PUBLIC SERVICE COMPANY OF OKLAHOMA℠

An AEP Company

BOUNDLESS ENERGY℠

INTEGRATED RESOURCE PLANNING REPORT

TO THE

OKLAHOMA CORPORATION COMMISSION

December 20, 2018

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serve load over the next ten (10) years, including any planned proposed changes to existing transmission facilities	
(11) Schedule K: An assessment of the need for additional resources to meet reliability, cost and price, environmental or other criteria established by the Commission, the State of Oklahoma, the Southwest Power Pool, North American Electric Reliability Council, or the Federal Energy Regulatory Commission. This assessment should address both base line forecast condition and important uncertainties, including but not limited to load growth, fuel prices, and availability of planned supplies	IRP Section 3.3
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Executive Summary

This Integrated Resource Plan (IRP or Report) is submitted by Public Service Company of Oklahoma (PSO or Company) based upon the best information available at the time of preparation. However, changes that affect this Plan can occur without notice. Therefore, this Plan is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. Accordingly, this IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

An IRP explains how a utility company plans to meet the projected capacity (*i.e.*, peak demand) and energy requirements of its customers. PSO is required to provide an IRP every three years that encompasses a 10-year forecast planning period (in this filing, 2019-2028). This IRP has been developed using the Company's current long-term assumptions for:

- Customer load requirements – peak demand and energy;
- commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- supply-side alternative costs – including fossil fuel, renewable generation, and storage resources; and
- demand-side program costs and impacts.

In addition, PSO must consider the impact of the ongoing promulgation of environmental rules, including greenhouse gas emissions, which could result in the Company taking additional supply- and demand-side compliance measures. Along with the uncertainty created by increasing environmental requirements, the electric utility industry is beginning a transition driven by emerging technologies including renewable energy, both large-scale and distributed, within the planning horizon. In aggregate, these uncertainties will likely influence the Company's decision whether or not to acquire new long-lived central plant generation.

Keeping all of the various considerations discussed above in mind, PSO has analyzed various scenarios that would provide adequate supply and demand resources to meet its peak load obligations, and reduce or minimize costs to its customers, including energy costs, for the next ten years.

Summary of PSO Resource Plan

PSO's retail sales are projected to grow at 0.4% per year with stronger growth expected from the industrial class (+0.9% per year) while the residential class remains relatively flat. PSO's internal energy and peak demand are expected to change at an average rate of 0.4% and 0.3% per year, respectively, through 2028. Figure ES - 1 shows PSO's "going-in" (i.e. before resource additions) capacity position over the planning period. In 2022, PSO anticipates experiencing a capacity shortfall of 510MW which then grows to a 1,383MW shortfall by 2028.

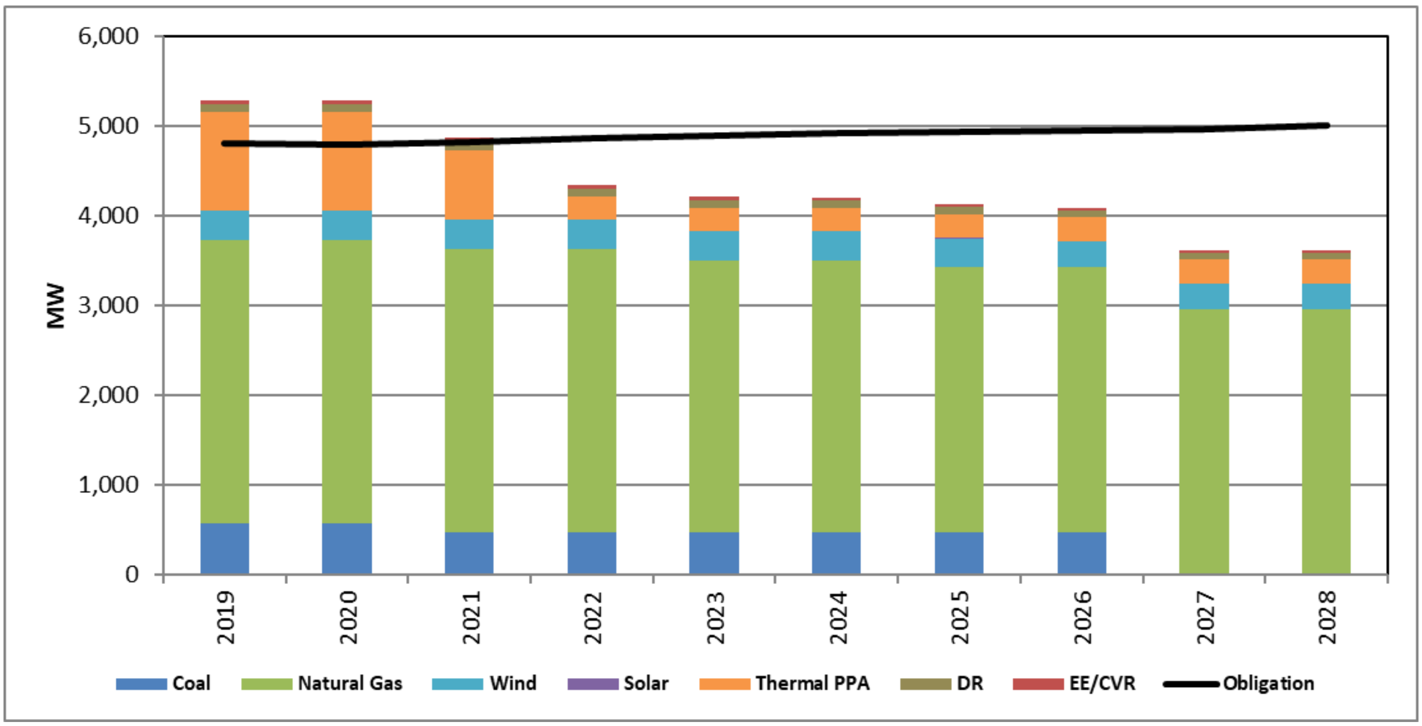


Figure ES - 1. PSO "Going-In" SPP Capacity Position

To determine the appropriate level and mix of incremental supply and demand-side resources required to offset such going-in capacity deficiencies, PSO utilized the *Plexos*® Linear Program (LP) optimization model to develop a "least-cost" resource plan. Although the IRP planning period is limited to 10 years (through 2028), the *Plexos*® modeling was performed through the year 2047 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

PSO used the modeling results to develop a Preferred Plan or "Plan". To arrive at the Preferred Plan, using Plexos®, PSO developed optimal portfolios based on four long-term commodity price forecasts and two load sensitivities. The Preferred Plan balances cost and other factors such as risk and environmental regulatory considerations, to cost effectively meet PSO's demand and energy obligations. For PSO, the Preferred Plan is the optimized portfolio modeled under the base commodity pricing scenario.

Table ES - 1[1] provides a summary of the Preferred Plan throughout the planning period (2019-2038), which resulted from analysis of optimization modeling under the load and commodity pricing scenarios.

[1] Note: This IRP begins adding new demand-side resources such as energy efficiency and CVR in 2022 that are incremental to programs that are currently approved or pending approval. The programs that are currently approved or pending approval during the 2018-2021 timeframe are embedded in the Company's load forecast.

Table ES - 1 Preferred Plan Cumulative Capacity Additions throughout Planning Period (2019-2038)

Preferred Plan		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2028 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2018-2028)
Base Commodity, Base Load	Base/Intermediate					373	373	373	373	373	746	746	(4,759)	(6,223)
	S.T. Cap. Purch.					100	250	200	150	100	150	150		
	Solar (Firm)							15	30	45	95	159		
	Solar (Nameplate)							150	300	450	600	900		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	33	29	24	19	15		
	CVR					12	25	38	38	38	44	52		
	Distr. Gen.	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1	1	1		
Capacity Reserves Above SPP Requirement without New Additions		**348**	**475**	**502**	**46**	**(510)**	**(679)**	**(709)**	**(804)**	**(858)**	**(1,350)**	**(1,383)**		
Capacity Reserves Above SPP Requirement with New Additions		**348**	**475**	**502**	**46**	**19**	**45**	**0**	**16**	**22**	**5**	**40**		

Base/Intermediate=NGCC; S.T. Cap. Purch.=Short-Term Capacity Purchase; CVR=Conservation Voltage Reduction; DG=Distributed

In summary, the Preferred Plan:

- Adds 600MW and 400MW (nameplate) of wind resources in 2022 and 2023, respectively for a total of 1,000MW (nameplate) by the end of the planning period.
- Adds utility-scale solar resources beginning in 2024 through 2028, for a total of 900MW (nameplate) of utility-scale solar by the end of the planning period.
- Implements customer and grid energy efficiency programs, including CVR, reducing energy requirements by 278GWh and capacity requirements by 67MW by 2028.
- Fills long-term needs through the addition of natural gas combined-cycle generation of 373MW in 2022 and 373MW in 2027.
- Fills short-term needs with the acquisition of Short-Term Capacity purchases ranging from 100MW in 2022 to a maximum of 250MW in 2023 over the planning period. This resource is due to the planning criteria related to intermittent resources (wind and solar) as defined by SPP.
- Anticipates retirement of Oklaunion 1 (102MW) and Northeastern 3 (469MW) coal units in 2020 and 2026, respectively.
- Anticipates expiration of several thermal resource PPAs (889MW combined) by 2022 and the Weatherford wind resource PPA (147MW nameplate) by 2026. Details related to PSO's available resources can be found in Exhibits E and F of the Appendix.

PSO capacity changes over the 10-year planning period associated with the Preferred Plan are shown in Figure ES - 2 and Figure ES - 3.

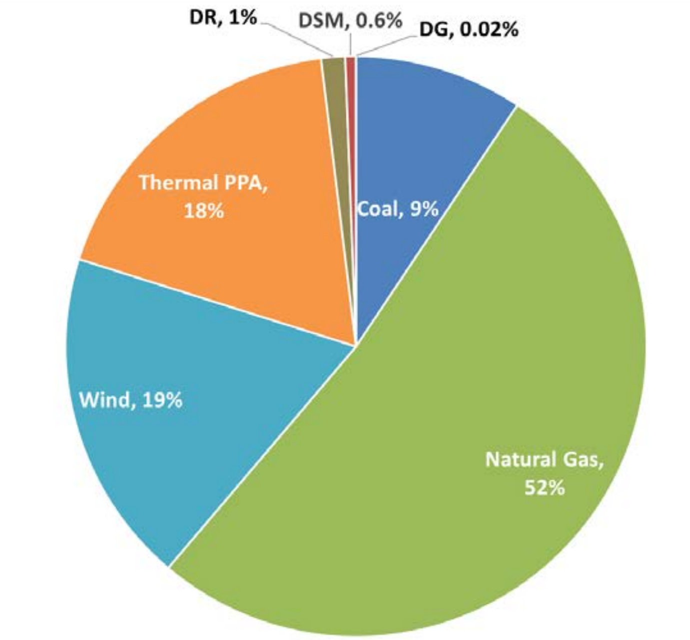


Figure ES - 2. 2019 Nameplate Capacity Mix

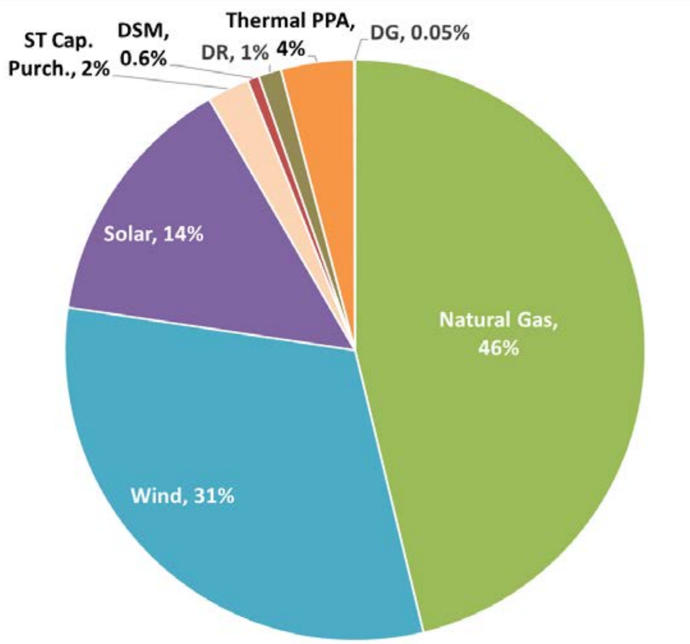


Figure ES - 3. 2028 Nameplate Capacity Mix

The relative impacts to PSO's annual energy position are shown in Figure ES - 4 and Figure

ES - 5.

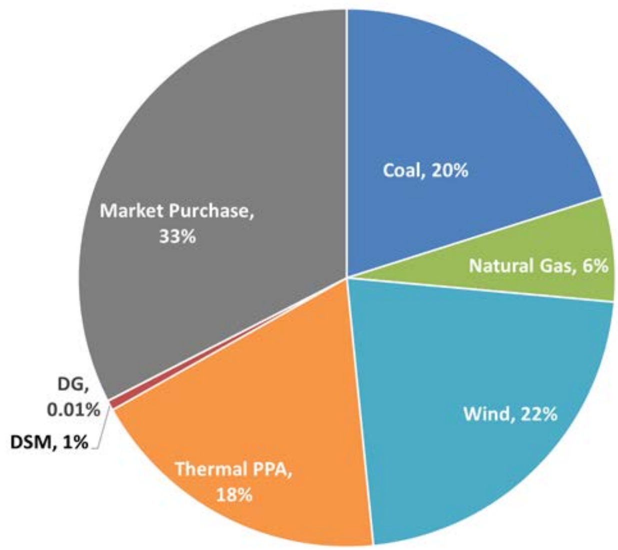


Figure ES - 4. 2019 PSO Energy Mix

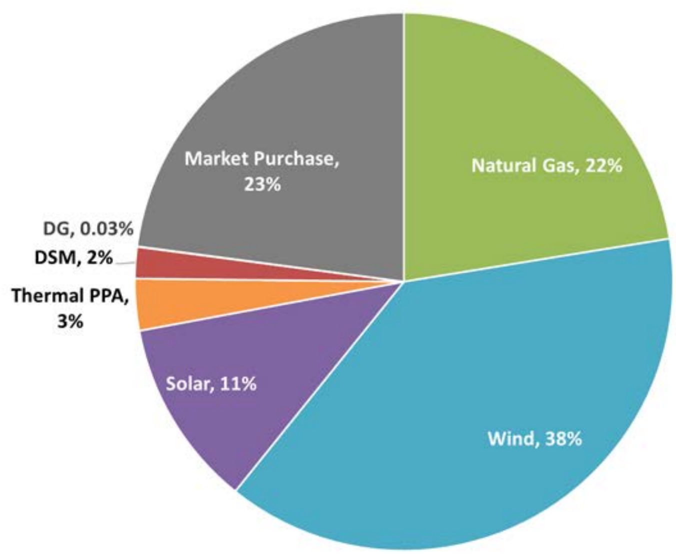


Figure ES - 5. 2028 PSO Energy Mix

Figure ES - 2 through Figure ES - 5 indicate that this Preferred Plan would reduce PSO's reliance on solid fuel-based generation, and increase reliance on demand-side, natural gas, and renewable resources. Specifically, over the 10-year planning horizon the Company's nameplate capacity mix attributable to solid fuel-fired assets declines from 9% to 0%, and natural gas assets would decrease from 52% to 46%. Solar assets make up 14% of the capacity mix and wind assets increase from 19% to 31%. Demand-side resources are added to the mix at 0.6% of total nameplate capacity resources and Short-Term Capacity Purchases are added at 2%.

PSO's energy output attributable to solid fuel generation decreases from 30% to 0% over the planning period, while energy from natural gas resources increases from 9% to 38%. The Preferred Plan introduces solar resources, attributing to 19% of total energy. Reliance on thermal PPA energy would decrease from 27% to 5% based on the planning assumption that thermal PPA's will be replaced with newly acquired natural gas combined-cycle generation. However, the final PPA percentages may change once a Request for Proposal process is conducted to determine if there are more cost effective market opportunities that exist to meet the capacity need in 2022 and beyond.

Figure ES - 6 and Figure ES - 7 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the treatment of capacity credit for intermittent resources within SPP; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they are a low cost energy resource. When comparing the capacity values in Figure ES - 6 with those in Figure ES - 2 and Figure ES - 3, it is important to note that Figure ES - 6 provides an analysis of SPP-recognized capacity, while Figure ES - 2 and Figure ES - 3 depict nameplate capacity.

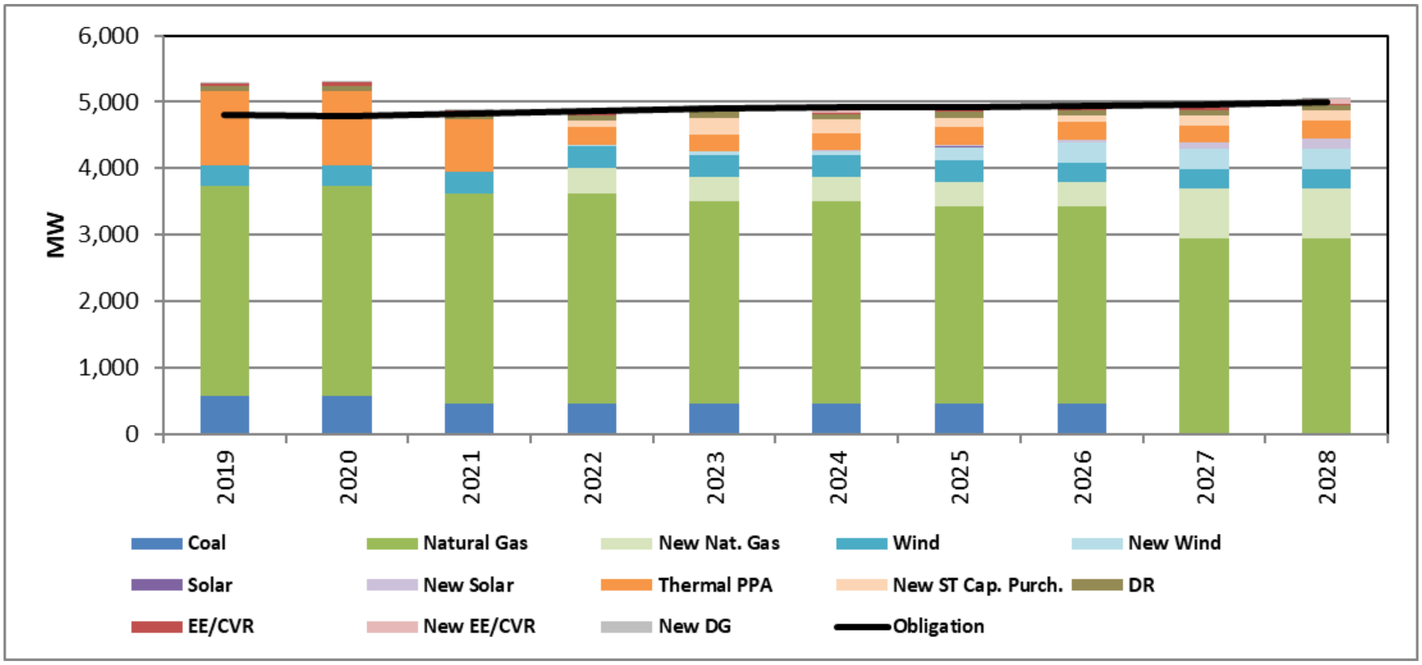


Figure ES - 6. PSO Annual SPP Capacity Position (MW) per the Preferred Plan

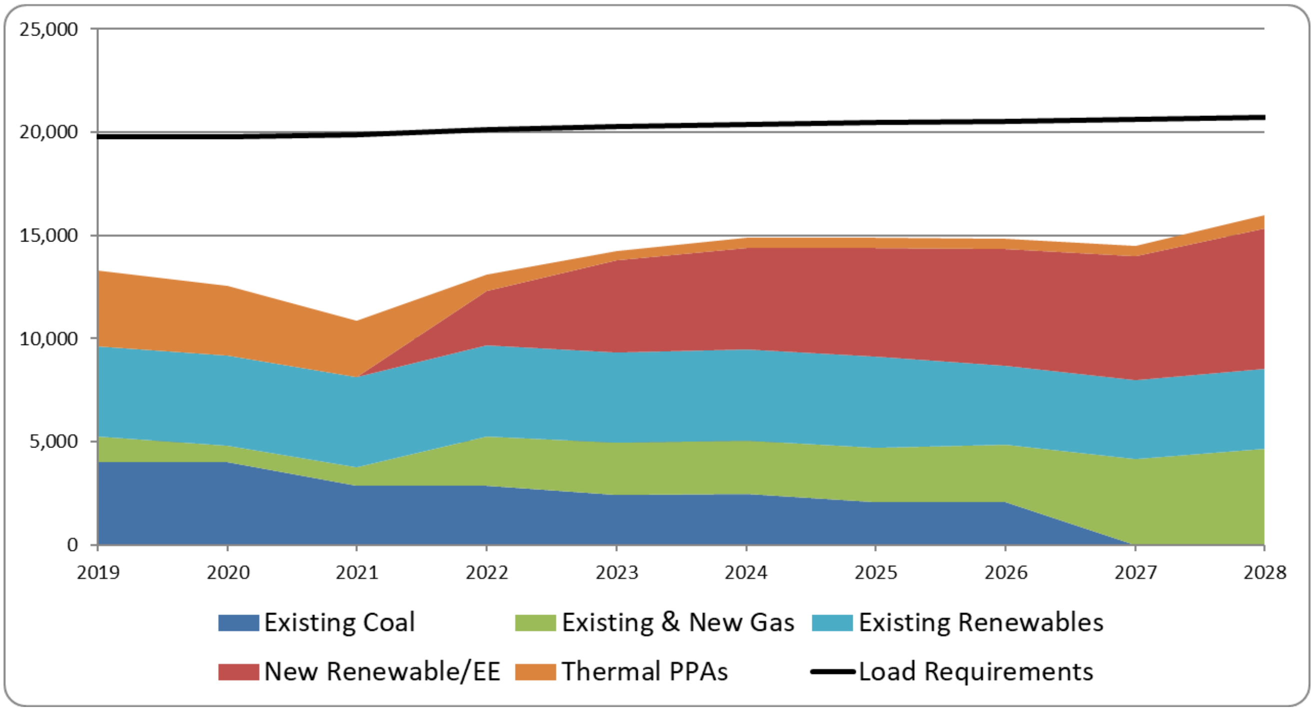


Figure ES - 7. PSO Annual Energy Position (GWh) per the Preferred Plan

PSO Five-Year Action Plan

Steps to be taken by PSO in the near future as part of its Five-Year Action Plan include:

1. Continue the planning and regulatory actions necessary to implement economic energy efficiency programs in Oklahoma.
2. Conduct a Request for Proposals (RFP) to explore opportunities to add cost-effective wind generation in the near future to take advantage of the Federal Production Tax Credit.
3. Consider conducting an RFP to explore adding cost effective utility-scale solar resources.
4. Initiate the RFP process to evaluate PSO's options for replacing the existing Thermal PPAs when they expire.
5. In conjunction with adding variable/intermittent resources, consider conducting an RFP to evaluate PSO's options for short-term capacity needs related to the incremental intermittent resource additions.
6. Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

Status of 2015 IRP Five-Year Action Plan

The following steps were identified in the 2015 IRP and the Company provides a summarized update of each action item below.

1. Continue the planning and regulatory actions necessary to implement economic energy efficiency programs in Oklahoma.

    Update: The Company continues to successfully create and implement cost-effective energy and demand savings through the commission approved Demand Portfolios of energy efficiency and demand response programs. The commission approved the current 2016-2018 Demand Portfolio on December 1, 2015 in OCC Order No. 647288 in Cause No. PUD 201500244. The three-year savings goals are 124 MW and 306,926 MWh. The third-party verified 2016 and 2017 program years created actual savings of 69.5 MW and 110,818 MWh and 70.7 MW and 111,198 MWh, respectively. The Company filed the 2019-2021 Demand Portfolio on June 29, 2018 in Cause no.

PUD 201800073 with three-year savings goals of 147 MW and 337,481 MWh. The Company continues to monitor the market for energy efficiency and demand response products. The Company is engaged in the recent Rulemaking on the Demand Portfolio, Cause No. PUD 201800010.

2. Explore opportunities to add wind generation in the near future to take advantage of the Federal Production Tax Credit.

   Update: An RFP was issued in the summer of 2016 for 100 to 300MW of wind resources. The Company was in the process of completing the RFP process when it was determined that further due diligence was needed on the impacts of curtailments and congestion. Upon completion of that analysis, the Company ultimately determined that the addition of wind resources that more fully mitigated congestion risk is a better risk-adjusted low cost solution for its customers. On July 26, 2017 the Company cancelled the RFP. In the second half of 2017 and into 2018 the Company pursued the "Wind Catcher" project, but ultimately withdrew its application at the OCC.

3. Explore adding cost effective utility-scale solar resources.

   Update: The Company continues to monitor the rapidly changing economics of utility-scale solar resources. The Company is also currently working with a large-customer to assess an opportunity to add up to 20MWac of networked solar generation resources at the customer's location.

4. Initiate the RFP process to evaluate PSO's options for replacing the existing PPAs when they expire in 2021 and 2022.

   Update: An RFP process was initiated in 2016. Since that time, changes to the load forecast and SPP's reserve margin criteria have lowered the need for capacity, and pushed back the need from 2021 to 2022. Initial results from the RFP indicated that competitively priced capacity is available from existing generation units, as opposed to newly constructed generation. The delay of a capacity need and the availability of capacity that does not require an early commitment for construction allowed the Company to terminate the RFP process and re-evaluate the need at a later date.

5. Evaluate the greenhouse gas rules. Work with the Oklahoma Executive Branch, Oklahoma Department of Environmental Quality, and the Office of the Attorney General on Oklahoma's response to the EPA's greenhouse gas rule.

    Update: As described in Section 3.4.7, in August of 2018, the EPA proposed a replacement for the Clean Power Plan titled the Affordable Clean Energy (ACE) Rule. In light of this development, the Company will continue to monitor the status of this rulemaking and/or future greenhouse gas rules.

6. Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

    Update: Change in the electric utility space continues to accelerate. Monitoring and predicting this change is increasingly important. In 2017, the Company completed an interim update to the 2015 IRP as a direct result of changing circumstances and assumptions.

Summary of PSO's 2018 IRP - Technical Meeting

On November 27, 2018, PSO held a technical meeting to review the details of the 2018 IRP. The transcript from the meeting can be found in Exhibit H of the Appendix, and the comments and feedback of the various stakeholders are summarized below.

- The Company should include the annual revenue requirements for each plan; this is included in Exhibit D of the Appendix.
- The Company should include a summary of significant changes from the 2017 IRP Update to the current 2018 IRP; following is a list of significant changes, which the Company also will present on at the IRP Public Meeting to be held on December 20, 2018:

  - Overall resource selection is similar. Wind, Natural Gas Combined Cycle, and Demand-side Management Resources are selected early. Solar and more Natural Gas Combined Cycle are selected later in the planning period.
  - Utilizing the SPP criteria, existing wind capacity credit was updated based on 2018 actuals. Incremental wind capacity credit assumption was updated to 30% from 15%.
  - Introduced a "Short-Term" Market Purchase to manage the reduced near-term "capacity value" for wind and solar.
  - Total wind build will be limited to 1,000 MW (nameplate).
  - Storage pricing was updated.
  - Updated the Fundamental Commodity Forecast, see Section 4.3.
  - Updated the Load Forecast, see Section 2.0.
  - Included the addition of "Congestion and Losses" to the cost of wind resources, see Section 4.5.5.2.
- The Company should improve its description of the development of the "Congestion and Losses" associated with new wind resources; the Company provided additional detail in Section 4.5.5.2.
- The Attorney General included written comments, which are included in total in Exhibit G of the Appendix and the Company has highlighted the most relevant comments, which was to include an improved description of solar resources, this is included in Section 4.5.5.1; the Company's provide additional details regarding the risk associated with the Preferred Plan, this is included in Section 5.4.

Conclusion

PSO's Preferred Plan provides the Company with an increasingly diversified portfolio of supply- and demand-side resources which provides flexibility to adapt to future changes to the power market, technology, and environmental regulations. The addition of efficient natural gas-fired generation along with increased renewables and demand-side management mitigates fuel price and environmental compliance risk.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in the course of resource portfolio evaluations, material changes in these assumptions could result in modifications. The action plan presented in this IRP is sufficiently flexible to accommodate possible changes in key parameters, including load growth, environmental compliance assumptions, fuel costs, and construction cost estimates, which may impact this IRP. By minimizing PSO's costs in the optimization process, the Company's model produced optimized portfolios with the lowest, reasonable impact on customers' rates.

1.0 Introduction

1.1 Overview

This Report presents the 2018 Integrated Resource Plan (IRP, Plan, or Report) for Public Service Company of Oklahoma (PSO or Company) including descriptions of assumptions, study parameters, and methodologies. The results integrate supply- and demand-side resources.

*The goal of the IRP process is to identify the **amount**, **timing** and **type** of resources required to ensure a reliable supply of capacity and energy to customers at the least reasonable cost.*

In addition to developing a long-term strategy for achieving reliability/reserve margin requirements as set forth by SPP, resource planning is critical to PSO due to its impact on such things as determining capital expenditure requirements, regulatory planning, environmental compliance, and other planning processes.

1.2 Integrated Resource Plan (IRP) Process

This Report covers the processes and assumptions required to develop an IRP for the Company. The IRP process for PSO includes the following components/steps:

- Description of the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning;
- provide projected growth in demand and energy which serves as the underpinning of the Plan;
- identify and evaluate demand-side options such as Energy Efficiency (EE) measures, Demand Response (DR) and Distributed Generation (DG);
- identify current supply-side resources, including projected changes to those resources (*e.g.,* de-rates or retirements), and transmission system integration issues; and
- identify and evaluate supply-side resource options.

1.3 Introduction to PSO

PSO is an affiliate company of American Electric Power (AEP). With more than five million customers and serving parts of 11 states, AEP is one of the country's largest investor-owned utilities. AEP's service territory covers 197,500 square miles in Louisiana, Arkansas, Texas, Oklahoma, Indiana, Michigan, Kentucky, Ohio, Tennessee, Virginia and West Virginia.

AEP owns and/or operates one of the largest generation portfolios in the United States, with approximately 26,000 megawatts of generating capacity in three RTOs. AEP's customers are served by one of the world's largest transmission and distribution systems. System-wide there are approximately 40,000 circuit miles of transmission lines and more than 222,000 miles of distribution lines.

The operating companies in AEP's Southwest Power Pool (SPP) zone collectively serve a population of about 4.25 million, which includes over 1 million retail customers in a 36,000 square mile area in parts of Arkansas, Louisiana, Oklahoma, and Texas.

PSO's customers consist of both retail and sales-for-resale (wholesale) customers located in Oklahoma (see red area in Figure 1). Currently, PSO serves approximately 550,000 retail customers. The peak load requirement of PSO's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. PSO's historical all-time highest recorded peak demand was 4,410MW, which occurred in August 2012; and the highest recorded winter peak was 3,193MW, which occurred in January 2018. The most recent actual PSO summer and winter peak demands were 4,107MW and 3,193MW, occurring on July 20, 2018 and January 17, 2018, respectively.

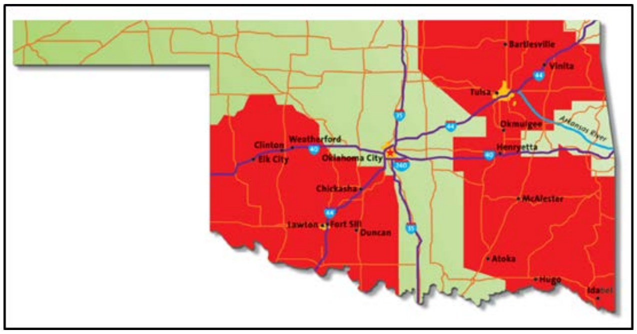


Figure 1. PSO Service Territory

1.3.1 Annual Planning Process

This IRP is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore, this plan is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislation to control greenhouse gases.

The implementation action items as described herein are subject to change as new information becomes available or as circumstances warrant.

PSO and AEP are engaged in planning activities throughout the year which impact the IRP. Major activities include updating the load forecast, fundamental commodity pricing forecast, and new generation cost and performance characteristics. The load forecasting process is ongoing; however, on an annual basis the load forecasting group produces a peak demand and energy usage forecast for each operating company. This process typically begins as actual values are received and reviewed and adjusted. The annual forecast is generally available in June of each year.

The fundamental commodity forecasting process is ongoing as well and is continually monitored relative to ongoing activities that could potentially impact the existing commodity forecast values. Typically, the fundamental commodity forecast is updated when material changes are observed or expected. The most recent commodity forecast was released in August of 2018.

New generation resource cost and characteristics are generally updated on an annual basis with a typical first quarter release date. This data is often updated as needed if additional material data is made known between the typical release dates.

Other input data utilized with the IRP process is generally updated on an annual basis unless material differences are identified between the existing input values and expected future values

2.0 Load Forecast and Forecasting Methodology

2.1 Summary of PSO Load Forecast

The PSO load forecast was developed by the American Electric Power Service Corporation (AEPSC) Economic Forecasting organization and completed in June 2018.[2] The load forecast is the culmination of a series of underlying forecasts that build upon each other. In other words, the economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 10 year period (2019-2028)[3], PSO's service territory is expected to see population and non-farm employment growth 0.4% per year. Likewise, PSO is projected to see customer count growth of 0.4% annually over this period. Over the same forecast period, PSO's retail sales are projected to grow at 0.4% per year with stronger growth expected from the industrial class (+0.9% per year) while the residential class remains relatively flat over the forecast horizon. Finally, PSO's internal energy and peak demand are expected to change at an average rate of 0.4% and 0.3% per year, respectively, through 2028.

2.2 Forecast Assumptions

2.2.1 Economic Assumptions

The load forecasts for PSO and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in December 2017. Moody's

[2] The load forecasts (as well as the historical loads) presented in this Report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

[3] 10 year forecast periods begin with the first full forecast year, 2019.

Analytics projects moderate growth in the U.S. economy during the 2019-2028 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.0% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.6% per year during the same period. Moody's projects regional employment growth of 0.4% per year during the forecast period and real regional income per-capita annual growth of 1.9% for the PSO service area.

2.2.2 Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and the U.S. Department of Energy (DOE) Energy Information Administration (EIA) outlook for the West South Central Census Region for the longer term. These price forecasts are incorporated into the Company's energy sales models, where appropriate.

2.2.3 Specific Large Customer Assumptions

PSO's customer service engineers are in frequent touch with industrial and commercial customers about their needs and activities. From these discussions, high-probability load additions or deletions are incorporated into the forecast.

2.2.4 Weather Assumptions

Where appropriate, the Company includes weather as an explanatory variable in its energy sales models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

2.2.5 Demand Side Management (DSM) Assumptions

The Company's long term load forecast models account for trends in EE both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards (Energy Policy Act of 2005 [EPAct], Energy Independence and Security Act [EISA] of 2007, etc.) modeled by the EIA. In addition to general trends in appliance efficiencies, the Company also administers multiple Demand-Side Management (DSM) programs that the Commissions approve as part of its DSM portfolio. The load forecast utilizes the most current DSM programs, which either have been previously approved by or are pending currently before the Commission, at the time the load forecast is created to adjust the forecast for the impact of these programs. For this IRP, DSM programs through 2021 have been embedded into the load forecast.

2.3 Overview of Forecast Methodology

PSO's load forecasts are based mostly on econometric, statistically adjusted end-use and analyses of time-series data. This is helpful when analyzing future scenarios and developing confidence bands in addition to objective model verification by using standard statistical criteria.

PSO utilizes two sets of econometric models: 1) a set of monthly short-term models which extends for approximately 24 months and 2) a set of monthly long-term models which extends for approximately 30 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast that is used for various planning purposes.

For the first full year of the forecast, the forecast values are generally governed by the short-term models. The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications like capital budgeting and resource allocation. While these models produce extremely accurate forecasts in the short run, without logical ties to economic factors, they are less capable of capturing structural trends in electricity consumption that are more important for longer-term resource planning applications.

The long-term models are econometric, and statistically adjusted end-use models which are specifically equipped to account for structural changes in the economy as well as changes in customer consumption due to increased energy efficiency. The long-term forecast models incorporate regional economic forecast data for income, employment, households, output, and population.

The short-term and long-term forecasts are then blended to ensure a smooth transition from the short-term to the long-term forecast horizon for each major revenue class. There are some instances when the short-term and long-term forecasts diverge, especially when the long-term models are incorporating a structural shift in the underlying economy that is expected to occur within the first 24 months of the forecast horizon. In these instances, professional judgment is used to ensure that the final forecast that will be used in the peak models is reasonable. The class level sales are then summed and adjusted for losses to produce monthly net internal energy sales for the system. The demand forecast model utilizes a series of algorithms to allocate the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

A flow chart depicting the sequence of models used in projecting PSO's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 2.

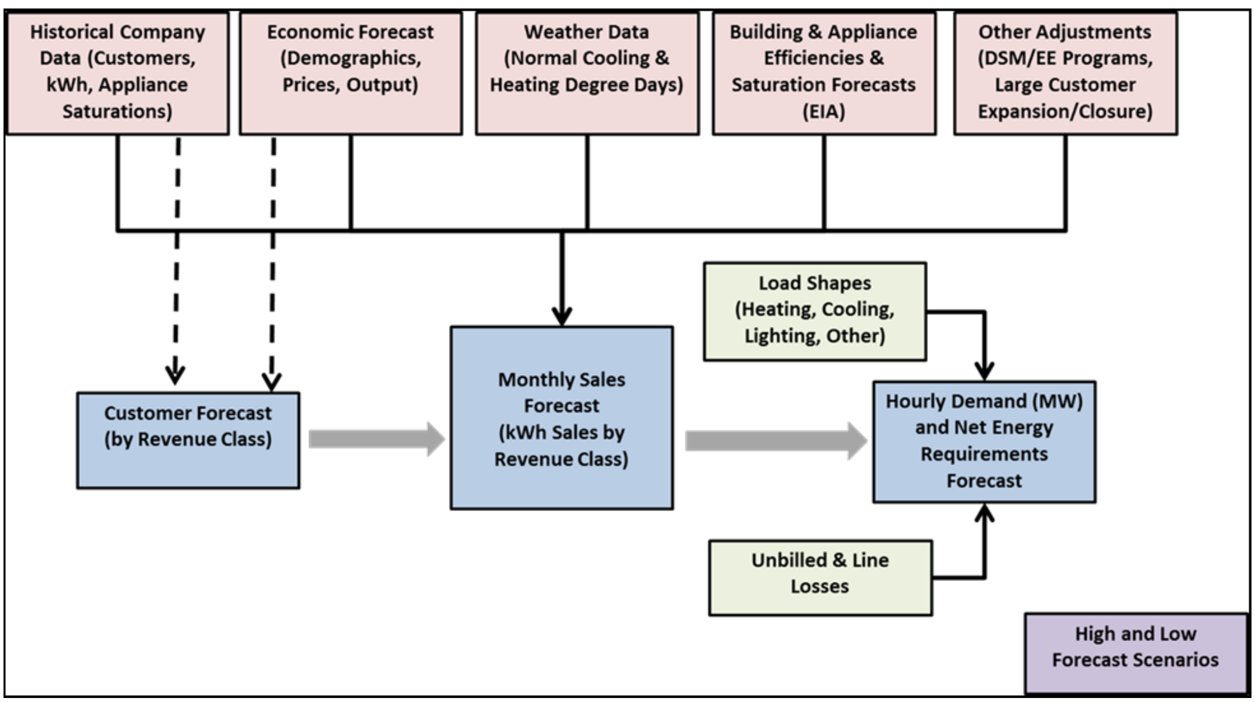


Figure 2. PSO Internal Energy Requirements & Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast

2.4.1 General

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of PSO's energy consumption, by customer class. Conceptually, the difference between short- and long-term energy consumption relates to changes in the stock of electricity-using equipment and economic influences, rather than the passage of time. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology influence the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include all or most of them in the formulation of long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to impact them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

2.4.2 Customer Forecast Models

The Company also utilizes both short-term and long-term models to develop the final customer count forecast. The short-term customer forecast models are time series models with intervention (when needed) using Autoregressive Integrated Moving Average (ARIMA) methods of estimation. These models typically extend for 24 months into the forecast horizon.

The long-term residential customer forecasting models are also monthly but extend for 30 years. The explanatory jurisdictional economic and demographic variables may include gross regional product, employment, population, real personal income and households used in various combinations. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The short-term and long-term customer forecasts are blended as was described earlier to arrive at the final customer forecast that will be used as a primary input into both short-term and long-term usage forecast models.

2.4.3 Short-term Forecasting Models

The goal of PSO's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on ARIMA models.

The estimation period for the short-term models was January 2008 through December 2017. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 16 large industrial models and models for the remainder of the industrial sector. The wholesale forecast is developed using a model for the Town of South Coffeyville. Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast as they are not requirements load or relevant to determining capacity and energy requirements in the IRP process.

2.4.4 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the PSO service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1995-2017 The long-term energy sales forecast is developed by blending of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

2.4.4.1 Supporting Model

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, a supporting model is used. This model is discussed below.

2.4.4.1.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of natural gas prices for each state's three primary consuming sectors: residential, commercial, and industrial. In the state natural gas price models sectoral prices are related to West South Central Census region's sectoral prices, with the forecast being obtained from EIA's "2018 Annual Energy Outlook." The natural gas price model is based upon 1980-2017 historical data.

2.4.4.2 Residential Energy Sales

Residential energy sales for PSO are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

The residential usage model is estimated using a Statistically Adjusted End-Use model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool, and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool, and Xother variables.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from PSO's residential customer survey. The saturation forecasts are based on EIA forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the West South Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE residential model is estimated using linear regression models. This monthly model is for the period January 2005 through December 2018. It is important to note, as will be discussed later, that this modeling *has* incorporated the reductive effects of the EPAct, EISA, American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential (and commercial) energy usage based on analysis by the EIA regarding appliance efficiency trends.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

2.4.4.3 Commercial Energy Sales

Long-term commercial energy sales are forecast using SAE models. These models are similar to the residential SAE models. These models utilize efficiencies, square footage and equipment saturations for the West South Central Region, along with electric prices, economic drivers from Moody's Analytics, heating and cooling degree-days, and billing cycle days. As with the residential models, there are Xheat, Xcool and Xother variables derived within the model framework. The commercial SAE models are estimated similarly to the residential SAE models.

2.4.4.4 Industrial Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, FRB industrial production indexes, and service area industrial electricity prices. In addition, binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. The last actual data point for the industrial energy sales model is December 2018.

2.4.4.5 All Other Energy Sales

The forecast of other retail sales, which is comprised of public-street and highway lighting and other sales to public authorities, relates energy sales to service area population and binary variables.

Wholesale energy sales are modeled relating energy sales to economic variables such as service area employment, heating and cooling degree-days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition of new customers.

2.4.4.6 Blending Short and Long-Term Sales

Forecast values for 2018 and 2019 are taken from the short-term process. Forecast values for 2020 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2020 the entire forecast is from the long-term models. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. However, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon.

2.4.4.7 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all

Federal Energy Regulatory Commission (FERC) revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

2.4.5 Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly Company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges.

In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of PSO and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West, or total AEP System. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

2.5 Load Forecast Results and Issues

All tables referenced in this section can be found in the Appendix of this Report in Exhibit A.

2.5.1 Load Forecast

Exhibit A-1 presents PSO's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other internal sales and losses) on an actual basis for the years 2015-2017 and on a forecast basis for the years 2018-2028. The 2018 data are six months actual and six months forecast. The exhibit also shows annual growth rates for both the historical and forecast periods.

Figure 3 provides a graphical depiction of weather normal and forecast Company residential, commercial and industrial sales for 2000 through 2028.

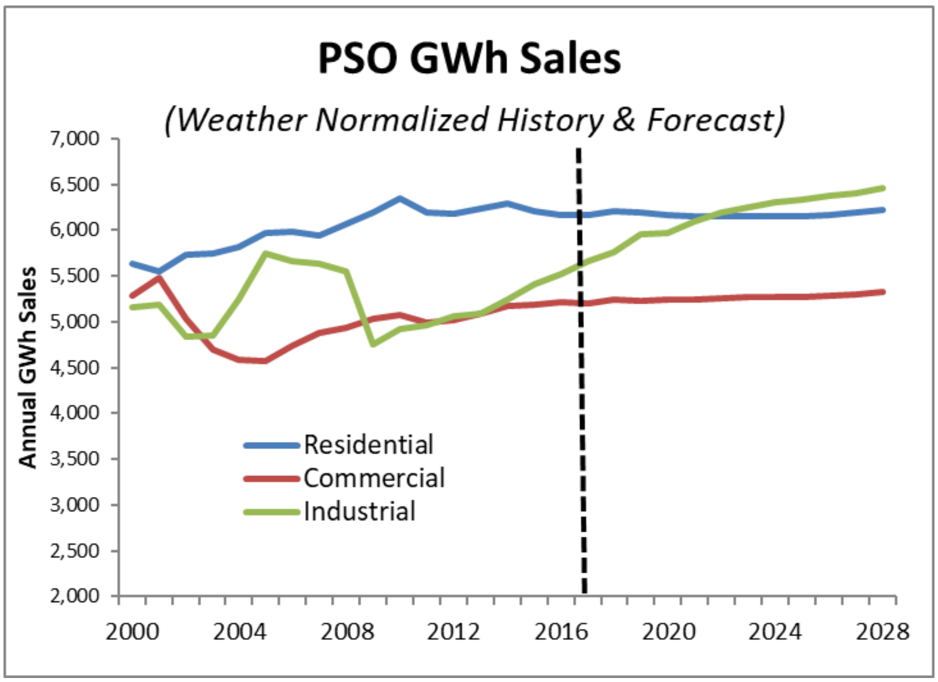


Figure 3. PSO GWh Sales

2.5.2 Peak Demand and Load Factor

Exhibit A-2 provides PSO’s seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2015-2017 and on a forecast basis for the years 2018-2028. The 2018 data are six months actual and six months forecast. The table also shows annual growth rates for both the historical and forecast periods.

Figure 4 presents actual, weather normal and forecast PSO peak demand for the period 2000 through 2028.

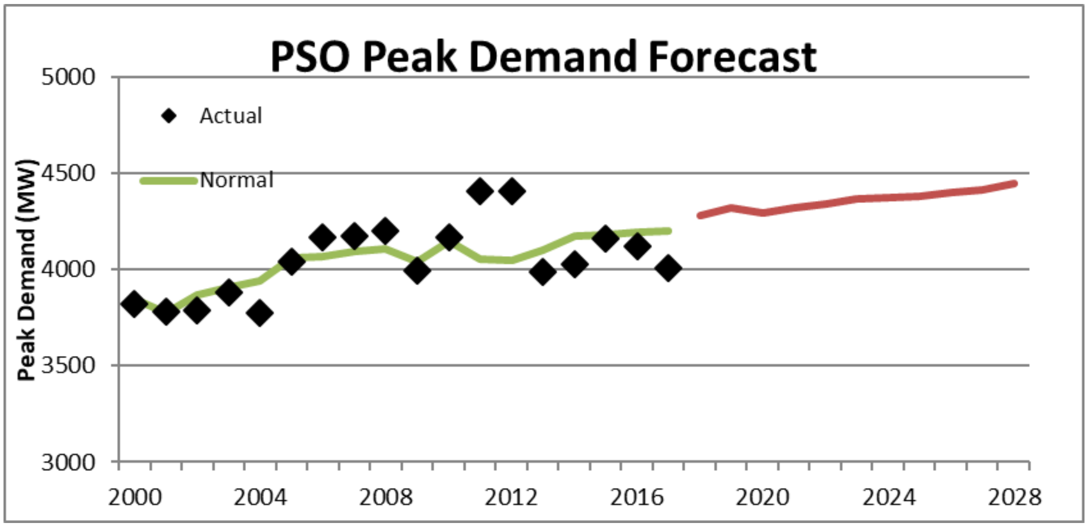


Figure 4. PSO Peak Demand Forecast

2.5.3 Weather Normalization

The load forecast presented in this Report assumes normal weather. To the extent that weather is included as an explanatory variable in various short- and long-term models, the weather drivers are assumed to be normal for the forecast period.

2.6 Load Forecast Trends & Issues

2.6.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 5 presents PSO's historical and forecasted residential and commercial usage per customer between 1991 and 2020. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 1.6% per year, while the commercial usage grew by 0.1% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.8% per year while the commercial class usage decreased by 1.0% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 0.5% per year while the commercial usage decreases by an average of 0.1% per year.

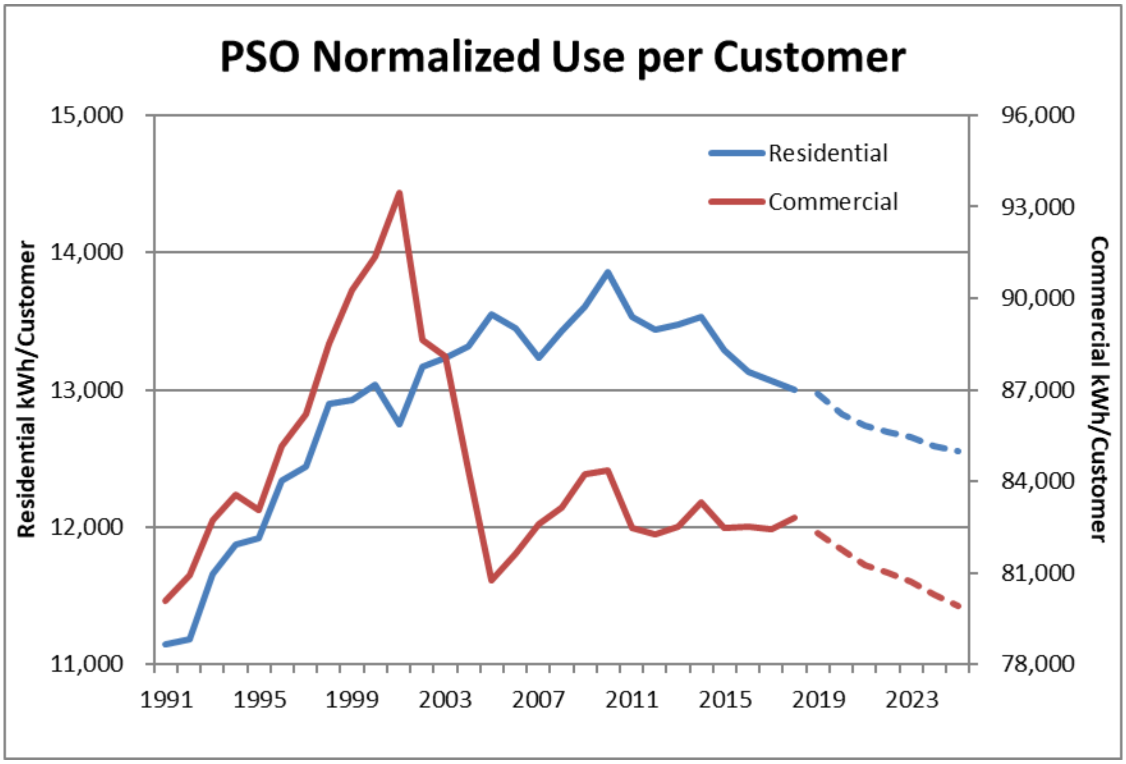


Figure 5. PSO Normalized Use per Customer (kWh)

The SAE models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every 3-4 years, the Company conducts a Residential Appliance Saturation Survey to monitor the saturation and age of the various appliances in the residential home. This information is then matched up with the saturation and efficiency projections from the EIA which includes the projected impacts from various enacted federal policies mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. For example, Figure 6 shows the assumed cooling efficiencies embedded in the statistically adjusted end-use models for cooling loads. It shows that the average Seasonal Energy Efficiency Ratio (SEER) for central air conditioning is projected to increase from 11.7 in 2010 to nearly 14.3 by 2028. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units. Figure 7 shows similar improvements in the efficiencies of lighting and clothes washers over the same period.

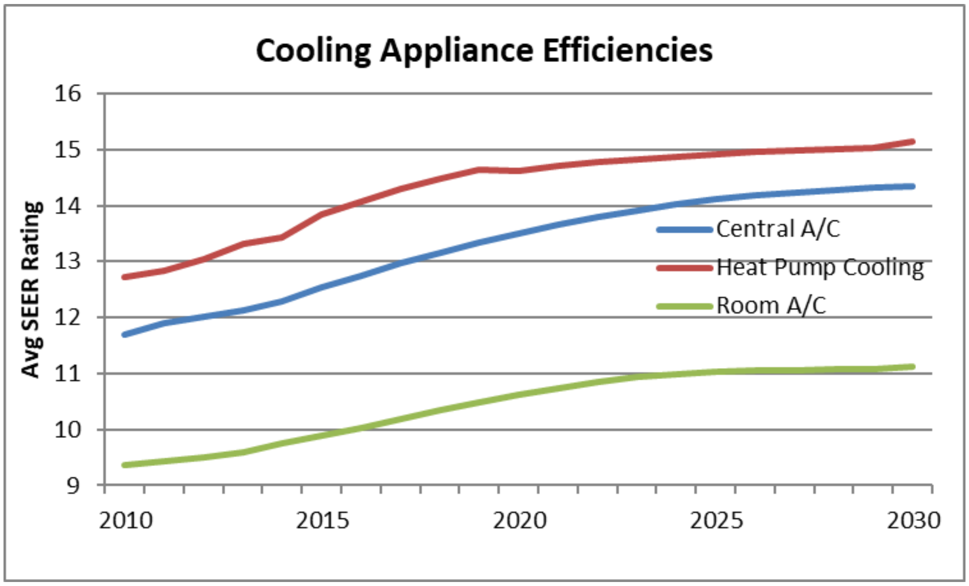


Figure 6. Projected Changes in Cooling Efficiencies, 2010-2030

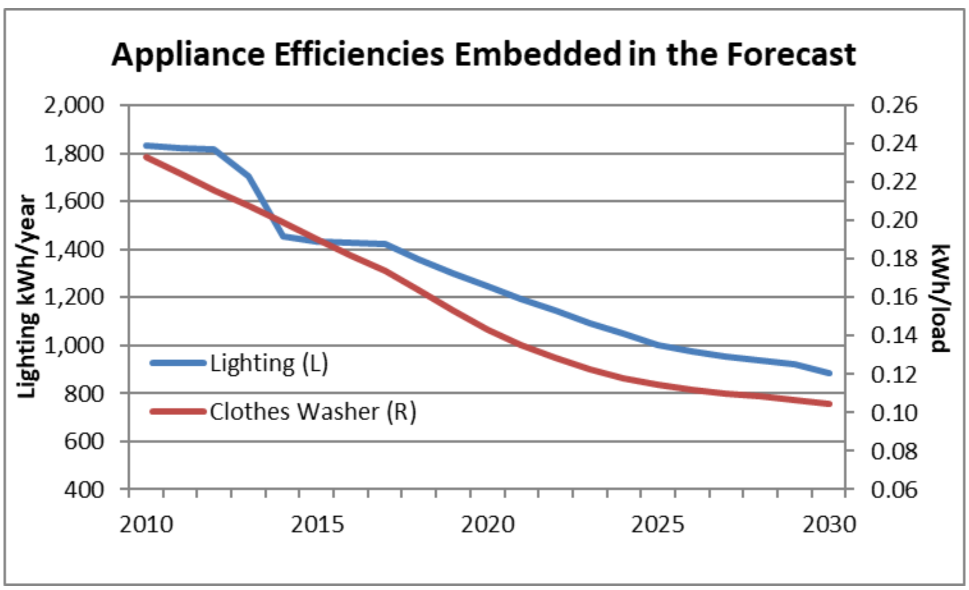


Figure 7. Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2030

Figure 8 shows the impact of appliance, equipment and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast PSO residential customers are provided.

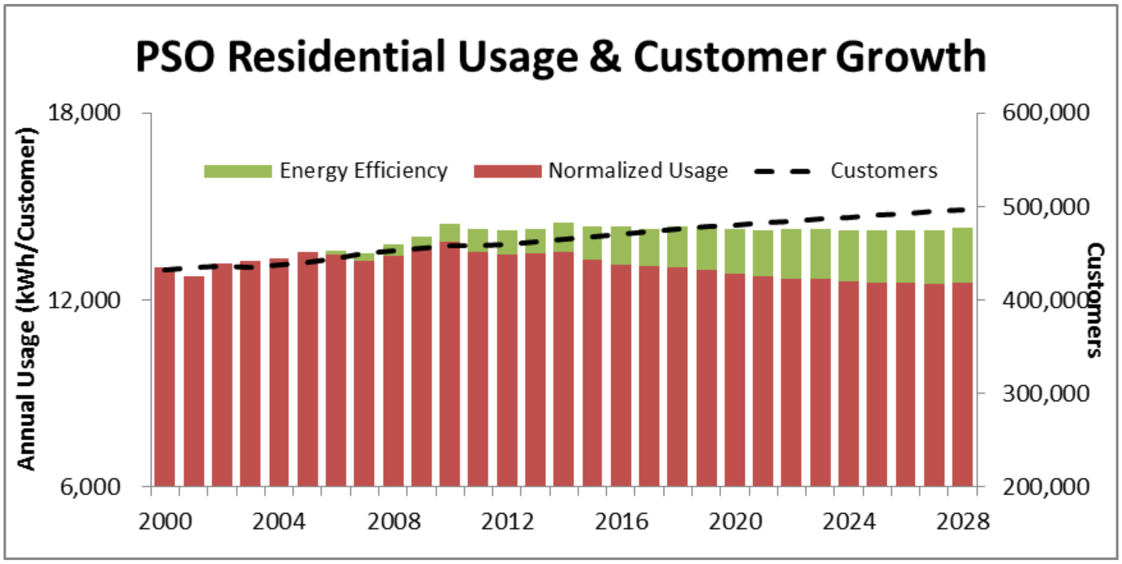


Figure 8. Residential Usage & Customer Growth, 2000-2028

2.6.2 Demand-Side Management (DSM) Impacts on the Load Forecast

The end-use load forecasting models account for changing trends and saturations of energy efficient technologies throughout the forecast horizon. However, the Company is also actively engaged in administering various commission approved DSM and EE programs which would further accelerate the adoption of energy efficient technology within its service territory. As a result, the base load forecast is adjusted to account for the impact of these programs that is not already embedded in the forecast.

For the near term horizon (through 2021), the load forecast uses assumptions from the DSM programs currently pending approval before the Commission. For the years beyond 2021, the IRP model selected optimal levels of economic EE, which may differ from the levels currently being implemented, based on projections of future market conditions. The initial base load forecast accounts for the evolution of market and industry efficiency standards. As a result, energy savings for a specific EE program are degraded over the expected life of the program. Exhibit A-8 details the impacts of the approved EE programs included in the load forecast, which represent the cumulative degraded value of EE program impacts throughout the forecast period. The IRP process then adds the selected optimal economic EE, resulting in the total IRP EE program savings.

Exhibit A-3 provides the DSM/EE impacts incorporated in PSO's load forecast provided in this Report.

2.6.3 Interruptible Load

The Company has one customer with interruptible provisions in their contracts. This customer has interruptible contract capacity of 50MW. However, this customer is expected to have 17MW and 24MW available for interruption at the time of the winter and summer peaks, respectively. An additional 138 customers have 65MW available for interruption in emergency situations in DR agreements. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking. Further discussion of the determination of DR is included in Section 3.4.3.1.

2.6.4 Blended Load Forecast

As noted above, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon. Exhibit A-4 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, all of the wholesale forecasts utilize the long-term model results.

In general, forecast values for the years 2018 and 2019 were typically taken from the short-term process. Forecast values for 2020 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2020 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results. Figure 9 illustrates a hypothetical example of the blending process (details of this illustration are shown in Exhibit A-5). However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

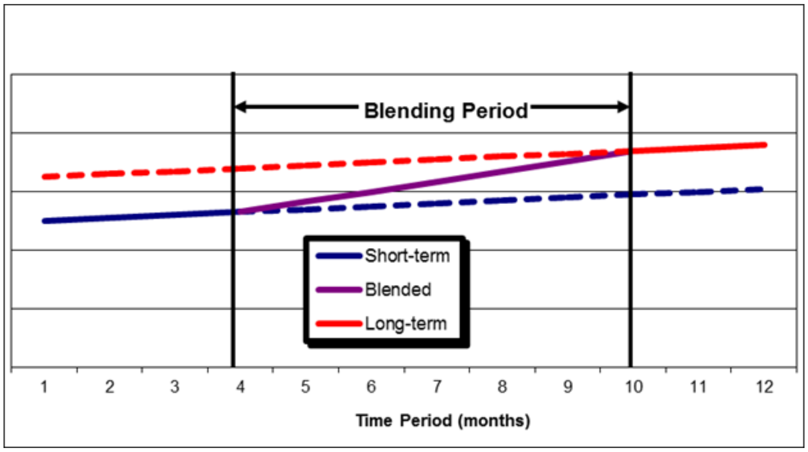


Figure 9. Load Forecast Blending Illustration

2.6.5 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then additional factors may be used to reflect those large changes that differ from the forecast models' output.

2.6.6 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs.

2.7 Load Forecast Scenarios

The base case load forecast is the expected path for load growth that the Company uses for planning. There are a number of known and unknown potentials that could drive load growth different from the base case. While potential scenarios could be quantified at varying levels of assumptions and preciseness, the Company has chosen to frame the possible outcomes around the base case. The Company recognizes the potential desire for a more exact quantification of outcomes, but the reality is if all possible outcomes were known with a degree of certainty, then they would become part of the base case.

Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2018 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for PSO are tabulated in Exhibit A-6. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for PSO are shown in Exhibit A-7.

For PSO, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2028, represent deviations of about 6.8% below and 4.8% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios.

Figure 10 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

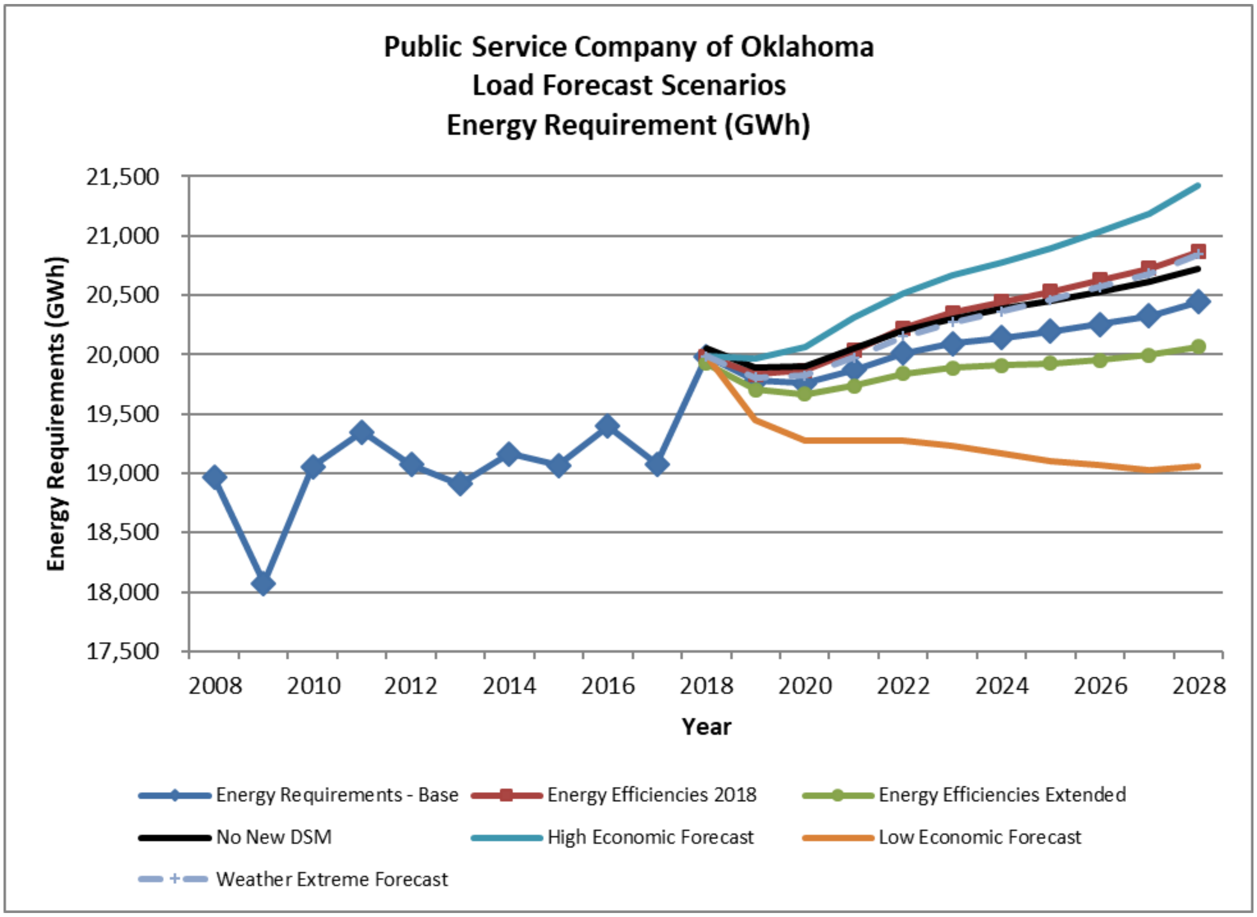


Figure 10. Load Forecast Scenarios

The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2018 scenario keeps energy efficiencies at 2018 levels for the residential and commercial equipment. Both of these scenarios result in a load forecast greater than the base forecast.

The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial equipment.

The weather extreme forecast assumes accelerated temperatures for both the winter and summer seasons. This analysis based on a study developed by Purdue University. This scenario results increased load in the summer and diminished load in the winter, with the net result being a higher energy requirements forecast.

All of these alternative scenarios fall within the boundary of the Company's high and low economic scenario forecasts. The Company's expectations are that any reasonable scenario developed will fall within this range of forecasts.

2.8 Price Elasticity

The long term load forecast models include electricity price as one of many explanatory variables. The coefficient of the electricity price variable is an estimate of the price elasticity, which is simply a measure of how responsive customers are to changes in price. The formula for price elasticity is simply the percentage change in the quantity demanded divided by the percentage change in price. If the change in demand is greater than the change in price, the elasticity estimate would be greater than 1 and it would be described as elastic demand. If the change in demand is less than the change in price, the elasticity estimate would be less than 1 and it would be classified as inelastic demand. The demand for electricity is very inelastic. For the Residential class, the long term elasticity estimate is approximately 0.1. For the Commercial class, the modeled price elasticity is 0.15 and the elasticity estimate for the Industrial class is 0.28. For comparison, the estimated long term elasticity for gasoline is 0.6 while the elasticity for restaurant meals is 2.3[4]. (Note: technically each of these elasticity estimates are negative values based on the inverse relationship between price and quantity demanded. The convention by economists when describing the elasticity is to report the absolute value of these elasticity estimates.)

[4] "O'Sullivan, Arthur, Steven M. Sheffrin, & Stephen J. Perez Survey of Economics: Principles, Applications, and Tools. Prentice Hall © 2012 Table 4.2 'Price Elasticities of Demand for Selected Products' pg 86.

3.0 Resource Evaluation

3.1 Current Resources

An initial step in the IRP process is the demonstration of the capacity resource requirements. This aspect of the traditional "needs" assessment must consider projections of:

- existing capacity resources—current levels and anticipated changes;
- anticipated changes in capability due to efficiency and/or environmental considerations;
- changes resulting from decisions surrounding unit disposition evaluations;
- regional and sub-regional capacity and transmission constraints/limitations;
- load and peak demand;
- current DR/EE; and
- SPP capacity reserve margin and reliability criteria.

3.2 Existing PSO Generating Resources

The underlying minimum reserve margin criterion to be utilized in PSO's resource needs assessment is based on the current SPP minimum capacity margin of 10.7 percent.[5] As a function of peak demand this converts to an equivalent "reserve margin" of 12.0 percent.[6] The reserve margin is the result of SPP's own system reliability assessment.

Table 1 identifies the generating resources identified in the CDR. Future plans surrounding these assets must take into account each unit's useful service life. Unit retirements are incorporated in PSO's plans based upon each unit's in-service date along with the anticipated service life. Retirement dates are continually reviewed and adjusted with respect to a unit's ability to maintain safe, reliable, and economic operation, as well as external factors such as environmental regulations.

[5] Per Section 4.1.9 of the "Southwest Power Pool Planning Criteria" (Latest Revision: July 25, 2017).

[6] $0.107 / (1 - 0.107) = 0.12$.

Table 1. PSO Owned Generation Assets as of December, 2018

Unit Name	PrimaryFuel Type	C.O.D. [1]	Rating (MW) [2]
Oklaunion 1	Coal	1986	102 (A)
Northeastern 3	Coal	1979	469
Northeastern 1	Gas (CC)	1980	422
Northeastern 2	Gas (CC)	1970	434
Comanche	Gas (CC)	1973	227
Riverside 1	Gas Steam	1974	448
Riverside 2	Gas Steam	1976	458
Southwestern 1	Gas Steam	1952	61
Southwestern 2	Gas Steam	1954	79
Southwestern 3	Gas Steam	1967	311
Tulsa 2	Gas Steam	1956	167
Tulsa 4	Gas Steam	1958	158
Weleetka 4	Gas (CT)	1975	51
Weleetka 5	Gas (CT)	1976	49
Weleetka 6	Gas (CT)	1976	50
Riverside 3	Gas (CT)	2008	72
Riverside 4	Gas (CT)	2008	73
Southwestern 4	Gas (CT)	2008	76
Southwestern 5	Gas (CT)	2008	75
			3,680

(1) Commercial operation date.
(2) Peak net dependable capability (Summer) as of filing.
(A) Represents PSO's 15.62% ownership stake in Oklaunion

PSO currently utilizes several additional capacity entitlements to meet the minimum SPP reserve margin requirement and customers' energy needs. Beginning in 2012, PSO began to receive approximately 520MW of generating capacity under a 10-year Power Purchase Agreement (PPA) with Exelon Generating Company LLC, from the Green Country Generating Station located in Jenks, OK. Other PPA's PSO has agreements with include: Exelon #2 for 250MW through 2020; Oneta for 260MW through 2030; Westar for 80MW through 2020 and Tenaska for 40MW through 2018.

Additionally, PSO currently has a total of 1,137MW (nameplate rating) of wind capacity from eight wind facilities in which the Company is receiving energy, capacity, and renewable energy credit attributes under separate renewable energy PPAs. For capacity resource planning purposes, however, an important distinction is that SPP criteria also dictates that intermittent resources such as wind may only recognize a small portion of such nameplate capacity rating. Using those guidelines, capacity credit of 118MW is used capacity planning purposes in 2018.

3.3 Capacity Needs Assessment

Based on the assessment of the AEP-SPP current resources and peak demand projections (Section 2.5.2, Exhibit A-2); a capacity needs assessment can be established that will determine the amount and timing of capacity resources for this IRP.

Figure 11 summarizes the going-in capacity position through the 10-year IRP window, see Exhibit E for PSO's Capacity, Demand and Reserves (CDR) summary. Figure 12 compares the demand (line) and total capacity (bar) trends over the period, illustrating PSO's net capacity position with respect to the company's load obligation, and with respect to SPP's 12% reserve margin requirement.

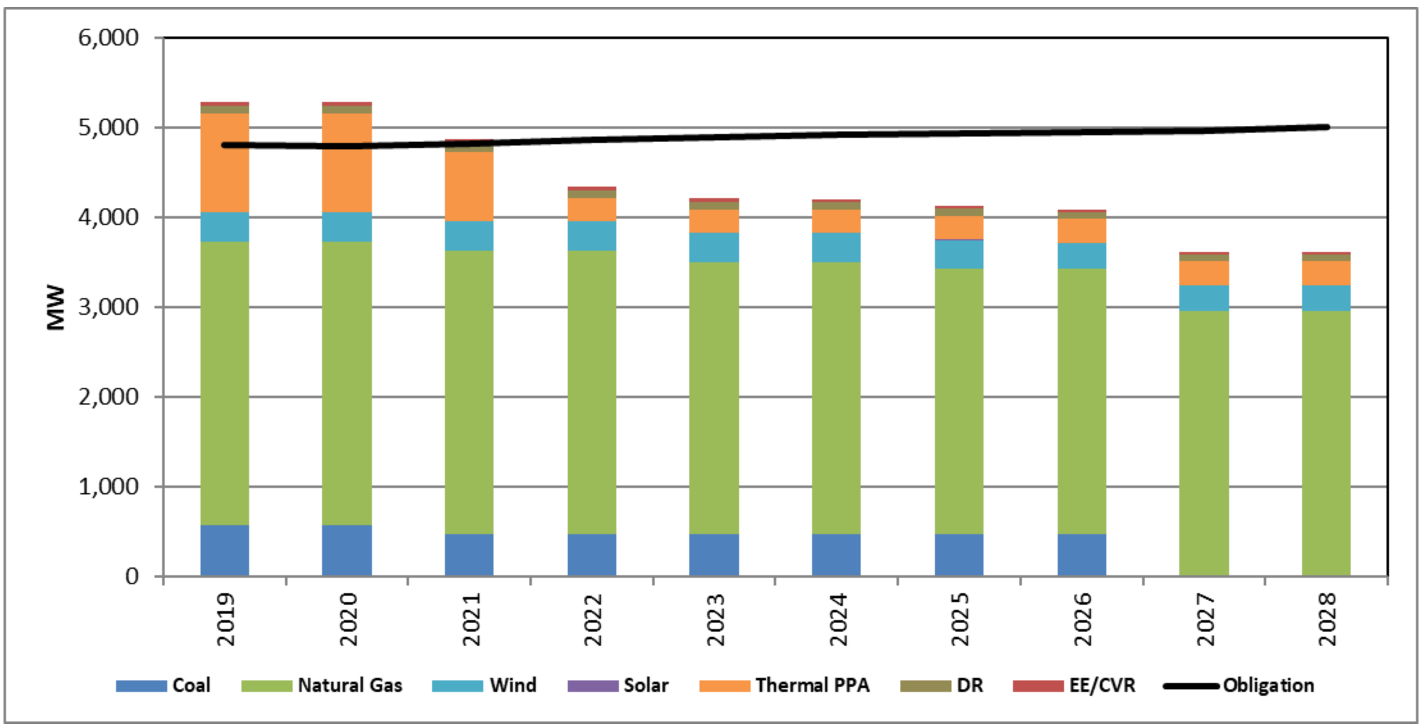


Figure 11. PSO "Going-In" SPP Capacity Position (MW) and Obligation (MW)

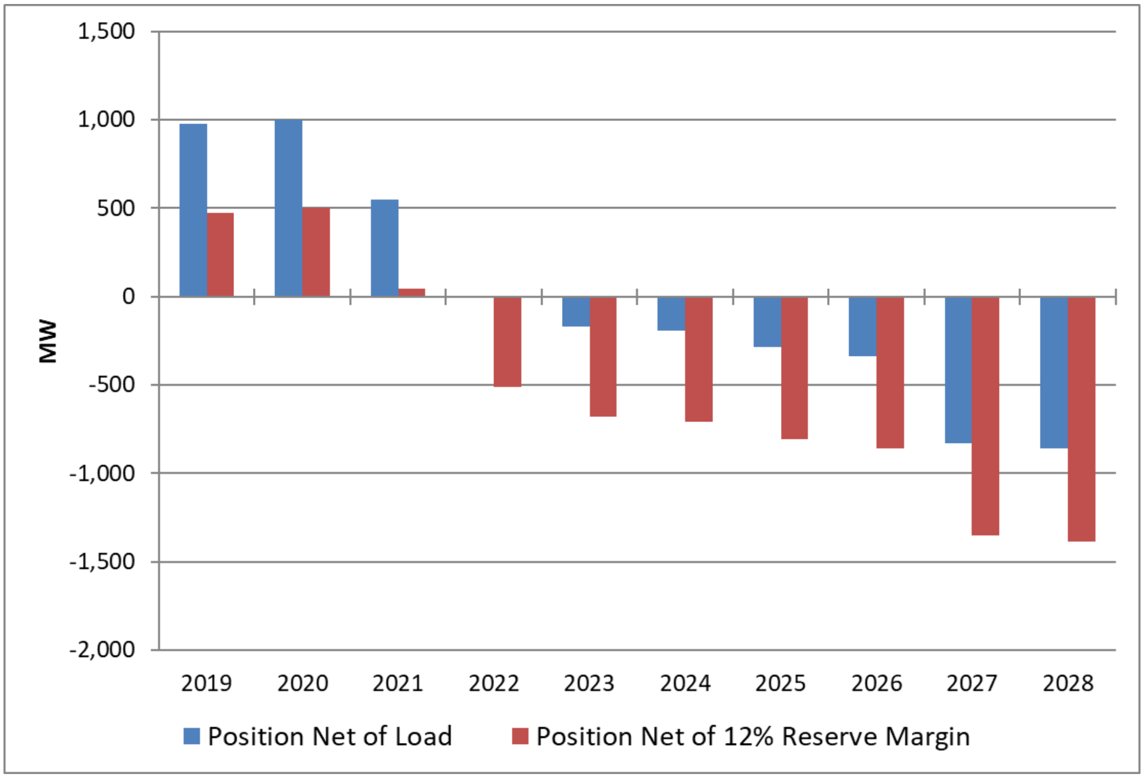


Figure 12. PSO Capacity Positions (MW) net of SPP Reserve Obligation

3.4 Environmental Compliance

It should be noted that the following discussion of environmental regulations is the basis for assumptions made by the Company which are incorporated into its analysis within this IRP. Activity including but not limited to Presidential Executive Orders, litigation, petitions for review, and Federal Environmental Protection Agency (EPA) proposals may delay the implementation of these rules, or eventually affect the requirements set forth by these regulations. While such activities have the potential to materially change the regulatory requirements the Company will face in the future, all potential outcomes cannot be reasonably foreseen or estimated and the assumptions made within the IRP represent the Company's best estimation of outcomes as of the filing date. The Company is committed to closely following developments related to environmental regulations, and will update its analysis of compliance options and timelines when sufficient information becomes available to make such judgments.

3.4.1 Clean Air Act (CAA) Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to the National Ambient Air Quality Standards (NAAQS) and the development of State Implementation Plans (SIPs) to achieve more stringent standards; (b) implementation of the Regional Haze program by the states and the Federal EPA; (c) regulation of hazardous air pollutant emissions under the Mercury and Air Toxics Standards (MATS) Rule; (d) implementation and review of the Cross-State Air Pollution Rule (CSAPR), a Federal Implementation Plan (FIP) designed to eliminate significant contributions from sources in upwind states to nonattainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil-fueled electric generating units under Section 111 of the CAA.

In March 2017, President Trump issued a series of executive orders designed to allow the Federal EPA to review and take appropriate action to revise or rescind regulatory requirements that place undue burdens on affected entities, including specific orders directing the Federal EPA to review rules that unnecessarily burden the production and use of energy. The Federal EPA published notice and provided an opportunity to comment on how to identify such requirements and what steps can be taken to reduce or eliminate such burdens. Future changes that result from this effort may affect AEP's compliance plans.

Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

3.4.2 National Ambient Air Quality Standards (NAAQS)

The CAA requires the Federal EPA to establish and periodically review NAAQS designed to protect public health and welfare. The Federal EPA issued new, more stringent NAAQS for PM in 2012, SO_2 in 2010 and ozone in 2015; the existing standards for NO_2 were retained after review by the Federal EPA in 2018. Implementation of these standards is underway. States are still in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the 2010 SO_2 NAAQS and may develop additional requirements for our facilities as a result of those evaluations. In April 2017, Federal EPA requested a stay of proceedings in the U.S. Circuit Court for the District of Columbia Circuit where challenges to the 2015 ozone standard are pending, to allow reconsideration of that standard by the new administration. The Federal EPA initially announced a one-year delay in the designation of ozone non-attainment areas, but withdrew that decision. In December 2017, the Federal EPA issued a notice of data availability and requested public comment on recommended designations for compliance with the 2015 ozone standard. Final designations for 51 nonattainment areas were published on June 4, 2018. In April and July 2018, the Federal EPA finalized nonattainment designations for the remaining areas. The Federal EPA has also issued information to assist the states in developing plans that address their obligations under the interstate transport provisions of the CAA. On November 7, 2018, EPA issued a final rule to provide state and local air management agencies with rules and guidance on planning to meet the 2015 ozone standard and setting SIP submittal deadlines for various elements of the 2015 standard. The earliest SIP revision is due within two years of the effective date of the non-attainment designation, during year 2020. PSO cannot currently predict the nature, stringency or timing of additional requirements for PSO's facilities based on the outcome of these activities.

3.4.3 Regional Haze Rule (RHR)

The RHR requires affected states to develop regional haze SIPs that contain enforceable measures and strategies for reducing emissions of pollutants that can impair visibility in certain federally protected areas. Each SIP must require certain eligible facilities to conduct an emission control analysis, known as a Best Available Retrofit Technology (BART) analysis, to evaluate emissions control technologies for NO_X, SO_2 and PM, and determine whether such controls should be deployed to improve visibility based on five factors set forth in the regulations. BART is applicable to Electric Generating Units (EGUs) greater than 250 megawatts (MW) and built between 1962 and 1977. If SIPs are not adequate or are not developed on schedule, regional haze requirements will be implemented through FIPs. In January 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. The rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the Federal EPA rule.

3.4.4 Oklahoma Regional Haze

The CAA and RHR require certain states, including Oklahoma, to make reasonable progress toward the "prevention of any future, and the remedying of any existing, impairment of visibility" in mandatory Class I Federal areas. Moreover, the Regional Haze Rule requires the State of Oklahoma to develop programs to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." Air pollutants emitted by BART eligible sources in Oklahoma, which may reasonably be anticipated to cause or contribute to visibility impairment, in any mandatory Class I Federal area are NO_x, SO_2, PM-10, and PM-2.5. EPA also provided guidance on what level of control is reasonable for certain BART-eligible sources, including EGUs, and published "presumptive BART" emission rates for SO_2 and NO_x based on the types of cost-effective controls available.

In November 2012, PSO reached an agreement with the Federal EPA, the State of Oklahoma and other parties that would provide for submission of a revised regional haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than April 2016, and the installation of a Dry Sorbent Injection (DSI) system, an Activated Carbon Injection (ACI) system, a Pulse Jet Fabric Filter (PJFF), and Continuous Emission Monitoring System (CEMS) on the second coal-fired Northeastern unit by April 2016, with retirement of the second unit no later than 2026. As a result of this agreement, PSO has taken the following measures:

- Northeastern Unit 3 – Installation of DSI and ACI systems, FF and CEMS, all placed in service February 26, 2016
- Northeastern Unit 4 – retired in place April 15, 2016

3.4.5 Mercury and Air Toxics Standard (MATS) Rule

The final MATS Rule became effective on April 16, 2012, and required compliance by April 16, 2015. AEP Management obtained administrative extensions for up to one year at several units, including PSO's Northeastern Units 3&4, to facilitate the installation of controls or to avoid a serious reliability problem. This rule regulates emissions of Hazardous Air Pollutants (HAPS) from coal and oil-fired EGUs. HAPS regulated by this rule are: 1) mercury; 2) certain non-mercury metals such as arsenic, lead, cadmium and selenium; 3) certain acid gases, including Hydrochloric Acid (HCl); and 4) certain organic HAPS. The MATS Rule establishes stringent emission rate limits for mercury, filterable PM as a surrogate for all regulated non-mercury metals, and HCl as a surrogate for all acid gases. Alternative emission limits were also established for the individual non-mercury metals, and for SO_2 (as an alternate to HCl) for generating units that have operating Flue Gas Desulfurization (FGD) systems. The MATS Rule regulates organic HAPS through work practice standards.

In addition to meeting the regional haze SIP requirements, the Northeastern Unit 3 environmental controls project installations listed in Section 3.4.1.2.1 above were installed to meet the MATS Rule requirements.

In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS Rule for further proceedings consistent with the U.S. Supreme Court's decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPS from power plants. The Federal EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. AEP submitted comments on the proposal. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. Petitions for review of the Federal EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument was scheduled for May 2017, but in April 2017 the Federal EPA requested that oral argument be postponed to facilitate its review of the rule, which remains in effect.

3.4.6 Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule (CAIR), a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind nonattainment with the 1997 ozone and PM NAAQS. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. The rule was vacated, but that decision was reversed on appeal to the U.S. Supreme Court. On remand, the U.S. Court of Appeals for the District of Columbia Circuit allowed Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. In July 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In October 2016, the Federal EPA issued a final rule to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule, also referred to as the CSAPR Update, significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitions and other challenges to the rule. AEP has been complying with the more stringent ozone season budgets while these petitions were pending.

PSO will rely on the installed NO_x and SO_2 reduction systems, the use of allocated NO_x and SO_2 emission allowances in conjunction with adjusted banked allowances, and the purchase of additional allowances as needed through the open market to comply with CSAPR Phase II and the CSAPR Update.

3.4.7 Carbon Dioxide (CO_2) Regulation

In October 2015, the Federal EPA published the final CO_2 emissions standards for new, modified and reconstructed fossil fuel fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources, known as the Clean Power Plan (CPP).

The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review.

In March 2017, the Federal EPA filed in the U.S. Court of Appeals for the District of Columbia Circuit notice of: (a) an Executive Order from the President of the United States titled "Promoting Energy Independence and Economic Growth" directing the Federal EPA to review the CPP and related rules, (b) the Federal EPA's initiation of a review of the CPP and (c) a forthcoming rulemaking related to the CPP consistent with the Executive Order, if the Federal EPA determines appropriate. In this same filing, the Federal EPA also presented a motion to hold the litigation in abeyance until 30 days after the conclusion of review of any resulting rulemaking. The U.S. Court of Appeals for the District of Columbia Circuit granted the Federal EPA's motion in part and has requested periodic status reports.

Subsequent Federal EPA efforts in the rulemaking process included issuing a proposed rule repealing the CPP in October 2017 and an advanced notice of proposed rulemaking seeking information that should be considered by the Federal EPA in developing revised greenhouse gas guidelines that was issued in December 2017. In August 2018, EPA proposed a replacement for the Clean Power Plan titled the Affordable Clean Energy (ACE) Rule. The ACE rule establishes a best system of emission reductions (BSER) for fossil fueled steam generators based on the potential for heat rate improvements (HRI) which would allow for generators to consume less fuel, and thus produce less CO_2 emissions, per unit of electric output. EPA also proposed a list of "Candidate Technologies" representing the most likely impactful HRI measures. In conjunction with the emission guidelines, Federal EPA has proposed revisions to the New Source Review applicability test, to help expedite permitting associated with HRI projects. Ultimately individual states are expected to establish standards of performance that reflect the BSER guidelines based on unit specific conditions. State plans are due within 3 years of the publication date of the final rule and must be ultimately approved by the Federal EPA. No specific timeline was provided as to when the measures in state plans will need to be effective and implemented. AEP Management is actively participating in this rulemaking and will be providing public comment. However, at this time, AEP Management is unable to definitively predict either the outcome of the rulemaking or the impact of state standards that may come as a result.

Absent CO_2 regulatory certainty, AEP has taken action to reduce and offset CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where cost effective and there is regulatory support for such activities.

3.4.8 Coal Combustion Residuals (CCR) Rule

In April 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired EGUs and also FGD gypsum generated at some coal-fired plants. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. Certain records must be posted to a publicly available internet site. Initial groundwater monitoring reports were posted in the first quarter of 2018, and some of AEP's existing facilities were required to begin assessment monitoring programs to determine if unacceptable groundwater impacts will trigger future remedial actions.

In December 2016, the U.S. Congress passed legislation authorizing states to submit programs to regulate CCR facilities, and the Federal EPA to approve such programs if they are no less stringent than the minimum federal standards. The Federal EPA may also enforce compliance with the minimum standards until a state program is approved or if states fail to adopt their own programs. Oklahoma has received approval to operate its state program in lieu of the federal rules.

The final 2015 rule has been challenged in the courts. In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule and asked that litigation regarding the rule be held in abeyance. The U.S. Court of Appeals for the District of Columbia Circuit heard oral argument in November 2017. In March 2018, the Federal EPA issued a proposed rule to modify certain provisions of the solid waste management standards and provide additional flexibility to facilities regulated under approved state programs. A final rule was signed in July 2018 that modifies certain compliance deadlines and other requirements in the rule, including postponing the closure obligation for unlined surface impoundments that exceed a groundwater protection standard or fail to meet the minimum separation distance from the upper-most aquifer until October 2020, establishing numeric groundwater protection standards for four compounds that do not have primary drinking water standards, authorizing state and federal regulators to suspend groundwater monitoring requirements under limited circumstances and issue technical certifications. Additional changes to the minimum performance standards that were contained in the March proposed rule will be addressed in future rulemakings. AEP Management supports the adoption of more flexible compliance alternatives subject to the Federal EPA or state oversight.

In August 2018, the U.S Court of Appeals for the District of Columbia Circuit issued a decision addressing all remaining issues in the litigation of the CCR rule. The court 1) denied EPA's request to hold the litigation in abeyance while EPA initiated rulemakings to respond to two petitions for reconsideration and the WIIN Act; 2) ruled in favor of the environmental petitioners vacating provisions of the rule that allow unlined CCR surface impoundments to continue receiving CCR material and excluding inactive surface impoundments at inactive faculties from the rule; and 3) rejected or remanded all legal challenges brought by industry. The court also remanded the vacated provisions to EPA for further rulemaking. Management is reviewing the implications of the decision and working with industry associations concerning next steps.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represents an “unpermitted discharge” under the Clean Water Act. The Federal EPA has opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of Clean Water Act permitting requirements for discharges to ground water. AEP Management is unable to predict the outcome of these cases or the Federal EPA’s rulemaking, which could impose significant additional costs on AEP’s facilities. PSO anticipates the need for major capital investment at Northeastern Unit 3 in the 2020 - 2023 time frame, to comply with the CCR Rule.

3.4.9 Clean Water Act Regulations

3.4.9.1 Clean Water Act “316(b)” Rule

A final rule under Section 316(b) of the Clean Water Act was issued by the Federal EPA on August 15, 2014, with an effective date of October 14, 2014, and affects all existing power plants (generally those whose construction began prior to January 17, 2002) withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water intake systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats.

Facilities subject to both the impingement standard and site-specific entrainment studies are required to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's NPDES permit for installation of any required technology changes, as those permits are renewed. Petitions for review were filed by industry and environmental groups in the U.S. Court of Appeals for the Second Circuit. The court denied the petitions and upheld the final rule. PSO's facilities are reviewing these requirements as their waste water discharge permits are renewed.

PSO's generating plants are not expected to require major capital investments, as a result of this rule.

3.4.9.2 Effluent Limitation Guidelines and Standards (ELG)

In November 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The final rule established limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements will be implemented through each facility's wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations, of which AEP is a member, filed a petition for reconsideration of the rule with the Federal EPA. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September of 2017. AEP Management continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting, and is actively participating in the reconsideration proceedings.

Northeastern Unit 3 may require modification of its bottom ash handling system in future years. However, a request for a Fundamentally Different Factors variance from the bottom ash transport water restriction was submitted in 2016 and no action has yet been taken. Oklaunion utilizes a dry fly ash handling system and does not discharge from either its bottom ash handling system or its FGD wastewater. Therefore, no issues are anticipated with respect to ELG compliance for Oklaunion.

3.5 PSO Current Demand-Side Programs

3.5.1 Background

DSM refers to, for the purposes of this IRP, utility programs, including tariffs, which encourage reduced energy consumption, either at times of peak consumption or throughout the day/year. Programs or tariffs that reduce consumption primarily at periods of peak consumption are DR programs, while around-the-clock measures are typically categorized as EE programs. The distinction between DR and EE is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.

Included in the load forecast discussed in Section 2.0 of this Report are the demand and energy impacts associated with PSO's DSM programs that have been previously approved or are currently pending Commission approval. As will be discussed later, within the IRP process, the potential for additional or "incremental" demand-side resources, including EE activity—over and above the levels embedded in the load forecast—as well as other grid related projects such as Conservation Voltage Reduction (CVR), are modeled on the same economic basis as supply-side resources. However, because customer-based EE programs are limited by factors such as customer acceptance and saturation, an estimate as to their costs, timing and maximum impacts must be formulated. For the year 2018, the Company anticipates 91MW of peak DSM reduction (total company basis); consisting of 18MW and 73MW of "passive" EE and "active" DR activity, respectively.[7]

3.5.2 Impacts of Existing and Future Codes and Standards

The EISA requires, among other things, a phase-in of heightened lighting efficiency

[7] "Passive" demand reductions are achieved via "around-the-clock" *EE* program activity as well as voluntary price response programs; "Active" DR is centered on summer peak reduction initiatives, including interruptible contracts, tariffs, and direct load control programs.

standards, appliance standards, and building codes. The increased standards will have a pronounced effect on energy consumption as explained in Section 2.6. Many of the standards already in place impact lighting. For instance, since 2013 and 2014 common residential incandescent lighting options have been phased out as have common commercial lighting fixtures. Given that "lighting" measures have comprised a large portion of utility-sponsored EE programs prior to the phase-out, this pre-established transition is already incorporated into the SAE long-term load forecast modeling previously described in Section 2.4.4 and may greatly affect the market potential of utility EE programs in the near and intermediate term. Table 2and Table 3 depict the current schedule for the implementation of new EISA codes and standards.

Table 2. Forecasted View of Relevant Residential Energy Efficiency Code Improvements

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Central AC	SEER 13; SEER 14 in South										
Room AC	EER 11.0										
Heat Pump	SEER 14.0/HSPF 8.0										
Water Heater (<=55 gallons)	EF 0.95										
Water Heater (>55 gallons)	Heat Pump Water Heater										
Screw-in/Pin Lamps	Advanced Incandescent (20 lumens/watt)					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
Refrigerator	25% more efficient										
Freezer	25% more efficient										
Clothes Washer	1.29 IMEF top loader			1.57 IMEF top loader							
Clothes Dryer	3.73 Combined EF										
Furnace Fans	Conventional				40% more efficient						

Table 3. Forecasted View of Relevant Non-Residential Energy Efficiency Code Improvements

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chillers	2007 ASHRAE 90.1										
Roof Top Units	EER 11.0/11.2										
PTAC	EER 11.7		EER 11.9								
Heat Pump	EER 11.0/COP 3.3										
PTHP	EER 11.9/COP 3.3										
Ventilation	Constant Air Volume/Variable Air Volume										
Screw-in/Pin Lamps	Advanced Incandescent (20					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
High Intensity Discharge	EPACT 2005		Metal Halide Ballast Improvement								
Water Heater	EF 0.97										
Walk-in Refrigerator/Freezer	EISA 2007		10-38% more efficient								
Reach-in Refrigerator/Freezer	EPACT 2005		40% more efficient								
Glass Door Display	EPACT 2005		12-28% more efficient								
Open Display Case	EPACT 2005		10-20% more efficient								
Ice maker	EPACT 2005			15% more efficient							
Pre-rinse Spray Valve	1.6 GPM				1.0 GPM						
Motors	EISA 2007	Expanded EISA 2007									

The impact of energy efficiency, including codes and standards, is expected to reduce residential load, commercial load, and industrial lighting load in total by about 3.3%, as shown in Figure 13.

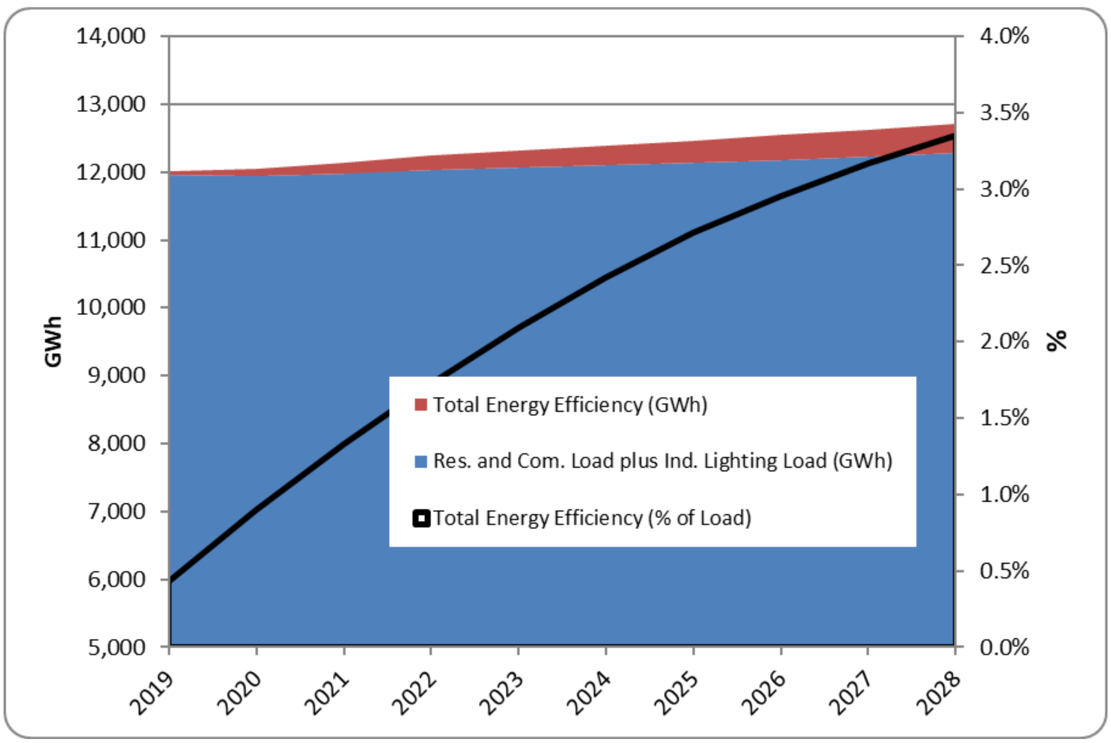


Figure 13. Total Energy Efficiency (GWh) Compared w/Total Residential & Commercial Load (GWh)

3.5.3 Demand Response (DR)

Peak demand, measured in MW, can be thought of as the amount of power used at the time of maximum customer usage. PSO's maximum (system peak) demand is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances, commercial equipment, and (industrial) machinery. At other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new generating capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak can be reduced. This can be addressed several ways via both "active" and "passive" measures:

- *Interruptible loads (Active DR)*. This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.
- *Direct load control (Active DR)*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Time-differentiated rates (Active DR)*. This offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) to as often as 15-minute increments in what is known as "real-time pricing." Accomplishing real-time pricing requires digital (smart) metering.
- *EE measures (Passive DR)*. If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less.

- *Voltage Regulation (Passive DR).* Certain technologies, such as Conservation Voltage Reduction can be deployed that allow for improved monitoring of voltage throughout the distribution system. The ability to deliver electricity at design voltages improves the efficiency of many end use devices, resulting in less energy consumption.

What may not be apparent is that, with the exception of EE and voltage regulation measures, the remaining DR programs do not significantly reduce the amount of energy consumed by customers. Less energy may be consumed at the time of peak load, but that energy will be consumed at some point during the day. For example, if rates encourage customers to avoid running their clothes dryer at 4:00 P.M., then they will run it at some other point in the day. This is often referred to as load shifting.

3.5.3.1 Existing Levels of Active Demand Response (DR)

PSO currently has active DR programs totaling 73MW of peak DR capability. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control.

3.5.4 Energy Efficiency (EE)

EE measures reduce bills and save money for customers. The trade-off is the up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If consumers conclude that the new technology is a viable substitute and will pay them back in the form of reduced bills over an acceptable period, they will adopt it.

EE measures most commonly include efficient lighting, weatherization, efficient pumps and motors, efficient Heating, Ventilation and Air Conditioning (HVAC) infrastructure, and efficient appliances. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will reduce the amount of energy consumed but may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. However, market barriers to EE may exist for the potential participant. To overcome participant barriers, a portfolio of EE programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of EE measure adoption.

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP begins adding new demand-side resources in 2022 that are incremental to programs that are currently approved or pending approval.

3.5.4.1 Existing Levels of Energy Efficiency (EE)

PSO currently has EE programs in place and forecasts EE measures will reduce peak demand in 2018 by 18MW and reduce 2018 energy consumption by approximately 74GWh.

3.5.5 Distributed Generation (DG)

DG typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. PSO's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate up to the amount of the customer's monthly bill.

The economics of DG, particularly solar, continue to improve. Figure 14 charts the fairly rapid decline of expected installed solar costs, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) U.S. Renewable Energy Market Outlook forecast.

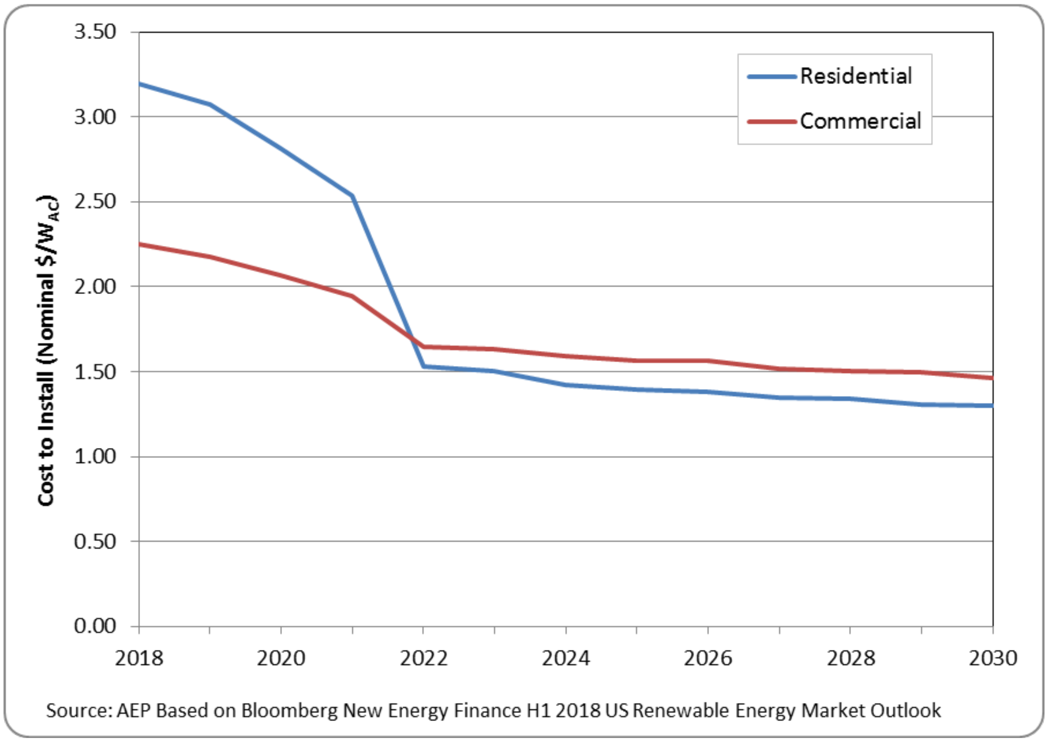


Figure 14. Residential & Commercial Forecasted Solar Installed Costs (Nominal W_{AC}$) for SPP

Prior to 2022, during the ITC phase out for residential systems, costs for residential customers are expected to decline rapidly. This decline, which is forecasted to bring residential costs down to commercial cost levels, is attributed to a shift from value-based pricing to cost-plus-margin pricing. Installers are expected to spend less on customer acquisition and less on customer specific solutions as they aim for the lowest cost installations possible.

While the cost to install residential solar continues to decline, the economics of such an investment are not favorable for the customer for a number of years. Figure 15 below illustrates, by PSO state jurisdictional residential sector, the equivalent value a customer would need to achieve, on a dollars per watt-AC ($/W$_{AC}$) basis, in order to breakeven on their investment, assuming a 25 year life of the installed solar panels based on the customer's avoided retail rate. Figure 15 also assumes that the monetary credit that the customer receives for excess generation can exceed the amount of their overall monthly bill. Also included is the average cost of solar residential installations in SPP. Figure 15 shows that the current cost of residential solar exceeds the cost which would allow a customer to breakeven on an investment over a 25 year period.

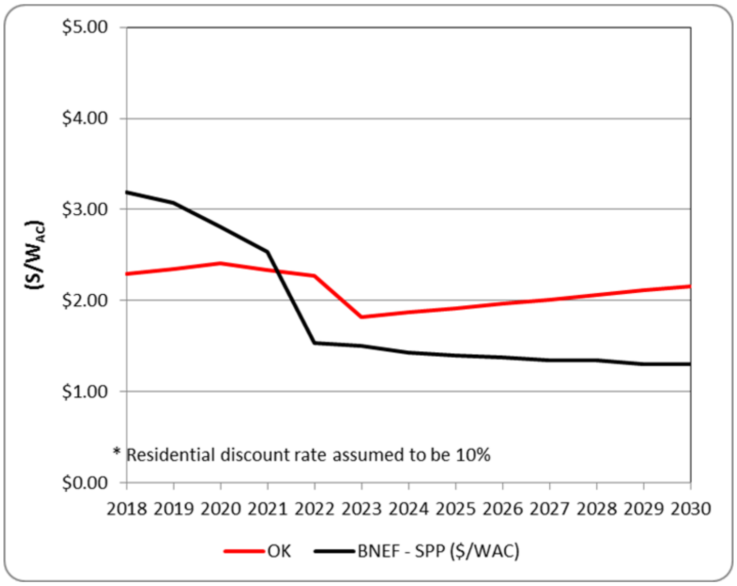


Figure 15. Distributed Solar Customer Breakeven Costs for Residential Customers ($/$W_{AC}$)

A challenge of determining the value of a residential solar system is assigning an appropriate cost of capital or discount rate. Discount rates for residential investments vary dramatically and are based on each individual's financial situation. Figure 16 shows how the value of a residential customer's DG system can vary based on discount rate.

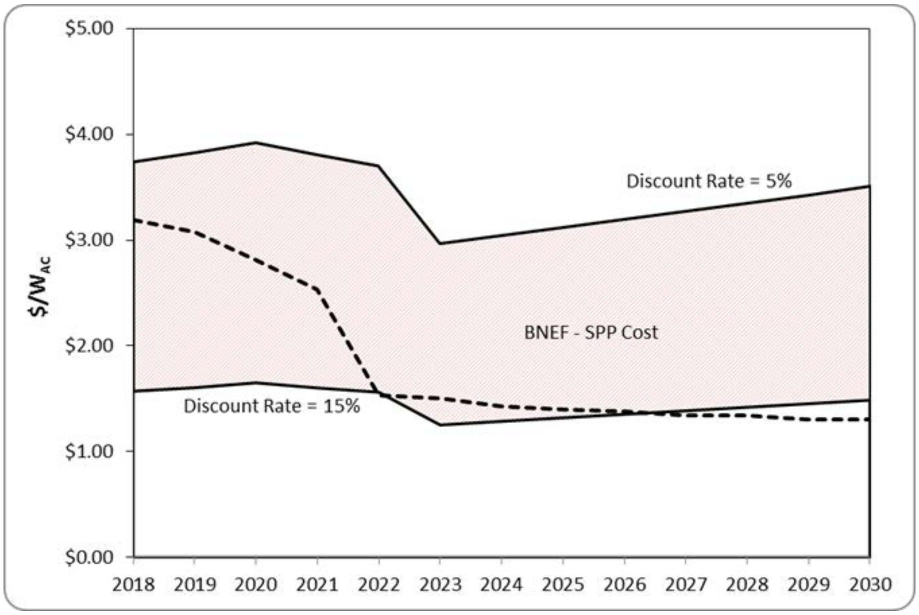


Figure 16. Range of Residential Distributed Solar Breakeven Values Based on Discount Rate

3.5.5.1 Existing Levels of Distributed Generation (DG)

At the end of 2017 PSO has a total of approximately 0.9MW of customer-installed DG. Forecasted levels of DG are described in Section 4.4.3.4.

3.5.5.2 Impacts of Increased Levels of Distributed Generation (DG)

Increasing levels of DG present challenges for the Company from a distribution planning perspective. Higher penetration of DG can potentially mask the true load on distribution circuits and stations if the instantaneous output of connected DG is not known, which can lead to under-planning for the load that must be served should DG become unavailable. Increased levels of DG could lead to a requirement that DG installations include smart inverters so that voltage and other circuit parameters can be controlled within required levels. Additional performance monitoring capabilities for DG systems will facilitate accurate tracking and integration of DG generators into the existing resource mix.

Currently, DG applicants in PSO's jurisdictions are required to fund any improvements needed to mitigate impacts to the operation and power quality of affected distribution stations and circuits. As DG penetration grows there is potential that the "next" applicant would be required to fund improvements that are a result of the aggregate impacts of previous DG customers because the incremental impact of the "next" customer now drives a need for improvements. This could lead to inequities among DG customers if necessary improvements are not planned appropriately.

3.5.6 Conservation Voltage Reduction (CVR)

An emerging technology known as CVR represents a form of voltage control that allows the grid to operate more efficiently, and ultimately results in energy savings for customers. Depicted at a high-level in Figure 17, with CVR sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor and voltage levels. Power factor is the ratio of real power to apparent power, and is a characteristic of electric power flow which is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies. In 2011 and 2012, PSO deployed CVR technology on 11 circuits in the city of Owasso as part of a pilot demonstration that also included other grid management technologies. Subsequently, CVR technology was expanded to two additional circuits in 2013. PSO conducted an evaluation of 2013 CVR performance, and additional evaluations, including impacts of the technology on customers, were performed by an independent and nationally recognized third party, Pacific Northwest National Labs. The results of the study showed energy savings between approximately 2% and 7% and demand savings between 2% and 5%. CVR has been modeled as a unique EE resource. PSO currently has CVR in service on 37 circuits which has resulted in 6.2MW of demand reduction and 24GWh of energy reduction.

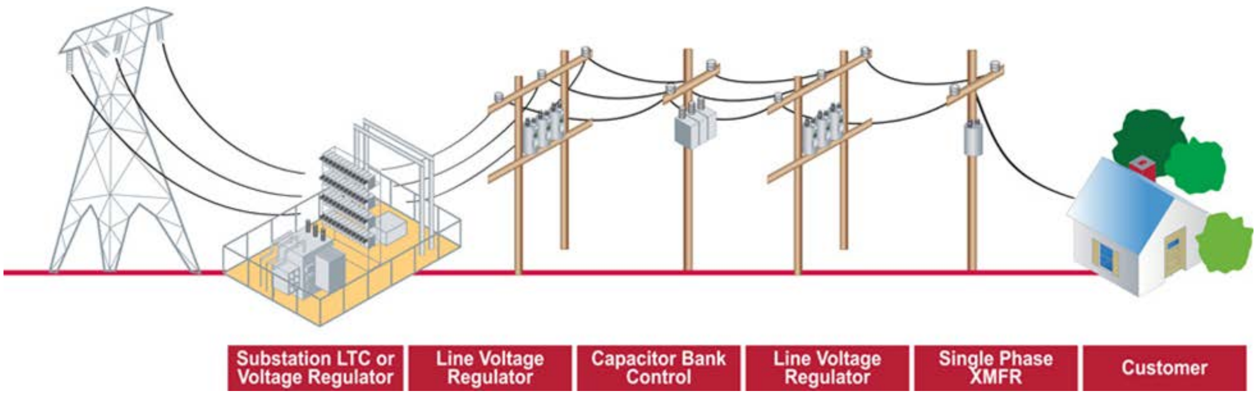


Figure 17. CVR Optimization Schematic

3.6 AEP-SPP Transmission

3.6.1 Transmission System Overview

The portion of the AEP Transmission System operating in SPP (AEP-SPP zone, or AEP-SPP) consists of approximately 1,300 miles of 345 kV, approximately 3,600 miles of 138 kV, approximately 2,500 miles of 69 kV, and approximately 400 miles at other voltages above 100 kV. The AEP-SPP zone is also integrated with and directly connected to ten other companies at approximately 90 interconnection points, of which approximately 70 are at or above 69 kV and to Electric Reliability Council of Texas (ERCOT) via two high voltage direct current (HVDC) ties. These interconnections provide an electric pathway to provide access to off-system resources, as well as a delivery mechanism to neighboring systems. Table 4 shows PSO's forecasted transmission capital expenditures throughout the IRP's ten-year planning period.

Table 4. Transmission Capital Spend Forecast for PSO (2019-2028)

Transmission - Capital Spend Forecast ($000)										
	2019	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*
Transmission - Capital	62,659	55,761	45,285	51,118	64,052	47,505	51,028	48,018	52,614	54,130

3.6.2 Current AEP-SPP Transmission System Issues

The limited capacity of interconnections between SPP and neighboring systems, as well as the electrical topology of the SPP footprint transmission system, influences the ability to deliver non-affiliate generation, both within and external to the SPP footprint, to AEP-SPP loads and from sources within AEP-SPP balancing authority to serve AEP-SPP loads. Moreover, a lack of seams agreements between SPP and its neighbors has significantly slowed down the process of developing new interconnections. Despite the robust nature of the AEP-SPP transmission system as originally designed, its current use is in a different manner than originally designed, in order to meet SPP requirements, which can stress the system. In addition, factors such as outages, extreme weather, and power transfers also stress the system. This has resulted in a transmission system in the AEP-SPP zone that is constrained when generation is dispatched in a manner substantially different from the original design of utilizing local generation to serve local load.

SPP has made efforts to solve seams issues. One project along the SPP-Midcontinent Independent System Operator (MISO) seam that came from the SPP Transmission Expansion Plan (STEP) process, discussed in Section 3.6.2.1 below, is a Layfield 500-230 kV station in northwestern Louisiana. This joint effort by SWEPCO and Cleco may improve transfer capability between SPP and MISO.

Also, SPP and MISO have engaged in a coordinated study process in an effort to identify transmission improvement projects which are mutually beneficial. Projects deemed beneficial by both RTOs will be pursued with joint funding, but no such projects have yet been deemed beneficial by both RTOs.

Additional background on SPP's Interregional Relations, including the Regional Review Methodology and SPP's Joint Operating Agreements with MISO and AECI may be found at: http://www.spp.org/engineering/interregional-relations/

3.6.3 The SPP Transmission Planning Process

Currently, SPP produces an annual STEP. The STEP is developed through an open stakeholder process with AEP participation. SPP studies the transmission system, checking for base case and contingency overload and voltage violations in SPP base case load flow models, plus models which include power transfers.

The 2018 STEP summarizes 2017 activities, including expansion planning and long-term SPP Open Access Transmission Tariff (OATT) studies (Tariff Studies) that impact future development of the SPP transmission grid. Key topics included in the STEP are:

1) Transmission Services,
2) Generator Interconnection,
3) Integrated Transmission Planning (ITP),
4) High Priority Studies,
5) Sponsored Upgrades,
6) Regional Cost Allocation Review,
7) Interregional Coordination, and
8) Project Tracking

These topics are critical to meeting mandates of either the SPP strategic plan or the nine planning principles in FERC Order 890. As an RTO under the domain of the FERC, SPP must meet FERC requirements and the SPP OATT, or Tariff. The SPP RTO acts independently of any single market participant or class of participants. It has sufficient scope and configuration to maintain electric reliability, effectively perform its functions, and support efficient and non-discriminatory power markets. Regarding short-term reliability, the SPP RTO has the capability and exclusive authority to receive, confirm, and implement all interchange schedules. It also has operational authority for all transmission facilities under its control. The 10-year RTO regional reliability assessment continues to be a primary focus.

STEP projects are categorized by the following designations:

- Generation Interconnect – Projects associated with a FERC-filed Interconnection Agreement;
- High Priority – Projects identified in the high priority process
- Interregional – Projects identified in SPP's joint planning and coordination processes;

- ITP – Projects needed to meet regional reliability, economic, or policy needs in the ITP study process;
- Transmission service – Projects associated with a FERC-filed Service Agreement;
- Zonal Reliability – Projects identified to meet more stringent local Transmission Owner criteria; and
- Zonal-Sponsored – Projects sponsored by facility owner with no Project Sponsor Agreement

The 2018 STEP identified 445 transmission network upgrades with a total cost of approximately $4.96 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 81% of the total cost in the 2018 STEP. The ITP process was designed to maintain reliability and provide economic benefits to the SPP region in both the near and long-term. The ITP10 assessment resulted in a recommended portfolio of transmission projects for comprehensive regional solutions, local reliability upgrades, and the expected reliability and economic needs of a 10-year horizon. Also, in the ITP Near-Term assessment, the reliability of the SPP transmission system was studied, resulting in Notification to Construct (NTC) letters issued by SPP for upgrades that require a financial commitment within the next four years.

The 2018 STEP is available at:

https://www.spp.org/documents/56611/2018_spp_transmission_expansion_plan_report.pdf

3.6.4 PSO-SWEPCO Interchange Capability

In previous years, operational experience and internal assessments of company transmission capabilities had indicated that, when considering a single contingency outage event, the firm capability transfer limit from Public Service Oklahoma (PSO) to SWEPCO and from SWEPCO to PSO was about 200 MW. However, in 2016, the Valliant-Northwest Texarkana 345 kV line from southeastern Oklahoma to northeastern Texas was placed in service, substantially improving the ability to transfer power across the PSO-SWEPCO interface. Note that the - transfer capability between the two companies is available to all transmission users under the provisions established by FERC Order 888 and subsequent orders. Thus, depending upon future transfers in and through the SPP region, the availability of future transfer capability between PSO and SWEPCO is unknown.

3.6.5 AEP-SPP Import Capability

Currently the capability of the transmission system to accommodate large incremental firm imports to the AEP-SPP area is limited. Generally, the transfers are limited by the facilities of neighboring systems rather than by transmission lines or equipment owned by AEP.

Increasing the import capabilities with AEP-SPP's neighboring companies could require a large capital investment for new transmission facilities by the neighboring systems or through sponsored upgrades by SPP transmission owners. An analysis of the cost of the upgrades cannot be performed until the capacity resources are determined. For identified resources, the cost of any transmission upgrades necessary on AEP's transmission system can be estimated by AEP once SPP has identified the upgrade. AEP's West Transmission Planning group can identify constraints on third-party systems through ad hoc power flow modeling studies, but West Transmission Planning does not have information to provide estimates of the costs to alleviate those third-party constraints.

3.6.6 SPP Studies that may Provide Import Capability

Some projects that may lead to improved transfer capability between AEP-SPP and neighboring companies and regions include:

- Chisholm-Gracemont 345 kV line across western Oklahoma from a new Chisholm 345-230 kV station near existing wind generation facilities west of Elk City to Gracemont station near Anadarko (completed)
- The new Layfield 500-230 kV station in northwestern Louisiana (completed)
- Valliant-Northwest Texarkana 345 kV line from southeastern Oklahoma to northeastern Texas (completed)
- Woodward District EHV-Tatonga-Matthewson-Cimarron 345 kV, second circuit

3.6.7 Recent AEP-SPP Bulk Transmission Improvements

Over the past several years, there have been several major transmission enhancements initiated to reinforce the AEP-SPP transmission system. These enhancements include:

- **Northwest Arkansas**— The AEP Transmission System serves approximately 1,300 MW of load in the Northwest Arkansas area, about 53% of which is Arkansas Electric Cooperative Commission (AECC) load. This load is supplied primarily by the SWEPCO and AECC jointly-owned Flint Creek generating plant, the SWEPCO Mattison generating plant, the Grand River Dam Authority (GRDA)-Flint Creek 345 kV line, and the Clarksville-Chamber Springs 345 kV line. Wal-Mart's international headquarters and its supplying businesses' offices and Tyson's headquarters are all located in this area. The Chamber Springs-Farmington Rural Electric Cooperative 161 kV line has been upgraded to a larger conductor with improved thermal capacity. The Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line is also being upgraded to a larger conductor with improved thermal capacity.
- **McAlester, Oklahoma area –** The Lone Oak-Broken Bow (Southwestern Power Administration) 138 kV line has been rebuilt with new structures and upgraded to a larger conductor with improved thermal capacity.
- **Cornville/Rush Springs, Oklahoma area –** In addition to the previously completed 138 kV rebuild and conversion of the Cornville-Lindsay Water Flood radial line, approximately 33 miles, a 138 kV connection, approximately 10 miles, has been built from this line to an existing radial that serves Rush Springs Natural Gas from the existing Cornville-Duncan 138 kV line. This has created a 138 kV loop, improving reliability of the transmission system in this area.

These major enhancements are in addition to several completed or initiated upgrades to 138 kV and 69 kV transmission lines to reinforce the AEP-SPP transmission system.

3.6.8 Impacts of New Generation

Integration of additional generation capacity within the AEP-SPP zone will likely require significant transmission upgrades. At most locations, any additional generation resources will aggravate existing transmission constraints. Specifically:

- **Western Oklahoma/Texas Panhandle** - This area is one of the highest wind density areas within the SPP footprint. The potential wind farm capacity for this area has exceeded 10,000 MW and has potential for substantial additional growth. Many wind farms are in operation, and several more are in the development stages. Wind generation additions in the SPP footprint in this region will likely require significant transmission enhancements, including EHV line and station construction, to address thermal, voltage, and stability constraints.

- **SPP Eastern Interface** - There are only five east-west EHV lines into the SPP region, which stretches from the Gulf of Mexico (east of Houston) north to Des Moines, Iowa. This limitation constrains the amount of imports and exports along the eastern interface of SPP with neighboring regions. It also constrains the amount of transfers from the capacity rich western SPP region to the market hubs east and north of the SPP region. Significant generation additions near or along the SPP eastern interface would likely require significant transmission enhancements, including EHV line and station construction, to address thermal and stability constraints should such generation additions adversely impact existing transactions along the interface.

Integration of generation resources at any location within the AEP-SPP zone will require significant analysis by SPP to identify potential thermal, short circuit, and stability constraints resulting from the addition of generation. Depending on the specific location, EHV line and station construction, in addition to connection facilities, could be necessary. Other station enhancements, including transformer additions and breaker replacements, may be necessary. Some of the required transmission upgrades could be reduced or increased in scope if existing generating capacity is retired concurrent with the addition of new capacity.

3.6.9 Summary of Transmission Overview

AEP continues supporting the SPP STEP and ITP transmission expansion processes, which include some projects which may improve import capability. Such capability improvements are more likely to be within SPP, but less so between SPP and neighboring regions to the east, partly due to lack of seams agreements which slows the development of new interconnections as discussed above. PSO and SWEPCO have been open to such imports as evidenced by the issuing of recent Requests for Proposals (RFPs) for non-site specific generation types. Such RFP solicitations allow bidding entities to offer generation coupled with transmission solutions, which would be subject to SPP approvals.

4.0 Modeling Parameters

4.1 Modeling and Planning Process – An Overview

The objective of a resource planning effort is to recommend a system resource expansion plan that balances least-cost objectives with planning flexibility, asset mix considerations, adaptability to risk, conformance with applicable North American Electric Reliability Corporation (NERC) and RTO criteria. In addition, given the unique impact of fossil-fired generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the EPA-driven environmental compliance planning process.

The information presented with this IRP includes descriptions of assumptions, study parameters, methodologies, and results, including the integration of traditional supply-side resources, renewable energy resources and DSM programs.

In general, assumptions and plans are continually reviewed and modified as new information becomes available. Such continuous analysis is required by multiple disciplines across PSO and AEP to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are constantly reassessed to ensure optimal capacity resource planning.

Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the PSO IRP process. Therefore, as a result, the objective function of the modeling applications utilized in this process is the development of a least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the most appropriate plan is the one with the absolute least cost over the planning horizon evaluated. Other factors were considered in the determination of the Plan. To challenge the robustness of the IRP, sensitivity analyses were performed to address these factors.

This overall process reflects consideration of options for maintaining and enhancing rate stability; economic development; and service reliability.

4.2 Methodology

The IRP process aims to address the gap between resource needs and current resources. Given the various assets and resources that can satisfy this expected gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution. *Plexos®* is the primary modeling application used by PSO for identifying and ranking portfolios that address the gap between needs and current available resources.[8] Given the cost and performance parameters around sets of potentially available proxy resources–both supply and demand side–and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, *Plexos®* will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the cumulative present worth (CPW), of the resulting stream of revenue requirements. The least cost option is considered the optimum portfolio for that unique input parameter scenario.

4.3 The Fundamentals Forecast

The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast. It is not created to meet a specific regulatory need in a particular jurisdiction; rather, it is made available to all AEP operating companies after completion. It is often referenced for purposes such as fixed asset impairment accounting, capital improvement analyses, resource planning, and strategic planning. These projections cover the electricity market within the Eastern Interconnect (which includes the Southwest Power Pool), the Electric Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC). The Fundamentals Forecasts include: 1) monthly and annual regional power prices (in both nominal and real dollars), 2) prices for various qualities of Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB), Powder River Basin (PRB) and Colorado coals, 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub, 4) uranium fuel prices, 5) SO_2,

[8] *Plexos®* is a production cost-based resource optimization model, which was developed and supported by Energy Exemplar, LLC. The *Plexos®* model is currently licensed for use in 37 countries throughout the world.

NO_x and CO_2 values, 6) locational implied heat rates, 7) electric generation capacity values, 8) renewable energy subsidies and, 9) inflation factors, among others.

The primary tool used for the development of the Fundamentals Forecast is the AURORA Energy Market model which is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, oil, and geo-thermal. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility which are subsequently exported to the AURORA model. The AURORA model iteratively generates regional, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions and capital costs, among others. Ultimately, utilizing the AURORA model, AEP creates a weather-normalized, long-term forecast of the market in which a utility would be operating. AEP also has ample energy market research information available for its reference which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. Although no exact forecast inputs from these sources of energy market research information are utilized, an in-depth assessment of this research information can yield, among other things, an indication of the supply, demand and price relationship (price elasticity) over a period of time. This price elasticity, when applied to the AURORA-derived natural gas fuel consumption, yields a corresponding change in natural gas prices – which is recycled through the AURORA model iteratively until the change in natural gas burn is de minimis. Figure 18 illustrates that the magnitude of that effect must be recycled through AURORA to determine a new merit order of dispatch. It is this new merit order of dispatch that takes into account the effect of operating conditions across North America and, in turn, determines zonal energy market prices.

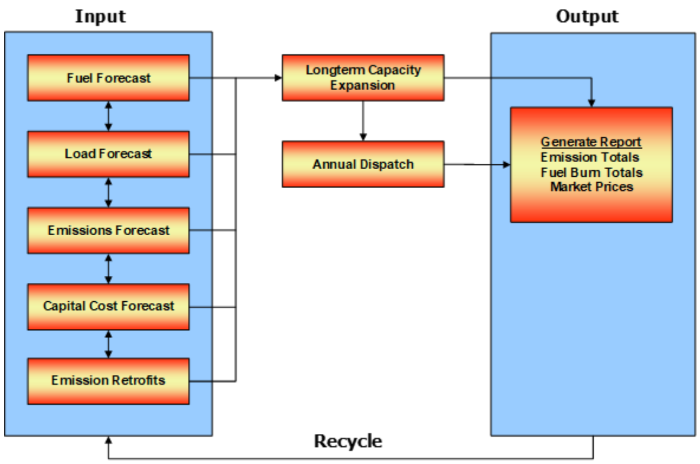


Figure 18. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Four scenarios were developed to construct resource plans for PSO under various long-term pricing conditions. In this Report, the four distinct long-term commodity pricing scenarios that were developed are the Base Case, Lower Band, Upper Band, and Status Quo scenarios. The overall fundamentals forecasting effort was most recently completed in August of 2018. The Base, Low Band, and High Band scenarios each consider the potential impact of carbon regulations. The modeling associated with each of these scenarios assumed a CO_2 dispatch burden, or allowance value, equal to $15/short ton commencing in 2028 and escalating at 5% per annum thereafter on a nominal dollar basis. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices. Generally, Lower and Upper Band fossil fuel prices vary one standard deviation above and below Base Case values. The Status Quo Scenario assumes there will be no regulations limiting CO_2 emissions throughout the entire forecast period.

4.3.2 Forecasted Fundamental Parameters

Figure 19 through Figure 25 illustrate the forecasted fundamental parameters (fuel, energy, capacity and CO_2 emission prices) that were used in the long-term optimization modeling for this IRP.

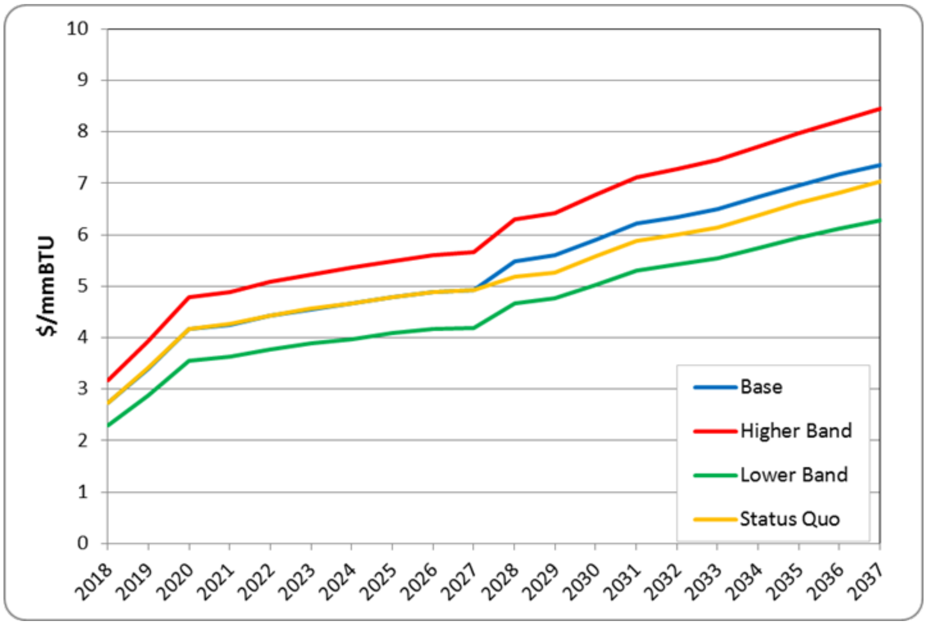


Figure 19. Panhandle Eastern TX-OK Natural Gas Prices (Nominal $ / mmBTU)

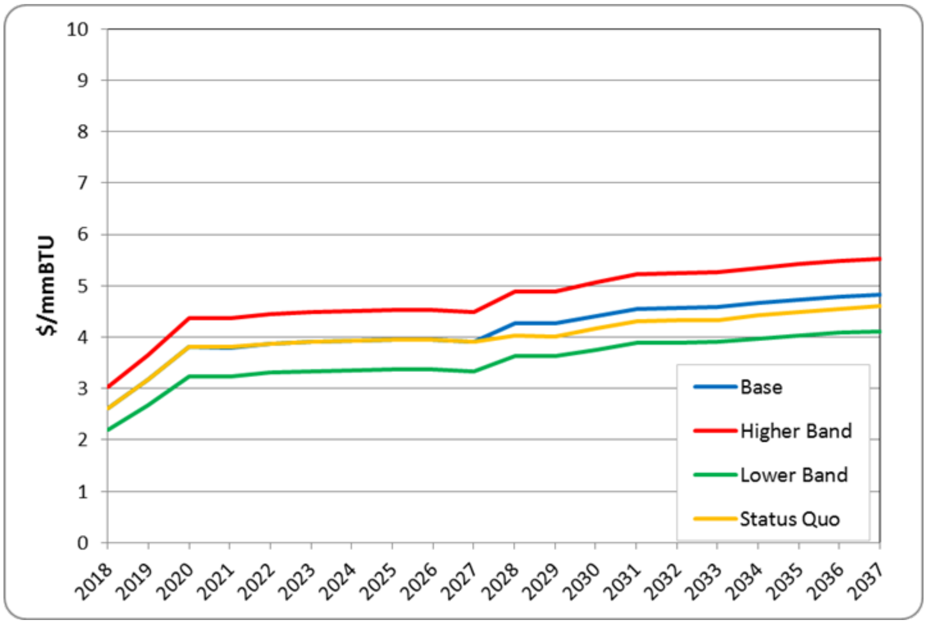


Figure 20. Panhandle Eastern TX-OK Natural Gas Prices (Real $ / mmBTU)

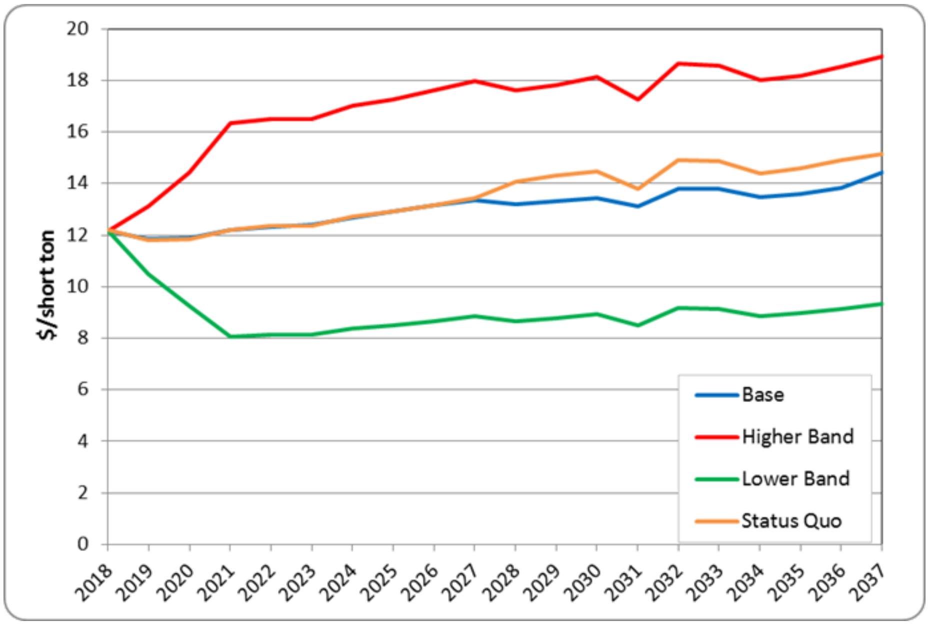


Figure 21. PRB 8800 Coal Prices (Nominal $ / ton, FOB origin)

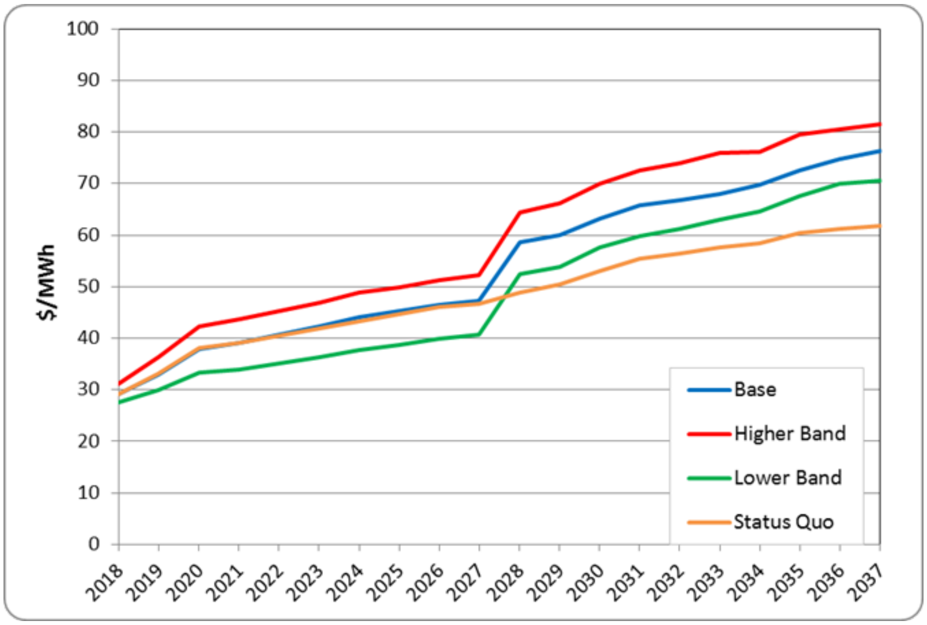


Figure 22.SPP On-Peak Energy Prices (Nominal $ / MWh)

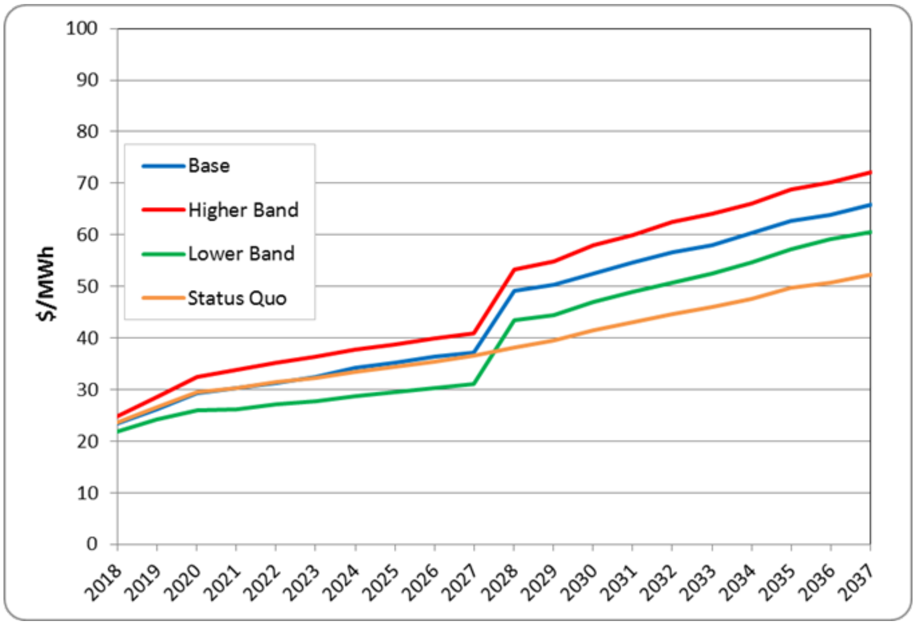


Figure 24. SPP Off-Peak Energy Prices (Nominal $ / MWh)

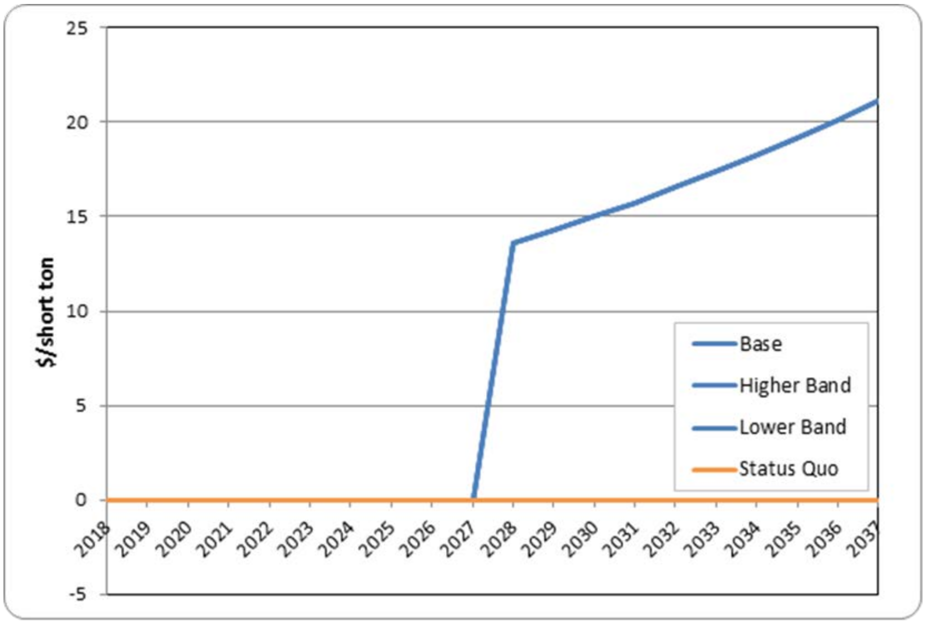


Figure 23. CO_2 Prices (Nominal $ / short ton)

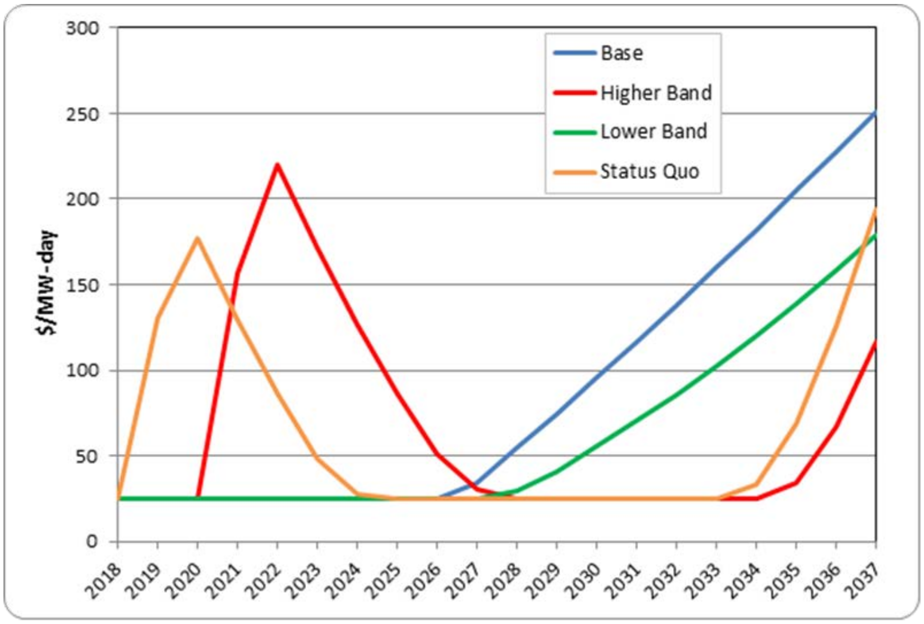


Figure 25. SPP Capacity Prices (Nominal $/MW-day)

4.4 Demand-Side Management (DSM) Program Screening & Evaluation Process

4.4.1 Overview

The process for evaluating DSM impacts for PSO is divided into two components: “existing DSM programs” and “incremental DSM programs.” Existing DSM programs are those that are known or are reasonably well-defined, and follow a pre-existing process for screening and determining ultimate regulatory approval. The impacts of PSO’s existing DSM programs are propagated throughout the long-term load forecast. Incremental DSM program impacts which are, naturally, less-defined, are developed with a dynamic modeling process using more generic cost and performance parameter data.

The potential incremental DSM programs were developed and ultimately modeled based on input from PSO’s internal subject matter experts and the Electric Power Research Institute’s (EPRI) “2014 U.S. Energy Efficiency Potential Through 2035” report. This report served as the basic underpinning for the establishment of potential EE “bundles”, developed for residential and commercial customers that were then introduced as a resource option in the *Plexos*® optimization model. In order to reflect potential energy savings available in the industrial sector, the end-usage associated with lighting was combined for both the commercial and industrial sectors. The indoor and outdoor lighting bundles shown below in Table 8 reflect the potential energy savings for both sectors.

4.4.2 Achievable Potential (AP)

The amount of available EE is typically described in three sets: technical potential, economic potential, and achievable potential. The previously-cited EPRI report breaks down the achievable potential into a High Achievable Potential (HAP) and an Achievable Potential (AP), with the HAP having a higher utility cost than the AP. Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether or not it is cost-effective (i.e., all EE measures would be adopted if technically feasible). The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic potential. This compares the avoided cost savings achieved over the life of a measure/program with the cost to implement it, regardless of who paid for it and regardless of the age and remaining economic life of any system/equipment that would be replaced (i.e., all EE measures would be adopted if economic). The third set of efficiency assets is that which is achievable. As highlighted above, the HAP is the economic potential discounted for market barriers such as customer preferences and supply chain maturity; the AP is additionally discounted for programmatic barriers such as program budgets and execution proficiency.

Of the total technical potential, typically only a fraction is ultimately achievable and only then over time due to the existence of market barriers. The question of how much effort and money is to be deployed towards removing or lowering the barriers is a decision made by state governing bodies (legislatures, regulators or both).

The AP range is typically a fraction of the economic potential range. This achievable amount must be further split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards. Both amounts are represented in this IRP as reductions to what would otherwise be in the load forecast.

4.4.3 Evaluating Incremental Demand-Side Resources

The *Plexos*® model allows the user to input incremental CHP, EE, DG, DR and CVR as resources, thereby considering such alternatives in the model on equal-footing with more traditional "supply-side" generation resource options.

4.4.3.1 Incremental Energy Efficiency (EE) Modeled

To determine the economic demand-side EE activity to be modeled that would be over-and-above existing EE program offerings in the load forecast, a determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs. It was assumed that the incremental programs modeled would be effective in 2022. Given that each of PSO's jurisdictions have a subset of customers that are allowed to opt-out of participating in EE programs, these customers were removed from the available EE potential and thus not modeled. Figure 26 and Figure 27 show the "going-in" make-up of projected end-usage in 2022 for PSO's residential and commercial sectors with lighting end-use also included for the industrial sector. Future incremental EE activity can further target these areas or address other end-uses.

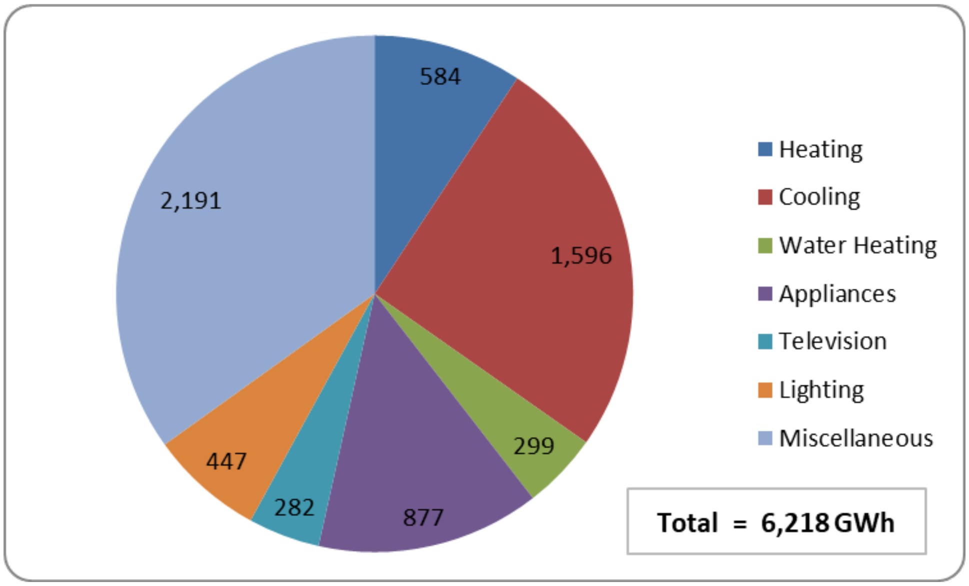


Figure 26. 2022 PSO Residential End Use (GWh)

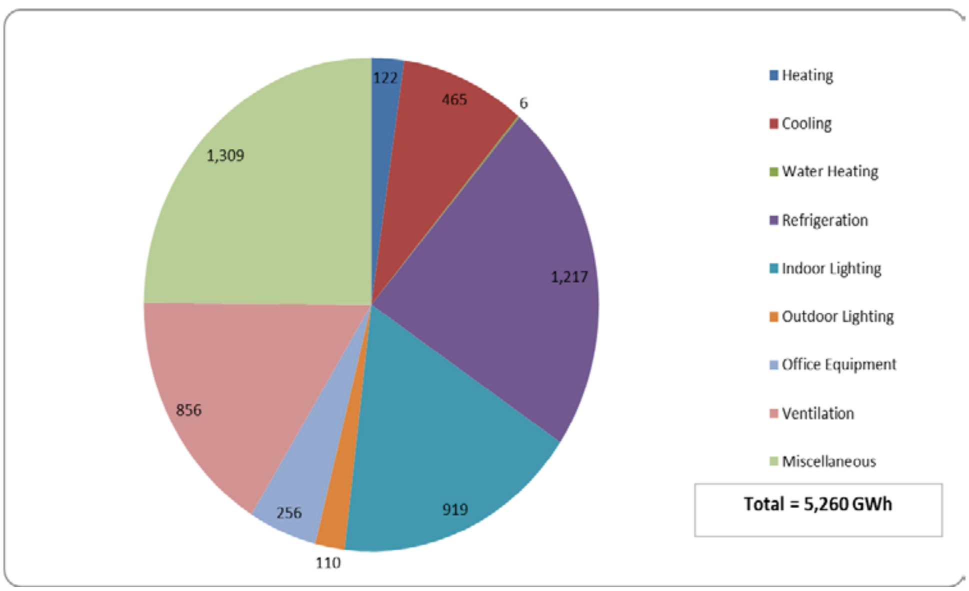


Figure 27. 2022 PSO Commercial End Use & Industrial Lighting End Use (GWh)

To determine which end-uses are targeted, and in what amounts, PSO looked at the previously-cited 2014 EPRI report and consulted its DSM team. The EPRI report and the PSO

DSM team provided information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. PSO utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 5 and Table 6**,** from the EPRI report, list the individual measure categories considered for both the residential and commercial sectors.

Table 5. Residential Sector Energy Efficiency (EE) Measure Categories

Central Air Conditioning	Programmable Thermostat	Storm Doors	Dishwashers
Air-Source Heat Pumps	Water Heating	External Shades	Clothes Washers
Ground-Source Heat Pumps	Faucet Aerators	Ceiling Insulation	Clothes Dryers
Room Air Conditioning	Pipe Insulation	Foundation Insulation	Refrigerators
Air Conditioning Maintenance	Low-Flow Showerheads	Duct Insulation	Freezers
Heat Pump Maintenance	Duct Repair	Wall Insulation	Cooking
Attic Fan	Dehumidifier	Windows	Televisions
Furnace Fans	Lighting – Linear Fluorescent	Reflective Roof	Personal Computers
Ceiling Fan	Lighting – Screw-in	Infiltration Control	Smart Plug Strips, Reduce Standby Wattage
Whole-House Fan	Enhanced Customer Bill Presentment		

Table 6. Commercial Sector Energy Efficiency (EE) Measure Categories

Heat Pumps	Water Heater	Energy-Efficient Motors	Lighting – Screw-in
Central Air Conditioning	Water Temperature Reset	Variable Speed Controls	Lighting – LED Street Lighting
Chiller	Computers	Programmable Thermostat	Anti-Sweat Heater Controls
Cool Roof	Servers	Duct Testing and Sealing	Floating Head Pressure Controls
Economizer	Displays	HVAC Retro-commissioning	Installation of Glass Doors
Energy Management System	Copiers Printers	Efficient Windows	High-Efficiency Vending Machine
Roof Insulation	Other Electronics	Lighting – Linear Fluorescent	Icemakers
Duct Insulation		Lighting – HID to LED	Reach-in Coolers and Freezers

What can be derived from the tables is that the 2014 EPRI report has taken a comprehensive approach to identifying available EE measures. From this information and recent PSO DSM activity, PSO has developed proxy EE bundles for residential, commercial and industrial customer classes to be modeled within *Plexos*®. These bundles are based on measure characteristics identified within the EPRI report, recent PSO DSM planning, and PSO customer usage.

Table 7 and Table 8 list the energy and cost profiles of EE resource “bundles” for the residential and commercial sectors, respectively. In order to reflect the potential EE savings available in the industrial sector, each of the lighting bundles shown in Table 8 includes potential savings for both commercial and industrial customers.

Table 7. Incremental Residential Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($2022/kWh)	Yearly Potential Savings (MWh) 2022-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2039	Yearly Potential Savings (MWh) 2040-2047	Bundle Life (Years)
Thermal Shell - AP	$0.34	1,109	0	0	0	15
Thermal Shell - HAP	$0.52	4,027	591	589	0	15
Cooling - AP	$0.75	77,756	16,903	7,831	2,932	17
Cooling - HAP	$0.95	41,317	11,913	5,316	1,310	16
Water Heating - AP	$0.68	8,357	2,504	2,891	1,689	14
Water Heating - HAP	$0.96	21,436	5,705	5,338	1,179	14
Appliances - AP	$0.09	5,288	1,075	592	0	13
Appliances - HAP	$0.14	7,434	0	0	0	13
Lighting - AP	$0.07	13,742	0	0	0	30
Lighting - HAP	$0.11	10,452	0	0	0	30
Enhanced Customer Bill	$0.11	22,700	0	0	0	10

**HAP Potential is incremental to AP Potential*

Table 8. Incremental Commercial & Industrial (Lighting) Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($2022/kWh)	Yearly Potential Savings (MWh) 2022-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2039	Yearly Potential Savings (MWh) 2040-2047	Bundle Life (Years)
Heat Pump - AP	$7.86	6,655	1,085	0	0	15
Heat Pump - HAP	$11.79	1,174	510	0	0	15
HVAC Equipment - AP	$0.22	2,189	0	0	0	16
HVAC Equipment - HAP	$0.34	2,731	0	0	0	16
Indoor Screw-In Lighting - AP	$0.03	5,922	0	0	0	6
Indoor Screw-In Lighting - HAP	$0.04	2,812	0	0	0	6
Indoor HID/Fluorescent Lighting - AP	$0.21	75,321	11,707	2,578	517	13
Indoor HID/Fluorescent Lighting - HAP	$0.32	13,292	5,191	1,848	517	13
Outdoor Lighting - AP	$0.11	12,073	2,020	0	0	15
Outdoor Lighting - HAP	$0.16	2,131	979	0	0	15

**HAP Potential is incremental to AP Potential*

As can be seen from the tables, each program has both AP and HAP characteristics. The development of these characteristics is based on the feedback from PSO's DSM team and the 2014 EPRI EE Potential report that has been previously referenced. This report further identifies Market Acceptance Ratios (MAR) and Program Implementation Factors (PIF) to apply to primary measure savings, as well as Application Factors for secondary measures. Secondary measures are not consumers of energy, but do influence the system that is consuming energy. The Residential Thermal Shell, Residential Water Heating and Commercial Cooling bundles—in both AP and HAP—include secondary measures. The MAR and PIF are utilized to develop the incremental AP program characteristics and the MAR only is used to develop the incremental HAP program characteristics.

Figure 28 shows the Levelized Cost of Electricity (LCOE) and potential energy savings in 2022 for each of the bundles offered into the model as a potential resource. To preserve a reasonable scale for illustrative purposes, the two bundles with the highest LCOE, Commercial Heat Pump AP and Commercial Heat Pump HAP, were omitted from Figure 28. The total potential energy savings for EE programs that begin in 2022 is approximately 338 GWh, 1.9% of PSO's total load. Figure 28 is offered as a rough comparison of EE bundle cost versus levelized market prices. However, it is not intended to illustrate which EE resources the model will select. Ultimately, the model will determine if an EE bundle is beneficial to an optimization scenario[9].

[9]For illustrative purposes, the Company has included in Figure 28 a proxy for the SPP Around-the-Clock LCOE, it should be noted within this calculation that, for comparison purposes only, these annual values are degraded over 15 years, which is similar to EE bundles with a 15-year life.

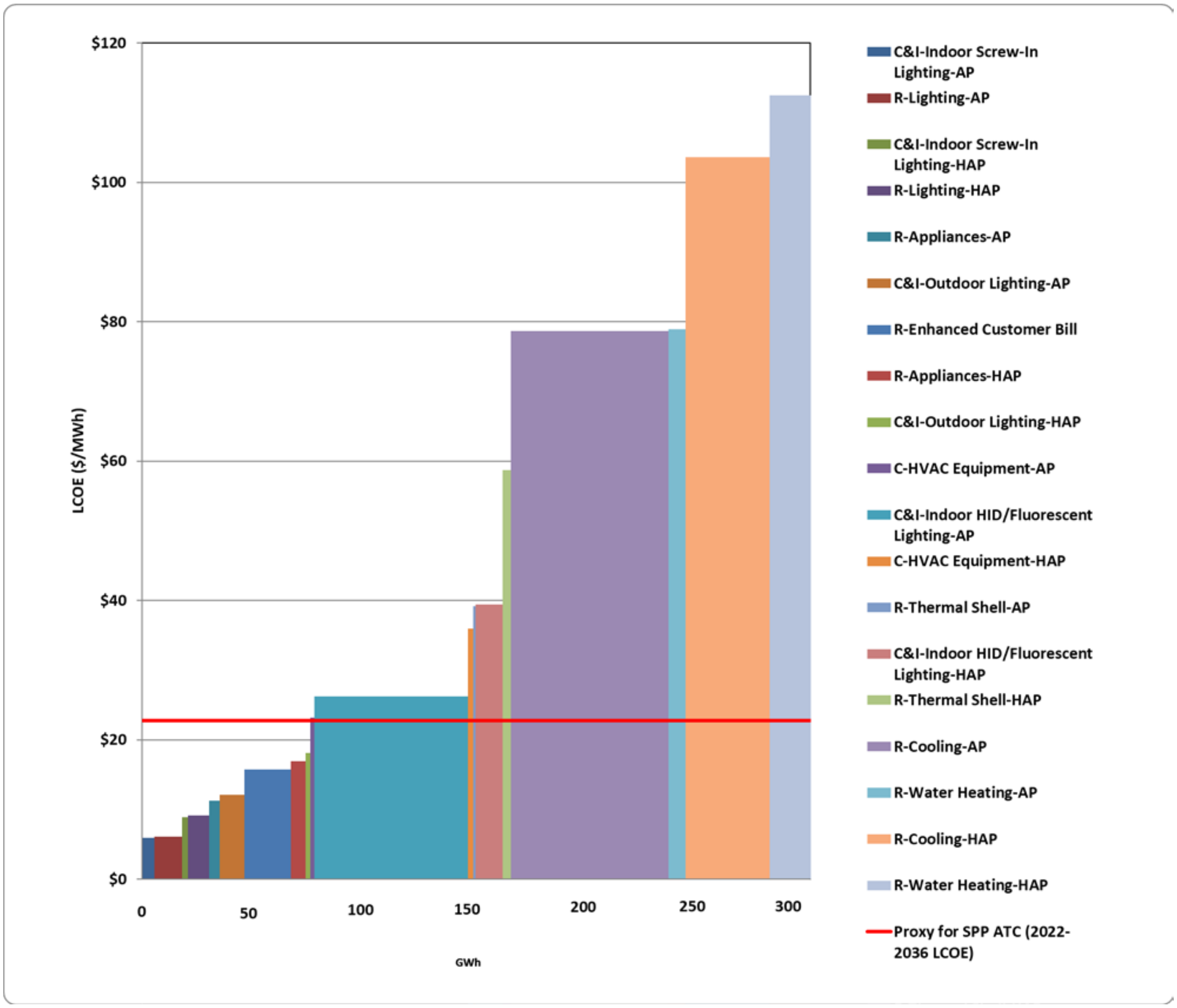


Figure 28. EE Bundle Levelized Cost vs. Potential Energy Savings for 2022

Each EE bundle is offered into the model as a stand-alone resource with its own unique cost and potential energy and demand savings. Should the model determine that a bundle is economical, that bundle will be included in the portfolio of optimized resources. To develop appropriate EE offerings to propose for PSO's customers, PSO will consider the details of each EE bundle that was optimized by the Plexos model and included in the Preferred Portfolio. Efforts to determine program attributes such as participant costs, penetration rates, and bill savings, prior to that point in time would be highly speculative and potentially inaccurate.

4.4.3.2 Conservation Voltage Reduction (CVR) Modeled

Potential future CVR circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 8 "tranches" based on the relative potential peak demand and energy reduction of each tranche of circuits. The *Plexos*® model was able to pick the most cost-effective tranches first and add subsequent tranches as merited. Table 9 details all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in 2017 dollars.

Table 9. Conservation Voltage Reduction (CVR) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	46	$11,500,000	$345,000	11,020	45,371
2	48	$12,000,000	$360,000	11,407	46,964
3	47	$11,750,000	$352,500	10,943	45,052
4	48	$12,000,000	$360,000	11,094	45,676
5	33	$8,250,000	$247,500	7,371	30,347
6	21	$5,250,000	$157,500	5,309	21,856
7	25	$6,250,000	$187,500	4,902	20,181
8	24	$6,000,000	$180,000	5,637	23,209

4.4.3.3 Demand Response (DR) Modeled

The current level of DR is maintained throughout the Plan and was discussed in Section 2.6.2. Looking into the future, other options, including expanded residential DR, may be considered.

4.4.3.4 Distributed Generation (DG) Modeled

As with the 2015 IRP, Distributed Generation (DG), namely rooftop solar, is not viewed as an economic investment for the Company's customers throughout the majority of the planning period as part of this IRP. However, this update continues to recognize that a portion of the Company's customers will choose to install rooftop solar systems for various motivations. To reflect this behavior, forecasted levels of DG were preset into each portfolio considered in this 2018 IRP. Figure 29 presents the Company's existing and forecasted levels of DG throughout the planning period. The annual growth of forecasted DG resources was 10%.

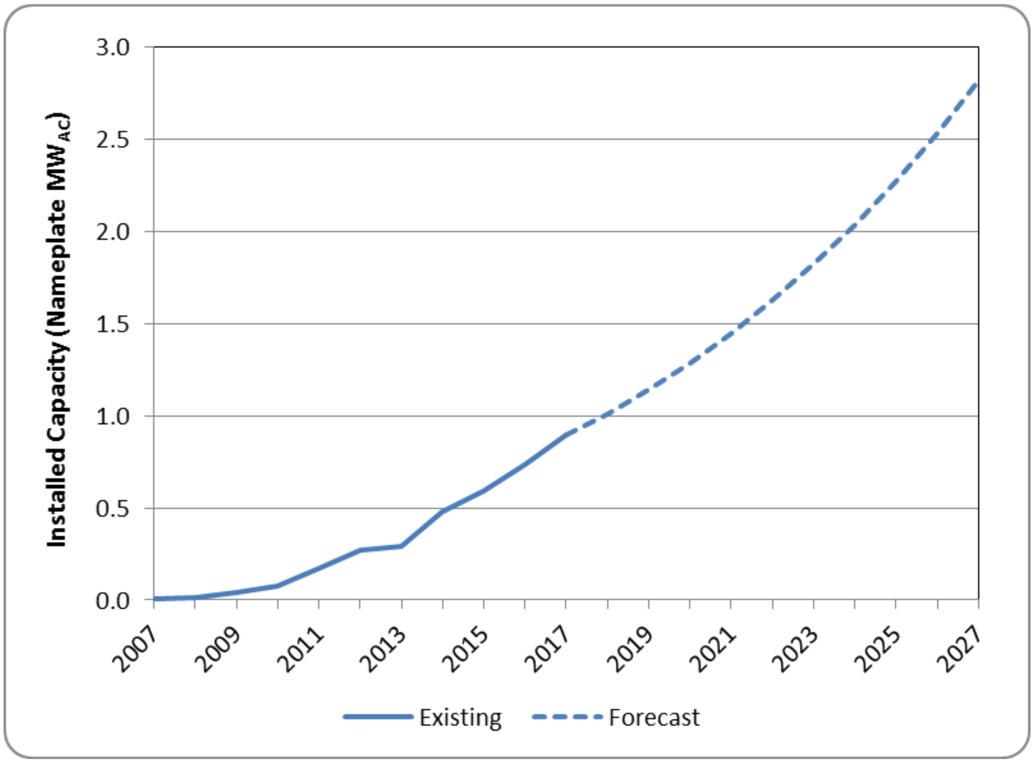


Figure 29. Cumulative Distributed Generation (Rooftop Solar) Additions/Projections for PSO

4.4.3.5 Optimizing Incremental Demand-side Resources

The *Plexos*® software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy.

4.4.3.6 Combined Heat and Power (CHP)

CHP (also known as Cogeneration) is a process where electricity is generated and the waste heat by-product is used for heating or other processes, raising the net thermal efficiency of the facility. To take advantage of the increased efficiency associated with CHP, the host must have a ready need for the heat that is otherwise potentially wasted in the generation of electricity.

PSO worked with AEP Generation Engineering to develop a generic CHP option. The CHP option developed is a 15MW facility utilizing a natural gas fired combustion turbine, Heat Recovery Steam Generator (HRSG) and SCR to control NO_x. A major assumption is that all of the steam is taken by the host and the efficiency of the modeled CHP resource is credited for the value of the steam provided to the host. The overnight installed cost is estimated to be \$2,100/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%.

4.5 Identify and Screen Supply-side Resource Options

4.5.1 Capacity Resource Options

New construction supply-side alternatives were modeled to represent peaking and base-load/intermediate capacity resource options. To reduce the number of modeling permutations in *Plexos®*, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant.

When applicable, PSO may take advantage of economic market capacity and energy opportunities. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

4.5.2 New Supply-side Capacity Alternatives

Natural gas base/intermediate and peaking generating technologies were considered in this IRP as well as large-scale solar and wind. Further details on these technologies are available in Exhibit B of the Appendix. To reduce the computational problem size within *Plexos®*, the number of alternatives explicitly modeled was reduced through an economic screening process which analyzed various supply options and developed a quantitative comparison for each duty-cycle type of capacity (i.e., base-load, intermediate, and peaking) on a forty year levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed Operations and Maintenance (O&M) costs, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

The best of class technology, for each duty cycle, determined by this screening process was explicitly modeled in *Plexos*®. These generation technologies were intended to represent reasonable proxies for each capacity type (base-load, intermediate, peaking). Subsequent substitution of specific technologies could occur in any later plan, based on emerging economic or non-economic factors not yet identified.

AEP continually tracks and monitors changes in the estimated cost and performance parameters for a wide array of generation technologies. Access to industry collaborative organizations such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers, as well as its own experience and market intelligence, provides AEP with current estimates for the planning process. Table 10 offers a summary of the most recent technology performance parameter data developed. Additional parameters such as the quantities and rates of solid waste production, hazardous material consumption, and water consumption are significant; however, the options which passed the screening phase and were included in *Plexos*® were natural gas facilities which generally have limited impacts on these areas of concern.

Table 10. New Generation Technology Options with Key Assumptions

Type	Capability (MW) (d)			Installed Cost (c,e)	Capacity Factor	LCOE (f)
	Std. ISO	Summer	Winter	($/kW)	(%)	($/MWh)
Base Load						
Nuclear	1,610	1,560	1,690	7,900	80	176.3
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,200	75	230.6
Combined Cycle (1X1 "J" Class)	540	700	720	1,000	75	62.3
Combined Cycle (2X1 "J" Class)	1,080	1,410	1,450	800	75	57.5
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	75	55.8
Peaking						
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	25	145.9
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	25	114.0
Aero-Derivative (2 - Small Machines) (g,h)	120	120	120	1,400	25	143.8
Recip Engine Farm	220	220	230	1,300	25	123.0
Battery	10	10	10	1,900	25	175.8

4.5.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by PSO but were not included in the *Plexos*® resource optimization modeling analyses. For coal generation resources, environmental regulation (see Section 3.4) makes the construction of new coal plants economically impractical. New nuclear construction is also economically impractical since it would potentially require an investment of $7,900/kW or more.

Intermediate generating sources are typically expected to serve a load-following and cycling duty and effectively shield base-load units from that obligation. Historically, many generators relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired or gas-steam units to serve such load-following roles. Over the last several years, these units have improved ramp rates and regulation capability, and reduced downturn (minimum load capabilities). With the anticipated retirement of PSO's subcritical units, such as Oklaunion 1 and Northeastern 3, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

4.5.3.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a HRSG producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-63% Lower Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain base-load needs. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

4.5.4 Peaking Alternatives

Peaking generating sources provide needed capacity during high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for "quick-response" capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten-year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide relatively little energy over an annual load cycle. As a result, fuel efficiency and other variable costs applicable to these resources are of lesser concern. Rather, this capacity should be obtained at the lowest practical installed/fixed cost, despite the fact that such capacity often has very high energy costs. Ultimately, such "peaking" resource requirements are manifested in the system load duration curve.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency, Black Start, capability to the grid.

4.5.4.1 Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" Combustion Turbine (CT) systems, air compressed by an axial compressor is mixed with fuel and burned in a combustion chamber. The resulting hot gas then expands and cools while passing through a turbine. The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A CT system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, *i.e.*, not recovered as in a combined-cycle design. While not as efficient (at 30-35% Lower Heating Value), they are inexpensive to purchase, compact, and simple to operate.

4.5.4.2 Aeroderivatives (AD)

Aeroderivatives (AD) are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7E frame machine requires 20 to 30 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is considerably higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. ADs can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide ADs the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: A) the penetration of variable renewables increase; B) base-load generation processes become more complex limiting their ability to load-follow and; C) more intermediate coal-fueled generating units are retired from commercial service.

AD units weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an AD over an industrial turbine. AD units in the less than 100MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in AD units.

4.5.4.3 Reciprocating Engines (RE)

The use of Reciprocating Engines (RE) or internal combustion engines has increased over the last twenty years. According to EPRI, in 1993 about 5% of the total RE units sold were natural gas-fired spark ignition engines and post 2000 sales of natural gas-fired generators have remained above 10% of total units sold worldwide.

Improvements in emission control systems and thermal efficiency have led to the increased utilization of natural gas-fired RE generators incorporated into multi-unit power generation stations for main grid applications. RE generators' high efficiency, flat heat rate curves and rapid response make this technology very well suited for peaking and intermediate load service and as back up to intermittent generating resources. Compared to AD units, RE generators generally have shorter start-time durations. Additionally, the fuel supply pressure required is in the range of 40 to 70 psig; this lower gas pressure gives this technology more flexibility when identifying locations. A further advantage of RE generators is that power output is less affected by increasing elevation and ambient temperature as compared to gas turbine technology. Also, a RE plant generally would consist of multiple units, which will be more efficient at part load operation than a single gas turbine unit of equivalent size because of the ability to shut down units and to operate the remaining units at higher load. Common RE unit sizes have generally ranged from 8MW to 18MW per machine with heat rates in the range of 8,100 –to- 8,600 Btu/kWh (Higher Heating Value).

Regarding operating cost, RE generators have a somewhat greater variable O&M than a comparable gas turbine; however, over the long term, maintenance costs of RE are generally lower because the operating hours between major maintenance can be twice as long as gas turbines of similar size.

4.5.4.4 Evaluation of Peaking Resources

The IRP process and modeling is driven off of hourly estimates of commodity prices over the planning period with the primary focus from a revenue perspective being the value of energy from all generating resources, as further described in Section 4.3.

With the development of Regional Transmission Organizations (RTOs) and actual pricing values for energy and ancillary services at both the Day-Ahead Hourly level and Real-Time 5-minute level; as well as the development of modeling software and affordable computing power, the Company now has the ability to analyze generating resources with the consideration of additional revenue sources than energy with a combined Day-Ahead and Real-Time margin perspective. While, the Company has relatively little experience with this type of analyses as compared to the "more traditional" IRP analyses that rely on hourly energy revenues to evaluate the cost effectiveness of the various resources considered in an IRP, this more granular analysis from both a time perspective and energy products perspective provides the Company and its stakeholders with additional information to assist in selecting new generating resources.

The Company's approach was to consider this new modeling capability with respect to "peaking" resources that the Company considers in its IRP process. The following is a summary of the process the Company followed for this analysis.

To develop the Day-Ahead and Real-Time energy and Ancillary services prices, the analysis was based upon both AEP's SPP Fundamental Forecast and historical hourly price ratios in proportion to the monthly Day Ahead around the clock energy. The ratios found were of Day Ahead and Real Time: energy, regulation up, regulation down, spin and non-spin. Site specific location was selected where energy resilience for a customer was needed at the Comanche node of SPP from which all historical prices were obtained. The historical hourly ratios calculated were divided into weekly segments, according to a winter, summer and shoulder (fall and spring) season. A metric was used to measure volatility of real time energy over the weekly segments. For each season, the weeks are further subdivided into thirds according to the metric of volatility where the bottom third is considered low volatility, middle is moderate volatility and top third is high volatility. For the forecast, the monthly energy prices from SPP Fundamental Forecast were used for an around the clock monthly average of day-ahead energy price. To get the hourly prices, historical weeks are randomly selected to match the season in the forecast and volatility category according to volatility scenario (Note: This is the same process utilized in the hourly IRP modeling). Next, ratios are multiplied by the fundamentals around the clock average to get the prices for Day Ahead (Figure 30) and Real Time (Figure 31): energy, regulation up, regulation down, spin and non-spin. The prices in Figure 30 and Figure 31 were taken from the High-Low scenario. While both Figure 30 and Figure 31 show monthly average prices, both Day Ahead and Real Time products are modeled at a five minute interval within Plexos; however, the Day Ahead products vary by hour and the Real Time products may vary every five minutes.

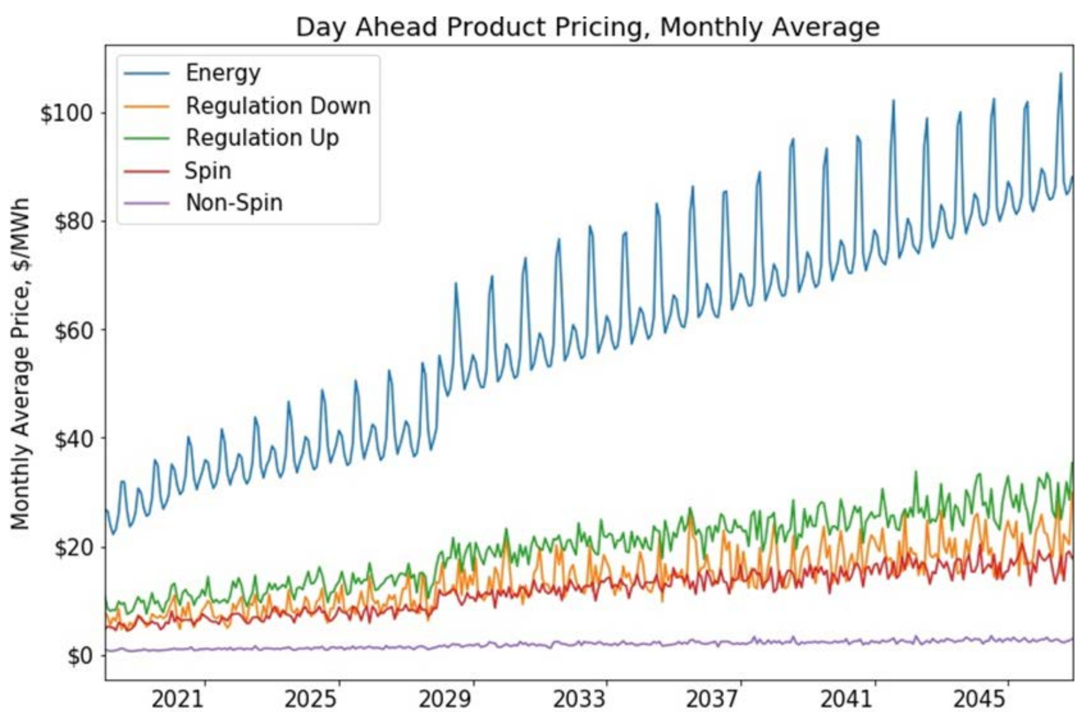


Figure 30. Day Ahead Average Energy Pricing

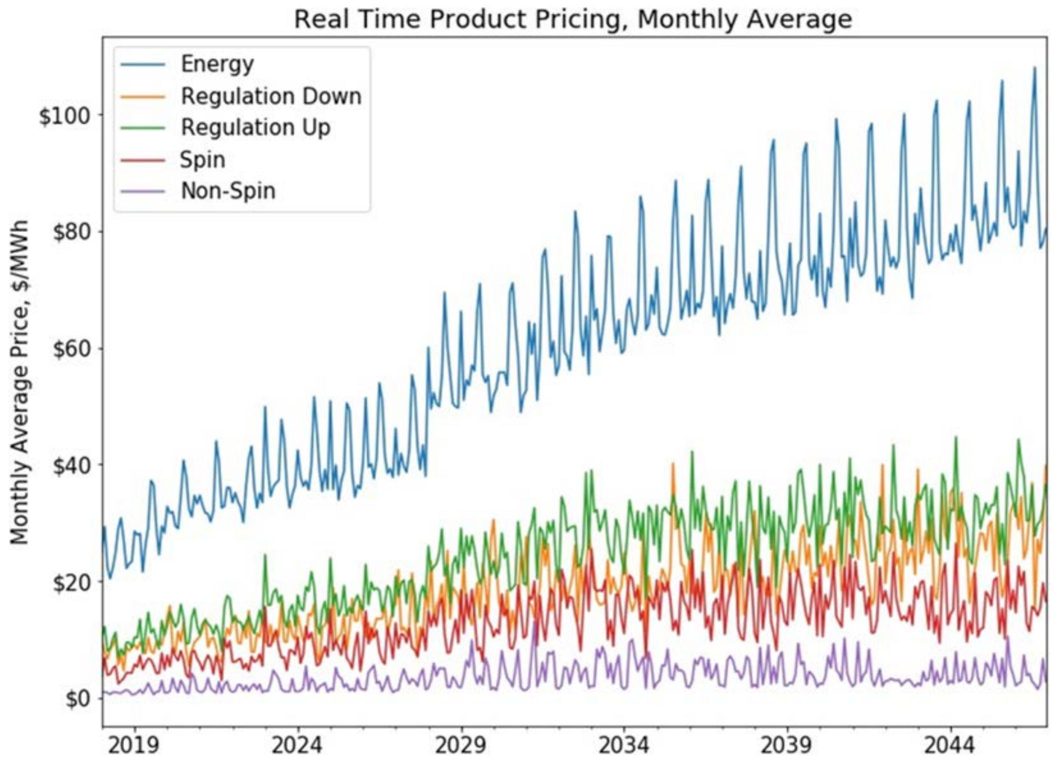


Figure 31. Real Time Monthly Average Energy Pricing of High-Lo Volatility Scenario

Three pricing volatility forecast scenarios (Stable, High and High-Low) were created to test the change in forecasted margin of each of the "peaking" quick reacting generation technology. The Stable Volatility Scenario forecast is where the historical volatility metric will be the same in the forecast, therefore, the forecast had the same average as history. The High Volatility Scenario forecast is where the metric starts out at the historical average, but steadily increases until halfway through the time horizon. The metric becomes the historical top third average and the bottom and middle third become less represented throughout the rest of the horizon. The High-Low Volatility Scenario is similar to the High Volatility Scenario where halfway through the top third of the historical metric is the forecast average, but it then decreases to where at the end of the forecast horizon it is back on the historical average. Figure 32 shows the typical distribution of the Real-time Energy prices modeled for the three volatility scenarios in year 2034.

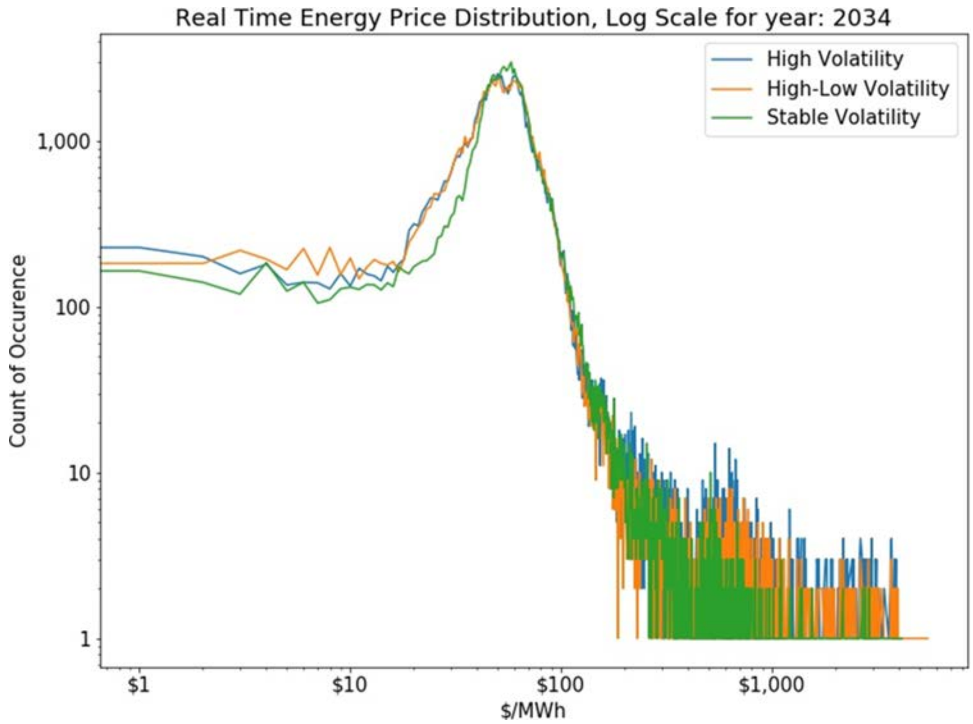


Figure 32. Distribution of Real Time Energy Pricing Scenarios over One Year

For this analysis, three quick start generating technologies were modeled, a reciprocating engine, an aeroderivative and a frame machine. The results of the model showed the reciprocating engine was the least costly generating technology on a per kW basis across all three volatility scenarios, see Figure 33. On the High and High-Low Volatility Scenarios the aeroderivative was the second least costly. On the Stable Scenario, there was not a difference in performance of the aeroderivative and frame machine. As mentioned earlier these results are based on a model of volatility of prices specific to the Comanche Node in SPP. Based on the analysis it provides support for PSO's decision to add a reciprocating engine generation.

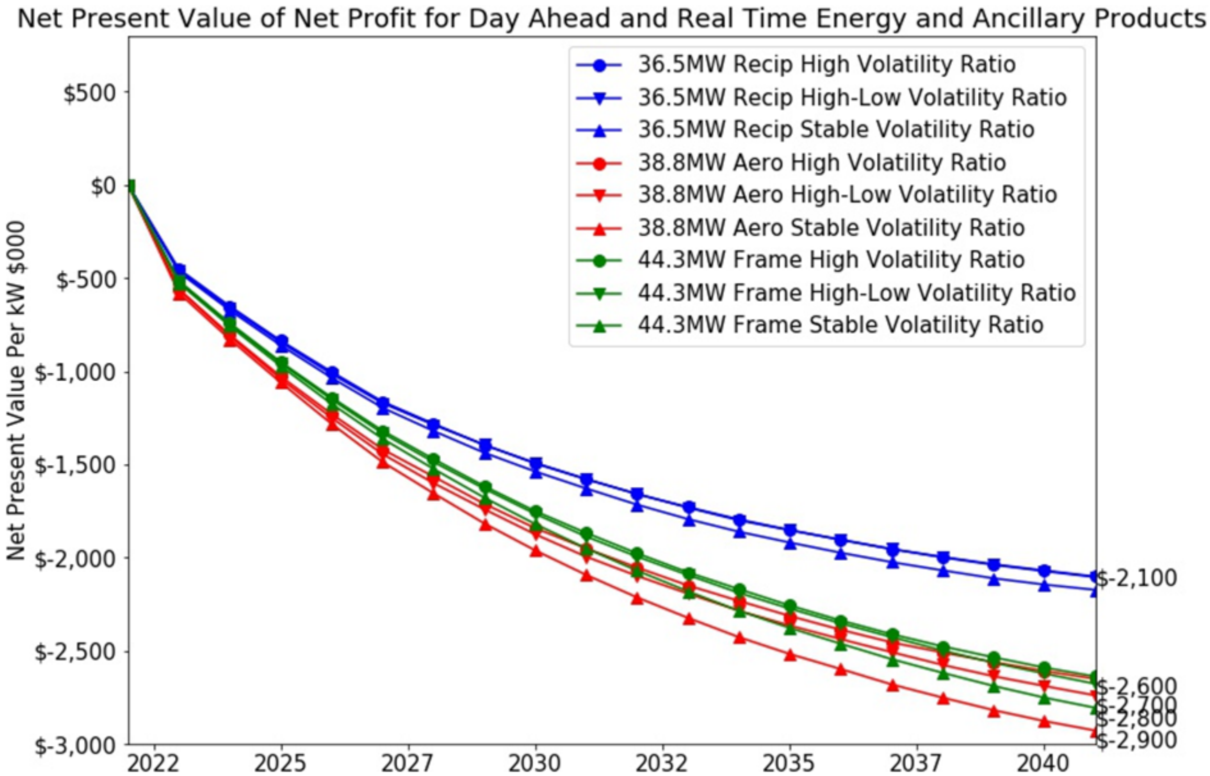


Figure 33. Net Present Value of the Three Technologies under Three Scenarios

4.5.4.5 Battery Storage

The modeling of Battery Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing platform for stationary storage applications. The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 40MWh, with a round trip efficiency of 87%. See Figure 34 for the forecasted installed cost of this resource. To develop this resource, AEP's Generation Engineering Services considered a wide range of sources including: the DOE/EPRI 2015 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI TAGWEB, BNEF and battery storage equipment suppliers.

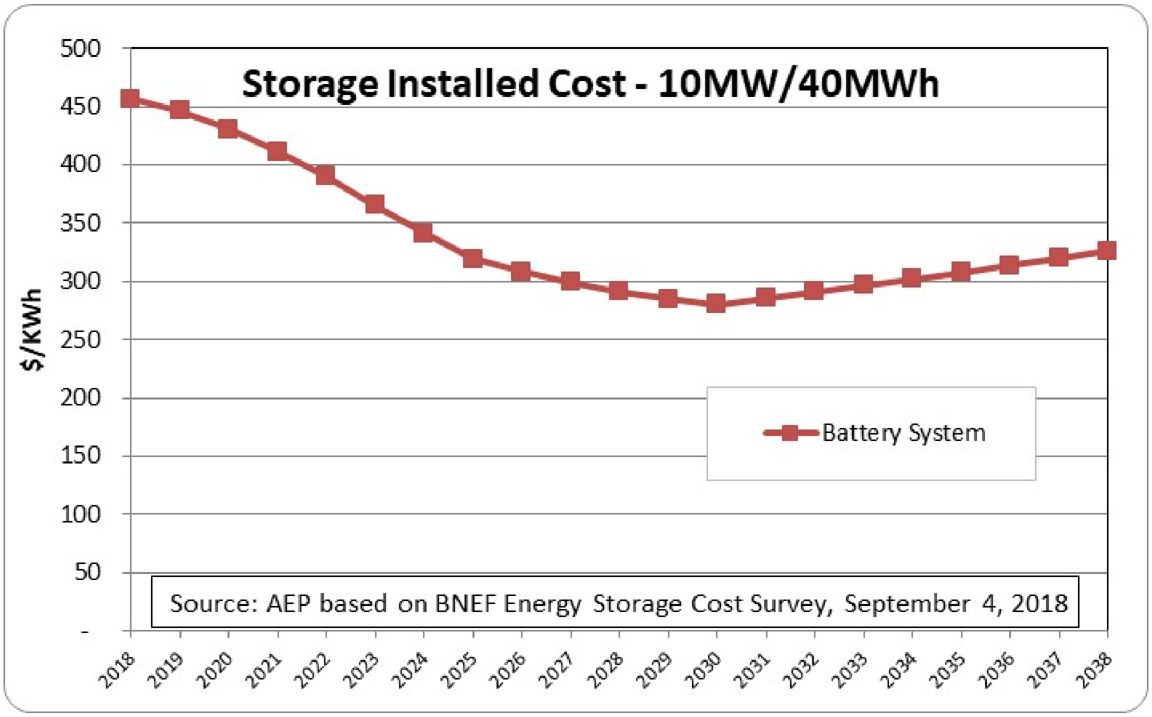


Figure 34. Energy Storage Installed Cost

4.5.5 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the past, on a national level development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

At this time within the industry, renewable energy resources, because of their intermittent nature, provide more energy value than capacity value. For this IRP, the overall threshold for intermittent resource additions, 40% of PSO’s energy demand for wind and 15% for solar. This assumes that the RTO and other key stakeholders will advance the understanding, forecasting and management of intermittent resources, ultimately supporting a higher penetration level and capacity planning values.

4.5.5.1 Solar

4.5.5.1.1 Large-Scale Solar

Solar power comes in two forms to produce electricity: concentrating and photovoltaics. Concentrating solar — which heats a working fluid to temperatures sufficient to generate steam to power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that respect. Photovoltaics can more easily be distributed throughout the grid and are a scalable resource that, for example, can be as small as a few kilowatts or as large as 500MW.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline (see Figure 35). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well, notwithstanding solar panel tariffs which from an IRP perspective are regarded as a short-term impact.

Large-scale solar plants require less lead time to build than fossil plants. There is no defined limit for how much utility solar can be built in a given time. However, in practice, solar facilities are not added without considering the timing impacts of obtaining siting and regulatory approval, for example.

Solar resources were made available in the *Plexos* model with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that large-scale solar resources were available in yearly quantities up to 300MWac[10] of nameplate capacity starting in 2021. A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources. Additionally, this 300MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified,

[10] Manufacturers usually quote system performance in DC watts; however electric service from the utility is supplied in AC watts. An inverter converts the DC electrical current into AC electrical current. Depending on the inverter efficiency, the AC wattage may be anywhere from 80 to 95 percent of the DC wattage.

permitted, constructed, and interconnected by PSO in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be 7 acres, implying that 700 acres of land would be required to develop 100MW of solar annually. Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of PSO's load obligation or 1,300MW. Certainly, as PSO gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Solar resources were available in two tiers. Referred to as tier 2 in this IRP, the overall pricing trend over the planning period is based on the BNEF utility scale solar pricing forecast. An additional pricing tier was developed, tier 1, which is 10% lower than the base BNEF forecast. The tier 1 pricing is considered a "Best-In-Class" solar resource. The 10% discount from the tier 2 product is based on the concept that during an RFP process the "Best Bids" would be approximately 10% less than the average bids. Both tiers of solar resources were available in blocks of 150MW, which is comprised of three 50MW installations and totals 300MW annually. Additionally, both tiers of solar resources were modeled with capacity factors of approximately 29%, which is representative of a solar resource located in Tulsa, OK.

Figure 35 illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs. The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has been commenced. The ITC benefit is included through 2030. At this point in time the 10% ITC benefit would become indiscernible from potential variations in forecasted prices.

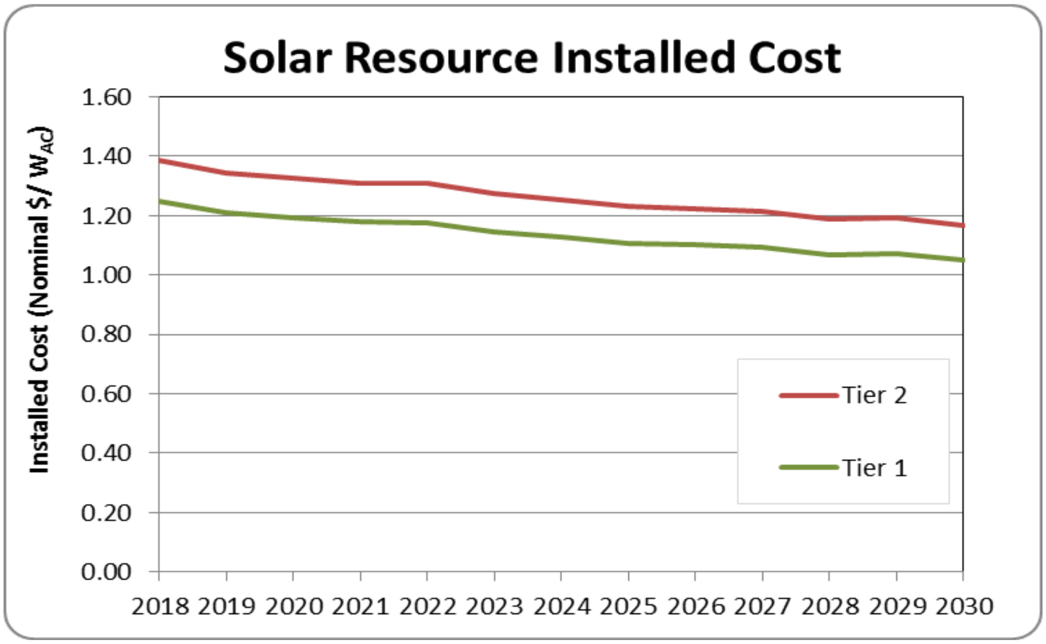


Figure 35. Large-Scale Solar Pricing Tiers

Solar resources are modeled with a 33% capacity credit, this is based on the expected long-term performance of the resource; however, SPP initially values solar at 10% of nameplate capacity rating for the first three years of operation and then allows the Company to adjust this value based on operating history. Solar capacity credit will be modeled with the SPP value for solar at 10% of nameplate capacity rating for the first three years of operation and then 33% based on the load shape and SPP Criteria for utility scale projects.

4.5.5.1.2 Trends in Solar Energy Pricing

As mentioned above, solar energy prices have declined significantly in recent years as shown below in Figure 36. From 2010 to 2018 installation costs have declined by more than 50% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale installations costing 51% and 31% less than residential and commercial installations, respectively, based on 2018 costs.

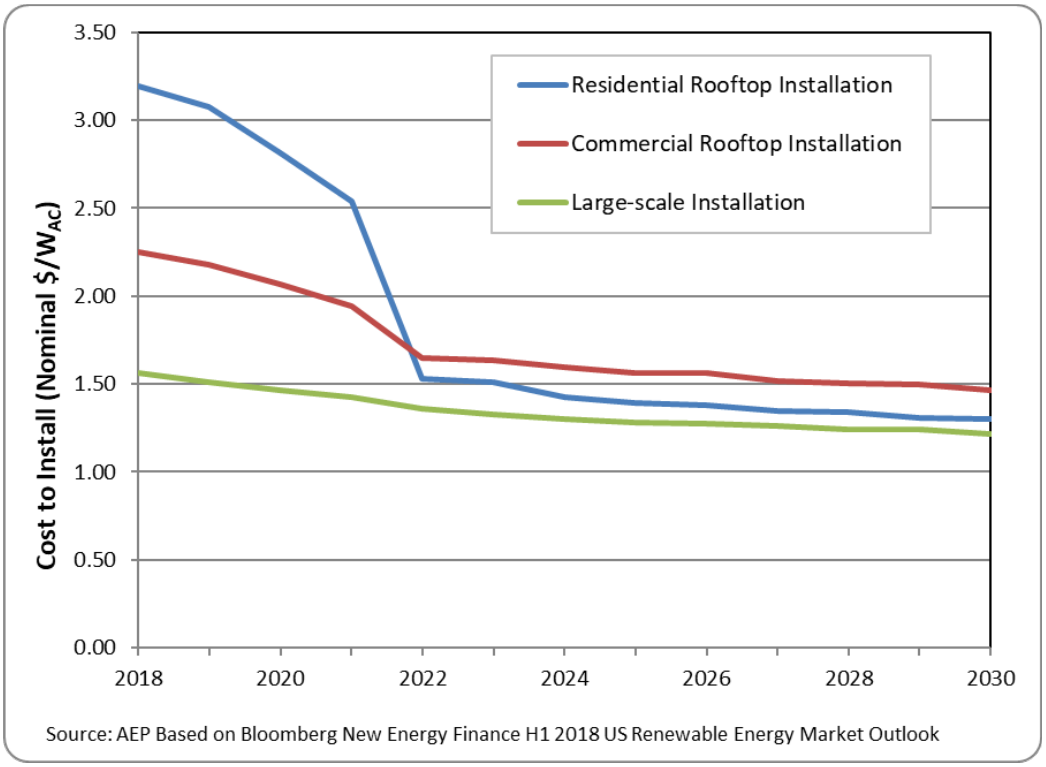


Figure 36. SPP Average Photovoltaic (PV) Installation Cost (Nominal $/W$_{AC}$) Trends, excluding Investment Tax Credit Benefits

4.5.5.2 Wind

Large-scale wind energy is generated by turbines ranging from 1.0 to 3.2MW. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical as not only does the wind resource vary by geography, but also its proximity to a transmission system with available capacity, which will factor into the cost.

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to over 50 percent (largely in more westerly portions of the U.S., including the Plains states), wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs.

Another consideration with wind power is that its most critical factors (*i.e.*, wind speed and sustainability) are typically highest in more remote locations, which forces the electricity to be transmitted longer distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid.

For modeling purposes, wind resources are first made available to the model in 2022 (i.e., commercial operation date 12/31/21), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals. Figure 37 below shows the LCOE price of one wind resource tranche assumed for the IRP. The tranche was modeled as a 48% capacity factor load shape and will be available in 200 MW blocks. The wind pricing reflects the value of Federal Production Tax Credits (PTCs). After 2020 tax credits reduce to 80%, 60% and 40% of their 2020 value in 2021, 2022, and 2023, respectively. These PTC values are based on developers taking advantage of the safe-harbor guidelines which provide up to a four-year delay in the effects of declining tax credits as long as adequate construction has commenced. Wind prices were developed based on the Bloomberg New Energy Finance H1 2018 U.S. Renewable Energy Market Outlook and market knowledge.

The tranche was assigned a capacity value of 5% of nameplate rating in the first three years and given a 30% capacity value for the remainder of its 25-year life. The 30% capacity value assigned after the tranche's third year was based upon SPP criteria for calculating wind capacity value, which requires three years of historical performance data to make the calculation. The Company utilized historical data from three existing AEP wind resources within SPP to calculate the assumed 30% capacity value.

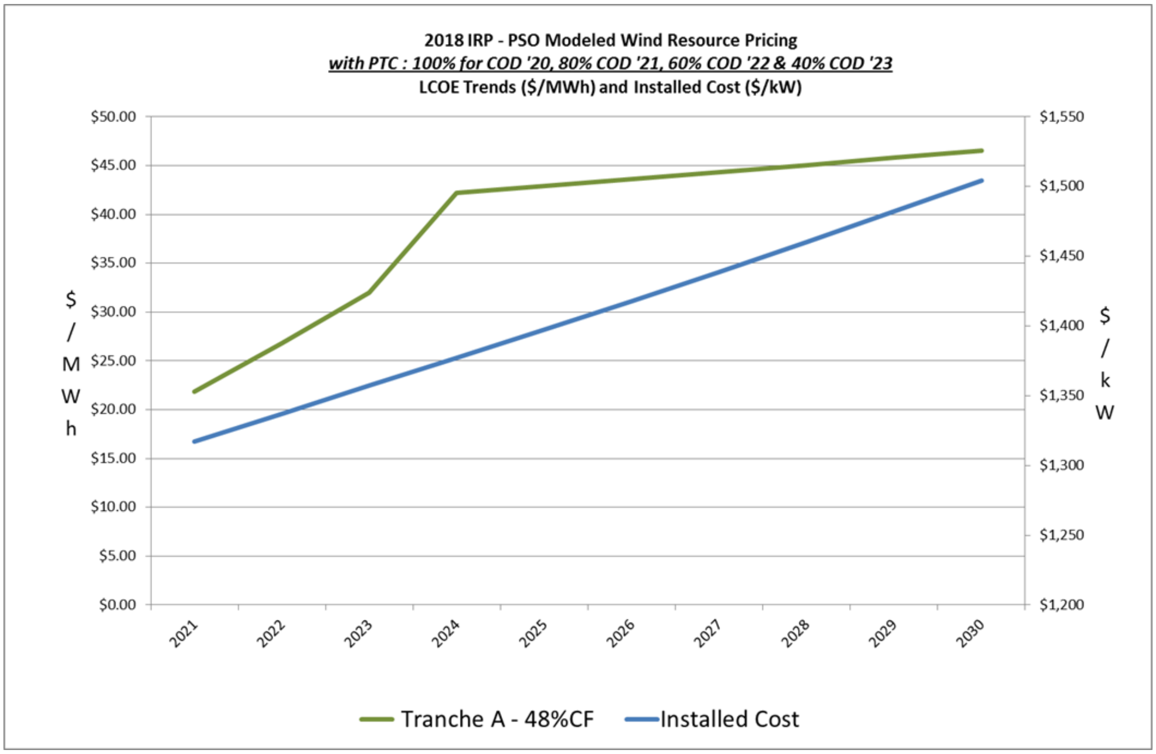


Figure 37. Levelized Cost of Electricity & Installed Cost of Wind Resources (Nominal $/MWh)

The expected magnitude of wind resources available beginning in 2022 was limited to 600MW nameplate annually through the remainder of the planning period. In total, wind resources were limited to 2,100MW nameplate over the planning period, currently PSO has contracts for 1,137MW of wind resources. The annual limit on wind additions is based on PSO's ability to plan, manage and develop either the construction or the procurement of these resources. As with solar resource additions, as PSO gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater later). This cap is based on the DOE's Wind Vision Report[11] which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe.

[11] *Wind Vision: A New Era for Wind Power in the United States* (2015). Retrieved from http://www1.eere.energy.gov/library/default.aspx?Page=12, Figure 1-5.

The cap for PSO allows the model to select up to 40% of generation energy resources as wind-powered.

Furthermore, based on recent experience and analysis the Company has included the cost of congestion and losses for incremental wind resource additions. Figure 38 shows the annual value of congestion and losses included with the incremental wind resource[12].

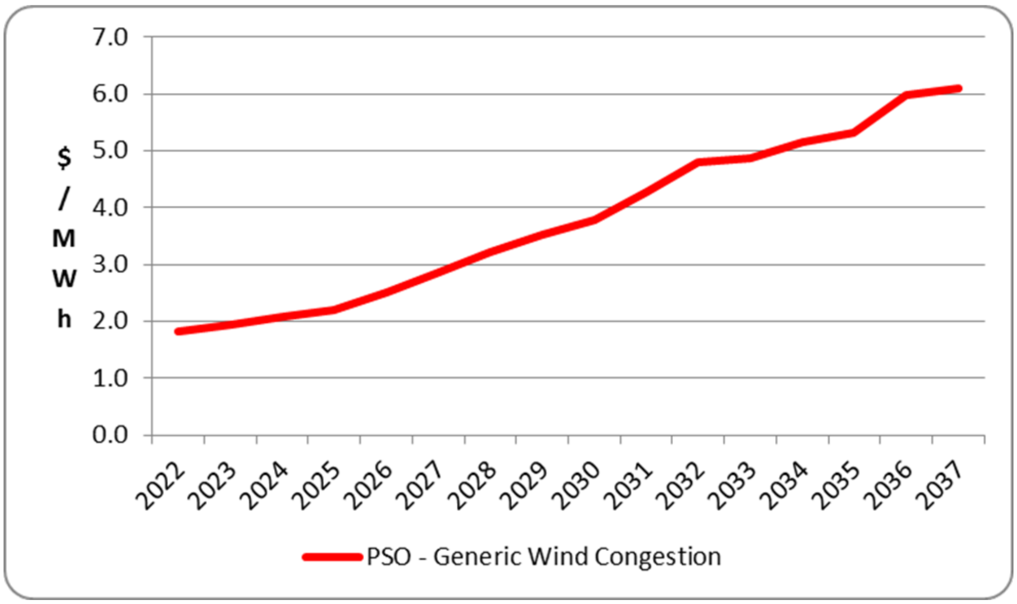


Figure 38. Modeled SPP Congestion & Losses for Wind Resources

[12] To recognize the impact of congestion the Company utilized the results of PROMOD analyses prepared by the Company and a third-party consultant, Brattle, as part of the 2017 Wind Catcher proceedings. Congestion and marginal losses from the Baseline (no incremental wind) and Generic Wind (1900 MW of incremental wind) cases under the 2016 Fundamentals Low Gas Scenario, which approximates the current 2018 Fundamentals Base Gas Scenario, were used to derive an estimate of the annual congestion and losses that would impact generation from new generic SPP wind resources.

4.5.5.3 Hydro

The available sources of, particularly, larger hydroelectric potential have largely been exploited and those that remain must compete with the other uses, including recreation and navigation. The potentially lengthy time associated with environmental studies, Federal Army Corp of Engineer permitting, high up-front construction costs, and environmental issues (fish and wildlife) make new hydro prohibitive at this time. As such, no incremental hydroelectric resources were considered in this IRP.

4.5.5.4 Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switch grass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials. Biomass costs will vary significantly depending upon the feedstock. Biomass is typically used in power generation to fuel a steam generator (boiler) that subsequently drives a steam turbine generator; similar to the same process of many traditional coal fired generation units. Some biomass generation facilities use biomass as the primary fuel, however, there are some existing coal-fired generating stations that will use biomass as a blend with the coal. Given these factors, plus the typical high cost and required feedstock supply and attendant long-term pricing issues, no incremental biomass resources were considered in this IRP.

4.6 Integration of Supply-Side and Demand-Side Options within *Plexos*® Modeling

Each supply-side and demand-side resource is offered into the *Plexos*® model on an equivalent basis. Each resource has specific values for capacity, energy production (or savings), and cost. The *Plexos*® model selects resources in order to reduce the overall portfolio cost, regardless of whether the resource is on the supply- or demand-side, and regardless of whether or not there is an absolute capacity need. In other words, the model selects resources that lower costs to customers.

4.6.1 Optimization of Expanded DSM Programs

As described in Section 4.4.3, EE and CVR options that would be incremental to the current programs were modeled as resources within *Plexos*®. In this regard, they are "demand-side power plants" that produce energy according to their end use load shape. They have an initial (program) cost with *no* subsequent annual operating costs. Likewise, they are "retired" at the end of their useful (EE measure) lives.

4.6.2 Optimization of Other Demand-Side Resources

Customer-sited DG, specifically rooftop solar, was not modeled. Instead, reductions in energy use and peak demand were built into the load forecast based on the adoption rates. CHP was modeled as a high thermal efficiency NGCC facility.

5.0 Resource Portfolio Modeling

5.1 The *Plexos*® Model - An Overview

Plexos® LP long-term optimization model, also known as "LT Plan®," served as the basis from which the PSO-specific capacity requirement evaluations were examined and recommendations were made. The LT Plan® model finds the optimal portfolio of future capacity and energy resources, including DSM additions, which minimizes the CPW of a planning entity's generation-related variable and fixed costs over a long-term planning horizon. By minimizing CPW the model will provide optimized portfolios with the lowest and most stable customer rates, while adhering to the Company's constraints. Low, stable rates benefit the entire region by attracting new commercial and industrial customers, and retaining/expanding existing load.

Plexos® accomplishes this by using an objective function which seeks to minimize the aggregate of the following capital and production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, *i.e.*, carrying charges on incremental capacity additions (based on an PSO-specific, weighted average cost of capital), and fixed O&M;
- fixed costs of any capacity purchases;
- program costs of (incremental) DSM alternatives;
- variable costs associated with PSO generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances and/or carbon 'tax,' and variable O&M costs;
- distributed, or customer-domiciled, resources which were effectively valued at the equivalent of a full-retail "net metering" credit to those customers; and
- a 'netting' of the production revenue earned in the SPP power market from PSO's generation resource sales *and* the cost of energy – based on unique load shapes from SPP purchases necessary to meet PSO's load obligation.

Plexos® executes the objective function described above while abiding by the following possible constraints:

- Minimum and maximum reserve margins;
- resource additions (i.e., maximum units built);
- age and lifetime of power generation facilities;
- retrofit dependencies (SCR and FGD combinations);
- operation constraints such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- fuel burn minimum and maximums;
- emission limits on effluents such as SO_2 and NO_x; and
- energy contract parameters such as energy and capacity.

The model inputs that comprise the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. *Plexos*® does not develop a full regulatory Cost-of-Service (COS) profile. Rather, it typically considers only the relative load and generation COS that changes from plan-to-plan, and not fixed "embedded" costs associated with existing generating capacity and demand-side programs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital expenditures for transmission interconnection costs.

5.1.1 Key Input Parameters

Two of the major underpinnings in this IRP are long-term forecasts of PSO's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas and, potentially, CO_2/carbon. Both forecasts were created internally within AEP. The load forecast was created by the AEP Economic Forecasting organization, while the long-term commodity pricing forecast was created by the AEP Fundamental Analysis group. These groups have many years of experience forecasting PSO and AEP system-wide demand and energy requirements and fundamental pricing for both internal operational and regulatory purposes. Moreover, the Fundamental Analysis group constantly performs peer review by way of comparing and contrasting its commodity pricing projections versus "consensus" pricing on the part of outside forecasting entities such as IHS- Cambridge Energy Research Associates (CERA), Petroleum Industry Research Associates (PIRA) and the EIA.

Additional critical input parameters include the installed cost of replacement capacity alternative options, as well as the attendant operating costs associated with those options. This data came from the AEP Engineering Services organization.

5.2 *Plexos*® Optimization

5.2.1 Modeling Options and Constraints

The major system parameters that were modeled are elaborated on below. The *Plexos* LT Plan® models these parameters in tandem with the objective function in order to yield the least-cost resource plan.

There are many variants of available supply-side and demand-side resource options and types. As a practical limitation, not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for baseload, intermediate, and peaking duty cycles.

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes. Other factors which will determine the ultimate technology type (e.g., choices for peaking technologies) are taken into consideration. The full list of screened supply options is included in Exhibit B of the Appendix.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Plexos*® for each designated duty cycle:

- *Peaking* capacity was modeled, effective in 2021 due to the anticipated period required to approve, site, engineer and construct, from:

- A 50% share of two CT units consisting of "F" class turbines with evaporative coolers and dual fuel capability, rated at 500MW total at summer conditions.
- AD units consisting of 2 aeroderivative turbines at 120MW total at summer conditions.
- RICE units consisting of 12 reciprocating engines rated at 220MW total at summer conditions.
- Battery Storage units available in 10MW blocks per year.

- *Intermediate-Baseload* capacity was modeled, effective in 2022 due to anticipated period required to approve, site, engineer and construct, from:
  - A 25% share of a NGCC (2x1 "H" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 1,490MW at summer conditions. The 25% interest assumes PSO coordinates the addition of this resource with other parties.
- Wind resources were made available up to 600MW annually beginning in 2022 (commercial operation date 12/31/21). The resource had a LCOE of $21.85/MWh in 2021 with an 80% PTC, without congestion and losses. The levelized congestion and losses for the 2021 wind resource is estimated to be approximately $4/MWh. Wind resources were assumed to have a SPP capacity value equal to 5% of nameplate rating during the first three years and a 30% capacity rating thereafter.

- Large-scale solar resources were made available in two tiers, with up to 150MW of each tier available each year beginning in 2021, for a total of up to 300MW annually. Initial costs for Tier 1 were approximately $1,180/kW in 2021 with the ITC. Tier 2 has an initial cost of approximately $1,311/kW in 2021 with the ITC. Solar resources were assumed to have a SPP capacity value equal to 10% of nameplate rating in the first three years and a 33% capacity rating thereafter.

- Short-Term Market Purchase alternative resources were made available to the model for selection during the development of the various optimal plans. These short-term capacity purchases were assumed to have no energy associated with them, a contract term of one year, and 250 MW was allowed to be added annually. The pricing of these purchases was based on the SPP Capacity Prices shown in Figure 25. The main purpose of these purchases was to assist in meeting the SPP reserve margin requirement during the initial 3 years after wind and large-scale solar resources were added that had limited capacity credits of 5% and 10%, respectively.

- DG, in the form of distributed solar resources, was embedded with a 10% annual growth rate over the planning period.
- CHP resources were made available in 15MW (nameplate) blocks, with an overnight installed cost of $2,100/kW and assuming full host compensation for thermal energy for an effective full load heat rate of ~4,800 Btu/kWh.
- EE resources—incremental to those already incorporated into the Company's long-term load and peak demand forecast in up to 21 unique "bundles" of Residential, Commercial, and Industrial measures considering cost and performance parameters for both HAP and AP categories. Industrial measures were limited to lighting.
- CVR was available in 8 tranches of varying installed costs and number of circuits/sizes ranging from a low of 4.9MW up to 11.4MW of demand savings potential.

5.2.2 Traditional Optimized Portfolios

The key decision to be made by PSO during the planning period is how to fill the resource need identified. Portfolios with various options addressing PSO's capacity and energy resource needs over time were optimized under various conditions. Six traditional scenarios were initially analyzed for this IRP, resulting in six unique portfolios (see Table 11). The portfolios discussed below represent incremental resources which are in additional to those currently in-service. The portfolios discussed below represent incremental resources which are in additional to those currently in-service.

Table 11. Traditional Scenarios/Portfolios

Type	Name	Commodity Pricing Conditions	Load Conditions
Commodity Pricing Scenarios	Mid	Mid	Base
	Low Band	Low Band	Base
	High Band	High Band	Base
	Status Quo	No Carbon	Base
Load Scenarios	Low Load	Low Band	Low
	High Load	Low Band	High

5.2.2.1 Base, Low Band, High Band, and Status Quo Commodity Pricing Portfolios

Table 12 shows the capacity additions associated with the Base, Low Band, High Band, and Status Quo commodity pricing scenarios. Recall from Section 4.3 that the modeling associated with the Base, Low Band, and High Band scenarios assumed a CO2 dispatch burden, or allowance value, equal to $15/ton commencing in 2028 and escalating at 5% per annum thereafter on a nominal dollar basis. The Status Quo scenario does not include a CO2 dispatch burden.

In addition, recall from Sections 4.5.5.1 and 4.5.5.2 that wind and solar tranches were assigned different firm capacity values in Years 1-3 versus Years 4 and onward. As a result, wind and solar firm capacity may not be correlated to nameplate capacity in the same manner under one portfolio when comparing it to another portfolio.

Table 12. Cumulative SPP Capacity Additions (MW) & Energy Positions (GWh) for Base, Low Band, High Band, & Status Quo Commodity Pricing Scenarios

Commodity Pricing Scenario		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2028 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2018-2028)
Base	Base/Intermediate					373	373	373	373	373	746	746	(4,759)	(6,223)
	S.T. Cap. Purch.					100	250	200	150	100	150	150		
	Solar (Firm)							15	30	45	95	159		
	Solar (Nameplate)							150	300	450	600	900		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	33	29	24	19	15		
	CVR					12	25	38	38	38	44	52		
	Distr. Gen. (Firm)	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1.0	1.0	1.0		
Low Band	Base/Intermediate					373	373	373	373	373	746	746	(4,699)	(5,454)
	S.T. Cap. Purch.					100	250	250	200	150	250	200		
	Solar (Firm)								15	30	45	95		
	Solar (Nameplate)								150	300	450	600		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	21	26	23	19	16	12		
	CVR							12	12	12	18	31		
	Distr. Gen. (Firm)	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1.0	1.0	1.0		
High Band	Base/Intermediate					373	373	373	373	373	746	746	(3,775)	(5,717)
	S.T. Cap. Purch.					100	200	200	100	0	100	50		
	Solar (Firm)						15	30	45	100	149	214		
	Solar (Nameplate)						150	300	450	650	800	1,100		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	38	36	31	25	20		
	CVR					12	25	38	51	59	65	71		
	Distr. Gen. (Firm)	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1.0	1.0	1.0		
Status Quo	Base/Intermediate					373	373	373	373	373	746	746	(7,163)	(5,913)
	S.T. Cap. Purch.					100	250	250	200	150	250	250		
	Solar (Firm)								15	30	45	95		
	Solar (Nameplate)								150	300	450	600		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	36	31	26	20	16		
	CVR											6		
	Distr. Gen. (Firm)	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1.0	1.0	1.0		

Base/Intermediate=NGCC; S.T. Cap. Purch.=Short-Term Capacity Purchase; CVR=Conservation Voltage Reduction; DG=Distributed

All four portfolios include similar resource additions, such as:

- Wind resources of 600MW (nameplate) or more beginning in 2022 and totaling 1,000MW (nameplate) by 2029;
- Solar resources of 150MW (nameplate) beginning as early as 2023 and totaling at least 600MW (nameplate) by the end of the planning period; and
- EE programs including CVR totaling 22MW or more by 2028.

All four portfolios result in PSO having a negative annual net energy position in the last year of the planning period, 2028.

5.2.2.2 Load Sensitivity Scenario Portfolios

Table 13 shows the capacity additions associated with the Low Load and High Load sensitivity scenarios, using Base commodity prices.

Table 13. Cumulative SPP Capacity Additions (MW) and Energy Positions (GWh) for Low Load and High Load Sensitivity Scenarios

Load Sensitivities		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2028 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2018-2028)
Low Load	Base/Intermediate					373	373	373	373	373	373	373	(4,309)	(4,640)
	S.T. Cap. Purch.						50	50	0	0	250	200		
	Solar (Firm)						5	20	35	62	111	166		
	Solar (Nameplate)						50	200	350	500	650	850		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	38	33	27	22	16		
	CVR					12	25	38	51	59	65	71		
	Distr. Gen. (Firm)	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1.0	1.0	1.0		
High Load	Base/Intermediate					373	373	373	373	373	746	746	(5,116)	(5,811)
	Peaking				248	248	248	248	248	248	248	248		
	S.T. Cap. Purch.						200	200	150	150	200	200		
	Solar (Firm)							15	30	45	95	154		
	Solar (Nameplate)							150	300	450	600	850		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	30	27	22	18	14		
	CVR					12	12	25	38	51	57	65		
	Distr. Gen. (Firm)	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1.0	1.0	1.0		

Base/Intermediate=NGCC; S.T. Cap. Purch.=Short-Term Capacity Purchase; CVR=Conservation Voltage Reduction; DG=Distributed

As expected, the overall capacity additions in the High Load scenario are naturally greater than those in the Low Load scenario. The High Load scenario calls for a natural gas combustion turbine for peaking capacity in 2021 whereas in the Low Load scenario this resource is not needed during the planning period.

5.3 Preferred Plan

Each of the six scenarios provides insight into a potential alternative mix of resources for the future. Given that the resource additions under the four commodity pricing scenarios offer comparable resource additions, PSO has elected to use the Base commodity pricing scenario as its Preferred Plan.

This plan was developed based on the following considerations:

- Minimizing revenue requirements (i.e. cost to customers) over the planning period, while meeting capacity obligations
- Optimizes the mix of generation to hedge short-term energy price volatility in the SPP Integrated Marketplace.
- Installing economical CVR and other incremental DSM.
- Adding renewable energy resources (wind and solar) in a cost effective manner.

The cumulative capacity additions associated with the Preferred Plan are shown below in Table 14.

Table 14. Cumulative SPP Capacity Additions (MW) and Average Annual Energy Position (GWh) for Preferred Plan

Preferred Plan		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2028 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2018-2028)
Base Commodity, Base Load	Base/Intermediate					373	373	373	373	373	746	746	(4,759)	(6,223)
	S.T. Cap. Purch.					100	250	200	150	100	150	150		
	Solar (Firm)							15	30	45	95	159		
	Solar (Nameplate)							150	300	450	600	900		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	33	29	24	19	15		
	CVR					12	25	38	38	38	44	52		
	Distr. Gen.	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1	1	1		
Capacity Reserves Above SPP Requirement without New Additions		**348**	**475**	**502**	**46**	**(510)**	**(679)**	**(709)**	**(804)**	**(858)**	**(1,350)**	**(1,383)**		
Capacity Reserves Above SPP Requirement with New Additions		**348**	**475**	**502**	**46**	**19**	**45**	**0**	**16**	**22**	**5**	**40**		

Base/Intermediate=NGCC; S.T. Cap. Purch.=Short-Term Capacity Purchase; CVR=Conservation Voltage Reduction; DG=Distributed

In conjunction with the Company's five-year action plan, the Preferred Plan offers PSO significant flexibility should future conditions differ considerably from its assumptions. For example, as EE programs are implemented, PSO will gain insight into customer acceptance and develop additional hard data as to the impact these programs have on load growth. This will assist PSO in determining whether to expand program offerings, change incentive levels for programs, or target specific customer classes for the best results. If current long-term renewable costs assumptions change, PSO could either accelerate or delay the installation of renewable generation facilities. Changes to PSO's existing portfolio associated with this Preferred Plan are described in greater detail in Section 6.1 of this report.

5.3.1 Demand-Side Resources

In the Preferred Plan, incremental EE resources were selected beginning in 2022 and throughout the remainder of the planning period. Economic savings are attributable to both Commercial/Industrial and Residential programs, with the majority coming from Residential programs. By 2028, overall EE savings – consisting of Other Energy Efficiency, Existing DSM Programs, and Incremental DSM Programs – provide a decrease in residential and commercial energy usage of approximately 3.4% (see Figure 39).

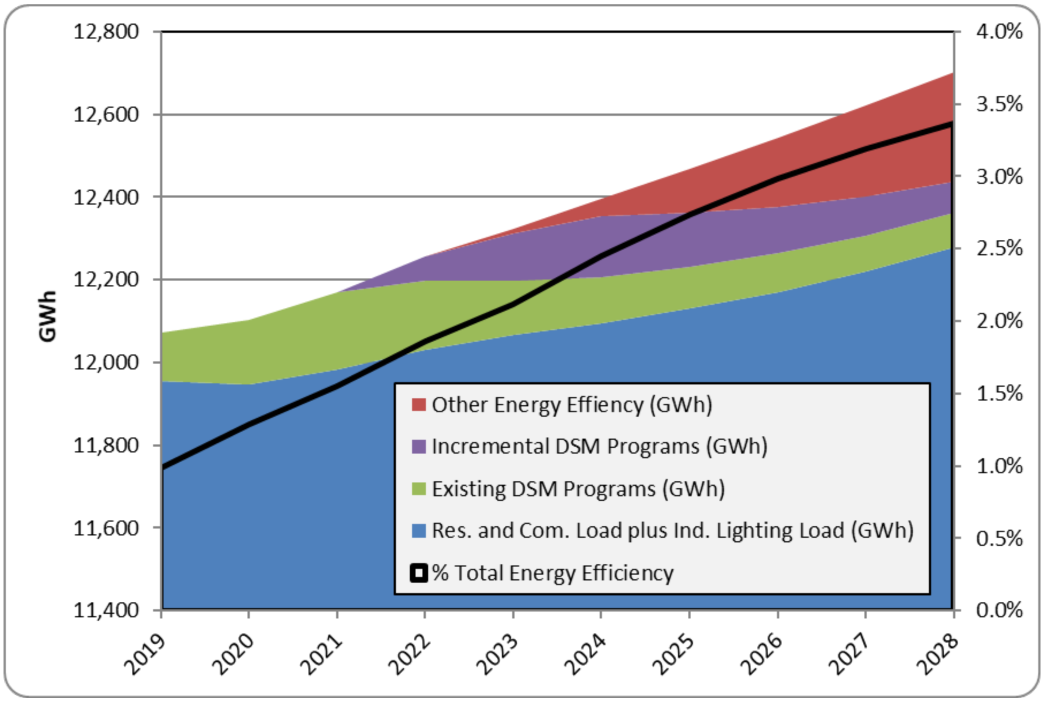


Figure 39. PSO Energy Efficiency Savings per the Preferred Plan

As part of the Preferred Plan, six of the eight available CVR tranches are proposed additions. When coupled with PSO's existing pilot installation, this results in a cumulative capacity reduction of 52MW by 2028. The six tranches of circuits (in addition to the pilot program) are added from 2022 through 2028. The CVR estimates are subject to future revision as more operational information is gained from the pilot installation as well as other tests that are currently underway throughout the AEP system.

DG (i.e. rooftop solar) resources were not modeled during the planning period. DG resources were added incrementally at a 10% annual growth rate (based on nameplate capacity), resulting in a total of 1MW of SPP capacity credit (3MW nameplate) by 2028.

5.3.2 Comparing the Cost of the Base Optimization

PSO included a 37MW natural gas fired reciprocating engine plant and an $11MW_{ac}$ solar plant as part of its "going-in" capacity position. Both of these proposed additions support continued diversification of the Company's generation portfolio. Additional analysis was performed to better understand the cost impact of including these resources. The incremental cost to add these resources, compared to not including them in the "going-in" capacity position, equates to less than 0.3% on a cumulative present worth basis.

5.4 Risk Analysis

In addition to comparing the Preferred Plan to the optimized portfolios under a variety of pricing assumptions, the Preferred Plan and an alternative portfolio were also evaluated using a stochastic, or "Monte Carlo" modeling technique where input variables are randomly selected from a universe of possible values, given certain standard deviation constraints and correlative relationships. This offers an additional approach by which to "test" the Preferred Plan over a distributed range of certain key variables. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a higher cost (revenue requirement) relative to the expected outcome.

This study included multiple risk iteration runs performed over the study period with three key price variables (risk factors) being subjected to this stochastic-based risk analysis. The results take the form of a distribution of possible revenue requirement outcomes for each plan. Table 15 shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other.

Table 15. Risk Analysis Factors & Their Relationships

	Gas	Market Prices	CO_2
Gas	1	0.73	0.97
Market Prices		1	0.76
CO_2			1
Standard Deviation	13%	14%	4%

Comparing the Preferred Plan to an alternative portfolio which is significantly different provides a data point that may be used to evaluate the risk associated with the Preferred Plan. The Preferred Plan has a similar resource profile to other optimized plans, so there would be little difference in the risk profiles between such portfolios and the Preferred Plan, and therefore those portfolios were not included in the stochastic analysis. Instead, a portfolio that does not contain any renewable resources was used for comparison. This allows PSO to determine if the renewable resources in the Preferred Plan introduce more risk than relying on no renewable additions. The range of values associated with the variable inputs is shown in Figure 40.

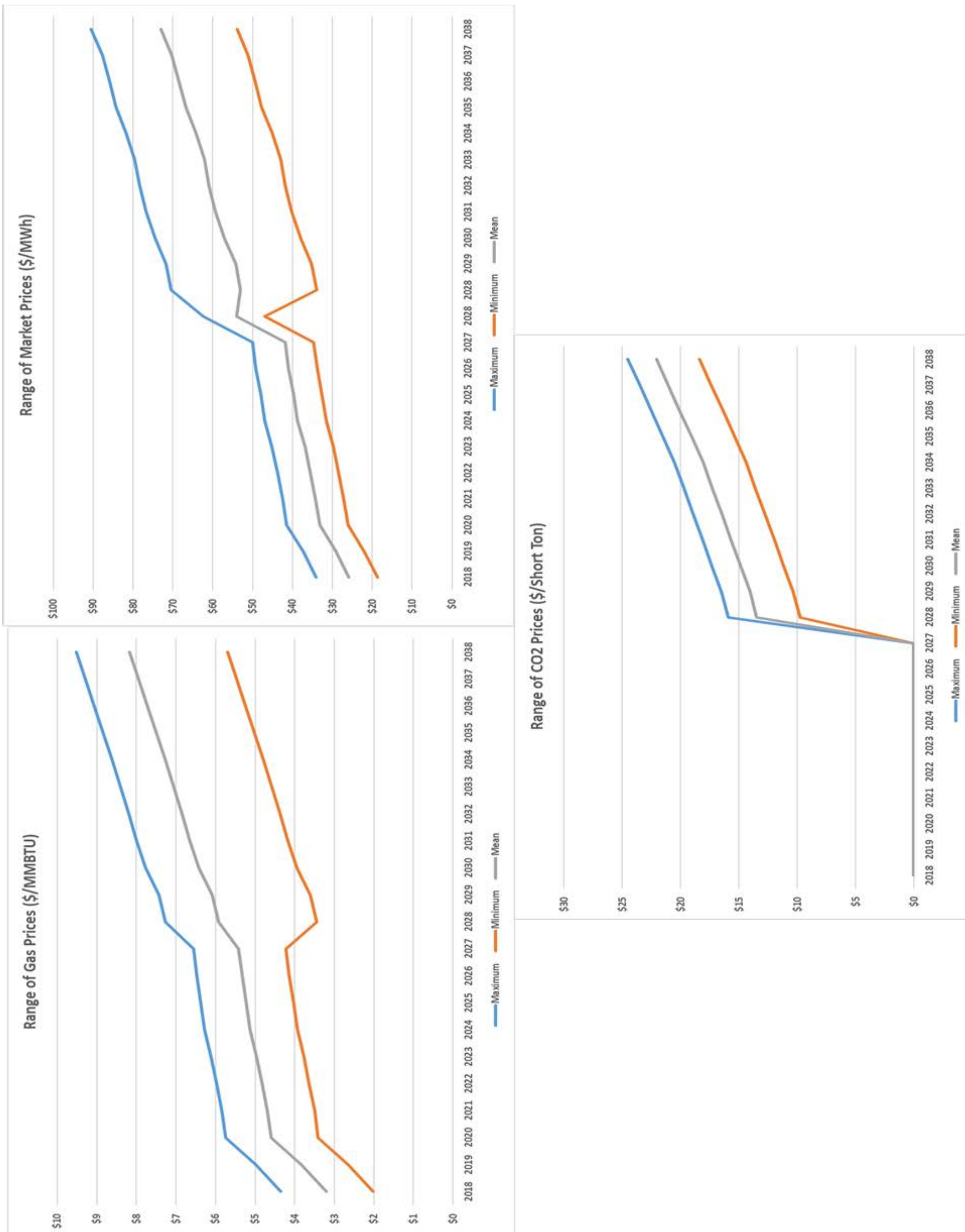


Figure 40. Range of Variable Inputs for Stochastic Analysis

5.4.1 Stochastic Modeling Process and Results

For each portfolio, the results of 100 random iterations are sorted from lowest cost to highest cost, with the differential between the median and higher percentile result from the multiple runs identified as Revenue Requirement at Risk (RRaR). For example, the 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, only five percent of the time. Thus, it is 95 percent likely that those higher-ends of revenue requirements would not be exceeded. The larger the RRaR, the greater the likelihood that customers could be subjected to higher costs relative to the portfolio's mean or expected cost. Conversely, there is equal likelihood that costs may be lower than the median value. These higher or lower costs are generally the result of the difference, or spread, between fuel prices and resultant SPP market energy prices. The greater that spread, the more "margin" is enjoyed by the Company and its customers.

Figure 41 illustrates the RRaR (expressed in terms of incremental cost over the 50th percentile).

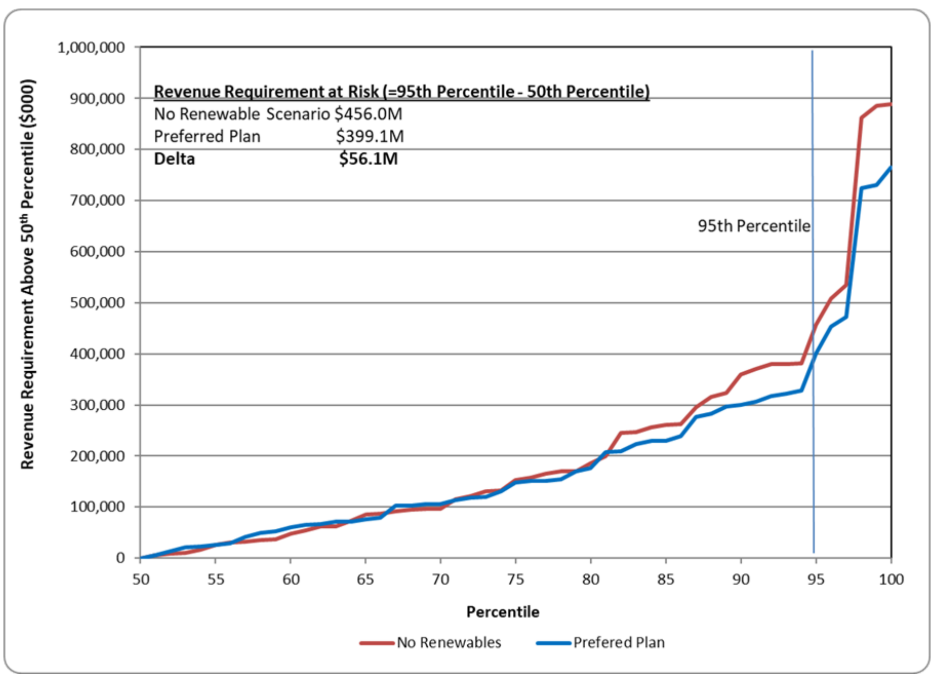


Figure 41. Revenue Requirement at Risk (RRaR) ($000) for Select Portfolios

The difference in RRaR between the two portfolios that were analyzed is relatively small over the 100 simulations, with the Preferred Plan being less risky by about $56.1M, which indicates that the additional renewable generation in the Preferred Plan does not introduce additional risk.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of the Preferred Plan, which includes a higher level of renewable resources, is not significantly greater than a portfolio with no renewable resources. This suggests that the Preferred Plan represents a reasonable combination of expected costs and risk.

5.4.2 Cost Versus Alternative Portfolios

Another method of determining whether the proposed plan is better for customers is to create reasonable, alternative portfolios that have different characteristics from the preferred (optimal) plan and compare the cost of those portfolios to the preferred plan. If the cost of one of the alternative portfolios is less than or close to the preferred plan under certain pricing scenarios, additional evaluations may be warranted.

Being that the optimal plan selected a significant volume of renewable resources and combined cycle capacity resources, PSO developed three alternative portfolios with limited renewable resources to test if those portfolios would be competitive with the optimal plan. The first two alternative plans allow the model to select natural gas combined cycle resources (CC), with the first plan limiting the amount of renewable (wind and solar) capacity to less than half of that in the optimal plan, and the second allowing no new wind or solar capacity. The third plan allowed the model to only pick natural gas combustion turbines (CT) for peaking capacity (no CC capacity), but did not limit renewable resources.

The results of this evaluation are shown in Table 16. Because the optimized renewable resources reduce the CPW of a portfolio, the alternatives with reduced renewables were more expensive than the optimal portfolio, with the portfolio with no renewables being the most expensive. The portfolio with the CT option only (no change in renewables) was more expensive than the optimal portfolio under all pricing scenarios, and more expensive than the portfolio with the CC option plus reduced renewables under Base and Low pricing scenarios. This is because the CC, while more expensive than the CT, provides significant energy value. However, the CT plan was less expensive than the CC with limited renewables under High and Status Quo pricing scenarios as the margins for CC energy are lower. This exercise is informative in that it validates the value the renewable resources bring to the portfolio and also shows how the energy value from a combined-cycle plant reduces overall costs compared to a peaking only facility.

Table 16. Comparison of Alternative Portfolios to the Optimal Portfolio

	CPW PSO Revenue Requirements ($000) Commodity Price Forecast			
Plan	**Base**	**Low**	**High**	**Status Quo**
Preferred	15,697,085	14,703,619	16,149,750	15,331,424
CC+Reduced Renewables	17,052,406	16,015,268	17,883,945	16,324,364
CC+No Renewables	18,423,795	16,753,489	19,368,542	17,152,999
CT+Renewables	17,223,195	16,256,930	17,576,511	16,071,460

	Cost Over Optimal Plan ($000) Commodity Price Forecast			
Plan	**Base**	**Low**	**High**	**Status Quo**
Preferred	Lowest Cost	Lowest Cost	Lowest Cost	Lowest Cost
CC+Reduced Renewables	1,355,321	1,311,649	1,734,195	992,939
CC+No Renewables	2,726,709	2,049,870	3,218,792	1,821,574
CT+Renewables	1,526,110	1,553,311	1,426,761	740,036

5.4.3 IRP Preferred Plan Cost Over Time

Calculating the Preferred Plan's annual cost impact on individual customers is a complicated exercise. The costs incurred by the utility are composed of fuel, purchased power, invested capital, operations and maintenance expenses for generation, transmission and distribution functions. These costs are allocated to customers in a variety of manners depending on the type of customer and the customer's usage. To develop an estimate of the cost of the Preferred Plan to a typical customer, PSO assumed that existing costs will increase due to normal inflation, and then calculated the incremental cost above that amount. Note that this calculation assumes no change in the components of utility costs that are not touched by the IRP recommendations, namely transmission and distribution expenses (with the exception of conservation voltage reduction expenses). To provide some context to this change in cost, the Preferred Plan is compared to a plan with no renewable resource additions (the CC plus no renewables plan identified in Section 5.4.2 above). Figure 42 shows the indicative change in monthly cost that a typical customer using 1,000 kWh/month may experience. Given the myriad of factors that go into how resources are acquired and allocated to various customer classes, the changes in Figure 42 should be viewed as order of magnitude values, not precise changes.

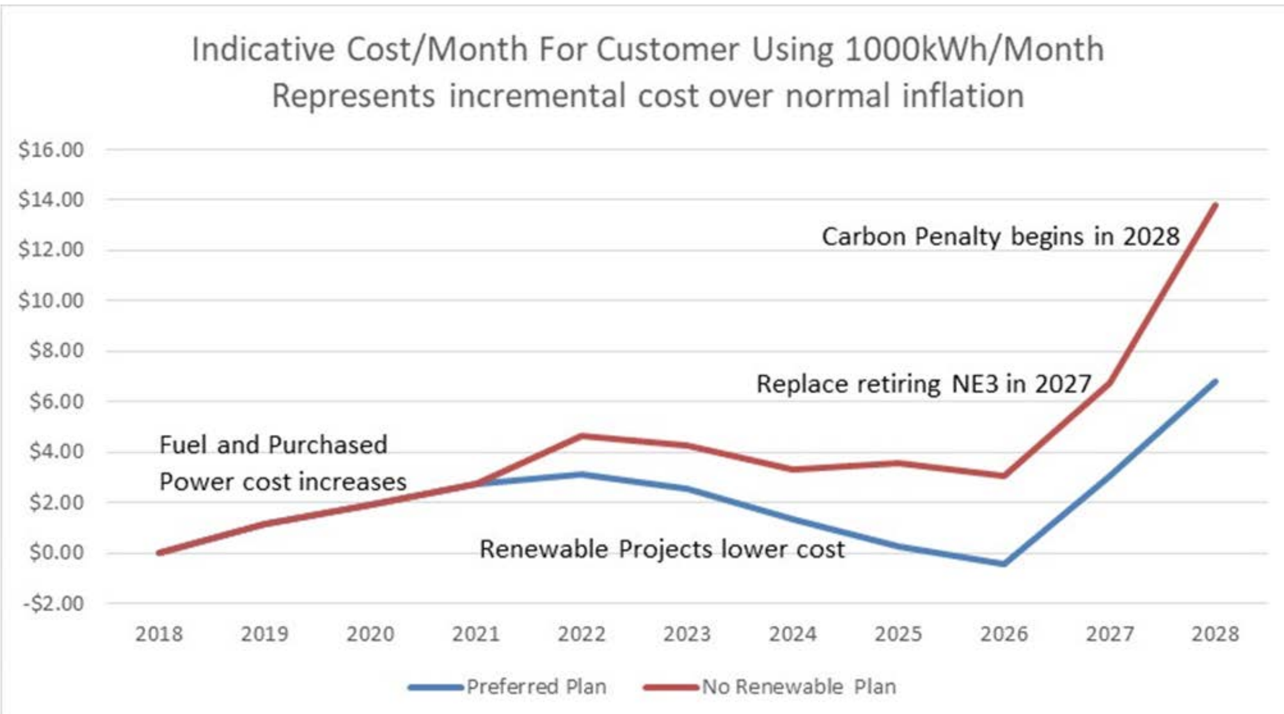


Figure 42. Indicative Customer Cost Impacts Over Time

6.0 Conclusions and Five-Year Action Plan

6.1 Plan Summary

PSO used the modeling results to develop a Preferred Plan or “Plan”. To arrive at the Preferred Plan, using Plexos®, PSO developed optimal portfolios based on four long-term commodity price forecasts and two load sensitivities. The Preferred Plan balances cost and other factors such as risk and environmental regulatory considerations, to cost effectively meet PSO’s demand and energy obligations. For PSO, the Preferred Plan is the optimized portfolio modeled under the base commodity pricing scenario.

Table 17[13] provides a summary of the Preferred Plan throughout the planning period (2019-2038), which resulted from analysis of optimization modeling under the load and commodity pricing scenarios.

[13] Note: This IRP begins adding new demand-side resources such as energy efficiency and CVR in 2022 that are incremental to programs that are currently approved or pending approval. The programs that are currently approved or pending approval during the 2018-2021 timeframe are embedded in the Company’s load forecast.

Table 17. Preferred Plan Cumulative Capacity Additions throughout Planning Period (2019-2038)

Preferred Plan		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2028 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2018-2028)
Base Commodity, Base Load	Base/Intermediate					373	373	373	373	373	746	746	(4,759)	(6,223)
	S.T. Cap. Purch.					100	250	200	150	100	150	150		
	Solar (Firm)							15	30	45	95	159		
	Solar (Nameplate)							150	300	450	600	900		
	Wind (Firm)					30	50	50	200	300	300	300		
	Wind (Nameplate)					600	1,000	1,000	1,000	1,000	1,000	1,000		
	Energy Efficiency					13	26	33	29	24	19	15		
	CVR					12	25	38	38	38	44	52		
	Distr. Gen.	0.3	0.3	0.3	0.3	0.7	0.7	0.7	0.7	1	1	1		
Capacity Reserves Above SPP Requirement without New Additions		**348**	**475**	**502**	**46**	**(510)**	**(679)**	**(709)**	**(804)**	**(858)**	**(1,350)**	**(1,383)**		
Capacity Reserves Above SPP Requirement with New Additions		**348**	**475**	**502**	**46**	**19**	**45**	**0**	**16**	**22**	**5**	**40**		

Base/Intermediate=NGCC; S.T. Cap. Purch.=Short-Term Capacity Purchase; CVR=Conservation Voltage Reduction; DG=Distributed

In summary, the Preferred Plan:

- Adds 600MW and 400MW (nameplate) of wind resources in 2022 and 2023, respectively for a total of 1,000MW (nameplate) by the end of the planning period.
- Adds utility-scale solar resources beginning in 2024 through 2028, for a total of 900MW (nameplate) of utility-scale solar by the end of the planning period.
- Implements customer and grid energy efficiency programs, including CVR, reducing energy requirements by 278GWh and capacity requirements by 67MW by 2028.
- Fills long-term needs through the addition of natural gas combined-cycle generation of 373MW in 2022 and 373MW in 2027.
- Fills short-term needs with the acquisition of Short-Term Capacity purchases ranging from 100MW in 2022 to a maximum of 250MW in 2023 over the planning period. This resource is due to the planning criteria related to intermittent resources (wind and solar) as defined by SPP.
- Anticipates retirement of Oklaunion 1 (102MW) and Northeastern 3 (469MW) coal units in 2020 and 2026, respectively.
- Anticipates expiration of several thermal resource PPAs (889MW combined) by 2022 and the Weatherford wind resource PPA (147MW nameplate) by 2026(1) Details related to PSO's available resources can be found in Exhibits E and F of the Appendix.

PSO capacity changes over the 10-year planning period associated with the Preferred Plan are shown in Figure 43 and Figure 44.

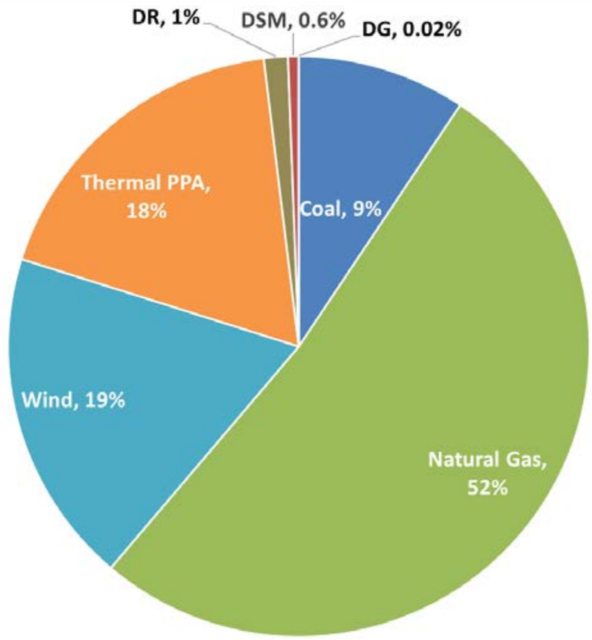


Figure 43. 2019 PSO Nameplate Capacity Mix

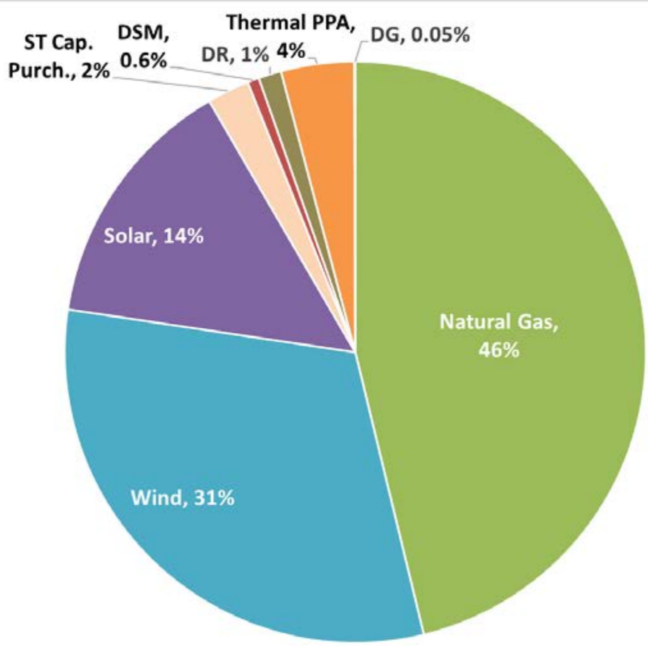


Figure 44. 2028 PSO Nameplate Capacity Mix

The relative impacts to PSO's annual energy position are shown in Figure 45 and Figure 46.

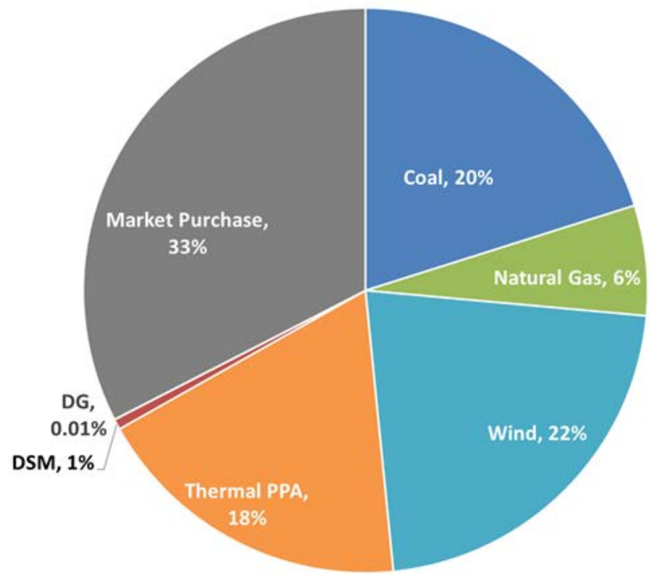


Figure 45. 2019 PSO Energy Mix

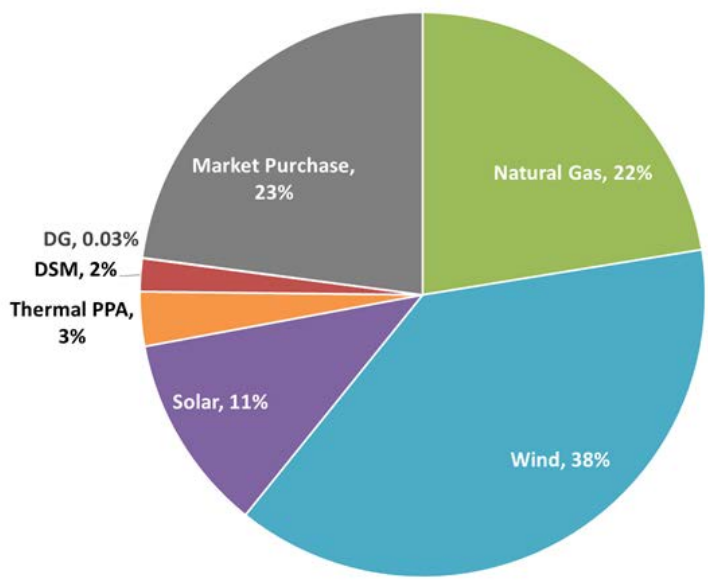


Figure 46. 2028 PSO Energy Mix

Figure 43 through Figure 46 indicate that this Preferred Plan would reduce PSO's reliance on solid fuel-based generation, and increase reliance on demand-side, natural gas, and renewable resources. Specifically, over the 10-year planning horizon the Company's nameplate capacity mix attributable to solid fuel-fired assets declines from 9% to 0%, and natural gas assets would decrease from 52% to 46%. Solar assets make up 14% of the capacity mix and wind assets increase from 19% to 31%. Demand-side resources are added to the mix at 0.6% of total nameplate capacity resources and Short-Term Capacity Purchases are added at 2%.

PSO's energy output attributable to solid fuel generation decreases from 30% to 0% over the planning period, while energy from natural gas resources increases from 9% to 38%. The Preferred Plan introduces solar resources, attributing to 19% of total energy. Reliance on thermal PPA energy would decrease from 27% to 5% based on the planning assumption that thermal PPA's will be replaced with newly acquired natural gas combined-cycle generation. However, the final PPA percentages may change once a Request for Proposal process is conducted to determine if there are more cost effective market opportunities that exist to meet the capacity need in 2022 and beyond.

Figure 47 and Figure 48 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the treatment of capacity credit for intermittent resources within SPP; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they are a low cost energy resource. When comparing the capacity values in Figure 47 with those in Figure 43 and Figure 44, it is important to note that Figure 47 provides an analysis of SPP-recognized capacity, while Figure 43 and Figure 44 depict nameplate capacity.

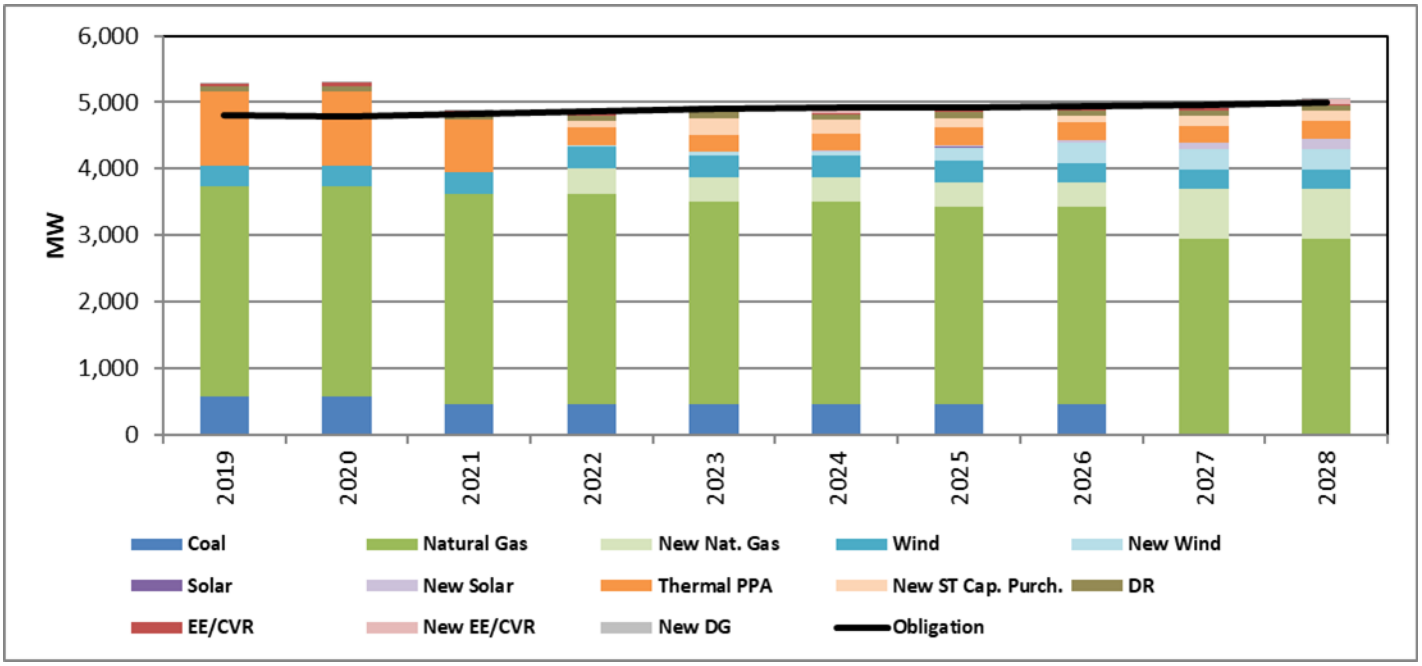


Figure 47. PSO Annual SPP Capacity Position (MW) per the Preferred Plan

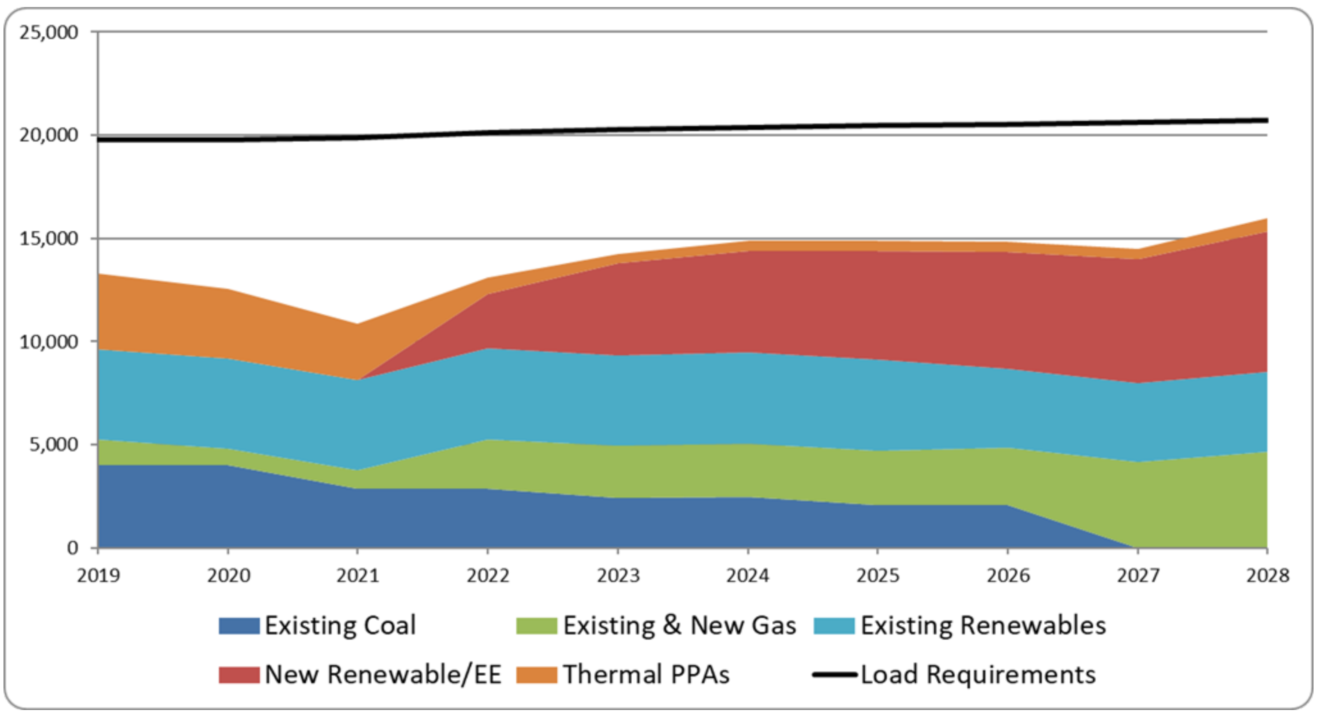


Figure 48. PSO Annual Energy Position (GWh) per the Preferred Plan

6.1.1 PSO Five-Year Action Plan

Steps to be taken by PSO in the near future as part of its Five-Year Action Plan include:

1. Continue the planning and regulatory actions necessary to implement economic energy efficiency programs in Oklahoma.
2. Conduct a Request for Proposals (RFP) to explore opportunities to add cost-effective wind generation in the near future to take advantage of the Federal Production Tax Credit.
3. Consider conducting an RFP to explore adding cost effective utility-scale solar resources.
4. Initiate the RFP process to evaluate PSO's options for replacing the existing Thermal PPAs when they expire.
5. In conjunction with adding variable/intermittent resources, consider conducting an RFP to evaluate PSO's options for short-term capacity needs related to the incremental intermittent resource additions.
6. Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

6.2 Conclusion

PSO's Preferred Plan provides the Company with an increasingly diversified portfolio of supply- and demand-side resources which provides flexibility to adapt to future changes to the power market, technology, and environmental regulations. The addition of efficient natural gas-fired generation along with increased renewables and demand-side management mitigates fuel price and environmental compliance risk.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in the course of resource portfolio evaluations, material changes in these assumptions could result in modifications. The action plan presented in this IRP is sufficiently flexible to accommodate possible changes in key parameters, including load growth, environmental compliance assumptions, fuel costs, and construction cost estimates, which may impact this IRP. By minimizing PSO's costs in the optimization process, the Company's model produced optimized portfolios with the lowest, reasonable impact on customers' rates.

Appendix

Exhibit A	**Load Forecast Tables**
Exhibit B	**Non-Renewable New Generation Technologies**
Exhibit C	**2018 Fuel Supply Portfolio and Risk Management Plan**
Exhibit D	**Optimization Model Cost Outputs**
Exhibit E	**Capacity, Demand and Reserves – “Going-In”**
Exhibit F	**Capacity, Demand and Reserves – “Preferred Plan”**
Exhibit G	**Attorney General Comments on 2018 DRAFT IRP**
Exhibit H	**Transcript from IRP Technical Meeting**

Exhibit A Load Forecast Tables

EXHIBIT A-1
Public Service Company of Oklahoma
Annual Internal Energy Requirements and Growth Rates
2015-2028

	Residential Sales		Commercial Sales		Industrial Sales		Other* Energy Requirements		Total Internal Energy Requiremer	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Grow
Actual										
2015	6,114	---	5,146	---	5,410	---	2,395	---	19,065	---
2016	6,229	1.9	5,266	2.3	5,534	2.3	2,368	-1.1	19,396	1.7
2017	5,943	-4.6	5,175	-1.7	5,669	2.4	2,288	-3.4	19,075	-1.7
Forecast										
2018	6,483	9.1	5,291	2.2	5,783	2.0	2,426	6.0	19,983	4.8
2019	6,205	-4.3	5,239	-1.0	5,964	3.1	2,373	-2.2	19,781	-1.0
2020	6,157	-0.8	5,234	-0.1	5,978	0.2	2,391	0.8	19,759	-0.1
2021	6,145	-0.2	5,238	0.1	6,094	1.9	2,397	0.3	19,873	0.6
2022	6,155	0.2	5,258	0.4	6,200	1.7	2,398	0.0	20,011	0.7
2023	6,160	0.1	5,266	0.2	6,252	0.8	2,415	0.7	20,093	0.4
2024	6,153	-0.1	5,270	0.1	6,302	0.8	2,418	0.2	20,144	0.3
2025	6,167	0.2	5,282	0.2	6,341	0.6	2,403	-0.6	20,194	0.2
2026	6,173	0.1	5,290	0.1	6,373	0.5	2,421	0.7	20,257	0.3
2027	6,185	0.2	5,300	0.2	6,407	0.5	2,433	0.5	20,324	0.3
2028	6,224	0.6	5,323	0.4	6,454	0.7	2,441	0.3	20,441	0.6

*Other energy requirements include other retail sales, wholesale sales and losses.

Note: 2018 data are six months actual and six months forecast

EXHIBIT A-2
Public Service Company of Oklahoma
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2015-2028

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2015	08/07/15	4,164	---	01/08/15	2,974	---	4,164	---	19,065	---	52.3
2016	08/11/16	4,123	-1.0	01/18/16	2,643	-11.1	4,123	-1.0	19,396	1.7	53.7
2017	07/21/17	4,011	-2.7	12/19/16	2,928	10.8	4,011	-2.7	19,075	-1.7	54.3
Forecast											
2018		4,270	6.5		3,193	9.1	4,270	6.5	19,983	4.8	53.3
2019		4,322	1.2		2,888	-9.6	4,322	1.2	19,781	-1.0	52.2
2020		4,298	-0.6		2,898	0.3	4,298	-0.6	19,759	-0.1	52.5
2021		4,323	0.6		2,904	0.2	4,323	0.6	19,873	0.6	52.5
2022		4,345	0.5		2,919	0.5	4,345	0.5	20,011	0.7	52.4
2023		4,368	0.5		2,922	0.1	4,368	0.5	20,093	0.4	52.5
2024		4,380	0.3		2,928	0.2	4,380	0.3	20,144	0.3	52.5
2025		4,387	0.2		2,932	0.1	4,387	0.2	20,194	0.2	52.5
2026		4,403	0.3		2,940	0.3	4,403	0.3	20,257	0.3	52.4
2027		4,418	0.3		2,947	0.3	4,418	0.3	20,324	0.3	52.5
2028		4,452	0.8		2,961	0.5	4,452	0.8	20,441	0.6	52.4

Notes: 2018 data are six monts actual and six months forecast. The winter 2017/18 peak occurred on January 17, 2018.

EXHIBIT A-3 Public Service Company of Oklahoma DSM/Energy Efficiency Included in Load Forecast Energy (GWh) and Coincident Peak Demand (MW)			
Year	Energy	Summer* Demand	Winter* Demand
2018	73.7	18.3	11.6
2019	118.7	29.4	18.9
2020	156.2	39.4	25.2
2021	188.6	49.0	31.2
2022	211.7	57.0	35.9
2023	223.7	62.2	38.7
2024	255.4	69.6	43.8
2025	278.2	74.7	47.7
2026	290.9	77.1	49.4
2027	308.9	81.0	52.3
2028	303.6	78.9	51.1

***Demand coincident with Company's seasonal peak demand.**

EXHIBIT A-4

Public Service Company of Oklahoma

Short-Term Load Forecast

Blended Forecast vs. Long-Term Model Results

Class	Retail Model
Residential	Long-Term
Commercial	Blend
Industrial	Long-Term
Other Retail	Long-Term

EXHIBIT A-5					
Blending Illustration					
	Short-term		**Long-term**		**Blended**
Month	**Forecast**	**Weight**	**Forecast**	**Weight**	**Forecast**
1	1,000	100%	1,150	0%	1,000
2	1,010	100%	1,160	0%	1,010
3	1,020	100%	1,170	0%	1,020
4	1,030	100%	1,180	0%	1,030
5	1,040	83%	1,190	17%	1,065
6	1,050	67%	1,200	33%	1,100
7	1,060	50%	1,210	50%	1,135
8	1,070	33%	1,220	67%	1,170
9	1,080	17%	1,230	83%	1,205
10	1,090	0%	1,240	100%	1,240
11	1,100	0%	1,250	100%	1,250
12	1,110	0%	1,260	100%	1,260

EXHIBIT A-6

Public Service Company of Oklahoma

Low, Base and High Case for

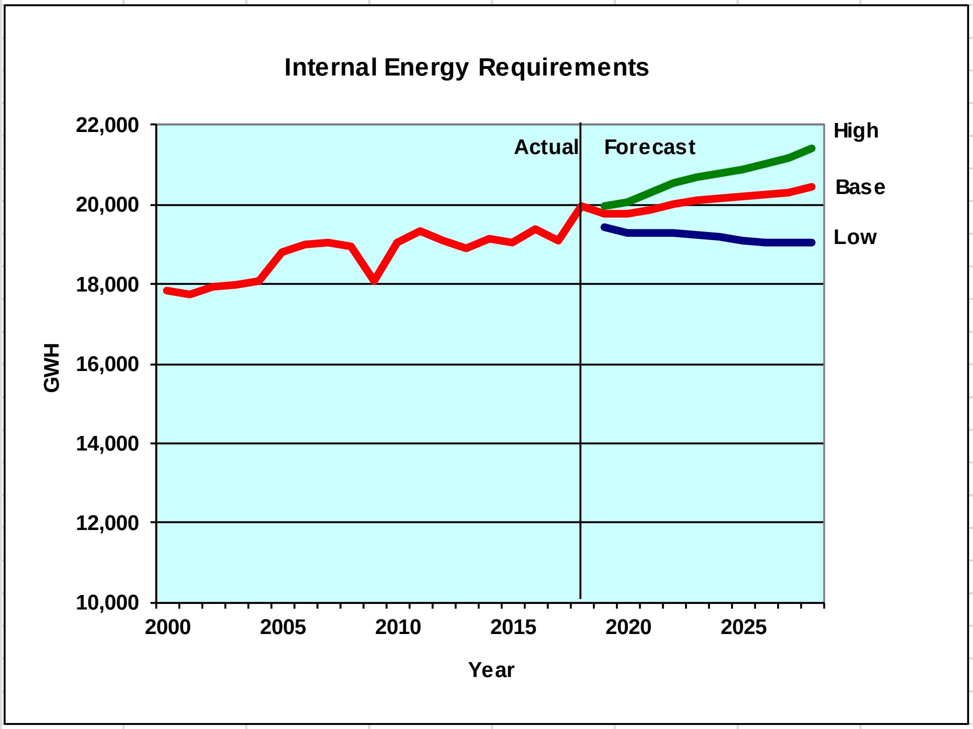
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2019	2,839	2,888	2,916	4,248	4,322	4,363	19,443	19,781	19,969
2020	2,826	2,898	2,941	4,192	4,298	4,363	19,272	19,759	20,058
2021	2,817	2,904	2,968	4,193	4,323	4,418	19,275	19,873	20,309
2022	2,812	2,919	2,993	4,184	4,345	4,455	19,272	20,011	20,518
2023	2,796	2,922	3,006	4,180	4,368	4,493	19,227	20,093	20,670
2024	2,786	2,928	3,021	4,168	4,380	4,518	19,167	20,144	20,780
2025	2,774	2,932	3,034	4,151	4,387	4,539	19,104	20,194	20,893
2026	2,767	2,940	3,053	4,144	4,403	4,572	19,066	20,257	21,036
2027	2,760	2,947	3,072	4,136	4,418	4,604	19,030	20,324	21,183
2028	2,760	2,961	3,103	4,150	4,452	4,665	19,056	20,441	21,420

EXHIBIT A-7

Public Service Company of Oklahoma

Range of Forecasts



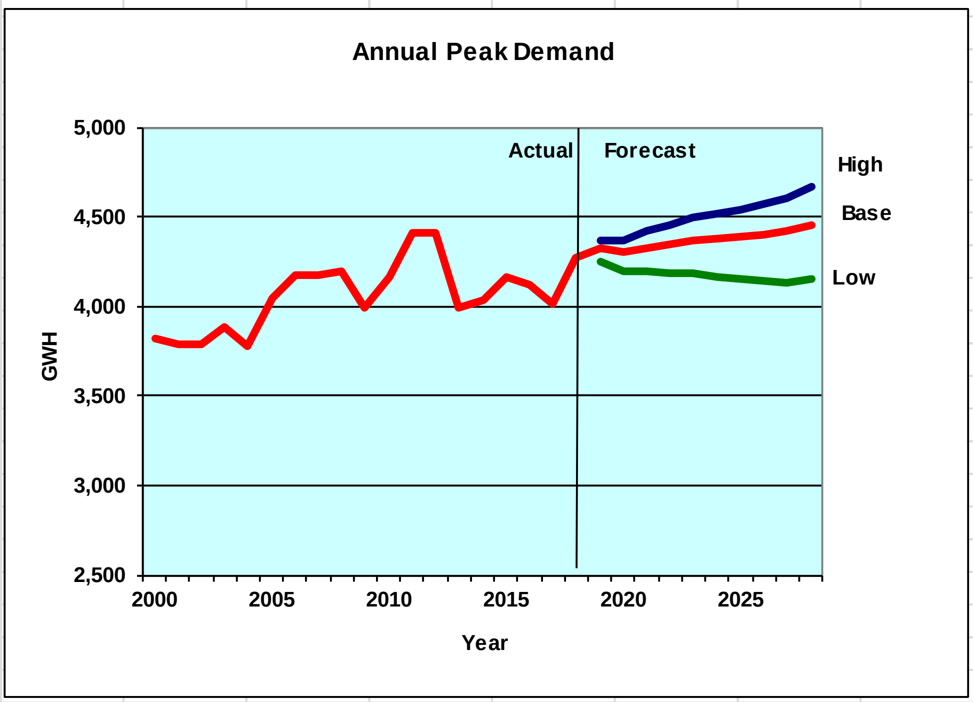


Exhibit A-8			
Public Service Company of Oklahoma			
DSM/EE - IRP Assumptions ("Degraded")			
Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2018	73,750	18.3	11.6
2019	118,668	29.4	18.9
2020	156,228	39.4	25.2
2021	188,609	49.0	31.2
2022	168,562	45.3	28.6
2023	131,927	35.4	22.4
2024	108,930	27.8	18.1
2025	99,985	25.8	16.3
2026	92,327	23.9	15.0
2027	85,214	22.1	13.8
2028	84,567	21.9	13.7

Exhibit B Non-Renewable New Generation Technologies

AEP System
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (d) Std. ISO	Capability (MW) (d) Summer	Capability (MW) (d) Winter	Installed Cost (c,e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load										
Nuclear	1,610	1,560	1,690	7,900	10,500	0.91	6.24	145.43	80	176.3
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,200	12,500	2.28	5.60	91.79	75	230.6
Combined Cycle (1X1 "J" Class)	540	700	720	1,000	6,300	2.94	1.97	10.81	75	62.3
Combined Cycle (2X1 "J" Class)	1,080	1,410	1,450	800	6,300	2.94	1.73	9.16	75	57.5
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	6,300	2.94	1.63	8.65	75	55.8
Peaking										
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	11,700	2.94	3.94	17.60	25	145.9
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	10,000	2.94	6.07	15.77	25	114.0
Aero-Derivative (2 - Small Machines) (g,h)	120	120	120	1,400	9,900	2.94	2.44	18.93	25	143.8
Recip Engine Farm	220	220	230	1,300	8,300	2.94	2.61	6.32	25	123.0
Battery	10	10	10	1,900	87% (i)	0.00	0.00	38.99	25	175.8

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2018 dollars, except as noted.
(c) $/kW costs are based on summer capability
(d) All Capabilities are at 1,000 feet above sea level
(e) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized cost of energy based on capacity factors shown in table
(g) Includes Dual Fuel capability and SCR environmental installation
(h) Includes Black Start capability
(i) Denotes efficiency, (w/ power electronics)

Exhibit C 2018 Fuel Supply Portfolio and Risk Management Plan

Public Service Company of Oklahoma

2018 Fuel Supply Portfolio and Risk Management Plan

May 15, 2018

Table of Contents

I. Introduction

Organized in Oklahoma in 1913, Public Service Company of Oklahoma ("PSO" or "the Company") is a vertically integrated utility engaged in the generation, transmission, and distribution of electric power to approximately 551,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electricity utility companies, municipalities, rural electric cooperatives and other market participants. As of December 31, 2017, PSO had 1,147 employees.

Under Order No. 454610, Cause No. PUD 200100096, PSO provides this Fuel Supply Portfolio and Risk Management Plan (Plan) on an annual basis. This document sets forth PSO's plan to provide reliable and flexible sources of fuel and energy for its customers at the lowest reasonable delivered cost.

As a vertically integrated public utility, PSO holds franchises and/or other rights to provide electric service in various municipalities and regions in its service territory. PSO owns 3,934 MW of generating capacity, which it uses to serve its retail and other customers. Exhibit 1 illustrates the approximate boundaries of PSO's service territory (in green) and the location of its generation resources. The red circles represent PSO's coal units and the purple circles indicate the location of natural gas generation units.

Exhibit 1: Map of PSO in Oklahoma

PSO is a member of the Southwest Power Pool ("SPP"), a Regional Transmission Organization ("RTO") that is mandated by the Federal Energy Regulatory Commission ("FERC") to provide reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity.

SPP's wholesale power market, known as the Integrated Marketplace ("IM"), consisting of Day-Ahead, Real-time, and Ancillary Service markets, began its fourth year of successful operation in 2017. PSO has continued to be an active participant in all of the various SPP IM markets, and continues to be an active stakeholder and advocate for its customers as it works with SPP to fine tune its market process. PSO actively manages changes in unit commitment, fuel procurement, unit dispatch, operating reserve procurement, transmission congestion management, and power settlement within the SPP IM.

In the SPP IM Day-Ahead market, market participants submit offers to sell energy and ancillary services, and load-serving entities submit day-ahead bids for load. PSO is required to offer sufficient available generating capacity into the market to cover its native load, but that capacity may or may not be selected for dispatch based on economics and reliability requirements. Available units that are not selected in Day-Ahead market may still be called on in the Real-Time market. Additionally, market resources may choose to self-commit to ensure participation in the market. Using security-constrained economic dispatch algorithms, SPP clears the bids and offers and produces a financially binding schedule that matches generation offers with demand bids, while satisfying operating reserve requirements. The differences between the established obligations from the Day-Ahead market are settled in the Real-Time market, which balances generation with load and establishes real-time locational marginal prices every five minutes. The operating reserve market provides for Regulation Reserve, Spinning Reserve, and Supplemental Reserves. As with the energy market, the operating reserve market is also a multi-settlement market clearing in the Day-Ahead with deviations being settled in the Real-Time market. The market also allows virtual bidding, which essentially trades Day-Ahead prices with Real-Time prices. While these trades occur in the physical market, they do not involve taking a physical position as each buy (or sell) in the Day-Ahead market will be a sell (or buy) in the Real-Time market. Such transactions have the effect of causing the Day-Ahead market and the Real-Time market prices to converge. PSO continuously works to ensure the most economic resources serve PSO's native load customers within the framework of the SPP IM.

A. Planning Objectives

PSO's Plan is designed to ensure sufficient quantities of fuel and power are available to safely and reliably meet customer needs under dynamic conditions, while striving to provide the over-all lowest reasonable delivered cost. In other words, PSO's fuel and purchased power procurement is first and foremost focused on the reliability of supply at the lowest reasonable delivered cost.

B. Resources & Capabilities

1. Generation

PSO's generating fleet is composed of both coal power plants and natural gas power plants, as summarized in Table 1.

Table 1: Plant Capacity

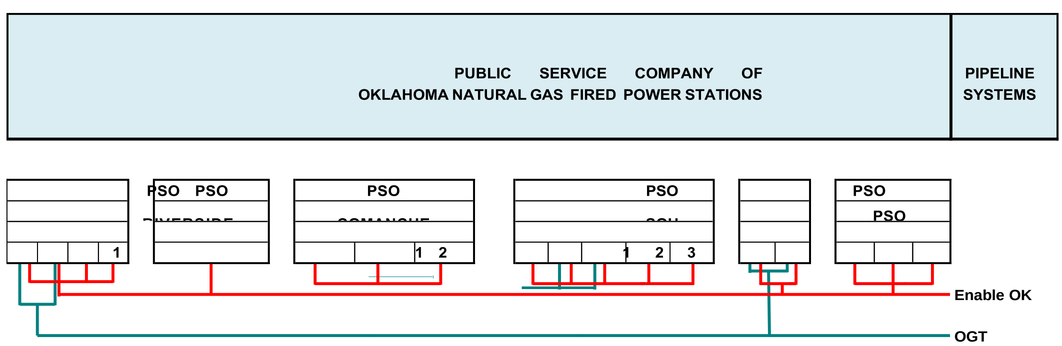
Plant Name	Fuel Type	Net Maximum Capacity (MW)
Comanche	Natural Gas	248
Riverside	Natural Gas	1,067
Southwestern	Natural Gas	635
Tulsa	Natural Gas	319
Weleetka	Natural Gas	185
Northeastern, Units 1 and 2	Natural Gas	906
Northeastern, Unit 3	Coal	469
Oklaunion*	Coal	105
Total		3,934

** Capacity at Oklaunion represents the PSO share.*

In addition, the steam generating units at Riverside can also use fuel oil to generate electricity. PSO maintains a limited quantity of fuel oil at the Riverside units as an emergency back-up fuel supply. The Riverside Plant is also connected to a pipeline capable of delivering fuel oil. PSO can also use natural gas to operate Northeastern Unit 3 at partial load in the event of coal curtailments or coal-related equipment outages.

Comanche, Northeastern Unit 1, Riverside Units 3 and 4, Southwestern Units 4 and 5, and Weleetka, are each connected to one pipeline system. Northeastern Units 2 and 3, Riverside Units 1 and 2, Southwestern Units 1, 2, and 3, and Tulsa Units 2 and 4 are each connected to two pipeline systems. These multiple natural gas pipeline connections provide the Company with access to reliable, flexible, and competitively priced natural gas supplies. The natural gas pipeline interconnections to each of PSO's natural gas plants are shown in Exhibit 2.

Exhibit 2: Existing Natural Gas Pipeline Interconnections to PSO



*Enable OK and OGT provide low pressure service to the Northeastern Plant Site which serves the generation needs for Unit 2, duct burner gas to Unit 1, and startup or emergency generation replacement fuel for Coal Unit 3.

Similarly, Northeastern Unit 3 has access to two competing rail carriers, Union Pacific ("UP") and Burlington Northern Santa Fe ("BNSF"), for coal deliveries from the Powder River Basin ("PRB") in Wyoming. Currently, UP provides coal deliveries to the Northeastern power plant with a shipping distance of approximately 1,000 miles. The BNSF railroad provides deliveries of coal to the Oklaunion power plant with a shipping distance of approximately 1,100 miles.

2. Purchased Power

PSO's purchased power activities extend beyond direct participation in the SPP IM. American Electric Power Service Corporation ("AEPSC"), on behalf of PSO, continues to directly engage with a variety of third-party market participants in the procurement of short and medium term capacity and energy contracts. AEPSC's Commercial Operations' employees leverage a broad cross-section of operations and market knowledge to optimize the PSO system.

Purchased Power Agreements ("PPAs") for capacity and firm energy that are entered into by PSO also utilize primarily Oklahoma resources. In 2018, PSO will purchase capacity and energy through long-term PPAs from the Green Country Generating Facility, located in Jenks, Oklahoma, the Oneta Energy Center in Coweta, Oklahoma, the Dogwood Energy Facility in Pleasantville, Missouri, and the Eastman Cogeneration Facility in Longview, Texas. The associated megawatts and start dates are listed in Table 2 below.

Table 2: PPA Contracts

PSO 2017 Purchased Power Contracts	Contract Maximum Quantity (MW)	Contract Start	Contract End
(1) EXELON GREEN COUNTRY I	519	June 2012	February 2022
(2) EXELON GREEN COUNTRY II	164	January 2016	December 2020
(3) ONETA	260	June 2016	May 2031
(4) WESTAR DOGWOOD	80	June 2016	May 2021
(5) TENASKA EASTMAN	40	June 2016	May 2019
Total	1,063		

3. Renewable Energy

PSO's wind contracts, like PSO's longer-term power purchases in general, were procured through competitive Request for Proposal ("RFP") solicitations. Wind energy provides

PSO's customers with a power supply that has very little correlation to fossil fuel prices and a hedge against many future environmental compliance requirements related to fossil-fired generation. In 2018, PSO estimates that approximately 22 percent of its energy to serve customers will come from Oklahoma wind generation resources.

C. Prior Period Results

PSO's generating plants, combined with purchased power and wind energy, offer a diverse fleet to PSO's customers. Table 3 below offers a comparison of the total generation resource mix in 2016 and 2017.

Table 3: Resource Percentage Comparison

Generation Resource (MWh Basis)	2016	2017	Delta
Natural Gas	21.0%	13.9%	-7.1%
Coal	15.4%	16.5%	1.1%
Purchased Power	41.2%	48.5%	7.3%
Wind Energy	22.4%	21.1%	-1.3%
Fuel Oil	<0.01%	<0.01%	<0.01%

In 2017, PSO's total average delivered cost of fossil fuel varied from a low of $1.45 per MMBtu in October to a high of $3.95 per MMBtu in May. The Company experienced an increase in the percentage of Purchased Power (7.3%) and Coal (1.1%), while Natural Gas (- 7.1%), and Wind Energy (-1.3%) saw decreases year over year. The percentage of Purchased Power utilization increased, in part, because of several purchased power contracts. PSO began receiving energy under these contracts in June of 2016. In 2017, PSO received energy under those contracts for a full 12 months versus only 6 months in 2016.

2017 Coal Procurement Summary

PSO purchases low sulfur PRB coal and has installed a Dry Sorbent Injection system to meet the emission rate of 0.40 lb. SO_2/MMBtu required for Northeastern Unit 3. Shipments of coal from the PRB to the Northeastern and Oklaunion plants during 2017 were made pursuant to transportation arrangements with UP and BNSF, respectively. Exhibit 3 summarizes the contracts used by PSO to purchase coal in 2017.

Exhibit 3: List of Coal Contracts in Effect in 2017

Northeastern Generation Station

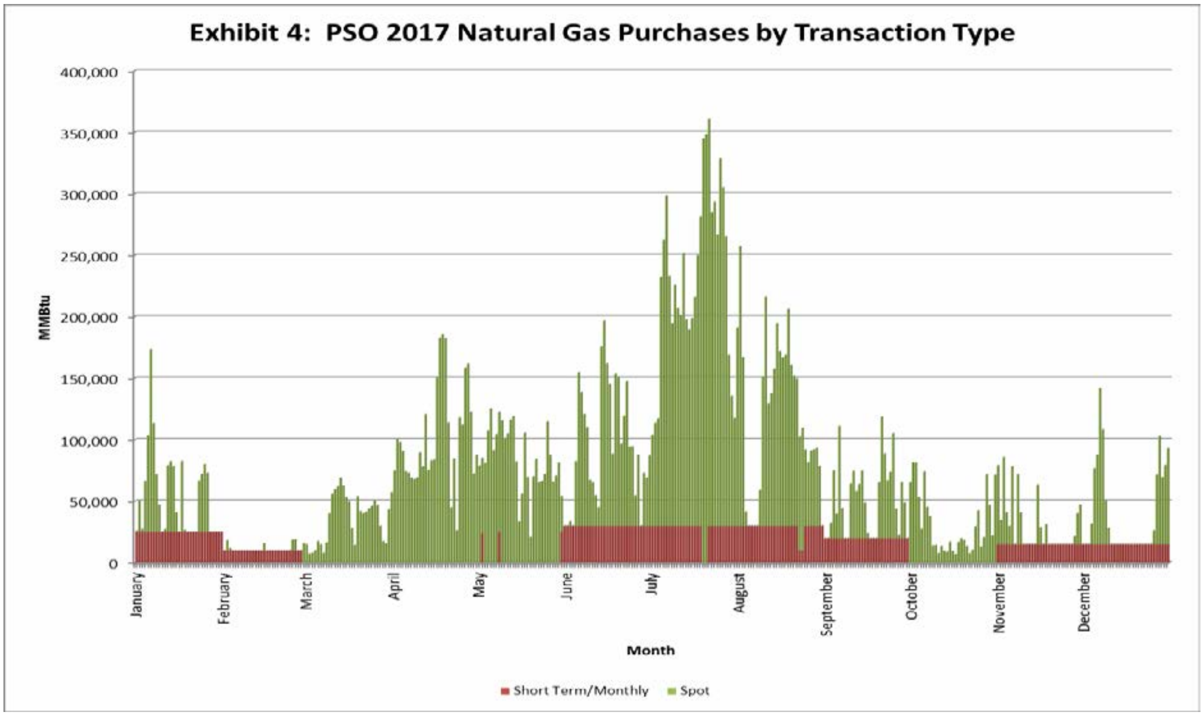
Vendor	Agreement Number	Tons Purchased
Peabody COALSALES, LLC	08-81-16-4M1	580,851
Peabody COALSALES, LLC	08-81-15-4M2	397,258
Peabody COALSALES, LLC	08-81-15-4M1	14,747
Arch Coal Sales Company, Inc.	08-81-16-4M2	30,672
Wisconsin Power and Light Company	08-81-17-001	15,328
Arch Coal Sales Company, Inc.	08-81-17-4M1	30,159
NRG Power Marketing LLC	08-81-17-002	16,569

Oklaunion Generation Station (Total Plant Basis)

Vendor	Agreement Number	Tons Purchased
Peabody COALSALES, LLC	08-11-15-4M2	494,657
Peabody COALSALES, LLC	08-81-16-4M1	224,809

2017 Natural Gas Procurement Summary

PSO's natural gas generating units were brought on-line and taken off-line on relatively short notice and the actual unit loading and resulting natural gas demand was highly variable. Exhibit 4 below illustrates the transaction types utilized for purchasing gas to meet the varying daily demands for natural gas generation. Due to the flexibility needed to operate in the dynamic SPP IM, PSO did not seek long term/annual purchase volumes.



To transport natural gas supplies to PSO gas plants as necessary, transportation contracts with Enable Oklahoma Intrastate Transmission, LLC (Enable OK) and ONEOK Gas Transportation, LLC (ONEOK or OGT) were used. PSO uses a mix of firm and interruptible agreements to provide reliable, flexible natural gas transportation at the lowest reasonable delivered cost. See Exhibit 2 for an illustration of the pipeline connections at each plant.

2017 Purchased Power Summary

On an energy basis, purchased power, including wind purchases, accounted for 69.6 percent in 2017, an increase of 6 percent from the prior year. A full year of delivery from purchased power contracts that took effect in June 2016 was the primary driver of the year-over-year increase. On average, year-over-year SPP IM prices were slightly higher in 2017 versus those experienced in 2016. The average SPP IM day-ahead market prices for SPP South Hub for 2016 and 2017, shown in Table 4 below, are based on the daily trading results as reported by Platts.

<u>Table 4: 2016 through 2017 Average SPP South Hub Prices</u>

Month	Average On-Peak ($/MWh)	Average Off-Peak ($/MWh)	Month	Average On-Peak ($/MWh)	Average Off-Peak ($/MWh)
Jan 16	$23.80	$20.91	Jan 17	$31.24	$26.31
Feb 16	$20.56	$16.99	Feb 17	$25.57	$20.25
Mar 16	$18.11	$13.30	Mar 17	$29.29	$21.13
Apr 16	$23.91	$16.55	Apr 17	$38.00	$26.48
May 16	$23.12	$16.39	May 17	$35.14	$25.32
Jun 16	$31.26	$21.16	Jun 17	$32.03	$21.39
Jul 16	$33.61	$24.55	Jul 17	$36.00	$25.29
Aug 16	$32.59	$22.19	Aug 17	$30.47	$22.32
Sep 16	$36.78	$23.17	Sep 17	$28.75	$21.23
Oct 16	$36.33	$24.13	Oct 17	$26.76	$16.96
Nov 16	$26.72	$20.90	Nov 17	$24.85	$17.96
Dec 16	$35.84	$28.94	Dec 17	$28.74	$22.26
2016 Average	$28.55	$20.77	2017 Average	$30.57	$22.24

II. 2018 Expectations

A. Forecast

PSO forecasts market conditions, weather patterns, unit outages, and purchased power opportunities in order to anticipate both short-term and long-term fuel supply needs. Table 5 below illustrates PSO's forecasted energy source mix for 2018, which will help drive purchases of fuel and other sources of power.

Table 5: Energy Source Percentages

Generation Resource (MWh Basis)	2018
Natural Gas	12%
Coal	10%
Wind	22%
Purchased Power	23%
SPP Market Purchases	33%

1. Demand Forecast

PSO's 2018 peak native load responsibility is forecasted to slightly increase to 4,284 MW, as compared with PSO's actual weather normalized peak of 4,200 MW realized in 2017.

2. Fuel

PSO's fuel planning is generally based on existing fuel and fuel-related contracts and anticipated market prices for any non-committed fuel. The fuel cost for each of PSO's generating plants is based on the cost of fuel sourced for each plant and the related transportation costs to deliver the fuel to the plant.

Coal

Northeastern Unit 3 and Oklaunion use sub-bituminous coal from the PRB of Wyoming that typically has a heat content of 8,200 to 8,900 Btu per pound. Projections of coal supply needs must consider railroad delivery constraints and cycle time performance. Currently, PSO has arrangements with UP and BNSF to deliver coal to Northeastern and Oklaunion, respectively. PSO expects its delivered costs in 2018 to remain stable and comparable to coal costs incurred in 2017.

Natural Gas

Natural gas consumption projections are based upon the trading prices of natural gas futures contracts from the New York Mercantile Exchange ("NYMEX") for delivery at the Henry Hub adjusted for estimated transportation costs and forward market basis differentials applicable to PSO's geographic region and delivery points. PSO analyzes the fundamental drivers of the fuel markets daily and considers industry standard forecasts published by analysts such as Platts Gas Daily and the United States Energy Information Administration ("EIA").

The price of natural gas is expected to remain flat in 2018 compared to 2017 with increased national consumption being balanced with a rise in production. Weather, generating unit availability, economic power purchase opportunities, and the SPP IM will all impact natural gas purchases for 2018.

Fuel Oil

Fuel oil is generally used at the Riverside Plant during natural gas supply disruptions and emergencies. While natural gas supply issues have arisen in the past due to extreme cold weather in Oklahoma, those conditions are rare and difficult to anticipate. Fuel oil is also used at Oklaunion for start-up and flame stabilization. According to the EIA's Short- Term Energy Fuels Outlook released in March 2018, the average price for diesel fuel (fuel oil) in 2018 is expected to rise at just under 15% compared to 2017. As a very small part of the PSO generation portfolio, fuel oil costs will not have a significant impact on PSO's overall cost of fuel in 2018.

3. Purchased Power

Conventional Purchased Power

SPP IM market prices increased slightly from 2016 to 2017 in both the on-peak and off-peak hours. The slight increases in market prices did not significantly impact PSO's market optimization activities. SPP IM market prices are expected to remain relatively unchanged in 2018. There are no new purchased power contracts scheduled to begin in 2018. Based on expected market prices and the unchanged portfolio of purchased power contracts, the amount of purchased power in 2018 is expected to be similar to that of 2017. However, unexpected changes in the SPP IM market prices can occur for a variety of reasons including transmission outages and extreme weather events. In optimizing its portfolio, PSO could increase or decrease the amount of purchased power as it responds to market fluctuations.

Wind Energy

PSO's commitment to a diversified generation portfolio, combined with its support of developing environmentally beneficial forms of energy production, is borne out by PSO's portfolio of wind energy contracts. PSO's first wind energy purchase began commercial operation in December 2005. Additionally, during 2013, PSO procured three new wind contracts totaling 599 MW and commencing delivery on January 1, 2016. Table 6 below shows PSO's wind resources that are in effect during 2018.

Table 6: Wind Contracts

PSO 2017 Wind Projects	Contract Maximum Quantity (MW)	Delivery Start Date (Month/Year)
(1) WEATHERFORD WIND ENERGY	147	April 2005
(2) SLEEPING BEAR WIND ENERGY	94.5	September 2007
(3) BLUE CANYON V WIND ENERGY	99	October 2009
(4) ELK CITY WIND ENERGY	98.9	January 2010
(5) MINCO WIND ENERGY	98.9	December 2010
(6) BALKO WIND ENERGY	199.8	January 2016
(7) GOODWELL WIND ENERGY	200	January 2016
(8) SEILING WIND ENREGY	198.9	January 2016
Total	**1,137.0**	

4. Procurement Strategy

Background and Future Strategy

PSO's overall procurement strategy is to assure reliable, adequate, flexible, and competitively-priced fuel supplies and transportation, as well as purchased power, at the lowest reasonable delivered cost to PSO's customers. To accomplish this objective, PSO maintains a portfolio of fuel and power supply contracts with varying contract terms.

Even within the context of the SPP IM, the flexibility in PSO's fuel supply plan and the diversity of its generating fleet continue to allow the Company to optimize its generation resources to take advantage of lower-priced spot market fuel and purchased power opportunities, while maintaining reliability of service to its customers. PSO's diversified generation and balanced fuel supply portfolio has been an important part of its risk management plan for many years. In PSO's recent history, fuel diversity has primarily been achieved through the traditional use of both coal and natural gas. However, with changes in environmental regulations, the SPP IM, and PSO generation fleet, PSO is addressing the positive attributes of fuel diversity in a more comprehensive way. Mitigating price risk now includes more renewables, more efficient generation, demand-side resources, and other programs. PSO continues to monitor its coal, natural gas, and purchased power pricing risk and takes steps to mitigate risk and ensure adequate resources.

The plan mitigates energy price risk in several ways. One such way is evidenced by three capacity and energy contracts which started delivery in 2016 and provide access to modern, highly-efficient combined-cycle natural gas-fired facilities secured through a competitive bidding process.

Coal Procurement Plan

PSO has an established coal and transportation procurement process that uses competitive bidding and market offers. The majority of the coal used as boiler fuel on PSO's system has been obtained at fixed prices through supply and transportation contracts having a term of one year or greater, with the remaining portion of PSO's coal requirements purchased in the spot market. As it has done in the past, PSO will continue to evaluate its contracts and negotiate reasonable terms.

PSO maintains a coal inventory to be both proactive and responsive to known, anticipated, and potential changes in operating, coal supply, and rail transportation conditions. With an eye toward effectively balancing reliability and cost, coal inventory targets are reviewed at least annually and are adjusted, as appropriate, to reflect changing conditions. In addition, PSO's coal inventory mitigates risk and allows the Company to take advantage of favorable market conditions. PSO's coal inventories also serve as a physical hedge against price volatility for that volume of coal already secured, on hand, and available for consumption.

Northeastern Unit 3 has continued with a strong operation under the SPP IM. It is important to continue to maintain the ability to adapt as necessary to changing market conditions, particularly with respect to balancing the need for flexibility with dynamic pricing changes. Oklaunion fuel requirements continue to be strongly dependent on levels of wind generation and natural gas pricing as a determinant for coal consumption at the plant. As a result, PSO will continue to rely on more spot and short-term purchases in order to in order to maintain flexibility and adapt to changes in market prices.

The UP delivers coal to Northeastern under a long term rail transportation agreement that began in January of 2013. Coal is received for Oklaunion under a rail transportation agreement with BNSF that is set to expire at the end 2018.

Natural Gas Procurement Plan

PSO procures all of its natural gas supplies competitively. To optimize its natural gas supply, PSO routinely evaluates its natural gas supply requirements. PSO expects to continue to experience similar levels of gas consumption seen since the SPP IM began. PSO's variability in natural gas consumption will likely limit the need for any long term supply agreements. In addition to daily purchases, monthly and seasonal baseload agreements are under consideration for 2018. PSO is active in the daily natural gas markets and stays abreast of current market changes, including any new potential natural gas suppliers that can be solicited.

For 2018, the decision to obtain seasonal or monthly supply will depend on the forecasted consumption, which can be affected by weather, wind generation, and unit operation. PSO's plan is to review the gas needs monthly and competitively bid any necessary seasonal or monthly firm gas supply to meet forecasted minimum monthly natural gas supply requirements and supplement the supply as needed with daily gas purchases.

PSO uses competitive bidding and competitive market offers for natural gas transportation services. PSO negotiates transportation arrangements with connecting pipelines for swing service beyond its daily nominations to meet its peak instantaneous, hourly and daily demands.

For 2018, PSO has a firm transportation agreement with Enable OK that can serve all of PSO's natural gas units. This agreement was competitively bid following the Oklahoma Corporation Commission rules and will expire at the end of 2020. PSO has interruptible transportation agreements with both Enable OK and OGT. Additionally, PSO is exploring the possibility of procuring seasonal firm transportation with OGT this summer for the Tulsa and Southwestern plants.

PSO's storage analysis has indicated that due to the difficulty in anticipating peak hourly and daily supply needs, it would be difficult for PSO to nominate natural gas storage withdrawals in advance. Storage injections and withdrawals typically must be accomplished at a steady flow rate that is not responsive to the peaking demands of natural gas electric generators. Also, the normal injection and withdrawal seasons for storage (injection – summer, withdrawal – winter) are opposite from PSO's needs. PSO would need to inject gas in the winter months when gas prices are typically higher and withdraw gas in the summer to meet the summer peak demands.

PSO's existing natural gas transportation contracts with Enable OK include services that provide similar reliability that storage services would offer. The most recent estimates indicate that firm natural gas storage arrangements (including transportation) would add approximately $2.87 per MMBtu of incremental cost above the related natural gas commodity costs. PSO's 2017 storage study as well as previous years' analysis for storage options demonstrate that the added cost along with the restrictive nature of injections and withdrawals make storage a less beneficial option for PSO.

Fuel Oil Plan

Though fuel oil is not used as a primary fuel supply for PSO's power plants, PSO will continue to purchase its fuel oil requirements by competitive bid. In late 2017, PSO issued a fuel oil RFP for Oklaunion for 2018 and 2019. Six responses to the RFP were received and evaluated resulting in a two-year contract being awarded to the bidder that provided the lowest reasonable delivered cost. PSO maintains a fuel oil inventory at the Riverside Plant for reliability purposes. The Riverside Plant is also connected to a pipeline capable of delivering fuel oil to the plant and will continue to maintain this service.

Purchased Power Plan

The purchased power plan for 2018 will have a diverse mix of transactions with a wide range of counterparties. For example, the Exelon PPAs, Oneta PPA, Tenaska PPA, and PSO's wind PPAs demonstrate PSO's utilization of cost-effective, long-term purchased power opportunities. PSO will continue to be actively engaged in all areas of the SPP IM and pursue activities to optimize its participation in those markets. The holistic and active management of the whole range of purchased power opportunities will provide the operational flexibility to effectively respond to a wide range of possible market scenarios.

Consumables (Reagents) Plan

PSO utilizes consumables, also known as environmental reagents, at Northeastern Unit 3 and at Oklaunion. Reagents are products that are introduced into the flue gas stream to reduce emissions from the process to levels that allow PSO to adhere to environmental regulations.

Northeastern Unit 3 uses two consumable products. Brominated activated carbon ("AC") is utilized for the capture of mercury. Sodium Bicarbonate ("SBC") is employed for SO_2 and hydrogen chloride mitigation.

Oklaunion uses AC and additionally uses Calcium Bromide ("CaBr2") for its mercury capture. CaBr2 enhances the mercury capture process at Oklaunion to maintain compliance. Limestone is used at Oklaunion for SO_2 mitigation.

In 2018, as with the procurement of fuels, PSO will purchase reagents through a competitive bid process to ensure that products with the required specifications are purchased at the lowest reasonable delivered cost.

5. Risk Management

a. Hedging

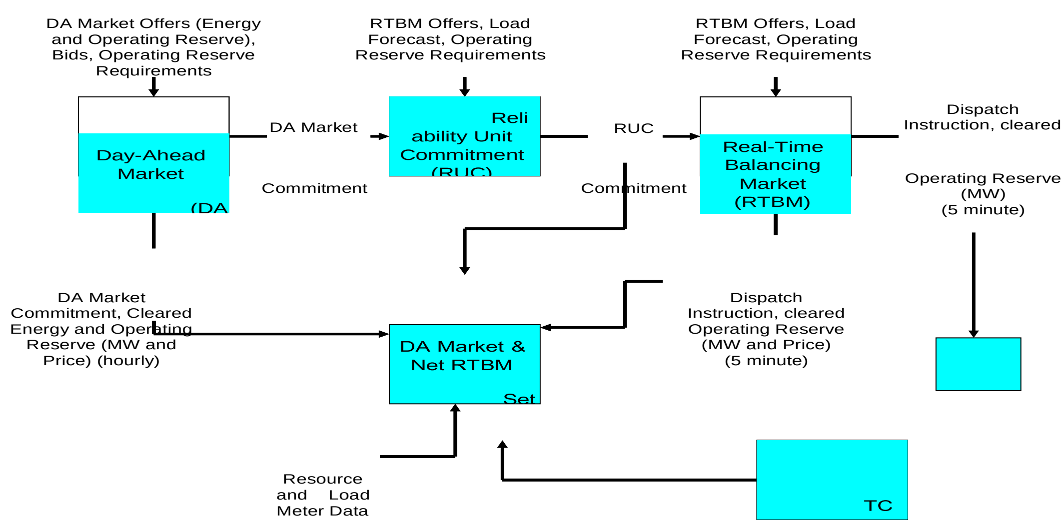
The primary objective of PSO's fuel hedging strategy is to reduce fuel and purchased power cost volatility experienced by customers. In many respects, a fuel hedging strategy is similar to insurance. A successful hedging program can effectively mitigate the risk of fuel cost volatility, but it also comes with a cost, and can limit potential fuel cost decreases if prices fall or remain unchanged. Financial hedging, through the use of forward market contracts is aimed at reducing volatility, but could potentially increase the overall fuel cost based on transaction costs and premiums required to lock in pricing. PSO continually evaluates its hedging strategy options to most appropriately balance conflicting objectives.

PSO's hedging strategy for 2018 incorporates operations in the SPP IM, as well as on- going changes to PSO's mix of resources, including PPAs. One way PSO is responding to these changes has been to increase the flexibility in its portfolio of purchased fuel. PSO is active in all phases of the Day-Ahead and Real-Time SPP markets to minimize the cost of purchased power. Going forward, as PSO's energy supply portfolio changes, efforts to mitigate price volatility may require a broader scope of hedging strategies to be considered.

b. Resource Optimization

AEPSC's purchased power and optimization activities have played a central role in how PSO manages fuel and energy price risks and minimizes costs for its customers. The SPP IM has expanded the range and impact of that role. The SPP IM requires a significant level of attention to detail and market intelligence to optimize PSO's resources and serve its load. Exhibit 5 illustrates the process design relationship between the market processes in which AEPSC participates on behalf of PSO.

Exhibit 5: Integrated Marketplace Process Design Relationships[1]



[1] "EMS" stands for Energy Management System

SPP's Day-Ahead Market is a financially binding market whose purpose is to match the set of market supply and market demand made available, which clears for the next Operating Day. The Reliability Unit Commitment ("RUC") is an operationally binding process whose purpose is to ensure there are adequate resources to satisfactorily cover the RTO load and reliability forecasts. There is a Day-Ahead RUC that exists for the same time period as the Day-Ahead Market as well as an Intra-Day RUC that exists for the balance of the day. The Real-Time Balancing

Market is a financially and operationally binding market with a purpose of ensuring that market resources committed through the Day-Ahead Market or lastly approved RUC process are dispatched according to Real-Time load forecast and clears for the next five-minute period. The Reserve Market, which is integrated within the Day- Ahead Market, RUC process and the Real-Time Balancing Market through co- optimization, ensures that adequate ancillary service products are procured so that the system can smoothly respond to contingencies. The Auction Revenue Rights ("ARR") Process/Transmission Congestion Rights ("TCR") Market, which is performed/clears annually and monthly, provides market participants with a mechanism to be pro-active and hedge against anticipated Day-Ahead market congestion, or increase financial benefits. Finally, the Settlement Process provides market participants with a measure of the financial benefits associated with their participation in the Day-Ahead and Real-Time Balancing Markets.

PSO continues to experience high congestion costs related to its portfolio of wind Renewable Energy Purchase Agreements ("REPAs"). Congestion occurs in situations where the desired amount of electricity is unable to flow due to either physical or regulated limitations. This impairs SPP's ability to use the least cost electricity to meet demand. The cost of congestion is included in the locational marginal prices, or LMPs, and can be seen in the price difference between source (generation point) and sink (load point). The continued rise in wind generation within the SPP footprint is one of the major drivers of increased congestion costs. PSO's portfolio of wind REPAs did not change from 2016 and 2017, but the increase in congestion from the addition of wind farms in SPP still impacted PSO's wind related congestion costs. In 2016, PSO's congestion costs related to its wind REPAs were approximately $15 million. In 2017, PSO's congestion costs related to its wind REPAs were approximately $25 million—an increase of $10 million dollars. Without significant changes, congestion costs will likely continue to be an impediment to delivering the most economic power available to customers throughout the SPP footprint as additional wind projects continue to be incorporated into SPP.

PSO is and will continue to actively optimize its SPP IM participation by maintaining the efficiency and availability of its generators, securing low cost fuel, performing proper scheduling of down times, and responding to price signals established by the market. Optimization of path selections for allocation in the TCR Market is an added responsibility and complexity compared to pre-SPP IM operations. Commitment of generating units through the SPP IM will likely continue to create additional uncertainties from a resource and fuel procurement standpoint, which creates more risks in arranging bilateral sales. The ability of the Commercial Operations personnel to get the most value for PSO's generating resources also enables them to maximize the off-system sales margins for the benefit of PSO's customers.

An additional issue that will increasingly impact resource optimization is the lack of harmonization between the natural gas and electric industries. Due to coal generation retirements in response to environmental regulations and the shale gas developments, U.S. reliance on gas-fired electric generation has grown over the last several years. This increased reliance on natural gas amplifies the need for continued improvements in coordination between the electric and natural gas industries. Although some coordination issues have been addressed by the FERC, challenges remain including market scheduling and fuel security. For example, once a unit has been committed to the SPP IM market, SPP has the ability to extend unit awards with only minutes of notice impacting the amount of fuel required. The timing of the notice (duration or time of day) may not allow the unit operator to purchase and schedule additional needed fuel supply possibly forcing the unit offline. AEP continues to work with SPP on these market protocol issues.

c. Contract Provisions

As mentioned previously, PSO procures fuel with a variety of contract provisions that serve as a hedge against fuel price volatility. Fuel contracts can utilize either fixed or indexed prices. The contract lengths also vary and are staggered to increase flexibility.

6. Retail Customer Programs and Tariffs

a. Managing Energy Usage and Costs

PSO offers a wide variety of programs to assist customers in managing their total energy usage and cost. With the deployment of Advanced Metering Infrastructure ("AMI"), PSO now offers programs such as Time of Use Pricing and Direct Load Control under the name of Power Hours. A customer web portal, called my Energy Advisor, is also available to help customers better understand and track their energy use. PSO recently began offering a residential pre-pay program called Power Pay to provide payment convenience and daily notifications. Customers on Power Pay have greater control over the frequency and timing of their payments, which can lead to a better understanding of consumption, thus, resulting in energy savings for some customers. PSO continues to offer a range of Demand Side Management ("DSM") programs to all customer classes to encourage reduced energy consumption, either at times of peak consumption or throughout the day or year. Programs or tariffs that reduce consumption at the system peak are Demand Reduction (DR) programs, while around-the-clock measures are typically categorized as Energy Efficiency (EE) programs.

A complete listing of PSO's DSM programs can be found in Table 7 below.

Table 7: PSO Demand Side Management Programs

Residential	Commercial & Industrial
· Home Weatherization	· High Performance Business
· High Performance Homes	· Business Demand Response
· Energy Saving Products	· Conservation Voltage Reduction
· Education	· Behavioral Modification
· Conservation Voltage Reduction	
· Behavioral Modification	

b. Retail Energy Usage and Cost Projections

Table 8 below provides monthly bill projections for summer 2018 and winter 2018, as well as the previous year's information.

Table 8: Monthly Bill Projections

Winter Bill

Customer Class and Usage**	Bill* 2017	Price–¢/kWh 2017	Projected Bill* 2018	Projected Price–¢/kWh 2018	Projected % Change Per kWh
Residential- 1070 kWh	$94.35	8.82	$101.48	9.48	7.55%
Small Commercial- 1760 kWh	$140.22	7.97	$161.01	9.15	14.83%

Summer Bill

Customer Class and Usage**	Bill* 2017	Price–¢/kWh 2017	Projected Bill* 2018	Projected Price–¢/kWh 2018	Projected % Change Per kWh
Residential- 1450 kWh	$140.95	9.72	$156.32	10.78	10.91%
Small Commercial- 2300 kWh	$207.60	9.03	$226.35	9.84	9.03%

*Actual and projected bill amounts include base service charges, seasonal energy charges, and the most recent fuel factors and all applicable riders. Actual and projected bill amounts do not include franchise fees or taxes.
**Class kWh levels are based on prior FSP Table levels.

7. Summary

PSO's risk management plan has a diversified resource portfolio, which includes coal generation, natural gas generation, fuel-oil generation, wholesale energy purchases, renewable energy, and EE/DR. Each of the commodities is procured under a competitive bidding or competitive market offer process. This includes energy purchases in lieu of PSO's generation when it can be arranged both economically and reliably. PSO's fuel supply plan allows PSO to appropriately respond to changes in the SPP IM and assists in ensuring a reliable fuel supply at the lowest reasonable delivered cost. Recognizing the dynamic market, PSO will continue to review and adapt its fuel procurement activities to ensure that the fuel procurement and risk management plan continues to meet the standards of providing the lowest reasonable delivered cost to PSO's customers.

Contact Information

For questions or additional information, please

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Exhibit D Optimization Model Cost Outputs

2018 PSO IRP Update
Integrated Resource Plan
Preferred Plan - 'Base' Band Commodity Pricing

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$532,195	$145,555	$2,731	$78,694	$21,855	$0	$19,090	$290,975	$509,145
2019	$605,783	$150,868	$2,456	$84,752	$19,722	$0	$6,998	$291,257	$579,321
2020	$688,106	$156,665	$2,417	$96,406	$18,207	$0	($7,077)	$300,771	$653,954
2021	$713,647	$139,484	$2,013	$102,513	$14,621	$3,473	($8,952)	$249,777	$717,021
2022	$752,135	$126,036	$2,038	$102,317	$23,603	$117,436	($11,807)	$339,530	$772,228
2023	$785,783	$116,825	$1,754	$109,030	$28,096	$173,584	($15,420)	$394,545	$805,109
2024	$829,380	$127,731	$1,832	$109,295	$32,287	$190,779	($20,627)	$445,295	$825,383
2025	$855,066	$133,191	$1,539	$108,627	$34,937	$200,475	($22,359)	$460,904	$850,572
2026	$885,407	$139,784	$1,430	$115,090	$39,528	$216,458	($16,128)	$497,308	$884,259
2027	$907,332	$181,605	$0	$110,470	$48,246	$274,106	($16,160)	$499,395	$1,006,202
2028	$1,159,208	$225,788	$32,059	$115,258	$58,953	$308,471	($58,319)	$707,937	$1,133,479
2029	$1,192,529	$229,866	$33,200	$118,580	$63,677	$324,155	($60,768)	$745,586	$1,155,655
2030	$1,259,346	$244,827	$35,396	$121,760	$73,005	$378,436	($81,096)	$857,909	$1,173,765
2031	$1,316,353	$345,282	$43,158	$119,751	$84,651	$433,601	($86,762)	$1,041,000	$1,215,033
2032	$1,358,868	$382,952	$44,433	$123,212	$91,109	$433,594	($88,015)	$1,097,605	$1,248,547
2033	$1,389,814	$392,240	$45,215	$132,429	$96,988	$477,396	($82,191)	$1,164,561	$1,287,330
2034	$1,445,894	$416,599	$49,301	$131,581	$107,911	$478,775	($85,905)	$1,219,549	$1,324,608
2035	$1,512,160	$512,142	$64,310	$129,478	$113,092	$528,462	($90,249)	$1,394,626	$1,374,768
2036	$1,557,609	$667,977	$90,287	$115,961	$150,495	$757,064	$0	$1,813,852	$1,525,541
2037	$1,605,936	$760,885	$106,159	$105,936	$171,283	$740,677	$0	$1,966,084	$1,524,792
2038	$1,684,883	$971,446	$142,306	$92,451	$185,122	$844,612	$0	$2,330,869	$1,589,950
2039	$1,702,693	$979,431	$144,885	$80,884	$196,926	$845,536	$0	$2,324,175	$1,626,180
2040	$1,765,245	$1,090,023	$165,645	$71,031	$210,803	$899,247	$0	$2,522,786	$1,679,208
2041	$1,830,291	$1,101,216	$170,793	$68,764	$214,108	$899,163	$0	$2,574,938	$1,709,396
2042	$1,856,498	$1,197,871	$192,026	$69,344	$227,037	$955,630	$0	$2,702,117	$1,796,289
2043	$1,927,158	$1,259,151	$205,200	$67,056	$233,570	$956,339	$0	$2,823,414	$1,825,059
2044	$1,986,766	$1,284,121	$215,569	$69,912	$238,634	$956,339	$0	$2,894,728	$1,856,614
2045	$2,034,872	$1,275,534	$217,567	$65,308	$241,314	$956,339	$0	$2,891,436	$1,899,498
2046	$2,102,186	$1,340,844	$235,060	$1,246	$248,289	$956,339	$0	$3,010,280	$1,873,684
2047	$2,168,162	$1,333,862	$238,156	$1,270	$251,998	$1,111,751	$0	$3,030,771	$2,074,427
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$12,788,807	$4,225,998	$495,322	$1,207,121	$872,797	$3,786,676	-$273,440	$10,767,820	$12,335,460
CPW of End Effects beyond 2045									$3,361,625
TOTAL Utility Cost, Net CPW (2018$)									$15,697,085

2018 PSO IRP Update
Integrated Resource Plan
'Base' Band Commodity Pricing

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
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2020	$688,106	$156,665	$2,417	$96,406	$18,207	$0	($7,077)	$300,771	$653,954
2021	$713,647	$139,484	$2,013	$102,513	$14,621	$3,473	($8,952)	$249,777	$717,021
2022	$752,135	$126,036	$2,038	$102,317	$23,603	$117,436	($11,807)	$339,530	$772,228
2023	$785,783	$116,825	$1,754	$109,030	$28,096	$173,584	($15,420)	$394,545	$805,109
2024	$829,380	$127,731	$1,832	$109,295	$32,287	$190,779	($20,627)	$445,295	$825,383
2025	$855,066	$133,191	$1,539	$108,627	$34,937	$200,475	($22,359)	$460,904	$850,572
2026	$885,407	$139,784	$1,430	$115,090	$39,528	$216,458	($16,128)	$497,308	$884,259
2027	$907,332	$181,605	$0	$110,470	$48,246	$274,106	($16,160)	$499,395	$1,006,202
2028	$1,159,208	$225,788	$32,059	$115,258	$58,953	$308,471	($58,319)	$707,937	$1,133,479
2029	$1,192,529	$229,866	$33,200	$118,580	$63,677	$324,155	($60,768)	$745,586	$1,155,655
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2031	$1,316,353	$345,282	$43,158	$119,751	$84,651	$433,601	($86,762)	$1,041,000	$1,215,033
2032	$1,358,868	$382,952	$44,433	$123,212	$91,109	$433,594	($88,015)	$1,097,605	$1,248,547
2033	$1,389,814	$392,240	$45,215	$132,429	$96,988	$477,396	($82,191)	$1,164,561	$1,287,330
2034	$1,445,894	$416,599	$49,301	$131,581	$107,911	$478,775	($85,905)	$1,219,549	$1,324,608
2035	$1,512,160	$512,142	$64,310	$129,478	$113,092	$528,462	($90,249)	$1,394,626	$1,374,768
2036	$1,557,609	$667,977	$90,287	$115,961	$150,495	$757,064	$0	$1,813,852	$1,525,541
2037	$1,605,936	$760,885	$106,159	$105,936	$171,283	$740,677	$0	$1,966,084	$1,524,792
2038	$1,684,883	$971,446	$142,306	$92,451	$185,122	$844,612	$0	$2,330,869	$1,589,950
2039	$1,702,693	$979,431	$144,885	$80,884	$196,926	$845,536	$0	$2,324,175	$1,626,180
2040	$1,765,245	$1,090,023	$165,645	$71,031	$210,803	$899,247	$0	$2,522,786	$1,679,208
2041	$1,830,291	$1,101,216	$170,793	$68,764	$214,108	$899,163	$0	$2,574,938	$1,709,396
2042	$1,856,498	$1,197,871	$192,026	$69,344	$227,037	$955,630	$0	$2,702,117	$1,796,289
2043	$1,927,158	$1,259,151	$205,200	$67,056	$233,570	$956,339	$0	$2,823,414	$1,825,059
2044	$1,986,766	$1,284,121	$215,569	$69,912	$238,634	$956,339	$0	$2,894,728	$1,856,614
2045	$2,034,872	$1,275,534	$217,567	$65,308	$241,314	$956,339	$0	$2,891,436	$1,899,498
2046	$2,102,186	$1,340,844	$235,060	$1,246	$248,289	$956,339	$0	$3,010,280	$1,873,684
2047	$2,168,162	$1,333,862	$238,156	$1,270	$251,998	$1,111,751	$0	$3,030,771	$2,074,427
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$12,788,807	$4,225,998	$495,322	$1,207,121	$872,797	$3,786,676	-$273,440	$10,767,820	$12,335,460
CPW of End Effects beyond 2045									$3,361,625
TOTAL Utility Cost, Net CPW (2018$)									$15,697,085

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Utility Costs (Nominal$)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$564,760	$138,446	$2,731	$78,694	$19,059	$0	$11,815	$277,061	$538,443
2019	$662,383	$151,109	$2,456	$84,752	$18,062	$0	($4,866)	$294,114	$619,781
2020	$763,442	$163,589	$2,417	$96,406	$17,406	$0	($23,134)	$317,655	$702,471
2021	$798,040	$151,819	$2,205	$102,513	$16,032	$3,473	($26,610)	$299,534	$747,939
2022	$840,062	$132,194	$2,311	$102,317	$31,953	$117,436	($30,291)	$396,510	$799,471
2023	$874,623	$127,012	$2,064	$109,030	$42,369	$173,584	($33,767)	$479,900	$815,015
2024	$914,757	$141,247	$2,099	$109,295	$43,650	$193,141	($37,925)	$531,781	$834,484
2025	$941,013	$138,937	$1,862	$108,627	$40,786	$205,764	($39,922)	$545,766	$851,300
2026	$972,043	$151,586	$1,777	$115,090	$44,552	$221,579	($31,333)	$602,326	$872,968
2027	$999,429	$201,964	$340	$110,470	$53,548	$278,295	($32,250)	$608,834	$1,002,961
2028	$1,266,159	$241,354	$41,414	$115,258	$62,149	$312,485	($76,601)	$835,861	$1,126,357
2029	$1,310,788	$249,267	$42,759	$118,580	$67,134	$329,271	($80,490)	$886,561	$1,150,748
2030	$1,391,907	$267,242	$46,351	$121,760	$74,468	$383,682	($99,397)	$1,005,261	$1,180,751
2031	$1,450,361	$307,195	$45,443	$119,751	$81,740	$396,309	($103,090)	$1,077,360	$1,220,349
2032	$1,503,400	$348,027	$48,027	$123,212	$88,092	$396,614	($104,531)	$1,144,731	$1,258,109
2033	$1,548,717	$359,507	$50,318	$132,429	$93,469	$434,805	($98,646)	$1,228,578	$1,292,020
2034	$1,573,588	$426,665	$58,161	$131,581	$101,744	$482,132	($100,089)	$1,318,968	$1,354,813
2035	$1,654,567	$458,713	$64,412	$129,478	$107,915	$482,123	($105,520)	$1,409,237	$1,382,450
2036	$1,686,928	$722,389	$102,626	$115,961	$150,614	$760,096	$0	$1,974,403	$1,564,210
2037	$1,722,371	$786,365	$113,863	$105,936	$164,536	$743,709	$0	$2,074,191	$1,562,588
2038	$1,769,417	$988,372	$144,203	$92,451	$181,377	$847,643	$0	$2,370,429	$1,653,033
2039	$1,815,648	$1,003,818	$147,511	$80,884	$193,533	$848,568	$0	$2,403,430	$1,686,531
2040	$1,862,860	$1,094,776	$167,251	$71,031	$206,008	$903,235	$0	$2,553,677	$1,751,484
2041	$1,904,959	$1,112,973	$174,142	$68,764	$209,640	$903,826	$0	$2,579,480	$1,794,825
2042	$1,969,916	$1,231,488	$197,266	$69,344	$223,175	$960,294	$0	$2,774,687	$1,876,797
2043	$2,030,254	$1,294,831	$207,726	$67,056	$229,432	$959,097	$0	$2,877,562	$1,910,833
2044	$2,102,730	$1,313,197	$214,500	$69,912	$234,010	$959,625	$0	$2,947,426	$1,946,547
2045	$2,152,673	$1,332,058	$225,967	$65,308	$238,388	$959,625	$0	$2,990,089	$1,983,930
2046	$2,240,098	$1,387,849	$241,643	$1,246	$245,210	$959,625	$0	$3,116,594	$1,959,076
2047	$2,302,277	$1,401,973	$249,965	$1,270	$249,753	$1,115,036	$0	$3,159,857	$2,160,416
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$13,924,738	$4,318,773	$527,202	$1,207,121	$888,856	$3,757,242	-$427,801	$11,547,352	$12,648,778
CPW of End Effects beyond 2045									$3,500,972
TOTAL Utility Cost, Net CPW (2018$)									$16,149,750

2018 PSO IRP Update
Integrated Resource Plan - Optimal Plan
Low Band Commodity Pricing

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$503,332	$163,442	$2,699	$78,694	$26,054	$0	$25,838	$317,876	$482,182
2019	$556,874	$166,438	$2,450	$84,752	$23,349	$0	$17,369	$306,636	$544,596
2020	$608,606	$168,765	$2,370	$96,406	$20,822	$0	$9,419	$299,556	$606,832
2021	$620,035	$146,211	$2,194	$102,513	$18,411	$3,473	$10,530	$266,746	$636,622
2022	$650,687	$120,144	$2,311	$102,317	$25,753	$115,536	$8,731	$323,154	$702,326
2023	$674,618	$116,562	$2,053	$109,030	$30,074	$167,492	$7,148	$365,866	$741,112
2024	$703,290	$117,741	$2,096	$109,295	$31,176	$168,657	$4,939	$379,455	$757,739
2025	$726,128	$123,414	$1,853	$108,627	$34,010	$180,020	$3,781	$395,946	$781,888
2026	$751,582	$129,830	$1,751	$115,090	$38,823	$196,003	$7,687	$429,669	$811,095
2027	$771,846	$164,522	$326	$110,470	$47,423	$253,651	$7,932	$431,134	$925,035
2028	$1,034,242	$212,212	$45,412	$115,258	$54,873	$271,450	($35,552)	$629,960	$1,067,935
2029	$1,064,410	$226,951	$48,751	$118,580	$61,309	$287,021	($38,414)	$675,205	$1,093,403
2030	$1,141,492	$243,271	$52,737	$121,760	$74,214	$358,351	($63,554)	$816,452	$1,111,820
2031	$1,193,543	$344,608	$63,625	$119,751	$89,570	$418,890	($71,416)	$1,006,705	$1,151,866
2032	$1,238,060	$369,144	$63,860	$123,212	$96,638	$429,838	($73,060)	$1,069,466	$1,178,226
2033	$1,280,951	$376,541	$65,632	$132,429	$101,156	$473,639	($69,583)	$1,144,508	$1,216,257
2034	$1,328,176	$387,019	$66,500	$131,581	$111,152	$476,240	($73,040)	$1,174,035	$1,253,593
2035	$1,400,129	$502,213	$89,747	$129,478	$118,933	$526,441	($77,556)	$1,395,684	$1,293,701
2036	$1,460,956	$670,625	$122,169	$115,961	$158,951	$756,443	$0	$1,852,550	$1,432,555
2037	$1,485,654	$728,458	$135,012	$105,936	$175,495	$739,205	$0	$1,938,997	$1,430,763
2038	$1,530,700	$902,293	$170,301	$92,451	$191,194	$842,228	$0	$2,230,339	$1,498,829
2039	$1,562,592	$899,684	$170,920	$80,884	$202,295	$843,134	$0	$2,229,016	$1,530,492
2040	$1,611,239	$1,010,364	$199,301	$71,031	$217,341	$896,844	$0	$2,426,456	$1,579,665
2041	$1,615,000	$991,883	$199,143	$68,764	$218,587	$896,760	$0	$2,360,192	$1,629,945
2042	$1,661,433	$1,092,823	$225,679	$69,344	$232,555	$953,228	$0	$2,528,938	$1,706,123
2043	$1,721,539	$1,137,042	$238,850	$67,056	$237,931	$950,929	$0	$2,620,123	$1,733,224
2044	$1,763,883	$1,114,285	$238,586	$69,912	$240,388	$950,929	$0	$2,607,017	$1,770,966
2045	$1,813,623	$1,147,270	$254,391	$65,308	$245,675	$950,929	$0	$2,676,799	$1,800,397
2046	$1,892,087	$1,207,487	$275,069	$1,246	$253,444	$950,929	$0	$2,815,002	$1,765,260
2047	$1,958,089	$1,229,813	$287,016	$1,270	$258,560	$1,106,341	$0	$2,883,308	$1,957,780
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$11,437,624	$4,027,397	$618,420	$1,207,121	$902,649	$3,678,735	-$96,933	$10,243,992	$11,531,021
CPW of End Effects beyond 2045									$3,172,598
TOTAL Utility Cost, Net CPW (2018$)									$14,703,619

2018 PSO IRP Update
Integrated Resource Plan - Optimal Plan
Status Quo Commodity Pricing

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$535,310	$158,397	$2,727	$78,694	$22,236	$0	$18,263	$304,014	$511,613
2019	$611,423	$165,067	$2,430	$84,752	$20,276	$0	$5,836	$309,561	$580,224
2020	$691,420	$181,493	$2,365	$96,406	$19,258	$0	($8,010)	$331,770	$651,161
2021	$714,597	$156,274	$2,194	$102,513	$16,917	$3,473	($9,254)	$298,732	$687,982
2022	$750,390	$128,326	$2,292	$102,317	$26,685	$115,536	($11,737)	$365,999	$747,811
2023	$779,221	$124,081	$2,070	$109,030	$30,886	$169,652	($14,398)	$417,990	$782,553
2024	$813,064	$124,564	$2,098	$109,295	$29,630	$169,772	($17,513)	$431,392	$799,518
2025	$841,807	$134,087	$1,857	$108,627	$32,417	$178,024	($19,687)	$455,184	$821,948
2026	$872,483	$142,891	$1,770	$115,090	$37,332	$194,007	($13,530)	$495,739	$854,303
2027	$894,059	$184,156	$326	$110,470	$45,467	$250,674	($13,773)	$494,020	$977,357
2028	$939,147	$123,206	$29,552	$115,258	$46,257	$267,180	($18,380)	$459,282	$1,042,938
2029	$978,307	$136,549	$31,611	$118,580	$51,185	$283,929	($22,664)	$504,722	$1,072,775
2030	$1,031,960	$138,751	$33,163	$121,760	$62,410	$357,624	($48,297)	$605,465	$1,091,907
2031	$1,083,148	$190,551	$38,559	$119,751	$74,795	$420,348	($57,899)	$722,118	$1,147,135
2032	$1,117,467	$185,519	$39,099	$123,212	$81,016	$432,558	($58,728)	$744,838	$1,175,305
2033	$1,151,474	$177,107	$38,207	$132,429	$85,675	$476,291	($55,779)	$785,910	$1,219,495
2034	$1,179,991	$161,916	$35,501	$131,581	$88,792	$478,875	($57,524)	$771,910	$1,247,221
2035	$1,234,831	$168,747	$39,127	$129,478	$97,167	$481,618	($60,762)	$813,656	$1,276,550
2036	$1,258,120	$222,978	$49,749	$115,961	$128,247	$759,176	$0	$1,041,866	$1,492,366
2037	$1,283,358	$213,372	$49,787	$105,936	$142,291	$741,938	$0	$1,041,987	$1,494,695
2038	$1,302,863	$230,744	$53,460	$92,451	$148,713	$844,961	$0	$1,073,544	$1,599,648
2039	$1,342,046	$233,869	$53,510	$80,884	$160,465	$844,972	$0	$1,092,076	$1,623,670
2040	$1,379,335	$238,703	$58,011	$71,031	$169,792	$898,599	$0	$1,124,967	$1,690,503
2041	$1,416,362	$223,408	$56,689	$68,764	$172,220	$898,599	$0	$1,117,339	$1,718,702
2042	$1,450,578	$221,550	$58,643	$69,344	$181,056	$954,626	$0	$1,128,176	$1,807,621
2043	$1,492,419	$216,549	$59,231	$67,056	$184,401	$953,620	$0	$1,136,637	$1,836,639
2044	$1,540,180	$223,228	$60,662	$69,912	$188,089	$952,442	$0	$1,164,614	$1,869,898
2045	$1,594,622	$223,021	$66,146	$65,308	$191,289	$950,077	$0	$1,190,489	$1,899,974
2046	$1,653,966	$211,783	$66,608	$1,246	$194,766	$948,375	$0	$1,202,288	$1,874,456
2047	$1,703,979	$199,562	$66,344	$1,270	$198,194	$1,102,465	$0	$1,205,461	$2,066,352
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$11,232,271	$1,985,684	$240,164	$1,207,121	$750,834	$3,667,258	-$175,890	$6,924,557	$11,982,884
CPW of End Effects beyond 2045									$3,348,540
TOTAL Utility Cost, Net CPW (2018$)									$15,331,424

2018 PSO IRP Update
Integrated Resource Plan
Low Load

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$502,337	$145,555	$2,731	$78,694	$21,855	$0	$19,090	$290,975	$479,287
2019	$560,433	$150,868	$2,456	$84,752	$19,722	$0	$6,998	$291,257	$533,971
2020	$631,508	$156,665	$2,417	$96,406	$18,207	$0	($7,077)	$300,771	$597,355
2021	$651,085	$139,484	$2,013	$102,513	$14,621	$3,473	($8,952)	$249,777	$654,460
2022	$685,492	$126,036	$2,038	$102,317	$22,690	$117,436	($11,807)	$339,530	$704,672
2023	$716,476	$116,825	$1,754	$109,030	$27,116	$179,190	($15,420)	$399,894	$735,078
2024	$756,663	$127,731	$1,832	$109,295	$31,780	$198,747	($20,627)	$451,511	$753,910
2025	$777,729	$133,191	$1,539	$108,627	$34,887	$208,216	($22,359)	$469,156	$772,674
2026	$802,681	$139,784	$1,430	$115,090	$40,273	$225,702	($16,128)	$507,082	$801,750
2027	$820,078	$136,232	$0	$110,470	$44,436	$242,509	($16,160)	$445,537	$892,028
2028	$1,041,037	$165,894	$23,654	$115,258	$52,317	$264,967	($58,319)	$612,208	$992,599
2029	$1,065,194	$170,752	$24,780	$118,580	$57,649	$281,716	($60,768)	$652,308	$1,005,596
2030	$1,119,077	$182,741	$26,538	$121,760	$67,228	$336,110	($81,096)	$760,102	$1,012,256
2031	$1,160,212	$280,269	$33,729	$119,751	$77,945	$396,649	($86,762)	$946,622	$1,035,172
2032	$1,190,798	$314,776	$34,359	$123,212	$84,210	$396,642	($88,015)	$999,604	$1,056,378
2033	$1,210,241	$323,043	$34,839	$132,429	$89,495	$437,843	($82,191)	$1,063,291	$1,082,407
2034	$1,248,584	$342,631	$38,041	$131,581	$93,195	$437,834	($85,905)	$1,110,488	$1,095,473
2035	$1,294,065	$359,923	$40,575	$129,478	$107,308	$437,824	($90,249)	$1,163,540	$1,115,384
2036	$1,321,986	$513,859	$65,805	$115,961	$149,925	$666,426	$0	$1,581,408	$1,252,554
2037	$1,353,382	$682,192	$93,425	$105,936	$153,405	$700,450	$0	$1,848,194	$1,240,597
2038	$1,413,211	$806,120	$115,072	$92,451	$167,151	$752,888	$0	$2,080,963	$1,265,929
2039	$1,419,507	$811,641	$116,803	$80,884	$178,696	$753,812	$0	$2,074,517	$1,286,825
2040	$1,461,518	$918,501	$136,309	$71,031	$192,234	$808,480	$0	$2,267,021	$1,321,052
2041	$1,506,056	$924,438	$139,887	$68,764	$195,163	$809,071	$0	$2,310,732	$1,332,648
2042	$1,515,953	$1,019,306	$159,989	$69,344	$207,858	$865,538	$0	$2,439,182	$1,398,807
2043	$1,560,135	$1,071,328	$170,924	$67,056	$213,454	$864,341	$0	$2,544,735	$1,402,503
2044	$1,590,705	$1,092,159	$179,420	$69,912	$218,083	$864,869	$0	$2,608,831	$1,406,317
2045	$1,608,125	$1,082,312	$180,454	$65,308	$220,565	$864,869	$0	$2,605,617	$1,416,016
2046	$1,641,963	$1,137,414	$195,066	$1,246	$226,872	$864,869	$0	$2,710,276	$1,357,154
2047	$1,670,940	$1,132,206	$197,540	$1,270	$230,480	$1,020,281	$0	$2,732,413	$1,520,303
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$11,191,641	$3,629,528	$399,960	$1,207,121	$811,429	$3,471,414	-$273,440	$9,897,430	$10,540,224
CPW of End Effects beyond 2045									$2,463,664
TOTAL Utility Cost, Net CPW (2018$)									$13,003,888

2018 PSO IRP Update
Integrated Resource Plan
High Load

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$498,391	$145,555	$2,731	$78,694	$21,855	$0	$19,090	$290,975	$475,341
2019	$576,272	$150,868	$2,456	$84,752	$19,722	$0	$6,998	$291,257	$549,810
2020	$658,574	$156,665	$2,417	$96,406	$18,207	$0	($7,077)	$300,771	$624,422
2021	$687,584	$140,425	$2,013	$102,513	$19,105	$3,473	($8,952)	$250,718	$695,442
2022	$731,701	$127,901	$2,038	$102,317	$27,360	$117,436	($11,807)	$341,444	$755,502
2023	$772,901	$117,881	$1,754	$109,030	$31,892	$183,200	($15,420)	$393,794	$807,445
2024	$823,386	$129,578	$1,832	$109,295	$36,723	$193,924	($20,627)	$444,942	$829,170
2025	$854,563	$134,940	$1,539	$108,627	$39,862	$200,577	($22,359)	$462,470	$855,279
2026	$889,503	$141,784	$1,430	$115,090	$45,480	$218,748	($16,128)	$501,329	$894,577
2027	$916,932	$183,927	$0	$110,470	$54,515	$276,396	($16,160)	$503,875	$1,022,204
2028	$1,176,031	$228,048	$32,385	$115,258	$64,749	$304,999	($58,319)	$705,655	$1,157,496
2029	$1,214,967	$232,574	$33,597	$118,580	$71,574	$320,570	($60,768)	$745,192	$1,185,903
2030	$1,290,791	$247,548	$35,795	$121,760	$83,500	$374,964	($81,096)	$857,380	$1,215,883
2031	$1,353,504	$347,994	$43,561	$119,751	$95,260	$435,503	($86,762)	$1,048,847	$1,259,964
2032	$1,403,069	$385,690	$44,848	$123,212	$105,457	$435,496	($88,015)	$1,107,057	$1,302,699
2033	$1,444,135	$394,519	$45,566	$132,429	$109,131	$476,696	($82,191)	$1,170,307	$1,349,977
2034	$1,509,893	$493,799	$61,065	$131,581	$115,826	$525,412	($85,905)	$1,335,816	$1,415,856
2035	$1,589,998	$515,236	$64,804	$129,478	$134,081	$526,769	($90,249)	$1,398,344	$1,471,772
2036	$1,649,676	$747,693	$102,960	$115,961	$165,245	$804,741	$0	$1,933,305	$1,652,972
2037	$1,714,515	$842,745	$119,416	$105,936	$186,291	$788,355	$0	$2,087,742	$1,669,517
2038	$1,817,268	$1,057,669	$156,522	$92,451	$200,540	$891,378	$0	$2,460,228	$1,755,599
2039	$1,854,790	$1,065,877	$159,362	$80,884	$212,510	$892,321	$0	$2,452,035	$1,813,710
2040	$1,943,934	$1,179,135	$180,899	$71,031	$226,764	$946,969	$0	$2,654,659	$1,894,072
2041	$2,039,387	$1,191,128	$186,518	$68,764	$230,213	$947,866	$0	$2,709,013	$1,954,863
2042	$2,097,197	$1,377,927	$224,337	$69,344	$252,976	$1,060,361	$0	$2,966,862	$2,115,280
2043	$2,208,938	$1,448,356	$239,733	$67,056	$260,213	$1,061,070	$0	$3,101,954	$2,183,412
2044	$2,310,313	$1,572,180	$269,814	$69,912	$275,846	$1,119,501	$0	$3,320,943	$2,296,623
2045	$2,403,998	$1,565,367	$273,236	$65,308	$278,919	$1,119,501	$0	$3,317,348	$2,388,982
2046	$2,525,718	$1,645,989	$295,051	$1,246	$287,025	$1,119,501	$0	$3,457,398	$2,417,133
2047	$2,652,474	$1,737,174	$319,387	$1,270	$301,183	$1,337,158	$0	$3,621,590	$2,727,055
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$13,266,292	$4,604,705	$562,397	$1,207,121	$974,574	$3,998,414	-$273,440	$11,321,415	$13,018,648
CPW of End Effects beyond 2045									$4,419,215
TOTAL Utility Cost, Net CPW (2018$)									$17,437,863

Exhibit E Capacity, Demand and Reserves – "Going-In"

PUBLIC SERVICE OF OKLAHOMA
CAPABILITY, DEMAND AND RESERVES FORECAST
2019 - 2051
(MW)

CAPABILITY

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Plant Capabilities											
	11	OKLAUNION #1	102	102	0	0	0	0	0	0	0	0
	10	COMANCHE # 1	227	227	227	227	227	227	227	227	227	227
	9	NORTHEASTERN # 1 & 2	856	856	856	856	856	856	856	856	856	856
	8	NORTHEASTERN # 3	469	469	469	469	469	469	469	469	0	0
	6	RIVERSIDE # 1 & 2	901	901	901	901	901	901	901	901	901	901
	5	RIVERSIDE CTs	145	145	145	145	145	145	145	145	145	145
	4	SOUTHWESTERN # 1, 2, 3	451	451	451	451	390	390	311	311	311	311
	3	SOUTHWESTERN # 4 & 5 CTs	151	151	151	151	151	151	151	151	151	151
	2	TULSA # 2 & 4	325	325	325	325	325	325	325	325	325	325
	1	WELEETKA # 4, 5, 6	100	100	100	100	0	0	0	0	0	0
1		**TOTAL**	**3,727**	**3,727**	**3,625**	**3,625**	**3,464**	**3,464**	**3,385**	**3,385**	**2,916**	**2,916**
	Adjustments to Plant Capability											
		Ft Sill RICE					36.5	36.5	36.5	36.5	36.5	36.5
		Ft Sill Solar			4	4	4	4	4	4	4	4
2		**TOTAL**	**0**	**0**	**4**	**4**	**40**	**40**	**40**	**40**	**40**	**40**
3	**Net Plant Capability (1 + 2)**		**3,727**	**3,727**	**3,629**	**3,629**	**3,504**	**3,504**	**3,425**	**3,425**	**2,956**	**2,956**
	Off-System Sales Without Reserves											
4		**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases Without Reserves											
		BALKO WIND	84.0	84	84	84	84	84	84	84	84	84
		GOODWELL WIND	78.0	78	78	78	78	78	78	78	78	78
		SEILING WIND	71.0	71	71	71	71	71	71	71	71	71
		MINCO WIND	17.0	17	17	17	17	17	17	17	17	17
		ELK CITY WIND	16.8	17	17	17	17	17	17	17	17	17
		BLUE CANYON II & V WIND	16.0	16	16	16	16	16	16	16	16	16
		SLEEPING BEAR WIND	11.0	11	11	11	11	11	11	11	11	11
		WEATHERFORD WIND	33.0	33	33	33	33	33	33	0	0	0
		EXELON GREEN COUNTRY	519	519	519							
		EXELON GREEN COUNTRY (2)	250	250								
		TENASKA										
		CALPINE	260	260	260	260	260	260	260	260	260	260
		WESTAR	80	80								
5		**TOTAL**	**1,436**	**1,436**	**1,106**	**587**	**587**	**587**	**587**	**554**	**554**	**554**
6	**Total Capability (3 - 4 + 5)**		**5,163**	**5,163**	**4,734**	**4,215**	**4,091**	**4,091**	**4,012**	**3,979**	**3,510**	**3,510**

DEMAND

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A	**Peak Demand Before Passive DSM**										
	Original Forecast	4,320	4,296	4,321	4,354	4,393	4,420	4,434	4,454	4,474	4,507
	Coffeyville, City of	2.12	2.11	2.12	2.14	2.15	2.16	2.16	2.16	2.17	2.18
		4,352	**4,337**	**4,372**	**4,402**	**4,430**	**4,450**	**4,462**	**4,480**	**4,499**	**4,531**
B	**Passive DSM**										
	APPROVED DSM PROGRAMS	20	24	27	23	13	6	4	2	0	0
	VOLT-VAR OPTIMIZATION (VVO)	9	16	22	22	22	22	22	22	22	22
	AMI (METERING (DLC/TOU)	2	2	2	2	2	2	2	2	3	3
	TOTAL	**31**	**41**	**51**	**47**	**37**	**30**	**28**	**26**	**25**	**25**
C	**Peak Demand (A - B)**	**4,320**	**4,296**	**4,321**	**4,355**	**4,393**	**4,420**	**4,434**	**4,454**	**4,474**	**4,506**
D	**Active DSM**										
	APPROVED DR PROGRAMS	56	56	56	56	56	56	56	56	56	56
	SPECIAL CONTRACT (ABOVE FIRM)	17	17	17	17	17	17	17	17	17	17
	TOTAL	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**
E	**Firm Demand (C - D)**	**4,248**	**4,224**	**4,248**	**4,282**	**4,320**	**4,347**	**4,362**	**4,381**	**4,401**	**4,433**
F	**Other Demand Adjustments**										
	DIVERSITY	23	22	23	24	23	23	23	24	23	25
	TOTAL	**23**	**22**	**23**	**24**	**23**	**23**	**23**	**24**	**23**	**25**
7	**Native Load Responsibility (E - F)**	**4,225**	**4,201**	**4,225**	**4,258**	**4,298**	**4,325**	**4,339**	**4,358**	**4,378**	**4,408**
	Off System Sales With Reserves										
8	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases With Reserves										
	PSO - SWPA ENTITLEMENT	39	39	39	39	39	39	39	39	39	39
9	**TOTAL**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**
10	**Load Responsibility (7 + 8 - 9)**	**4,186**	**4,162**	**4,186**	**4,219**	**4,259**	**4,286**	**4,300**	**4,319**	**4,339**	**4,369**

RESERVES

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
11	**Reserve Capacity (6 - 10)**	**977**	**1,001**	**548**	**-4**	**-168**	**-195**	**-288**	**-340**	**-829**	**-859**
12	**% Reserve Margin ((11/10) *100)**	**23.3**	**24.0**	**13.1**	**-0.1**	**-3.9**	**-4.5**	**-6.7**	**-7.9**	**-19.1**	**-19.7**
13	**% Capacity Margin (11/(6) *100)**	**18.9**	**19.4**	**11.6**	**-0.1**	**-4.1**	**-4.8**	**-7.2**	**-8.5**	**-23.6**	**-24.5**
14	**Reserve Above 12% Reserve Margin (MW)**	**475**	**501**	**46**	**(510)**	**(679)**	**(709)**	**(804)**	**(858)**	**(1350)**	**(1383)**

Exhibit F Capacity, Demand and Reserves – "Preferred Plan"

PUBLIC SERVICE OF OKLAHOMA
CAPABILITY, DEMAND AND RESERVES FORECAST
2019 - 2051
(MW)

CAPABILITY

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Plant Capabilities										
	11 OKLAUNION #1	102	102	0	0	0	0	0	0	0	0
	10 COMANCHE # 1	227	227	227	227	227	227	227	227	227	227
	9 NORTHEASTERN # 1 & 2	856	856	856	856	856	856	856	856	856	856
	8 NORTHEASTERN # 3	469	469	469	469	469	469	469	469	0	0
	6 RIVERSIDE # 1 & 2	901	901	901	901	901	901	901	901	901	901
	5 RIVERSIDE CTs	145	145	145	145	145	145	145	145	145	145
	4 SOUTHWESTERN # 1, 2, 3	451	451	451	451	390	390	311	311	311	311
	3 SOUTHWESTERN # 4 & 5 CTs	151	151	151	151	151	151	151	151	151	151
	2 TULSA # 2 & 4	325	325	325	325	325	325	325	325	325	325
	1 WELEETKA # 4, 5, 6	100	100	100	100	0	0	0	0	0	0
1	TOTAL	**3,727**	**3,727**	**3,625**	**3,625**	**3,464**	**3,464**	**3,385**	**3,385**	**2,916**	**2,916**
	Adjustments to Plant Capability										
	Ft Sill RICE					36.5	36.5	36.5	36.5	36.5	36.5
	Ft Sill Solar			4	4	4	4	4	4	4	4
	New CC				373	373	373	373	373	746	746
	CVR				12	25	38	38	38	44	52
	EE				13	26	33	29	24	19	15
	Distributed Generation	0	0	0	1	1	1	1	1	1	1
	IRP Wind				30	50	50	200	300	300	300
	IRP Solar						15	30	45	95	159
	Short-Term Capacity Purchase				100	250	200	150	100	150	150
2	TOTAL	**0**	**0**	**4**	**533**	**765**	**749**	**860**	**921**	**1,395**	**1,463**
3	**Net Plant Capability (1 + 2)**	**3,727**	**3,727**	**3,629**	**4,158**	**4,229**	**4,213**	**4,245**	**4,306**	**4,311**	**4,379**
	Off-System Sales Without Reserves										
4	TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases Without Reserves										
	BALKO WIND	84.0	84	84	84	84	84	84	84	84	84
	GOODWELL WIND	78.0	78	78	78	78	78	78	78	78	78
	SEILING WIND	71.0	71	71	71	71	71	71	71	71	71
	MINCO WIND	17.0	17	17	17	17	17	17	17	17	17
	ELK CITY WIND	16.8	17	17	17	17	17	17	17	17	17
	BLUE CANYON II & V WIND	16.0	16	16	16	16	16	16	16	16	16
	SLEEPING BEAR WIND	11.0	11	11	11	11	11	11	11	11	11
	WEATHERFORD WIND	33.0	33	33	33	33	33	33	0	0	0
	EXELON GREEN COUNTRY	519	519	519							
	EXELON GREEN COUNTRY (2)	250	250								
	TENASKA										
	CALPINE	260	260	260	260	260	260	260	260	260	260
	WESTAR	80	80								
5	TOTAL	**1,436**	**1,436**	**1,106**	**587**	**587**	**587**	**587**	**554**	**554**	**554**
6	**Total Capability (3 - 4 + 5)**	**5,163**	**5,163**	**4,735**	**4,744**	**4,815**	**4,800**	**4,832**	**4,859**	**4,864**	**4,933**

DEMAND

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A	**Peak Demand Before Passive DSM**										
	Original Forecast	4,320	4,296	4,321	4,354	4,393	4,420	4,434	4,454	4,474	4,507
	Coffeyville, City of	2.12	2.11	2.12	2.14	2.15	2.16	2.16	2.16	2.17	2.18
		4,352	**4,337**	**4,372**	**4,402**	**4,430**	**4,450**	**4,462**	**4,480**	**4,499**	**4,531**
B	**Passive DSM**										
	APPROVED DSM PROGRAMS	20	24	27	23	13	6	4	2	0	0
	VOLT-VAR OPTIMIZATION (VVO)	9	16	22	22	22	22	22	22	22	22
	AMI (METERING (DLC/TOU)	2	2	2	2	2	2	2	2	3	3
	TOTAL	**31**	**41**	**51**	**47**	**37**	**30**	**28**	**26**	**25**	**25**
C	**Peak Demand (A - B)**	**4,320**	**4,296**	**4,321**	**4,355**	**4,393**	**4,420**	**4,434**	**4,454**	**4,474**	**4,506**
D	**Active DSM**										
	APPROVED DR PROGRAMS	56	56	56	56	56	56	56	56	56	56
	SPECIAL CONTRACT (ABOVE FIRM)	17	17	17	17	17	17	17	17	17	17
	TOTAL	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**	**73**
E	**Firm Demand (C - D)**	**4,248**	**4,224**	**4,248**	**4,282**	**4,320**	**4,347**	**4,362**	**4,381**	**4,401**	**4,433**
F	**Other Demand Adjustments**										
	DIVERSITY	23	22	23	24	23	23	23	24	23	25
	TOTAL	**23**	**22**	**23**	**24**	**23**	**23**	**23**	**24**	**23**	**25**
7	**Native Load Responsibility (E - F)**	**4,225**	**4,201**	**4,225**	**4,258**	**4,298**	**4,325**	**4,339**	**4,358**	**4,378**	**4,408**
	Off System Sales With Reserves										
8	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases With Reserves										
	PSO - SWPA ENTITLEMENT	39	39	39	39	39	39	39	39	39	39
9	**TOTAL**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**
10	**Load Responsibility (7 + 8 - 9)**	**4,186**	**4,162**	**4,186**	**4,219**	**4,259**	**4,286**	**4,300**	**4,319**	**4,339**	**4,369**

RESERVES

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
11	**Reserve Capacity (6 - 10)**	**977**	**1,001**	**549**	**525**	**557**	**515**	**532**	**541**	**526**	**564**
12	**% Reserve Margin ((11/10) * *100*)**	**23.4**	**24.0**	**13.1**	**12.5**	**13.1**	**12.0**	**12.4**	**12.5**	**12.1**	**12.9**
13	**% Capacity Margin (11/(6) * *100*)**	**18.9**	**19.4**	**11.6**	**11.1**	**11.6**	**10.7**	**11.0**	**11.1**	**10.8**	**11.4**
14	**Reserve Above 12% Reserve Margin (MW)**	**475**	**501**	**46**	**19**	**46**	**0**	**16**	**22**	**5**	**40**

Exhibit G Attorney General Comments on 2018 DRAFT IRP

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

2018 INTEGRATED RESOURCE PLAN	)
OF PUBLIC SERVICE COMPANY OF	)
OKLAHOMA	)

COMMENTS OF THE ATTORNEY GENERAL

Mike Hunter, the Attorney General of Oklahoma, hereby submits his comments regarding the 2018 integrated resource plan ("IRP") draft submitted by Public Service Company of Oklahoma ("PSO") pursuant to OAC 165:35-37-5. The Attorney General appreciates the opportunity to provide comments on PSO's proposed IRP. On behalf of PSO's customers, the Attorney General now presents observations on three aspects of the draft IRP.

I. Cost and Resource Assumptions

The draft IRP evaluates numerous options for meeting PSO's capacity and energy needs over the next ten years.[1] The draft IRP evaluates a variety of generation resources within those options, including wind, solar, and several types of natural gas generation.[2] PSO's preferred plan—which provides the basis for PSO's future action steps—relies on a combination of wind, solar, and natural gas resource additions even after being tailored to the actual load growth eventually experienced by PSO.[3]

A. Solar Resources

While the Attorney General does not take a position on the specific resource additions contemplated by PSO, the assumptions around the cost and productivity of each resource are important aspects of determining which resources are cost-effective and thus valuable for the preferred plan. PSO included information describing how it determined the costs and productivity

[1] *See* Draft of the Integrated Resource Planning Report to the Oklahoma Corporation Commission 75–77, Public Service Company of Oklahoma (2018) [hereinafter "Draft IRP"].
[2] *Id.*
[3] *Id.* at 103–04.

of some resources, including wind and natural gas combined cycle plants.[4] However, the draft IRP currently does not describe PSO's assumptions around solar resources, such as the capacity factor or location of the solar resources. These assumptions are important for evaluating the reasonableness of PSO's plan to add solar resources—for example, solar resources located in the western part of Oklahoma may have a higher capacity factor, which must be offset by the higher transmission costs for delivery. On the other hand, solar resources located near PSO's largest load area in Tulsa should reflect capacity factors available in that area.

The Attorney General supports adding information about PSO's assumptions for solar resources to complement the helpful information included for other resources such as wind and natural gas generation resources.

B. Natural Gas Forecast

PSO's draft IRP relies on a forecast of natural gas prices, among other forecasts, to help generate PSO's preferred plan.[5] For the forecast, PSO relied on the Fundamentals Forecast developed by an affiliate subsidiary of American Electric Power Co., Inc. ("AEP").[6] AEP's 2016 Fundamentals Forecast played a central role in the recent case, Cause No. PUD 201700267, regarding PSO's proposed Wind Catcher Energy Connection Project.[7] The Attorney General and others presented substantial evidence in that case that AEP's Fundamentals Forecast from 2016 overstated the future price of natural gas significantly, overstating the benefits of the proposed

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[4] *E.g.*, Draft IRP 90–93 (discussing congestion, capacity factor, and capacity cost assumptions for wind).
[5] *Id.* at 59–61.
[6] *Id.* at 59–61.
[7] *See* Report and Recommendation of the Administrative Law Judge 14–16, *Pub. Serv. Co. of Okla. Wind Catcher Energy Connection Project*, No. PUD 201700267 (Okla. Corp. Comm'n Feb. 12, 2018) ("Forecasted natural gas prices are a primary driver of the projected energy savings benefits of the Project because natural gas prices directly impact SPP market-energy prices.").

project.[8] The new 2018 Fundamentals Forecast relied upon by PSO has reduced forecasts for future natural gas prices, which is movement in a more realistic direction. However, the Attorney General at this time does not have certainty that the new Fundamentals Forecast is a reliable barometer for future prices. The Attorney General will therefore continue to carefully monitor PSO's use of the AEP Fundamentals Forecast moving forward.

II. Alternative Plans

The draft IRP also describes PSO's process for developing the preferred plan, which represents the basis for PSO's future action steps.[9] The process relies on the Plexos model, specialized software that generates the optimum set of generation resources given various inputs and parameters.[10] The Plexos model inputs include PSO's generation resource assumptions, its load growth forecast, and its natural gas and electricity assumptions.[11] The model also has parameters surrounding reserve margins and operational concerns.[12] The output of the Plexos model is a resource plan that has been optimized to minimize the net present value of customer costs, or "cumulative present worth" under PSO's terminology.[13] The preferred plan thus results in the lowest-cost plan to meet customer needs, subject to PSO's assumptions.

PSO then further expanded its analysis by altering the inputs of the Plexos model based on the four different scenarios used in the AEP Fundamentals Forecast as well as different forecasts of growth in electricity demand by PSO customers.[14] The conclusion of this analysis presented by PSO is that the core of the plan, to add a combination of solar, wind, and natural gas combined

[8] *See id.* at 14–16 (collecting evidence from witnesses for Attorney General, Public Utility Division, and Oklahoma Industrial Energy Consumers).
[9] Draft IRP 96–105.
[10] *Id.* at 96–100.
[11] *Id.* at 96.
[12] *Id.* at 97.
[13] *See id.* at 96.
[14] *Id.* at 100–02.

cycle plants, remained relatively stable across each set of changed parameters.[15] The notable difference appeared to be a possible need to add natural gas turbine plants if PSO's customer load growth exceeds current estimates.[16]

The draft IRP presented by PSO omits information on the risks presented by the plan compared to alternatives. For example, the draft IRP does not include net present value figures for plans that would rely on more renewables or no renewables compared to the preferred plan. The draft IRP also does not present variations in timing of adding various generation resources. This lack of information stems from the Plexos software used by PSO, which generates a specific optimized plan based on the input assumptions. However, it is valuable and helpful for stakeholders to evaluate the software's analysis by understanding the net present value of costs for a variety of plans, as well as the variation of those costs across fuel price scenarios. For that reason, the Attorney General believes information about alternative plans should be included in the final IRP presented by PSO to the Commission.

III. Conclusion

The Attorney General appreciates the opportunity to comment on the draft IRP provided by PSO. The Attorney General believes greater disclosure of assumptions used to model solar resources as well as analysis of alternative plans would allow the Attorney General and other stakeholders to better evaluate the information presented in the IRP. The Attorney General also appreciates developments to update the Fundamentals Forecast to include more realistic assumptions about natural gas production technology and to disclose the effects of potential carbon dioxide regulation on prices. The Attorney General nevertheless intends to continue to monitor natural gas price forecasts and their impact on customer costs.

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[15] *See* Draft IRP 102.
[16] *See id.* at 103 (showing addition of peaking units in high load scenario).

Respectfully submitted,

MIKE HUNTER
ATTORNEY GENERAL OF OKLAHOMA

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Exhibit H Transcript from IRP Technical Meeting

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PSO'S INTEGRATED RESOURCE PLAN

PRESENTED TO THE

OKLAHOMA CORPORATION COMMISSION

NOVEMBER 27, 2018

****

OFFICIAL REPORTER:

AMY L. CUMMINGS, CSR

P R O C E E D I N G S

MR. VELEZ: Good morning. Mike Velez, Public Utility Division. Today we are here on a technical conference, PSO technical conference, and that was pursuant to Order No. 683727 issued in Cause No. 201893. The order required PSO to submit a draft IRP on or before October 22nd, conduct a technical conference sometime the during week of November 26th, and submit and IRP to the Commission for review on or before December 21st.

Today the -- we are -- PSO has submitted its IRP, and we are set for a technical conference, and we have a public meeting scheduled for December 20th. And with that, I will give it over to PSO.

MR. BECKER: Good afternoon, everyone. Thank you for attending our technical conference to review elements of our draft, 2018 PSO IRP. This afternoon we'd like to try to keep this as informal as possible. So ask your questions as they come to you. We'll probably have sufficient time at the end of the conference to have Q&A as well.

My name is Mark Becker, I'm a manager in the resource planning department, and I thought before we get started, we'd kind of go around the table here and do introductions.

MS. TRECAZZI: Good afternoon. My name's Connie Trecazzi, and I work in the fundamental analysis group, forecasting.

COMMISSIONER ANTHONY: Connie, could you spell your last name for the reporter?

MS. TRECAZZI: T-R-E-C-A-Z-Z-I.

MR. DRUGAN: Good afternoon everyone. My name is Dylan Drugan -- try that again -- good afternoon everyone. My name is Dylan Drugan, and I'm in the resource planning group, work on putting this report together and the modeling.

MR. FISHER: Hello, I'm Scott Fisher with American Electric Power Service Corporation, and I'm a manager in our resource planning group.

MR. BURNETT: Hello, my name's Chad Burnett, and I'm the director of economic forecasting for AEP Service Corp.

MR. BROWN: And my name's Jeff Brown with consumer programs and efficiency manager at Public Service Company of Oklahoma.

MR. BECKER: We seem to be having a little technical difficulty here with the overhead. There are some draft presentations behind Scott here, if you'd like a paper copy of it, because we'll work off of those until we get the slides working.

Today we'd like to talk a little bit about certain elements of the draft IRP report that was issued on October the 22nd. To start with, we'd like to talk about the results of the draft preliminary preferred plan.

The very first slide shows PSO's capacity and energy mix through time in 2018 until 2028 under the implementation of the draft preferred plan. And this draft preferred plan will have PSO transforming its capacity in energy mix through a higher reliance on more efficient combined cycle generation, diversification of its renewable portfolio through the addition of solar resources, utility solar resources, while increasing its wind generation.

And as that happens, we'll also be diversifying PSO's overall capacity in energy mix more towards renewable resources as well as implementation in the continued growth of energy efficiency programs and conservation voltage reduction programs.

On this slide there's one thing of note, if you look at the energy pie chart for 2028, you'll see that the wind energy is roughly 46 percent of the capacity mix. As we work our way through the final preferred plan, we'll set that at our target rate a little bit closer to 40 percent.

So today we'd like to overview the IRP process and some of the inputs, the major inputs, that go into that process; how we arrived at the optimal plans for the various scenarios that we looked at and developed a draft preferred plan and then what are our next steps.

CHAIRMAN MURPHY: Before -- and maybe you can let me know when it's the appropriate time, but one thing I'm gonna be interested in, wherever you want to weave it in there, is looking back at your past IRPs when -- you had the 2015, September 2015, and I think it was updated last year.

So just to help kind of put things in perspective of -- just in a high summary of kind of where you've been and where things are whenever it's appropriate. I'm not saying you should start out that way, but it helps me if I kind of know where we -- where you've been, what you've proposed before, how that's changed, and then the process of what you're doing.

So whenever it's appropriate to respond to that, but I've got -- I always like to look at the past IRPs, and it kind of gets those in my mind and then understand what it is you're proposing that's different, or what changes have resulted in law or whatever. You know, like the Wind Catcher and other things, how that's impacted to give me some perspective on where you're headed.

MR. BECKER: Of course. We'll go --

THE COURT: Whenever it's appropriate.

MR. BECKER: Okay. All right.

On slide three -- so we're gonna overview the IRP process, some of the major inputs, how we arrived at our draft preferred plan, and what are our steps going forward.

The IRP process is very similar to what we've used in the past several years and several iterations for PSO as well as across our eight regulated jurisdictions that require us to file IRPs. Essentially it develops the scenarios that we want to look at, get input information for our models, and then allow the models to work and create optimal plans for various scenarios that we've developed, and then take those optimal plans and boil them down into one preferred plan and then create an implementation plan for going forward.

So, to start the discussion about the inputs, we'd like to talk a little bit about the load forecast, and Chad Burnett will walk us through that.

MR. BURNETT: Thanks, Mark.

So here on slide 6, this chart is showing you an update to how this latest load forecast compares to the load forecast that was used in the 2017 update to the 2015 IRP. So you can see in the longer term, it's just slightly higher and that's largely due to some new industrial expansions that we have learned about since last year.

The chart also is showing both the historical and weather normalized historical data and then I've put -- the table in the lower left, you can kind of see how this forecast total is the average historical growth rate as well as the forecasted growth rates, how they compare along with some of the major economic drivers that would also be pretty fundamental here.

So you can see the energy sales are projected to grow at about a half a percent per year. The peak demand would be growing at about seven-tenths percent per year, and our customer count growth would be about four-tenths percent per year. And when you look at how that compares with some of the major economic drivers, that's pretty consistent with what you'd expect with our non-farm employment and population growth both growing at about four-tenths percent per year as well.

Moving on to the next slide, slide 7, this kind of gives you a little bit more flavor for why or what's changing within our growth. And I thought this chart was pretty interesting because you can clearly see there is a change in the mix of sales growth within PSO's footprint. You can see that the projection is that by 2022, our industrial sales will be the largest sector of sales and that is a pretty dramatic change from where we were back in 2010, even.

And then you see in the lower right-hand, we've also added that chart that shows the growth by class. And, again, what we're seeing for the most part, is not a lot of growth in residential and commercial despite the stronger customer growth, so we're seeing it trend a decline in usage per customer, but that is being somewhat offset by the growth that is happening in our industrial sector. And again, a lot of the is coming from some of the economic development activities we've been active in.

Moving on to slide eight, this is a -- kind of a snapshot of what is happening within our industrial sales and where that growth is actually coming from. And it's not surprising that a lot of that growth that we're seeing in the industrial sector is actually coming from the oil and gas extraction, and the oil and gas activity in the state. So the chart at the top kind of shows our top private industrial sectors for PSO industrial sales, and you can certainly see that oil and gas has been moving upwards, especially in the last two -- three or four years and recently has overtaken as now the largest sector for PSO industrial sales.

The other chart in the lower left, I thought was interesting, is looking at how the growth in our oil and gas sector sales compares to the rest of the industrial sales. And you can see there, certainly within the last year, since the third quarter of 2017, we are seeing a pretty substantial increase in our sales to the oil and gas sectors, and that is certainly dominating the growth that we would be seeing in the other sectors.

CHAIRMAN MURPHY: So that we don't have to come back, could you just tell me really quickly, like what service territory is this oil and gas extraction where the growth is coming from? And then, I guess I'm also interested in the paper. Does that include that new plant that's gonna come in from, I think it was Italy, like the Italian paper makers, Sofela or something like that?

MR. BURNETT: Sofidel. Yes, so, let's try to answer both of those. So these are all within the PSO service territory and a lot of these are in the Woodford shale play. And then in terms of the paper, that one was not online yet, so it would not show up in this. This chart is just showing historical, where the growth has been. But, certainly, that will be one going forward that would raise our paper outlook as well.

CHAIRMAN MURPHY: Well, when I think about oil and gas, I think about the Stack play and the SCOOP play, and I guess I wasn't sure if PSO's service territory covers part of the SCOOP play, 'cause I wouldn't think it would be in the Stack. The SCOOP would be like Garvin, Stephens, Grady, that particular area.

MR. FISHER: I'm not sure -- you know, like what we can probably do for the next one is look at a map and kind of show you where a lot of those industrial oil and gas stuff is happening within PSO's footprint.

CHAIRMAN MURPHY: All right. Thank you.

MR. FISHER: Let me make a note of that. While we're doing that, on the next slide, slide nine, you'll notice this is our historical weather normalized as well as projections for residential use per customer.

And, so, we've shown this chart in previous IRP conferences before, we just kind of rolled it forward so you can kind of see, but clearly there has been a change in the pattern of usage per customer. So, you know, in the green, for the year 1998 to 2008, we actually were seeing an increasing period of use per customer. Use per customer was growing during this period. And then from about 2000 -- the mid-2000's and in this instance, 2008 to 2018, you can see that growth and use per customer started to decline. And again, that's really when we had several federal policies on energy standards as well as the company's promotion of energy efficient power programs, really kind of kicked into gear and you can see the effect that that has had on use per customer going forward.

And then even in the next ten-year period, you can see we're projecting that use per customer will continue to decline at a rate of three-tenth's percent per year. Again, that's just higher saturation of more efficient appliances and technologies being deployed in our residential customers.

The last slide I wanted to talk about on the load section, is just kind of tee up some of the different load forecast scenarios that we do. So here, what you're seeing, the black dots, that represents kind of our base forecast, but we do a number of scenarios around that just to kind of give us a feel for what different technologies might happen.

And then what we would ultimately hand off to the rest of the resource planning group when they are doing their modeling is the high economic and low economic. And the reason we do that, those are those upper and lower boundaries. And, so, if you are running scenarios for your resource plan under the highest and lowest boundary, you would capture any of the other changes within those.

But some of the examples of different scenarios that we would look at are if you assumed more -- an extended efficiency policy that doesn't exist today, but if new policies came in that would raise efficiencies, you could see that would be kind of a orange line. If -- if we were to freeze, if you could do that, freeze the technologies and the efficiencies that exist today, and you don't assume that were any additional efficiency gain going forward, that would be kind of the blue line that's about 18 high efficiency.

And we've also done some extreme weather scenarios where you would assume a dramatic increase in temperatures and in warming pattern over our service territory, we've done electric vehicles, but really the things that we are having the biggest impact or whether it would be a high economic scenario or a low economic scenario. So, again, those are the ones that ultimately get modeled when we hand off to the resource planning.

And with that I'll hand it over to Jeff

Brown who will talk about the demand-side management programs.

MR. BROWN: Thank you, Scott. I'm gonna talk a little bit about the 2019 and 2021 energy efficiency and demand response programs that are being recommended for this time period.

So, PSO always has run energy efficiency programs since 2008. They've been very successful since about 2012 when they really hit stride, and I kind of point that out for the fact that energy efficiency in the work that we do with our trade allies being the HVAC contractors, the lighting contractors, engineering firms, architects, home builders, those different entities that we're working with that we call the trade allies, you know, that the scope of that group has risen significantly over time, and that's something that takes time to -- to gain, although they're buying in to support these kind of programs.

So, as you look back across the different IRPs back in the 2015 IRP, energy efficiency made up a significant portion. It did as well in the 2017 update of the IRP. And so these programs kind of build upon what we've seen in the 2017 IRP.

And so, as you look down the left-hand side of these -- of this slide, you see the different programs. So, what we do is present a variety of programs to meet all demographics as well as geographic areas of our service territory. So when you look at home weatherization, that is a limited income program. When you look at home rebates, those are activities that we have with many of the home builders as well as the HVAC contractors, and currently, we work with about 140 different entities there.

Energy saving products, that's where we're buying down products in retail outlets, and we have over a hundred retail stores that are involved across the service territory.

Our education program is where we're educating fifth graders about energy efficiency. We also have kits that they can take home that have energy saving products in them such as light bulbs and power strips that they can work with their families on to engage again in ways to save energy at home.

Our Power Hours program is a program that's enabled by the AMI network. It's fully deployed at PSO, and we have about 20 thousand customers currently, and going forward, we expect to add about another 9 thousand customers to the Power Hours program.

Multi-family's something new in the sense that this program is -- is something we've always had, a multi-family, but here we're actually calling it out to a specific program.

Conservation voltage reduction is a CVR program. At the end of this three-year period, we'll be up to about 86 circuits out of PSO's approximately seven hundred circuits throughout the system. So this is something that's, you know, reaching a barrier of customers that fail to participate or have a hard time participating.

And then we get in our commercial programs. Very similarly, we've got a small-business program that's part of our business rebate. We're piloting an oil and gas, specifically targeting that sector, as well as our traditional programs.

Peak performance is a demand response program that provides about 55 or so megawatts of peak demand reduction. Again, CVRs touching all customer classes as well as multi-family. The table there on the right just shows the savings that we expect over the next three years and then the couple of comments kind of talk about the total portfolio.

When you look at that, that's the -- the 337 gigawatt hours of savings over those three-year periods of approximately the equivalent of 25 thousand homes that we're basically taking them off the grid, so to speak, and the amount of energy savings which they're providing.

And then, finally, it touches on a CVR program, and CVR's actually called out separately here in the IRP, but these are the numbers that are actually in this demand portfolio.

MR. BECKER: So now that we've talked a little bit about the load, one of the very first things we do in the IRP process is try to identify the capacity position of the company before we add new resources. And what slide 13 does, is provides us a going-in capacity position. In other words, where does PSO stand as far as their existing and known capacity prior to any new additions, compared to their capacity requirements which is represented by the solid black line which is their peak load plus the mandatory 12 percent reserve margin.

And what you can see from this graph is, is that, PSO begins to experience a capacity need in 2021 roughly of about a hundred megawatts. And due to the expiration of a large purchase power agreement that's roughly 525 megawatts in 2022, that capacity need grows to about 700 megawatts. And it continues to grow through the time as other units are retired and, as Chad said, we're anticipating a little bit of load growth, so that grows to roughly 1550 megawatts by 2028, the end of the reporting period.

So, as you can see here, we've got some fairly near-term capacity requirements to fulfill, and those continue to grow as time goes on. And one the ways that we will try to fill those capacity gaps is through demand-side resources. So the next few slides we'll talk about those resources that we'll use to fill those gaps, the demand-side resources and supply-side resources.

MR. DRUGAN: Thank you, Mark.

So, from a demand-side resource perspective, I'm now on slide 15, this is just giving you an overview of what we modelled, potential that is out there on demand side, EE-type resources to select from. So you see this picture of the four concentric circles. There's your technical potential, which is what is technically available out there without any regard to costs. There's your economic potential which would be cost effective resources, but then in reality, in real life, we also have some barriers of customers, customer participation, so we break it down even further into high achievable potential and achievable potential. And those two circles are the potential that we've modeled.

Going on to slide 16, we have a pretty robust list of energy efficiency measures. So a measure would be something like an LED light bulb or a more efficient air conditioning unit. But, for purposes of modeling, we take cost effective measures, and we put them into what we call bundles. And slide 16 gives you an idea of what those bundles are.

Again, there's achievable potential bundle and a high achievable potential bundle. The difference between the two being, the achievable potential bundle is a incentive cost to the customer at 50 percent of the incremental cost; whereas, the high achievable is at 75 percent. So, the idea of being -- it'd be a little more costly to get more potential, but that's what we wanted to show there.

So each of these bundles have a load shape that go along with them. Obviously a cooling bundle, which would be HVAC air conditioning equipment, would have a different load shape than water heating, let's say. Again, we did that for residential and commercial.

Slide 17 is attempting to give kind of a visual representation of the cost of each of these bundles verses the amount of energy they can potentially save. So the horizontal X axis is showing, for each of those bars, how much energy could be saved, and the vertical Y axis shows cost. So, the taller the bar, the more expensive it is, the wider the bar, the more potential for energy savings.

And also see there above the $20 range, there's a red line going across, and that's trying to demonstrate that -- that red line represents SPP around-the-clock pricing over a 15-year time period, just kind of a rough -- rough estimate. And typically speaking, the bars that are below that line, more or less, will be selected in the model. The bars above it are too expensive and would not be selected.

Moving along to slide 18, this kind of gives you a look at the CVR --

COMMISSIONER ANTHONY: So of all those bars, which one's the most attractive or the most beneficial?

MR. DUGAN: Well, from -- from a cost perspective, it would be the one farthest to the left which is on the right-hand side, you see the legend there, the cheapest would be commercial industrial indoor screw-in lighting. But as you can see, the bar is kind of skinny, so it has a certain amount of potential savings that would go along with it --

COMMISSIONER ANTHONY: I just asked you to name one.

MR. DRUGAN: Sure. That would be the cheapest on --

COMMISSIONER ANTHONY: I would think it would be that one.

MR. DRUGAN: Yeah. From and energy -- that's what I was about to say. From energy perspective, that would offer you the most potentials so that would be --

COMMISSIONER ANTHONY: Is that called appliance AP?

MR. DRUGAN: That looks like it is a CNI indoor, for us, an HID lighting, AP. So I don't --

COMMISSIONER ANTHONY: What color's that?

MR. DRUGAN: That's that turquoise -- it's kind of hard to see it. In about the middle of the legend there, it's between the purple HVAC equipment and the orange HVAC equipment, if you see those two.

COMMISSIONER ANTHONY: Okay. Thank you.

MR. DRUGAN: You're welcome.

And moving on to slide 18, shows, we call them tranches, of CVR that are available to be selected. Each tranche you can see there has a certain number of circuits and a certain amount of -- certain capital investment dollar amount attached to it, with also a certain demand reduction and energy reduction as well.

So the model would have each of these tranches to choose from when it's making its decision making processes, resources to select.

And moving on to slide 19 there, is our -- this slide represents our distribute generation. Now, it's important to note that DG was forced into the model. The reason being, is distribute generation tends to be about 50 percent more expensive than utility scale, solar resources, which we'll talk about, some slides up ahead here. But, the chart below there kind of shows the existing levels of DG which is less than today -- less than a megawatt of capacity, and we force it in the model going forward at a ten percent annual growth rate.

So those were the demand side resources that we modeled, and now I'm gonna turn it over to Scott, and he's gonna talk to y'all about the supply-side resources that are modeled.

MR. FISHER: Okay. Let's -- I'm on slide 21, and the first supply-side resource we're gonna focus on is wind resources. And what we're showing here is the cost of the wind resource -- in the chart, we're showing the cost of the wind resource that we included in our model. And the green line represents levelized cost for that -- that resource being installed in that year shown.

So currently, PSO has over 1100 megawatts of wind. And for capacity planning purposes, that equates to about 120 megawatts of firm capacity. So what we made available in the model, is wind resources at 200 megawatt blocks up to 600 megawatts per year. And in the draft report, we included up to 1200 megawatts to be selected over the planning period. And as Mark noted on that second slide, we ended up with more wind energy than what we want to target. We really want to target 40 percent, and so, what we will see in the final report is that wind limit being reduced, two hundred megawatts to a thousand megawatts.

So moving on, the assumed capacity factor for our wind resource is 48 percent load shape. And in the draft report, we assume the capacity credit for wind to be 15 percent over its life. And again, we -- we got the 2018 actual data for our existing wind resources, and when we reviewed that data, we found that our newest wind resources, the capacity credit had increased significantly. And so going forward in our final report, we're gonna raise the capacity value of our wind resource to 30 percent. And you see that in the note on the bottom of the page.

So one significant change from previous

IRPs, is we have not included congestion before when we've modeled wind or solar or any resource. And based on the feedback from last year, we've included a congestion cost for wind resources. And the congestion cost is approximately $6 a megawatt hour added to our wind resource.

All right, moving on to solar. The chart is showing the two tiers of solar that we've made available in our model. And tier one -- the tier two cost is based mostly on Bloomberg New Energy Finance's forecast for solar cost with adjustments for AP ownership. And then the tier one cost is based on the concept if you -- if we do an RFP, most likely we would get bids that would be ten percent lower than the average. It's just the ability to sort of create a ladder in the model, and so the model has two options of solar resources to choose from. And each tranche had 150 megawatts available per year in 50 megawatt blocks. And over the planning period, we allowed 1300 megawatts of solar to be selected.

The shape that we used is based on a Tulsa installation, and it's approximately a 29 percent Capacity Factor with a Capacity Credit of 33 percent. And on Page 23, is a summary of our storage resource. I believe we included storage last year. You know, as everybody reads, the storage costs continue to decline. The blue line is the storage cost that was included in our draft report. Since then, we've received new information, and in our final report, we'll include the storage cost shown, represented by the red line. And we're looking at a four-hour storage product based on the lithium ion technology.

All right, slide 24 is a summary of the traditional resources that are included. We have the combined cycle, the large combined cycle, which we've modeled a 25 percent share of a large H class 2x1 facility. And then for peaking, we have really four different options. We have the large F class turbines. We have aero-derivatives, the reciprocating engine technology, and then the battery storage that I just talked about. And you can see on the table on the lower right, the relative levelized cost of electricity for those various technologies.

All right, with that, we're gonna start talking about our modeling scenario that we considered and some results. And Connie Trecazzi's gonna go over the scenarios that are included in our -- based on our fundamental forecast.

COMMISSIONER ANTHONY: I'm sure it's very elementary, but tell me what a capacity credit is.

You've mentioned that several times.

MR. FISHER: So, the IRP's main objective function is to solve for the capacity planning reserve margin that SPP requires us to have. And so each resource, you know, has a nameplate capacity, and then it has its firm capacity value. And so, for traditional resources, normally the nameplate equals its firm capacity value. Like a combined cycle or a gas peaking plant --

COMMISSIONER ANTHONY: Okay.

MR. FISHER: -- or a coal plant, right, might be rated at a thousand megawatts and for capacity planning purposes, it's a thousand megawatts or one minus its E4, maybe, but really close to its nameplate ratting.

So for variable generation or intermittent generation such as solar and wind, the RTO or SPP, has a rule to establish the value of an intermittent generator, and that's what it -- is the capacity credit.

And so, for the first three years, SPP advises us for wind, it's five percent of its nameplate, and then for solar, it's ten percent. And then after you have three years of history, you can use your history to assign the long-run capacity credit value for that specific resource. So these are our planning assumptions related to solar and wind.

COMMISSIONER ANTHONY: I think I understood what you said, and I thought you explained it pretty well, so I hope both of those things are true.

MR. FISHER: So do I.

COMMISSIONER ANTHONY: Please continue.

MS. TRECAZZI: Okay. We had four capacity -- commodity price scenarios that we included in the modeling for capacity. We had base case, a high band prices, basically, one standard deviation above the base price, and a low band, approximately one standard deviation below that price, and then we had a status quo scenario that all of those scenarios include a carbon price and then the status quo scenario is the base case excluding a carbon price.

We developed a carbon assumption in interaction with our environmental group, and we assumed a $15 per metric ton carbon price beginning in 2028. At the time we developed this forecast, the clean power plan was on hold, it had not yet been replaced, so we -- we assume that it would be pushed out and at a lower rate than what we had modeled the last time.

There were also two load sensitivities, a high-load sensitivity based on the base commodity price and a low-load sensitivity also based on the base commodity price.

Now if we'll look at slide 27, you can see the results of the commodity pricing scenarios and the SPP On-Peak Nominal Prices have -- have come down and it's primarily due to lower gas prices and lower loads.

And if we move on to slide 28, you can see the forecasted gas prices for Panhandle Eastern TX-OK, and again, those have come down. The base case is very similar to our low case in the last forecast, and we brought those prices down due to the technological innovation, the lower cost of production, the higher resource base that has developed subsequent to our last forecast. And we're relatively flat on a real basis, but you can see the impact of the carbon price in 2028.

On slide 29, each of these cases are fully integrated scenarios. We iterate back and forth between our models. The final model is the aurora model where we saw for the power price, all of these underlying commodity prices are input into that model, and so we iterate back and forth between the commodity prices based on -- on the resulting power prices and the resulting demand, and so you see the result on the power resulting in, 8800 coal price here, and then I've also given you a view of the CO2 price used in each of these scenarios.

And I'm gonna hand it off to Mark to talk about the results of that.

MR. BECKER: So at this point in the process, we've got the amount of capacity that we've got to add when that occurs. We've got some alternatives to meet that capacity. We've got some scenarios to -- to run those capacity optimizations under.

So starting on slide 30, is what our Plexos LT plan model has said is the optimal resource plan for the various commodity price and load sensitivities. And when I say optimal, that's the lowest overall cost over a 30-year horizon plus end effects. So probably the easiest way to go through this is just to take an example.

Under the first block of data that we have here, we've got the base commodity price scenario. We've got the base load forecast scenario, and it shows that we'll be adding roughly 750 megawatts of intermediate to base load capacity beginning in 2022. And that will increase to about 1200 megawatts by 2028. That's mainly driven by those larger holes in the capacity need.

We see that solar's coming in early in 2021. That was mainly to meet that 100 megawatt capacity need in 2021. We're adding roughly 300 megawatts of nameplate solar to get that firm capacity of 100 megawatts. And that solar addition continues to grow to about 900 megawatts by 2028.

We see that we're adding wind resources in 600 megawatt blocks in 2022 and 2023 up to the limit of the 1200 megawatts that we've put in the model. Energy efficiency, you can see that it continues to grow as well as the conservation voltage reduction, and then we do have imbedded in our modeling, the distributed generation capacity.

And Commissioners, this might be a good time to talk a little bit about your question, as far as how does this compare to our previous IRPs? I think, going from memory, if you go back to our 2017 update of the 2015 IRP -- if you have it in your hand.

CHAIRMAN MURPHY: I do.

MR. BECKER: You'll see that things are fairly similar. We still have those large capacity gaps beginning in 2022. We're still adding pretty significant amounts of wind resources, as well as solar resources, and we're continuing to grow our energy efficiency. As Chad said, the load hasn't grown substantially. Connie indicated that our gas price forecast was a little bit lower than last time. So, relativity, I think we're dealing with pretty much the same situation that we did back in 2017 when we did the update.

CHAIRMAN MURPHY: But it seems like one of the things that's different is you really start from a different base, right?

MR. BECKER: A different base.

CHAIRMAN MURPHY: Base intermediate. I'm looking at the 2017, and it's got numbers that are in the seven hundreds, and when I look at your base intermediate line, that's in the 400's to 900. So is that because it's taking out some retirements already so you start out from a different base intermediate place? I guess I don't -- that's the only place I saw significantly --

MR. BECKER: Well, what this is, on that very first line, the base intermediate in this update --

CHAIRMAN MURPHY: Uh-huh.

MR. BECKER: -- that's really the addition of two of those blocks of combined cycle capacity. So, it's roughly 700 megawatts, and I believe in the 2017 IRP, we had roughly 500 to 700 megawatts of need in 2022. We're still losing the same purchase power agreement in 2022 that we were in 2017.

CHAIRMAN MURPHY: Okay. I think I just had them switched, so I had the numbers switched.

MR. BECKER: Oh, okay. Okay. So I think you'll see that a lot of this is the same as well as under the low band scenario, which is the next block of data, You'll see that we had a little less solar, a little less EE and CVR, and that's driven mainly by the lower market prices. But you'll still see the same wind and based intermediate capacity generation that you do in the base case.

And in the high band, you'll see a little bit more solar. A little bit more EE, a little bit more CVR, but you still see the same combined cycle generation being added and wind generation added, so we're starting to get a theme here that those -- at least those two things, if not the solar itself, as well, are being added in a lot of these different scenarios.

And I think that's probably what you saw in 2017 as well. The status quo scenario is fairly close to our low band scenario as far as the pricing goes. So it has a -- a resource portfolio that's comparable to the low band. So now we have our commodity price scenarios covered as far as optimal resource plans. So the next slide takes a look at the high and low band load forecast scenarios, 'cause we want to try to bound that as well in case our load forecast deviate one way or another.

CHAIRMAN MURPHY: So can you just remind me, just so when I'm looking at these -- you -- you don't see that being significantly different from the one that you presented in October -- it was October 25 of last year?

MR. BECKER: If we're going from my memory, no, I think the larger elements, as far as our capacity needs and what we're going to fill those capacity needs with, I think they're comparable, going from my memory, anyway.

CHAIRMAN MURPHY: Okay.

MR. BECKER: On slide 31, we talk a little bit about the load forecast scenarios. Under the low load scenario, we see a decreased need for based intermediate resources. We're only adding roughly, I'll say, about half of that. But we do still see the same wind generation as we did in the base optimization. We see the solar being delayed a little bit, but by the time you read 2028, that capacity is roughly the same as the base.

Under the high load scenario, pretty much the same base and intermediate resources, but we've got to add a combustion turbine in 2021 to meet that little bit higher load in 2021. You'll see a little bit more solar to meet those increasing capacity requirements and a little bit higher levels of EE and CVR.

MR. FISHER: So, Mark, one difference from last year, is Oklaunion is not included in this.

MR. BECKER: Right. There's about a hundred megawatt reduction beginning in 2021 for the Oklaunion retirement --

MR. FISHER: And Waleetka 6.

MR. BECKER: And then Waleetka 6 of about 50 megawatts and roughly the same point in 2019, I believe. But they -- there still was enough capacity length in 2019 to allow that.

CHAIRMAN MURPHY: To cover those?

MR. BECKER: Yes.

CHAIRMAN MURPHY: Okay. Thank you.

MR. BECKER: So now that we've got the commodity price scenario, optimal plans, and the load forecast optimal plans, how do we take that and try to come up with one preferred plan?

Well, we essentially lay them out on the table and look at the common elements to all of those different optimal plans, and that's how we've developed the draft preferred plan that's shown on page 33. And essentially, it adds utility scale solar in 2021, and this plan is very similar to the base plan, the base optimal plan. The additional solar in 2021 and growing that solar capacity to 900 megawatts by 2028. We're adding 600 megawatts of wind resources in 2022 and another 600 megawatts in 2023 to reach our target of 1200 megawatts.

The one slight difference is, is we've accelerated the CVR a little bit from the base optimal plan and it's preferred plan, that way we have the continuity of implementation. As Jeff said, we've got CVR being added out in the field right now. The model would tend to want to delay that a couple of years, so in order so that we don't have to mobilize and remobilize and mobilize again, we've slid that forward in the plan, accelerated it a couple of years, so that we have a little bit more continuity in the installation of that.

And then again, we've got the long-term capacity need being fulfilled by the addition of combined cycles. And again, as Scott said, it anticipates the retirement of Oklaunion and Northeast 3 at the end of 2020 and 2026 respectively, and anticipates the expiration of some purchase power contracts mainly in 2022, that's what's causing that large void in 2022, and as we work our way through the plaining period, through 2028.

CHAIRMAN MURPHY: Okay. So, I think it says on here that, to fill the long-term needs from the expiring PPA's that's -- so it that to build a natural gas combined cycle?

MR. BECKER: Those are really just place holders for combined cycle capacity. It could be billed; it could be purchased. We'll run an RFP for resources to fill the 2022 needs, so these again, are just kind of generic place holders for the type of capacity that you would want to add in those respective years.

So we've looked at a graph of how the preferred plan meets the capacity requirements, so we'll turn this a little bit and look at how it meets the energy requirements. So the solid black line is PSO's load requirements. The shaded areas underneath are the energy generated by our existing resources and the new resources that we're adding into the draft preferred plan.

So you can see that there is a fairly significant need for additional energy until we get to '21, '22 when we start to add renewable resources. The generation from our existing and new fleet starts to increase to where there is not quite the need for additional energy to meet those load requirements.

Slide 35 was actually the first -- very first slide we put up there. Again, this is our draft preferred plan and how our capacity and energy mix changes through time roughly over the next ten years with the implementation of that draft preferred plan.

So where do we go from here? Our path forward is going to be to build off some refinements and updates that we had to our going-in assumptions that built that draft preferred plan, and they mainly affect our going-in capacity position.

As Scott mentioned, we have some newer existing purchase power agreements, wind purchase power agreements that have finally been in place for more than three years, so now we can calculate their capacity credit, the value that we get to count towards meeting our reserve margin targets. And we've done that, and that's increased the capacity that we've got in our going-in position by about 150 megawatts. That's probably the most significant change going forward.

Then that has allowed us to also increase the capacity value of the wind resources that we have as an alternative in our model from 15 percent to 30 percent. One of the things that we've done is we've scaled back our wind target to about a thousand megawatts to try to get us a little bit closer to that 40 percent of energy target.

We've updated our storage prices so, we'll reiterate and go back through the optimization process with these new assumptions as well as any kind of modifications that we hear today that we receive on our draft preferred plan. We'll remake those optimization runs, create a new preferred plan and then submit our report on December 21st and have a public meeting on the 20th.

As I said, the biggest change was our going-in capacity position. And you'll see from this graph with the changes that we made on the previous slide that, we no longer have a need for capacity in 2021, that that's been pretty much eliminated by that increase in the rating of our wind resources as well as some of those other changes.

In 2022, our need for capacity has been reduced to roughly 500 megawatts instead of 700 megawatts, and then by 2028, we now have a need of about 1400 megawatts as opposed to 15/1600 megawatts in the previous draft preferred plan.

So now we've recast our going-on position, and we've actually done a model run around the base commodity price forecast just to get a look at what those changes did to our base optimal plan. And probably the best way to do this, is to go ahead and go to the next slide that compares the draft optimal plan, base optimal plan, what we currently have. And as you can see, we've eliminated the need of about 375 megawatts of combined cycle capacity in 2022 carrying on through 2028. Because we no longer need that capacity in 2021, the solar has been shifted now back to roughly 2024. It was providing us the capacity value that we needed in 2021 to meet that hundred megawatt shortage in the draft plan.

The wind has been updated. Now we're moving towards a hundred mega -- a thousand megawatt target, and you can see that that thousand megawatts is being built in the very first two years that it can be added in 2022 and 2023.

One of the things that we introduced in this latest round of modeling is short-term capacity purchases to try to fill in around those capacity needs while we're -- the new wind is going through the first three years of existence leading up to that 30 percent firm capacity rating as well as the solar has a similar type of ten percent for the first three years, and then we're using 33 percent there on out. So we -- we were trying to allow the model to pick from some short-term resources rather than filling in those short terms needs with long-term resources. So that's what the -- the short-term capacity purchases are there for that we've now added into our modeling.

You'll also see that the CVR has increased a little bit trying to make up those capacity differences that we have as we add wind and solar resources when their firm capacities are a little bit lower than what their final form is.

COMMISSIONER ANTHONY: When you say, for example, a thousand megawatts of wind, is that something that your company would -- or your affiliates would build, or is that purchase power or does it matter at this point?

MR. BECKER: I don't think -- it really doesn't matter at this point. What we've represented in our IRP model is utility-owned. We have an RFP on the street for wind resources right now. So we'll see what that brings back to us.

COMMISSIONER ANTHONY: Okay.

MR. BECKER: So one of the things that we did to test the economics of this new prefer -- or draft base optimal plan is, is we've run some alternative scenarios, ones that had some different resources in them just to test the economics of this -- of this optimal plan.

So we looked at a couple of three different scenarios. One of them was the addition of a combined cycle unit -- or combined cycle units plus the same renewables that we had in -- in the base optimization except we'll cut those potentials by about 50 percent. So we've got the combined cycle optimization with reduced renewables at about 50 percent of the level that we had in this first optimal plan.

And then we have a another scenario where we allow combined cycle to optimize into the model and no renewables. So we're looking at combined cycles. We're looking at EEs, CVR resources. And the third one was combustion turbines in replacement of the combined cycle resources as well as all of the renewables.

So as you can see from this table here, the base optimal plan still has the lowest cost even after comparing it to some of these other alternative scenarios, and it's roughly somewhere between 1.3 billion and two-and-a-half billion dollars less expensive over the study period than some of these alternative scenarios.

One of the things that we'll do once we recast our preferred plan for the final report, is we'll run our stochastic risk evaluation as we typically do in most of our IRPs. We don't quite have our revised preferred plan yet, so we'll do that for the final report.

And at this point, I think we're done with the presentation, so if there are any additional questions or feedback, we'd like to hear them.

CHAIRMAN MURPHY: Just a couple of things, and I'm sure the people have questions.

Okay. So on your going-in capacity, you projected like by 2028 a 1550 megawatt gap, right? I'm seeing that on the Page 13.

MR. BECKER: That's on the draft. If you go to slide 38, that's been reduced to about 1400 megawatts.

CHAIRMAN MURPHY: Okay. But I thought you'd said that there was a change.

MR. BECKER: That's right.

CHAIRMAN MURPHY: So, how does that -- and you said that is because you've had the wind resources in place for a while, and so you can now tell what their capacity is, right?

MR. BECKER: Correct.

CHAIRMAN MURPHY: A greater capacity. And then I think you gave another reason.

MR. BECKER: There are also -- similar

things happen with our solar resources, we get reduced capacity credits for the first three years, and then larger capacity credits. There's also -- and this going-in this capacity -- or this revised capacity position, we've also gone and looked at increasing our conservation voltage reduction as well as some unit-up rates, but I think, really, the biggest driver in this is the re-rate of the renewable of the wind contracts.

CHAIRMAN MURPHY: Okay. And then just a couple of other more general questions, kind of skipping around.

What was the basis for coming up with the congestion costs that you said was not included in the prior IRPs?

MR. FISHER: The basis for developing the cost curve for congestion was the work that was done on the wind catcher project where, you know, much more extensive analysis was done on the transmission grid, and they developed congestion pricing over the forecast period, and so we leveraged off of that work, and we've included it in this analysis.

CHAIRMAN MURPHY: So it just -- it was internal related to you? I mean there wasn't like data that came from SPP or any other source?

MR. FISHER: I believe it was developed by, you know, AEP and AEP's -- AP Service Corp. and the consultants that we employed for the Wind Catcher analysis, I believe the Bridal Group and, you know, the -- the foundation of that data is SPP data.

CHAIRMAN MURPHY: Okay. And then going back to the gap, the 1550 to 1400. I tried to find another slide that was equal to that on the other -- the prior one, and I didn't see it. Was there a similar -- were you projecting something similar? Is there -- I guess the main thing I'm interested in, is there any significant variations in what you were kind of planning for looking forward from then to kind of what it is now? Like were there some retirements? Were there PPAs -- were there things that were different that put you in a different place then and as you look forward and then as you're kind of projecting, what are the things that you see which was really interesting to me in the oil and gas side, because I went back and looked at kind of what was in the prior plan too?

MR. BECKER: I would be a little surprised if it wasn't in a presentation that we had prior to this. Typically it's one of the slides that we put in, but to answer your question, I think, again you're looking at some of the similar types of situations that we had in 2017. The loss of a large purchase power agreement. One thing that's a little bit different this time around is, is we've assumed a hundred megawatts of Oklaunion now goes away at the end of 2020 as well as 50 megawatts of Waleetka capacity, those are for small turbine capacity. So, I think if you balanced everything out, you'd probably be just about in the same spot that you were in 2017.

And, again, a lot of the same elements are being added that were in 2017, but a lot of this will come to fruition as we issue these RFPs for resources, and we'll see exactly what the market can bring as far as renewable resources and supply-side resources to meet those gaps. But I think we're pretty much in the same position that we were last year.

CHAIRMAN MURPHY: Okay. And just generally on a go forth, so Oklaunion and Waleetka were --

MR. BECKER: Oklaunion is about a hundred megawatts and Waleetka is about 50 megawatts.

CHAIRMAN MURPHY: But they were your plants --

MR. BECKER: That's right, or we were co-owners.

CHAIRMAN MURPHY: Okay. So on a go forward, what -- what are the next things that look to be retired?

MR. BECKER: I believe we have some small gas plants that we're projecting retirement as well as the rest of the Waleetka plants. So we've got some retirements included in the going-in capacity position.

CHAIRMAN MURPHY: Okay. Because I know Commissioner Anthony asked, and I think to me just generally, I know you're looking at what we need or what the capacity is regardless if it's a PPA or you're building it or something like that, but it's just, for me, I like to have kind of in my mind really what the PSO-owned resources are as you're looking at what gaps you need to fill and even though if it's whether it's a PPA or if it's building something. I like -- I like to keep in my mind what the status is on what PSO actually owns as far as their own facilities.

MR. BECKER: One of the things that we may be able to do in the final report is to put in some kind of table of resources or our capacity demand and reserve table, in the final report. That will give you a reference to go back to see, okay, this is what's retiring. This is what's being added. That may be -- that may be helpful.

MR. FISHER: Or in our presentation we could put -- there's a table in our report that shows our own resources. We could put that in the next presentation if that's something you'd like.

CHAIRMAN MURPHY: It's just for me to get a bigger perspective, because I'd still like to see what's happened; what did you actually -- what was the skill in the ground? Where are you today? And where are you going? Even with the capacity, what's the crux of trying to deal with it.

MR. FISHER: Okay.

CHAIRMAN MURPHY: So that's really -- I mean that's in my own mind. I don't know if it needs to be affiliated with the IRP or not, but I think when you know what the foundation is, and then you see as things are changing, it helps you kind of follow the path of what you're proposing.

So, I did go back and look, and I think that chart was in there, but I'm just saying the way you all have been doing them where you can go back and look and see if it's a similar chart where it's easier to compare, that's helpful. But I thought I would let you know, because I know it's probably a little extra effort and some things you update and change with the programs, but it's helpful when you can see what was and then kind of compare that. I really like to -- I do that on all of these. I think it's helpful for me. So I appreciate all your efforts on this, too. Thank you.

MR. BECKER: One of the things that you might be able to do is go back to slide either 13 or the one that we have towards the end, 38, and if it's a little bit helpful, is to kind of look at these bars that we have here. Starting with the blue bar.

In 2018, we're seeing capacity from our Northeast 3 facility and Oklaunion. As we work our way through 2021, we see that blue bar start to tail off, that's the retirement of Oklaunion, a hundred megawatts. By 2027, Northeast 3 has been retired. The red bar gives you an idea of PSO's natural -- existing natural gas resources, and you can see through time that they are -- that that bar is getting a little bit smaller, and that's mainly due the retirements of the Waleetka units and some of our older smaller gas steam units.

The wind, as we work our way through time, you see that that bar has actually grown. Well, that's our ability to perhaps re-rate that capacity as well as the thermal PPAs is the orange bar. Those -- that's really what's causing, if you look at this, is one of the biggest factors that's causing the need for capacity. 'Cause you can see in 2022, that that orange bar has gotten significantly smaller. And that's the Exelon PPA from the Green Country facility expiring. And that's where we'll probably focus our next RFP on here in the future, is 2022.

But we can also add a table or something like that so that you can go back and forth between the two.

CHAIRMAN MURPHY: Well, I think that was helpful. So the Northeast 3 retired. You show that at --

MR. BECKER: End of 2026.

CHAIRMAN MURPHY: Okay. So that's at the time when there will be no coal resources.

MR. BECKER: That's correct. And that's part of our transition to a more renewable mix as well.

CHAIRMAN MURPHY: And I'm assuming that part of the things that were already planned for retirement were based on what you already -- what's already been done, the mats and the other environmental regulations that were put in place. Those haven't -- I know the clean power plant doesn't -- is not here anymore, but, are the things -- is it a combination of the environmental regulations that confronted the companies at an earlier point in time along with kind of managerial discretion or decisions about moving forward with no coal?

MR. BECKER: I would say that the coal retirements are being driven as far as Northeastern goes, by our environmental compliance plan that we have been working on over the last few years.

CHAIRMAN MURPHY: Right.

MR. BECKER: Some of the gas steam retirements, those are just our best estimates of when those units might retire. You know, we -- we projected that the Waleetka unit may live on a little bit longer but Waleetka 6 had a catastrophic failure, and it just wasn't economic to go ahead and replace that unit or -- not necessarily replace it, but to repair that unit. So as time goes on, we may or may not see more situations like that and -- with our existing gas steam units.

So, as things like that happen, we make decisions as a utility and help PSO make decisions as a utility. What's the most economic thing to do with that particular facility.

CHAIRMAN MURPHY: Okay. Thank you.

MR. BECKER: Uh-huh.

COMMISSIONER ANTHONY: So do other companies in the AEP group have a presentation that's similar to this? I went to some of the other states, but they have slides with lots of the same titles and approach.

MR. BECKER: As a matter of fact, we're -- we're working on four IRPs this year for AEP jurisdiction companies. SWEPCO we're working on right now. I think -- the presentation would be similar to what we've done here. We've got a IRP going on in Indiana this year, and that will eventually go into Michigan. As well as, we've done one for Virginia earlier in the spring.

So we've got several presentations that maybe aren't exactly like this, but are similar. We try to, as I said, use the same process over and over again, so that would lend itself to doing similar presentations of the results.

COMMISSIONER ANTHONY: All right. A couple of elementary questions. You have this slide on Page 16 that talks about bundled life. It's got numbers like 15, 30, and ten. What are the units of that?

MR. BECKER: Oh, those are years.

COMMISSIONER ANTHONY: Do you think it would be helpful to put years on there?

MR. BECKER: It probably would.

COMMISSIONER ANTHONY: I think so.

Throughout, you use the acronym or abbreviation CVR. Is that explained anywhere?

MR. BECKER: It is in the report. It's conservation voltage reduction.

COMMISSIONER ANTHONY: Conservation voltage reduction. Okay.

And if you were describing to somebody, I think you even gave a name of when you made reference to this model, does it -- is there some name for the model?

MR. BECKER: Oh yes. It's Plexos LT Plan.

COMMISSIONER ANTHONY: Spell that.

MR. BECKER: P-L-E-X-O-S.

COMMISSIONER ANTHONY: Okay. And how would you describe it? Like is it -- in terms of anything you want to describe, mathematics.

MR. BECKER: It -- we've been using it roughly since 2012. It's a production --

COMMISSIONER ANTHONY: No. The name of the model. Describe --

MR. BECKER: Plexos.

COMMISSIONER ANTHONY: Okay. You've got the name. Is it a economic model, input/output model?

MR. BECKER: No. It's a linear optimization model. It does both production costing and resource optimization using a linear program. So we actually use it --

COMMISSIONER ANTHONY: I heard you use the term "objective function."

MR. BECKER: Correct.

COMMISSIONER ANTHONY: I think the lady

used that.

MR. BECKER: Yes.

COMMISSIONER ANTHONY: So is that a part of linear programing?

MR. BECKER: Yes, it is. It's what you drive your solution to, an objective function is the minimization of overall cost for a particular plan or a dispatch of generating units. We've been using it for a while now. Through the last several --

COMMISSIONER ANTHONY: So it's a linear programming model?

MR. BECKER: Correct.

COMMISSIONER ANTHONY: Anything else you could use? Is it stochastic?

MR. BECKER: We have the ability to do the stochastic model -- risk analysis in that model, and we'll do that when we reach our final preferred plan.

COMMISSIONER ANTHONY: So when you got to the end, it looked like you had your demand or your load, and then it's how are you gonna meet that? Am I understanding that correctly?

MR. BECKER: Correct.

COMMISSIONER ANTHONY: That was kind of the sequence.

MR. BECKER: That's correct.

COMMISSIONER ANTHONY: All right. Is there a test on this?

So then on the very last page where you gave your scenarios, scenarios are just running the same model with some different parameters, if that's the right word. And, so, what do you think the conclusion is? You had your base optimal, and then you had those other three scenarios, and they were showing a difference of eight percent, sixteen percent and nine percent. That means these would be more extensive?

MR. BECKER: That's correct.

COMMISSIONER ANTHONY: And so those percentages pertain to the total cost of providing the supply-side to the demand-side that you had forecast earlier?

MR. BECKER: That's correct. That's the cumulative present worth of those costs over the planning period which is through 2047. Then at the end of that, we have an end-effects period that takes those additions that may be made in the last few years and allows them to run their lives out for a period of time, and then the combination of those two things produces the study period.

But what -- what those four scenarios are, one is allowing the model to optimize with all of the resources that we've been talking about. The next step is, is to look at, well, what if we limit the amount of renewables that we have but still allow it to have combined cycle generation? That's what's represented by the CC plus reduced renewables. Then if we allow the model optimize around a -- alternatives that have a combined cycle and no renewables, what happens.

And then a combustion turbine and renewables. Just to get a sense for, is the optimal plan truly optimal? And what happens if you change some of the alternatives and change the mix in trying to fulfill that capacity requirement, how does that change the cost?

COMMISSIONER ANTHONY: All right. To say it in different words, your -- your base optimal has a considerable amount of renewables, particularly when. And these three alternatives to it are showing that, not to do it that way would be more costly?

MR. BECKER: Correct.

COMMISSIONER ANTHONY: And so without me having to turn to some pages, the base optimal plan going -- say you pick one, five or ten years out, would have what amount of wind?

MR. BECKER: It would have one thousand megawatts of wind, and that wind would be added in 2022

and 2023.
COMMISSIONER ANTHONY: Okay. And the one thousand would be on -- based on a total load at that time or should I pick -- that'd be a percent of -- is that -- let's just say capacity. A thousand would be, is that a third or a fourth of your total capacity or what?
MR. BECKER: Well, we -- again, we don't get that much firm capacity from wind that's the nameplate rating of the wind.
COMMISSIONER ANTHONY: The thousand?
MR. BECKER: Yes, sir.
COMMISSIONER ANTHONY: Okay. So that's your utilization 'cause intermittent would be much less?
MR. BECKER: Correct. About 30 percent capacity credit.
COMMISSIONER ANTHONY: Okay. All right. I'll bet these other people might have some questions.
CHAIRMAN MURPHY: I think we're supposed to share.
COMMISSIONER ANTHONY: All right.
CHAIRMAN MURPHY: While Tom is coming up, I guess the last question along with Commissioner Anthony, so even in your base optimal with adding the nameplate and adding in the congestion costs, those different

factors, it's still the -- it's still the lowest cost?

MR. BECKER: It's still one of the low cost. It was picked in the optimization along with the other resources to meet that capacity need.

CHAIRMAN MURPHY: Okay.

MR. BECKER: I wouldn't necessarily say it's the lowest cost. I -- I'm not sure that it -- that it is the lowest cost, but it is -- it's low cost enough to meet the requirements of creating a plan that gives you the lowest overall cost set of resources.

CHAIRMAN MURPHY: Which would be all wind?

MR. BECKER: No. Not necessarily.

CHAIRMAN MURPHY: A thousand. A thousand of the -- a thousand, you said, would be wind?

MR. BECKER: A thousand of the -- of nameplate wind would be added in the base optimal plan, yes.

CHAIRMAN MURPHY: Okay. And then so what else besides wind? Because I thought you said --

MR. BECKER: We've got some bond cycles being added. We've got -- if you look at Page 40.

CHAIRMAN MURPHY: But the majority of it is wind; is that right? Is that accurate or not?

MR. BECKER: I don't know that that's necessarily quite correct, because you've got -- you've got a thousand megawatts or so of combined cycle resources. And that thousand megawatts, we know that we can count the majority of that towards meeting our reserve margin requirement.

CHAIRMAN MURPHY: Okay. I think I must have misunderstood your response to Commissioner Anthony because I was taking away the base optimal, the predominant -- the predominant resource is going to be wind. The thousand.

MR. BECKER: In the near term, we're adding a thousand megawatts of wind.

CHAIRMAN MURPHY: Okay. That's really -- okay. I just need -- I needed to put it in context. Okay.

MR. BECKER: Okay.

COMMISSIONER ANTHONY: Probably I shouldn't ask this question, but how would the base optimal scenario compare to, if you've got -- would have gotten Wind Catcher approved?

MR. BECKER: Well, we would probably have fulfilled our wind need with Wind catcher.

COMMISSIONER ANTHONY: Right.

MR. BECKER: So you probably wouldn't see wind sources -- resources being added in this plan, until maybe some other point in time when we had existing wind contracts.

COMMISSIONER ANTHONY: I'm just looking for a dollar percentage.

MR. BECKER: I'm not sure I can give you a dollar percentage.

COMMISSIONER ANTHONY: You've got -- you've got your base optimal plan, and it has a certain price tag.

MR. BECKER: Correct.

COMMISSIONER ANTHONY: If we would have approved the Wind catcher and gone on about our business, after five or ten years, what would have been the total cost of providing the electricity, more or less?

MR. BECKER: I -- I don't know.

COMMISSIONER ANTHONY: I bet you're supposed to say well, this is gonna cost more because the Wind Catcher was such a good deal.

MR. BECKER: I think -- I think we maybe, from an IRP perspective at this level of the IRP, the cost would be equivalent, because you -- we're just, you know, we're -- since we don't have Wind catcher, the wind resource that's included in the base optimal plan is a basically an approximate.

COMMISSIONER ANTHONY: I understand that.

Okay. Right.
Tom, if you don't hurry, we'll have some more questions.
MR. SCHROEDTER: Tom Schroedter, on behalf of OIEC. And, Mark, thank you to you and your team for the presentation.
MR. BECKER: You're welcome.
MR. SCHROEDTER: Very much appreciated. Regarding that, would you be able to make this available electronically so that I could share this with Mr. Norwood who's not able to be here today?
MR. BECKER: Sure. I would think so.
MR. SCHROEDTER: Okay. Very good.
So I've got just a few questions, and I'll kind of start with one major one at the beginning, and that is: Could you put in your plan the estimated revenue requirement and customer rate impacts of the preferred plan that you've come up with for each of the first ten years of the IRP period?
MR. BECKER: We will look at that and see what we can do.
MR. SCHROEDTER: Okay.
MR. BECKER: Did you say ten years, Tom?
MR. SCHROEDTER: Correct. So, if you would provide the estimated revenue requirement and customer

rate impact of the preferred plan, that would be great. I think you may have done that in the past, but I don't want to speak for you. Maybe I -- you have?

MR. BECKER: Yeah. We attempted in the draft, in the appendix, we included the revenue requirement overall, but we didn't do the rate calculation. We'll do that in the -- it's expected to be in the final report.

MR. SCHROEDTER: Okay. Thank you.

Could PSO also provide the forecasted revenue requirements and rate impacts for major plan transmission investments for the first ten years of the projects? Is that something that you could include?

MR. BECKER: I don't think we can do that because these alternatives are un-cited. That would probably come more in the RFP process once we've identified specific resources to meet this need.

MR. SCHROEDTER: Okay. Just one follow up. I mean, do you have an idea of the transmission expansion that you're going to be doing over the next few years, and if so, that would be helpful to be included in an integrated resource plan just to understand what the magnitude of those investments is as well as the customer impact.

MR. BECKER: Oh. Just as our general

transmission plan.

MR. SCHROEDTER: Yeah.

MR. BECKER: Okay. Okay. I misunderstood.

MR. SCHROEDTER: Yeah. Not transmission associated with each.

MR. FISHER: Okay. That's why I thought you were -- so currently we do have a description for that in the document. We don't have any -- I don't think we have dollars associated with it. We'll consider that.

MR. SCHROEDTER: Okay.

MR. FISHER: I'll talk to the company about that.

MR. SCHROEDTER: Now, regarding the wind that you're adding, so you're gonna add approximately one thousand megawatts of wind, but, Mark, you also referenced the fact that you've got and IRP -- I'm sorry, and RFP on the street for six hundred megawatts of wind. So why was it assumed that no wind is available before 2022 in your IRP?

MR. FISHER: The wind -- we modeled the wind beginning January 1st of '22, so it would be 2021 PTC qualified wind. But that's talking with our renewable developers -- or not developer, but our renewable manager that manages our renewable acquisitions, they believed that that would be the soonest resource that we could get approved and in service.

MR. SCHROEDTER: Okay. But that's where I'm going with my question though, so it is possible that the wind that you're going out for bid for, the 600 megawatts, would qualify for one hundred percent of the PTCs.

MR. FISHER: I guess my answer would be anything's possible. We don't -- since we don't have any of the RFPs back, you know, we don't know, but for the IRP, our planning assumption was the soonest we could get wind in service would be end of year 2021. The -- the RFP would be totally separate.

MR. SCHROEDTER: I understand.

MR. FISHER: And the RFP is not asking for 600 megawatts, just to be clear.

MR. SCHROEDTER: I thought it was, so...

MR. FISHER: It's asking for minimum bids of 100 megawatts.

MR. SCHROEDTER: Is it asking for a maximum?

MR. FISHER: Not that I'm aware of. And there will be a technical conference for that wind RFP on December the 6th.

MR. SCHROEDTER: Thank you.
MR. FISHER: And they may be able to answer some of your questions there.
MR. SCHROEDTER: Following up on Commissioner Murphy's questions regarding the congestion cost. Would it be possible to, in the IRP, set forth the basis for the forecasted congestion cost?
MR. FISHER: I believe that's already included. There's a description.
MR. SCHROEDTER: Because, according to our review, they seem to be far lower than the cost used in the Wind Catcher case.
MR. FISHER: No. I didn't -- my understanding is, my source pulled the data directly from the rebuttal testimony in the Wind Catcher case.
MR. SCHROEDTER: Yeah. But that will be -- but that source will be identified in the final draft of the IRP, in terms of the basis for the congestion cost, just so we know.
MR. FISHER: The basis -- the description of the analysis is already in the draft report, so if you have a specific comment that -- about that paragraph, please let us know.
MR. SCHROEDTER: Yeah. My comment would be that according to our review, it's far lower than the

cost used in the Wind Catcher case and --

MR. FISHER: Okay. I'll try to add a couple of more sentences there.

MR. SCHROEDTER: Okay. The -- the combined cycle addition, was that hardwired into the IRP such that you're gonna add combined cycle no matter what, or was it just the lowest reasonable cost alternative to meet the plan?

MR. BECKER: It was the latter. It was the lowest reasonable cost of combined cycle options and the combustion turbine options that Scott talked about. And it -- as well as, that's being mixed in all with all of the other alternatives. So, what you see in the -- any of those optimal plans, that was -- those were the optimal resources to drive you to the lowest overall cost. So it's not being hardwired in the plan.

MR. SCHROEDTER: Okay. Was it compared to solar?

MR. BECKER: Yes.

MR. SCHROEDTER: Okay. Regarding the --

MR. BECKER: And, in fact, Tom, it was compared to everything -- to all of the alternatives.

MR. SCHROEDTER: Okay. Regarding the -- the planned retirements, for example, the hundred megawatts of Oklaunion, is that for sure, or is that possible, but not for certain? And, also, I'm interested in knowing the timing and is it for certain that it will retired in 2020? And, also, the final question on it would be, why is that plan being retired?

MR. BECKER: Well, one of the things that you have to think about, is I don't know that anything is certain, but that's what the vote of the co-owners was. The analysis that PSO did, showed that continuing to operate Oklaunion was in their customer's best interest. But, the overall majority of those owners were the ones that voted for the retirement, and it will be retired at the end of 2020.

MR. SCHROEDTER: And then what? Will it be retired, but will it be mothballed? Will it be in the cost of doing all that?

MR. BECKER: I don't know.

MR. SCHROEDTER: And what is the plan date for the RFPs that you mentioned, Mark, to replace the existing PPAs? Do you have a planned date for issuing that RFP?

MR. BECKER: No, not at this time. We're still working on that.

MR. SCHROEDTER: And is it possible that the owners of those units, for example, the combined cycle Exelon unit would want to extend that PPA, and is that a consideration? Would that be a -- something that they could bid into?

MR. BECKER: Absolutely.

MR. SCHROEDTER: All right. And do you -- do you know whether you have the option to extend those expiring PPAs?

MR. BECKER: I don't know that, but I would think that, because we are probably going to go out with another RFP, that if we did have that option we were waiving it or that there was a hard deadline in that contract term.

MR. SCHROEDTER: All right. Thank you all. Appreciate it.

MR. HAINES: Jared Haines on behalf of the Oklahoma Attorney General. The Attorney General provided some written comments for AEP's consideration. I think they're all gone already. Hopefully y'all got a copy. A couple of main things that the Attorney General requested in the comments were the more information, the disclosure of the assumptions around the solar resources and a description about alternative options from the selected plan from the models.

As was made clear by your conversation with the Commissioners, the Plexos model generates an optimum kind of plan at the output of the model. From a stakeholder perspective, from the Attorney General perspective, that can feel like kind of a black box, what's coming out of this model. It's helpful to be able to evaluate it with the other plans, and you all made some great strides to do that with the with the CT plus renewables, no renewables and all those kinds of things.

I think it would be helpful in the final IRP to include that kind of information. Maybe to also include how those stack up under different fuel scenarios. It'd be helpful to see, you know, what plans are -- see a wider variety of outcomes based on the fuel outcomes, fuel scenarios, which ones see a wider variety of outcomes based on the -- the load outcomes. So we may see that some things kind of have a wider variety, and that means they're more risky based on what could possibly happen in the future. So that would be helpful.

You all did provide the solar assumptions in the presentation, and I think it would be helpful for those to be in the draft IRP also.

MR. BECKER: We will run our stochastic risk analysis to look at revenue at risk for our preferred plan versus, I'll say some alternative plan that typically, you know, doesn't include renewables and things like that. That may be helpful to you.

What we might be able to do is some kind of matrix of these plans and those alternatives plans, if that's what you'd like to see, in particular those plans, we can run those under the different commodity price scenarios and maybe give you a matrix. Would that be helpful?

MR. HAINES: I think something like that would be what we were looking for, yes.

MR. BECKER: Okay. Yeah. A lot of times we do that with the optimal plans, before we had our stochastic ability, was to take the base optimal plan and run it under the low band forecast just to see how the cost changed.

Now, that would mean that we would take that base optimal in its final form and put it under low band. It wouldn't be a reoptimization of it, it would just be what happens if all of the sudden gas prices and market energy prices dropped? How -- what would that do to the plan --

MR. HAINES: Right.

MR. BECKER: -- compared back to the low optimal plan. I can kind of see something like that, perhaps, for this.

MR. HAINES: Yeah. That's the kind of

information that is really invaluable for stakeholders to evaluate what the different options were and how they were evaluated. We can see, you know, this plan is cheaper based on your analysis, then, you know, what would be kind of some other common sense alternatives like -- like using combustion turbines, or having a combined cycle and that's really helpful to put dollar figures on it rather than just the black box option.

MR. BECKER: Sure. Sure. As far as the alternative scenarios that we ran and the presentation, is that the universe that you're talking about?

MR. HAINES: That -- that looked like a reasonable set of things. You know, we could probably come up with other -- like what if you only added solar all the time or something like that? I don't know if that's really a reasonable outcome with the gas, but --

MR. BECKER: That's kind of why we selected the resources that we did. You know, let's have a base optimal that has all of the renewables in there. And let's have one that 50 percent and then one that has no renewables and that helps to bound that solution a little bit.

And then what happens if we don't do combined cycle capacity and the model only has combustion turbine capacity to look at? How does that

-- how do those economics stack up against each other? So, if that's the universe that you'd like to see, then we can probably do something like that for the final.

MR. HAINES: I think that's a reasonable side --

MR. BECKER: Okay.

MR. HAINES: I mean, we could add or subtract things --

MR. BECKER: We can do them all day long.

MR. HAINES: Yes.

MR. BECKER: But are they gonna be, you know, informative for you?

MR. HAINES: Got it. I think it was reasonable. Thank you.

MR. BECKER: Okay.

CHAIRMAN MURPHY: I had just one last question. On the -- when you did the presentation on the demand-side management and the energy efficiency, was it just -- I mean, I don't know that it would have much -- don't I know what the impact would be. Would it be based on just a little thing like they are now?

MR. BROWN: Yeah, solar is.

CHAIRMAN MURPHY: Because, you know, there's this discussion going on about what we're gonna do with the energy efficiency rules and the various opinions? Are we starting over or are we trying to -- you know, what are we doing with that? And so I didn't know if that -- if you based what was provided on those rules or did that really have anything to do with it?

MR. BROWN: So I think that the answer to your -- first question is: The rule making didn't have anything to do with it necessarily. The energy efficiency programs that have been proposed and recommended for the 2019 to '21 period, they're based on the existing rules --

CHAIRMAN MURPHY: Those rules.

MR. BROWN: -- right. But they were also informed by previous IRPs that selected energy efficiency is part of that resource mix. And so, since those IRPs had energy efficiency in them that was cost effective and met, you know, the energy mix, then we continued to put together a portfolio within those rules that -- that supported that IRP.

CHAIRMAN MURPHY: So it's really the -- whatever you're coming up with on the proposals for your IRP, it's bound within whatever the exist -- whatever the rules are at the time.

MR. DRUGAN: No. I think -- there's two separate pieces here. Again, what Jeff was describing is the '19 to '21 piece of it. Going forward after that, we modeled the energy efficiency resources pretty similarly across all of our companies, and it's not based on any particular --

CHAIRMAN MURPHY: Jurisdiction's rules.

MR. DRUGAN: Correct. They're just proxies going forward -- it's kind of like the same discussion with, well we got wind resource in there. We're going to do a wind IRP. It's the same kind of idea. We have proxy EE resources, and then when we get to that point, Jeff will do his demand-side management filing to kind of flush all that out.

CHAIRMAN MURPHY: Okay. Well, I just -- I knew we've had a lot of discussion about the energy efficiency rules, and I just wanted to make sure I had conceptually some of idea of how that would interplay with what you all were doing.

MR. BROWN: And I guess I'd add to that is, you know, all these rules as we've talked about in a number of venues, all passed the California test which is five tests and we passed four of the five on all the efficiency programs and the total resource cost test is one of them that is the most predominantly used by most states, and so that is kind of comparing energy efficiency as a resource option in terms of the total resource cost as it would fit in with the assumptions made in the IRP.

CHAIRMAN MURPHY: Okay. That's helpful. Thank you.

MR. HAINES: Jared B. Haines, again, on behalf of the Attorney General. You knew I had to stand up once the energy efficiency came up again.

Could you all provide some clarity on the assumptions around energy efficiency, specifically the categories of financial costs included, were they just the cost of the programs to implement them, or the cost of the programs supplemented by expected lost net revenue or incentive recovery? How are they modeled in the IRP?

MR. DRUGAN: Yes. So, again, they're proxies what -- typically what we do, is we have the incremental costs of the measures and as we explained in the presentation, there's achievable potential and high achievable potential. One's at a 50 percent incentive level, the other at 75 percent incentive level. We also have, to reflect I guess, what you're kind of getting at with overall program costs. We have a 20 percent administrative kind of adder to kind of incapsulate those things that go into the general cost of running a program. But, again, they aren't specific, necessarily. They're a general proxy, and that's how we model them.

If that helps you out and answers your question.

MR. HAINES: So the -- the way it was modeled was not exactly how the recovery would work in Oklahoma.

MR. DRUGAN: We tried to capture that with the general 20 percent administrative adder.

MR. HAINES: Okay. That's an adder you use in all your jurisdictions?

MR. DRUGAN: Pretty much, yeah.

MR. HAINES: Okay. All right. Thank you.

CHAIRMAN MURPHY: Well, I don't know that it looks like there are any other questions. I don't see Mr. Velez, so I guess I can say that if we're finished, that the meeting will be adjourned.

(End of Proceedings)

REPORTER'S CERTIFICATE

STATE OF OKLAHOMA)
) SS:
COUNTY OF OKLAHOMA COUNTY)

I, Amy L. Cummings, CSR and Official Court Reporter for Oklahoma County, State of Oklahoma, do hereby certify that the foregoing transcript in the above-styled case is a true, correct, and complete transcription of my machine shorthand notes of the proceedings requested to be transcribed in said cause.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal this 14th day of December, 2018.

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AMY L. CUMMINGS, CSR #2007
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NOTICE OF TRANSCRIPT COMPLETION

TRANSCRIPT OF THE PROCEEDINGS

HAD ON THE 27TH DAY OF NOVEMBER, 2018

PSO'S INTEGRATED RESOURCE PLAN

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AMY L. CUMMINGS, CSR