different than what had been forecasted. Several types of risk analysis studies exist. The most frequently used types are Sensitivity Analysis and Scenario Analysis. Sensitivity Analysis is primarily concerned with determining how a particular expansion plan would be impacted by the change in a single variable (such as fuel costs). Scenario Analysis looks at the impacts on the selected expansion plan considering the possibility that future conditions might influence the change in more than one variable. For example, a higher load growth scenario might also suggest that fuel costs and capital costs could be higher due to higher rates of inflation.

Finally, the results of the **Integration Process** and the **Sensitivity and Risk Analysis** are evaluated and the utility reaches a decision regarding its preferred IRP.

D. The Commission IRP Proceedings and Workshops

On March 25, 2013, the Utilities Division Staff requested that a Docket be opened for the purpose of Resource Planning and Procurement in 2013 and 2014. Docket No. E-00000V-13-0070 was established for this purpose. All plans and reports required by the Rules (R14-2-701 through -706) for 2013 and 2014 were required to be filed in the Docket. The Historical Planning reports for 2012 and 2013 were filed by APS, AEPCo, UNSE, and TEP pursuant to A.A.C. R14-2-703 in the first quarter of 2013 and the first quarter of 2014, respectively. The required IRPs were filed in this Docket by APS, TEP, UNSE and AEPCo in April, 2014.

The Commission sponsored an IRP workshop, open to the public and all other stakeholders, on September 11, 2014. The Commission held a second IRP workshop meeting November 7, 2014. The presentation materials from the workshops are available on the Commission web site at http://www.azcc.gov.

At the first workshop, Commission Staff opened the meeting with a short discussion on the purpose of the meeting and a review of the agenda. Each of the load-serving entities (APS, TEP, UNSE and AEPCo) then presented its IRP and discussed the development of its IRP. This was followed by a presentation by Western Resource Advocates entitled “What Should Commissioners Consider when Reviewing Arizona Resource Plans?” Staff then conducted a panel discussion in which stakeholders presented questions to a panel consisting of representatives of each of the load-serving entities. In attendance were representatives of each of the four load-serving entities and the following groups:

Southwestern Power Group II
Western Resource Advocates
Arizona Center for Law in the Public Interest
Copper State Consulting
Arizona Community Action Association
Insight Consulting
Solar Energy Industries Association
Sierra Club
Energy Strategies
Southwest Energy Efficiency Project
Western Grid Group
Lux Consulting

For the second workshop, held on November 7, Staff presented the findings and conclusions of the Staff draft report, which was docketed on November 3. There was a lively discussion among the parties in attendance, which included representatives of all four of the load-serving entities and the following groups:

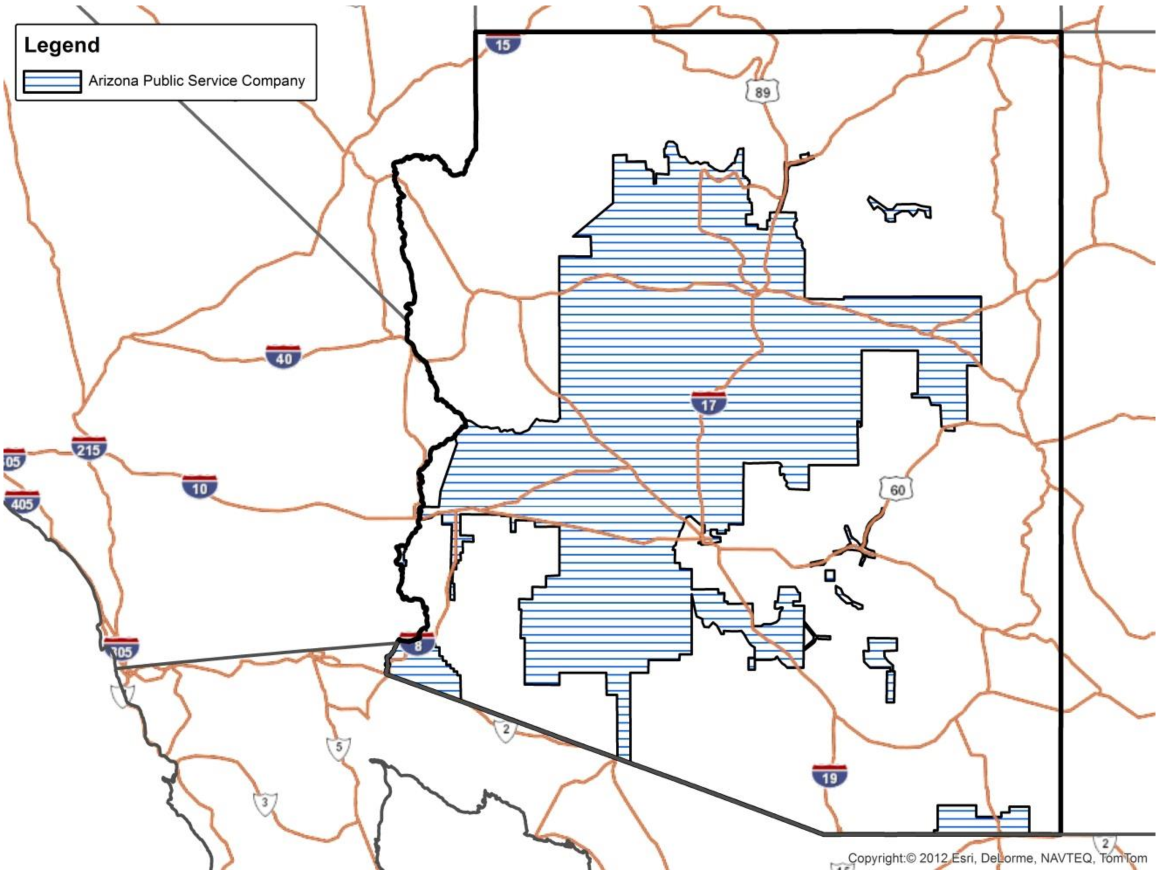
Lux Consulting
Southwest Energy Efficiency Project
Residential Utility Consumer Office
Solar City

Solar Energy Industries Association
Sierra Club
Copper State Consulting
Arizona Competitive Power Alliance
Western Grid Group
Arizona Competitive Power Alliance,

Many of the parties attending the workshops also filed docketed comments regarding the Staff draft report. A discussion of these docketed comments is included in section V.

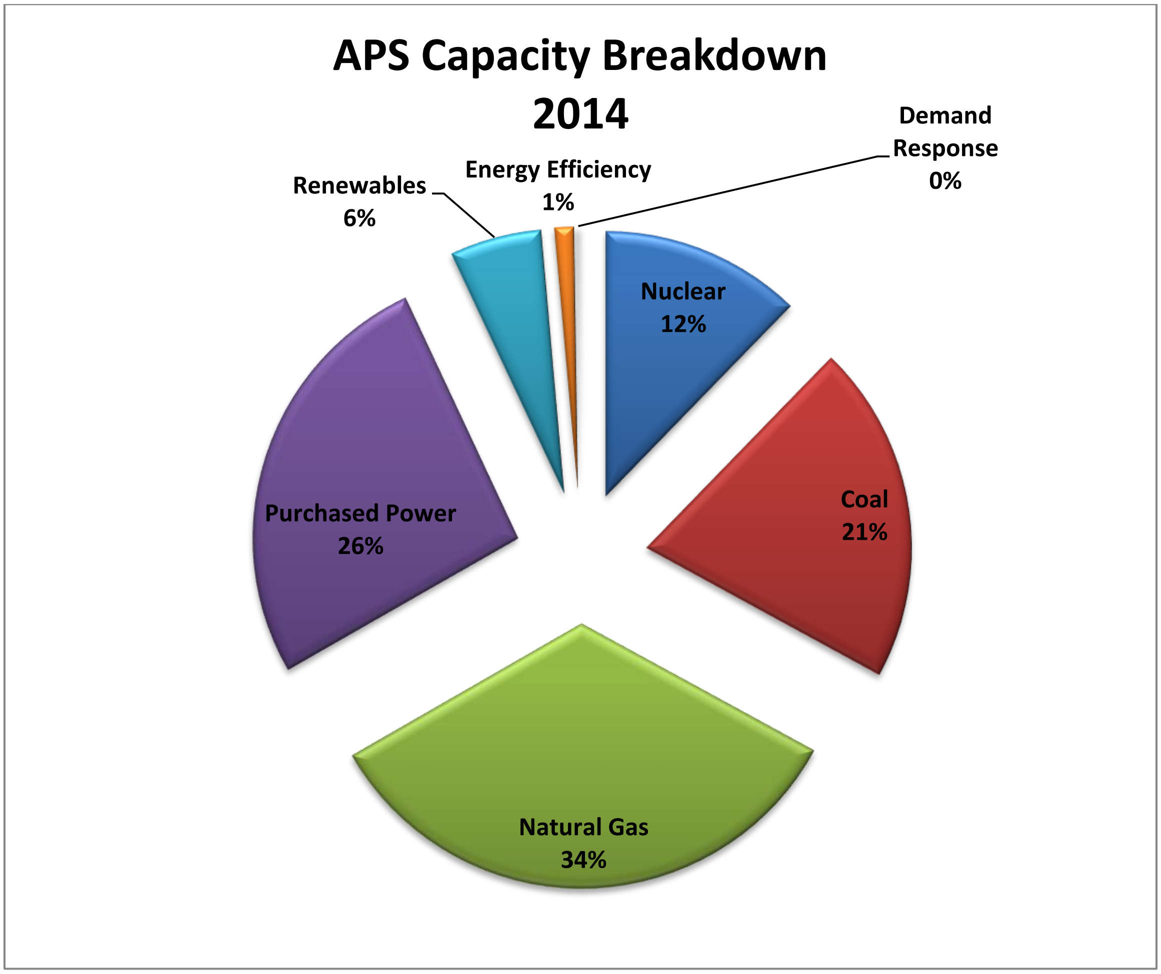
II. The Arizona Electric Utilities

A. Arizona Public Service Company ("APS")



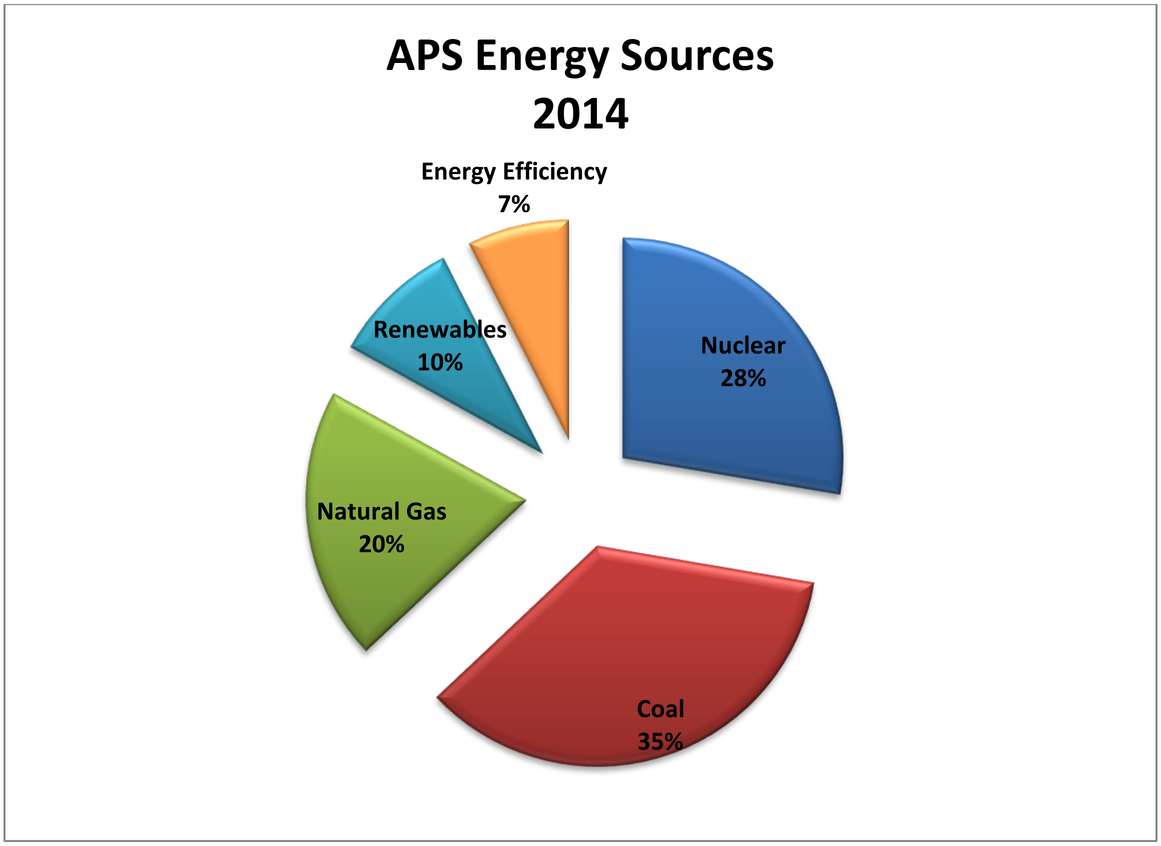
APS is the largest electric utility in Arizona, with a service territory that covers some 35,000 square miles and encompasses a portion of Phoenix. APS's 2012 peak demand was 7,207 megawatts and its total installed capacity (generating capacity plus purchased power) in 2012 was 8,776 megawatts. The company's 2013 peak demand fell to 6,927 megawatts and the total installed capacity in 2013 was 9,054 megawatts.

The breakdown of 2014 installed capacity by fuel type, based on contributions to system peak demand, is shown in the following chart:

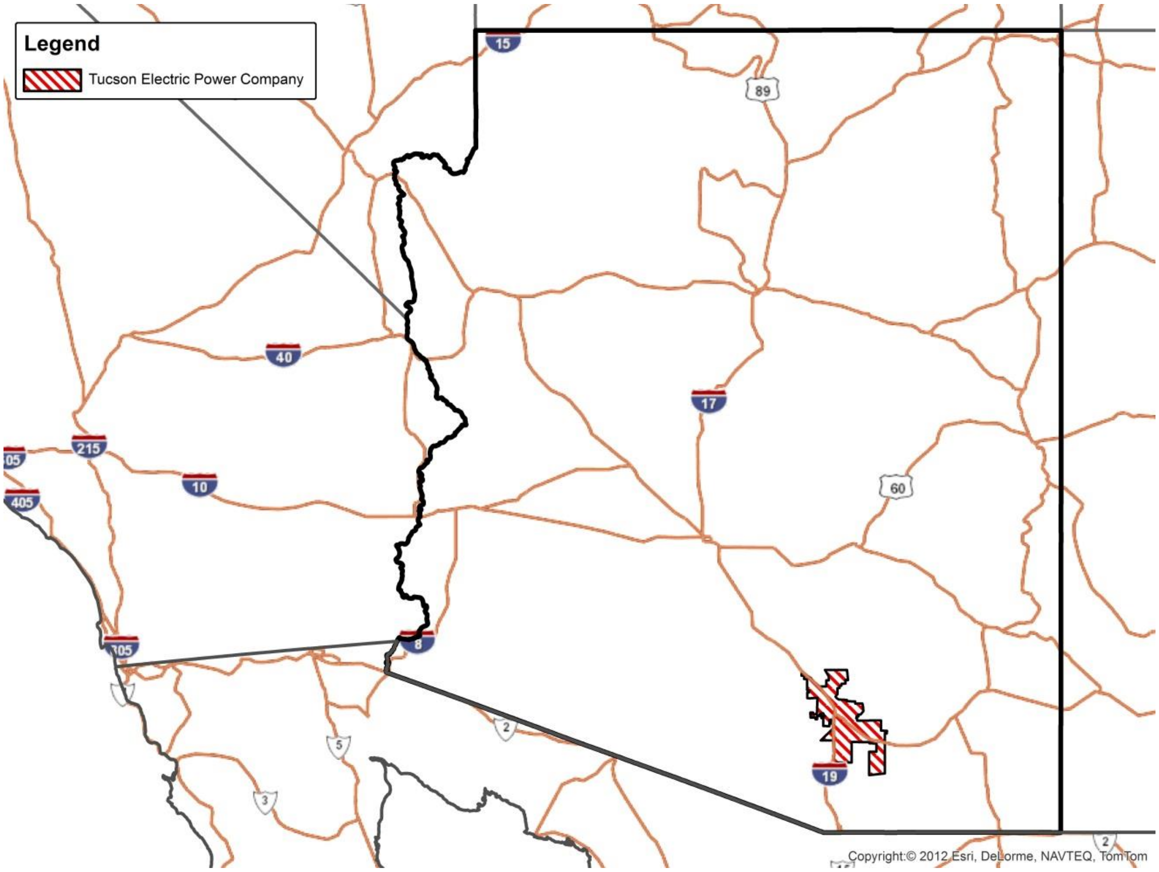


Renewables include distributed generation, renewable purchases and APS-owned renewable generation. Approximately 40% of natural gas capacity is procured through purchased power contracts. APS co-owns and operates the Palo Verde Nuclear Generating Station ("PVNGS"), which is the largest nuclear generating station in the United States. APS has a 29.1% ownership share, which equates to 1,146 megawatts of capacity. The company also co-owns and operates the Four Corners Power Plant, a 1,540 megawatt coal-fired facility located on the Navajo Indian Reservation. APS currently owns 63% (or 970 megawatts) of the capacity at Four Corners. APS also operates and owns Units 1, 2 and 3 of the Cholla coal-fired power plant located in northeastern Arizona near Holbrook, providing 647 megawatts of capacity to APS. PacifiCorp owns the remaining unit at Cholla, Unit 4. Finally, APS owns 14% (or 315 megawatts) of the Navajo coal-fired generating station located on the Navajo Reservation near Page in northern Arizona. Navajo is operated by SRP and is owned by a partnership of five utilities and the U.S. Bureau of Reclamation.

The following chart shows the forecasted 2014 breakdown in energy produced by fuel type:

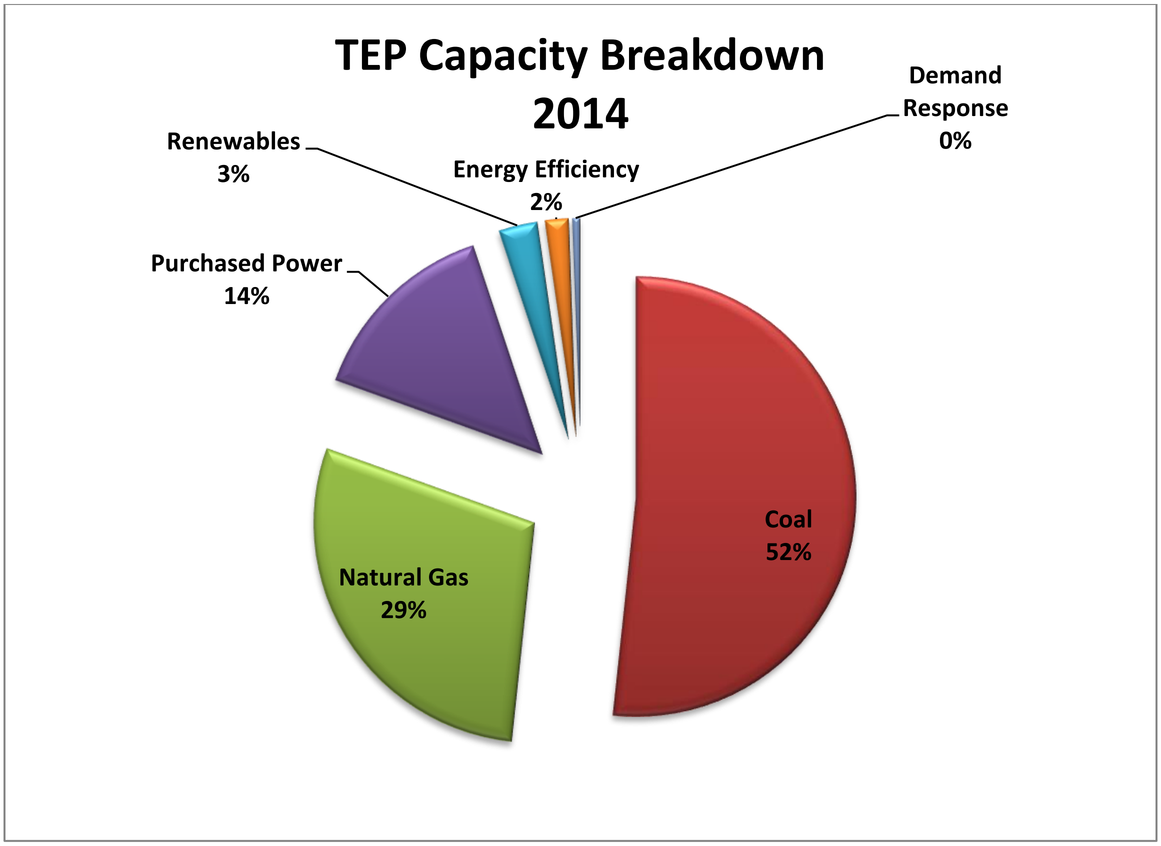


B. Tucson Electric Power Company ("TEP")



TEP is the second largest investor-owned electric utility in Arizona, serving more than 400,000 customers in the Tucson metropolitan area (Pima County). Both TEP and UNS Electric, Inc. are subsidiaries of Unisource Energy Corporation. TEP's 2012 peak demand was 2,290 megawatts and the total available capacity in 2012 was 2,809 megawatts. TEP saw a peak demand in 2013 of 2,230 megawatts. Total available capacity for 2013 was 2,867 megawatts.

The breakdown of TEP's 2014 capacity, based on contribution to system peak demand, is shown in the following chart:



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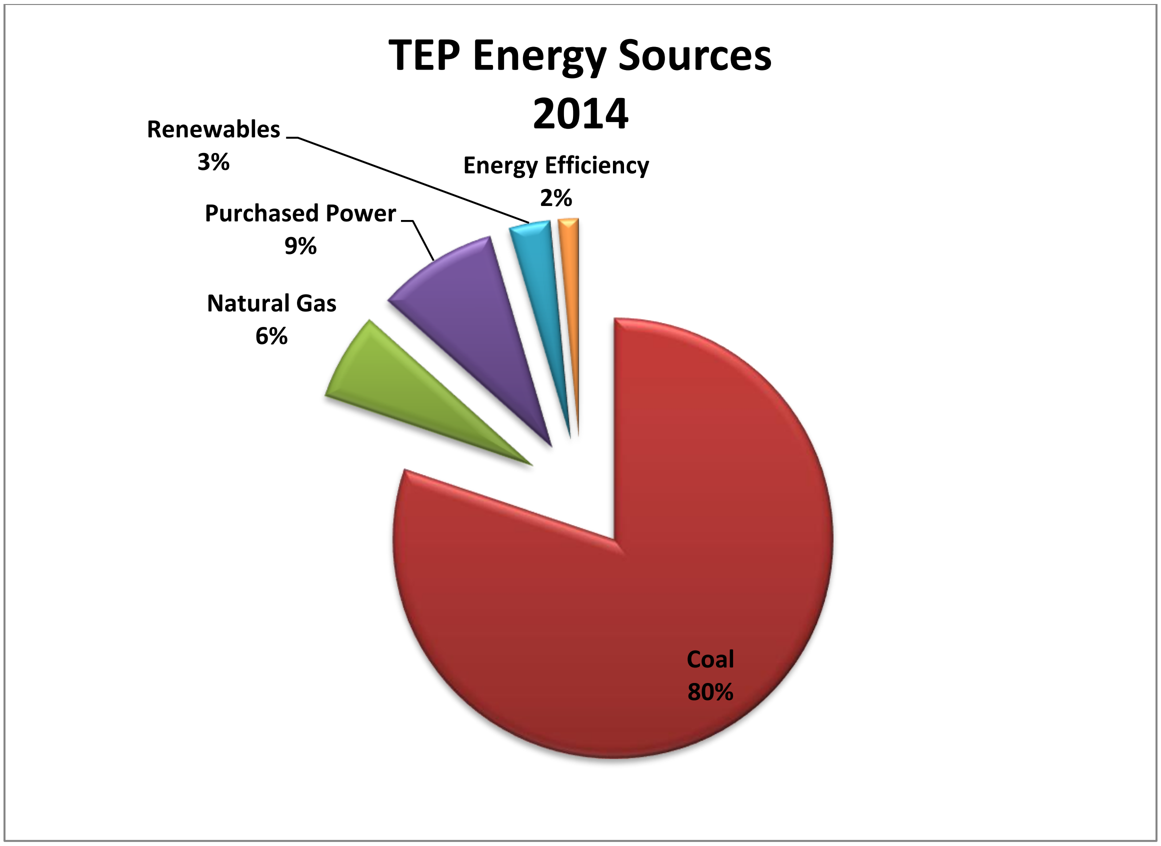
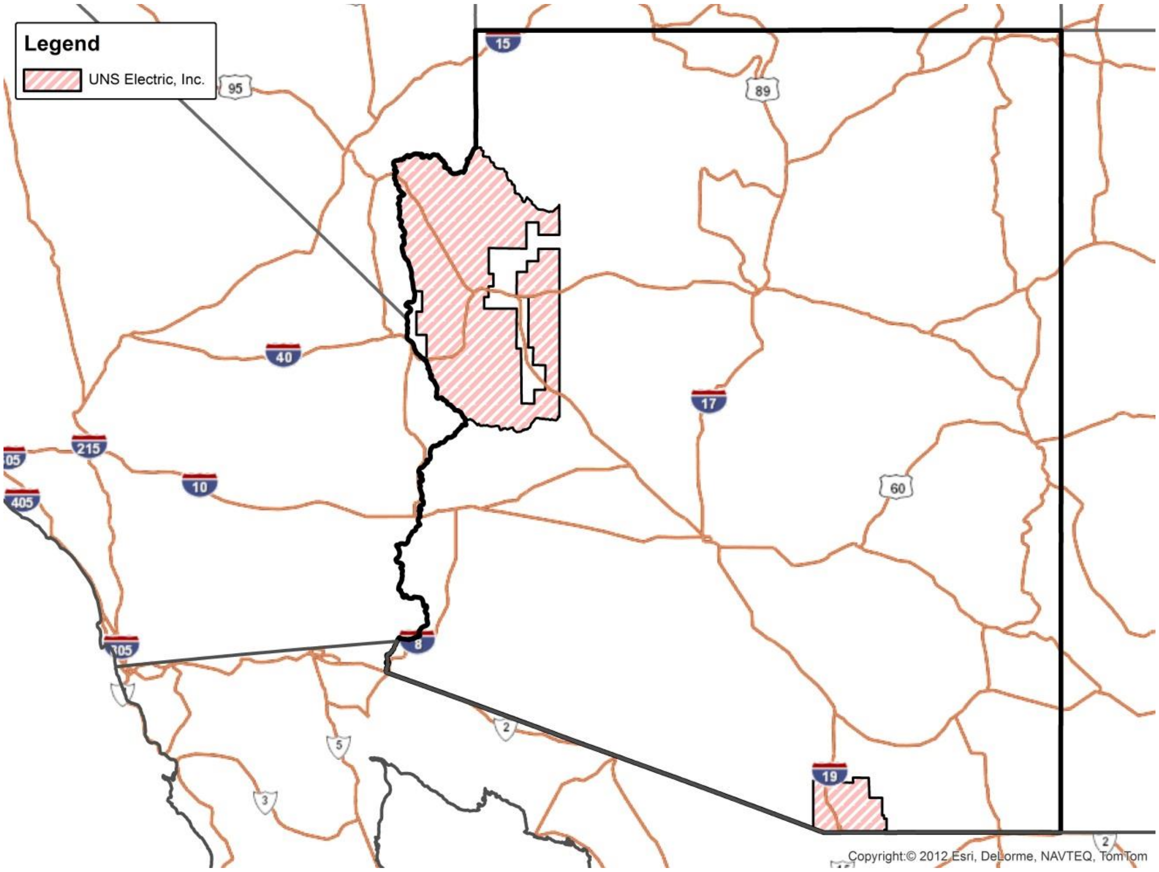
Renewables include distributed generation, renewable purchases and TEP-owned renewable generation. TEP's coal-fired resources include units 1 and 2 of the Springerville generating station (totaling 777 megawatts), a 50% ownership in San Juan units 1 and 2 (totaling 340 megawatts), a 7.5% interest in Navajo units 1, 2 and 3 (totaling 168 megawatts), a 7% ownership in Four Corners units 4 and 5 (totaling 110 megawatts), and unit 4 at the Sundt generating station, which is capable of operating on natural gas (at 156 megawatts) or coal (at 125 megawatts). In addition, TEP owns one-third of the Luna natural gas-fired combined cycle facility (190 megawatts) and 217 megawatts of natural gas-fired combustion turbines.

The following chart shows the forecasted 2014 breakdown of TEP energy produced by resource type:



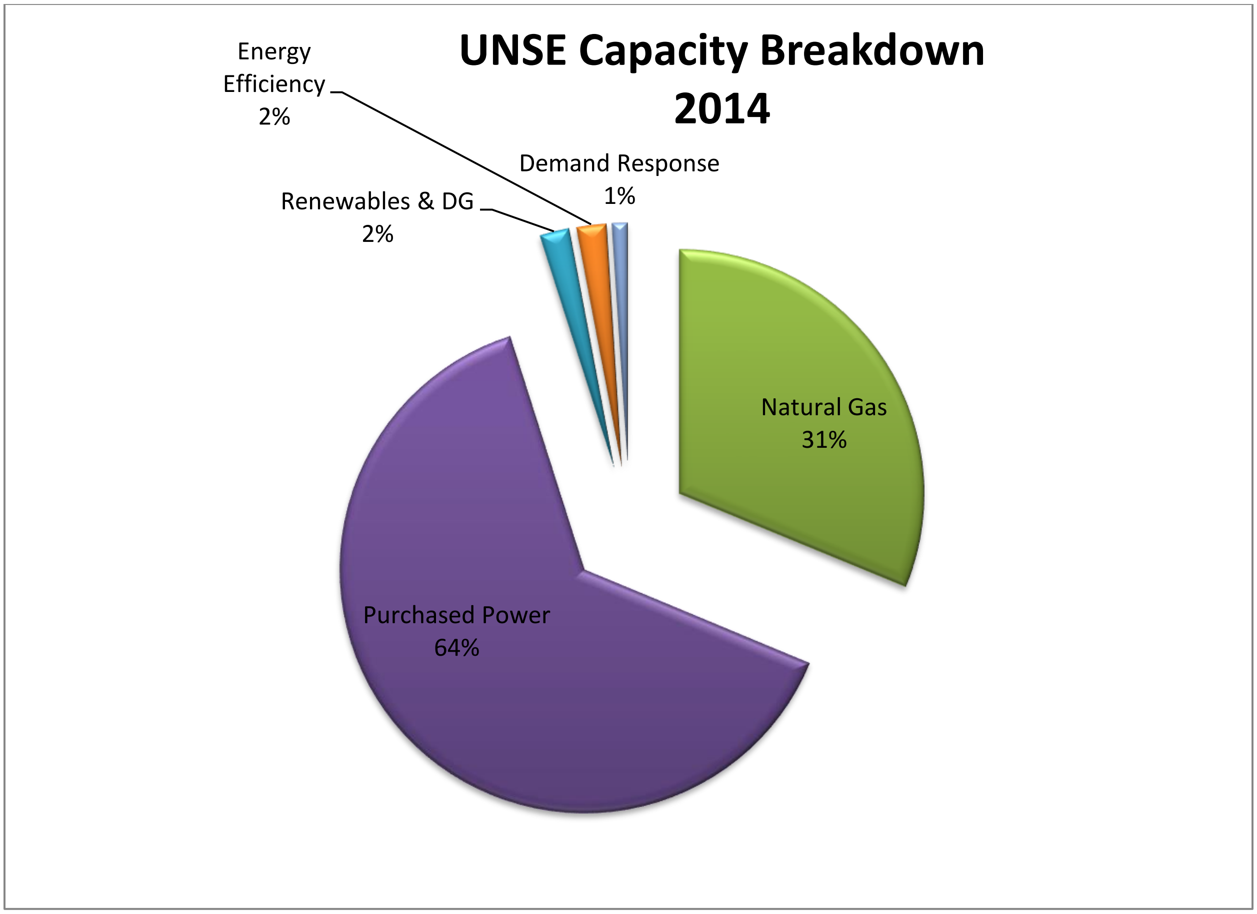
As demonstrated in the above chart, TEP is currently highly dependent on coal generation. Environmental issues concerning coal generation will be a major factor in TEP's IRP.

C. UNS Electric, Inc. ("UNSE")



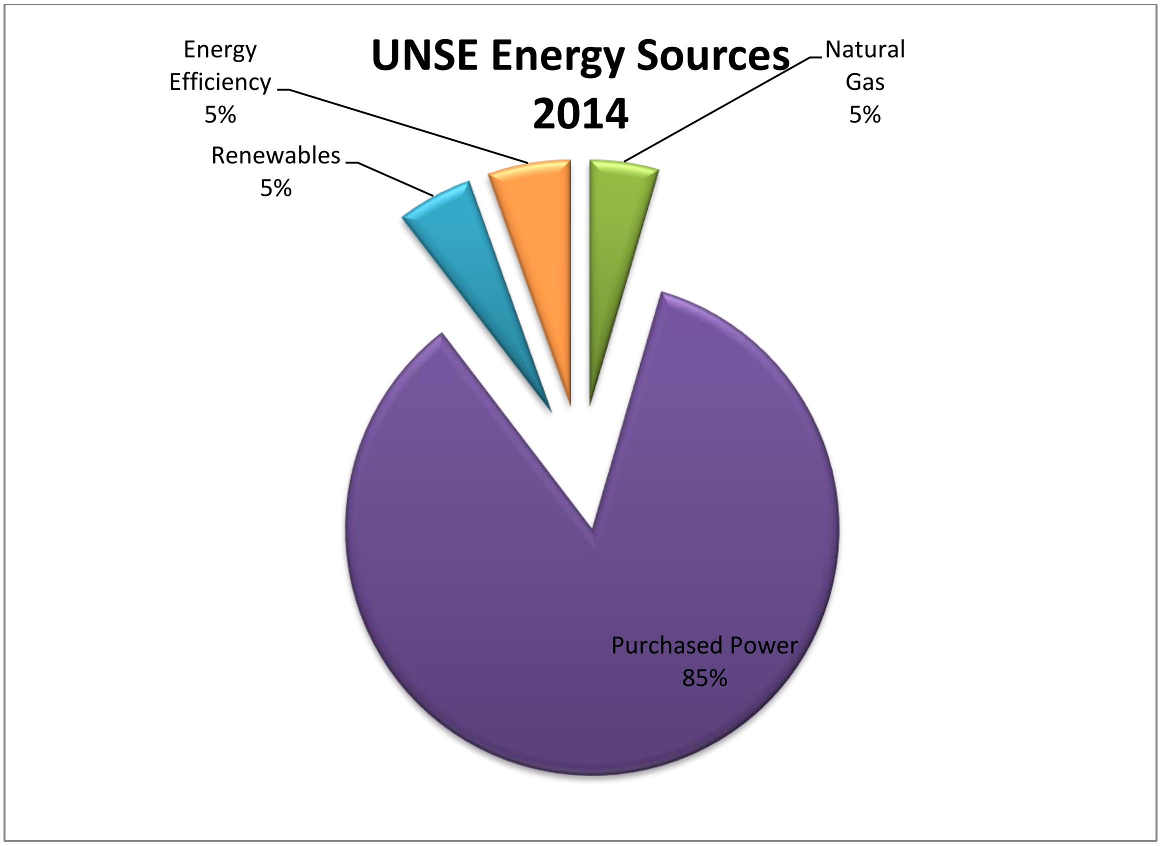
UNSE serves approximately 90,000 customers in two distinct geographic areas – Mohave County in northwest Arizona and Santa Cruz County in southeast Arizona. The Mohave County portion of the UNSE service territory includes the Kingman and Lake Havasu City areas. The southern territory encompasses the Nogales area. UNS's 2012 peak demand was 438 megawatts, served by 378 megawatts of existing resources, supplemented by short-term purchased power. UNSE saw a 2013 peak demand of 435 megawatts with 203 megawatts of existing resources, supplemented by short-term power purchases.

UNSE's 2014 capacity mix, based on contribution to system peak demand, is shown in the following chart:



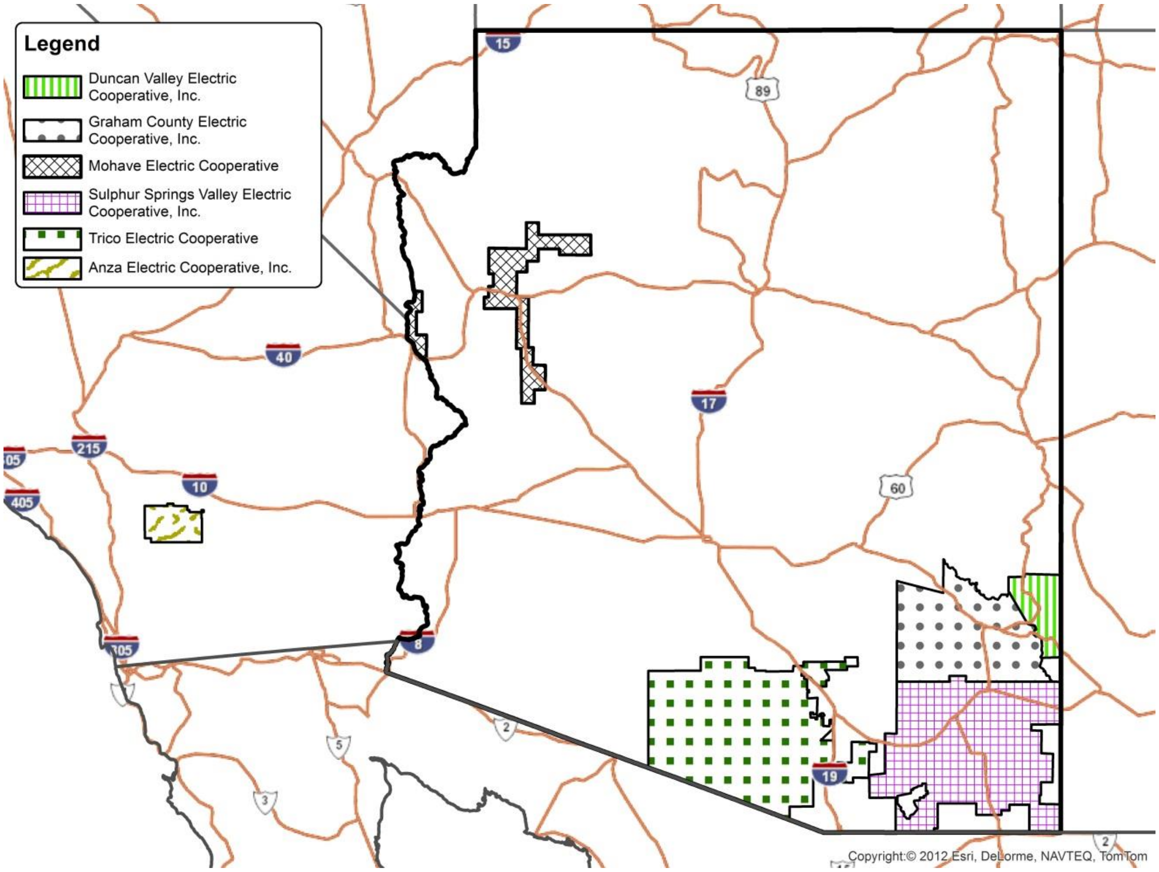
Renewables include distributed generation, renewable purchases and UNSE-owned renewable generation. UNSE owns 150 megawatts of natural gas-fired combustion turbines located at the Black Mountain and Valencia generating stations. Other than this combustion turbine capacity, UNSE depends on purchased power.

The following chart shows the 2014 breakdown of UNSE energy produced by resource type:



As shown in these charts, UNSE is highly dependent on purchased power, a large portion of which comes from the wholesale power markets.

D. Arizona Electric Power Cooperative, Inc. ("AEPCo")



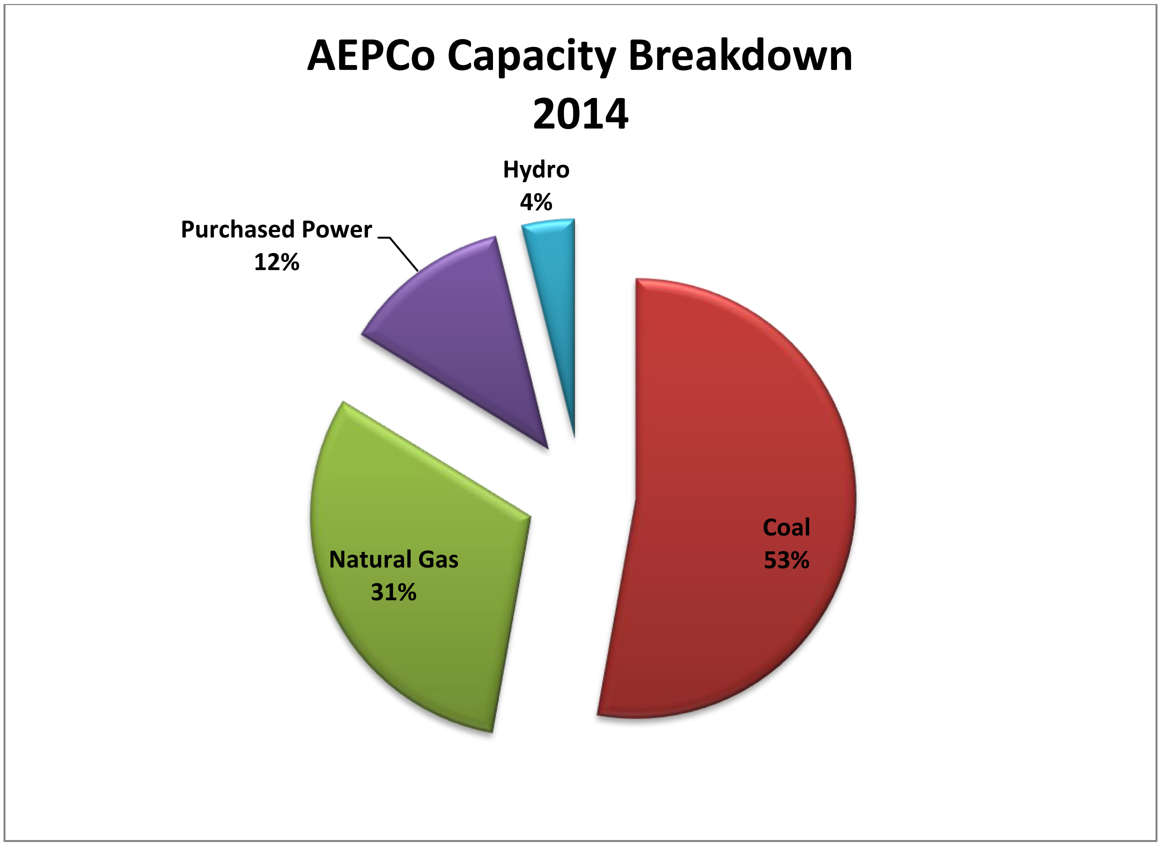
AEPCo is the generation cooperative serving six distribution cooperatives - Duncan Valley Electric Cooperative ("DVEC"), Graham County Electric Cooperative ("GCEC"), Mohave Electric Cooperative ("MEC"), Sulphur Springs Valley Electric Cooperative ("SSVEC"), Trico Electric Cooperative ("TEC"), and Anza Electric Cooperative ("AEC"). Each of these distribution cooperatives is located in Arizona, except for AEC, which is located in California.[11]

Three of the distribution cooperatives served by AEPCo, namely DVEC, GCEC and AEC are all-requirements members, meaning AEPCo is responsible for planning and providing all current and future power and energy needs for these members. The remaining members are partial-requirements members. According to AEPCo, pursuant to contracts most recently approved by the Commission in Decision No. 72055 (January 6, 2011), its only responsibility to the partial-requirements members is to provide the capacity and associated energy from existing resources that are allocated to these members. However, AEPCo is assisting its partial requirements members in studying the feasibility of potential future resources.

[11] DVEC provides service to Arizona and portions of New Mexico.

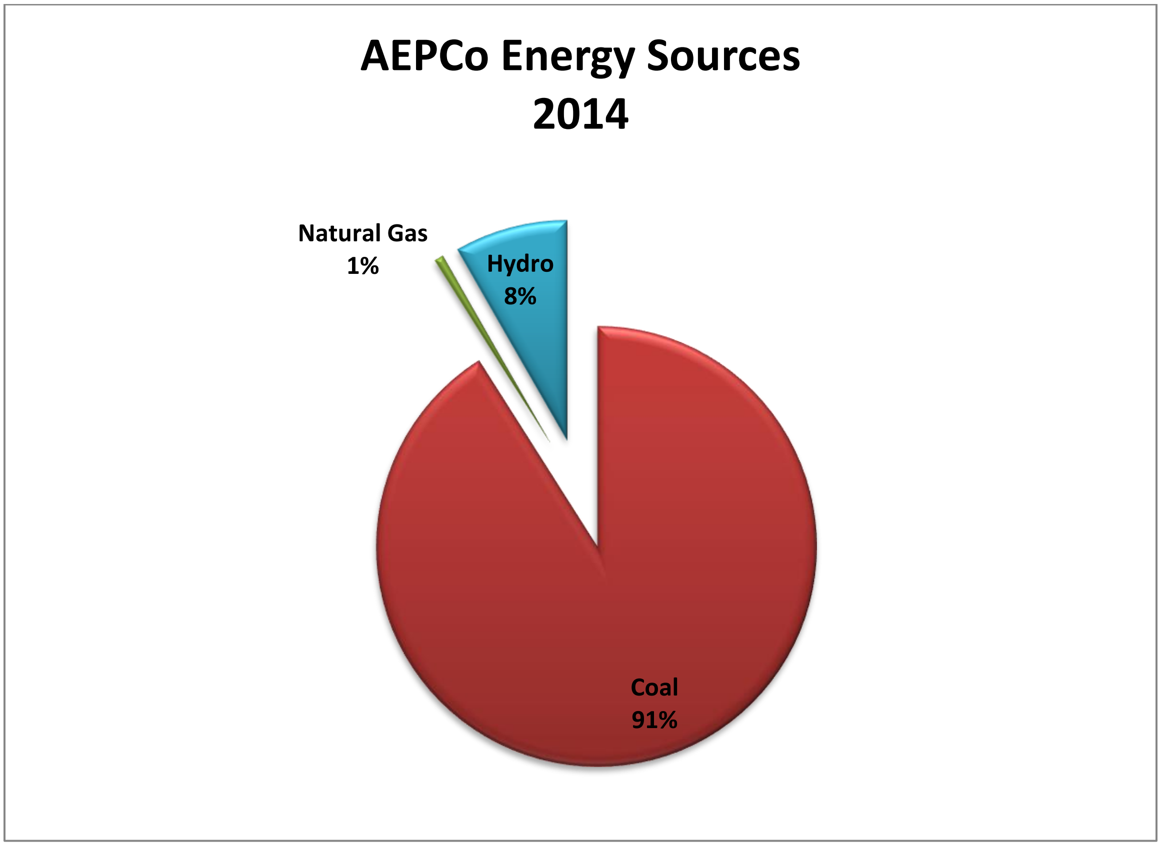
Due to the nature of AEPCo's relationships with its member cooperatives, AEPCo's IRP only addresses the needs of its all-requirements members. The potential needs of AEPCo's partial-requirements members are not included within AEPCo's IRP.

AEPCo's 2014 capacity mix, based on contribution to system peak demand, is shown in the following chart:



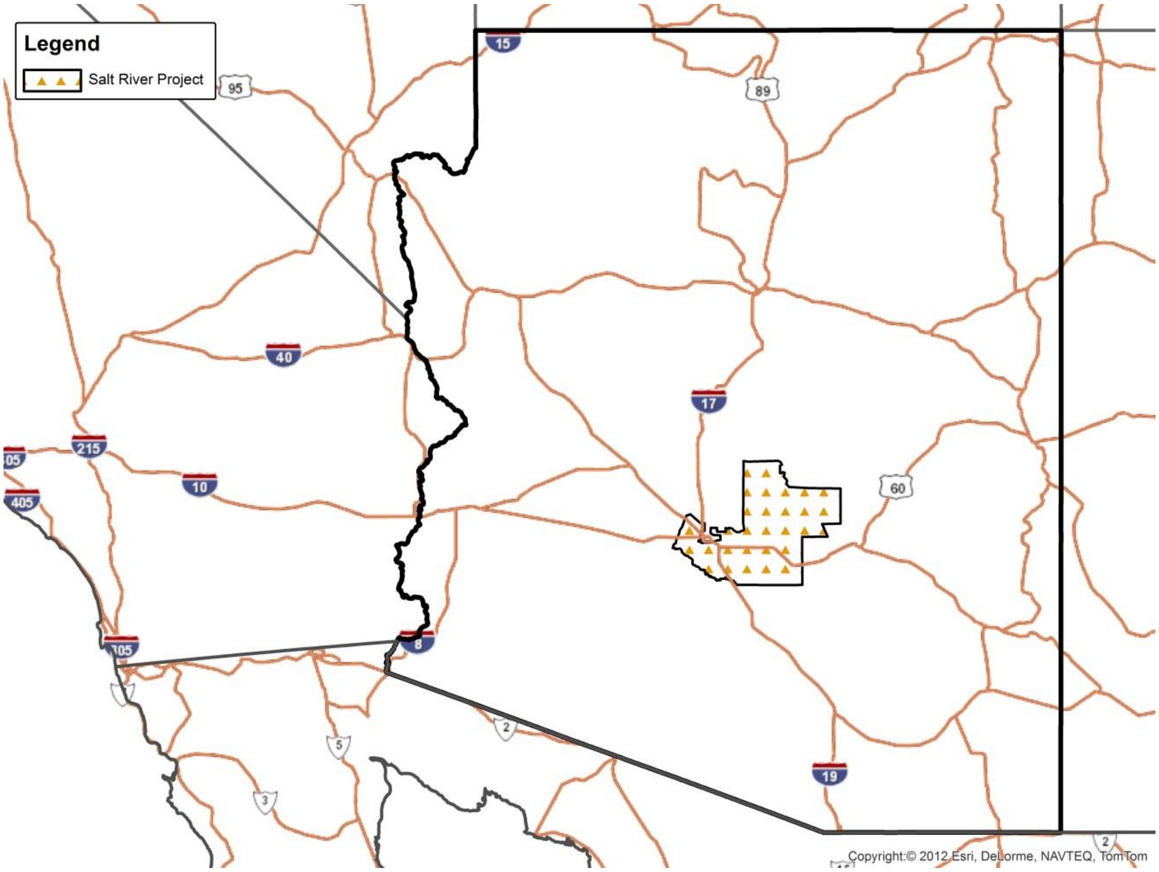
AEPCo owns and operates the Apache generating station in Cochise County, which consists of 350 megawatts of coal-fired generation and 205 megawatts of gas-fired generation. The coal-fired Apache units are also capable of operating on natural gas. In addition, AEPCo has some 30 megawatts of federal hydro allocation, and small amounts of purchased power.

The following chart provides estimated energy production by resource type in 2014.



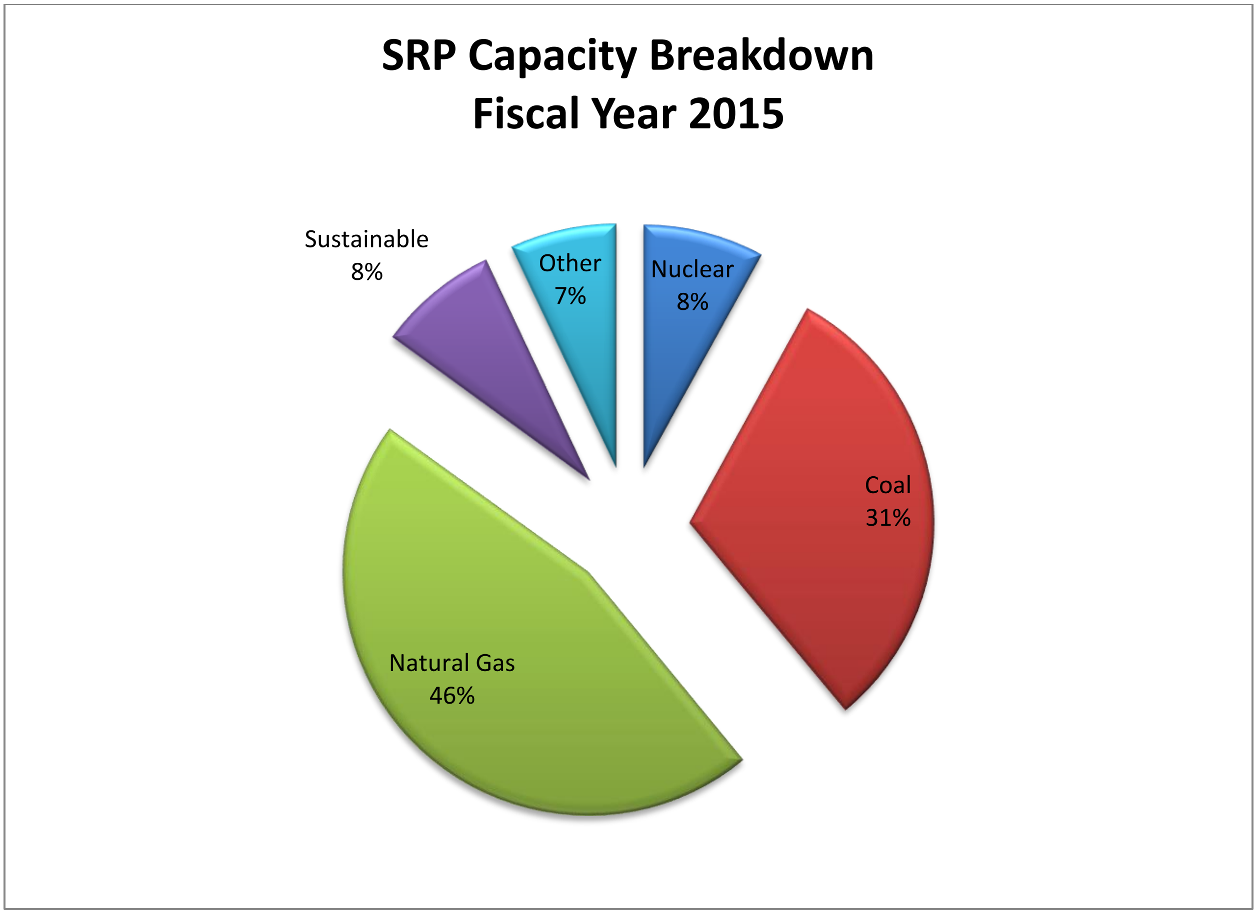
AEPCo does not anticipate significant utilization of the natural gas-fired portion of the Apache station in 2014. As is evident in the energy chart, AEPCo is currently highly dependent on coal generation.

E. Salt River Project ("SRP")



SRP provides electricity to over 950,000 customers in central Arizona, in and near Phoenix. SRP is not subject to the Commission's IRP rules and thus has no obligation to file an IRP with the Commission. SRP was invited to participate in the two IRP public workshops, but respectfully declined to participate. Publicly available information was extracted from SRP's website and SRP voluntarily supplied additional information for this report. SRP experienced a total system peak demand in 2013 of 7,614 megawatts, a retail system peak of 6,567 megawatts, and had installed generating capacity totaling 6,577 megawatts. SRP forecasts for 2014 a retail peak demand of 6,768 megawatts (actual peak demand for 2014 is not yet available).

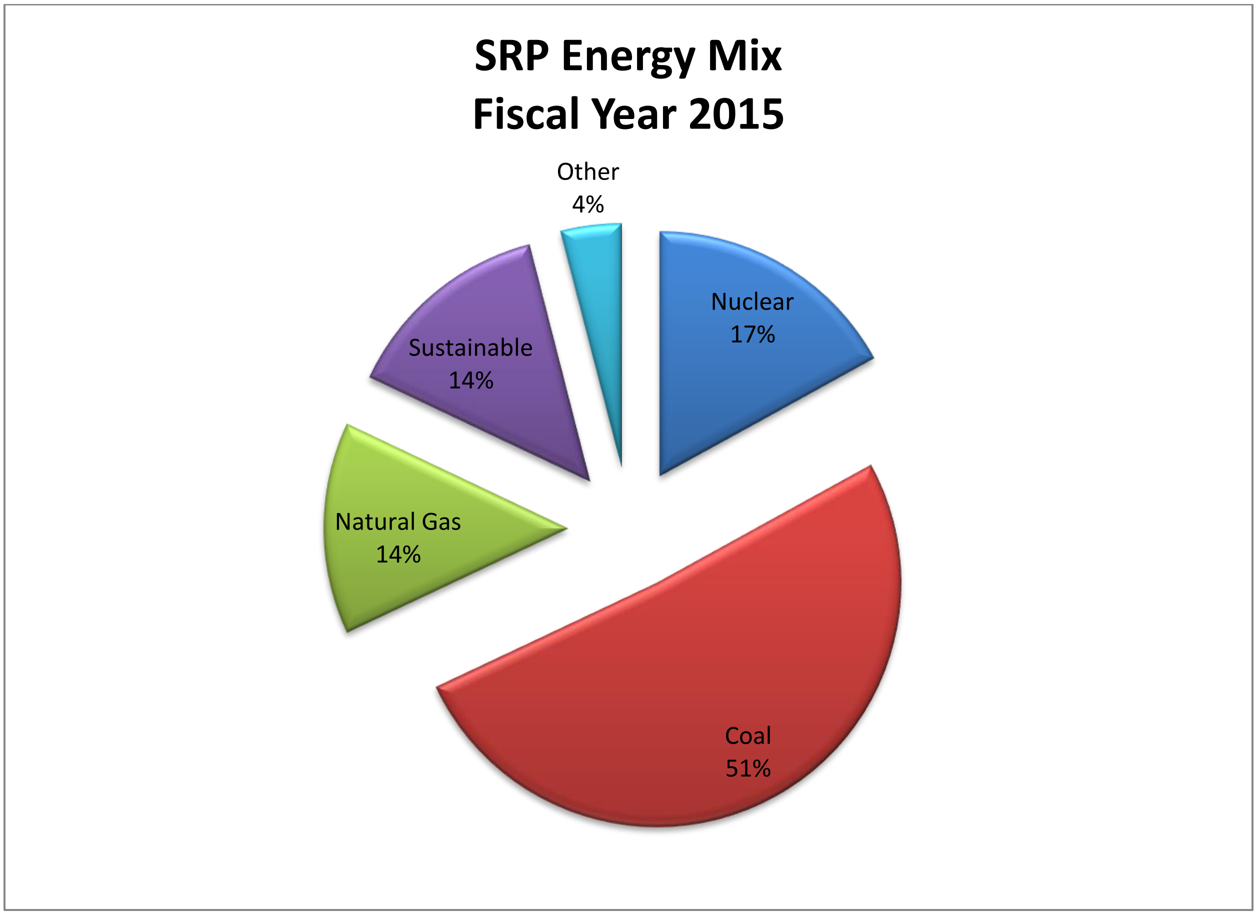
The breakdown of SRP's sources for capacity, based on contribution to system peak demand, is shown in the following chart:



SRP's Fiscal Year 2015 covers the period of May 1, 2014, through April 30, 2015. "Sustainable" generation includes renewable, energy efficiency, demand response and hydro. The "Other" category includes purchased power and Colorado River Storage Project power purchases.

SRP owns and operates the Agua Fria, Kyrene, Desert Basin, and Santan natural gas-fired generating stations, the Coronado coal-fired generating station and several hydro-electric facilities. In addition, SRP is part owner of PVNGS, as well as the Hayden, Navajo, Craig, and Four Corners coal-fired generating stations. SRP also owns Unit 4 of the Springerville coal-fired generating station, purchases a portion of the output of Springerville Unit 3, purchases 100% of the output of the Coolidge gas-fired generating station, and operates the Navajo generating station.

The energy production by resource type is shown in the following chart:



As shown in this chart, SRP's energy mix is weighted heavily towards coal.

III. The Arizona IRPs

A. Load Forecasts

1. Methodology

There are three basic methodologies available for load forecasting – Econometric, End-use and Trending. The econometric method uses regression techniques to forecast energy use and peak demand. A regression approach develops a series of equations that forecast load based on a series of input variables. For example, energy sales can be forecast based on a relationship to other variables such as real disposable income, demographic data, weather patterns, etc.

End-use forecasting is a much more detailed load forecasting method and is essentially a "bottoms-up" approach that builds up a total forecast from individual components, such as the number of residential electric appliances in use. The advantage of end-use forecasting is that it provides valuable information that can be used in the analysis of DSM programs.

The last method, Trending, although popular in the past, is not widely used today. Trending simply develops a forecast from previous growth trends. The following table identifies the load forecasting methodologies employed by the four load-serving entities:

	Econometric	End-use	Trending
APS	Yes	Yes	Yes
TEP	Yes	No	No
UNSE	Yes	No	No
AEPCo	Yes	No	No

APS – APS forecasts the future needs of each customer class separately. For residential customers, APS forecasts the growth in the number of residential customers using a forecasted growth in population, anticipated changes in migration rates, the age distribution of the population, and the regional location of new households. This information is combined with an end-use model that estimates the electricity consumed by each household to arrive at the residential load forecast. An econometric method is utilized to forecast the loads of small commercial and industrial customers (less than 3 megawatts), based on economic growth, occupied floor space, the price of electricity and weather. The forecast for large commercial and industrial customers is developed through interviews with those customers. Finally, the estimated load growth for irrigation and street lighting is based on a trending analysis.

TEP – TEP develops a separate monthly energy forecast for each major rate class – residential, commercial, industrial and mining. For the residential and commercial classes, an econometric approach is utilized, based on historical usage, weather, demographic forecasts and economic conditions. For the industrial and mining classes, individual forecasts are developed for each customer based on historical usage, information from the customers on future expansions of operations, and information from internal company resources working closely with the customers.

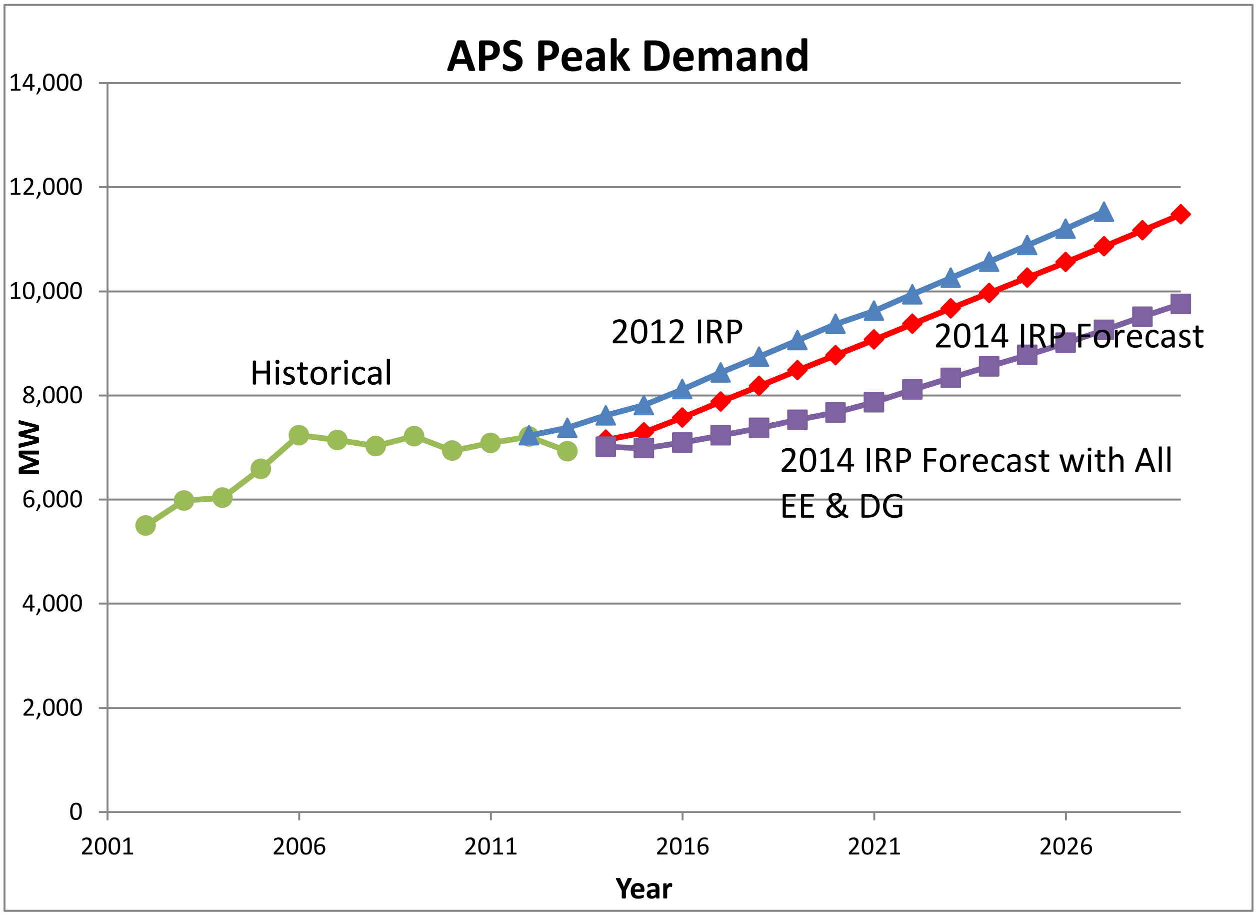
UNSE – UNSE also develops a separate monthly energy forecast for each major rate class, but due to the disparate geographical sections of the UNSE service territory, also develops separate energy forecasts for three geographical areas – Kingman, Havasu City and Mohave. For the residential and commercial classes, an econometric method is applied, based on historical usage, weather, demographic forecasts and economic conditions. The forecasts of the industrial and mining classes are produced for each individual customer and are based on historical usage patterns, information from the customers, and internal company resources.

AEPCo – AEPCo developed individual load forecasts for all six of its member distribution cooperatives, using econometric methods based on population growth, economic activity, energy prices, income levels, weather and demographics. The results of the forecasts were used as stated in Exhibit C to the IRP.

SRP – SRP has not provided any information concerning the methodology used to develop load forecasts.

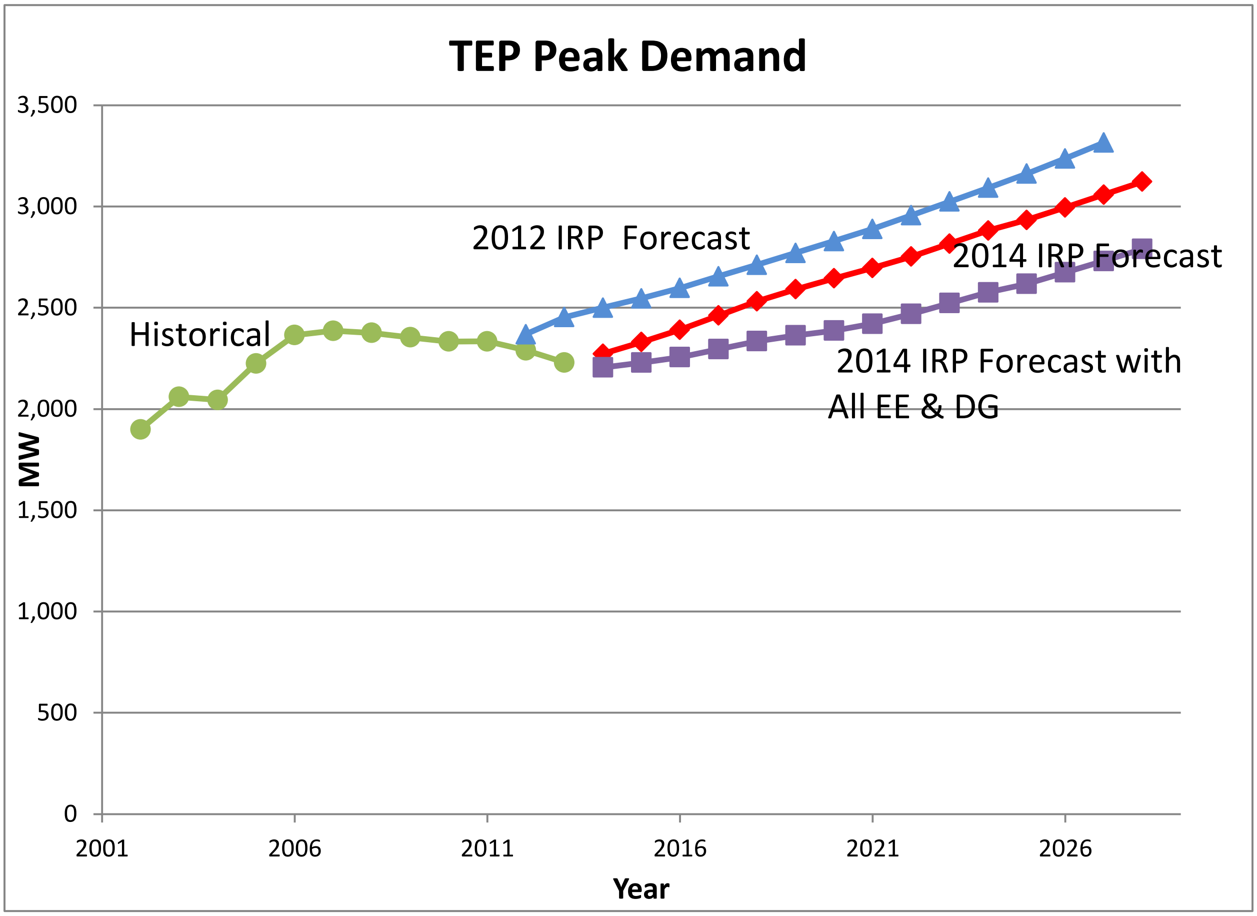
2. Peak Demand Forecasts

The annual forecast of peak demand (the highest one-hour need for electricity) drives each utility's need for additional resources. To maintain reliable service, each utility must maintain sufficient resources to meet the annual peak demand plus reserves. The following charts compare historical peak demands to the forecasted peak demands (prior to the impact of distributed generation and added demand-side programs) from each of the utility's 2012 and 2014 IRPs.

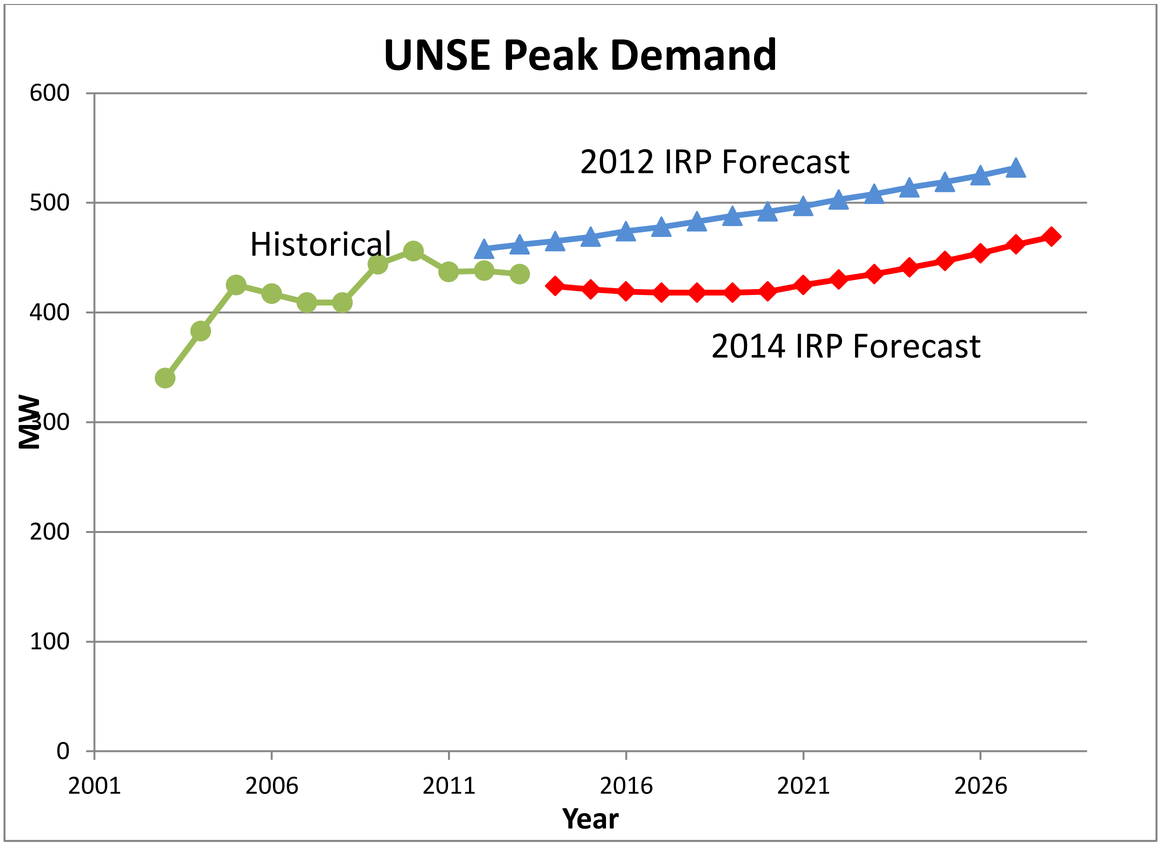


Even though APS experienced negative load growth from 2006 through 2013, the company is forecasting average load growth of more than 3% per year from 2014 through 2029, prior to the impact of new distributed generation and demand-side programs. The 2012 IRP forecast was almost identical to the 2014 forecast, in that it also predicted annual load growth of about 3% per year. APS's load forecast for 2013 was approximately 6.5% higher than its actual load. year. This information indicates that APS' current forecast may be somewhat optimistic, i.e. high.

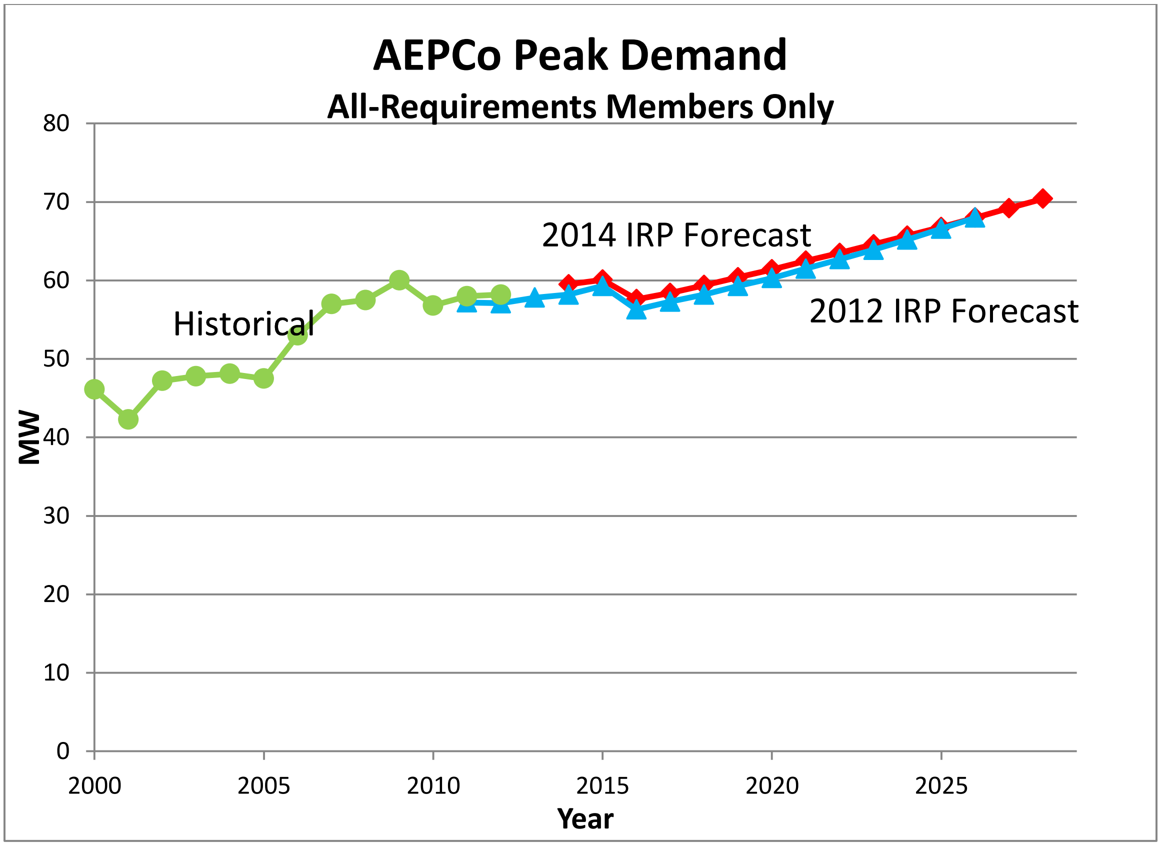
Other information that would also indicate that APS' 2014 forecast is overly optimistic was included in the presentation made by Western Resource Advocates ("WRA") at the first IRP workshop on September 11, 2014. WRA stated that population growth in Arizona has slowed in recent years, and the number of low-income residents in the state has increased.



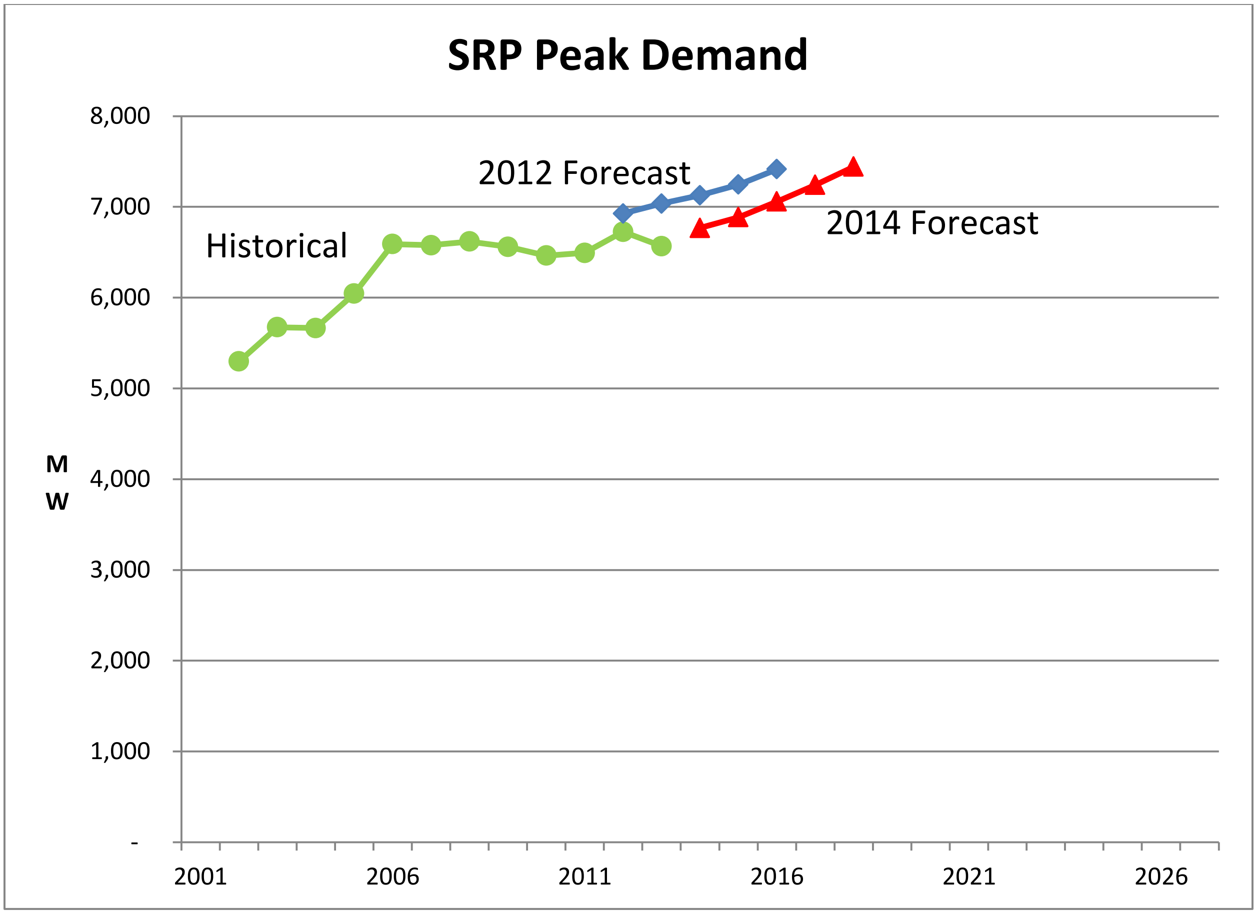
A comparison of the TEP historical peak demand, 2012 IRP forecast and the 2014 IRP forecast is remarkably similar to the comparison of the APS information discussed on the previous page. TEP experienced negative load growth from 2006 through 2013, yet the company now predicts constant future load growth averaging over 2% per year, prior to the impact of new distributed generation and demand-side programs. TEP's load forecast for 2013 was approximately 10% higher than its actual load that year. It appears that the TEP 2014 forecast may also be somewhat optimistic concerning future load growth.



UNSE also experienced negative load growth in recent years, but UNSE's current forecast is predicting no load growth through 2020 and is forecasting an average growth rate of less than 1% per year from 2014 through 2028. UNSE's load forecast for 2013 was approximately 6.2% higher than its actual load that year. UNSE's load forecast also appears somewhat optimistic given recent history.

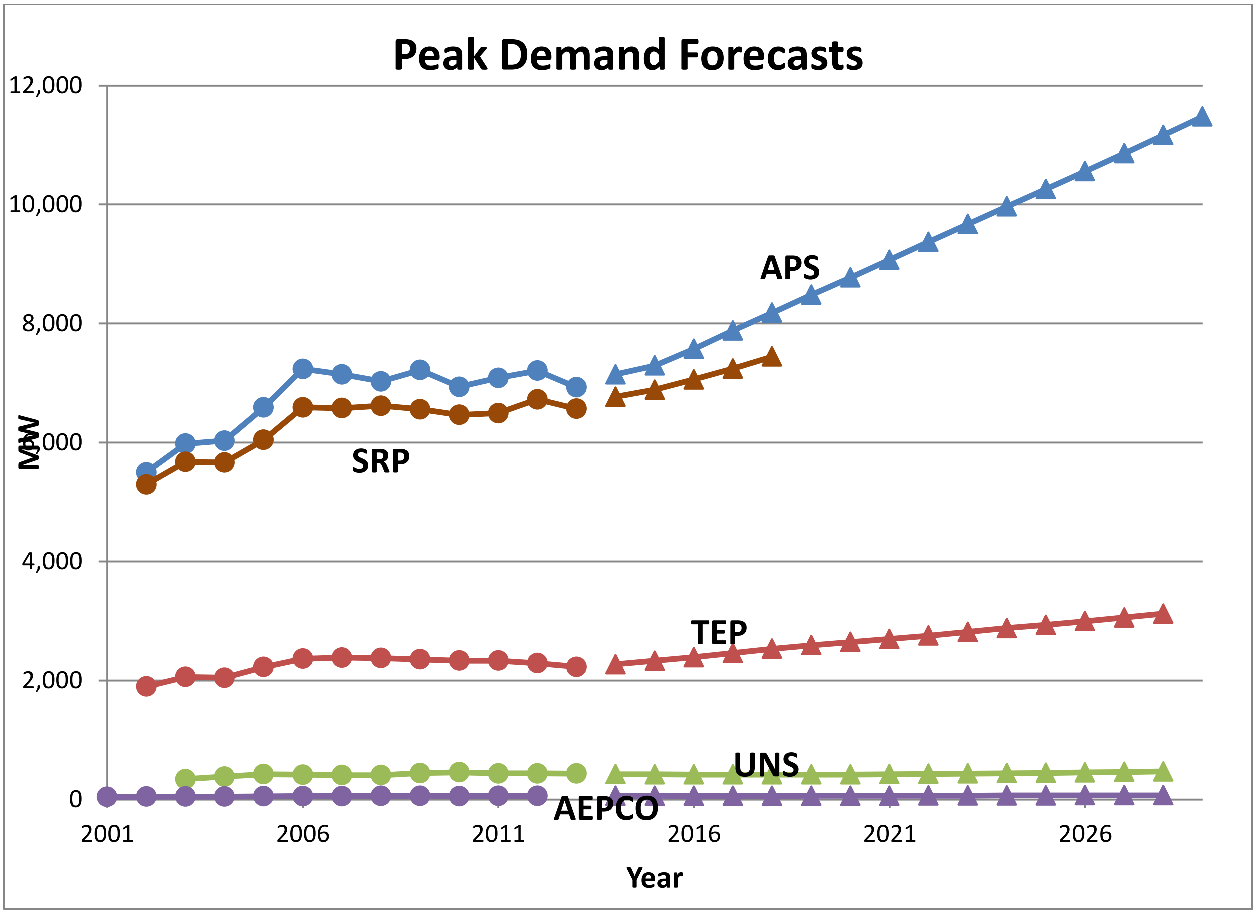


The AEPCo 2014 IRP forecast is only slightly higher than the 2012 IRP forecast, and forecasts an average increase of 1.2% per year. The dip in the 2016 forecasted AEPCo peak demand is due to the loss of certain customers to the City of Safford in that year. AEPCo's forecast appears to be reasonable.



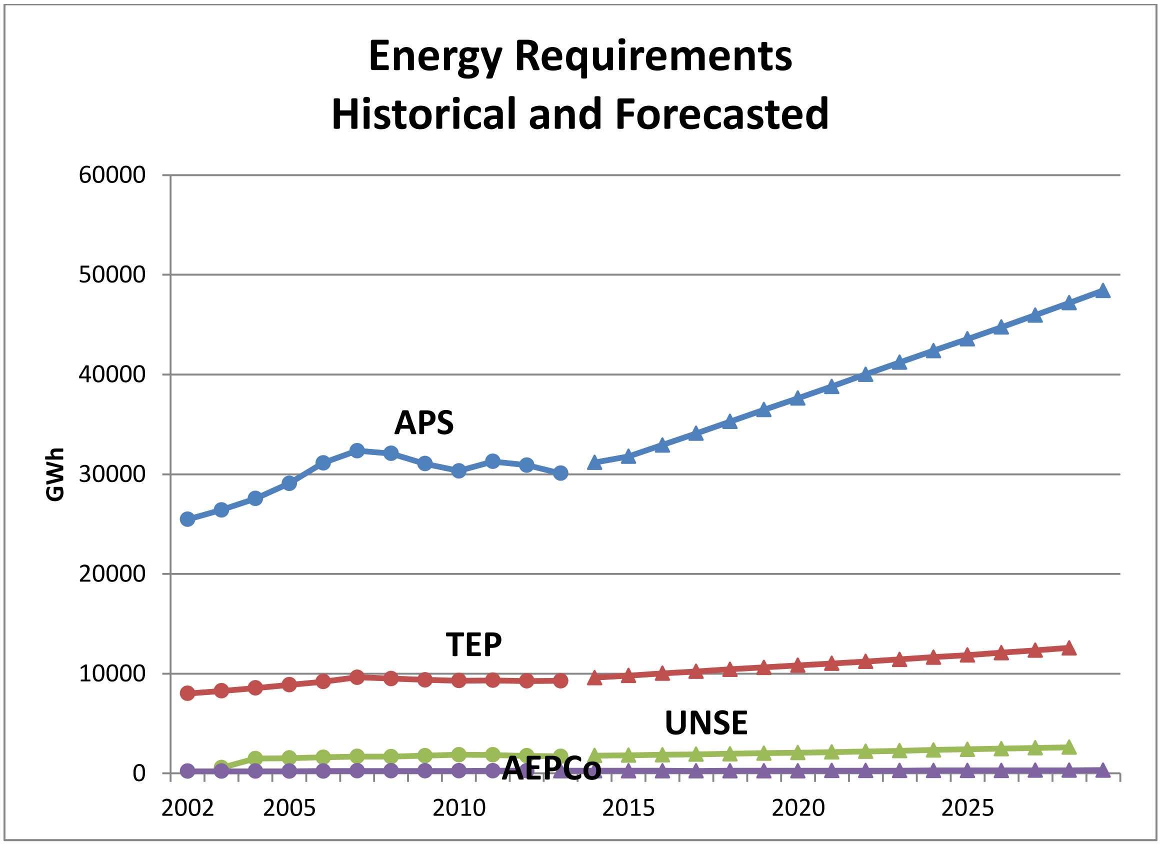
SRP is predicting, for 2014 through 2018, average load growth of approximately 2.5%. Comparing SRP's previous load forecast to the current load forecast, SRP appears to be overly optimistic in predicting future load growth, in a manner similar to APS and TEP. SRP's 2012 forecast appears to have significantly over-estimated the 2013 peak demand.

The following chart displays the historical peak demand data and the peak demand forecasts of the five companies for comparison:


Peak Demand Forecasts
12,000
10,000
8,000
6,000
4,000
2,000
0
MW
2001
2006
2011
2016
2021
2026
Year
APS
SRP
TEP
UNS
AEPCO

3. Annual Requirements Forecasts

The following chart compares the historical and forecasted annual energy requirements of each utility, prior to the impacts of distributed generation and added demand-side programs:

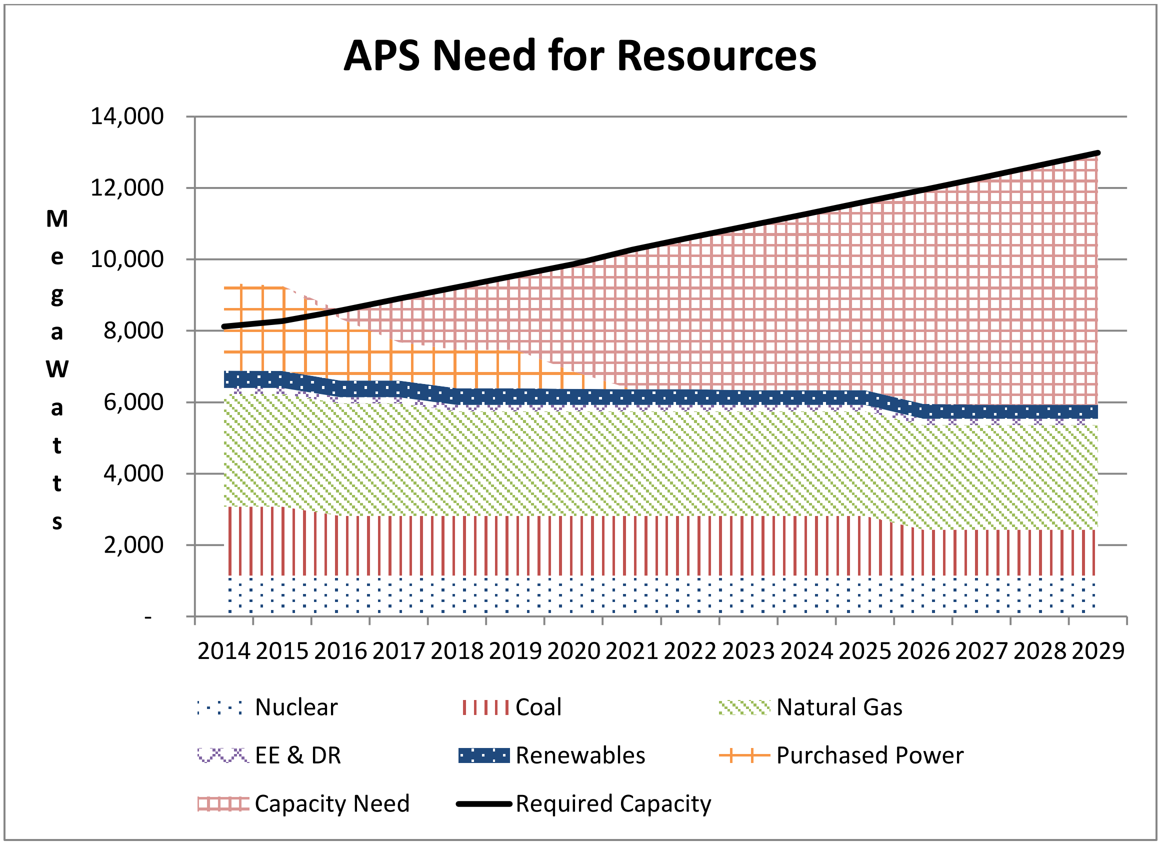


The AEPCo information concerns only AEPCo's all-requirements members.

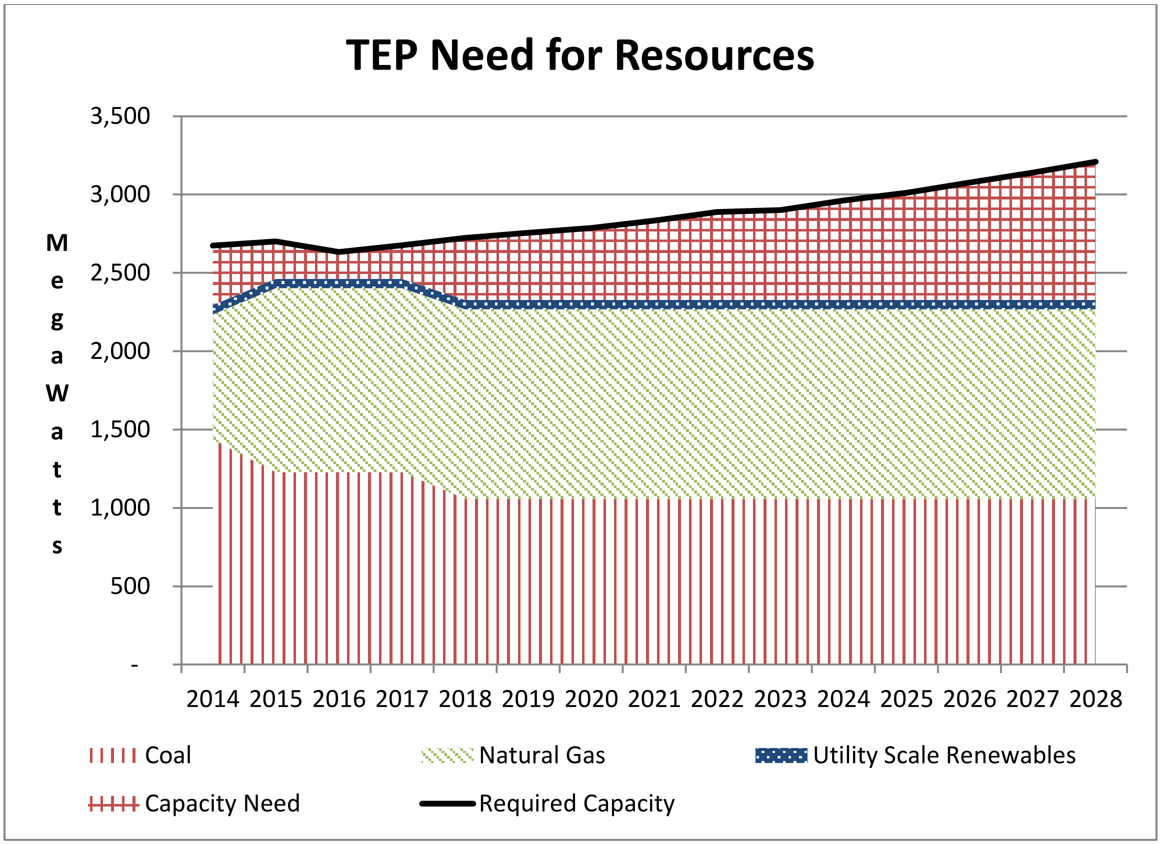
The predicted annual average growth rates for energy are 3.0% for APS, 2.0% for TEP, 2.8% for UNSE and 1.3% for AEPCo.

B. Future Need for Additional Resources

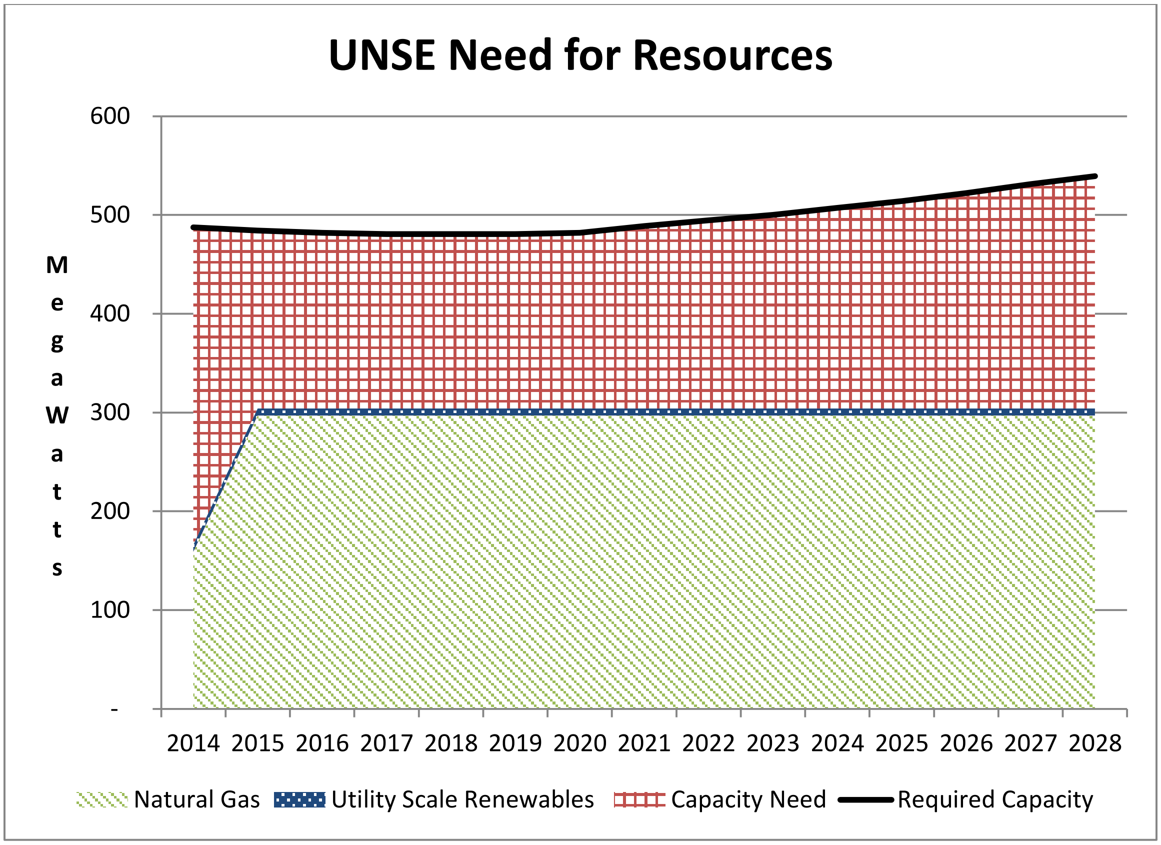
The future need for additional resources for each of the load-serving entities is driven by the annual forecast of peak demand (the highest one-hour need for electricity) and the planning reserve margin. APS, TEP and UNSE each utilize a 15% planning reserve margin, which equates to an additional capacity requirement of 150 megawatts for each 1,000 megawatts of forecasted peak demand. Comparing the on-peak capability of existing resources to the forecasted peak demand plus the planning reserve requirement reveals the need for additional resources for each load-serving entity. The following charts show these needs for each load-serving entity.



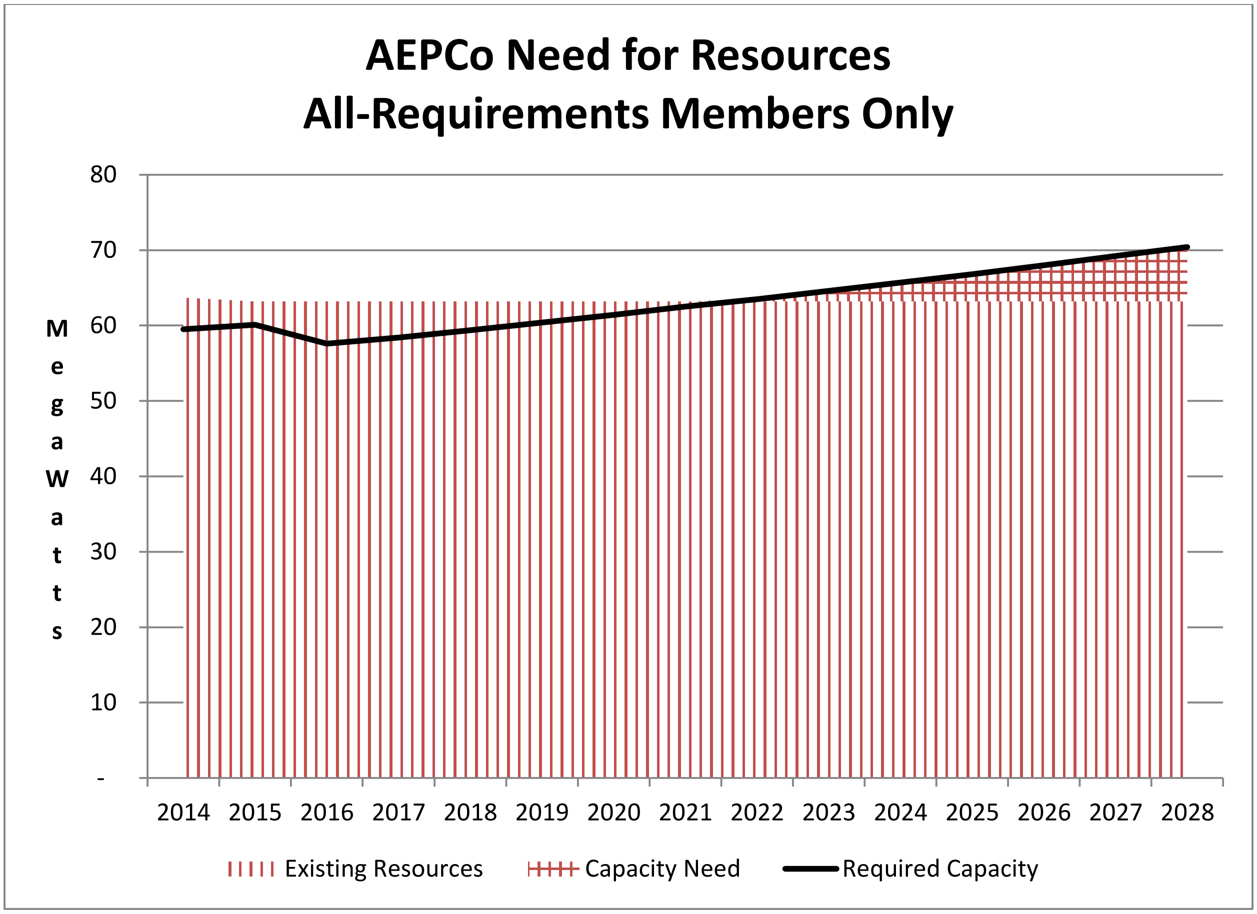
APS does not need additional resources until 2016. APS has call options that expire in 2015 that are contributing to this extra capacity in the near term. After 2015, APS's need for additional resources, based on its optimistic load forecast, grows from over 200 megawatts in 2016 to over 7,000 megawatts in 2029. If APS's load forecast were only 2.5%, like SRP's, then it would need only 133 megawatts in 2016, and it would need less than 6,000 megawatts in 2029.



Based on its annual two percent load growth forecast, TEP has needs for additional resources in all years of the planning period, growing from 379 megawatts in 2014 to 882 megawatts in 2028. TEP has entered into an agreement to purchase capacity from the Gila River Combined Cycle facility, which will provide 374 megawatts of gas-fired capacity beginning in 2015. The Gila River capacity is included in the chart.



UNSE also shows a need for additional resources in all years, starting at 322 megawatts in 2014 and declining to 235 megawatts in 2028. UNSE has entered into an agreement to acquire capacity from the Gila River Combined Cycle facility, which will provide 138 megawatts of gas-fired capacity beginning in 2015. The Gila River capacity is included in the chart.



AEPCo has a small surplus of capacity through 2021, followed by a small need for additional capacity that grows to seven megawatts by 2028.

C. Demand-Side Options

1. General Considerations

The Commission's rules require, in part, that each load-serving entity select a portfolio of resources based upon comprehensive consideration of a wide range of supply-side and demand-side options[12]. Demand-side options are generally grouped into two main categories – energy efficiency ("EE") and load management or demand response ("DR"). EE programs reduce electricity usage throughout the year through programs that, for example, incent homeowners to replace older air conditioning systems with new more efficient systems. DR programs, on the other hand, target the critical periods when electricity usage is highest and provide the customers of the jurisdictional load-serving entity with incentives to reduce the usage on peak as, for example, with time-of-use price plans that send higher price signals during on-peak hours and programs that allow the load-serving entity to reduce the usage of residential air conditioning during on-peak hours. Distributed generation or customer-owned generation can also be considered a demand-side option, but will be discussed in a separate section of this report.

Each load-serving entity is required to attain certain levels of annual energy savings from demand-side options, expressed as a percentage of retail energy sales in the prior calendar year. The required percentages begin at 3% in 2012 and increase annually to 22% in 2020.

2. DSM Cost Effectiveness

The Commission's rules require that each selected DSM program be cost-effective according to the "Societal Test"[13]. The Societal Test is a ratio defined as follows:

Societal Test = (Program Benefits) / (Program Costs)

If program benefits exceed program costs, the Societal Test will be greater than one, meaning the program is cost-effective. Program benefits include avoided supply-side capacity costs, avoided supply-side operating costs (including fuel costs) and monetized societal benefits (to the extent practical), such as avoided air pollution and avoided water usage. Program costs include utility costs to implement and administer the program, participant costs to partake in the program and monetized societal costs (if any).

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[12] A.A.C. R14-2-703(F)(1).
[13] A.A.C. R14-2-2412

3. DSM Programs Considered

The following table shows the EE programs considered by each load-serving entity during the development of the 2014 IRPs. For SRP, the programs shown are those considered and currently offered by SRP. Because AEPCo does not have retail customers, AEPCo does not offer EE programs. However, the load forecasts for AEPCo's member cooperatives reflect the impacts of EE programs deployed by AEPCo's member cooperatives.

Energy Efficiency Programs Considered and Selected

	APS	TEP	UNSE	SRP
Residential Programs				
Consumer Products	◆			◆
Existing Homes HVAC	◆	◆	◆	◆
New Construction	◆	◆	◆	◆
Home Performance with Energy Star	◆			
Appliance Recycling	◆			◆
Low Income Weatherization	◆	◆	◆	◆
Conservation Behavior Pilot	◆			◆
Multi-Family Construction	◆			☒
Shade Tree	◆	◆	◆	◆
Codes and Standards	◆			
Energy Star CFL Buy-Down		◆	◆	
Clothes Washers	☒			☒
Heat Pump Water Heaters	☒			☒
Evaporative Cooled Air Conditioners	☒			
Energy Star Refrigerators	☒			
Window Film	☒			
Home Energy Reports				◆
Education and Outreach		◆	◆	◆
Energy Codes Enhancement Program				◆
Residential Energy Financing				◆
SEER Air Conditioners				◆
LED Christmas Lights	☒			◆
Thermostatic-Controlled Showerheads	☒			◆
Home Energy Information		◆	◆	◆
Non-Residential Programs				
Large Existing Facilities	◆	◆	◆	◆
New Construction	◆	◆	◆	◆
Small Business	◆	◆	◆	◆
Schools	◆			◆
Energy Information Systems	◆			◆
Window Films	☒			◆
Gaskets	◆			◆
Retro-Commissioning				◆
Compressed Air Solutions	◆			◆

◆ Included in IRP

☒ Considered but rejected

The following table shows the DR programs considered by each load-serving entity in the development of the 2012 IRPs. For SRP, the programs shown are those considered and currently offered by SRP.

Demand Response Programs Considered and Selected	APS	TEP	UNSE	SRP
Residential Programs				
Direct Load Control	◆			
Time of Use Rates	◆			◆
Non-Residential Programs				
APS Peak Solutions	◆			
Interruptible Rates	◆			◆
Direct Load Control	◆	◆	◆	◆
Time of Use Rates	◆			◆
◆ Included in IRP				
⊠ Considered but rejected				

Because AEPCo does not have retail customers, AEPCo does not offer DR programs. However, the load forecasts for AEPCo's member cooperatives reflect the impacts of DR programs deployed by AEPCo's member cooperatives.

D. Supply-Side Options

1. Options Considered

The following table lists the supply-side options that were considered by APS, TEP, UNSE and AEPCo. AEPCo only considered short-term purchased power as a supply-side option.

SRP only discusses the additional resources it plans to add in 2014 through 2018. In these years, SRP plans to add additional short-term purchases and additional renewable resources.

Supply-Side Options Considered	APS	TEP	UNSE	AEPCo
Renewable Technologies:				
Wind Turbines	◆	◆	◆	
Solar Photovoltaic Fixed	◆	◆	◆	
Solar Photovoltaic Single-Axis Tracking	◆	◆	◆	
Solar Trough Concentrating without Storage	◆			
Solar Trough Concentrating with Storage	◆			
Solar Power Tower with Storage	◆			
CSP Hybrid Cooled with Storage		◆	◆	
CSP Hybrid Cooled without Storage		◆	◆	
Geothermal	◆			
Biomass	◆	◆	◆	
Biogas	◆			
Natural Gas-Fired Generation				
Combustion Turbine - GE 7FA	◆	◆	◆	
Combustion Turbine - GE LMS100	◆	◆	◆	
Combustion Turbine - GE LM6000	◆	◆	◆	
Combined Cycle	◆	◆	◆	
Coal-Fired Generation				
Sub-critical Pulverized Coal	◆	◆	◆	
Integrated Gasification Combined Cycle	◆	◆	◆	
Nuclear Generation				
Nuclear Generation	◆	◆	◆	
Energy Storage				
Pumped Hydro	◆	◆	◆	
Compressed Air Energy Storage	◆	◆	◆	
Batteries	◆	◆	◆	
Flywheels	◆	◆	◆	
Ultracapacitors		◆	◆	
Fuel Cells		◆	◆	
Purchased Power				
Long-Term	◆	◆	◆	
Short-Term	◆	◆	◆	◆

2. Cost Assumptions

The following table compares the capital cost assumptions utilized by APS, TEP and UNSE for the various supply-side options. AEPCo did not consider the addition of new generating facilities.

There are significant differences in the assumed capital costs for many of the supply-side additions. For example, TEP's and UNSE's estimated capital cost for new nuclear generation is 48% higher than APS's estimated cost, and TEP's and UNSE's estimated capital cost for solar photovoltaic single tracking facilities is 58% higher than APS's estimated cost. It is unclear why such significant differences exist, but the situation adds strength to the argument that the utilities should seriously consider joint planning of new generating facilities.

Assumed Costs - Supply-Side Options *($/KW)*			
	APS	**TEP**	**UNSE**
Renewable Technologies:			
Wind Turbines	$2,200	$2,278	$2,278
Solar Photovoltaic Fixed	$1,754	$1,993	$1,993
Solar Photovoltaic Single-Axis Tracking	$2,098	$3,313	$3,313
Solar Trough Concentrating without Storage	$4,458		
Solar Trough Concentrating with Storage	$7,782		
Solar Power Tower with Storage	$8,265		
CSP Hybrid Cooled with Storage		$5,591	$5,591
CSP Hybrid Cooled without Storage		$7,144	$7,144
Geothermal	$4,880		
Biomass	$2,157	$3,624	$3,624
Biogas	$2,513		
Natural Gas-Fired Generation			
Combustion Turbine - GE 7FA	$701	$808	$808
Combustion Turbine - GE LMS100	$1,106	$1,243	$1,243
Combustion Turbine - GE LM6000	$1,224	$1,062	$1,062
Combined Cycle	$910	$1,367	$1,367
Coal-Fired Generation			
Sub-critical Pulverized Coal	$2,852	$4,144	$4,144
Integrated Gasification Combined Cycle	$4,676	$6,523	$6,523
Nuclear Generation			
Small Modular Reactors	$5,530	$8,210	$8,210
Energy Storage			
Pumped Hydro	$2,600		
Compressed Air Energy Storage	$2,778	$1,703	$1,703
Batteries	$2,750		
Flywheels	$8,300		

E. Distributed Renewable Generation

The following table shows the options considered by each load-serving entity for distributed renewable generation.

Distributed Renewable Options Considered				
	APS	TEP	UNSE	SRP
Solar Hot Water	◆	◆	◆	◆
Solar Photovoltaic	◆	◆	◆	◆
Small Hydro				◆
Small Wind	◆			
Geothermal Heat Pumps	◆			

APS offers the widest array of distributed renewable generation options. AEPCo does not discuss distributed renewable generation in its IRP because under Commission Rules, AEPCo is not involved in determining distributed renewable programs at the retail level. That function is reserved to its members by R14-2-1814.

F. Assumptions

1. Basic Assumptions

The following table shows the basic assumptions made by APS, TEP and UNSE. AEPCo did not provide this information in its IRP filing.

	APS	TEP	UNSE
Planning Reserve Margin	15%	15%	15%
Inflation	2.5%	2.5%	2.5%
Wind Integration Cost per MWh	$3.25	$1.40	$4.50
Solar PV Integration Costs per MWh	$2.00	$5.20	$7.60
Solar CSP Integration Costs per MWh		$3.80	$5.55

The Planning Reserve Margin establishes the utility's need to install resources above and beyond the annual peak demand for electricity. For example, if a utility expects an annual peak demand of 1,000 megawatts and has assumed a 15% reserve margin, the utility must plan to install resources that can supply 1,150 megawatts (the peak demand plus 15% of the peak demand). The Planning Reserve Margin generally covers the unexpected loss of generating resources and excessive peak demand caused by unusual weather. All three load-serving entities have established a planning reserve margin of 15%, which is a reasonable level for planning reserve margin. The reserve margins are unchanged from the 2012 IRPs.

All three load-serving entities have assumed a rate of inflation at 2.5%, which is also a reasonable assumption. Actual inflation over the last five years averaged 2.07%. The assumed rates of inflation are also unchanged from the 2012 IRPs.

Differences arise in the assumed Wind Integration Cost and assumed Solar Integration Costs. These integration costs are estimates of the cost to assimilate the intermittent generation from wind and solar facilities into the generation system. For example, if the wind should unexpectedly cease at a wind facility, the controllable generating resources (which are generally the fossil fuel resources) must quickly increase the production of electricity to replace the unexpected loss in wind energy. Wind and solar facilities can cause added stress on fossil fuel resources, and in some cases, require the utility to carry additional operating reserves. These integration costs are added to the operating costs of wind and solar facilities.

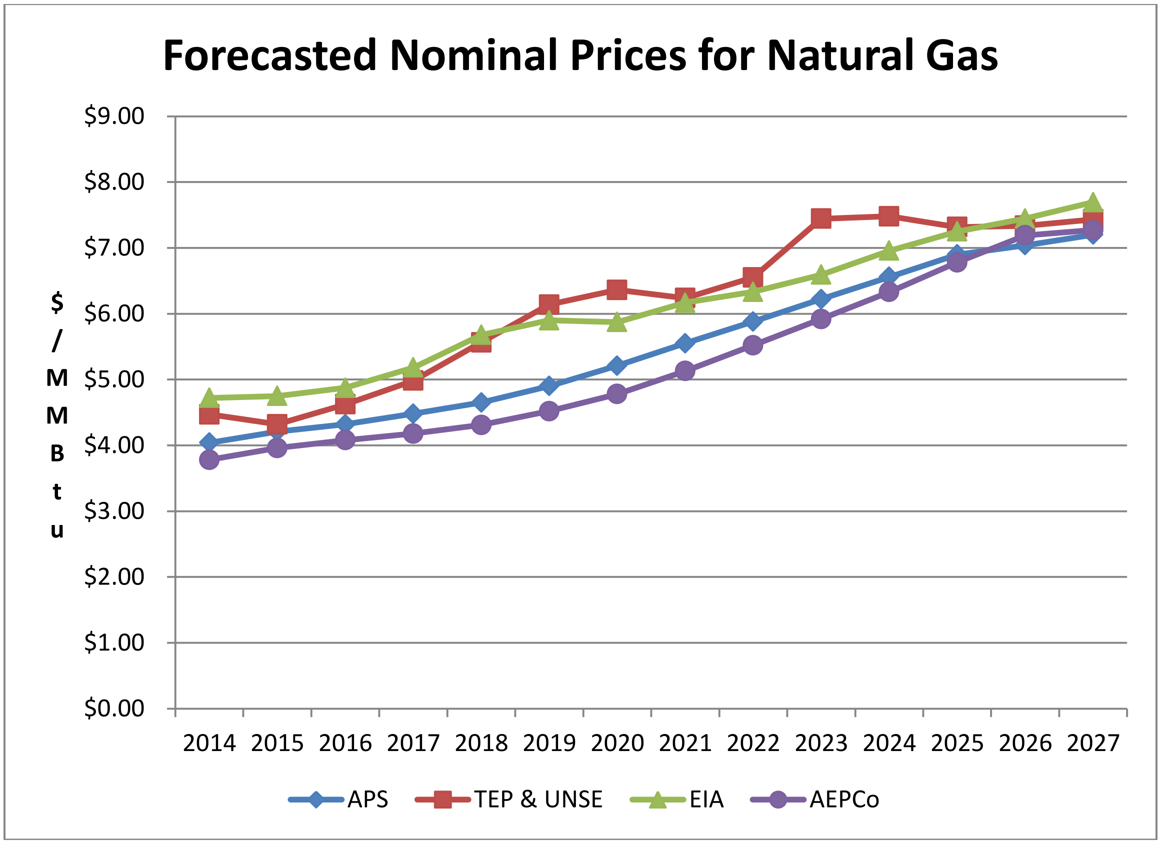
For wind integration costs, APS continues to rely on the APS Wind Integration Cost Impact Study conducted by Northern Arizona University in September 2007. For solar integration costs, APS now relies on a more recent study performed by Black & Veatch in

November 2012, the “Solar Photovoltaic (PV) Integration Cost Study” specific to the APS system. APS’s revised solar integration costs are $0.50 per MWh lower than the solar integration costs used in APS’s 2012 IRP. TEP and UNSE developed new wind and solar integration costs using the AuroraXMP model, specific to each system. The revised wind integration costs for TEP and UNSE are lower than those used in the 2012 IRPs, while the revised solar integration costs are higher than those used in the 2012 IRPs.

Because solar and wind integration costs depend to a large extent on current local conditions – wind patterns in the area, local fossil generation mix, local penetration levels of intermittent resources, etc., it is important to utilize integration costs that reflect the characteristics of each individual load-serving entity. The integration costs used in the 2014 IRPs now satisfy this requirement.

2. Natural Gas Price Forecasts

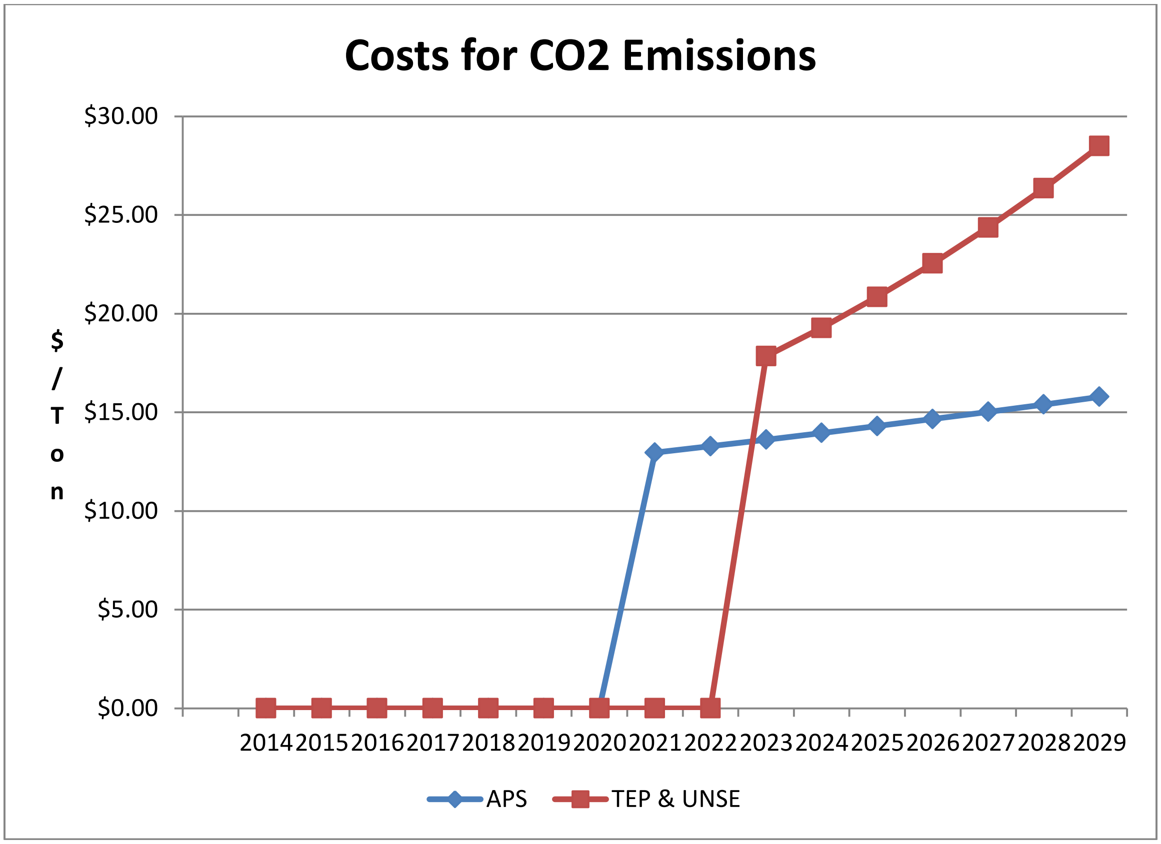
A critical assumption of IRP is the projected cost of natural gas. The base forecasted costs of natural gas utilized by APS, TEP, UNSE and AEPCo are shown in the following chart, along with the current base forecast by the Energy Information Administration ("EIA") from the EIA Annual Energy Outlook 2014.



The projections by APS, TEP, UNSE and AEPCo appear reasonable, when compared to the EIA forecast. In addition to this base forecast for natural gas, APS, TEP and UNSE also considered higher than base and lower than base forecasts as part of their risk and sensitivity analyses.

3. CO2 Emission Cost Forecasts

Although it is still unknown whether CO2 emissions will be taxed in the future, it is reasonable to assume that such taxes will be implemented over time. APS, TEP and UNSE each assume that CO2 taxes will materialize in the future. The following chart compares the timing and prices assumed for the taxation of CO2 emissions. AEPCo did not provide this information in its IRP.



The assumed timing and pricing for the taxing of CO2 emissions by the utilities represents a reasonable estimate. APS, TEP and UNSE also analyzed lower and higher CO2 taxes as part of their risk analyses.

4. Retirements

Both TEP and APS are including the retirement of generating facilities as base assumptions in their IRPs.

TEP decided in August 2013 to reduce its commitment in the coal-fired Springerville Unit 1 from 387 megawatts to 190 megawatts. In addition, due to environmental compliance issues, TEP plans to reduce its coal capacity at the San Juan generating station from 340 megawatts to 170 megawatts.

APS has assumed the retirement of the existing steam units at the Ocotillo plant, which now provide 220 megawatts of capacity. In addition, the Company assumes the retirement of the Cholla Unit 2 coal-fired generating unit in April of 2016, to avoid substantial environmental upgrade costs. Unit 2 currently provides 260 megawatts of capacity. The APS IRP also assumes that Cholla Units 1 and 3 will be retired in 2025, although APS is reserving the right to consider the conversion of those two units to natural gas, should that option provide savings.

G. Software Tools for IRP Selection

The selection of a “best” mix of demand-side and supply-side resources to form an IRP is a complex task. In most cases, the possibilities number in the thousands or even millions. Sifting through all the myriad possibilities to select an IRP under just one set of assumptions is a difficult task. But the selection must be repeated many times over during the risk and sensitivity analyses. Electric utilities generally utilize a software tool to perform the selection process.

TEP and UNSE both used two software tools – “Capacity Expansion” and “Planning & Risk”. These tools were also used by TEP and UNSE in the development of their 2012 IRPs. In the development of its 2012 IRP, APS selected “best” IRPs using a manual process. For the 2014 IRP, APS utilized PROMOD IV and Strategist. The APS, TEP and UNSE software tools for IRP development are well known, industry-standard tools.

H. IRP Development

1. APS

APS considered four specific expansion plans, or portfolios, which were developed using Strategist, and performed risk and sensitivity analyses on these four portfolios. All portfolios assumed the modernization of the Ocotillo plant, which results in the retirement of 220 megawatts of aging gas-fired steam units and the addition of 510 megawatts of new combustion turbine gas-fired capacity, for a net increase of 290 megawatts.

- Base Portfolio
  - Continue existing coal operations
  - 4,205 megawatts of natural gas-fired CTs and CCs added in 2017-2029
- Enhanced Renewable Portfolio
  - Continue existing coal operations
  - Additional 210 megawatts of renewable generation over Base Portfolio
  - 4,001 megawatts of natural-gas fired CTs and CCs added in 2017-2029
- Coal Reduction Portfolio
  - Retire Cholla Unit 2 in April of 2016
  - Retire Cholla Units 1 and 3 in the mid 2020's
  - 4,817 megawatts of natural gas-fired CTs and CCs added in 2017-2029
- Coal-to-Gas Portfolio
  - Convert Cholla units 1, 2 and 3 to natural gas in 2016 and 2017
  - 4,205 megawatts of natural gas-fired CTs and CCs added in 2016-2029

Each of the four portfolios meets or exceeds the EE, Renewable Energy and Distributed Energy requirements of the Commission.

APS performed a scenario analysis to assess the economic risk associated with each of the portfolios. Six scenarios were developed, each having differing assumptions concerning the following:

- Forecasted natural gas prices
- Forecasted CO2 prices
- Capital costs
- Renewable Tax Credits
- Environmental policy
- Inflation
- Load growth
- Energy efficiency
- Distributed generation
- Interest rates

The six scenarios are:

- Current Path
- Gas Dominates
- Sustained High Gas Price
- Increased Environmental Policy
- Economic Contraction
- Economic Boom

Each portfolio was evaluated under each of the six scenarios to find the portfolio that provides the best value under changing futures.

1. TEP

In the development of its IRP, TEP developed a Reference Case and four alternative cases for further evaluation:

- Reference Case
  - 200 to 400 megawatts of short-term market purchases in 2014-2018
  - Springerville Unit 1 coal-fired capacity reduced from 380 to 190 megawatts
  - San Juan coal-fired capacity reduced from 340 to 170 megawatts
  - Sundt Unit 4 coal-fired unit converted to natural gas
  - Acquire 374 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
  - 820 megawatts of natural gas-fired CCs and CTs added in 2019-2028
  - 50 megawatts of storage capacity (possibly batteries) added in 2019-2028
- Full Coal Retirement Case
  - All coal-fired capacity retired
  - 125 to 400 megawatts of short-term market purchases in 2014-2018
  - Acquire 374 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
  - 1,920 megawatts of natural gas-fired CCs and CTs added in 2018-2028
  - 50 megawatts of storage capacity (possibly batteries) added in 2019-2028
- Market Based Case
  - 125 to 450 megawatts of short-term market purchases in 2014-2028
  - Springerville Unit 1 coal-fired capacity reduced from 380 to 190 megawatts
  - San Juan coal-fired capacity reduced from 340 to 170 megawatts
  - Sundt Unit 4 coal-fired unit converted to natural gas
  - Acquire 374 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
  - 270 megawatts of natural gas-fired CCs and CTs added in 2019-2028
  - 50 megawatts of storage capacity (possibly batteries) added in 2019-2028
- Coal Plant Retrofit Case
  - 325 to 450 megawatts of short-term market purchases in 2014-2028
  - Retain all existing coal-fired capacity, and retrofit as required by environmental regulations

- 820 megawatts of natural gas-fired CCs and CTs added in 2019-2028
- 50 megawatts of storage capacity (possibly batteries) added in 2019-2028

- High Renewable Case
  - Add utility scale renewables to serve 25% of retail load
  - 200 to 400 megawatts of short-term market purchases in 2014-2018
  - Springerville Unit 1 coal-fired capacity reduced from 380 to 190 megawatts
  - San Juan coal-fired capacity reduced from 340 to 170 megawatts
  - Sundt Unit 4 coal-fired unit converted to natural gas
  - Acquire 374 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
  - 865 megawatts of natural gas-fired CCs and CTs added in 2019-2028
  - 80 megawatts of storage capacity (possibly batteries) added in 2019-2028

Each of the five cases meets or exceeds the EE, Renewable Energy and Distributed Energy requirements of the Commission.

TEP evaluated each of these five cases using base assumptions and then subjected each to a computerized risk analysis. In the risk analysis, each case was evaluated against a set of 100 possible futures, each with a set of correlated assumptions regarding natural gas prices, wholesale power prices, and retail loads. TEP then developed risk profiles for each case to evaluate the robustness of each case considering the range of potential futures.

2. UNSE

In the development of its IRP, UNSE developed a Reference Case and three alternative cases for detailed analysis:

- Reference Case
  - 150-325 megawatts of short-term market power added in 2014-2018
  - Acquire 138 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
  - 111 megawatts of natural gas-fired CTs added in 2019
  - 2 megawatts of storage resources (possibly batteries) added in 2019-2028
- Future Combined Cycle Case
  - 150-325 megawatts of short-term market power added in 2014-2018
  - Acquire 138 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
  - 100 megawatts of natural gas-fired CC added in 2019
  - 2 megawatts of storage resources (possibly batteries) added in 2019-2028
- Market Based Case
  - 100-300 megawatts of market power added in 2014-2028
  - Acquire 138 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
  - 21 megawatts of natural gas-fired CT added in 2019
  - 2 megawatts of storage resources (possibly batteries) added in 2019-2028

- High Renewable Case
    - Add utility scale renewables to serve 25% of retail load
    - 150-325 megawatts of short-term market power added in 2014-2018
    - Acquire 138 megawatts of the Gila River natural gas-fired combined cycle plant in 2015
    - 111 megawatts of natural gas-fired CTs added in 2019
    - 2 megawatts of storage resources (possibly batteries) added in 2019-2028

Each of the four cases meets or exceeds the EE, Renewable Energy and Distributed Energy requirements of the Commission.

UNSE evaluated each of these five cases using base assumptions and then subjected each to a computerized risk analysis. In the risk analysis, each case was evaluated against a set of 100 possible futures, each with a set of correlated assumptions regarding natural gas prices, wholesale power prices, and retail loads. UNSE then developed risk profiles for each case to evaluate the robustness of each case considering the range of potential futures.

I. Transmission Considerations

The transmission requirements within the IRP process of the Commission stipulate that each load-serving entity will provide "[a]n 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 [("BTA")] decision regarding the adequacy of transmission facilities in Arizona."[14] The most recently completed BTA is for the period 2014-2023. The 8th Biennial Transmission Assessment was approved by the Commission on October 16, 2014, in Decision No. 74785.[15]

Each of the four load-serving entities, as well as SRP, make an annual transmission filing with the Commission. These filings (along with those of other transmission providers in Arizona) are assessed biennially by the Commission, with the 7th BTA being the most recent at the time of the IRP filings. In addition, transmission needs must be filed as a part of each utility' IRP filings. As a result of variables discussed above such as economic outlook, regulatory frameworks, etc., the plans analyzed in the 7th BTA, the information filed in annual transmission plans, and information provided in the respective IRP's are not totally consistent. However, these variations in plans may be expected given the regulatory uncertainties existing with EPA regulations on power plant emissions affecting decisions on new resources and the economic downturn of the last six years. This is evidenced by the delay in constructing a number of lines or increasing the capacity of certain lines. Each of the four load-serving entities fully meets the filing requirements of the IRP.

The transmission system within Arizona is a robust and reliable system due to the significant planning processes in effect. The BTA, the annual transmission filings to the Commission and the regional planning processes provide assurances the backbone of the transmission system continues to provide safe and reliable transmission of power within and "wheeled" throughout Arizona. In-depth review of a utility's transmission plans or a specific transmission project can be accessed by visiting the BTA report or the annual transmission plans filed with the Commission at:

http://www.azcc.gov/divisions/utilities/electric/biennial.asp

1. General Transmission Recommendations

The current transmission analysis and policy provisions of the Commission provide a comprehensive and robust assessment of transmission current needs and future expansion needs. It is recommended that the BTA process continue and the results of each BTA continue to play a prominent role in the utilities' filing of their IRPs along with the annual filing which can and should be utilized to modify any of the BTA projects as economic or load growth dictates.

[14] *See* A.A.C. R14-2-703(D)(1)(g).
[15] *See* Docket No. E-00000D-13-0002.

J. Environmental Considerations

1. Environmental Impacts[16]

A.A.C. R14-2-703 requires that each load-serving entity provide detailed environmental impacts for each generating unit and power purchase contract. Environmental impacts include air emission quantities (in metric tons or pounds) and rates (in quantities per megawatt-hour) for regulated air pollutants, water consumption quantities and rates, and other standards subject to current or expected future environmental regulations. The code also requires the load-serving entity to provide descriptions of programs that mitigate or manage environmental impacts and the risks and uncertainties associated with environmental impacts.

2. Current Regulations

a) National Ambient Air Quality Standards ("NAAQS")

The Clean Air Act ("CAA") established NAAQS for six pollutants: ozone, nitrogen dioxide ("NO2"), sulfur dioxide ("SO2"), particulate matter ("PM"), carbon monoxide ("CO"), and lead. These standards are set to protect public health and welfare. State Implementation Plans ("SIPs") govern how emissions from various sources within a geographical area would be limited to attain the NAAQS levels. Such plans will set maximum allowed emission limits for various sources. The CAA also requires the EPA to periodically review those standards and adjust the NAAQS levels based on the most current scientific data.

The ADEQ states the SIP is the cumulative record of all air pollution strategies, state statutes, state rules and local ordinances implemented under Title I of the CAA by governmental agencies within Arizona. Revisions to Arizona's SIP must be submitted to the EPA by the director of ADEQ on behalf of the governor. Once approved by EPA as published in the Federal Register, the provisions contained in the SIP revision become enforceable by the federal government as well as by the appropriate governmental entities of Arizona. The cumulative and complete record of SIP revisions that have been approved by EPA and federally enforceable in Arizona is called the "applicable Arizona SIP."

The first Arizona SIP submittal was in 1972. Because there have been so many changes to federal, state and local air quality programs in the last 30 years, there is not a single definitive document that contains all of the SIP requirements.

In addition to ADEQ, there are local air planning organizations that share in the responsibility of completing SIP requirements. The Maricopa Association of Governments ("MAG") and the Pima Association of Governments ("PAG") are metropolitan planning

[16] The information and documentation for the Environmental Section is compiled from information from the EPA, ADEQ, and the authors' experience.

organizations that have been delegated the responsibility to complete SIP revisions for their respective county areas.

ADEQ is in the process of posting recent SIP revisions on the Internet. However, due to the volume of information, it is expected to be a lengthy process. Hard copies of SIPs are available at the ADEQ main offices for review. SIP revisions completed by the MAG or the PAG are available at their respective offices.

b) Mercury and Air Toxics Standards ("MATS") Rule

On December 16, 2011, the EPA signed a rule to reduce emissions of toxic air pollutants from power plants. Specifically, these mercury and air toxics standards for power plants will reduce emissions from new and existing coal and oil-fired electric utility steam generating units ("EGUs"). The MATS Rule will reduce emissions of heavy metals, including mercury ("Hg"), arsenic ("As"), chromium ("Cr"), and nickel ("Ni"); and acid gases, including hydrochloric acid ("HCl") and hydrofluoric acid ("HF").

On March 28, 2013, the EPA finalized updates to certain emission limits for new power plants under the MATS. This includes emission limits for mercury, PM, SO2, acid gases and certain individual metals. Additionally, certain monitoring and testing requirements that apply to new sources were adjusted. The new standards affect only new coal- and oil-fired power plants that will be built in the future. The update does not change the final emission limits or other requirements for existing power plants. New power plants will use the same types of state-of-the-art control technologies to meet these standards as they would have used under the previously finalized standards. The agency reconsidered the new source limits for MATS based on new information and analysis that became available to the agency after the rule was finalized. The updates are calculated from data about the emissions rates achieved by the best performing source for each of the air toxics or surrogates. The calculated limits remain very low and will still require new power plants to be among the most modern and cleanest ever built. EPA projects that these updates will result in no significant change in costs, emission reductions or health benefits from MATS.

On June 25, 2013, EPA reopened, for 60 days, the public comment period on the startup and shutdown provisions included in the November 2012 proposed updates to pollution limits for new power plants under MATS.

- Existing sources generally will have up to 4 years if they need it to comply with MATS. This includes the 3 years provided to all sources by the CAA. EPA's analysis continues to demonstrate that this will be sufficient time for most, if not all, sources to comply.
- Under the CAA, state permitting authorities can also grant an additional year as needed for technology installation. EPA expects this option to be broadly available.
- EPA is also providing a pathway for reliability critical units to obtain a schedule with up to an additional year to achieve compliance. This pathway is described in a separate enforcement policy document. The EPA believes there will be few, if any situations, in which this pathway will be needed.

In the unlikely event that there are other situations where sources cannot come into compliance on a timely basis, consistent with its longstanding historical practice under the CAA, the EPA will address individual circumstances on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution.

The requirements under the MATS Rule are as follows:

- For all existing and new coal-fired EGUs, the rule establishes numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals), and HCl (a surrogate for all toxic acid gases).
- For existing and new oil-fired EGUs, the standards establish numerical emission limits for PM (a surrogate for all toxic metals), HCl, and HF. EGUs may also show compliance with the HCl and HF limits by limiting the moisture content of their oil.
- The rule establishes alternative numeric emission standards, including SO2 (as an alternate to HCl), individual non-mercury metal air toxics (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM) for certain subcategories of power plants.
- The standards set work practices, instead of numerical limits, to limit emissions of organic air toxics, including dioxin/furan, from existing and new coal- and oil-fired power plants. Because dioxins and furans form as a result of inefficient combustion, the work practice standards require an annual performance test program for each unit that includes inspection, adjustment, and/or maintenance and repairs to ensure optimal combustion.
- The standards also set work practices for limited-use oil-fired EGUs in the continental U.S.
- A range of widely available and economically feasible technologies, practices and compliance strategies are available to power plants to meet the emission limits, including wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters.
- The revisions to the New Source Performance Standards ("NSPS") for fossil-fuel-fired EGUs include revised numerical emission limits for PM, SO2, and NOX.

The following power plants in Arizona and New Mexico will be affected by the MATS Rule:

- Agua Fria (SRP)
- Apache Station (AEPCo)
- Cholla (APS)
- Coronado (SRP)
- Ocotillo (APS)
- H. Wilson Sundt Generating Station (TEP)
- Four Corners (APS)
- Kyrene (SRP)
- Navajo (SRP)
- Saguaro (APS)
- San Juan (Public Service Company of New Mexico with sales into Arizona – Units 2 & 3 will be retired by December 31, 2017. Units 1 & 4 to have Non-Catalytic Reduction added by early 2016
- Springerville (TEP)
- Yucca (APS)

c) Toxics Release Inventory ("TRI") Program, Hydrogen Sulfide: Lifting of Administrative Stay

EPA is taking steps to provide communities with additional information about toxic chemicals being released to the environment. The EPA is announcing that it is lifting the Administrative Stay of the Toxics Release Inventory reporting requirements for hydrogen sulfide. The Agency's review of hydrogen sulfide is part of its efforts to examine the scope of TRI chemical coverage and provide communities with more complete information on toxic chemical releases.

In April 2012, EPA finalized a rule to increase tribal participation in the TRI Program. Under this rule, facilities meeting TRI reporting requirements and located in Indian country are required to submit TRI reports to EPA and the appropriate tribe, rather than to the state in which the facility is geographically located. The final rule also clarifies that a tribal chairperson or equivalent elected official has equivalent opportunities to a state governor to petition EPA to request: 1) that individual facilities located within their Indian country be added to TRI, and 2) that a particular chemical(s) be added to or deleted from the TRI chemical list. EPA determines whether to add a facility or add/delete a chemical to the TRI Program.

In August 2013, EPA published a final rule requiring facilities to submit TRI forms electronically via TRI-MEweb. EPA has published a final rule requiring facilities to report all non-trade secret TRI data to EPA using the TRI-MEweb online reporting application. This rule also requires facilities to electronically submit any revisions or withdrawals of previously-submitted TRI reporting forms. Facilities may revise or withdraw TRI forms going back to reporting year (RY) 1991, but not for years prior to this. This rule applies to all facilities required to report to the TRI Program. This rule is effective January 21, 2014. Once the rule becomes effective, facilities submitting non-trade-secret TRI reporting forms for the 2013 TRI reporting year (forms due on July 1, 2014) or prior reporting years must report electronically.

d) Prevention of Significant Deterioration ("PSD") and Title V Operating Permit Greenhouse Gas ("GHG") Tailoring Rule Step 3 and GHG Plantwide Applicability Limits

Greenhouse gas emissions from the largest stationary sources will, for the first time, be covered by the Prevention of Significant Deterioration and Title V Operating Permit Programs. These permitting programs, required under the CAA, are proven tools for protecting air quality and the same tools will be used to reduce GHG emissions. But the thresholds established in the CAA for determining when emissions of pollutants make a source subject to these permitting programs, 100 and 250 tons per year, were based on traditional pollutants and were not designed to be applied to GHGs.

EPA's GHG Tailoring Rule, issued in May 2010, established an approach to permitting GHG emissions under PSD and Title V. The rule set initial emission thresholds - known as Steps 1 and 2 of the Tailoring Rule - for PSD and Title V permitting based on carbon dioxide equivalent ("CO2e") emissions. EPA's Step 3 of the GHG Tailoring Rule, issued on June 29, 2012, continues to focus GHG permitting on the largest emitters by retaining the permitting thresholds that were established in Steps 1 and 2. In addition, the Step 3 rule improves the usefulness of plant-wide applicability limitations ("PALs") by allowing GHG PALs to be established on CO2e emissions, in addition to the already available mass emissions PALs, and to use the CO2e-based applicability thresholds for GHGs provided in the "subject to regulation" definition in setting the PAL on a CO2e basis. The rule also revises the PAL regulations to allow a source that emits or has the potential to emit at least 100,000 tons per year of CO2e, but that has minor source emissions of all other regulated NSR pollutants, to apply for a GHG PAL while still maintaining its minor source status.

State and local permitting authorities have long-standing experience working together with owners and operators of industrial facilities, and EPA believes they are best suited to issue CAA permits to sources of GHG emissions. EPA is working closely with permitting authorities to ensure that the transition to GHG permitting runs seamlessly. The following table lists contacts for Arizona Permits.

Area	**Type of Permit**	**Permitting Authority**	**Regulations**
All of Arizona except Maricopa County, Pima County, Pinal County and Indian Country	nonattainment minor NSR	Air Quality Division Arizona Department of Environmental Quality 1110 W. Washington St. Phoenix, AZ 85007 602 207-2308	Arizona State Implementation Plan

Area	Type of Permit	Permitting Authority	Regulations
All of Arizona except Maricopa County, Pima County, Pinal County and Indian Country	PSD	Air Quality Division Arizona Department of Environmental Quality 1110 W. Washington St. Phoenix, AZ 85007 602 207-2308	Arizona State Implementation Plan for all pollutants except for PM_{10} which is subject to 40 CFR 52.21
Maricopa County	PSD nonattainment minor NSR	Maricopa County Environmental Services Department Air Quality Division 1001 N. Central Ave., Suite 200 Phoenix, AZ 85004 (602) 506-6010	40 CFR 52.21
Pima County	PSD nonattainment minor NSR	Pima County Department of Environmental Quality 150 W. Congress Street Tucson, AZ 85701-1332 (520) 740-3340	40 CFR 52.21
Pinal County	PSD nonattainment minor NSR	Pinal County Air Quality Control District P.O. Box 987 Florence, AZ 85232 520-866-6929	Arizona State Implementation Plan
Indian Country	PSD	Air Division U.S. EPA Region 9 75 Hawthorne Street San Francisco, CA, 94105 (415) 947-8021	40 CFR 52.21

On June 29, 2012, the EPA issued a final rule that does not revise the GHG permitting thresholds that were established in Step 1 and Step 2 of the GHG Tailoring Rule. These emissions thresholds determine when CAA permits under the New Source Review PSD and Title V Operating Permit programs are required for new and existing industrial facilities. This action became effective on August 13, 2012.

This is the third step in EPA's phased-in approach to GHG permitting under the CAA. Currently, new facilities with GHG emissions of at least 100,000 tons per year ("tpy") CO2e and existing facilities with at least 100,000 tpy CO2e making changes that would increase GHG emissions by at least 75,000 tpy CO2e are required to obtain PSD permits. Facilities that must obtain a PSD permit anyway, to cover other regulated pollutants, must also address GHG emissions increases of 75,000 tpy CO2e or more. New and existing sources with GHG emissions above 100,000 tpy CO2e must also obtain operating permits.

e) Final Action to Address Regional Haze

On May 30, 2012, EPA finalized a rule allowing the trading programs in the Cross-State Air Pollution Rule ("CSAPR") to serve as an alternative to determining source-by-source Best Available Retrofit Technology ("BART"). This rule provides that states in the CSAPR region can substitute participation in CSAPR for source-specific BART for sulfur dioxide and/or nitrogen oxides emissions from power plants. EPA also finalized a limited disapproval of certain states' plans that previously relied on the Clean Air Interstate Rule ("CAIR") to improve visibility and substituted a Federal Implementation Plan ("FIP") that relies on CSAPR. Although Arizona is not in the CSAPR region, EPA has issued a final Regional Haze FIP for the state of Arizona.

On June 27, 2014, EPA issued a final rule: Arizona's Regional Haze Federal Implementation Plan (FIP). EPA is finalizing a federal plan, also known as a FIP, to reduce harmful emissions from six facilities in Arizona. The federal plan is estimated to reduce 2,900 tons of nitrogen oxides (NOx) and 29,300 tons of sulfur dioxide (SO2) per year and help improve visibility at 17 protected national parks and wilderness areas in Arizona, New Mexico, Utah and California.

The six facilities that are subject to today's action are:

- Tucson Electric Power Sundt Generating Station Unit 4
- Lhoist North America Nelson Lime Plant Kilns 1 and 2
- ASARCO Incorporated Hayden Smelter
- Freeport-McMoran Incorporated Miami Smelter
- Phoenix Cement Company (PCC) Clarkdale Plant Kiln 4
- CalPortland Cement (CPC) Rillito Plant Kiln 4

EPA is taking this action because the State's plan was partially approved and partially disapproved on July 30, 2013, for not meeting the requirements of the CAA and EPA's Regional Haze Rule.

f) Final Revisions to the Implementation of the New Source Review ("NSR") Program for Condensable Particulate Matter ("PM")

On October 12, 2012, EPA released final revisions to the implementation of NSR for condensable PM. This final revision clarifies that condensable particulate matter should be included as part of the emissions measurements for regulation of PM2.5 and PM10. The final rule removes the inadvertent requirement in the 2008 PM2.5 NSR Implementation Rule, that measurements of condensable particulate matter be included as part of the measurement and regulation of much larger particles included as "particulate matter emissions."

The EPA is issuing a final rule that revises the definition of "regulated NSR pollutant" contained in two sets of Prevention of Significant Deterioration (PSD) regulations and in the EPA's Emission Offset Interpretative Ruling. The revision corrects an inadvertent error made in 2008 when the EPA issued its rule to implement the New

Source Review (NSR) program for fine particles with an aerodynamic diameter of less than or equal to 2.5 micrometers (PM2.5). This revision removes a general requirement in the definition of “regulated NSR pollutant” to include condensable PM when measuring one of the emissions-related indicators for particulate matter (PM) known as “particulate matter emissions” in the context of the PSD and NSR regulations. However, the rule preserves the requirement in some particular cases to include condensable PM in measurements of “particulate matter emissions” as required by other regulations. In addition, measurement of condensable PM continues to be required in all cases for two other emissions-related indicators for emissions of PM—emissions of particles with an aerodynamic diameter of less than or equal to 10 micrometers (PM10 emissions) and PM2.5 emissions.

3. Expected Regulations

a. Clean Power Plan

Overview

On June 2, 2014, the EPA, under President Obama's Climate Action Plan, proposed what it refers to as a commonsense plan to cut carbon pollution from existing power plants. The U.S. EPA claims science shows that climate change is already posing risks to our health and our economy. The Clean Power Plan ("CPP") proposes to help cut carbon pollution from the power sector by 30 percent from 2005 levels. Power plants are the largest source of carbon pollution in the U.S., accounting for roughly one-third of all domestic greenhouse gas emissions. The proposal states the CPP will also cut pollution that leads to soot and smog by over 25 percent in 2030. EPA's analysis concludes there will be enough generating capacity across the U.S. electricity system to meet the anticipated level of demand. However, the Plan does not account for specific impacts to the utility system of individual utilities within any state nor does it give guidance as to how individual utilities within a state will deal with stranded investment of coal generating resources that will be idled by the Plan.

Coal, oil and natural gas will continue to have an important role in a diverse U.S. energy mix for years to come—with coal and natural gas remaining the two leading sources of electricity generation, each providing more than 30 percent of projected generation in 2030. However, the implementation of the CPP will cause utilities to rethink their IRPs in order to meet the requirements of the CPP.

The CPP has two main parts: state-specific goals to lower carbon pollution from power plants and guidelines to help the states develop their plans for meeting the goals.

- The goal is a target states have to meet by 2030, while starting to make meaningful progress toward reductions by 2020.
- States develop plans to meet their goals, but EPA is not prescribing a specific set of measures for states to put in their plans.
- States may choose what goes into their plans, which will lay out how they will achieve the needed reductions.

Each state's goal is a rate – a single number for the future carbon intensity of that state. Each state's goal reflects the fact that CO_2 emissions from fossil fuel-fired power plants are determined both by how efficiently they operate and by how much they operate. The EPA state goals recognize the opportunity for reductions through energy efficiency improvements. However, the EPA goals do not reflect the reduction in greenhouse gas emissions and the increase in renewables and energy efficiency programs already in effect in Arizona. The state will have to determine how to share the responsibility of compliance with each utility. As is currently defined by the EPA, compliance will be based on pounds of CO2 emissions/MWh. This criterion may not reflect a utility's progress in reducing greenhouse gas emissions implemented prior to 2012.

States will have about a 13-year window after the CPP is final in which to plan for and achieve reductions in carbon pollution from affected units. States will choose how to meet the goal through whatever measures reflect their particular circumstances and policy objectives.

Proposed State Plan Dates

June 30, 2016 – Initial plan or complete plan due

June 30, 2017 – Complete individual plan due if state is eligible for a one-year extension

June 30, 2018 – Complete multi-state plan due if state is eligible for two-year extension (with progress report due June 30, 2017

b. Proposed Carbon Pollution Standards for Modified and Reconstructed Power Plants

On June 18, 2014, the EPA released a proposed rule for carbon pollution standards for modified and reconstructed power plants. The EPA is proposing standards of performance for emissions of greenhouse gases from affected modified and reconstructed fossil fuel-fired electric utility generating units. Specifically, the EPA is proposing standards to limit emissions of carbon dioxide from affected modified and reconstructed electric utility steam generating units and from natural gas-fired stationary combustion turbines. This rule, as proposed, would continue progress already underway to reduce carbon dioxide emissions from the electric power sector in the United States.

c. 2013 Proposed Carbon Pollution Standard for New Power Plants

On Sept. 20, 2013, the Environmental Protection Agency issued a new proposal for carbon pollution from new power plants. After considering more than 2.5 million comments from the public about the 2012 proposal and consideration of recent trends in the power sector, EPA is changing some aspects of its approach. EPA is proposing to set separate standards for natural gas-fired turbines and coal-fired units.

On April 13, 2012, the EPA proposed a new source performance standard for emissions of carbon dioxide for new affected fossil fuel-fired electric utility generating units. The EPA received more than 2.5 million comments on the proposed rule. After consideration of information provided in those comments, as well as consideration of continuing changes in the electricity sector, the EPA determined that revisions in its proposed approach are warranted. Thus, in a separate action, the EPA is withdrawing the April 13, 2012, proposal, and, in this action, the EPA is proposing new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. This action proposes a separate standard of performance for fossil fuel-fired electric utility steam generating units and integrated gasification combined cycle units that burn coal, petroleum coke and other fossil fuels that is based on partial implementation of carbon capture and storage as the best system of emission reduction. This action also proposes standards for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. This action also includes related proposals concerning permitting fees under Clean Air Act Title V, the Greenhouse Gas Reporting Program, and the definition of the pollutant covered under the prevention of significant deterioration program.

d. Coal Combustion Residuals (“CCRs”) – Proposed Rule

Coal Combustion Residuals, often referred to as coal ash, are currently considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (“RCRA”). CCRs are residues from the combustion of coal in power plants and captured by pollution control technologies, like scrubbers. Potential environmental concerns from coal ash pertain to pollution from impoundment and landfills leaching into ground water and structural failures of impoundments, like that which occurred at the Tennessee Valley Authority’s plant in Kingston, Tennessee. The need for national management criteria was emphasized by the December 2008 spill of CCRs from a surface impoundment near Kingston, Tennessee. The tragic spill flooded more than 300 acres of land with CCRs and flowed into the Emory and Clinch rivers.

EPA is proposing to regulate coal ash for the first time to address the risks from the disposal of the wastes generated by electric utilities and independent power producers. EPA is considering two possible options for the management of coal ash for public comment. Both options fall under RCRA. Under the first proposal, EPA would list these residuals as special wastes subject to regulation under subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. Under the second proposal, EPA would regulate coal ash under subtitle D of RCRA, the section for non-hazardous wastes. EPA considers each proposal to have its advantages and disadvantages, and includes benefits which should be considered in the public comment period. Under both alternatives, EPA is proposing to establish dam safety requirements to address the structural integrity of surface impoundments to prevent catastrophic releases.

K. Review of IRPs for Environmental Impacts Requirements

1. Existing Air Emission Environmental Impacts

A.A.C. R14-2-703(B)(1)(p) requires the load-serving entity to provide for each generating unit and purchased power contract for the previous calendar year a description of the environmental impacts, including air emissions quantities (tons/lbs) and rates

(/MWh) for CO_2, nitrogen oxides (NO_X), SO_2, Hg, particulates (PM10 and PM2.5), and other air emissions subject to current or expected regulation.

a) APS

APS' 2013 emissions rates and quantities for SO_2, NO_x, CO_2, PM10, CO, VOC, and Hg are located in a supplemental document of the IRP called "Historical Data." APS' 2012 emissions rates and quantities for SO_2, NO_x, CO_2, PM10, CO, VOC, and Hg are located in a supplemental document of the IRP called "Annual Filing Historical Year."

b) AEPCo

AEPCo provides 2013 air emissions for CO_2, total PM, SO_2, Hg, and NO_x for each generating unit at the Apache Generating Station in the 2013 Integrated Resource Planning Actual Data Filing.

AEPCo provides 2012 air emissions for CO_2, total PM, SO_2, Hg, and NO_x for each generating unit at the Apache Generating Station in the 2012 Integrated Resource Planning Actual Data Filing.

c) TEP

TEP provides 2013 air emissions data for SO_2, NO_x, CO_2, PM, Hg and coal ash. The historical data for 2013 is in a supplement to the Final IRP entitled "Historical Data." TEP provides 2012 air emissions data for SO_2, NO_x, CO_2, PM, Hg and coal ash. The historical data for 2012 is in a supplement to the Final IRP entitled "Resource Planning Filing Historical Data."

d) UNSE

UNSE provides 2013 air emissions data for SO_2, NO_x, CO_2, PM, and Hg. The historical data for 2013 is in the document "2014 Resource Planning and Procurement Filing, 2013 Historical Data Information," a supplement to the Final IRP. UNSE does not compare the historical rates and quantities to existing regulations.

UNSE provides 2012 air emissions data for SO_2, NO_x, CO_2, PM, and Hg. The historical data for 2012 is in the document "2013 Resource Planning and Procurement Filing, 2012 Historical Data Information," a supplement to the Final IRP. UNSE does not compare the historical rates and quantities to existing regulations.

2. Existing Water Consumption Environmental Impacts

A.A.C. R14-2-703(B)(1)(q) requires for each generating unit and purchased power contract for the previous calendar year a description of the water consumption quantities and rates.

e) APS

APS' 2013 water consumption rates and quantities are located in a supplemental document of the IRP called Historical Resource Planning Information for the Historical Year 2013. The requirements for A.A.C. R14-2-703(B)(1)(q) are in Tab V.

APS' 2012 water consumption rates and quantities are located in a supplemental document of the IRP called Resource Planning Information for the Historical Year 2012. The requirements for A.A.C. R14-2-703(B)(1)(q) are in Tab V.

f) AEPCo

AEPCo provides the following statement regarding water consumption in the 2013 Integrated Resource Planning Actual Data Filing:

Information is not available regarding water consumption per generating unit. For all units [at Apache], an estimated total of 4,642 acre-feet of water was used in 2013 based on metered production well output.

AEPCo provides the following statement regarding water consumption in the 2012 Integrated Resource Planning Actual Data Filing:

Information is not available regarding water consumption per generating unit. For all units [at Apache], an estimated total of 3,756 acre-feet of water was used in 2012 based on metered production well output.

g) TEP

TEP provides water consumption quantities and rates for 2013. The historical data for 2013 are in the "Historical Data" supplement to the Final IRP. TEP provides water consumption quantities and rates for 2012. The historical data for 2012 are in the "Resource Planning Filing Historical Data" supplement to the Final IRP.

h) UNSE

UNSE provides water consumption quantities and rates for 2013. The historical data for 2013 are in the "2014 Resource Planning and Procurement Filing, 2013 Historical Data Information," supplement to the Final IRP. UNSE does not compare the historical rates and quantities to existing regulations.

UNSE provides water consumption quantities and rates for 2012. The historical data for 2012are in the "2013 Resource Planning and Procurement Filing, 2012 Historical

Data Information," supplement to the Final IRP. UNSE does not compare the historical rates and quantities to existing regulations.

3. Existing Coal Ash Environmental Impacts

A.A.C. R14-2-703(B)(1)(r) requires for the previous calendar year a description of the tons of coal ash produced per generating unit.

i) APS

APS' 2013 tons of coal ash produced per generating unit table is located in the Historical Resource Planning Information for the Historical Year 2013 supplement of the IRP.

APS' 2012 tons of coal ash produced per generating unit table is located in the Resource Planning Information for the Historical Year 2012 supplement of the IRP. The requirements for R14-2-703(B)(1)(r) are in Tab V.

j) AEPCo

AEPCo provides the tons of coal ash produced per generating unit in 2013 on page 61 of the 2013 Integrated Resource Planning Actual Data Filing, and the tons of coal ash produced per generating unit in 2012 on page 64 of the 2012 Integrated Resource Planning Actual Data Filing.

k) TEP

TEP provides the tons of coal ash produced per generating unit in 2013 in its IRP. The historical data for 2013 are in the 2013 Historical Data Information supplement to the Final IRP.

TEP provides the tons of coal ash produced per generating unit in 2012 in its IRP. The historical data for 2012 are in the 2012 Historical Data Information supplement to the Final IRP.

l) UNSE

In response to (B)(1)(r), UNSE states they have no coal generation in the "2013 Resource Planning Annual Filing for Historical Year 2012."

4. Projected Environmental Impacts

A.A.C. R14-2-703(D)(1)(a) requires projected data for each of the items listed in A.A.C. R14-2-703(B)(1), for 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. This includes air emissions, water consumption, and coal ash. Applicable sections in A.A.C. R14-2-703(B)(1) include subsections (B)(1)(p) - (r).

a) APS

Projected data for each generating unit and purchased power resource are provided in the Attachment D.1(a)(8) of the IRP. APS provides projections for 2014-2029 for each unit CO2 emissions, CO emissions, volatile organic compounds ("VOCs"), NOx emissions, SO2 emissions, Hg emissions, PM10 emissions, coal fly ash collected, coal fly ash bottom collected, and water consumption.

b) AEPCo

To comply with A.A.C. R14-2-703(B)(1)(p) as it relates to subsection D(1)(a), AEPCo provides an emissions forecast based on long-range load forecast data and past emissions performance. The emissions performance data were derived from 2013 actual measured emissions, where available, and emission factors developed for specific generating unit designs and fuels. AEPCo has no emissions data available for purchase power contracts. The Apache Station Forecast Emissions 2014-2028 are considered confidential information.

Insofar as A.A.C. R14-2-703(B)(1)(q) relates to subsection D(1)(a), AEPCo states that it does not expect the amount of water usage to significantly increase as it is focusing on increasing process water reuse plant-wide as an alternative to using fresh water.

AEPCo provides a forecast for coal ash production for the years 2014 through 2028 on page 55 of its 2014 Resource Planning Filing.

c) TEP

Projected environmental impacts for each plant are provided in the supplemental workbook "Reference Case Final (Confidential)". TEP provides 15 years (2014 – 2028) of projections for CO2, NOx, SO2, PM10, and Hg quantities and rates. TEP also provides projections for water and coal ash quantities and rates.

In Chapter 8, TEP discusses current and expected regulations and the effect they may pose on the utility. These regulations include Regional Haze, Utility MATS Rule, NAAQS, mandatory reporting of GHGs, regulation of GHGs under CAA, GHG New Source Performance Standards (NSPS), and CCRs.

d) UNSE

Projected environmental impacts are provided in the supplemental workbook "UNSE Reference Final (Confidential)". UNSE provides 15 years (2014 – 2028) of projections for CO_2, NO_x, SO_2, PM, and Hg. UNSE does not provide total water consumption rates.

UNSE provides projected environmental impacts for each unit for CO_2, SO_2, NO_x, Hg, and water consumption in the supplemental workbook "UNSE Reference Final (Confidential)".

5. Costs of Compliance - Existing and Expected Environmental Regulations

A.A.C. R14-2-703(D)(1)(h) requires the load serving entity to provide a 15-year resource plan, providing for each year cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations.

a) APS

In response to A.A.C. R14-2-703(D)(1)(h), APS provides cost analyses and projections in the IRP attachment D.10. The cost of existing and expected environmental regulations is embedded within the capital and operations and maintenance ("O&M") figures.

b) AEPCo

In response to A.A.C. R14-2-703(D)(1)(h), AEPCo's cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations are considered confidential information and are unavailable in the public version of the 2014 Integrated 15-Year Resource Plan.

c) TEP

The TEP IRP index lists the requirements of A.A.C. R14-2-703(D)(1)(h) in the Financial Report of the Reference Case Final (Confidential). The Environmental Capital Expenditures are included in this analysis. A discussion of the existing and expected environmental regulations is not included in this supplemental workbook; however it is included in the main IRP document.

d) UNSE

The UNSE IRP index lists the requirements of A.A.C. R14-2-703(D)(1)(h) in the UNSE Reference Case Final (Confidential). The Environmental Capital Expenditures are included in this analysis. A discussion of the existing and expected environmental regulations is not included in this supplemental workbook or in the main IRP document.

6. Environmental Impacts Mitigation and Management

A.A.C. R14-2-703(D)(14) requires the load serving entity to provide descriptions of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure the expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure.

A.A.C. R14-2-703(D)(17) requires a plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

a) APS

Section "Response to Rules Section D – Supply" Provides estimates of 2013 energy efficiency environmental impacts reductions by energy efficiency programs. Attachment D.14(a) and D.14(b) provide detailed information for the energy efficiency programs.

The APS response to A.A.C. R14-2-703(D)(17) is located in section "Response to Rules Section D – Supply" Figures 33 and 34. These figures provide a plan and timeline for reducing impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

b) AEPCo

In response to A.A.C R14-2-703(D)(14), AEPCo states that, because AEPCo supplies no power at retail and, therefore, has no customers for demand management programs or measures, none are included in AEPCo's plan.

In response to A.A.C R14-2-703(D)(17), AEPCo describes how it manages water consumption and air emissions environmental impacts but does not describe solid waste or other environmental factors.

c) TEP

TEP provides detailed descriptions of its energy efficiency programs in Chapter 11 of the IRP. In the TEP IRP Index, in response to A.A.C R14-2-703(D)(14)(d), TEP states there is "No Energy Efficiency Case" in the IRP PDF Report.

d) UNSE

UNSE provides detailed descriptions of its energy efficiency programs in Chapter 8 of the IRP. In the UNSE IRP Index, in response to A.A.C R14-2-703(D)(14)(d), UNSE states there is "No Energy Efficiency Case" in the IRP PDF Report.

7. Environmental Impacts, Risks and Uncertainties

A.A.C. R14-2-703(E) requires analyses to identify and assess errors, risks, and uncertainties completed using methods such as sensitivity analysis and probabilistic analysis for the costs of compliance with existing and expected environmental regulations and any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations. This section also requires the load serving entity to discuss means and measures for managing the errors, risks, and uncertainties.

A.A.C. R14-2-703(F)(3) requires the 15-year plan to address the adverse environmental impacts of power production. A.A.C. R14-2-703(F)(7) requires the plan to provide how the utility will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

a) APS

APS provides lengthy discussion in the Section "Response to Rules Section E – Risk" regarding the regulations stated above.

APS provides responses to A.A.C. R14-2-703(F)(3) and A.A.C. R14-2-703(F)(7) in section "Response to Rules Section F – 2014 IRP."

b) AEPCo

AEPCo's response to A.A. R14-2-703(E)(1)(d) is confidential and unavailable in the public version of the 2014 Integrated 15-Year Resource Plan. This section should provide the analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis: the costs of compliance with existing and expected environmental regulations.

AEPCo offers a "mission statement" relating to A.A.C. R14-2-703(F)(3) to address adverse environmental impacts of power production.

In response to A.A.C. R14-2-703(F)(7), AEPCo states,

> In AEPCO's last rate case decision, Decision No. 74173 dated October 25, 2013, the Commission confirmed Staff and AEPCO's agreement that it would continue to conduct its study of the future role of the Apache Station and how that role relates to its members' needs for future power supply. AEPCO will include, among other things, in that study potential rate impacts associated with known or pending EPA regulatory actions that could impact Apache Station. Data gathering concerning actual usage of Apache Station has been conducted concerning the rate designs and usage patterns associated with the Station in order to assess its role and potential environmental impacts. AEPCO currently anticipates the study will be completed and filed as directed with the Commission by June 30, 2014.

c) TEP

The TEP IRP index lists the information required by A.A.C. R14-2-703(E)(1)(d) in the IRP "Environmental Regulations, Chapter 8." In Chapter 8, the IRP discusses its plans for compliance for environmental impacts including the FIP for Regional Haze, MATS Rule, NAAQS, and GHG regulations. The IRP discusses carbon price assumptions quantitatively including projections of carbon emissions prices per ton through 2029. This also meets the requirements for A.A.C. R14-2-703(E)(1)(e).

The TEP IRP index lists the information required by A.A.C. R14-2-703(E)(1)(e) in the IRP "Reference Case Assumptions, Chapter 15." This chapter also meets the requirements of A.A.C. R14-2-703(E)(1)(d). This chapter forecasts the price of natural gas, wholesale power, delivered coal, and emissions and their effect on TEP.

d) UNSE

The UNSE IRP index lists the information required by A.A.C. R14-2-703(E)(1)(d) and (e) in the IRP "Reference Case Assumptions, Chapter 12." The IRP discusses carbon price assumptions quantitatively including projections of carbon emissions prices per ton through 2029. This also meets the requirements for A.A.C. R14-2-703(E)(1)(e).

The UNSE IRP provides the information required by A.A.C. R14-2-703(F)(3) and (7) in "Integrated Resource Planning Results, Chapter 14." UNSE developed a 15-year plan that addresses the adverse environmental impacts of power production and how UNSE plans to manage uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

L. Conclusions on Environmental Issues

1. Utilities' IRPs Compliance with Arizona Administrative Code

The load-serving entities in Arizona are required to submit IRPs according to A.A.C. R14-2-703. The four load-serving entities' IRPs that have been reviewed in this report have met these criteria to varying degrees. While each entity has provided information for each criterion regarding environmental impacts, they provide varying amounts of detailed information regarding the existing and projected environmental impacts. For example, there could be more comparison between existing regulations and historical emission rates, water consumptions, and other regulated environmental impacts. However, the utilities do a fairly good job of describing proposed environmental regulations, but only marginally perform thorough quantitative emission reduction analyses expected from new management technologies and then only from an over-all expected benefit. There is no discussion of percentage saturation expected, or needed, to achieve the results provided.

From reviewing each of the load-serving entities' IRPs, the following conclusions can be made.

- All utilities may benefit from comparing their historical data to existing regulations for emissions and other environmental impacts.
- All utilities may benefit from providing quantitative projections of reduced emissions and other environmental impacts from new environmental management technologies.
- On June 30, 2014, AEPCo submitted a study of the future role of the Apache Station that included, among other things, the potential rate impacts associated with known or pending EPA regulatory actions that could impact Apache Station..

2. Utilities' Compliance with Expected Environmental Regulations

The four load-serving entities do a good job of discussing expected environmental regulations and management technologies. AEPCo conducted a study of the future role of the Apache Station that included, among other things, potential rate impacts associated with known or pending EPA regulatory actions that could impact Apache Station. This was completed and submitted to the Commission June 30, 2014. However, AEPCo does provide qualitative discussions on upcoming regulations and their effects on the utility. APS, TEP, and UNSE also discuss how their utilities will be affected by proposed environmental regulations as well as the associated risks and uncertainties. All four utilities should discuss how their proposed management technologies will quantitatively reduce emissions and other impacts. In conclusion, the utilities are aware of upcoming regulations and the needed improvements to meet these regulations including new particulate emission requirements and mercury and air toxics standards.

M. Innovation and Technological Development Considerations

In November of 2013, the Commission opened its "Innovation and Technological Development" docket (docket No. E-00000J-13-0375). This docket was opened to provide a forum for discussing the impacts emerging technologies will have on the electric utility industry, and to help the Commission recognize regulatory issues that will arise as technology evolves. Technological developments that could potentially disrupt the traditional utility business model were of particular interest. The ACC conducted six workshops, and invited a broad range of industry experts and professionals to speak about several key topics.

The Innovation and Technological Development docket and workshop series made it clear that technology is progressing quickly in the energy industry and much of that advancement is difficult to predict. The Commission must be ready to address a changing regulatory environment in the face of emerging technologies. In the long term, the electric utility business model may change completely. Presenters discussed entirely new business models, such as a transactive energy mechanism that includes a high level of multi-directional power flow on the grid and enables significantly higher customer participation in both generation and grid operation than possible today.

Due to the significance of ongoing changes to the industry in both the near and long-term, it would be beneficial for the Commission to know how and when new technologies are being used by Arizona utilities. The workshop series has provided an informative forum for understanding emerging technology today, but to regulate effectively, the ACC needs to stay apprised of changing technologies. The Commission could take a number of approaches to ensure this important goal is accomplished.

One option is to modify the state's existing IRP rules to include more technology reporting. The IRP process is intended to keep the Commission apprised of how utilities will fulfill the energy needs of their customers over a 15 year timeframe, as well as how they plan to satisfy demand response, energy efficiency, and renewable energy requirements, so IRP would be an appropriate venue for discussing how emerging technologies fit into those plans.

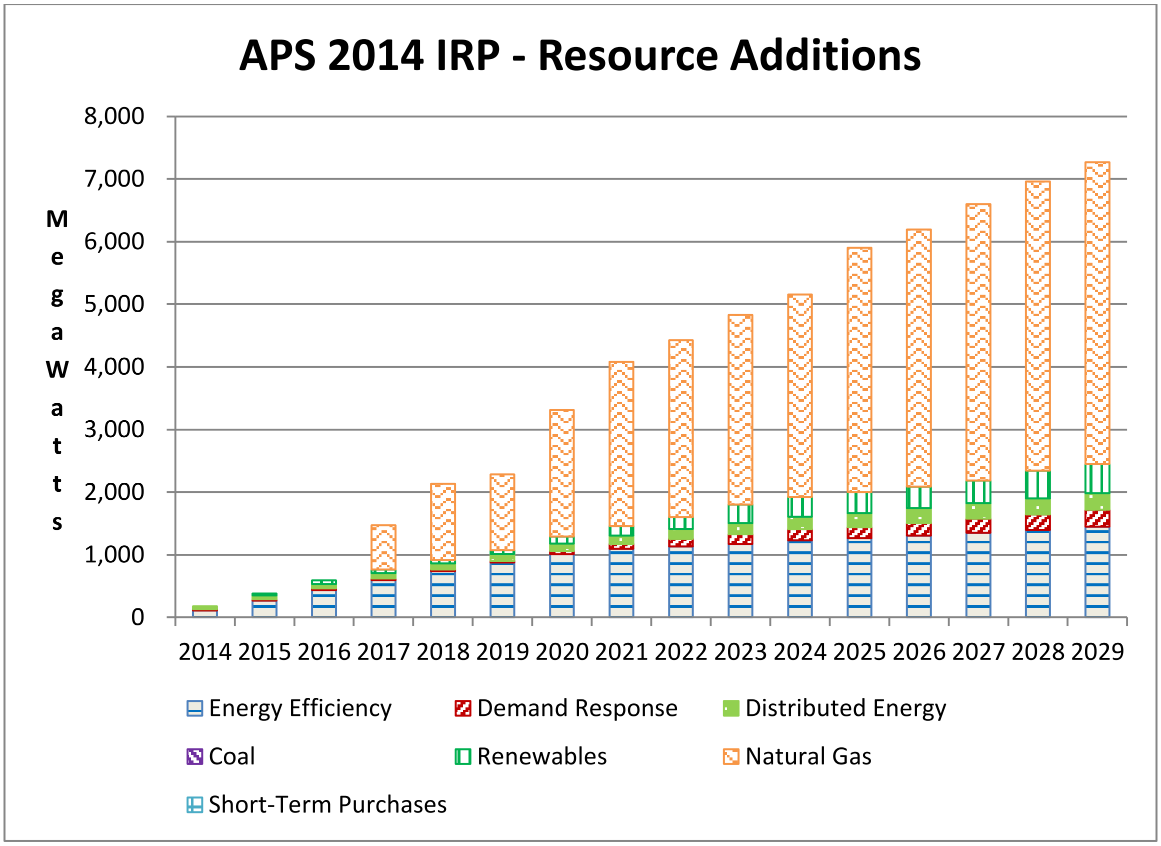
New topics to be discussed in the Load-Serving Entities' IRPs could include the topics outlined in this report, i.e. microgrid development, AMI data management and security, voltage optimization and distribution automation, and renewables integration strategies including EIMs, and a description of any new technologies the utility is evaluating, the range of impacts on the system, cost projections, and anticipated viability.

Until such time as the Commission decides if a link between the Innovation and Technological Development docket and the IRP process is appropriate, Stakeholders are advised to monitor filings in docket No. E-00000J-13-0375.

N. The 2014 Selected Integrated Resource Plans

1. APS

The following chart displays the resource additions selected by APS in its 2014 IRP, based on contribution to system peak demand:

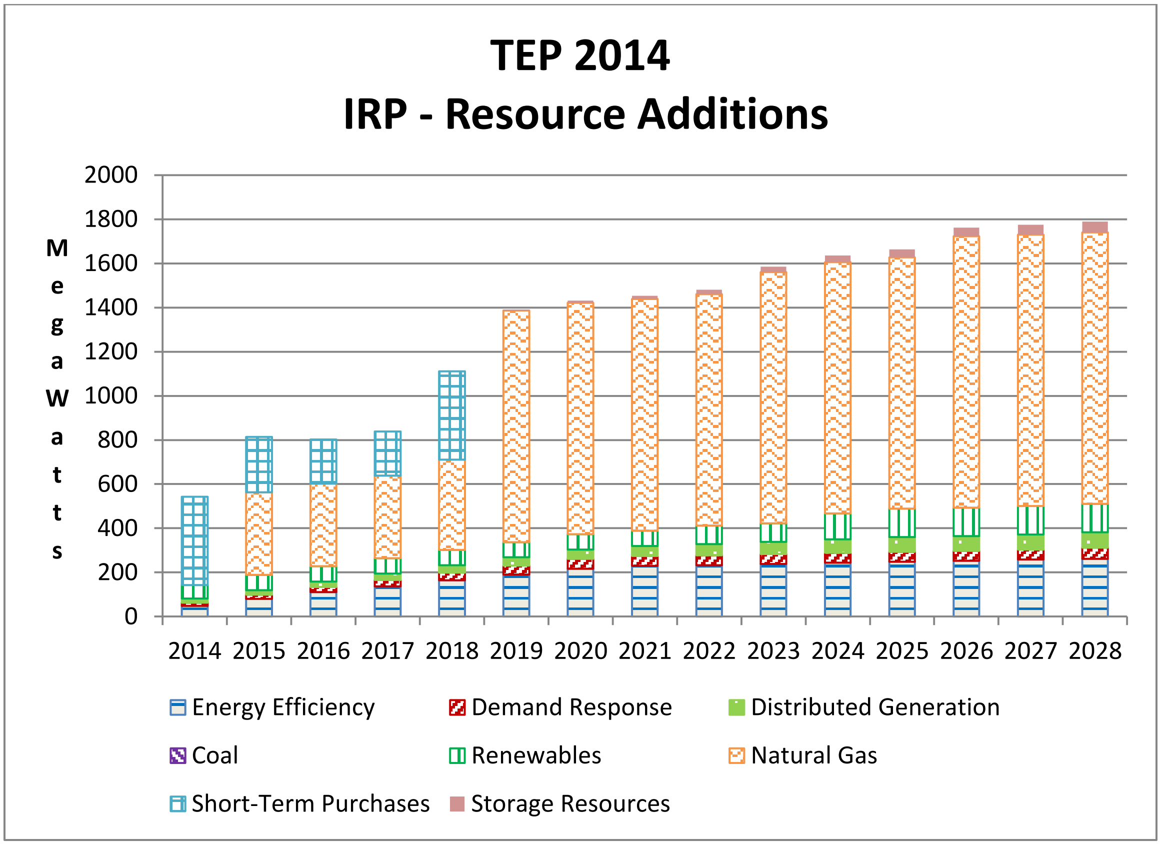


Although in its original IRP filing, APS had selected its Base Portfolio as the preferred IRP, in a supplemental filing dated September 17, 2014, APS modified its selection to the Coal Reduction Portfolio, which it now refers to as the Managed Coal Strategy. The primary change to the APS IRP is that, under the Managed Coal Strategy, APS will retire the Cholla Unit 2 coal-fired generating unit in April of 2016 to avoid substantial environmental upgrades, and also plans to retire Cholla Units 1 and 3 in 2025. The retirement of these coal units requires additional new resources in the APS IRP. APS has requested specific approval by the Commission of the Cholla Unit 2 retirement.

APS plans to add EE programs and DR programs sufficient to meet the Commission's EE requirement, utility-scale renewable generation sufficient to meet the Commission's RE requirement, and distributed renewable generation sufficient to meet the Commission's distributed renewable energy requirement.

2. TEP

The following chart displays the resource additions selected by TEP in its 2012 IRP, based on contribution to system peak demand:

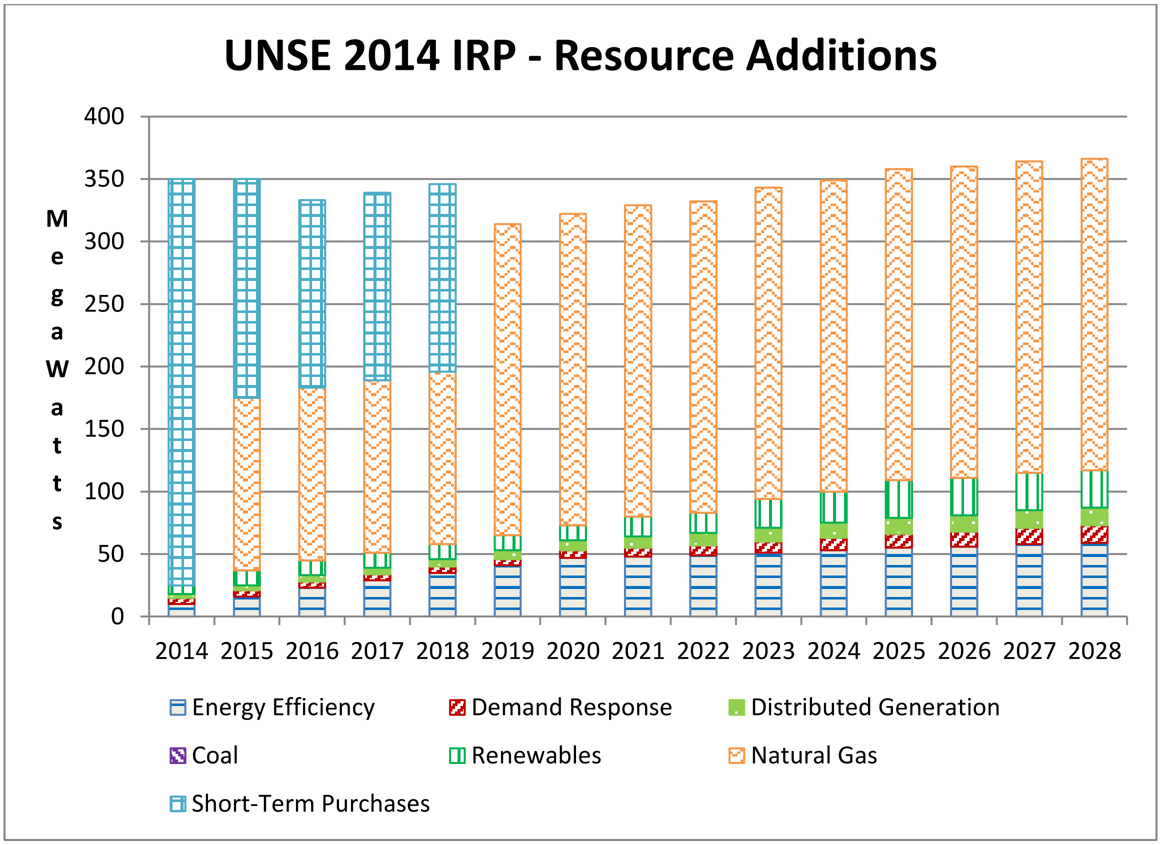


TEP selected its Reference Case as the preferred 2014 IRP. In this plan, TEP acquires 374 megawatts of the Gila River combined cycle natural gas-fired plan in 2015, short-term market purchases in 2014-2018, and additional natural gas-fired resources in 2019-2028. TEP also adds 50 megawatts of storage resources (batteries) across the study period.

TEP plans to add EE programs and DR programs sufficient to meet the Commission's EE requirement, utility-scale renewable generation sufficient to meet the Commission's RE requirement, and distributed renewable generation sufficient to meet the Commission's distributed renewable energy requirement.

3. UNSE

The following chart displays the resource additions selected by UNSE in its 2014 IRP, based on contribution to system peak demand:

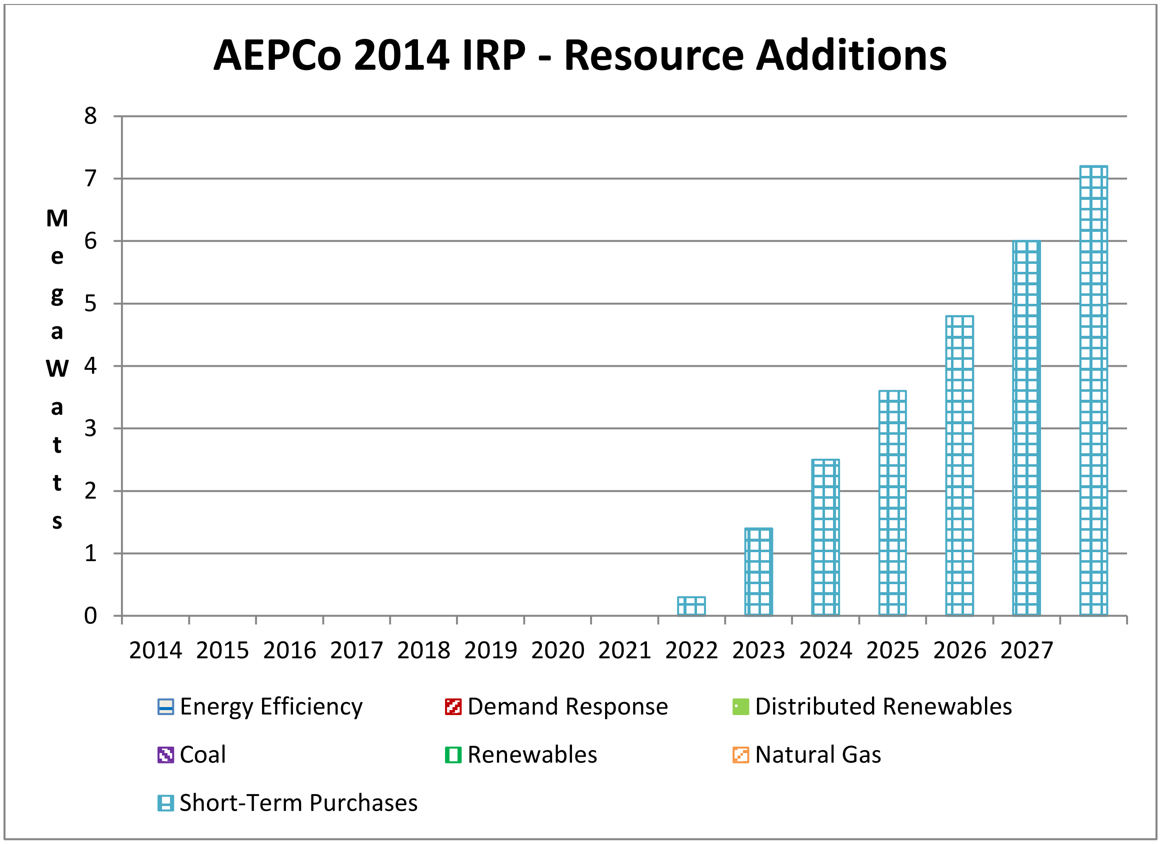


UNSE selected its Reference Case as the preferred 2014 IRP. In this plan, UNSE acquires 138 megawatts of the Gila River combined cycle natural gas-fired plan in 2015, short-term market purchases in 2014-2018, and additional natural gas-fired resources in 2019-2028. UNSE also adds 2 megawatts of storage resources (batteries) across the study period.

UNSE plans to add EE programs and DR programs sufficient to meet the Commission's EE requirement, utility-scale renewable generation sufficient to meet the Commission's RE requirement, and distributed renewable generation sufficient to meet the Commission's distributed renewable energy requirement.

4. AEPCo

The following chart displays the resource additions selected by AEPCo in its 2012 IRP, based on contribution to system peak demand:



These additions reflect the needs of AEPCo's all-requirements members only.

The IRP produced by AEPCo only considered short-term market purchases as potential resource additions. It should be noted that the resource additions projected by AEPCo are a small fraction of the resource additions projected by the other load-serving entities.

5. SRP

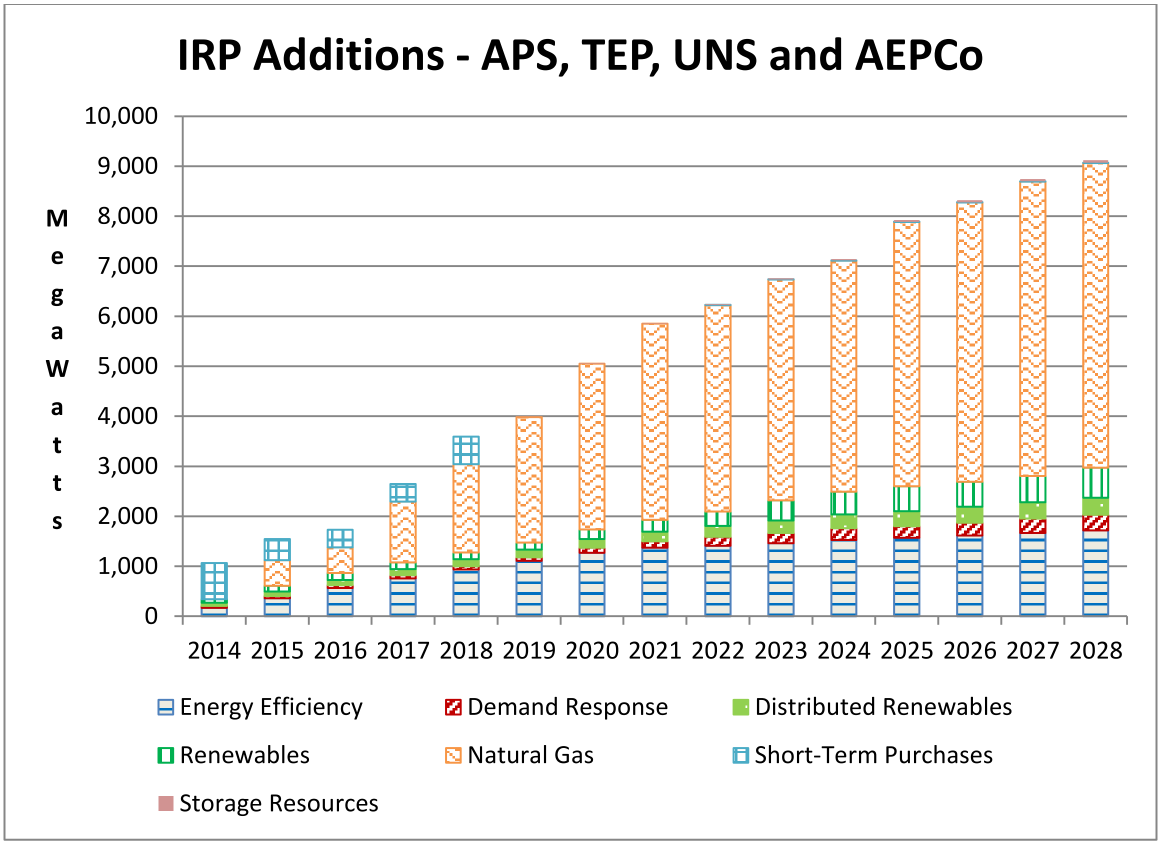
The information supplied by SRP does not address planned resource additions beyond the year 2018. In the years 2014 through 2018, SRP plans to add short-term power purchases and additional renewable resources.

6. Combined IRPs

The following table shows the additional resources selected by APS, TEP, UNSE and AEPCo in their 2014 IRPs, based on contribution to system peak demand:

IRP Additions - APS, TEP, UNS and AEPCo							
Megawatts							
	Energy Efficiency	Demand Response	Distributed Renewables	Renewables	Natural Gas	Storage Resources	Short-Term Purchases
2014	167	41	67	67	0	0	725
2015	363	45	88	114	512	0	425
2016	567	55	104	138	512	0	350
2017	760	60	120	138	1,216	0	350
2018	937	66	137	138	1,761	0	550
2019	1,109	71	153	138	2,512	5	0
2020	1,272	102	168	192	3,318	10	0
2021	1,373	128	188	240	3,920	15	0
2022	1,412	179	216	289	4,124	20	0
2023	1,463	205	247	401	4,418	25	1
2024	1,527	231	276	456	4,622	30	3
2025	1,568	231	303	497	5,287	35	4
2026	1,616	257	317	503	5,581	40	5
2027	1,668	283	327	525	5,887	45	6
2028	1,717	314	337	607	6,091	50	7

The same information is shown in the following chart:

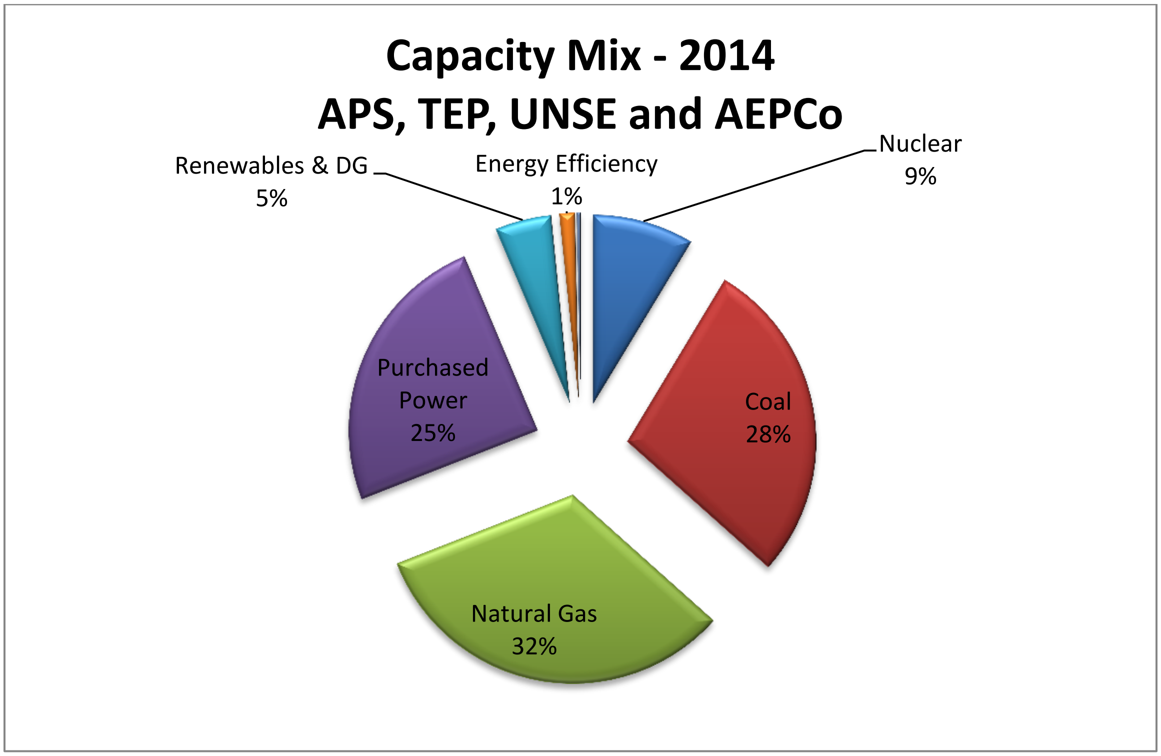


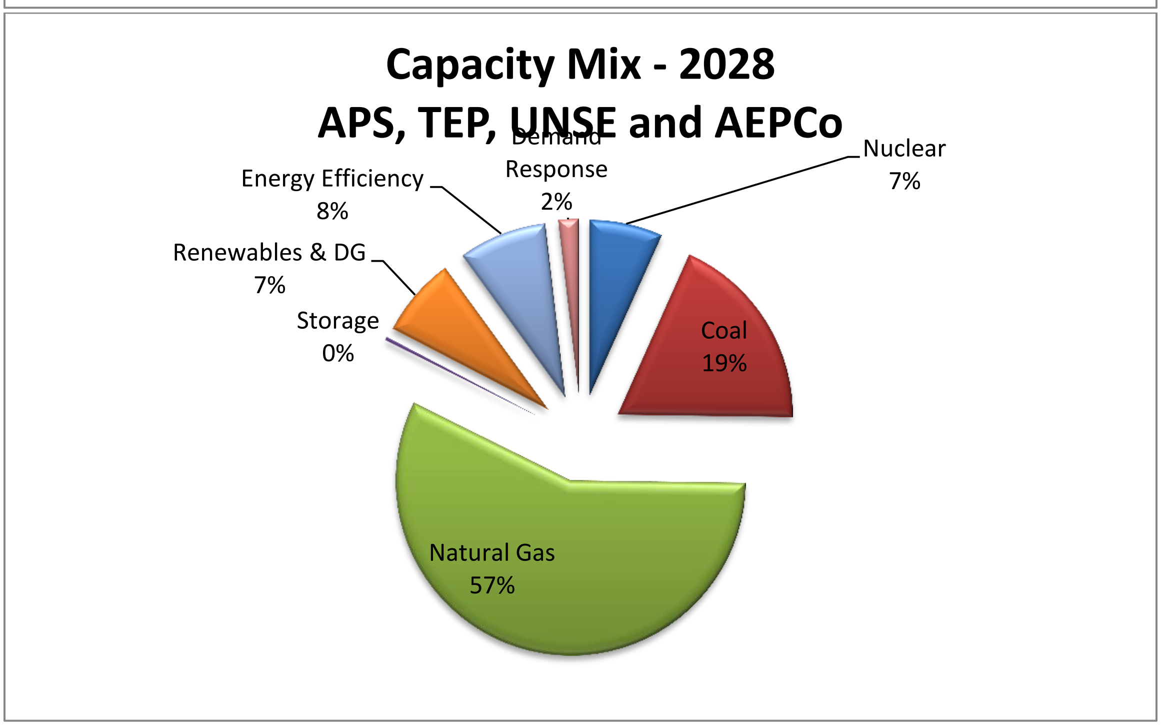
Observations:

- Resource additions are dominated by new natural gas-fired generating facilities. Although this situation reduces the former over-reliance on coal generation, it may bring additional fuel cost risk. However, it is unclear that another path is available.

7. Change in Capacity Mix

The following charts compare the capacity mix change that will occur under the 2014 IRPs filed by APS, TEP, UNSE and AEPCo, based on contribution to system peak demand:

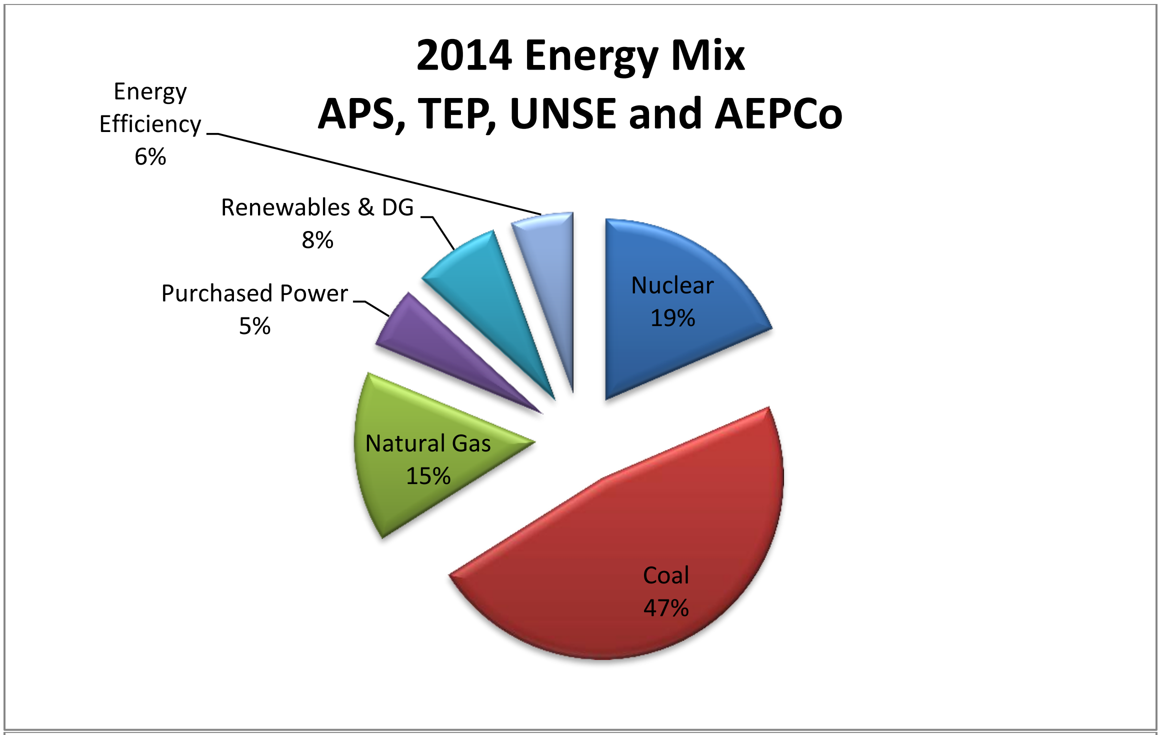


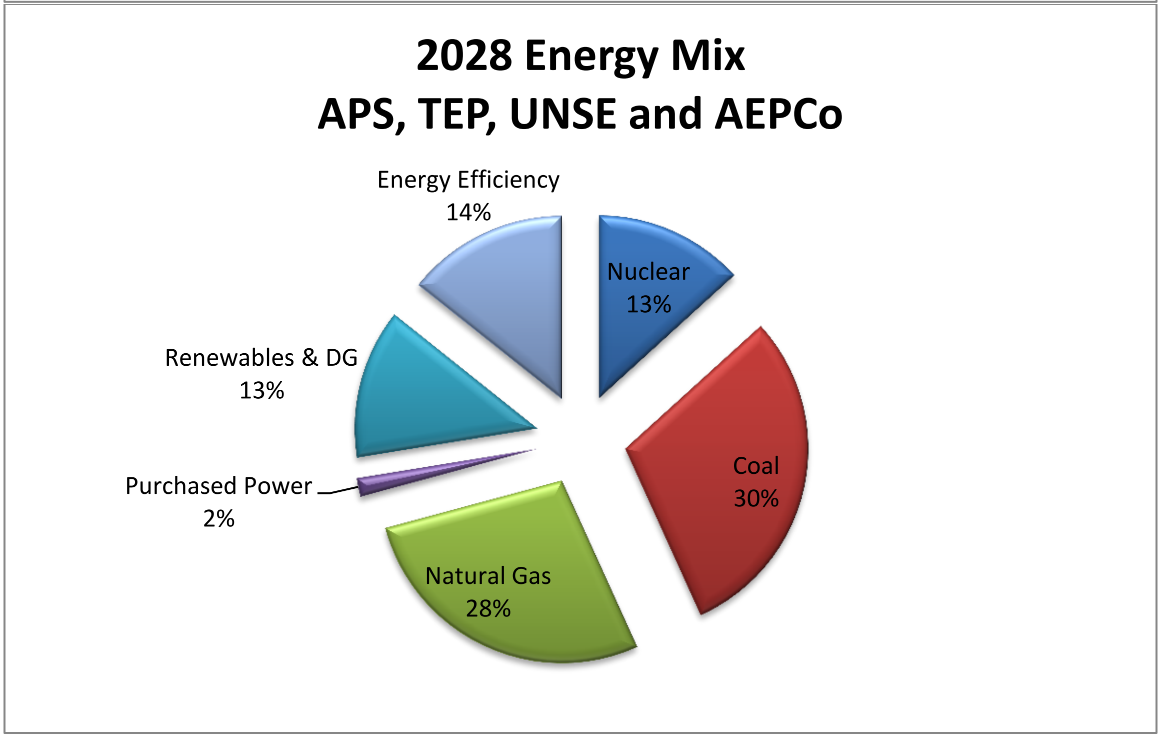


The charts reflect the major reductions in coal generators, and the additions planned in EE programs, renewable generation (both utility-scale and distributed) and natural gas-fired generators.

8. Change in Energy Mix

The following charts compare the energy mix change that will occur under the 2012 IRPs filed by APS, TEP, UNSE and AEPCo:

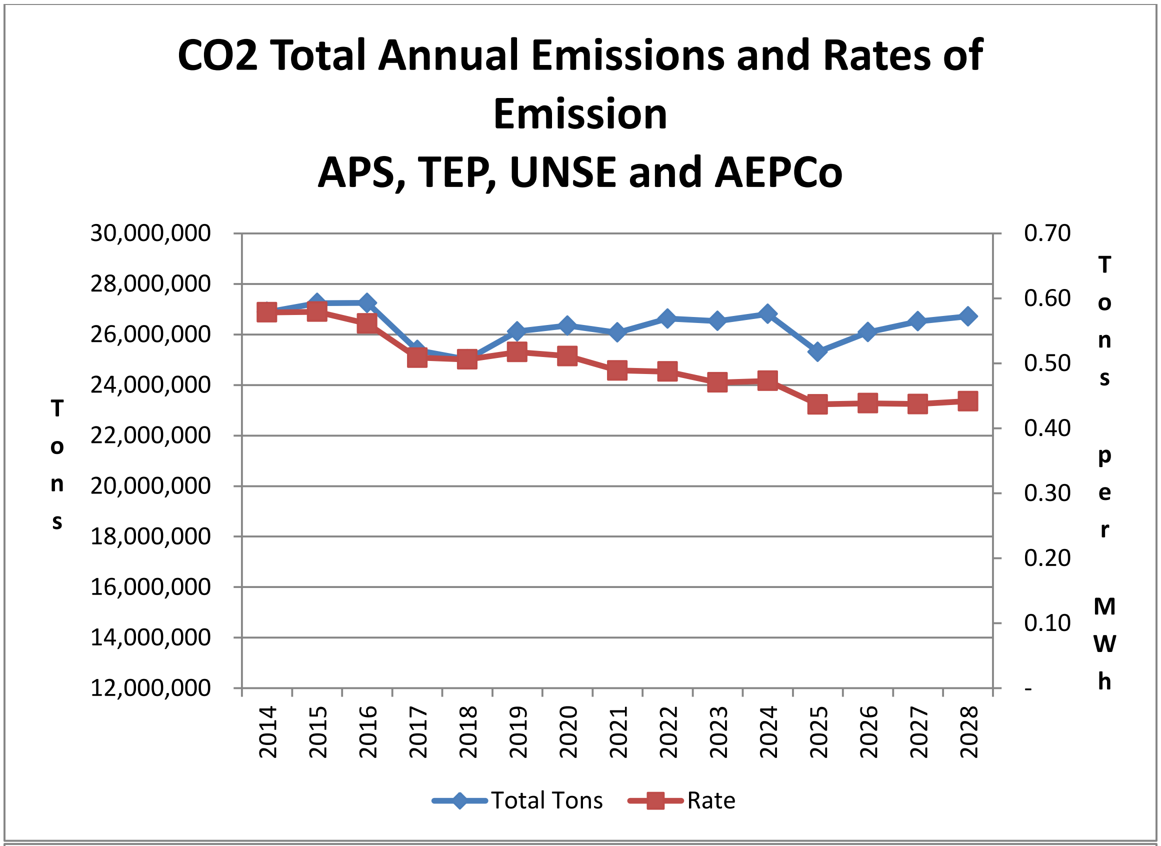


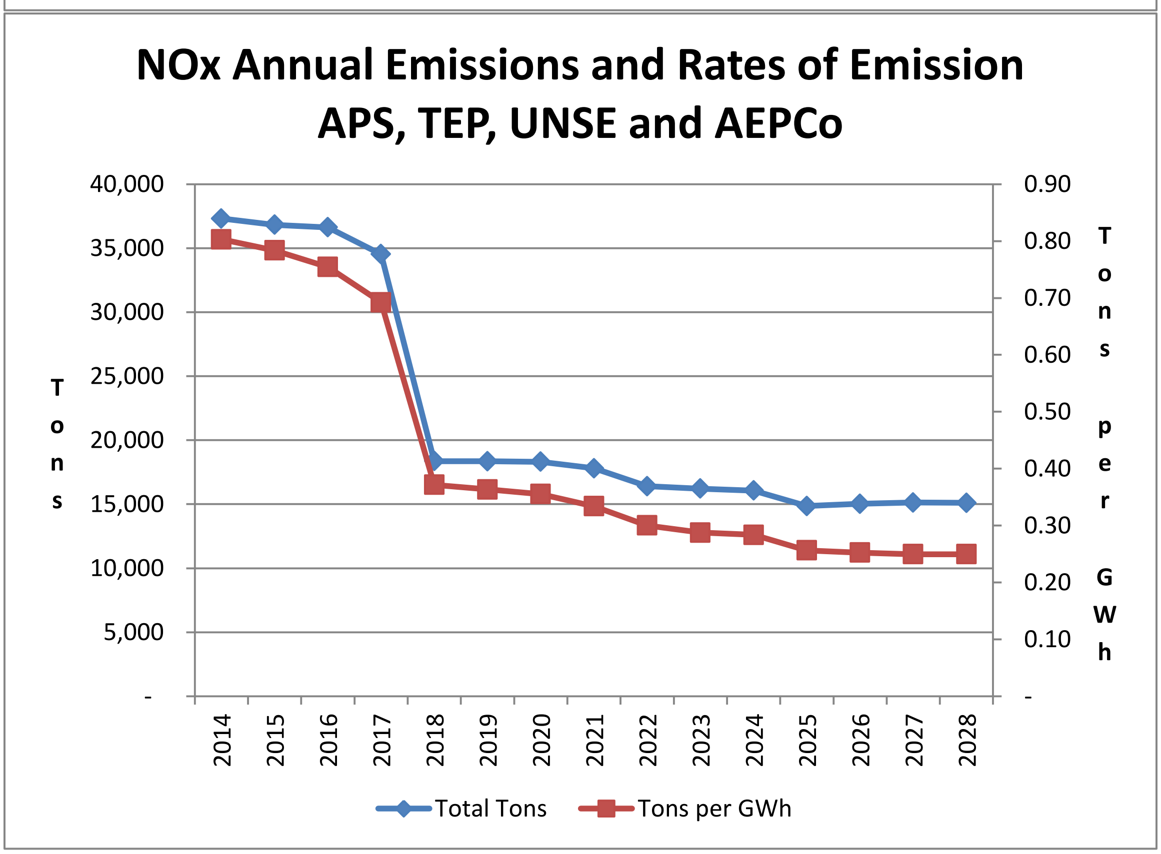


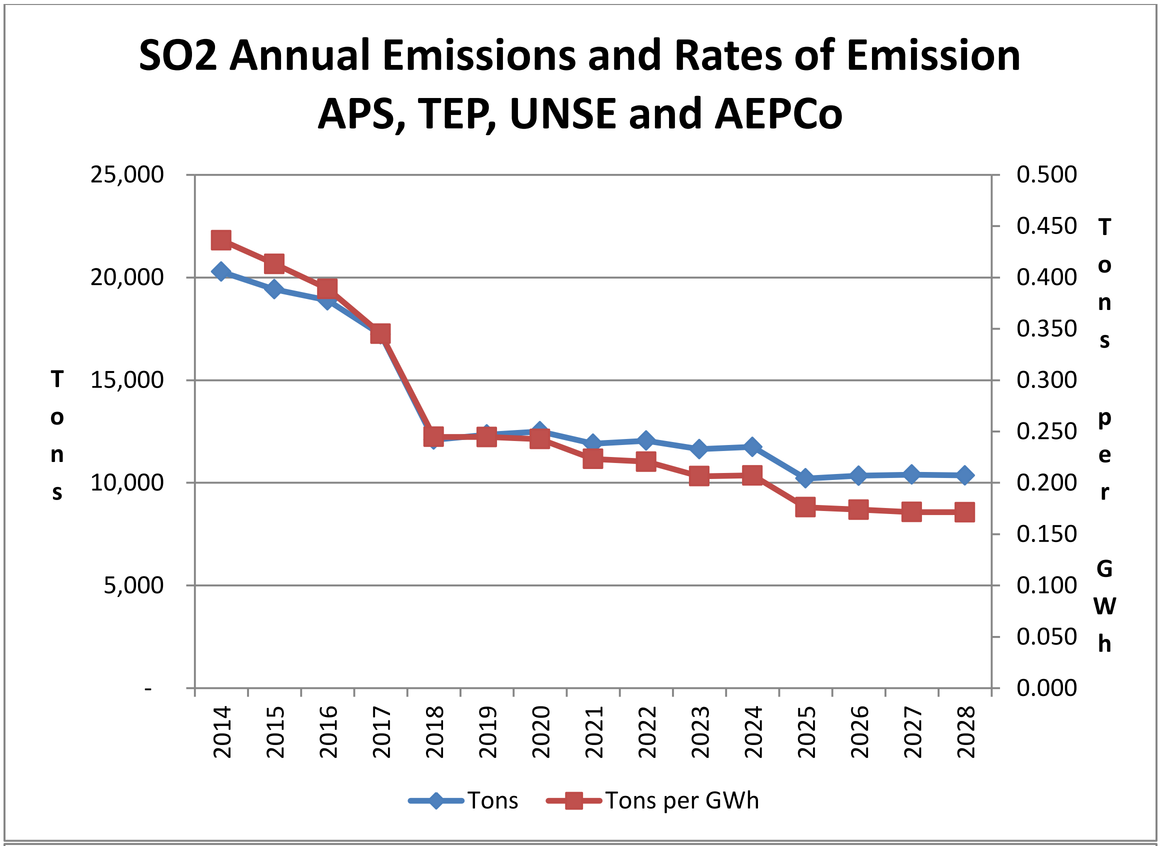
As the charts show, the 2014 IRPs reflect a dramatic decline in the prominence of coal-fired generation over the 15 year horizon, with energy efficiency programs, renewable generation and natural gas-fired generation playing a much more significant role. Overall, the four load-serving entities have a balanced fuel mix.

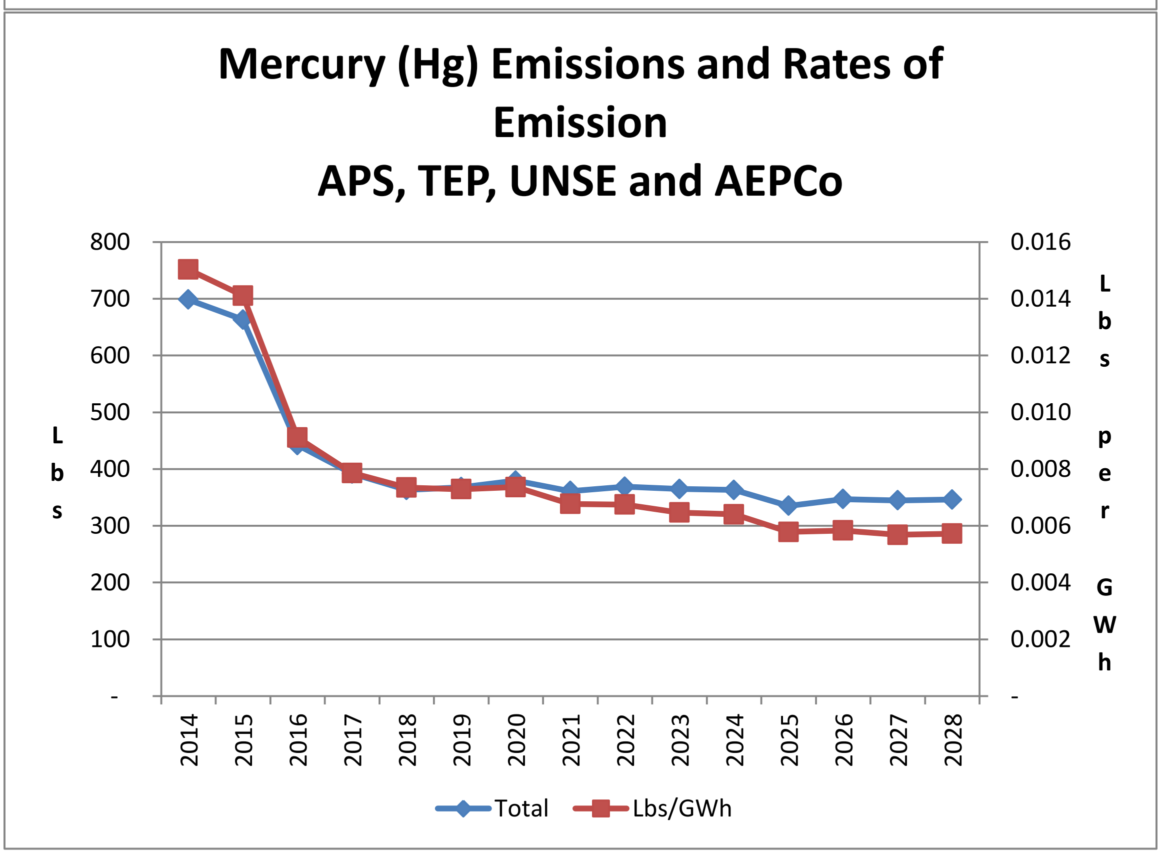
9. Impacts on Emissions and Water Usage

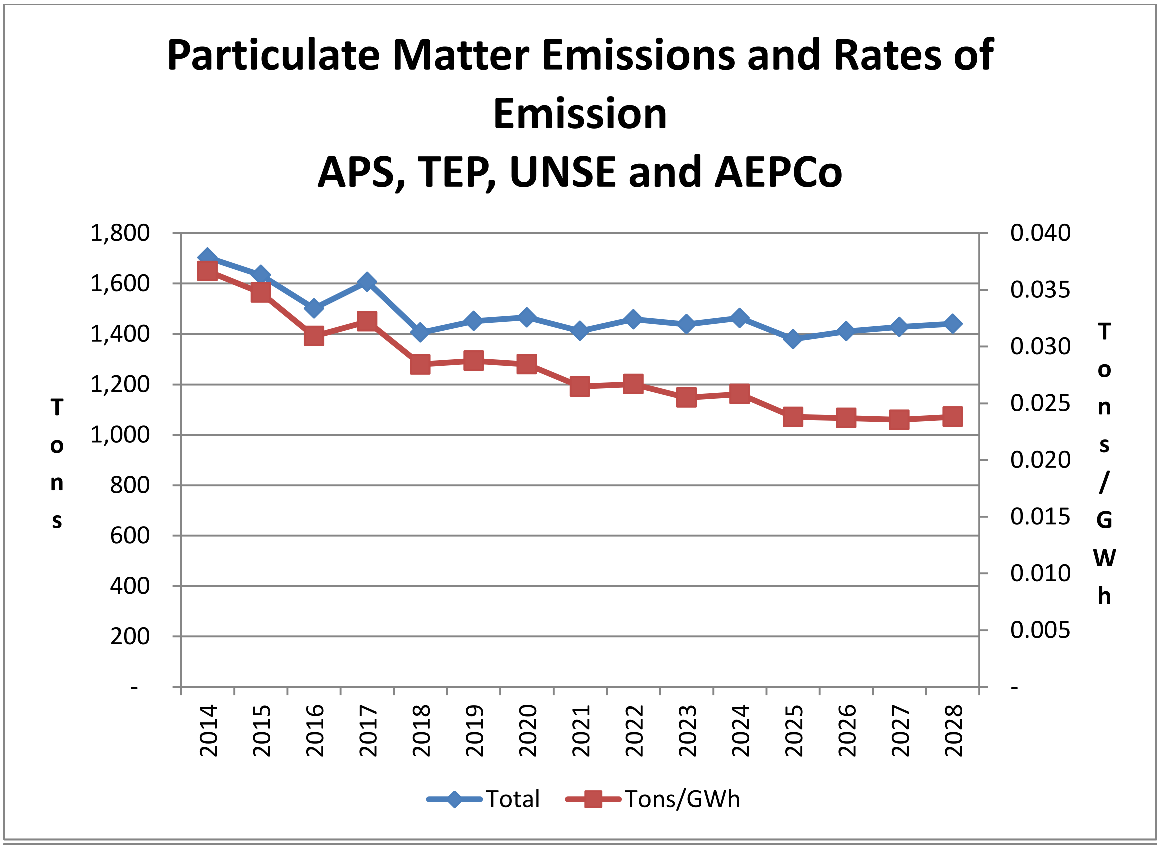
The following charts show the impact of the 2014 IRPs on CO2, NOx, SO2, mercury, and particulate matter emissions, along with water usage and coal ash production. These are the combined impacts of the APS, TEP, UNSE and AEPCo IRPs.

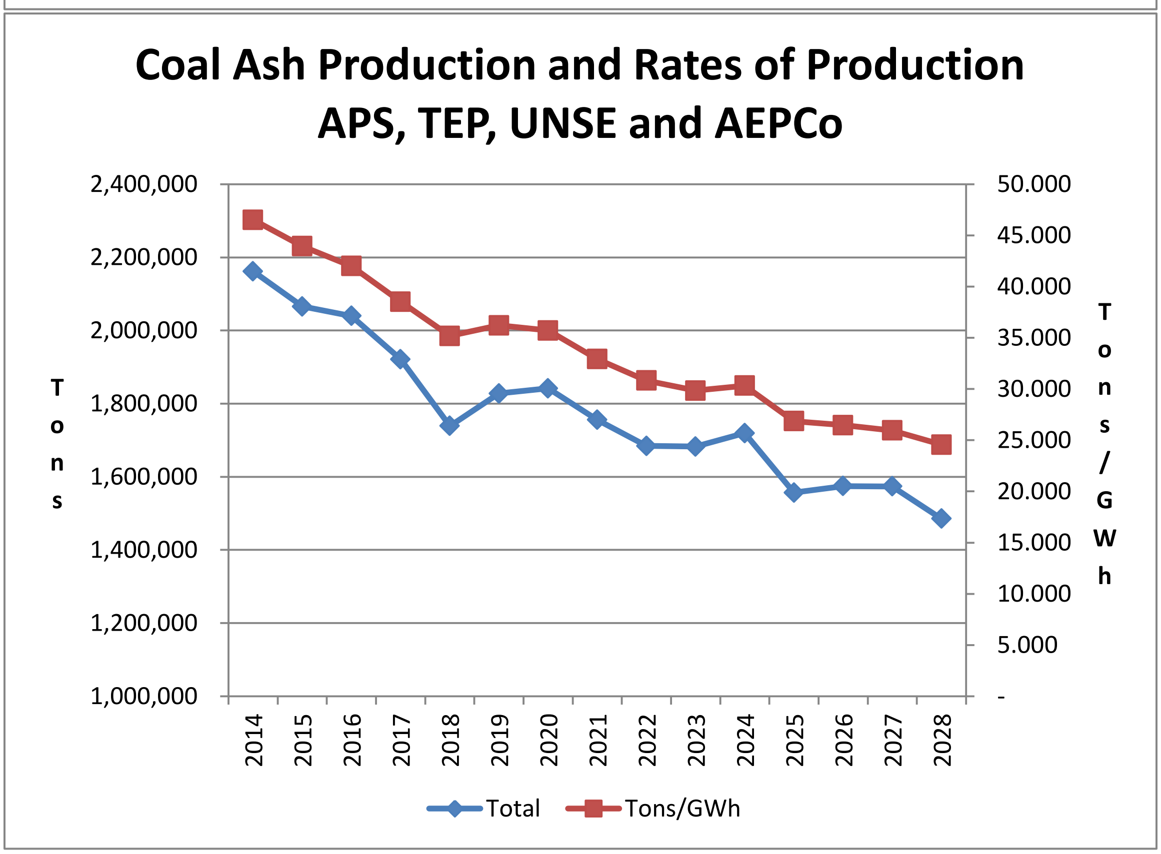

CO2 Total Annual Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
Tons
Tons per MWh
30,000,000
28,000,000
26,000,000
24,000,000
22,000,000
20,000,000
18,000,000
16,000,000
14,000,000
12,000,000
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total Tons
Rate

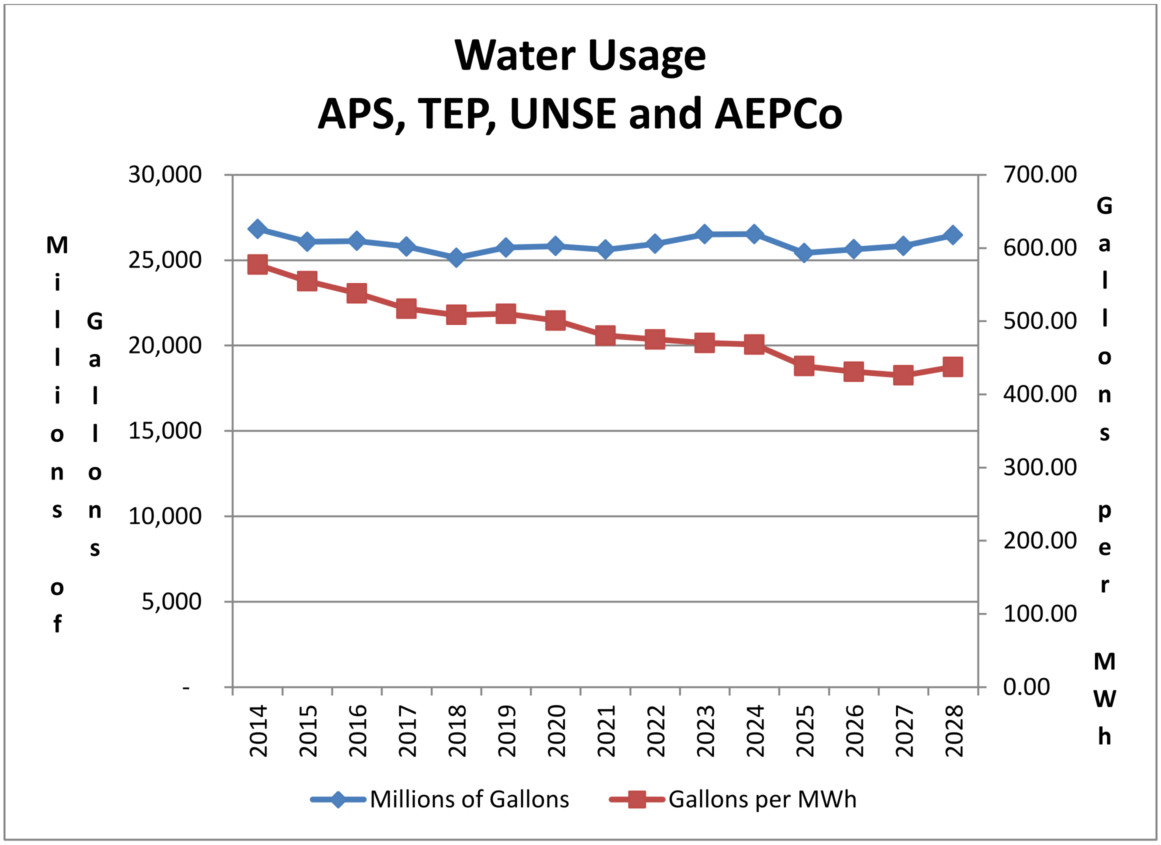

NOx Annual Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
Tons
Tons per GWh
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
-
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total Tons
Tons per GWh


SO2 Annual Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
25,000
20,000
15,000
10,000
5,000
-
Tons
0.500
0.450
0.400
0.350
0.300
0.250
0.200
0.150
0.100
0.050
0.000
Tons per GWh
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Tons
Tons per GWh


Mercury (Hg) Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
800
700
600
500
400
300
200
100
-
Lbs
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
-
Lbs per GWh
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total
Lbs/GWh


Particulate Matter Emissions and Rates of Emission
APS, TEP, UNSE and AEPCo
Tons
Tons/GWh
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
0.040
0.035
0.030
0.025
0.020
0.015
0.010
0.005
-
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total
Tons/GWh


Coal Ash Production and Rates of Production
APS, TEP, UNSE and AEPCo
Tons
Tons/GWh
2,400,000
2,200,000
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
50.000
45.000
40.000
35.000
30.000
25.000
20.000
15.000
10.000
5.000
-
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Total
Tons/GWh



Under the 2014 IRPs, the rates of production of all emissions, the rate of coal ash production, and the rate of water usage per unit energy produced are decreasing significantly throughout the 15-year period. In addition, the total annual emissions of NOx, SO2, mercury and particulate matter, and the total annual production of coal ash are significantly reduced across the study period. This trend is largely due to the movement toward renewable energy, energy efficiency programs and natural gas-fired generation, and away from coal-fired generation. However, CO2 production and total water usage remain essentially unchanged across the 15 year period.

10. Rate Impacts

In response to a request from Staff, TEP and UNSE have provided the estimated impacts on retail rates arising from their IRPs over the 15 year planning period. TEP forecasts an average annual retail rate increase of 3.9% per year and UNSE forecasts an average annual retail rate increase of 3.7% over the planning period.

APS did not provide estimated impacts on retail rates arising from their IRP. However, APS did provide the estimated annual average system generation costs, which is the sum of annual revenue requirements of existing generation, new generation, new transmission and variable costs (such as fuel, O&M, etc.) divided by the annual energy requirement. Under APS's IRP, the annual average increase in average system generation costs is estimated to be 3.2%. However, this growth rate for APS is not a projection of future rates or rate impacts.

O. Natural Gas Supply

Over the next fifteen years, the Arizona electric utilities plan to construct over 6,000 megawatts of new natural gas-fired generating facilities. A natural question arising is – can the Arizona natural gas supply and delivery infrastructure accommodate these planned facilities?

Arizona's natural gas needs are supplied by three major gas basins – the San Juan, Permian and Rockies basins. Transportation of natural gas into the state is accomplished via a pipeline network that is comprised of a dual system served by El Paso and Transwestern.

For the APS 2012 IRP, Information Handling Services' subsidiary Cambridge Energy Research Associates ("IHS CERA") prepared a fuel supply outlook which led APS to conclude that it does not "foresee any fuel supply issues during the Planning Period"[17]. In addition to this analysis, Bentek prepared a study for APS reviewing the Southwest Natural Gas Market for the period 2013-2029. In addition, APS has been actively involved in the 2013-2014 Western Interstate Energy Board's Natural Gas-Electric Interdependency study conducted with Energy and Environmental Economics, and APS produced a 2014 Gas Transportation Analysis summary for its selected resource plan[18]. APS does not foresee any difficulties in supplying its planned and existing natural gas-fired generators. TEP and UNSE both foresee sufficient natural gas supply and transportation in future years[19]. AEPCo does not include new gas-fired generating facilities in its IRP, but AEPCo does plan to convert Apache Steam Unit 2 to natural gas in 2018. AEPCo is currently assessing the additional natural gas needs it will face under the conversion of Apache Steam Unit 2 to natural gas.

Based on these assessments by the load-serving entities, it appears that the existing infrastructure will be sufficient to supply planned new gas-fired generators[20].

[17] *See* APS 2012 Integrated Resource Plan, p. 105.
[18] *See* APS 2014 Integrated Resource Plan, p. 113.
[19] *See* TEP 2014 Integrated Resource Plan, chapter 16; *see also* UNSE 2014 Integrated Resource Plan, chapter 13.
[20] This statement assumes that the CPP will not require the replacement of a large number of existing coal plants with natural gas-fired generating facilities.

IV. State of the IRP Rules

During 2013, APS, TEP and UNSE made important long-term decisions that impact each load-serving entity's IRP. APS made the decision in 2013 to carry out the Ocotillo Modernization Project, which will add 290 megawatts of new capacity at the Ocotillo site. In the development of its 2014 IRP, APS has assumed that this project will go forward in all scenarios studied. TEP and UNSE made the decision in 2013 to acquire portions of the Gila River combined cycle merchant plant. In the development of their 2014 IRPs, TEP and UNSE assumed this purchase will be finalized in all cases studied.

Although these 2013 decisions by APS, TEP and UNSE may be entirely reasonable, the decisions were made outside the context of the IRP filings, were not subject to stakeholder review and the economic consequences have not been fully vetted in the context of an IRP. Staff believes that making these types of resource decisions outside of the IRP process illustrates a shortcoming of the IRP rules.

Staff's experience in the processing of this IRP as well as prior IRPs has led Staff to believe that the current IRP process does not properly incent participation by the utilities that are subject to the IRP rules. There is no link between the IRPs prepared under the rules to subsequent Commission approval processes for resource additions. Staff notes that the Commission's Biennial Transmission Assessment effectively incents participation in that process by offering a firm and mandatory link between a company's future transmission plans (as submitted in the required 10-year transmission plans) and the Certificate of Environmental Compliance ("CEC") that is required to implement the company's plan. There is no such link between the resource plans prepared under the IRP process and the CEC process. This disconnect could lead to the entities filing IRPs that technically meet the requirements of the IRP rules, but may not accurately reflect the entities' true plans.

The Commission may wish to consider requiring entities to provide a narrative description of any substantial changes to previously filed IRPs and having them amend their resource plans whenever a substantive change in either planned generation capacity or load forecast is anticipated.

Another area of concern for Staff is the fact that the current IRP Rules only apply to four load-serving entities (APS, TEP, UNSE, and AEPCO). These four entities account for approximately 60% of the total State-wide electric generation by utility companies. The Commission's IRP process does not consider the generation capacity and loads of SRP, Independent Power Producers (aka merchant generators), municipal power companies, electric service districts, or combined heat and power producers. Therefore, the Commission's evaluation considers less than two-thirds of the electric infrastructure in Arizona. Without being able to consider 100 percent of the state's generation resources to the Commission cannot complete a true state-wide review and assessment as contemplated by the Rules.

With the specter of EPA Rule 111(d) looming, knowledge of the total planned resource mix with which Arizona has at its disposal to meet future consumer load requirements while staying in compliance will only increase in importance.

V. Comments of the Parties

Many of the parties involved in this docket provided written, docketed comments concerning the IRPs and the Staff draft report. Staff has summarized the comments and, in some cases, provides responses below. The complete docketed comments can be found on the Commission web site at http://www.azcc.gov.

Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNSE")

TEP and UNSE provided comments to Staff concerning the Staff's draft report on November 19, 2014. The comments concerned Staff's recommendation that TEP's load forecast techniques be re-examined prior to the 2016 IRP filing and differences pointed out by Staff concerning the APS and TEP/UNSE capital cost assumptions for new generating facilities.

Concerning the load forecasting issue, TEP and UNSE state that the Staff recommendation may be based on a comparison of actual peak demand data to forecasted peak demand data that is absent energy efficiency and distributed generation impacts. TEP and UNSE recommend that Staff review the information that was analyzed and consider additional data supplied by TEP and UNSE. Staff has considered the additional data supplied, and has made revisions to this final report. However, Staff still has concerns regarding the TEP peak demand load forecast.

Regarding capital cost assumptions, TEP and UNSE provided additional information concerning the development of their supply-side cost assumptions, and also provided information to explain some of the large discrepancies in the APS assumptions as compared to the TEP/UNSE assumptions. Staff has incorporated some of this information in this final report.

Solar Energy Industries Association ("SEIA")

SEIA's comments concern the APS and TEP IRPs, and the amount of renewable generation contained in those IRPs. According to SEIA, APS and TEP are planning to rely predominately on natural gas to fulfill future energy and capacity needs. While some incremental renewable resource additions are included, the amount is relatively small in comparison to natural gas. The TEP IRP does not even anticipate adding sufficient renewables to meet the RES requirements.

This reliance on natural gas puts customers at greater financial risk since fuel costs are largely passed through to customers and not borne by the utility. Unlike renewables, gas plants also pose the additional risk of becoming stranded assets if fuel prices were to increase substantially, or new environmental regulations restrict their use.

Under the "High RE Portfolios" studied by APS and TEP, the fuel price risks to customers is substantially mitigated, and the incremental cost of these High RE Portfolios is relatively small, under base assumptions. In SEIA's opinion, the cost of the High RE

Portfolios is essentially “in the noise”. In addition, analysis of various scenarios suggests that the High RE Portfolios are likely to yield cost savings to customers, and updating the IRP cost assumptions would further support the High RE Portfolios.

Both the APS and TEP IRPs propose new combustion turbines to provide the flexibility needed for the integration of renewable generation. However, there is little evidence in the IRPs that new combustion turbines are needed to meet flexibility needs in the short term. The utilities have not demonstrated this need quantitatively through robust reliability analysis.

SEIA makes the following recommendations:

- Use High RE Portfolios as the Base Portfolios.
- Focus Commission analysis on future risk and cost to ratepayers.
- Update the assumptions in the APS and TEP IRPs to more accurately reflect current and future market costs for solar as well as future environmental policies.
- Establish a method for quantifying the need for flexible resources and require consideration of all options for meeting those needs.

Tucson Electric Power Company (“TEP”)

TEP filed written comments in response to certain portions of SEIA’s comments that concern TEP’s IRP. SEIA claimed in its comments that TEP’s IRP does not anticipate adding sufficient RE resources to meet the RES requirements.

TEP states that SEIA’s claim is incorrect. Although TEP does not add any utility scale RE resources between 2017 and 2022, this is because TEP plans to generate excess RE from 2014 through 2018, and utilize excess credits for 2019-2028 to make up for any annual shortfalls. This early over compliance is based on TEP’s commitment to take advantage of the 30% Investment Tax Credit that is scheduled to expire in 2016.

Western Resource Advocates (“WRA”)

WRA’s comments concern APS’s 2014 IRP. WRA supports APS’s decision to amend its 2014 IRP by changing its preferred plan to the Managed Coal Strategy. They support APS’s proposed discontinuation of coal-fired generation at the Cholla plant, and concur with Staff’s recommendation that the Commission approve the retirement of Cholla Unit 2 as requested by APS.

WRA notes that the Managed Coal Strategy does not increase costs, according to APS’s analysis. The Managed Coal Strategy will reduce APS’s carbon dioxide emissions as compared to the Base Portfolio, but carbon dioxide emissions will still increase. Under the selected plan, APS’s reliance on natural gas increases so that 35% of all energy resources in 2029 require the combustion of natural gas. Natural gas prices have fluctuated wildly in the past and it is prudent to expect large variations in the future.

Concerning future resource plans, WRA recommends that APS examine portfolios that reduce its reliance on natural gas by substituting renewable energy and additional energy efficiency resources for natural gas resources. APS should also consider a more specific set of investment in energy storage, smart inverters and other technologies to better integrate solar and wind energy. Finally, APS should consider locating new renewable resources near the Cholla site, and evaluate additional coal plant retirements.

Concerning APS's load forecasts, WRA states that the forecasts appear to be high. WRA concurs with Staff on this point and agrees that APS should reexamine its load forecasting techniques prior to the filing of its 2016 IRP.

Arizona Electric Power Cooperative, Inc. ("AEPCo")

AEPCo's comments serve to correct several statements made in the Staff's draft report concerning information provided by AEPCo on coal ash production. Staff has made the requested corrections.

Southwest Energy Efficiency Project ("SWEEP")

SWEEP's comments concern the role of energy efficiency and demand response programs in the 2014 IRPs of APS and TEP. The key findings in SWEEP's comments are the following:

1. APS and TEP need additional resources to meet load obligations over the next 15 years.
2. Energy efficiency and demand response programs play a significant role in enabling APS and TEP to meet these obligations.
3. APS and TEP both identify energy efficiency as the least expensive energy resource available to meet customer needs.
4. Total costs for customers will increase if TEP and APS under-invest in the EE resources documented in their IRPs, as they will need to substitute for resources that are comparatively more expensive. If anything, APS and TEP should implement more EE than the EE Standard requires in order to meet customer needs and to keep total customer costs lower than they would otherwise be.
5. EE programs meet capacity needs by building up the EE resource over time.
6. EE resources should be built up over time in order to lower program and ratepayer costs.
7. Cost-effective EE built up over time provides benefits today and tomorrow and helps to support and provide flexibility for new innovations and opportunities.

The bottom line of SWEEP's comments is to recommend that APS and TEP employ energy efficiency measures in excess of those required by the EE Standard.

SWEEP filed Supplemental comments into the docket on December 15, 2014. In this filing, SWEEP reiterated comments from its earlier filing, and offered several examples of how EE plays an important role in avoiding investment in more costly generation.

Joint Comments

Joint comments were filed by the Arizona Competitive Power Alliance ("ACPA"), Efficiency First AZ ("EFAZ"), Residential Utility Consumer office ("RUCO"), Southwest Energy Efficiency Project ("SWEEP"), Solar City, Solar Energy Industries Association ("SEIA"), Western Grid Group, and Western Resource Advocates ("WRA"). These Joint Parties describe concerns with the existing IRP process and offer suggestions on how to improve the current IRP process. Identified concerns within the existing IRP process include the following:

Inappropriate Planning Assumptions – The Joint Parties are concerned that, in the current IRP process, inappropriate planning assumptions are made regarding critical inputs such as load forecasts, resource costs, adoption rates of new technologies, assessment of impacts of future regulations and customer preferences.

Disconnect between Resource procurement and Resource Planning – The current process does not hold utilities accountable for making investment decisions upon the plans they submit. Resource procurement decisions can – and have been – made outside the IRP framework without a full evaluation of alternatives and without stakeholder input.

Insufficient Data and Analysis – The current process fails to fully capture the challenges and opportunities of rapidly changing technology, new consumer preferences, and environmental regulations. More data and analyses are needed to understand the trends shaping the electric industry.

Absence of Independent Analysis – Additional independent analysis would increase the objectivity, value, and usefulness of the IRP process. Consultants used by the Commission to date have provided little critical analysis of the costs, benefits, or risks of the alternative portfolios, nor provided information to the Commission that could be used to evaluate, consider and acknowledge a preferred plan. A more comprehensive analysis of resource planning issues is needed.

The Joint Parties propose a set of reforms to modify the current IRP process. These reforms would require that the Commission, through an RFP process, hire a consultant (likely a team of experts) to conduct an independent analysis of utility resource needs and provide a critical analysis of the IRPs and three year action plans. The revised IRP process would consist of the following steps:

1. **Define Key Assumptions, Resource Options, etc. –** Stakeholder workshops would be conducted by the Commission to help determine key assumptions. The consultant would obtain reliable information on the cost and availability of various resources, the timing of resource procurement and resource operating characteristics. If certain additional information is needed, an RFI could be issued to collect that information.

2. Obtain Data and Conduct Analyses to Provide Guidance to Utilities – The consultant would gather and analyze data to recommend additional scenarios and portfolios in the IRP plans for utilities to analyze. This process of recommending portfolios and scenarios should consider customer preferences, state-enacted policies and federal regulations.

3. Develop IRP and Near Term Action Plan – Based upon input and results from the previous steps, the utilities would develop their 15 year IRPs in accordance with the existing rules. Utilities should address integration of generation with transmission and distribution planning in the IRP. To the extent possible, the Consultant and utilities should take a statewide perspective. The consultant would then review and analyze the plans. The Commission would approve the Action Plan and acknowledge a long-term IRP with a selected portfolio if it concluded that doing so is in the public interest.

4. Review Near Term Action Plan and Specify Details of the Resource Needs – If near-term resource needs were identified by the utility in its Action Plan, the consultant would evaluate and verify these needs. This would not establish prudency for rate making purposes. Based on the needs in the Action Plan, the consultant in partnership with the utility and stakeholders would also establish specific parameters of the needs for the purposes of resource procurement.

5. Conduct Competitive Resource Procurement – Utilities would follow the established rule to procure resources, as identified in an approved Action Plan, through a competitive Request for Proposal (RFP) process. The Commission, its consultant, and stakeholders would be provided an opportunity to review and comment on the RFP prior to its release. The RFP process would include an Independent Monitor as specified in existing policy. The results of the RFP would be subject to an independent review and comment by the Commission consultant.

Arizona Public Service Company (“APS”)

Based upon discussions with RUCO and other stakeholders, APS makes the following recommendations for potential next steps in advancing and improving the IRP process:

1. Conduct Utility-Specific Requests for Information – The initial step in the development of an IRP would be to hire an independent monitor (“IM”). Once the IM has been selected, individual utilities would conduct a Request for Information (“RFI”) to gather current pricing and performance information for various technologies. The RFI process would be reviewed by the IM, and the results of the RFO and IM review would be made available to the Commission Staff and its independent consultant.

2. Collaborative Process for Utility Planning Assumptions and Needs – After each utility has gathered and developed information about operational needs and expected load growth, APS recommends that a workshop be convened at Commission direction to allow interested parties to provide comments to utilities regarding the underlying information used to develop each utility's IRP. The Commission's independent consultant may participate and provide comments and an independent review of each utility's needs and resource alternatives.

3. Additional Enhancements to the IRP Process – APS recommends that the Commission approve utility resource plans. In addition, APS is supportive of further enhancing the IRP process to include concepts such as the integration with transmission and distribution planning and utilizing the IRP process to better determine the level, types and timing of energy efficiency and other demand side management resources.

4. Post Commission Approval and Procurement – As new resources are needed, each utility would develop a competitive bidding process whereby resource needs would be solicited for specific projects through Requests for Proposals ("RFP"). The process would be overseen by an IM and information from the solicitations would be shared, under protective agreement, with Commission Staff and their consultant. Generation projects requiring a Certificate of Environmental Compatibility ("CEC") would continue to advance through this process as currently defined by statute; however, APS would be supportive of expanding the eligible technologies subject to CEC.

Concerning the proposed Ocotillo Modernization Project ("OMP"), APS disagrees with the statement in the draft Staff report that OMP "may not be the most economic choice, and the construction of additional capacity at Ocotillo should not be initiated without the issuance of an RFP to satisfy the additional 290 megawatt addition that APS plans at Ocotillo." APS has conducted extensive analyses regarding the economics of the OMP, and has identified a variety of other economic and non-economic benefits of the OMP. Staff has modified the language concerning the OMP in this final report.

Questions regarding whether APS mentioned its plans for Ocotillo in its 2012 IRP were raised at the Commission's second IRP workshop. APS makes reference to several statements in the 2012 IRP concerning Ocotillo.

APS argues that an RFP is not required by the Commission rules for the additional capacity planned at Ocotillo. However, APS also states that, in an abundance of caution and to alleviate concerns that have been raised, APS intends to proceed with an RFP for the additional capacity prior to proceeding with this phase of the OMP.

APS requests that the "Rate Impact" information shown on page 99 of the draft Staff report be withdrawn or modified to accurately convey what this information reflects. Staff has made the requested changes in this final report.

APS argues that any conclusions that the APS load forecast is "aggressive" or "optimistic" are unwarranted and appear to result from apples-to-oranges comparisons of forecast data to historical data. Staff has corrected the load forecast charts that appeared on page 32 of the draft Staff report. However, Staff remains concerned that the APS load forecast may be too optimistic.

Regarding the DSM programs listed in a table on page 45 of the draft Staff report and the supply side resource listed in a table on page 48 of the draft Staff report, APS requests corrections to the tables. Staff has made the requested corrections in this final report.

Freeport Minerals Corporation ("FMC") and Arizonans for Electric Choice and Competition ("AECC")

FMC and AECC support the IRP process as a means to ensure that Arizona electric utilities plan for and construct generation facilities when appropriate, but only after seeking wholesale market alternatives that represent the least-cost options for the benefit of ratepayers. The market should dictate how generation resources are developed across a long planning horizon.

In addition, FMC and AECC agree with Staff's finding that APS's proposed Ocotillo Modernization Project does not represent the most economic choice for an additional 290 megawatts of generation capacity. The existing wholesale market can provide more economic options without any incremental impact on the environment, as these generating facilities have already been built.

Also, FMC and AECC agree with Staff's finding that the APS and TEP load forecasts are aggressive given the state of today's economy, as well as more recent load-growth data. The historical load growth patterns upon which APS and TEP rely are outdated and do not accurately represent what future generation needs will be.

FMC and AECC are concerned with the lack of analysis regarding the projected rate increases under the APS and TEP IRPs. The projected rate increases should be compared to those in other regions, and the Staff report should contain more information and detailed analysis about the link between planned facilities and their projected cost impact on rates.

Finally, FMC disagrees with stakeholders who argue that the incremental cost of renewable technology can serve as a hedge to ratepayers and offset the risk of rising natural gas prices. On the contrary, FMC argues that there is no indication that the long-term price of natural gas will make today's renewable technology more attractive at the price-per-kwh it takes to develop such resources.

VI. Conclusions and Recommendations

For the most part, the 2014 Integrated Resource Plans produced by APS, TEP and UNSE are reasonable and in the public interest, based upon the information available to the Staff at the time this report was prepared and the factors set out in R14-2-704(B). While Staff believes the IRPs of APS, TEP and UNSE meet the requirements of the Commission's IRP rules, the following issues have been identified concerning the IRPs of APS, TEP and UNSE:

<u>APS:</u>

- In Staff's Draft Assessment of the 2014 Integrated Resource plans (docketed November 3, 2014), Staff expressed concerns regarding the additional 290 MWs of additional capacity that is included in APS's proposed Ocotillo Modernization Project ("OMP"). Staff concluded with a recommendation to the Commission that APS should be directed to conduct an all-resource Request for Proposal ("RFP") process prior to initiating the construction of the proposed additional capacity so as to be certain that the proposed capacity addition was the most cost-effective option.

- Since docketing the Draft Assessment, Staff has reviewed the testimony from the OMP Certificate of Environmental Compatibility hearing before the Commission's Line Siting Committee (Docket #E-00000V-13-0070). Based on this review, Staff believes that the OMP may offer a unique opportunity to add capacity at a strategic location within the Phoenix Load Pocket. In addition, existing Ocotillo site attributes such as the availability of water, natural gas, and transmission infrastructure support the redevelopment activities proposed in the OMP. Further, Staff recognizes that APS conducted a variety of economic feasibility studies which point to the economic viability of the OMP.

- In making its earlier recommendation regarding the all-resources RFP, Staff partially relied on its interpretation of the R14-2-705 "Procurement" section of the Resource Planning and Procurement Rules ("Rules"). Staff initially believes that these Rules could be interpreted to require Load Serving Entities to procure new capacity through an RFP process. Based on discussions with APS, Staff concludes that there may be ambiguity in the rules as to when the RFP process is required. Exclusion to the RFP process contained in R14-2-705B(5) may apply to the OMP.

- Staff notes that APS has volunteered to conduct an all-resources RFP process prior to adding the additional 290 MW of capacity. Staff commends APS for making this voluntary commitment and believes that the information derived through the RFP process may provide useful information at such time that APS seeks cost recovery of the OMP.

- Staff recommends that if APS believes such information would be useful in demonstrating the prudency of the OMP, APS may conduct all-resources RFP prior to initiating construction, as it has volunteered to do.

- APS has requested that the Commission specifically approve the proposed retirement of Cholla Unit 2 in April of 2016. APS cites the provisions of R 14-2-704(E) as the basis for this specific approval. Subsequent to the receipt of this request for specific approval, Staff issued a set of Data Requests to APS inquiring, among other things, whether APS would seek recovery of stranded costs associated with the Unit 2 retirement, and if APS understands that any Commission approval of the Cholla Unit 2 retirement under this IRP proceeding would not be considered an approval of the prudency and cost of the retirement. APS responded affirmatively to both questions.

- Based on APS's recognition that the specific approval under this IRP proceeding of the Cholla Unit 2 retirement in April 2016 is not an approval of the prudency or costs associated with the retirement, Staff recommends that the Commission grant approval of said retirement. However, this approval would not imply a specific treatment or recommendation for rate base or rate making purposes in APS's future rate filings.

TEP and APS:

- The TEP and APS load forecasts appear to be somewhat optimistic, in that both assume a rapid return to historical load growth, even though recent experience does not support this assumption. Staff recommends that TEP and APS re-examine their load forecasting techniques prior to the filing of the 2016 IRPs.

All Load Serving Entities

- All four Load Serving Entities should include a discussion of how their proposed management technologies will quantitatively reduce emissions and other impacts.

- All four Load Serving Entities should hold public workshops jointly with Staff prior to filing future IRPs. The purpose of these workshops would be to allow all stakeholders to jointly define issues to be considered in the resource plans. Issues to be considered in the plans would include risk factors, new technologies, proposed and anticipated environmental regulations, and other issues identified by the stakeholders.

AEPCO

- Concerning AEPCo, Staff finds that the information supplied by AEPCo satisfies the requirements of Decision No. 73884.

With the above recommendations, Staff recommends that the Commission acknowledge the 2014 IRPs filed by APS, TEP and UNSE.