PUBLIC SERVICE COMPANY OF OKLAHOMA℠

An AEP Company

BOUNDLESS ENERGY℠

2021 IRP Document

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Cross Reference Table

Requirement from OAC 165:35-37-4(c)	Location of PSO's Response
(1) Schedule A: An electric demand and energy forecast	IRP Section 2.5
(2) Schedule B: A forecast of capacity and energy contributions from existing and committed supply- and demand-side resources	IRP Sections 3.5 and 8.4.3
(3) Schedule C: A description of transmission capabilities and needs covering the forecast period	IRP Section 4
(4) Schedule D: An assessment of need for additional resources	IRP Section 3.5
(5) Schedule E: A description of the supply, demand-side and transmission options available to the utility to address the identified needs	IRP Sections 5 and 6
(6) Schedule F: A fuel procurement plan, purchased-power procurement plan, and risk management plan	Appendix, Exhibit D
(7) Schedule G: An action plan identifying the near-term (i.e., across the first five [5] years) actions that the utility proposes to take to implement its proposed resource plan	IRP Section 10.2
(8) Schedule H: Any proposed RFP(s), supporting documentation, and bid evaluation procedures by which the utility intends to solicit and evaluate new resources	Appendix, Exhibit F
(9) Schedule I: A technical appendix for the data, assumptions and descriptions of models needed to understand the derivation of the resource plan	IRP Exhibits B & C
(10) Schedule J: A description and analysis of the adequacy of its existing transmission system to determine its capability to serve load over the next ten (10) years, including any planned proposed changes to existing transmission facilities	IRP Section 4
(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 3.5
(12) Schedule L: An analysis of the utility's proposed resource plan and any alternative scenarios necessary to demonstrate how the preferred plan best meets the planning criteria. Technical appendices should be included to document the planning analysis and assumptions used in preparing this analysis	IRP Sections 7 and 8
(13) Schedule M: A description and analysis of the Utility's consideration of physical and financial hedging to determine the Utility's ability to mitigate price volatility for the term covered by the IRP	Appendix, Exhibit D

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.

In the 2018 IRP, the following steps were identified 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.

    Status: PSO continues to plan, implement and report on energy efficiency and demand response programs. The Company's most recent Demand Portfolio of program for 2022-2024 was just approved by the commission.

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.

    Status: PSO issued a RFP in 2019, which led to the development and purchase of the North Central Wind Facilities. Sundance and Maverick are operational and PSO expects the final facility, Traverse, to reach commercial operation in early 2022. Additionally, the Company is planning to release an RFP for wind resources to be operational by the end of 2024 and 2025.

3. Consider conducting an RFP to explore adding cost effective utility-scale solar resources.

    Status: In coordination with the RFP mentioned above, the Company is planning to release an RFP for solar resources to be operational by the end of 2024 and 2025.

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.

    Status: The Company secured short term paper capacity resources in 2020 to meet capacity needs in 2022, 2023 & 2024.

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

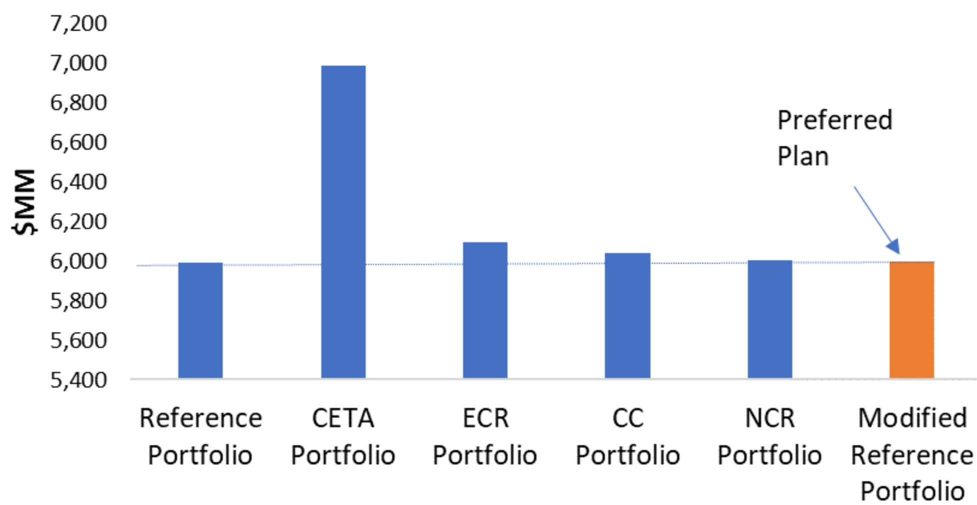
PSO defined four objectives for the Preferred Plan in the 2021 IRP that align to customer and corporate priorities, these are: customer affordability, rate stability, maintaining reliability, and local impacts & sustainability. This report sets out how the Company is planning to meet the four objectives over the 10-year planning period for the benefit of its customers.

Reliable and Affordable Power

The Company's customers have come to expect reliable and affordable power and this IRP outlines how the Company intends to continue to deliver on customers' needs. In this IRP, PSO started from evaluating a known "going-in" capacity position that shows current expectations about existing owned resources and contracts. This going-in position reveals a need for new capacity in the mid 2020's as PSO's Northeastern 3 unit retires in 2026 and contracts with existing thermal resources expire. PSO used the AURORA model to select a set of resources that provided the lowest expected costs to customers subject to certain constraints and balanced against non-cost factors of the scorecard. The list of candidate resources considered in the 2021 IRP includes demand-side management ("DSM"), energy efficiency ("EE"), and other non-wires alternatives ("NWAs") as resources options that can be selected alongside or as an alternative to new utility-scale generation when meeting customer needs. The candidate resources selected reflect the priorities and objectives defined by PSO and are aligned to customer needs.

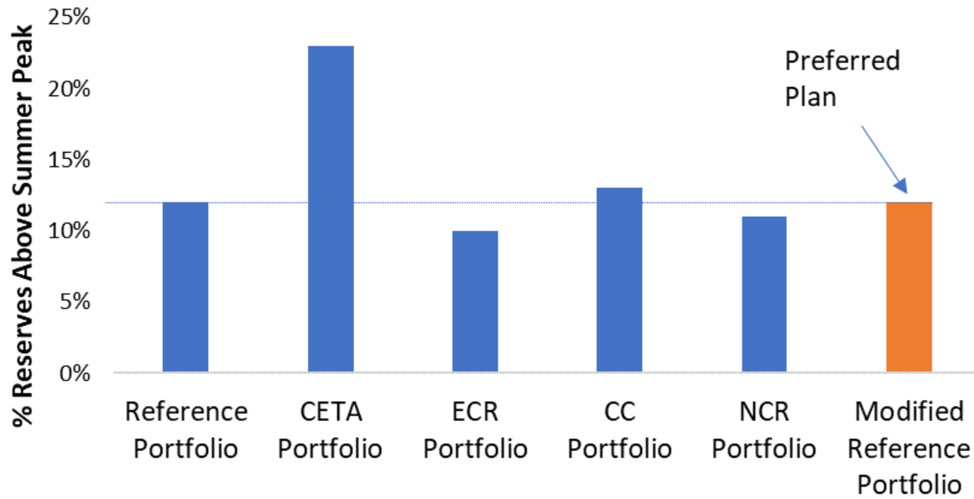
As discussed in Section 8.6, the combination of supply- and demand-side resources selected in the Preferred Plan was among the lowest cost plans evaluated under expected conditions when viewed over the 2022-2031 timeframe, as seen below in Figure 1.

Figure 1: 10-year NPVRR of Generation Costs – Reference Scenario



While other candidate portfolios show similar levels of cost to the Preferred Plan over the 10-year time horizon. These plans do not provide the same level of reliability when viewed over the entire set of future market conditions considered in the IRP. As seen below in Figure 2, alternative plans that are similar in cost to the Preferred Plan fall short of meeting SPP summer reserve requirements when viewed as an average across all of the IRP scenarios.

Figure 2: Average 2022-2031 Summer Reserves – All Scenarios



Responsive to Changing Customers' Needs

Through increased electrification, deployment of electric vehicles ("EVs") and higher penetration of distributed energy resources ("DERs"), the way PSO's customers are interacting with the electricity system is changing and PSO's Preferred Plan must be responsive to changing customers' needs. PSO considered how customer's needs change under a wide range of market scenarios that consider macroeconomic growth and other fundamental factors that drive the rate in of growth in demand for electricity, in addition to changes in customer preferences and end-use technologies that are shifting or are expected to shift PSO customer load patterns in the future. PSO developed forecasts of customer load that were used as inputs into the portfolio model, as well as forecasts of EE and other demand-side resources in the service territory. The result is a set of load assumptions that describe a base, high, and low outlook of the energy and capacity requirements to serve PSO's customers over the 10-year IRP forecast period.

Over the next 10-year period (2022-2031) in the base case, PSO is projected to see customer count growth of 0.3% annually while PSO's retail sales are projected to grow at 0.2% per year with stronger growth expected from the industrial class (0.8% per year) but a decline expected from the residential class at a rate of 0.1% per year. PSO's internal energy and peak demand are expected to change at an average rate of 0.2% and 0.0% per year, respectively, through 2031.

Furthermore, PSO considered advanced and innovative solutions to meeting customer needs. Conservation voltage reduction ("CVR") and other operational measures were considered alongside demand-side resources and new generation technologies when evaluating the best way to meet future customer needs. PSO evaluated the emerging supply-side technologies such as hydrogen and small modular nuclear reactors, as well as long-duration storage technologies were considered as solutions to meet customer requirements under shifting policy conditions. These advanced technologies may provide system benefits that allow PSO to continue to be responsive to changing customers' needs under emission constrained scenarios.

PSO also evaluated the adequacy of its transmission system to accommodate changing customers' needs and this IRP introduces a discussion of PSO's distribution system and the role that distribution-level solutions can plan to meet customers' needs in future planning.

Empowering Customers with Choices

PSO's customers are already benefiting from existing demand-side programs including DSM and EE measures as well as energy savings from customer-sited distributed generation. Nonetheless, PSO continues to explore further the potential to implement demand-side programs to the benefit of the Company's customers. As a result, this IRP considers a broad range of demand-side resource options to meet future capacity needs. Options include energy efficiency measures, demand response programs and distributed energy resources that can be selected alongside new utility-scale generation. These options empower customers with choices over how and when they interact with the energy system.

The Preferred Plan increases deployment of demand-side resources in the PSO service territory over the next ten years. In total, the 2021 Preferred Plan adds 25 MW of new demand response, 68 MW of incremental energy efficiency measures, 5 MW of new distributed generation, and 12 MW of conservation voltage reduction. These demand-side options complement new additions of wind and solar units to meet future PSO customer needs.

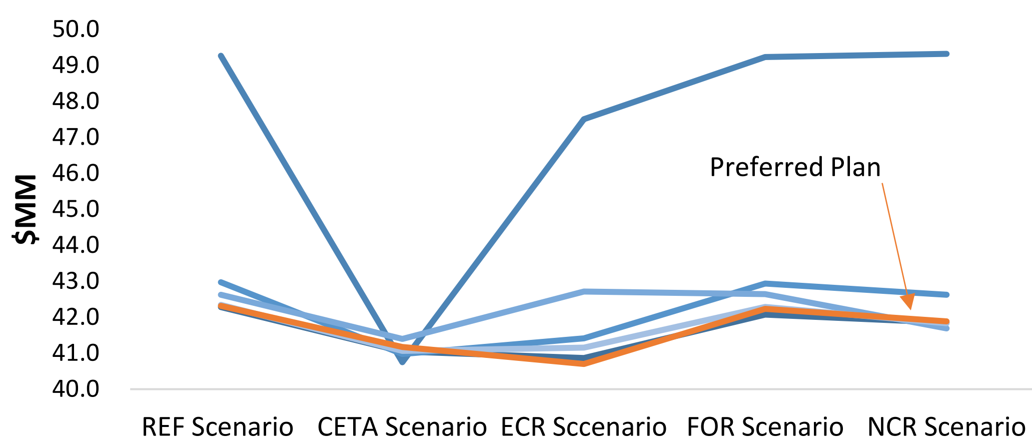
Planning for Uncertain Futures

PSO knows the importance of reliability to its customers and set an objective for the Preferred Plan to protect customers from high costs during unexpected or adverse market conditions. This IRP includes two methods for evaluating cost risks, the results of which are used to inform the development of the Preferred Portfolio:

- The first approach is a scenario analysis where PSO tested candidate portfolios over a set of five market scenarios that test plausible but materially different long-term views of fundamental external market conditions such as commodity prices, customer load and preferences, policy requirements, resource costs, and transmission availability.
- The second approach is a stochastic analysis where PSO subjected the candidate portfolios to a large number of randomly drawn market simulations that combined volatility in power prices and natural gas prices with volatility in generator output to observe how the candidate portfolio performed under adverse market conditions.

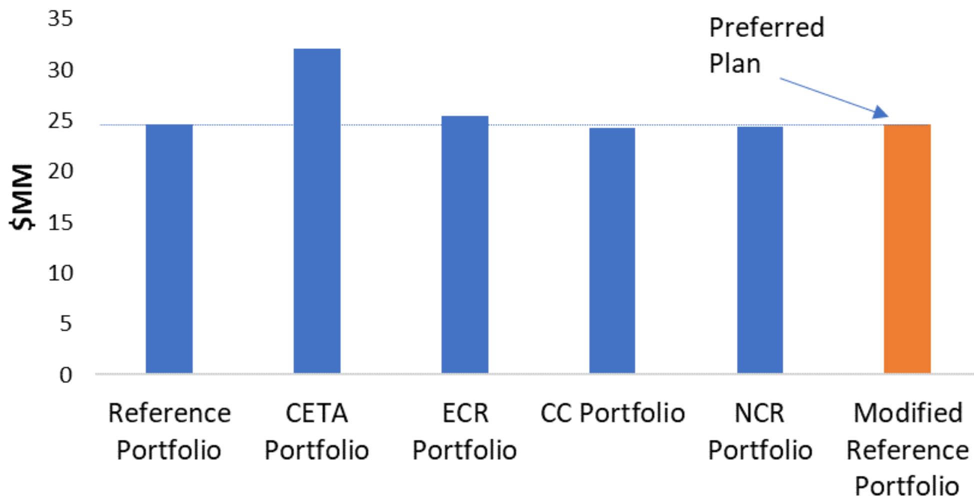
Figure 3 below illustrates the range of candidate portfolio costs, measured as a 10-year net present value revenue requirement ("NPVRR"), when viewed across all 2021 IRP scenarios. This figure illustrates how the Preferred Plan protects customers against higher costs under a wide range of future SPP market conditions that include variations on load, fuel prices and technology costs.

Figure 3: Range of 10-yr Portfolio NPVRRs Across All IRP Scenarios



The 2021 Preferred Plan also protects customers from higher power costs when exposed to market volatility and extreme weather. As seen below in Figure 4, the combination of resources selected under the Preferred Plan, while dominated by new renewable additions, does not expose PSO's customers to significantly higher costs than alternatives that include additions of new gas resources, such as the CC Portfolio.

Figure 4: 2031 Cost Risk of Candidate Plans Under 250 Stochastic Iterations



Powering a Greener Future for All

PSO's parent company, AEP, has announced a goal of reducing CO_2 emissions 80% relative to 2000 levels by 2030 and achieving net zero emission by the year 2050. The Preferred Plan was among the candidate portfolios that score best by this metric, reducing PSO portfolio emission by 95% relative to the 2000 baseline by the year 2031, and putting the company on track to achieve the longer-term net zero targets.

Consulting Stakeholders

PSO held two technical meetings, the first being on September 21, 2021 and October 19, 2021, to review the details of the 2021 IRP. Both meetings were held virtually due to continued risks related to the COVID pandemic. A summary of these Technical Conferences are noted below and the full transcripts from the meetings can be found in Exhibit H of the Appendix.

September 21, 2021:

- Approximately 20 external stakeholders participated in this Technical Conference.
- The Company presented, during the first half of the call, a discussion related to the IRP Process, key objectives, IRP Scenarios considered and key model inputs. Opportunities were taken throughout this part of the presentation for Stakeholder questions but there were none.
- The second half of the presentation focused on the specific IRP portfolios modeled for the IRP and the associated analysis. During this discussion, an extensive review was provided to the Stakeholders on the results of the modeling outputs and how the various portfolios modeled performed under the different scenarios. A presentation was made to further explain the stochastics analysis performed and the subsequent development of the IRP scorecard to compare the broad set of results across the different portfolios.

- Stakeholders were again encouraged to provide feedback and questions throughout the presentation. Although not many questions were raised, the Company appreciated the feedback received including in part:
    - An expressed appreciation for PSO to include sustainability as one of the four priorities for the portfolio.
    - Feedback related to the draft report on some points to check within the report for corrections. The Company committed to reviewing and addressing the feedback provided.
- Prior to the start of the September 21 Technical Conference, the Company received a memo/email from the Attorney General office expressing deep concern with the timing between the initial release of the draft IRP and this particular Technical Conference. In this correspondence, included in Exhibit G, a request was made to schedule a Technical Conference during the third week of October (2021).

October 19. 2021:

- Based on feedback from the Attorney General's office related to the first Technical Conference, the Company held a second Technical Conference to ensure all Stakeholders had enough time to review the draft IRP and to arrange to participate in the Technical Conference.
- Approximately 20 external stakeholders participated in the second Technical Conference.
- The presentation used for the September 21 Technical Conference was used for this meeting and followed the same format.
- A summary of feedback and questions raised in part, during this stakeholder Technical Conference included the following:
    - Early questions during the first half of the presentation were raised regarding how the Company tested extreme weather event conditions with an interest where the Company provided further discussion on this.
    - An interest in the Company's thoughts related to the sense for how projected EV loads would translate into terms of peak demand and energy growth?
    - An inquiry to the Company's capacity price forecast and how this was considered within the modeling. Additionally, the question was further expressed in terms of considering short-term capacity resources as an alternative to investing in new resources.
    - With respect to the Load Forecast, a question was posed to clarify if electrification trends for residential, commercial sales, including transportation, are they entirely offset by gains in appliance and HVAC efficiency?
    - Stakeholder interest was also expressed around the selection of renewables, and in particular, Solar vs. Wind. Discussion around the associated tax credits, capacity credits assigned by SPP and the associated resource costs was held to better understand the selection of wind resources relative to solar resources.
    - Additional interest was expressed in understanding how storage resources were considered in the model as the Preferred Plan did not include any.
    - Feedback was offered related to the Company's plan to add renewables resources in the next 10 years. More specifically, this was further elaborated

to the risks the Company might be exposed to related to traditional generation resources not being added and that not seeing a plan beyond 10 years as presented in the Technical Conference introduces a concern if the plan is sustainable.

- The Attorney General included written comments on the Company's 2021 Draft IRP, which are included in total in Exhibit G of the Appendix.

Five-Year Action Plan (2022 to 2026)

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

- Continue the planning and regulatory actions to implement cost effective energy efficiency and demand response programs that reduce energy use and peak demand for PSO customers.
- Continue to investigate opportunities to incorporate advanced technologies related to a DER technology to provide both capacity relief and improved reliability
- Conduct a Request for Proposals (RFP) to explore opportunities to add cost-effective renewable generation in the near future to take advantage of the Federal Tax Credit.
- Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

The Preferred Plan is informed from an optimized analysis to meet SPP minimum reserve margins including forecasted resource ratings to meet this margin, which are both subject to change. Based on this uncertainty, the Company will continue to evaluate its capacity position relative to potential changes in SPP's reserve margin requirements and the Company's overall SPP capacity position. The Company may consider adding additional firm resources (e.g., 3 to 5%) to the Preferred Plan optimized resources in the future to ensure adequate additional capacity length and to manage resource performance risk associated with SPP's summer capacity reserve requirement and the uncertainty around intermittent resources contribution to reserve margins, load growth and other factors.

1. Introduction

This Report presents the 2021 Integrated Resource Plan ("IRP") for Public Service Company of Oklahoma ("PSO" or "Company") including descriptions of assumptions, study parameters, and methodologies. The IRP identifies the amount, timing, and type of supply- and demand-side resources required to ensure affordable and reliable energy to customers.

For this IRP, PSO engaged Charles River Associates ("CRA") to assist in the development and analyses. CRA is a leading global consulting firm that offers economic, financial, and business management consulting expertise and applies advanced analytic techniques and in-depth industry knowledge to complex engagements for a broad range of clients. The energy practice of CRA has staff located in Washington DC, Boston, London, and Toronto. CRA advises a range of clients on a range of issues including resources planning, asset valuation, auction design and implementation, policy development, and procurement and planning strategies. Recently CRA has supported numerous investor- and publicly-owned utilities to develop long-term generation, transmission and distribution plans that meet the evolving needs of customers, regulators, and other stakeholders.

1.1. IRP Objectives and Framework for Evaluation.

The Company defined a set of performance objectives and metrics and arranged them into a scorecard to provide a structured approach to comparing the tradeoffs between different resource alternatives relative to the objectives defined by PSO.

These objectives and performance indicators were not just used to develop the scorecard. They also informed the assumptions and steps taken in the IRP analysis to create and evaluate candidate resource plans.

This IRP is developed to align with PSO's objectives as follows:

- **Customer affordability** by considering broad range of resource options including renewables to take advantage of tax credits for the Company's customers, and considering a suite of demand-side measures including energy efficiency, demand response and customer-sited generation to empower customers with choices over how they consume energy;
- **Rate stability** by considering renewable resources to reduce uncertainties around future fuel prices and carbon policies, and using comprehensive scenario and stochastic analyses to inform portfolio choices to minimize rate risks to customers;
- **Maintaining reliability** by considering PSO's portfolio performance against seasonal reserve margins and adverse system events, and beginning to incorporate transmission and distribution considerations in generation resource planning; and
- **Local impacts & sustainability** through inclusion of renewable and advanced generation technologies as resource options to enable greener future for all as well as responding to customers' other needs including demand for clean energy, electrification, and customer-sited generation.

The details of the 2021 IRP portfolio analysis framework and the scorecard elements are discussed below in Section 8.

1.2. 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:

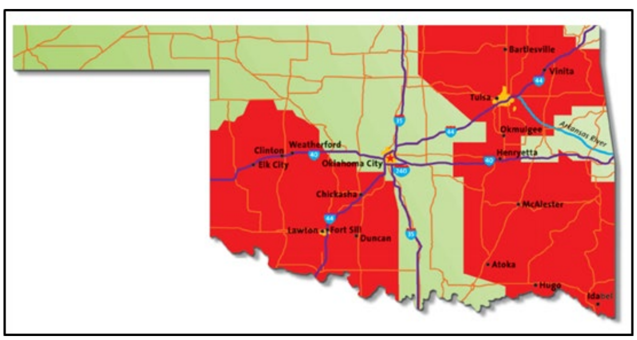
- Describe future customer needs and evaluate how those needs were likely to change over the 10-year period forecast in the 2021 IRP (see Chapter 2);

- Assess the adequacy of current resources, both demand- and supply-side, in meeting future customers' needs taking into account near term changes in the portfolio and the potential impact of future legislations on the resource performance (see Section 3);
- Evaluate transmission and distribution system integration issues in meeting future customer needs and the impact on potential future resource options (see Section 4);
- Identify a list of candidate resources that could be selected by the portfolio model to meet future customer needs. Candidate resources include both supply-side (see Section 5) and demand-side options (see Section 6) including for instance, energy efficiency measures, demand response, renewables technologies and advanced generation technologies;
- Assess sources of future risks and uncertainties, and devise market scenarios and stochastic analysis to represent those risks as part of portfolio optimization (See Section 7);
- Define the objectives or targets that the preferred resource plan should achieve, and evaluate all resource options to identify the portfolio options (see Section 8);
- Engage with stakeholders and incorporate feedback (See Section 9); and
- Reflect stakeholder feedback in formulating the preferred resource plan and the associated five-year action plan (See Section 10).

1.3. Introduction to PSO

PSO's customers consist of both retail and sales-for-resale (wholesale) customers located in Oklahoma (see red area in Figure 5). Currently, PSO serves approximately 563,000 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 4,410 MW, which occurred in August 2012; and the highest recorded winter peak was 3,193 MW, which occurred in January 2018. The most recent actual PSO summer and winter peak demands were 3,884 MW and 3,129 MW, occurring on August 10, 2020 and February 14, 2021, respectively.

Figure 5: PSO's 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 as much as 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 soliciting market data on the cost of new resources. 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 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 relied upon in this IRP was released in July of 2021.

New generation resource cost and characteristics are generally based on the assumptions used by the US Energy Information Administration in the 2021 Annual Energy Outlook report. PSO generally relies on technology cost improvements rates from the NREL Annual Technology Baseline report.

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. Load Forecast and Forecasting Methodology

2.1. Overview

The PSO load forecast was developed by the American Electric Power Service Corporation ("AEPSC") Economic Forecasting organization and completed in June 2021.[1] 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 (2022-2031), PSO's service territory is expected to see population to have little growth and non-farm employment growth of 0.4% per year. Likewise, PSO is projected to see customer count growth of 0.3% annually over this period. Over the same forecast period, PSO's retail sales are projected to grow at 0.2% per year with stronger growth expected from the industrial class (0.8% per year) while the residential class declines at a rate of 0.1% per year over the forecast horizon. Finally, PSO's internal energy and peak demand are expected to change at an average rate of 0.2% and 0.0% 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 January 2021. Moody's Analytics projects moderate growth in the U.S. economy during the 2022-2031 forecast period, characterized by a 2.2% annual rise in real Gross Domestic Product ("GDP"), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.1% per year. Industrial output, as measured by the Federal Reserve Board's ("FRB") index of industrial production, is expected to grow at 1.4% 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 2.2% for the PSO service area.

2.2.2. Energy 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.

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1 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

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 approved by the Commission 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 2026 are included in 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.

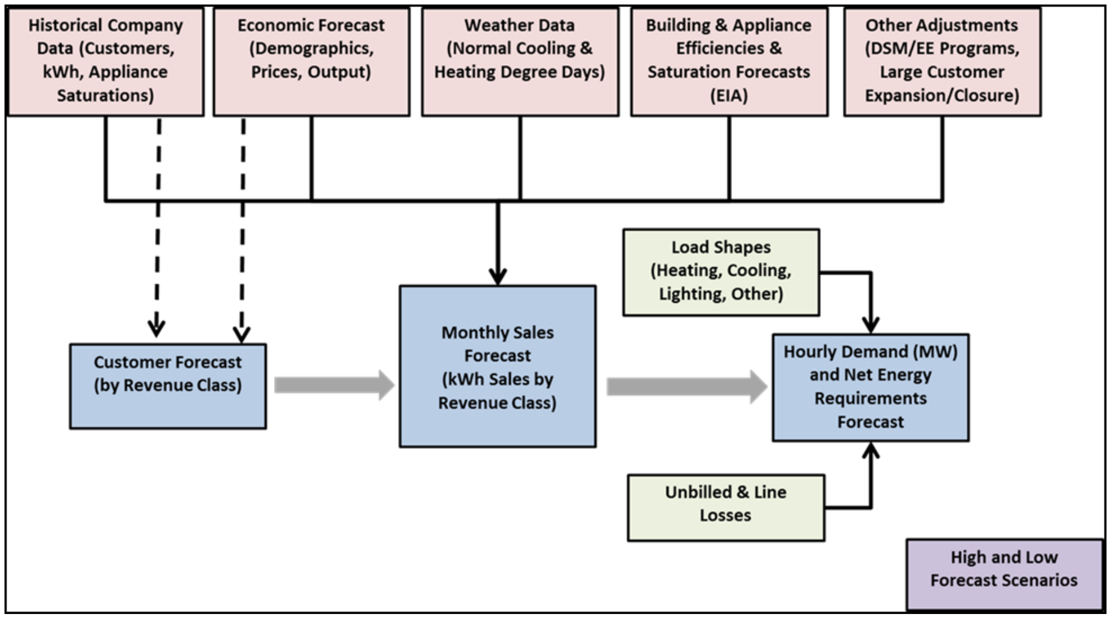
For the first full year of the forecast, the forecast values are generally governed by the short-term models. The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications 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 6.

Figure 6: PSO Internal Energy Requirements & Peak Demand Forecasting Method



2.4. Detailed Explanation of Load Forecast

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 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.

2.4.1. 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.

2.4.2. 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 2011 through January 2021. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 17 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.

2.4.3. 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 1995-2020, although individual models may vary in the length of the modeling period. 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. 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.

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 “2021 Annual Energy Outlook.” The natural gas price model is based upon 1980-2020 historical data.

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 January 2021. 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.

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.

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 January 2021.

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.

Blending Short and Long-Term Sales

Forecast values for 2021 and 2022 are taken from the short-term process. Forecast values for 2023 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 2023 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.

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

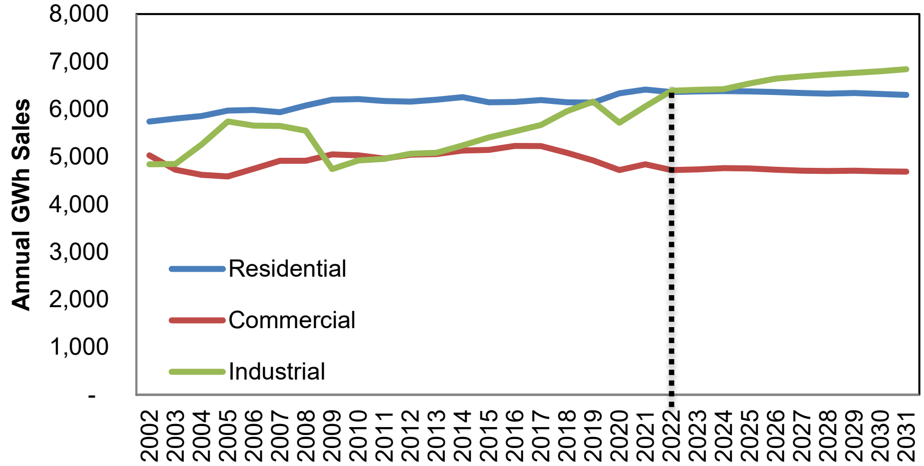
All tables referenced in this section can be found in the Appendix of this Report in Exhibit A.

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 2018-2020 and on a forecast basis for the years 2021-2031. The 2021 data are six months actual and six months forecast. The exhibit also shows annual growth rates for both the historical and forecast periods.

Figure 7 provides a graphical depiction of weather normal and forecast Company residential, commercial, and industrial sales for 2002 through 2031.

Figure 7: Weather Normalized History and Forecast of PSO's Sales by Category

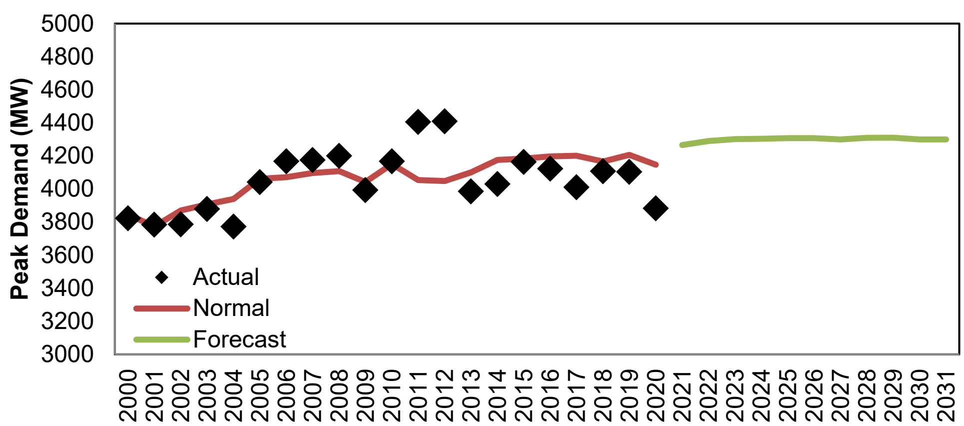


2.5.2. Peak Demand and Load Factor

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 2018-2020 and on a forecast basis for the years 2021-2031. The 2021 data are six months actual and six months forecast. The table also shows annual growth rates for both the historical and forecast periods.

Figure 8 presents actual, weather normal and forecast PSO peak demand for the period 2000 through 2031.

Figure 8: PSO's Peak Demand Between 2000 and 2031



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.

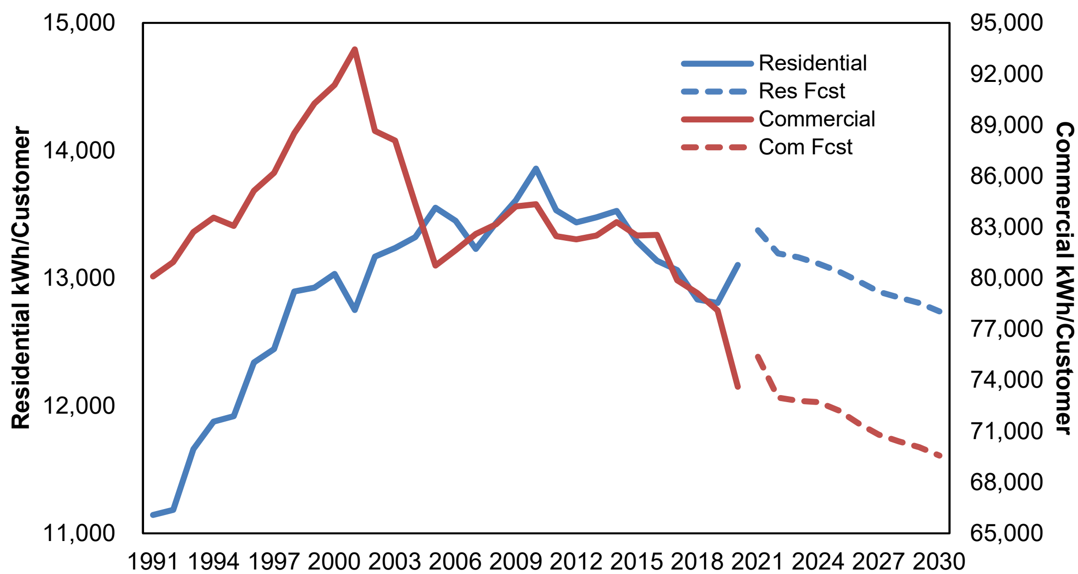
2.6. Load Forecast Trends & Issues

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 9 presents PSO's historical and forecasted residential and commercial usage per customer between 1991 and 2030. 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 most recent decade, shown (2011-2020) residential usage declined at a rate of 0.3% per year while the commercial usage decreased by an average of 1.1% per year.

The COVID-19 Pandemic had a significant effect on usage in 2020. With more people staying at home, residential usage increased by 2.3%. Meanwhile, commercial activity curtailment played a major role in the 5.7% decline in commercial usage. These events dampened the 2011-20 average decline in residential usage and amplified the commercial decline in usage over the period. Residential and commercial usage are projected to decline 0.5% and 0.9% per year over the 2021-30 forecast horizon.

Figure 9: PSO's Normalized Usage Per Customer by Customer Type



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 10 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 11.8 in 2010 to 14.8 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units. Figure 11 shows similar improvements in the efficiencies of lighting and clothes washers over the same period. There are not much additional efficiency gains expected from lighting for residential customers, as consumers have adopted the newer technologies and moved away from incandescent lighting.

Figure 10: Projected Changes in Cooling Efficiencies, 2010 - 2030

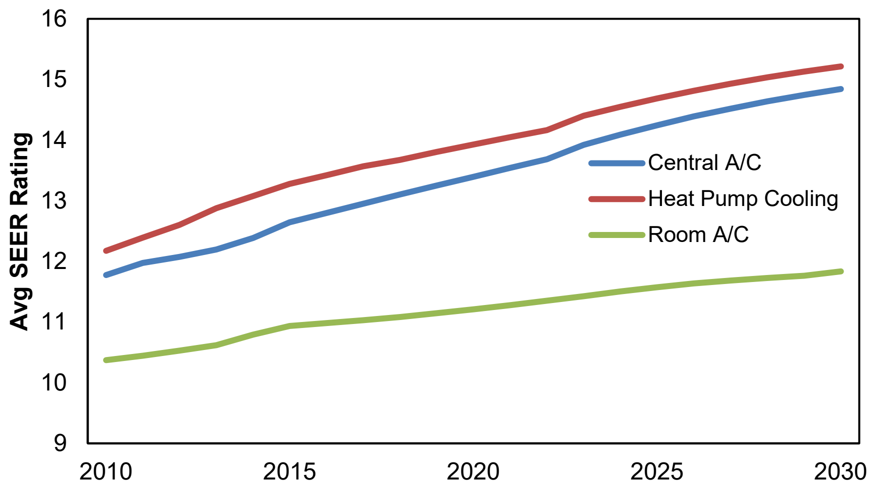


Figure 11: Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2030

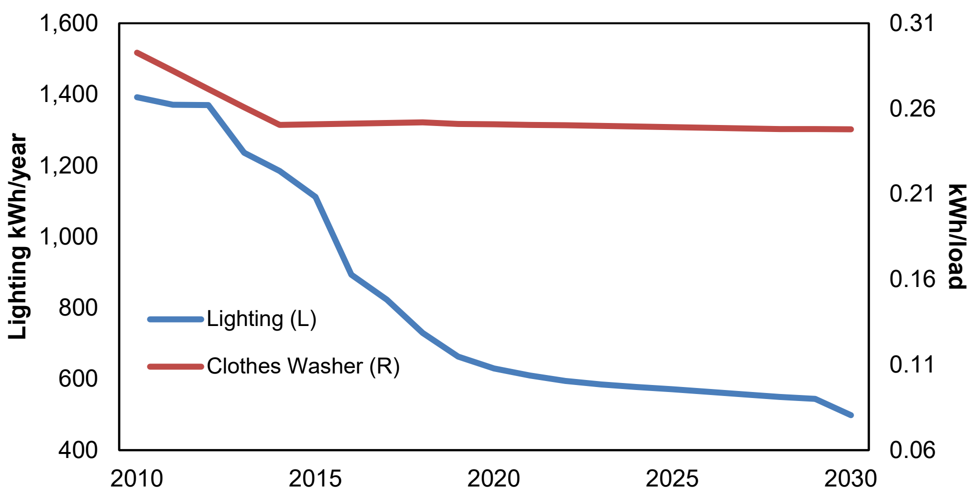
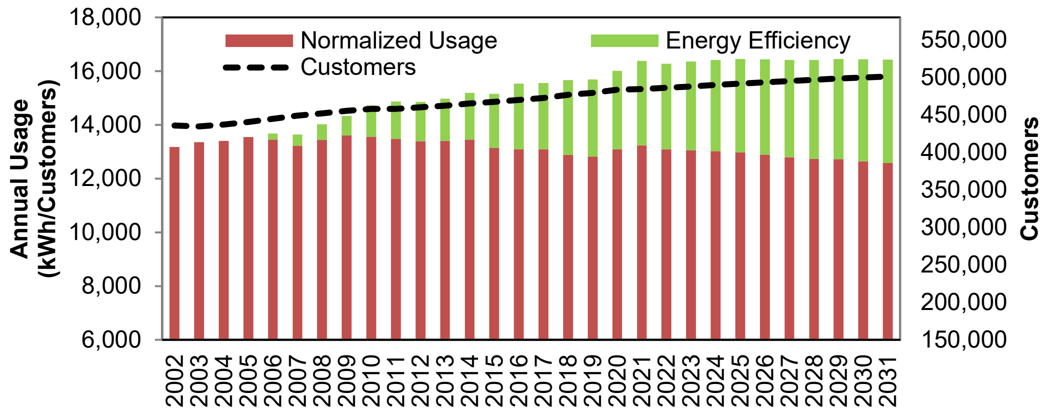


Figure 12 shows the impact of appliance, equipment, and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast PSO residential customers are provided.

Figure 12: Residential Usage and Customer Growth, 2002 - 2031



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 2026), the load forecast uses assumptions from the DSM proposed plan submitted to the Commission. For the years beyond 2026, 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-3 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

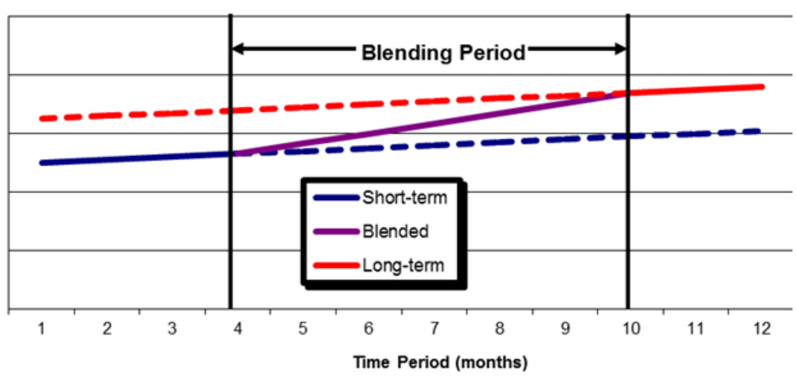
The Company has one customer with interruptible provisions in their contracts. This customer has interruptible contract capacity of 50 MW. However, this customer is expected to have 17 MW and 24 MW available for interruption at the time of the winter and summer peaks, respectively. An additional 1,713 customers have 54 MW available for interruption in emergency situations in DR agreements. The Company has a voluntary thermostat control program with 7,115 sites and a potential of 6 MW. 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 3.1.

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 2021 and 2022 were typically taken from the short-term process. Forecast values for 2023 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 2023 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 13 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 13: Load Forecast Blending



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 2021 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.

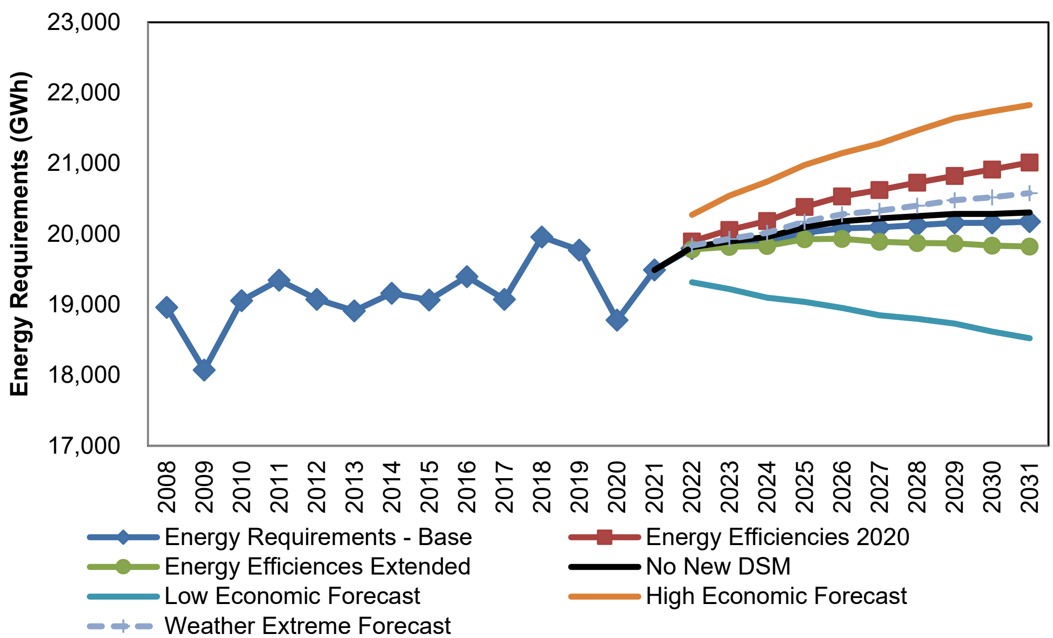
The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for PSO are tabulated in Exhibit A-6. Graphical displays of the range of forecasts, including the weather scenario, of summer peak demand and winter peak demand for PSO are shown in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

For PSO, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2031, represent deviations of about 8.2% below and 8.2% above, respectively, the base-case forecast.

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

Figure 14 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

Figure 14: PSO's 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 2021 scenario keeps energy efficiencies at 2021 levels for the residential and commercial equipment. Both scenarios result in a load forecast greater than the base forecast.

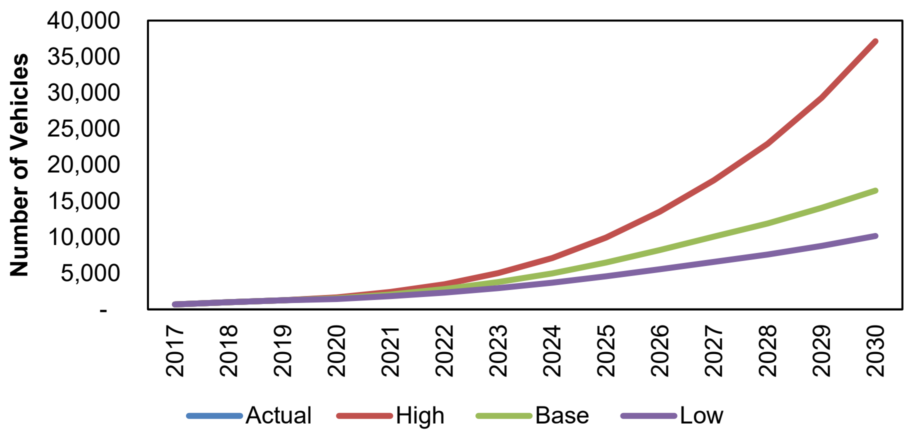
The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the EIA. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial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

Although the Company does not explicitly account for enhanced adoption of electric vehicles in the load forecast, it does continually monitor the adoption rate and will address the issue as it becomes more significant. The Company has developed high, low, and base scenarios on adoption in the service area through 2030. These scenarios a presented graphically in Figure 15.

Figure 15: PSO Service Area Electric Vehicle Forecast Scenarios



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 0.32. For comparison, the estimated long-term elasticity for gasoline is 0.6 while the elasticity for restaurant meals is 2.3[2]. (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.)

2 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. Current Resource Evaluation

3.1. Introduction

PSO's resource portfolio comprises a diverse set of supply- and demand-side resources that serve the Company's capacity, energy, and other reliability requirements. The generating resources include a mix of wind, solar, and fossil-fired resources. The demand-side resources include active demand response ("DR") and energy efficiency ("EE") programs. Customers wishing to generate their own energy can also participate in PSO's distributed generation ("DG") program, which has recently seen exponential growth.

3.2. Existing PSO Generation Resources

Table 1 identifies the current PSO generating resources.

Table 1: PSO's Owned Generation Asset as of May 7, 2021

Unit Name	Primary Fuel Type	C.O.D.[1]	Rating (MW)[2]
Comanche 1	Gas (CC)	1973	220
Northeastern 1	Gas (CC)	1980	422
Northeastern 2	Gas Steam	1970	434
Northeastern 3	Coal	1979	465
Riverside 1	Gas Steam	1974	448
Riverside 2	Gas Steam	1976	448
Riverside 3	Gas (CT)	2008	72
Riverside 4	Gas (CT)	2008	72
Southwestern 1	Gas Steam	1952	56
Southwestern 2	Gas Steam	1954	79
Southwestern 3	Gas Steam	1967	311
Southwestern 4	Gas (CT)	2008	74
Southwestern 5	Gas (CT)	2008	75
Tulsa 2	Gas Steam	1956	164
Tulsa 4	Gas Steam	1958	158
Weleetka 4	Gas (CT)	1975	47
Weleetka 5	Gas (CT)	1976	49
Sundance	Wind	2021	91 (A)
Maverick	Wind	2021	131 (A)
Traverse	Wind	2022	455 (A)

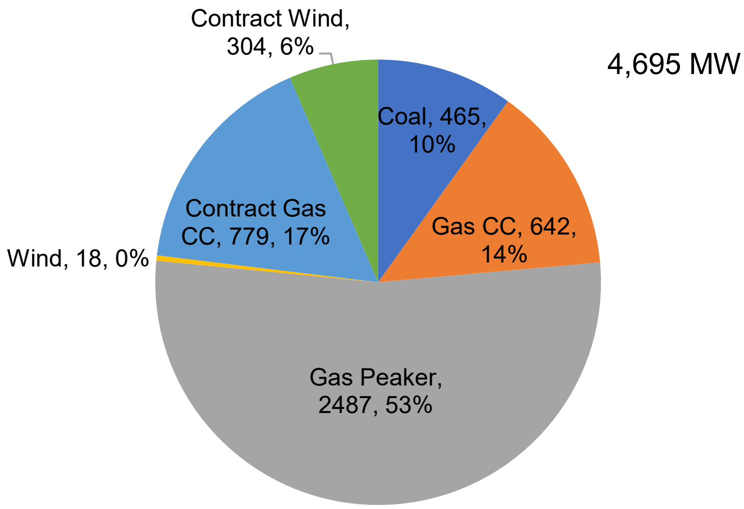
(1) Commercial operation date

(2) Peak net dependable capability (Summer) as of filing.

(A) Installed capacity; Represents PSO's 45.5% ownership stake

PSO currently has a total of 1,137 MW (nameplate) of wind capacity from eight wind facilities. The Company receives capacity, energy, and renewable energy credit attributes from these projects under separate renewable energy PPAs. The capacity contribution for summer peak resource adequacy of these projects is 304 MW. Figure 16 shows PSO's current owned and contracted generation capacity contribution for peak.

Figure 16: PSO Generation Asset Summer Capacity Contribution by Type (MW)



3.3. Current Demand-Side Programs

PSO utilizes cost effective demand-side programs as a tool in meeting its load obligation reliably and sustainably, while maintaining customer affordability. PSO's demand-side portfolio include customer DR, customer EE, distributed energy resources ("DER") and CVR. PSO has successfully designed, implemented, and reported on Demand Portfolio programs since 2008. PSO recently received Order 720134 in PUD 202100041, approving the 2022-2024 Demand Portfolio plan. In the PUD 202100041 application to the commission, PSO requested a waiver to extend the portfolio period to 2026. This request was not approved.

The programs assumed for the 2022-2026 period closely mirror the existing programs, discussed in Section 3.3.1 and 3.3.2, recognizing some consolidation for cost savings, new technologies and market changes. The portfolio includes funding to conduct research in development (R&D) pilots that may lead to future programs. The R&D program includes the following pilots.

1. Demand Management Integrated Resources to research innovative and emerging technologies to enhance PSO's demand response program offerings. This will consist of two primary components:
    - Battery Storage (site solar/battery)
    - Connected Water Heaters and other devices
2. Efficient Homes and Communities to review and field test residential technologies:
    - Efficient Community Demonstration will study shared ground-source and air-source heat pumps, shared solar projects with battery storage, and solar streetlights with battery backup.
    - Manufactured New Homes will offer incentives for high efficiency low-cost homes.
    - Zero-Net Energy Homes (ZEH) will provide incentives for ZEH new construction or ZEH-ready homes.
    - Solar Water Heating will study solar water heating technology for new construction homes.

3. Non-Wires Solution to research a capacity constrained circuit(s) in PSO service territory to reduce demand through energy efficiency and other portfolio measures.
4. Virtual Diagnostics Tool to use AMI meter data to identify new energy efficiency and demand response opportunities for residential and commercial customers.

3.3.1. Customer Demand Response Programs

PSO's demand response portfolio consists of two programs: Power Hours and Peak Performers. The demand response programs sole aim is to provide load reduction capabilities during times of high demand. However, because of participants' voluntary load reductions during event days, there are energy savings associated with the program. These energy savings are not persistent in the same way that the installation of energy-efficient equipment provides energy savings for the life of the equipment; rather energy savings from the Business DR Program only occur during event days.

The Power Hours Program, which targets residential customers provides ways to reduce energy usage of residential customers during peak demand periods by offering customers the option of participating in Direct Load Control ("DLC") events through connected smart thermostats. PSO provides rebates for the purchase of new smart thermostats. DLC events reduce energy usage when demand is highest by communicating with registered Wi-Fi enabled thermostats installed in the homes of participants. Participating customers agreed to allow PSO to adjust the thermostat by a few degrees during an event. The customer has the option of opting out of an event through the thermostat. Incentives are set at $2.50 per participating event. There is no direct penalty for opting out of specific event days. PSO calls no more than sixteen per year.

Under the Business Demand Response Program, known as Peak Performers, which targets commercial and industrial customers, customers voluntarily reduce their electricity load during PSO called load reduction events in exchange for paid incentives based on the average electricity usage reduction over the course of all events. Incentives are set at $32 per average kW reduction over all event hours and participants receive a 5 percent payment bonus if they participate in all reduction events throughout the year. There is no direct penalty for opting out of specific event days. PSO calls no more than three peak events per week, no more than four per month, and no more than twelve per year. The program is active during summer months when average demand typically approaches designated capacity thresholds.

Current Customer Participation

The number of residential customers participating in the Power Hours Program in 2020 was 23,681 customers with 9,104 devices participating in DLC, which yielded a net energy savings of 2,438 MWh and reduced the peak demand by a net demand of approximately 6,187 kW. The Business Demand Response Program is evaluated by industry sector. The top three facility types that participated during 2020 were K-12 schools (29 percent), offices (23 percent), and industrial / manufacturing facilities (11 percent). The Business Demand Response Program yielded a net energy savings of approximately 37.1 MWh and reduced peak demand by a net demand of approximately 47.4 MW. For both programs, the 2020 demand impacts were lower than historical due to a mild summer and the COVID impact on the economy[3].

3 Public Service Company of Oklahoma, 2020 Energy Efficiency & Demand Response Programs: Annual Report, March 2021

3.3.2. Customer Energy Efficiency Programs

PSO offers residential customers and commercial / industrial customers EE options designed to reduce energy usage while providing the same or improved service. Program performance is assessed on a levelized dollar per lifetime energy savings (kWh) basis and cost effectiveness test defined by the California Standard Practice Manual[4].

Current Available Energy Efficiency Programs to Customers

In 2020, PSO offered customers eight energy-efficiency programs that included five residential, one commercial / industrial, and two cross-sector programs. The residential programs included Home Weatherization, Energy Saving Products, Home Rebates, Education, and Behavioral Modification. The commercial / industrial program included Business Rebates and the two cross-sector programs included Multi-Family and Conservation Voltage Reduction. The latter program, Conservation Voltage Reduction ("CVR"), is discussed in more detail in Section 3.3.4.

Current Program Results

Table 2 provides a summary of the EE program net energy impacts:

Table 2: Summary of EE Program Net Energy Impacts - 2020

Program	Net MWh	Net MW
Business Rebates	44,396	7.54
Multi-Family	3,106	0.82
Home Weatherization	4,240	2.25
Energy Saving Products	33,256	5.93
Home Rebates	5,313	2.22
Education	3,596	0.74
Behavioral	21,063	4.11
Conservation Voltage Reduction	14,426	4.17
Energy Efficiency Totals	**129,396**	**27.77**

PSO's Business Rebates Program provided a range of energy efficiency measures for small businesses, large businesses, schools, municipalities, and industrial businesses to participate in receiving an incentive to reduce energy consumption. The Business Rebates Program offered subprograms of Small Business Energy Solutions ("SBES"), Midstream, and Custom and Prescriptive ("C&P"). The program offers incentives for many measures including lighting, plug load & controls, Insulation, Windows & Doors, Appliance & Equipment, HVAC, and Refrigeration.

The Multifamily Program is in its second year in the portfolio serving 112 dwellings. To be eligible for the Multifamily Program, the property must be composed of three or more dwelling units with the service territory. Energy efficiency equipment is eligible within dwelling units, in common areas, and in office spaces. The Multifamily Program offers commercial measures in addition to the residential measures. The measures include LED lamps and fixtures, air infiltration, ceiling insulation, duct sealing, HVAC system replacements, water heaters, ENERGY STAR® windows, ENERGY STAR® pool pumps, ENERGY STAR® washing machines, ENERGY STAR® dryers, vending machine controls, and ice machines.

4 The California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects, 2001 edition, produced by the California Energy Commission and the California Public Utility Commission

PSO's Home Weatherization Program objective is to generate energy savings and peak demand reduction for limited income residential customers through the direct installation of weatherization measures in eligible dwellings. The weatherization program provides no-cost energy efficiency improvements to PSO customers with household incomes of $50,000 or less a year.

PSO's Energy Saving Products ("ESP") Program seeks to generate energy and demand savings for residential customers through the promotion of a variety of energy efficient measures. The ESP upstream program consisted of retail price discounts for qualifying LED light bulbs, room air purifiers, advanced power strips, bathroom ventilation fans, water dispensers, spray foam, door sweeps and seals, room air conditioners, and air filters. The program also included distribution of free LEDs in partnership with food banks and local food pantries within the PSO service territory. The ESP downstream program offers mail-in rebates from PSO for qualifying heat pump water heaters, clothes dryers, clothes washers, refrigerators, and level 2 electric vehicle chargers.

The Home Rebates Program seeks to generate energy and demand savings for residential customers through the promotion of comprehensive efficiency upgrades to building envelope measures and HVAC equipment for both new construction homes and retrofits to existing homes. Offering PSO customers direct inducements for higher efficiency measures offsets the first cost obstacle, encouraging customers to choose the upgraded products. The program has three components: New Homes, Multiple Upgrades, and Single Upgrade.

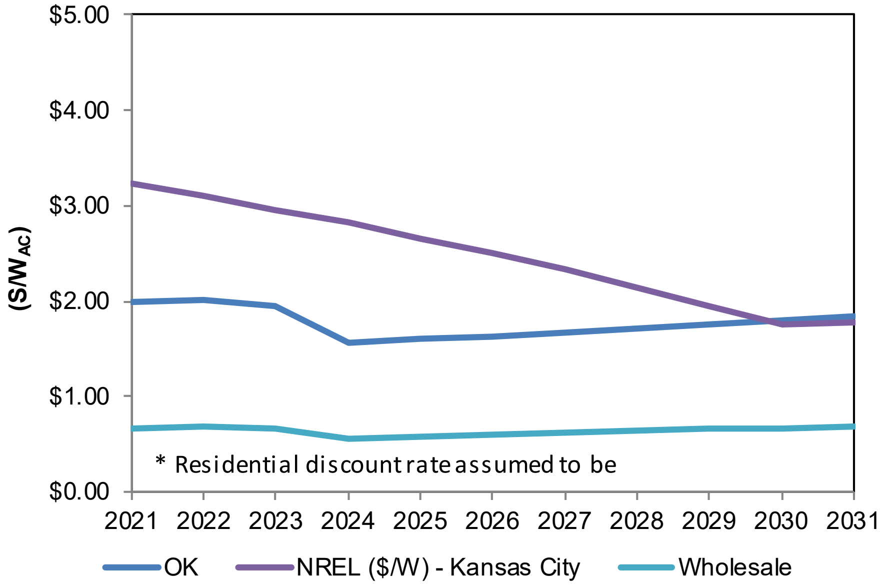
The PSO Education Program, known by teachers, students, and parents as the PSO Energy Saver Kits Program, provides educational materials and energy-efficient products to 5th grade students. The program annually provides approximately 16,000 students and families with the opportunity to learn about energy efficiency and provides energy efficient products to reduce home energy use.

The Behavioral Modification Program provides energy usage reports to approximately 190,000 residential customers. The program was designed to generate greater awareness of energy use and ways to manage energy use through energy efficiency education in the form of an energy report. The energy report provides customers with energy saving behaviors and compares their current energy use to previous years as well as energy use in similar homes. It is expected that through this education, customers will adopt energy conservation tips that will lead to more efficient energy use in their homes. Customers can choose to opt out if they no longer want to receive the emailed energy reports. In addition to receiving a report that encourages saving energy, participants are also encouraged to go to an online portal where they could input more specific information to receive tips addressing their specific energy use.

3.3.3. Customer-Owned Distributed Energy Resources

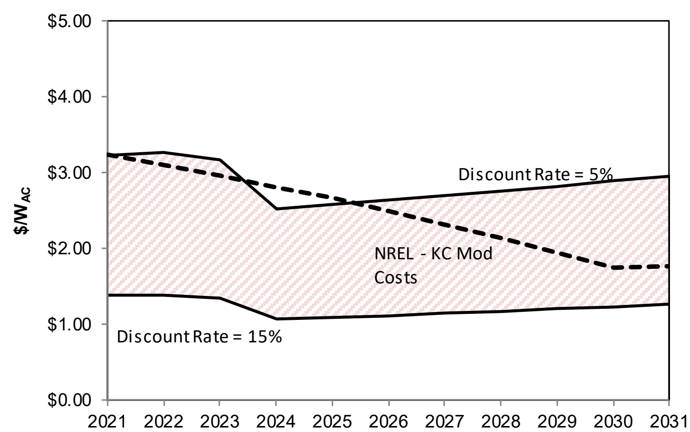
The economics of distributed generation ("DG"), particularly solar, continue to improve but the economics of such an investment are not favorable for the customer for a number of years. Figure 17 below illustrates, by PSO state jurisdictional residential sector, the equivalent value a customer would 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 17 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 NREL cost of solar residential installations in SPP. Figure 17 below 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 17: 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 18 below, shows how the value of an Oklahoma residential customer's DERs system can vary based on discount rate.

Figure 18: Distributed Solar Customer Breakeven Costs for Residential Customers ($/W$_{AC}$)

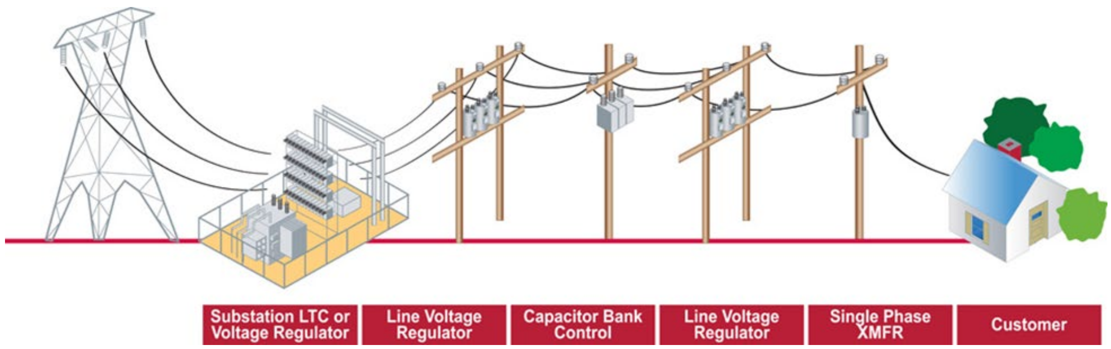


PSO supports customers who are installing their own DERs and seeks rates that accurately reflect the true cost to serve them. The Company's website, https://www.psoklahoma.com/business/industry-solutions/, provides customers with ideas and links related to energy transformation solutions and energy savings. Additionally, PSO provides renewable options including ways to be 100% wind energy at https://www.psoklahoma.com/clean-energy/renewable/.

3.3.4. Conservation Voltage Reduction

PSO's Conservation Voltage Reduction ("CVR") Program uses a system of devices, controls, software, and communications equipment to manage reactive power flow and lower voltage level for implemented distribution circuits. With the usual system design, customers close to a substation receive voltages closer to 126 volts and customers farther from the substation receive lower voltages. Because most electric devices are designed to operate most efficiently at 115 volts, any "excess" voltage is typically wasted, usually in the form of heat. Figure 19 depicts an overview of the CVR installation.

Figure 19: CVR Optimization Schematic



PSO's CVR program uses a software program called "Yukon", a control system from Eaton that monitors the voltage and power factor along the distribution circuit and lowers the voltage profile within an acceptable bandwidth. The tighter voltage regulation provided by CVR technology allows end-use devices to operate more efficiently without any action on the part of consumers. The average consumer receives a lower but still acceptable voltage and use less energy to accomplish the same tasks. PSO has approached the implementation of CVR in a holistic, system-wide manner, to fully optimize the energy efficiency potential.

PSO has implemented CVR on 86 distribution circuits through the end of 2020 and seeks to continue implementing CVR in the 2022-2024 Demand Portfolio, consistent with PSO's commitment to CVR as shown its Integrated Resource Plans dating back to the 2015 Integrated Resource Plan. The circuits deployed for 2020, achieved an annual net energy savings of approximately 14,425,875 kWh and an annual net peak demand savings of approximately 4,169 kW.

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.

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, SO2 in 2010 and ozone in 2015; the existing standards for NO2 were retained after review by the Federal EPA in 2018 and 2019, respectively. 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 SO2 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. The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA confirmed that the CSAPR program satisfied all interstate transport obligations associated with the 2008 ozone standard, but that finding was reversed by the U.S. Court of Appeals for the D.C. Circuit. That court also remanded the 2015 secondary ozone standard and is reviewing Federal EPA’s 2018 rule governing implementation of the 2015 ozone standard.

The Federal EPA completed external review drafts of the integrated science assessment and policy assessment for the ozone standard in 2019. Any further changes will require additional rulemaking. 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 NOx, SO2 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. The Federal EPA announced in 2019 it would reconsider the visibility program revisions in response to petitions for reconsideration. 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 SO2 and NOx 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 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 initial SIP must require certain eligible facilities to conduct an emission control analysis, known as a BART analysis, to evaluate emissions control technologies for NOx, SO2 and particulate matter ("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 EGUs greater than 250 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. The Federal EPA announced in 2019 it would reconsider the visibility program revisions in response to petitions for reconsideration. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

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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
- Within the same Regional Haze agreement, PSO committed to evaluate, within calendar year 2021, whether the projected generation from Northeastern 3 can be replaced by

lower or equal total projected cost natural gas or renewable resources. If power is available from such resources, then Northeastern Unit 3 is to retire no later than December 31, 2025. The Company will perform this analysis in the fourth quarter of 2021.

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. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin / furans. Compliance was required within three years. The Company obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

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 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the Federal EPA proposed to retain the current MATS standards without change. A final rule adopting the findings in the proposal was issued in April 2020. The rule has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit.

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 SO2 and NOx 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 SO2 and/or NOx 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 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 was challenged in the courts and in 2019, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) remanded the CSAPR Update to the Federal EPA because it determined the Federal EPA had not properly considered the attainment dates for downwind areas in establishing its partial remedy, and should have considered whether there were available measures to control emissions from sources other than generating units. In March 2021, EPA finalized a Revised CSAPR Update Rule to address the Court's concerns. The revised rule reduced the Ozone Season NOx budgets of 12 states beginning in 2021, of which Oklahoma was not one.

PSO will rely on the installed NOx and SO2 reduction systems, the use of allocated NOx and SO2 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 (CO2) Regulation**

In October 2015, the Federal EPA published the final CO2 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 CO2 emissions from existing sources, known as the Clean Power Plan (CPP).

The final rules were challenged in the courts. In 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, pending a final decision by the U.S. Court of Appeals for the District of Columbia Circuit and any petitions for review to the U.S. Supreme Court. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance, and issued a final rule repealing the CPP in 2019. The cases were then dismissed.

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 2019, the Federal EPA finalized the Affordable Clean Energy (ACE) rule replacing the CPP with new emission guidelines for regulating CO2 from existing sources. The ACE rule required states to evaluate the applicability and effect of implementing specific heat rate improvement measures at coal-fired generating units, and to develop a standard of performance for each affected unit within their jurisdiction. State plans were due in July 2022; however, in January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it to the Federal EPA. It is too soon to predict how the Federal EPA will respond to the court's remand. In 2018, the

Federal EPA also proposed to revise the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. That rule has not been finalized.

Absent CO2 regulatory certainty, AEP has taken action to reduce and offset CO2 emissions from its generating fleet and expects CO2 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 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. In 2018, some AEP operating company facilities were required to begin monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures. Based on additional groundwater data, further studies to design and assess appropriate corrective measures have been undertaken at two facilities.

In a challenge to the final 2015 rule, the parties initially agreed to settle some of the issues. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit addressed or dismissed the remaining issues in its decision vacating and remanding certain provisions of the 2015 rule. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

Prior to the court's decision, the Federal EPA issued the July 2018 rule that modifies certain compliance deadlines and other requirements in the 2015 rule. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted the Federal EPA's motion. During 2019 and 2020, Federal EPA proposed multiple rulemakings to address the court's decisions and stakeholder concerns. In August 2019, the Federal EPA published a proposal to revise the beneficial use criteria and definition of CCR piles. In December 2019, the Federal EPA published proposed revisions to implement the court's decision regarding timing for closure of unlined surface impoundments and impoundments not meeting the required distance from an aquifer. The comment period closed in January 2020. The Federal EPA also published a proposed federal CCR permit program in February 2020, implementing the Water Infrastructure Improvements for the Nation Act, which will apply in states that do not have a federally approved state CCR program. In March 2020, the Federal EPA published a proposed rule that would allow a facility to make an alternative demonstration to continue operating unlined surface impoundments. In August 2020, the Federal EPA finalized its proposed revisions to the CCR rule to include a requirement that unlined CCR storage ponds cease operations and initiate closure by April 11, 2021. The revised rule provides two options that allow facilities to extend the date by which they must cease receipt of coal ash and close the ponds.

The first option provides an extension to cease receipt of CCR no later than October 15, 2023 for most units, and October 15, 2024 for a narrow subset of units; however, the Federal EPA's grant of such an extension will be based upon a satisfactory demonstration of the need for additional time to develop alternative ash disposal capacity and will be limited to the soonest timeframe technically feasible to cease receipt of CCR.

The second option is a retirement option, which provides a generating facility an extended operating time without developing alternative CCR disposal. Under the retirement option, a generating facility would have until October 17, 2023 to cease operation and to close CCR storage ponds 40 acres or less in size, or through October 17, 2028 for facilities with CCR storage ponds greater than 40 acres in size.

Under both the first and second options, each request must undergo formal review, including public comments, and be approved by the Federal EPA. AEP's applications are still pending before Federal EPA.

Because AEP operating companies currently use surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities and conduct any required remedial actions. Closure and post-closure costs have been included in Asset Retirement Obligation (ARO) in accordance with the requirements in the final rule. Additional ARO revisions will occur on a site-by-site basis if groundwater monitoring activities conclude that corrective actions are required to mitigate groundwater impacts, which could include costs to remove ash from some unlined units.

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 represent an "unpermitted discharge" under the Clean Water Act (CWA). Two cases were accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. In April 2020, the Supreme Court issued an opinion remanding one of these cases to the Ninth Circuit Court of Appeals based on its determination that discharges from an injection well that make their way to the Pacific Ocean through groundwater may require a permit, if the distance traveled, the length of time to reach the ocean, and other factors make it "functionally equivalent" to a direct discharge from a point source. The second case was also remanded to the lower court.

Prior to the Supreme Court's decision, the Federal EPA opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to ground water, and issued an interpretative statement considering comments received in the rulemaking docket and determined that "releases to groundwater are excluded from the scope of the National Pollutant Discharge Elimination System (NPDES) program, even where pollutants are conveyed to jurisdictional surface waters via groundwater." In December 2020, the Federal EPA issued draft guidance for public comment on applying the outcome of the Supreme Court's decision and consideration of functionally equivalent factors. The impact of these developments on CCR units will be determined by further EPA guidance, additional permitting decisions, and future action from the courts.

3.4.9. Clean Water Act Regulations

Clean Water Act "316(b)" Rule

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants pursuant to section 316(b) of the Clean Water Act that is intended to reduce mortality of aquatic organisms impinged or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's NPDES permit as those permits are renewed and have been incorporated into permits at several AEP facilities. AEP facilities that have had their wastewater discharge permits renewed have been asked to monitor intake flows or to enhance monitoring practices to assure the current technology is being properly managed to ensure compliance with this rule.

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines (ELG) for generating facilities. The 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 would be implemented through each facility's wastewater discharge permit. The rule was challenged in the U.S. Court of Appeals for the Fifth Circuit. In 2017, the Federal EPA announced its intent to reconsider and potentially revise the standards for FGD wastewater and bottom ash transport water. The Federal EPA postponed the compliance deadlines for those wastewater categories to be no earlier than 2020, to allow for reconsideration. In April 2019, the Fifth Circuit vacated the standards for landfill leachate and legacy wastewater, and remanded them to the Federal EPA for reconsideration. Those standards have not been reissued. In November 2019, the Federal EPA proposed revisions to the standards for FGD wastewater and bottom ash transport water discharges from existing generation facilities. A final rule was published in the Federal Register on October 13, 2020, establishing additional options for reusing and discharging small volumes of bottom ash transport water, provides an exception for retiring units, and extends the compliance deadline to a date as soon as possible beginning one year after the rule is published but no later than December 2025. The Company has assessed technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water. Permit modifications for affected facilities were filed in January 2021 that reflect the outcome of that assessment.

3.4.10. Waters of the United States ("WOTUS") Rule

In 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. Various parties challenged the 2015 rule in different U.S. District Courts, which resulted in a patchwork of applicability of the 2015 rule and its predecessor. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers proposed a replacement rule. In September 2019, the Federal EPA repealed the 2015 rule. The final replacement rule was published in the Federal Register in April 2020 and became effective in June 2020. The final rule limits the scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, artificial ponds, and waste treatment systems. Challenges to the final rule and requests for a preliminary injunction have been brought by states and other groups in multiple U.S. District Courts. In June 2021, federal EPA announced its intent to reconsider and revise the rule. Meanwhile, in August 2021, a District Court in Arizona vacated the rule and remanded it to federal EPA. Federal EPA and the Army Corps of Engineers have indicated that in light of the District Court's order, the agencies will halt implementation of the 2020 rule and will interpret "Waters of the United States" consistent with the pre-2015 regulatory regime until further notice. The Company is monitoring these various proceedings.

In April 2020, the U.S. District Court for the District of Montana issued a decision vacating the U.S. Army Corps of Engineers' (Corps) General Nationwide Permit 12 (NWP 12), which provides standard conditions governing linear utility projects in streams, wetlands and other waters of the United States having minimal adverse environmental impacts. The Court found that in reissuing NWP 12 in 2017, the Corps failed to comply with Section 7 of the Endangered Species Act (ESA), which requires the Corps to consult with the U.S. Fish and Wildlife Service regarding potential impacts on endangered species. The Court remanded the permit back to the Corps to complete its ESA consultation, and also enjoined the Corps from authorizing any dredge or fill activities under NWP 12 pending completion of the consultation process. The Department of Justice filed a motion to stay the injunction and tailor the remedy imposed by the Court. In May 2020, the Court revised its order lifting the injunction for non-oil and gas pipeline construction activities and routine maintenance, inspection, and repair activities on existing NWP 12 projects. The Department of Justice appealed the Court's decision to the Court of Appeals for the Ninth Circuit and moved for stay pending appeal, which was denied. In June 2020, the Department of Justice submitted an application to the U.S. Supreme Court requesting a stay of the District Court's Order, and the Court granted the request with respect to all oil and gas pipelines except the Keystone Pipeline. The Company is monitoring the litigation and evaluating other permitting alternatives but is currently unable to predict the impact of future proceedings on current and planned projects.

In September 2020, the Corps issued for public comment the proposed renewal of all General Nationwide Permits. As part of that proposal the Corps has narrowed the focus of NWP 12 to only oil and natural gas pipeline activities. The Corps proposed two new Nationwide Permits governing electric utility line and telecommunications activities, and other utility lines (e.g., conveyance of potable water, sewage, other substances), respectively. In January 2021, the Corps issued 16 final Nationwide Permits, including NWP 12 and the two new utility line permits, NWP 57, and NWP 58. The Corps chose not to reissue or modify the remaining Nationwide Permits at this time. The 2017 versions of those permits remain in effect. Management is currently assessing impacts of the rulemaking on current and planned projects.

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

3.4.11. 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.

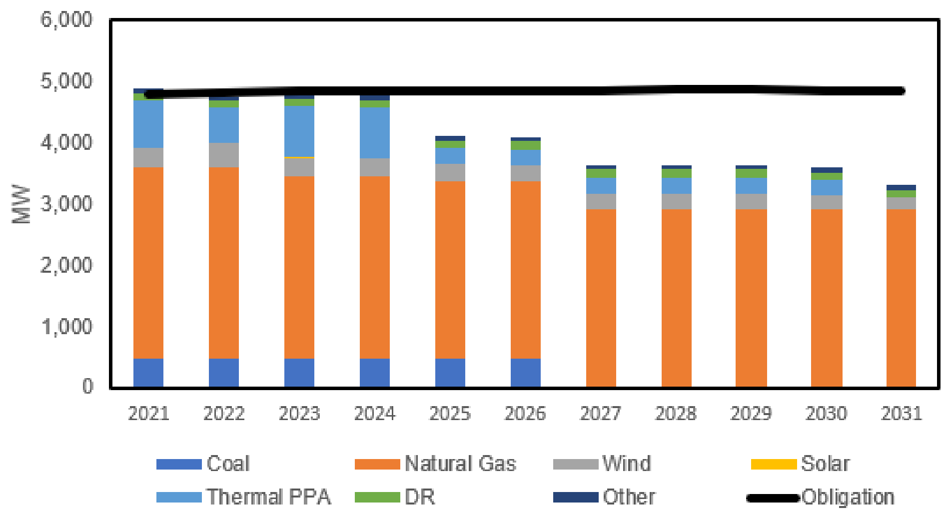
Northeastern Unit 3 may require modification of its bottom ash handling system in future years. However, a request for a Fundamentally Different Factors variance from the bottom ash transport water restriction was submitted in 2016 and no action has yet been taken.

3.5. Capacity Needs Assessment

Figure 20 illustrates the starting capacity needs of PSO through 2031. PSO's capacity need is the difference between the load obligation which includes the minimum reserve margin (denoted by the black line) and the capacity of the existing generation resources by year (denoted by the bars). A significant capacity gap emerges in 2025 due to planned retirement of existing units and expiration of thermal PPA. PSO plans to retire five units in the next five years: Weleetka (gas CT) units 4 and 5 in 2022; Southwestern (gas CT) units 1 and 2 in 2022 and 2024; and the Northeastern (coal) unit 3 in 2026.

Additionally, PSO utilizes two Power Purchase Agreements ("PPA") to meet the minimum SPP reserve margin requirement and customers' energy needs. The first PPA, expiring in 2024, is a 520 MW contract with Exelon Generating Company LLC from the Green Country Energy plant located in Jenks, Oklahoma. The other agreement, expiring in 2030, is a 260 MW contract with the Calpine Oneta gas plant.

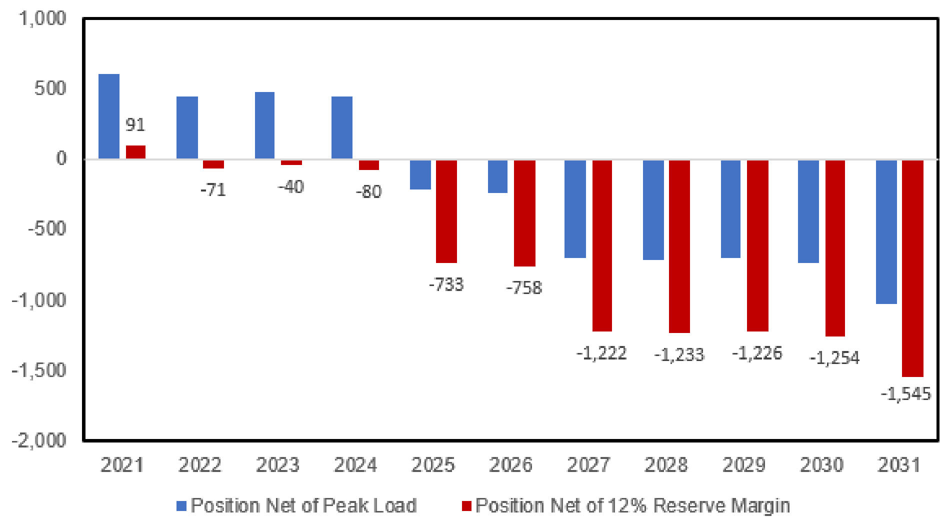
Figure 20: PSO "Going-In" SPP Capacity Position and Obligation



PSO assumes a minimum reserve margin of 12.0%[5] in its resource planning. The minimum reserve margin is the result of SPP's system reliability assessment. Figure 21 illustrates PSO's net capacity position with respect to the Company's load obligation, and with respect to SPP's 12% reserve margin requirement.

5 Per Section 4 of the "SPP Planning Criteria" (Latest Revision: April 2, 2021).

Figure 21: PSO Capacity Position net of SPP Reserve Obligation



PSO also considered winter seasonal requirements as part of the 2021 IRP. One market scenario, the Focus on Resiliency case (discussed in Section 7), enforces a 12% planning requirement in winter and changes to the resource adequacy contribution of different technologies. Seasonal capacity needs are filled by supply- and demand-side resources using the AURORA model. DSM resource options are discussed in Section 6 and new utility-scale resources are covered in Section 5.

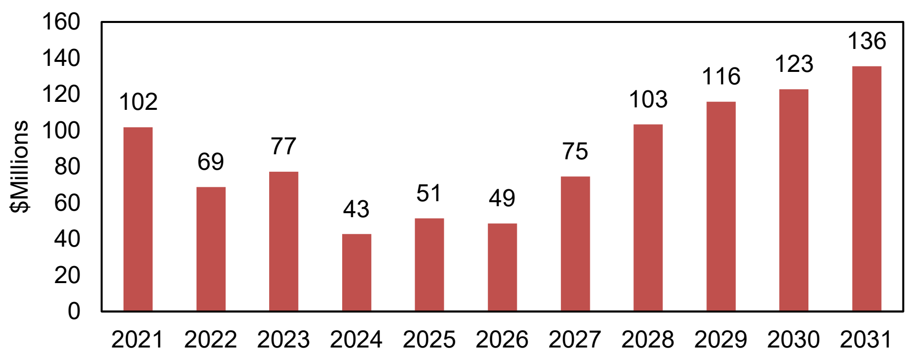
4. Transmission and Distribution Evaluation

4.1. Transmission System Overview

AEP continues supporting the SPP Transmission Expansion Plan ("STEP") and the SPP Integrated Transmission Planning Assessment ("ITP") processes, which include some projects which may improve import capability. PSO has 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.

The portion of the AEP Transmission System operating in SPP (AEP-SPP zone, or AEP-SPP) consists of approximately 1,500 miles of 345 kV, approximately 3,750 miles of 138 kV, approximately 2,300 miles of 69 kV, and approximately 390 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. Figure 22 shows PSO's forecasted transmission capital expenditures throughout the IRP's ten-year planning period.

Figure 22: Transmission Capital Spend Forecast for PSO



4.2. 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. 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. 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. 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/

4.3. 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 2021 STEP summarizes 2020 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. Balanced Portfolio,
5. High Priority Studies,
6. Sponsored Upgrades,
7. Interregional Coordination, and
8. Integrated Transmission Planning 20-Year Assessment

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 2021 STEP identified 386 transmission network upgrades with a total cost of approximately \$3.19 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 68% of the total cost in the 2021 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 2021 STEP is available at:
https://www.spp.org/documents/56611/2021%20step%20report.pdf

4.4. Recent AEP-SPP Bulk Transmission Improvements

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.

4.4.1. AEP-SPP Import Capability

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.

4.4.2. 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 – Woodward / Border tie 345 kV line. This project allows more east Texas / west Oklahoma bulk transfer capabilities.

- Chisholm – Woodward / Border tie 345 kV line. This project allows more east Texas / west Oklahoma bulk transfer capabilities.
- Sooner to Wekiwa 345 kV line build. This project was a competitive project awarded to Transource and relieves congestion in the west Tulsa area for the outage of Cleveland to Tulsa North 345 kV line.

4.4.3. 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 Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line has been upgraded to a larger conductor with improved thermal capacity.

- **McAlester, Oklahoma area:** The McAlester City to Atoka 69 kV line has been rebuilt with new structures and upgraded to a larger conductor with improved thermal capacity.
- **Tulsa Metro, Oklahoma area:** The Tulsa area upgrades include Tulsa Southeast to E. 61st St, 138 kV line, Riverside Station Upgrade, Tulsa Southeast to S. Hudson 138 kV line, Tulsa Southeast to 21st Street Tap 138 kV line. These projects improve the capacity in the area with larger conductor and new breakers for the Riverside station.

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.

4.5. PSO Distribution System Overview

PSO serves approximately 562,618 customers in 232 cities and towns across 30,000 square miles of eastern and southwestern Oklahoma. This includes approximately 484,000 residential, 64,000 commercial, 6,800 industrial, and 8,300 other customers. PSO's Distribution Operations organization includes three districts: Tulsa, Lawton, and McAlester. PSO's distribution system includes approximately 15,300 overhead circuit miles and almost 5,200 underground circuit miles. PSO's distribution system includes approximately 15,900 primary miles and 4,600 secondary miles.

4.5.1. Distribution Investments

PSO's normal distribution investment portfolio includes projects that support employee and customer safety, new customer growth, customer requests for new service, customer satisfaction, conservation voltage reduction, as well as reliability improvements.

Since 2018, PSO has targeted additional investments on projects that support the safety and reliability of the distribution system as part of the Distribution Reliability and Safety rider portfolio.

In PSO's most recent rate case filing, PSO has proposed a significant investment to revitalize and transform its distribution grid. Successful implement of the proposed plan would require an approximately $500M in capital investment in PSO's distribution grid over the next five years. Table 3 provides an overview of this plan.

Table 3: PSO Grid Transformation and Infrastructure Program

Project Type	Estimated Spend (Millions $)
Distribution Automation / Circuit Reconfiguration (DA / CR)	77
Technology Deployment D-Line	103
Deploy Reclosing Technology D-Line	30
Deploy Sensors and Predictive Analysis Technology	8
Install Microgrid Technology	7
Overhead to Underground Conversion	25
Harden / Renew Distribution Line Infrastructure	165
Harden / Renew Distribution Substation Infrastructure	52
Technology Deployment D-Substation	9
Total	**476**

4.6. Impacts of New Energy Future

The current power system is designed for a one-way power flow with electricity flowing from transmission-connected generators through the transmission system down to the distribution system to customers. This is changing. The new energy future will require changes in how transmission, distribution and generation planning are conducted for PSO to continue delivering on our objectives of customer affordability, rate stability, system reliability, and positive local impacts and sustainability. This section discusses the impact of emerging trends of the new energy future that will impact future planning process and how PSO is evolving its planning capability to address future challenges. The emerging trends include:

- Increasing new transmission-connected additions;
- Electrification;
- Deployment of electric vehicles ("EVs"); and
- Increased DERs.

4.6.1. New Transmission-Connected Generation Capacity

Integration of additional transmission-connected 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 extra high voltage ("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.

4.6.2. Electrification

Electrification is the process of customer's converting end-uses such as heating, ventilation, air conditioner ("HVAC"), transportation and industrial machinery to electricity and away from fossil fuels. Economics, existing technology, climate goals, and continued advancements of electric technologies are key factors in the pace of electrification.

The electrification of end-use technologies in industry, buildings and the transportation sector has the potential to enable customers to be more energy efficient through the use of more and increasingly cleaner electricity while replacing direct fossil fuel use. This trend continues to grow as society seeks to replace fossil fuels with clean electricity to heat homes and buildings, power vehicles and operate industrial equipment. The benefits are significant for the environment, society, and business. However, the shift to an electrified economy requires

Distribution Planning to ensure infrastructure is in place to meet our customers' needs and the right policies and regulations are established to support them.

4.6.3. Electric Vehicle Charging Stations

On March 2, 2021, AEP, in partnership with five major utilities, announced plans for the Electric Highway Coalition. The plan will ensure that electric vehicle ("EV") drivers have access to a corridor of charging stations across several regions in the U.S. AEP, Dominion Energy, Duke Energy, Entergy Corp., Southern Co., and the Tennessee Valley Authority ("TVA") announced the plans to provide EV drivers with access to EV DC Fast Chargers along frequently traveled interstate roads. Each is taking steps to ensure sufficient EV charging stations within their service territories, as part of an unprecedented effort to create convenient travel solutions for EV drivers. Each station will be equipped to charge EVs in approximately 20 to 30 minutes. For added convenience, these stations will be strategically positioned along major highway routes, as a direct result of collaboration amongst the partnering companies and leveraging existing and planned compatible DC Fast charging stations. Millions of drivers will soon have access to the corridor, with initial site deployment scheduled for the third quarter of 2021. The Level 3-DC Fast Chargers already deployed along major transportation corridors in PSO's service territory already meets the current specifications of the Coalition. Therefore, no additional deployments are needed to fulfill the requirements. However, additional EV chargers could be deployed to supplement the existing locations, as warranted.

4.6.4. Distributed Energy Resources

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

4.7. Journey to Fully Integrated Planning Process

PSO believes that continuing to deliver safe, reliable, and affordable energy in the future power system will require an integrated approach between transmission, distribution, and resource planning. For example, local capacity needs that were previously met through transmission-connection generation might be addressed at a lower cost by distributed energy resources. Non-wire alternatives ("NWA") such as microgrid and distributed scale solar and storage might be a lower cost solution to transmission and distribution constraints than new wire assets. Resilience and safety are enhanced with better visibility over future EV deployment and distributed generation at distribution circuit level to allow the planners to plan for multiple load conditions and increase hosting capacity to integrate more green energy generation. Better visibility also allows PSO to better understand locational value of distribution generation across its network which could lead to more efficient pricing and reduce inequities among DER customers.

In meeting its mission in the power system of tomorrow, AEP, has recently created a new Regulated Investment Planning team which brings together under one organization Integrated Resource Planning & Analysis, Transmission Planning & Analysis, Distribution Planning & Analysis, and Interconnection Services. Regulated Investment Planning will plan AEP's regulated infrastructure programs across generation, transmission, and distribution to derive solutions that best meet the needs of customers.

Some elements of integrated planning process have been incorporated in this IRP. For example, PSO Distribution Planning along with AEP Corporate Planning analyzes the transition risks, physical risks and opportunities, and the socioeconomic aspect of coal plant retirements and involved a diverse team representing all parts of the company and including engineers; resource planners; meteorologists; and experts in generation, transmission, distribution, legal, air quality and environmental, along with enterprise risk and insurance, investor relations, economic development, customer solutions, and corporate sustainability, among others. PSO's internal team conducted the analysis and modeled potential scenarios. In addition, PSO consulted with numerous external resources, reports and studies, and climate expertise to further inform analysis.

Achieving a fully integrated planning process will require new tools, models, processes, and capabilities. To this end, AEP has engaged an external consultant to evaluate AEP's existing planning tools, models, processes and capabilities and produce a roadmap for AEP and PSO to achieve fully integrated planning. The project is in progress at the time of this report. In addition to the project, AEP will also continue to leverage new technologies, analytics, and automation as needed to deliver value for all stakeholders.

5. Supply-side Resource Options

5.1. Introduction

The future landscape of generation technologies has become increasingly uncertain. The roles of traditional technologies in providing base-load and intermediate-load electricity are being challenged by zero marginal cost renewable technologies. The emergence of advanced generation technologies could significantly change the future economics of generation rendering certain technologies obsolescent leading to a risk of premature retirements. The evolving electricity generation mix may also require a more diverse set of resources that can provide different system needs at different times to maintain system reliability particularly under extreme weather conditions.

The supply-side resource options considered by PSO in this IRP fall into five categories: base / intermediate alternatives, peaking alternatives, renewable alternatives, advanced generation alternatives and long-duration storage alternatives. As part of the consideration for advanced generation alternatives, this IRP also considers the potential opportunity to transition natural gas fueled technologies to utilize hydrogen when the hydrogen supply chain is sufficiently developed.

Unless stated otherwise, PSO relied on EIA's 2021 AEO as the starting point for the technology cost and performance assumptions for new utility scale generation in the SPP footprint. Reference case changes to technology cost and performance over time are based on the medium case of the 2020 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("NREL ATB 2020") report.[6] Cost assumptions for advanced technologies are generally based on a compilation of estimates from different external sources, reflecting uncertainties associated with cost estimates for technologies under development.

5.2. Base / Intermediate Alternatives

Base-load electricity is the minimum level of electricity demand in the system. Traditionally, base-load electricity demand is met by base-load power plants, i.e., plants that are optimized for continuous running and cannot vary their outputs quickly such as coal and traditional nuclear. However, the electricity supply mix is changing with increased intermittent renewable generation reducing the value of base-load electricity. Furthermore, regulations and changing customers' needs have made new coal and nuclear plant economically infeasible. As such, coal and traditional nuclear are not part of supply-side resource options in this IRP.

Unlike base-load power plants, intermediate power plants adjust outputs as electricity demand fluctuates, i.e., load following. This role is traditionally met by older and relatively less efficient power plant but as these power plants retire new capacity will be needed. For this IRP, natural gas combined cycle is considered as a resource option for intermediate power plants.

5.2.1. Natural Gas Combined Cycle (NGCC)

Natural gas combined cycle units combine a steam and a gas turbine cycle to generate electricity. In the gas turbine cycle, atmospheric air is pressurized using a compressor, injected with fuel, and ignited to generate high-temperature pressurized gas that expands to drive the turbine and generate electricity. The waste heat from the gas turbine is then used to

6 *NREL Electricity Annual Technology Baseline (ATB) 2020.* Retrieved from https://atb-archive.nrel.gov/electricity/2020/data.php

generate steam to drive a steam turbine to generate additional electricity, increasing generation efficiency.

Modern NGCCs have moderate capital costs, high generating efficiency, low carbon emissions, and the ability to load follow. These characteristics make the technology desirable for baseload and intermediate applications.

In addition, turbine manufacturers are developing the ability of new gas turbines to burn increasing volume of hydrogen in the gas steam. Recent turbines can burn up to 30% hydrogen by volume[7] in the gas steam and can be retrofitted to burn 100% hydrogen when the hydrogen supply chain is sufficiently developed. Section 5.5.3 provides further details on the modelling assumptions associated with retrofitting NGCC units to burn hydrogen exclusively.

NGCCs are modeled in AURORA as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. Two NGCC configurations in the model are available for selection, including the H-class turbine single shaft configuration with 430 MW capacity and the H-class turbine multi-shaft configuration with 1,100 MW capacity.

Overnight capital cost assumptions for NGCC options are shown in Figure 23. The variable operations and maintenance cost ("VOM"), the fixed operations and maintenance cost ("FOM") and heat rate assumptions are shown in Table 4.

Figure 23: Capital Cost Assumptions for NGCC

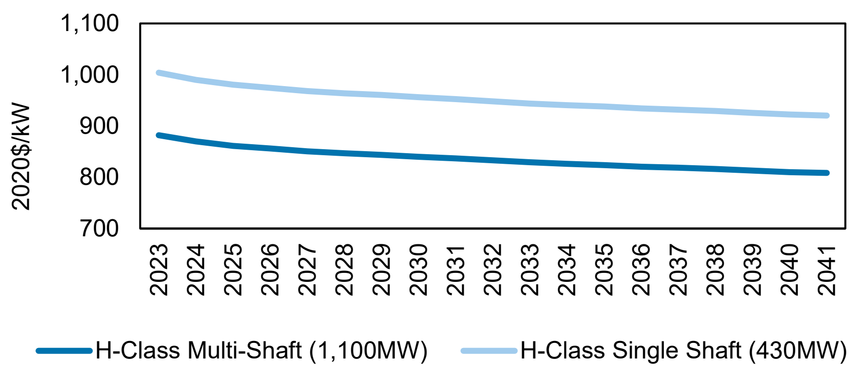


Table 4: Operating and Heat Rate Assumptions for NGCC

		H-Class Multi-Shaft (1,100 MW)	H-Class Single Shaft (430 MW)
VOM	$2020 / MWh	1.88	2.56
FOM	$2020 / kW-yr	12.26	14.17
Heat Rate	Btu / kWh	6,370	6,431

7 *Gas turbines in the US are being prepped for a hydrogen-fuelled future (2021).* Retrieved from https://www.nsenergybusiness.com/features/gas-turbines-hydrogen-us/

5.3. Peaking Alternatives

Peaking sources have traditionally provided top-up generating capacity during demand peaks that typically occur a few hours each year. Given the low utilization of peaking generators, focus in the past has been on minimizing capital and fixed costs instead of fuel efficiency and other variable costs.

More recently, greater amounts of intermittent renewable generation in the market combined with more extreme weather patterns have necessitated more flexible resources. For example, an unanticipated drop in wind generation during the day will require quick response from other generators to keep supply and demand in balance. A string of extreme cold weather days will require top-up generating capacity beyond the few hours each year traditionally supplied by peak generators. Certain peaking technologies can also provide ancillary services such as frequency response, black start, and inertia that help keep the system reliable. In this IRP, four peaking sources considered are simple cycle combustion turbines, aeroderivatives, reciprocating engines and lithium-ion batteries.

5.3.1. Simple Cycle Combustion Turbines (NGCT)

A combustion turbine system uses a compressor to pressurize atmospheric air, which is injected with fuel and ignited to generate high-temperature pressurized gas that expands to drive the turbine and generate electricity. Unlike NGCCs, unused energy is released as exhaust gases into the atmosphere instead of being recovered. NGCTs are usually expected to start up once a day and operate at full capacity during peak demand hours in the day, making them well suited for a power system with predictable peak patterns.

As discussed in Section 5.2.1, recent turbines can burn up to 30% hydrogen by volume in the gas steam and can be retrofitted to burn 100% hydrogen when the hydrogen supply chain is sufficiently developed. Section 5.5.3 provides further detailed on the modelling assumptions associated with retrofitting NGCT units to burn hydrogen exclusively.

NGCTs are modeled in AURORA as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One NGCT configuration is available for AURORA to select, i.e., the 240 MW F-Class unit.

The NGCT overnight capital cost assumptions are shown in Figure 24. FOM, VOM, and heat rate assumptions are shown in Table 5.

Figure 24: Capital Cost Assumptions for NGCT

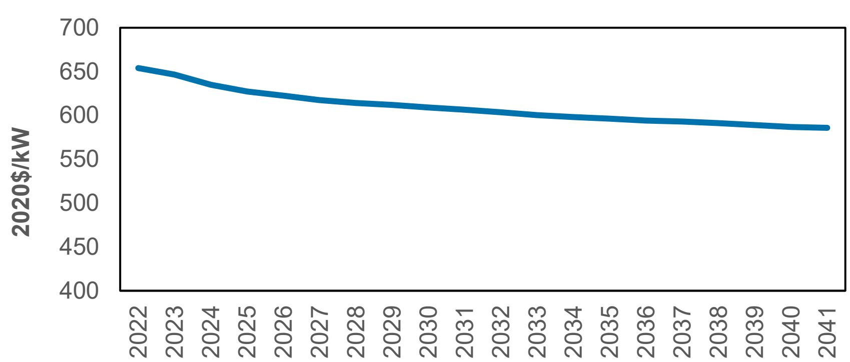


Table 5: Operating and Heat Rate Assumptions for NGCT

		F-Class CT (240 MW)
VOM	$2020 / MWh	0.61
FOM	$2020 / kW-yr	7.04

Heat Rate	Btu / kWh	9,905

5.3.2. Aeroderivative (AD)

Aeroderivatives units are aircraft jet engines used for power generation. Their operating characteristics make them well suited with high renewable penetration as they can quickly response to significant shift in supply and demand conditions in the power system. For example, the GE 9E series NGCT requires 30 minutes to start up whereas the GE LM6000 AD unit requires only 5 minutes. This allows AD units to operate at full load even for a small amount of time. In addition, AD units are more efficient in a simple cycle operation than NGCTs for capacity less than 100 MW. However, AD units are relatively more expensive than NGCTs.

AD units are modeled in AURORA in 100 MW units as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

The AD overnight capital cost assumptions are shown in Figure 25. FOM, VOM, and heat rate assumptions are shown in Table 6.

Figure 25: Capital Cost Assumptions for AD

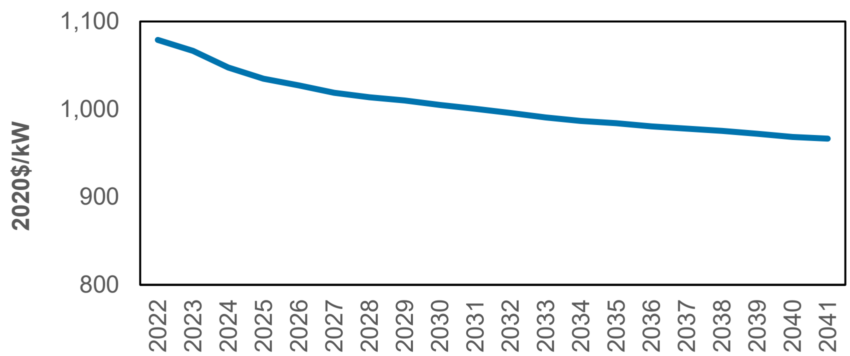


Table 6: Operating and Heat Rate Assumptions for AD

		AD (100 MW)
VOM	$2020 / MWh	4.72
FOM	$2020 / kW-yr	16.38
Heat Rate	Btu / kWh	9,124

5.3.3. Reciprocating Engines (RE)

Like NGCTs, REs rely on the combustion of air mixed with fuel to generate hot pressurized gases. Unlike NGCT, the expansion of these gases creates pressure which is used to drive a rotating motion to generate electricity. Multiple RE units are usually incorporated into a larger generating set for main grid applications.

RE generating sets can usually start and reach full load in less than five minutes, making them even faster than AD units in responding to system needs. RE generating sets can also run more efficiency at part load as individual RE units within the generating set can be shut down to reduce output while allowing remaining units to run a full load. Unlike NGCTs or ADs, RE units can by started multiple times in a day without incurring additional maintenance costs. These characteristics make RE units well suited for power systems that require frequent but short-duration dispatches such as those with high wind and solar penetration.

REs are modeled in AURORA in 20 MW units as a standard dispatch resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

The RE overnight capital cost assumptions are shown in Figure 26. FOM, VOM, and heat rate assumptions are shown in Table 7.

Figure 26: Capital Cost Assumptions for RE

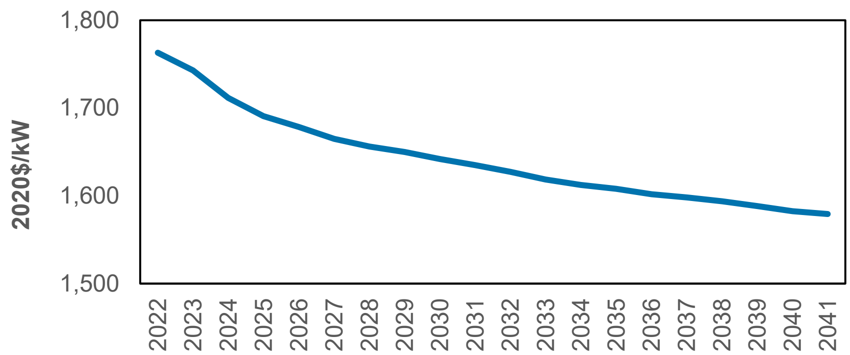


Table 7 Operating and Heat Rate Assumptions for RE

		RE (20 MW)
VOM	$2020 / MWh	5.72
FOM	$2020 / kW-yr	35.34
Heat Rate	Btu / kWh	8,295

5.3.4. Lithium-Ion Battery (Li-ion)

Li-ion batteries store and discharge energy through the movement of lithium ions between a negative and positive electrode, separated by an electrolyte. Unlike other peaking technologies considered, Li-ion batteries do not provide additional energy. Instead, they provide additional capacity during periods of peak energy demand through discharging of energy stored generally during periods of low energy demand. Accordingly, increased deployment of Li-ion in the system can smooth out energy price volatility.

Li-ion batteries are experiencing rapid growth in deployment in utility-scale storage applications. This reflects advantageous operating characteristics that include high round-trip efficiency, high energy density, and lower self-discharge. The batteries can also respond to systems within a second, making them well suited for primary frequency regulations, i.e., providing initial immediate response to deviations in grid frequency driven by sudden demand spikes or supply losses. However, Li-ion batteries have limited cycle life due to degradation; battery augmentation is required during the project lifetime to maintain performance.

Li-ion batteries are modeled in AURORA as an energy storage option with a duration of four hours. AURORA optimizes charging and discharging of the resource against projected SPP hourly electricity prices, taking into account a round-trip efficiency of 85%, a self-discharge rate of 0.3% per day, maximum of one cycle per day, a minimum charge level of 10%, and a maximum charge level of 90%. As a duration-limited resource, the ability of Li-ion batteries to meet demand peaks will decline as greater amounts of renewable generation widen the length of demand peaks. Therefore, the capacity credit for Li-ion batteries is assumed to decline from 100% today to 46-69% by 2041, depending on the amount of renewable generation in the scenario (see Section 7.3).

The overnight capital cost assumptions for Li-ion batteries in 2021 are shown in Figure 27. Figure 28 shows the assumed FOM for a Li-ion battery built in that specific year.

Figure 27: Capital Cost Assumptions for Li-Ion

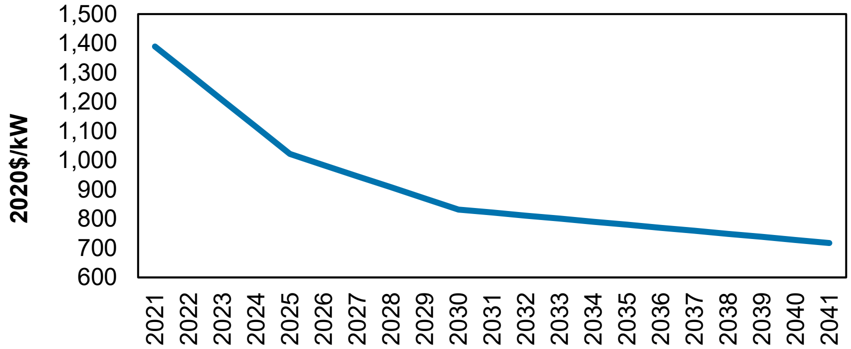
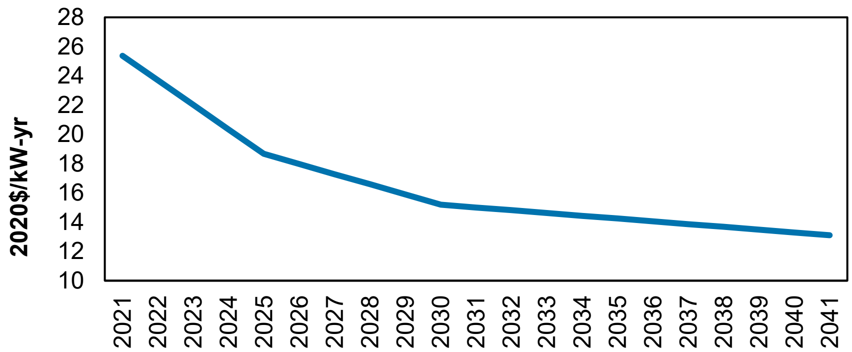


Figure 28: FOM Assumptions for Li-Ion



5.4. Renewable Alternatives

The cost of renewable generation alternatives is expected to continue to decline, providing an opportunity to increase affordable clean energy to address future electricity needs, consistent with PSO's aim of enabling a greener future for all. These technologies can provide a hedge against future uncertainties in fuel prices, carbon policies, and technology risks as they have zero carbon emissions and zero marginal costs and as such, they are more likely to remain competitive against other technologies as fuel prices fluctuate and new generation technologies become available, minimizing pricing and stranded cost risk to customers. The impact of increased renewable generation on the electricity system is further discussed in Section 7.5.2.

In this IRP, two renewable alternatives considered are onshore wind and utility-scale photovoltaic. These two technologies are made available as resource options in AURORA. In addition, AURORA can also choose to pair either onshore wind or utility-scale photovoltaic with lithium-ion battery where a paired solution is economic.

5.4.1. Wind

Wind energy is based on exploiting the air pressure differential across two sides of the blade, causing the rotor blade to spin and generate electricity.

Wind is first made available as a resource option in AURORA from 2024. It is modeled as a must-run resource dispatching according to a generic production profile representative of the region with an average capacity factor of 44%. As an intermittent resource, wind may not be generating at full capacity during the time of system peak. Capacity credit for wind is assumed to be 14.7% across all months. Both the hourly production profile, average capacity factor, and capacity values are estimated based on historical production data of existing AEP wind resources in SPP.

The overnight capital cost for onshore wind in 2023 is based on EIA AEO 2021. The cost reduction curve from NREL ATB 2020 is applied to the capital cost in 2023 to project the capital costs for 2024 and beyond, as shown in Figure 29 below.

Figure 29: Capital Cost Assumptions for Onshore Wind

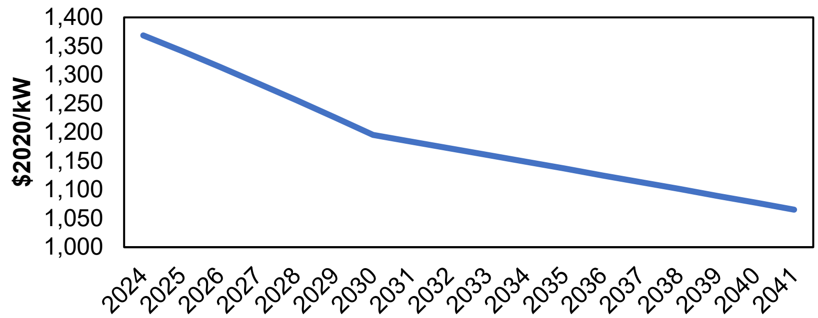
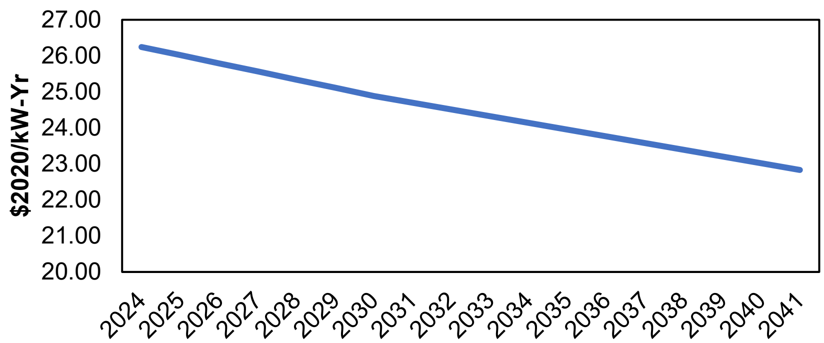


Figure 30 shows the FOM cost assumptions for onshore wind, excluding property tax and insurance, for a wind farm built in that specific year. Property tax and insurance premium are modelled as a positive adder to the FOM costs.

Figure 30: FOM Assumptions for Onshore Wind



Sites with high quality wind resources are often in rural areas far from demand centers. The reliance on transmission networks to deliver wind energy leads to transmission losses as well as network congestion. To account for the full cost of wind resources, a congestion charge is added as a variable cost adder for new wind projects at a rate of $2 / MWh for the first 2 GW, and $5 / MWh thereafter.

Projects entering service before the end of 2025 are eligible for a Production Tax Credit ("PTC"), added to the project value at a rate of $15 / MWh[8], which is implemented in AURORA as a negative variable cost adder. PTC levels vary by scenario, described further in Section 7.4. Additional new wind is limited to annual amounts of 1,400 MW up to 2025, 1,600 MW beyond 2025, and a total of 2,600 MW over a 20-year period.

8 In 2021 dollars

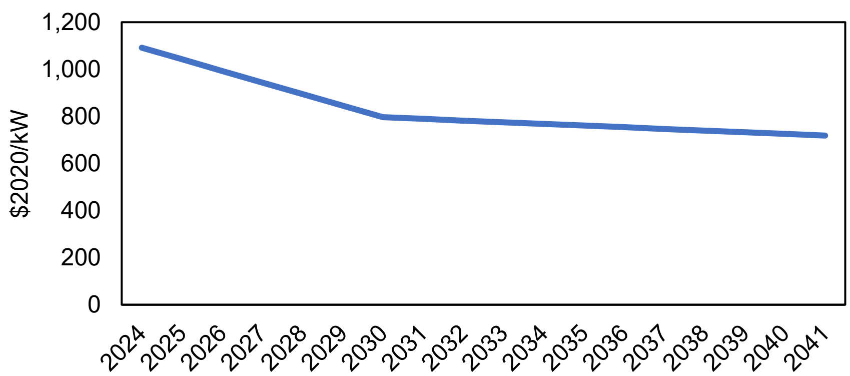
5.4.2. Solar

Solar photovoltaic ("solar PV") uses semiconductor materials surrounded by protective layers to convert sunlight into electricity. The system has a modular structure which allows it to be scaled to meet different levels of energy needs, large or small.

Utility-scale solar PV is first made available as a resource option in AURORA from 2024. Like wind, solar generation is modeled as a must-run resource with a generic hourly production profile representative of the region with a capacity factor of 26.6%. Solar capacity credit for summer is estimated at a percentage of ICAP. Currently that percentage is 60% but it declines to 27-34% by 2041, depending on the scenario (see Section 7.5.2). The hourly production profile, average capacity factor and capacity values are estimated based on historical production data of existing AEP solar resources within SPP.

The overnight capital cost assumptions for solar PV are shown in Figure 31.

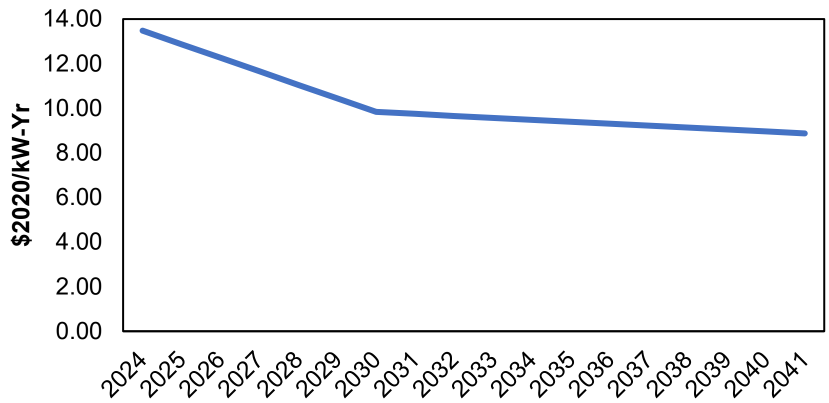
Figure 31: Capital Cost Assumptions for Utility-Scale Solar PV



Investment Tax Credit ("ITC") value is assigned to the project by applying a reduction in modeled upfront capital cost at a rate of 30% for projects entering service before the end of 2023, 26% for projects entering service before the end of 2025, and 10% thereafter. In order to comply with requirements for regulated utilities to normalize tax credit benefits over the life of owned projects, an adjustment cost of $5.61/MWh was applied for the lifetime of owned solar projects which received 26% ITC benefit. An adjustment of $6.08/MWh was applied to solar+storage projects with a 3-1 solar-storage ratio. ITC levels vary by scenario, described further in see Section 7.4. Additional new solar is limited to annual amounts of 450 MW, and a total of 4,500 MW over a 20-year period.

Figure 32 shows the FOM cost assumptions for onshore wind, excluding land lease, property tax and insurance, for a wind farm built in that specific year. Land lease, property tax and insurance premium are modelled as a positive adder to the FOM costs on a levelized basis.

Figure 32: FOM Assumptions for Utility-Scale Solar PV



5.5. Advanced Generation Alternatives

Advanced generation technologies are low-carbon technologies that are still in the development stage but could be commercially available during the planning horizon of this IRP. When they are available, they could potentially render specific generation technologies obsolete leading to their premature retirement. Including advanced generation technologies in this IRP allows PSO to consider the impact of future technology uncertainties on the Company's generation portfolio and identify technologies that are available today but might be at risk of obsolescence. This informs the selection of the preferred portfolio that minimizes technology risks and allows PSO to continue to deliver reliable and affordable power to customers.

Based on a survey of literature on generation technologies, three advanced generating technologies are potentially available within the planning horizon of this IRP, namely small modular reactor ("SMR"), carbon capture and storage ("CCS"), and hydrogen.

5.5.1. Small Modular Reactor (SMR)

Small Modular Reactor is a new generation of nuclear fission technology utilizing smaller reactor designs, module factory fabrication and passive safety features. Key features of an SMR include:

- Small physical footprints;
- Limited on-site preparation, leading to faster construction time and scalability;
- Siting flexibility including sites previously occupied by coal-fired plants; and
- Passive safety features, allowing the reactor to safely shutdown in an emergency without requiring human interventions.

SMR can be a zero-carbon alternative for providing base-load electricity without CO_2 emissions. Its siting flexibility and improved safety features allow it to be sited closer to demand centers, reducing transmission investments. However, it is subject to the same economic challenges facing base-load power plants today, namely the erosion in value of base-load electricity as a result of increased intermittent generation.

SMR is still in the early stages of development and there remain uncertainties over the cost, performance, and availability of the technology. The cost assumptions for the First-of-a-Kind ("FOAK") are based on the EIA AEO 2021, adjusted to include AEP overheads. The Nth-of-a-Kind ("NOAK") cost assumptions in this IRP is based on projecting the FOAK cost forward using a learning rate from a Department of Energy ("DOE") study on the learning rate for

SMR[9]. The DOE study provides a learning rate as cost reduction per each doubling of installed capacity. As such, it is further assumed for the purpose of projecting SMR cost reduction that the first SMR unit with FOAK cost assumptions will be built in 2028 and subsequently one new SMR plant will be built each year in the first five years, two new SMR plants for the next five years, and four new SMR plants for the five years after that. Figure 33 below shows the assumed overnight capital cost of SMR cost over time.

Figure 33: Capital Cost Assumptions for SMR

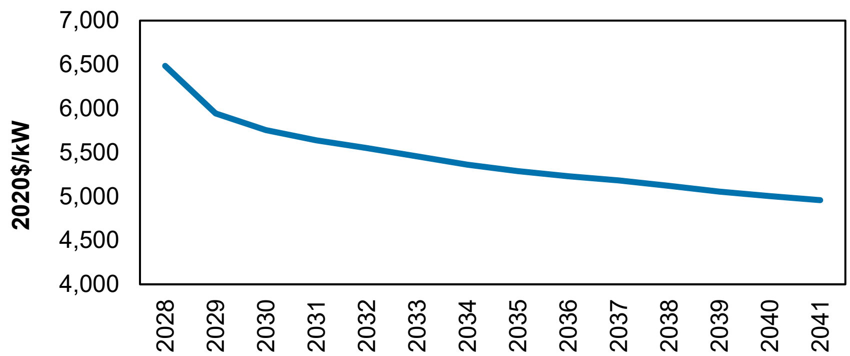


Table 8: Operating and Heat Rate Assumptions for SMR

		SMR
VOM	$2020 / MWh	3.02
FOM	$2020 / kW-yr	95.48
Heat Rate	Btu / kWh	10,455

Like traditional nuclear, SMR cannot adjust its output to match fluctuating electricity demand easily. Therefore, SMR is modeled in AURORA as a must-run resource. It is assumed that SMR will not be available for commercial deployment until 2032.

5.5.2. Carbon Capture and Storage Technologies (CCS)

CCS technology provides another alternative for producing reliable low-carbon baseload electricity. Carbon dioxide ("CO_2") in the flue gas from the combustion of fossil fuels is captured by amine-based solvent in the absorption column and then released from the solvent in a concentrated from in a stripper column. The process requires a significant amount of steam to break the bond between the CO_2 and the solvent, and auxiliary power to run the compressor and other mechanical equipment. As such, CCS-equipped power plants have heat rate and capacity penalties relative to power plants without CCS.

In AURORA, CCS is modeled as new build options and retrofit options. CCS plants are treated as standard dispatch resources in AURORA, which are assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. The passage of Section 45Q legislation provides a tax credit of $50 / t of CO_2 sequestered. This incentive is implemented in AURORA as a negative variable cost adder, improving dispatch economics.

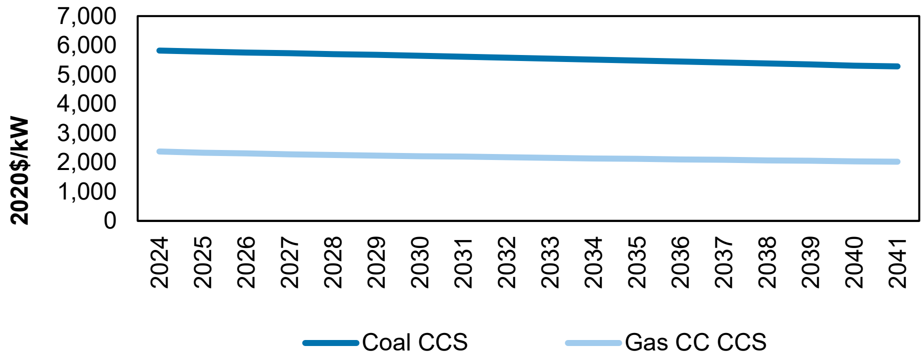
9 Department of Energy (2013), Small Modular Nuclear Reactors: Parametric Modelling of Integrated Reactor Vessel Manufacturing Within a Factory Environment Volume 2, p. 59

New build options

Two new build CCS configurations are available for selection in AURORA, including the 650 MW ultra-supercritical coal power plant with 90% carbon capture and the 430 MW H-class combined-cycle natural gas turbine with 90% carbon capture.

The assumptions on overnight capital costs for new build CCS are shown in Figure 34. FOM, VOM, and heat rate assumptions are shown in Table 9 below.

Figure 34: Capital Cost Assumptions for New Build CCS



Note – Coal CCS represents a 665 MW ultra-supercritical unit with 90% capture rate; Gas CC CCS represents a 430 MW single shaft CCGT with 90% capture rate

Table 9: Operating and Heat Rate Assumptions for New Build CCS

		Coal	Gas
VOM	$2020 / MWh	11.03	5.87
FOM	$2020 / kW-yr	59.85	27.74
Heat Rate	Btu / kWh	12,507	7,124

Retrofit options

It is also possible for AURORA to choose to retrofit PSO's existing NGCC units and coal-fired units with CCS. The cost and performance assumptions for retrofitted NGCCs are based on a compilation of assumptions from various sources including the Clean Air Task Force, Global CCS Institute and National Energy Technology Laboratory.

Table 10: Operating and Heat Rate Differentials for retrofit CCS

		Retrofitted NGCC
Capacity penalty	% of pre-retrofit capacity	13.2%
Heat rate penalty	% of pre-retrofit heat rate	17.2%
Incremental capital cost	$2020 / kW post-retrofit capacity	870
Incremental FOM	$2020 / kW post-retrofit capacity	19.6
Incremental VOM	$ / kWh	1.2

The cost and performance parameters for retrofit coal units are taken from the Environmental Protection Agency's ("EPA") modelling assumptions in its power sector modeling platform[10]. The applied parameters vary based on the capacity and heat rate of the coal unit as shown in Table 11 below. The table shows significant heat rate and capacity penalties on coal units with 400 MW capacity; coal units with lower than 400 MW capacity are assumed to be ineligible for retrofit due to unfavorable economics.

Table 11: EPA Performance and Unit Cost Assumptions for CC Retrofits on Coal Plants

Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	FOM ($/kW-year)	Variable O&M (mills/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)
	9,000	2,595	36.9	18.2	33.6	50.6
400	10,000	2,960	41.2	19.7	37.3	59.5
	11,000	3,373	46.1	21.3	41.0	69.6
	9,000	1,852	23.7	14.9	19.2	23.7
700	10,000	2,071	26.1	15.6	21.3	27.0
	11,000	2,302	28.6	16.4	23.4	30.6
	9,000	1,625	19.7	13.9	13.4	15.5
1000	10,000	1,810	21.6	14.5	14.9	17.5
	11,000	2,001	23.6	15.0	16.4	19.6

Carbon Storage and Transportation Costs

CCS plants also incur costs associated with storing and transporting CO_2. The parameters in Table 12 were derived from EPA National Electric Energy Data System ("NEEDS") v6, representing the cost of transporting and storing CO_2 across potential CO_2 storage sites for PSO power plants. Low cost storage may be depleted over time as more CCS is added to the system, therefore the carbon storage and transportation costs will be higher over time as the storage capacity of the lowest cost option is depleted.

Table 12: Carbon transport and storage schedule ($2020 / tCO_2)

	Texas	Oklahoma	Kansas	Missouri	Arkansas	Colorado	New Mexico
Storage Cost	9.86	4.93	4.93	9.86	9.86	9.86	14.79
Transport Cost	21.54	13.57	19.16	16.32	10.31	29.11	36.18
Total Cost	**31.40**	**18.50**	**24.09**	**26.18**	**20.17**	**38.97**	**50.97**

5.5.3. Hydrogen (H_2)

Two key components that make up a hydrogen system are the polymer electrolyte membrane ("PEM") electrolyzer and the hydrogen gas combusting turbine ("H_2 CT").

H_2 CTs operate on the same principle as the NGCT systems discussed in Section 5.3.1 but with some differences in operating characteristics including:

- **Energy density**: H_2 is one third less energy dense than natural gas. Using hydrogen as a fuel will require a fuel accessory system configured to provide three times higher fuel flow rates into the turbine relative to using natural gas;

10 *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model (2018).* Retrieved from https://www.epa.gov/sites/default/files/2018-05/documents/epa_platform_v6_documentation_-_all_chapters_v15_may_31_10-30_am.pdf

- **Flame speed:** H_2 has about 4.5 times the flame speed of natural gas. The combustion systems have to be configured specifically for hydrogen to prevent the flame from propagating upstream;
- **Flammability:** H_2 is more flammable than natural gas. The enclosure and ventilation system have to be designed to limit the concentration of hydrogen; and
- **Flame temperature:** H_2 burns at a higher temperature than natural gas, resulting in higher NO_x emissions. A selective catalytic reduction system is required to reduce NO_x emissions.

H_2 can play multiple roles within an electricity system. It can provide storage capacity during periods of high renewable generation and, depending on H_2 prices, cycling capabilities for intermediate loads or generation capacity during periods of high electricity demand. As a gas turbine technology, hydrogen can also provide system services such as inertia, frequency response, voltage support, regulating reserves and black start.

The cost, cost reduction curve, and efficiency assumptions for the PEM electrolyzer are developed based on a compilation of various sources including PNNL[11], IEA[12], EPRI[13], DOE[14] and the International Council on Clean Transportation[15]. The capital cost assumption for the PEM electrolyzer component included stack replacement costs. The cost and performance modeling assumptions for H_2 CT is from conversations with power equipment vendors. The capital cost reduction curve is based on NREL for NGCT. Overnight capital cost assumptions are shown in Figure 35, FOM for electrolyzer in Figure 36, efficiency for electrolyzer in Figure 37. Other parameters shown in Table 13 are VOM and NGCT's FOM and heat rate; these are not expected to improve over time. The fixed operating cost for a H_2 CT is estimated to be twice the EIA AEO 2021 estimate for NGCT, reflecting additional costs for maintaining a system with high levels of water and steam injection for emission control.

11 *2020 Grid Energy Storage Technology Cost and Performance Assessment 2020 (December 2020).* Retrieved from https://www.pnnl.gov/sites/default/files/media/file/Hydrogen_Methodology.pdf

12 *The Future of Hydrogen – Assumption Annex (December 2020),* Retrieved from https://iea.blob.core.windows.net/assets/29b027e5-fefc-47df-aed0-456b1bb38844/IEA-The-Future-of-Hydrogen-Assumptions-Annex_CORR.pdf

13 *Program on Technology Innovation: Prospects for Large-Scale Production of Hydrogen by Water Electrolysis.* Retrieved from https://www.epri.com/research/products/000000003002014766

14 *Hydrogen Production Cost from PEM Electrolysis – 2019 (February 2020).* Retrieved from https://www.hydrogen.energy.gov/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf

15 *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe (June 2020).* Retrieved from https://theicct.org/sites/default/files/icct2020_assessment_of_hydrogen_production_costs_v1.pdf

Figure 35: Capital Cost Assumptions for PEM Electrolyzer and H_2 CT Components

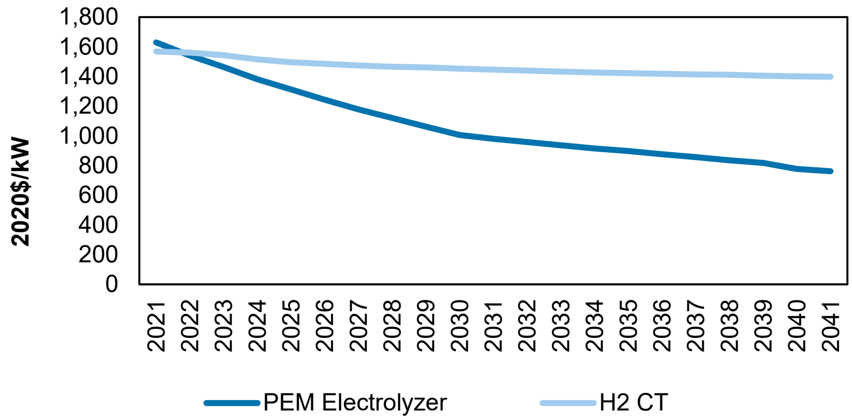


Figure 36: FOM Assumptions for PEM Electrolyzer

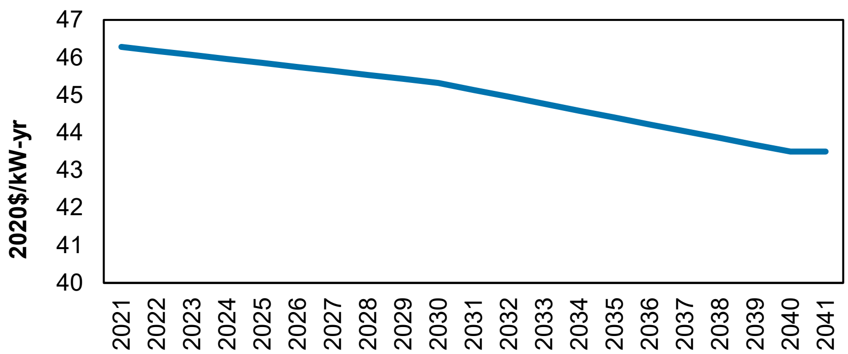


Figure 37: Efficiency Assumptions for PEM Electrolyzer

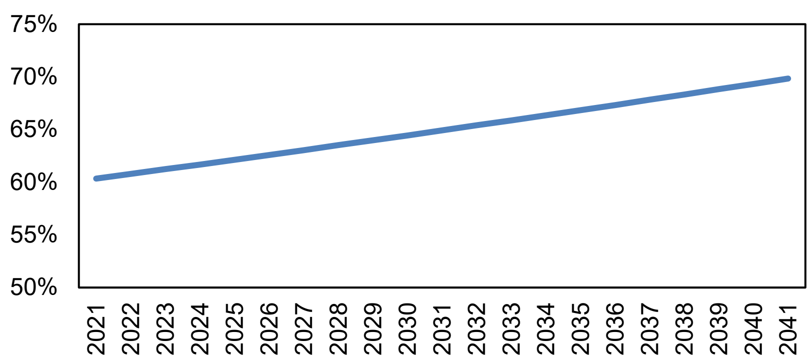


Table 13: Operating and Heat Rate Assumptions for PEM Electrolyzer and H_2 CT

		PEM Electrolyzer	**H_2 CT**
VOM	$2020 / MWh	0.50	0.61
FOM	$2020 / kW-yr	Figure 36	7.04
Heat Rate	Btu / kWh	Figure 37	9,655

Hydrogen is made available in AURORA starting in 2030. The year is based on statements by various major power equipment providers committing to provide 100% H_2 CTs by 2030. Hydrogen resources are offered in AURORA in three possible configurations:

- **Integrated H_2 chain** - PSO owns both the electrolyzer and the H_2 CT, thus the modelled cost is a combined cost of both elements. The resource is modelled as a storage option. AURORA optimizes the production of H_2 and the firing of H_2 against projected SPP hourly electricity prices, considering efficiency losses at both the PEM electrolyzer and H_2 CT. The resource is assumed to have no self-discharge and no cycling limits;
- **Third-party H_2 supply** – PSO only owns the H_2 CT, thus the modelled costs comprise the capital cost, FOM and VOM of H_2 CT only with fuel prices being the levelized cost of hydrogen. The levelized cost of hydrogen is calculated based on the levelized cost of the PEM electrolyzer plus the electricity costs for the SPP region. Relative to the first configuration, this configuration will have lower capital costs and FOM but higher variable fuel cost. The supply of H_2 is assumed to be available on demand. The H_2 CT is then modelled as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints;
- **Third-party H_2 + retrofit CT** – This is similar to the second configuration except that instead of building a new H_2 CT unit AURORA can choose to retrofit an existing NGCT unit to burn 100% H_2 fuel. Retrofitting an existing NGCT unit will incur additional capital costs due to the difference in operating characteristics between natural gas and H_2 as discussed earlier. The retrofit will incur a one-time cost of 15% of the capital cost of the new CT cost, based on a bottom-up analysis of the costs of the H_2 accessory system and the selective catalytic reduction system as well as a study on the H_2 retrofit cost in the UK. Post-retrofit, the FOM, VOM and heat rate are assumed to be the same as for a new build H_2 CT.

5.6. Long Duration Storage Alternatives

For the purposes of this IRP, long-duration storage refers to storage that can provide 20 hours' worth of energy. A storage of this duration can be used to balance diurnal variations in renewable energy resources as well as variations in demand from weekends (low demand) to weekdays (high demand). The technology can also provide needed capacity during longer duration weather events, such as cold periods or wind droughts that could last for several days.

The value of long-duration storage is likely to increase as intermittent renewable generation increases within PSO's service territory and extreme weather events become more frequent. In addition to energy arbitrage, some long-duration technologies can also increase system reliability through the provision of frequency, inertia, voltage, short circuit levels and restoration. Increased deployment of long-duration storage can also dampen price volatility and displace more expensive forms of generation during periods of high electricity demand, contributing to rate stability and customer affordability.

Pumped hydro energy storage is currently the dominant form of long duration storage, however its potential has largely been depleted and is not considered as part of this IRP. Three alternative long-duration technologies are considered, including pumped thermal energy storage, vanadium flow battery storage and compressed air energy storage.

Cost and performance assumptions for the IRP are developed based on a compilation of projections from various sources.

5.6.1. Pumped Thermal Energy Storage (PTES)

PTES refers to a group of technologies that use a heat pump and heat engine to convert electricity into stored heat which is in turn converted back to electricity. The heat is stored in a thermal medium, such as molten salt in an insulated tank to reduce heat leakage. When needed, a heat engine takes the heat from the tank to generate steam to drive a turbine to generate electricity.

Large insulated thermal tanks have already been widely deployed as part of the development of concentrated solar power plants. Whereas concentrated solar power plants use reflected sunlight to heat the thermal medium, PTES uses the heat pump instead.

Key benefits of PTES include relatively low capital costs, siting flexibility, high energy density, ability to provide inertia and avoided use of toxic or hazardous chemicals to store energy. However, it has relatively low round-trip efficiency, slower response time, and high self-discharge.

As a turbine-based technology, PTES can provide various ancillary services including inertia, frequency response, regulating reserve and voltage support. However, the response time of PTES is around 10 seconds, which is slower than other storage technologies such as Lithium-Ion battery or vanadium flow battery.

PTES is modeled in AURORA as an energy storage option. AURORA optimizes charging and discharging of the resource against projected SPP hourly electricity prices, taking into account a round-trip efficiency of 65% and a self-discharge rate of 1% per day.

The forecasted PTES overnight capital cost and FOM assumptions are developed based on averages of values reported in a wide range of sources including reports published by NREL, the UK Department for Business, Energy & Industrial Strategy ("BEIS") and academic studies. The assumptions are shown in Figure 38 and Figure 39 below.

Figure 38: Capital Cost Assumptions for 20-hour duration PTES

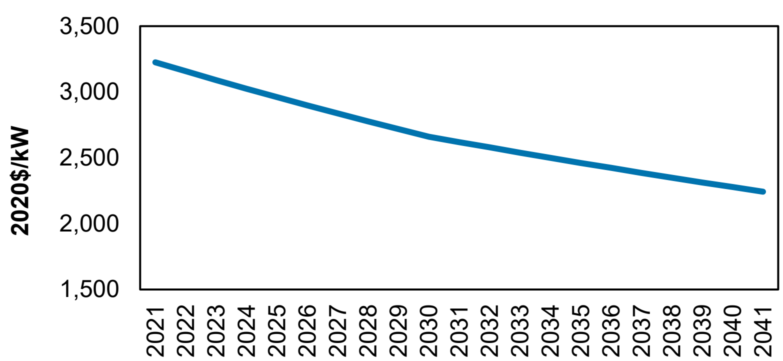
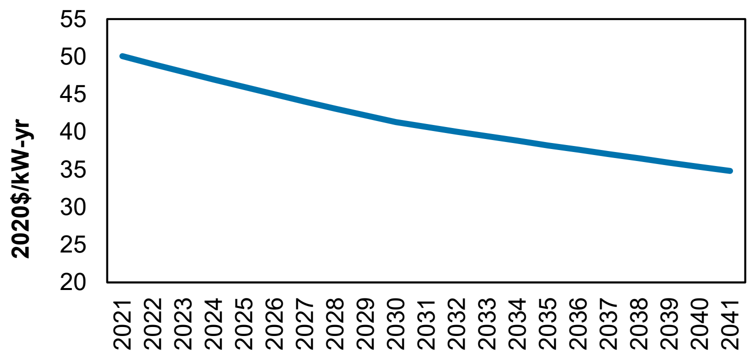


Figure 39: FOM Assumptions for 20-hour duration PTES



5.6.2. Vanadium Flow Battery Storage (VFB)

VFB stores energy in vanadium-based electrolytes that can transfer electrons back and forth between four different oxidation states causing charge and discharge. The electrolytes are dissolved in water and stored in two tanks connected by an iron selective membrane. During a discharge, electrolyte is spent producing DC power which is converted to AC power using converters and controllers. Electrolytic fluid is then regenerated using DC power from the converter during a charge. VFB is already being commercially deployed, but the supply chain is not as mature as lithium-ion battery.

Key benefits of VFB include quick response time of less than 1 second, high round-trip efficiency, siting flexibility and no degradation during its lifetime. Disadvantages include high operating costs and the use of corrosive electrolyte.

VFB is modeled in AURORA as an energy storage option. AURORA optimizes charging and discharging of the resource against projected SPP hourly electricity prices, considering a round-trip efficiency of 70% and a self-discharge rate of 1% per day.

The forecasted VFB overnight capital cost and FOM assumptions are developed based on an average of values reported in wide range of sources including reports published by EIA, PNNL, BEIS and academic studies. These assumptions are shown in Figure 40 and Figure 41 below.

Figure 40: Capital Cost Assumptions for 20-hour duration VFB

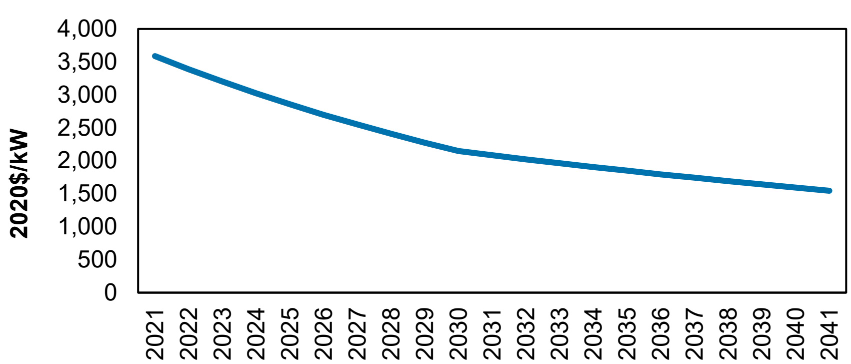
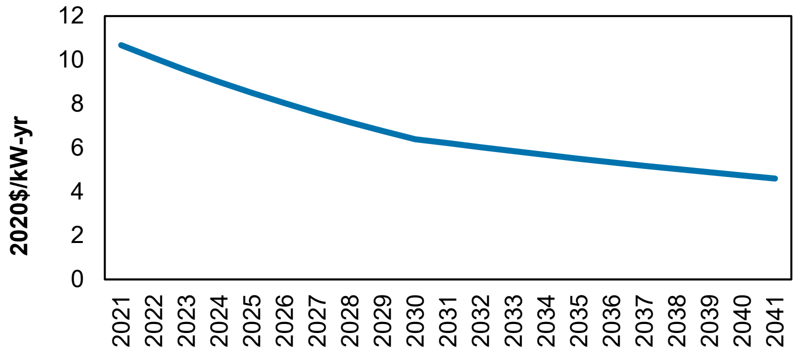


Figure 41: FOM Assumptions for 20-hour duration VFB



5.6.3. Compressed Air Energy Storage (CAES)

CAES is using compressed air to generate electricity. First, electricity is used to drive a compressor to pump air into a pressurized reservoir, e.g., salt cavern, abandoned natural gas storage facilities or depleted oil and gas fields. The compressor generates heat which is captured by a heat exchanger and stored in a separate thermal energy storage device. To discharge, the compressed air in the reservoir is combined with the stored heat to create hot high-pressure air which expands in a turbine to generate electricity.

Existing CAES projects are based on a diabatic process where the heat generated by the compressor is released into the atmosphere instead of being stored. As a result, an alternative source of heat, often fossil fuel, is required during the expansion stage, leading to a lower round-trip efficiency.

Key advantages of CAES include avoided use of toxic or hazardous chemicals, relatively mature and well understood component parts of the technology, and the opportunity to revive abandoned energy infrastructures such as abandoned natural gas storage facilities. Disadvantages include siting limitations and relatively low round-trip efficiency. CAES also has relatively longer response time of about a minute, which is slower than other technologies in this section.

CAES is modeled in AURORA as an energy storage option with a round trip efficiency of 52% and a self-discharge rate of 0.05% per day. AURORA optimizes charging and discharging of CAES based on projected SPP hourly electricity prices.

The forecasted CAES overnight capital cost and FOM is based on an average of a wide range of sources including reports from DOE, PNNL, BEIS and academic studies. Reflecting the relative maturity of the technology, the FOM and capital cost are assumed to be constant in real terms at 2020$17.19 / kW-year and 2020$1,771 / kW, respectively.

6. Demand-side Resource Options

6.1. Introduction

This chapter considers four categories of demand-side resources as alternatives to new generation supply in meeting future capacity needs. The categories include energy efficiency programs, conservation voltage reduction, demand response, and customer-owned distributed generation.

6.2. Energy Efficiency Measures

This IRP considers incremental EE programs as resource options to meet future capacity needs. These incremental EE programs, starting from 2027, are in addition to the existing demand-side programs and programs that run were requested in PSO's 2022-2026 Demand Portfolio application to the commission, PUD 202100041. PSO requested a waiver to extend the portfolio period to 2026. This request for 2025 and 2026 was not approved as discussed in Section 3.3.2. Nevertheless, the modeling here was conducted with the filed application plan through 2026.

6.2.1. EE Cost and Performance Assumptions

The cost and performance parameters for the incremental EE programs evaluated are 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 with updates from the 2019 Technical Update of this same report. The EPRI report and the PSO Energy Efficiency and Consumer Programs 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. Table 14 provides a list of current and anticipated EE measures for both the residential and commercial sector.

Table 14 Energy Efficiency Measure Categories by Sector

Residential Measures	Ceiling Insulation Dish Washer Television Central AC Water Heating	Wall Insulation Refrigerator Heat Pump Clothes Washer Behavioral	Windows Freezer Lighting Clothes Dryer
Commercial Measures	Heating Measures Water Heating Personal Computers Outdoor Lighting*	Cooling Measures Commercial Ventilation Servers	Chiller Space Cooling Refrigeration Indoor Lighting*

Note: *Indoor and outdoor lighting categories apply to both commercial and industrial sectors to account for potential EE savings in the industrial sector.

The amount of available EE potential can be broken into three categories: technical, economic, and achievable. Technical potential refers to the amount of EE that could be deployed regardless cost and barriers to deployment. Economic potential refers to the amount of cost effective EE that could be deployed regardless of deployment barriers. Cost-effectiveness is based on the Total Resource Cost ("TRC") test which compares the avoided cost savings over the life of an EE measure with the cost to implement it, regardless of who bears the cost. Achievable potential is a subset of economic potential accounting for market acceptance and implementation barriers.

The achievable potential can further be broken into the amount that would be accomplished if implemented through utility-sponsored programs, and the total amount that would fall under codes and standards. The former is included as part of resource options for capacity expansion while the latter is accounted for as reductions from the load forecast.

6.2.2. Modeling EE measures as resource options

PSO ranked individual EE measures according to their lifetime levelized cost. Residential measures were ranked separately from commercial measures to reflect different operating characteristics between residential and commercial EE programs. Once ranked, EE measures were grouped into bundles based on the following criteria:

- First, the highest cost measure in the bundle cannot exceed twice the average cost of the measures in the bundle. This is to preserve a degree of cost homogeneity among the measures within the same bundle;
- Second, the gross energy savings potential in each bundle is at least 1% of the total system load. This is to ensure that each bundle represents a significant energy resource option when compared against other energy resource options, such as new generating units.

Table 15 lists the EE bundles for the residential and C&I sectors. The high-cost bundle for the commercial and industrial sectors is excluded from resource modeling due to its prohibitively high levelized cost beyond other available supply- and demand-side options in the model.

Table 15: Energy Efficiency Bundles Statistics

	LCOE ($ / MWh)			2027 Gross Total Energy Savings Potential (MWh)	Energy Saving as % of Total 2027 Load
	Min	Mean	Max		
Residential					
Low	6	16	29	198,700	1.8%
Medium	35	49	65	445,895	4.0%
High	77	113	194	442,642	4.0%
Commercial					
Low	3	7	13	276,064	2.5%
Medium	14	26	50	257,677	2.3%
High	559	4,417	13,211	254,625	2.3%

Table 16 provides incremental gross average yearly energy savings potential for each bundle overtime

Table 16: Incremental Gross Average Yearly Energy Savings

	Time Period (MWh / Year)		
	2027-2031	2032-2036	2037-2041
Residential			
Low	38,532	5,527	3,719
Medium	85,843	14,127	0
High	30,802	0	5,658
Commercial			
Low	55,403	5,040	0
Medium	7,911	0	0

Each EE bundle has a unique 8760 hourly load shape, allowing for a consideration of the impact of the bundle on energy demand as well as assessing the contribution of the bundle to meeting capacity needs during summer and winter peaks. The load shape reflects the impact on customer load shapes of different electricity end uses and the mix of individual EE measures included in the bundle. For example, Table 17 shows the composition of individual EE measures comprising the medium cost bundle for residential sector for 2027-31 and 2032-36. The individual EE measures are from three electricity end-uses: residential heating, residential cooling, and other.[16] The load shape for this bundle is the weighted average shape of the three end uses where the weights are the gross energy savings potential of each end use in each time period. The load shapes for each end-use remain the same over time, but the load shape in each bundle will change over time due to the changes in the gross energy savings potential of each underlying measure.

Table 17: Composition of Individual EE measures in Medium Residential Bundle by Year

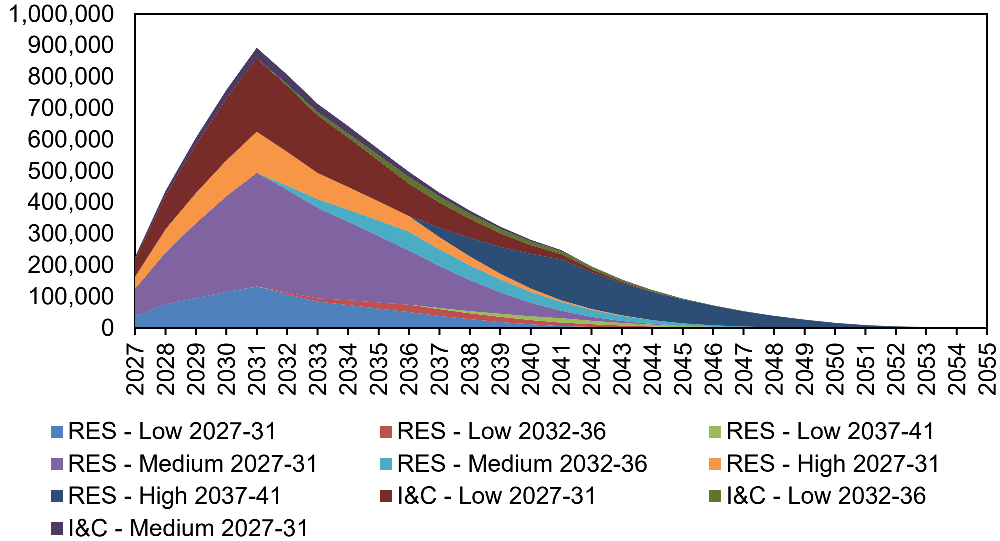
		Gross Incremental Energy Savings Potential (MWh)	
Individual EE measure	**Electricity End Use**	**2031**	**2036**
Duct Repair	Heating + Cooling	76,160	3,694
Infiltration Control	Heating + Cooling	10,604	1,260
Pipe Insulation - Water Heating	Other	4,983	336
Smart Thermostats	Heating + Cooling	6,943	0
ENERGY STAR Refrigerator	Other	10,750	1,254
SEER 16 Heat Pump	Heating + Cooling	166,850	33,267
Efficient Dishwasher	Other	3,928	389
SEER 16 - Central AC	Cooling	148,998	0
Total		**429,215**	**70,635**

Each bundle is available for selection in any given year during each five-year window. If the bundle is not selected within the selection window, it will not be available for selection in the next selection window. This assumes that the underlying EE measures within each bundle would have been obsolete by the next selection window. Once the bundle is selected, it will remain activated over its life regardless of when in the selection window it is selected.

Figure 42 shows net annual energy savings potential across all available EE bundles. The Figure assumes that all EE bundles would be selected in the first year of each selection period. At its peak in 2031, net annual energy savings potential available from EE bundles accounts for 8% of total energy demand in the year.

16 Other includes electric water heating, electric cooking, refrigerator, freezer, dishwasher, clothes washer, clothes dryer, TV sets, furnace fans and miscellaneous

Figure 42: Net Annual Energy Savings Potential Across EE Bundles



6.3. Conservation Voltage Reduction Optimization

Potential Conservation Voltage Reduction ("CVR") circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 5 "tranches" based on the relative potential peak demand and energy reduction of each tranche of circuits. The Aurora model was able to pick the most cost-effective tranches first and add subsequent tranches as merited. Table 18, details all of the tranches offered into the model and the respective cost and performance of each.

Table 18: Conservation Voltage Reduction Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	49	$11,475,000	$344,250	11,813	48,638
2	50	$12,500,000	$345,489	9,234	40,421
3	50	$11,870,000	$356,100	8,500	34,997
4	50	$12,440,000	$373,200	4,595	18,916
5	11	$2,750,000	$82,500	461	1,898

6.4. Demand Response

The current level of DR is maintained throughout the plan is discussed in Section 3.3. Incremental levels of DR were included in the IRP model. These resources, which are included in the model as a resource for the entire operating company, were modeled based on the continuation of the Power Hours program for the Residential DR and the Business Demand Response program for the Commercial DR. The Power Hours program is a thermostat program that provides customers more control of the heating, ventilation, and air conditioning system. The Business Demand Response (also referred to as Peak Performers) is a demand response program targeted to commercial and industrial customers served by PSO capable of reducing demand on short notice. After receiving a curtailment message from PSO, facility operators shed electric load in many different ways such as shutting down motors, pumps, compressors, air conditioning equipment, and lighting.

Table 19 below, shows the Residential and Commercial DR resource available for selection. Each unit has a service life of fifteen years.

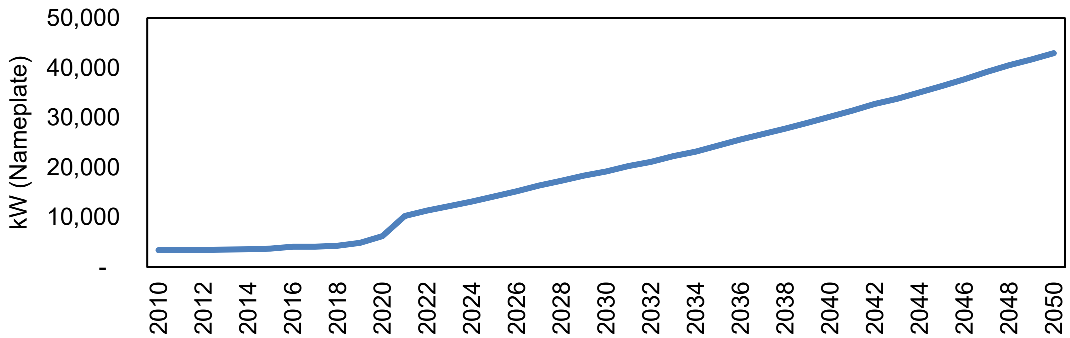
Table 19: Demand Response Resource Profiles

Sector	Demand Savings (kW)	Energy Savings (kWh)	Enrollment/ Installation Cost	Total First Year Cost	Ongoing Annual Cost	Service Life (Years)
Residential	1,000	0	0	$5,700	$85,700	15
Commercial	1,250	0	0	$1,000	$56,000	15

6.5. Customer-owned Distributed Generation

DG resources are evaluated assuming a residential and commercial rooftop solar resource, as this is the primary distributed resource. To determine the level of customer penetration, the DG forecast was based on EIA AEP2021 Residential and Commercial Solar Photovoltaic forecast. This forecast considered the level of solar photovoltaic installations over the period of 2020-2050. Figure 43 below depicts the forecast of nameplate DG resources in PSO over the planning period. To determine the level of DG penetration, PSO applied the incremental growth rates from EIA's forecast to existing levels of DG in the service territory.

Figure 43: Forecast Installed Nameplate Capacity of Rooftop Solar in PSO's Territory



7. Planning Scenarios and Uncertainties

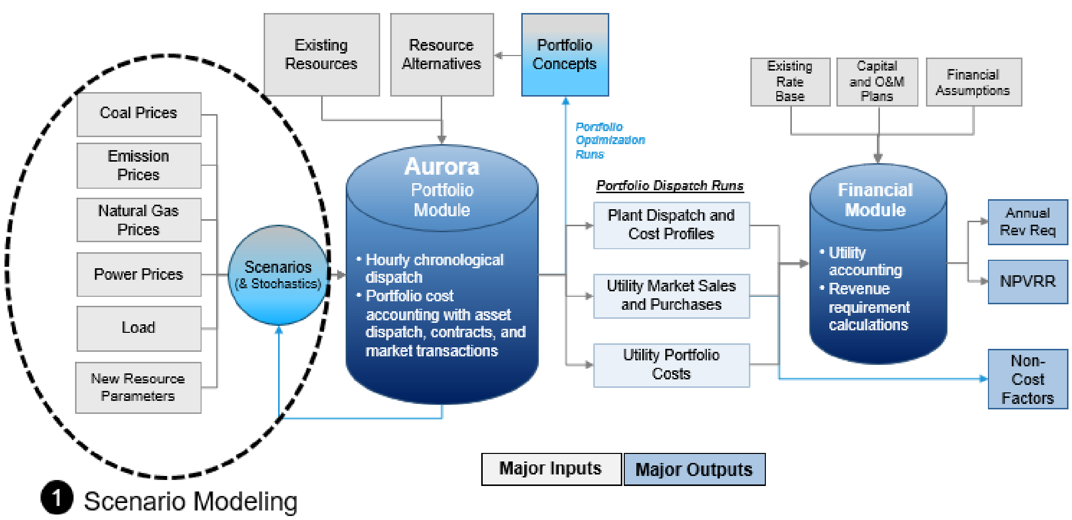
7.1. Introduction

Rate stability and maintaining reliability are two of PSO's objectives for the 2021 IRP. In the context of rising future uncertainties, this section explains how the 2021 IRP analysis captures the key uncertainties and planning risks facing the PSO portfolio that affects system reliability and costs to customers. The analysis informs the selection of candidate resources that balances customer affordability with rate stability, maintaining reliability, and providing positive local impacts to PSO's customers. PSO evaluates uncertainty and risk using two different methods as part of the 2021 IRP.

The first method is based on developing a set of five market scenarios that test plausible but materially different long-term views of fundamental external market conditions such as commodity prices, customer preferences, policy requirements, and transmission availability. In addition to the Reference scenario, which is intended to reflect a middle-of-the-road outcome, PSO developed four market scenarios that test the boundaries of expected long-term outcomes. These fives scenarios were used to inform the creation of candidate portfolios of demand- and supply-side resources. Each candidate portfolio was then stress-tested under all five market scenarios.

Each of these market scenarios is supported by a set of assumptions describing the fundamental inputs from the Company's Fundamental Forecast described in Section 7.3.3 that combine to reflect a specific theme or "what-if" narrative. The key categories of assumptions used to develop the 2021 IRP market scenarios include: load, fuel prices (natural gas prices and coal), CO_2 prices, reserve requirements by season, demand- and supply-side technology cost, and technology performance inputs that describe dispatch and reserve characteristics. All five scenarios in the 2021 IRP were modeled using AURORA to evaluate the evolution of generation capacity and prices across SPP under these different sets of fundamental conditions. This process is illustrated in Figure 44.

Figure 44: 2021 IRP Modeling Framework



The second method subjected the candidate portfolios to a large number of randomly drawn market simulations in the 2021 IRP as part of the stochastic analysis. This means that each candidate portfolio was dispatched in a high number of market outcomes that combine volatility of power prices and natural gas prices with volatility of generator output to observe the impact on customer costs. In some simulations, these factors combine into severe operating conditions similar to those observed during the extreme weather experienced in February 2021 that disrupted both the SPP and ERCOT markets. PSO analyzes the portfolio costs under these severe outcomes to assess how much higher customers costs are likely to be under adverse or extreme market conditions, and how exposed customers are to higher costs under the candidate resource plan.

7.2. The Fundamentals Forecast

AEP's EIA-based Fundamentals Forecast is a long-term, weather-normalized commodity market forecast principally based upon the assumptions contained in the EIA's Annual Energy Outlook (EIA AEO). The Fundamentals Forecast is not specific to this IRP analysis; rather, it is made available to AEPSC and all AEP operating companies for various planning and analysis uses. Outputs of the Fundamentals Forecast include: 1) hourly, monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) sulfur dioxide, nitrogen oxides, and CO_2 burden values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors.

The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. The Aurora model iteratively generates zonal, 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.

The AURORA model 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, and oil. 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.

Figure 45 below describes AEP's EIA-based Fundamentals Forecast components, which were sourced directly from the previously-described EIA AEO, third-party energy consultancies, and internally-generated information.

Figure 45: EIA-based Fundamentals Forecast Components

Forecast Components	EIA	Other	Source
Economy; Inflation/GDP deflators	✓		EIA Reference case
Generating Reserve Margins		✓	RTO Requirements
Electric Load		✓	AEP Load Forecasting
Electric Load shapes		✓	AEP Fundamentals
Solar/Wind production shapes by area		✓	NREL
Coal; Delivered price to EIA regions	✓	✓	EIA Reference case FOB prices + AEP Fundamentals
Natural gas price; Henry Hub	✓		EIA Reference case
Natural gas price; Locational values	✓	✓	EIA Reference case - Henry Hub + AEP Fundamentals
Natural gas supply; Lower 48 production	✓		EIA Reference case
Natural gas demand (incl. losses)	✓		EIA Reference case
Natural gas; net pipeline/LNG exports	✓		EIA Reference case
Oil price, WTI	✓		EIA Reference case
Fuel Oil price; locational values	✓	✓	EIA Reference case - WTI + AEP Fundamentals
Uranium prices		✓	AEP Fundamentals
Other Fuel(Biofuel, etc…)	✓		EIA Reference case
New gen unit options and capital costs	✓		EIA Reference case
Existing gen units	✓		EIA Reference case
Announced new gen units	✓		EIA Reference case
Aged-out retirements of existing gen units	✓		EIA Reference case
Gen unit maintenance schedule		✓	AEP Fundamentals
Gen unit outages		✓	AEP Fundamentals
Unit-level emission rates; CO_2, SO_2, NO_x		✓	US EPA CEMS data
Application of a CO_2 burden		✓	AEP Environmental
REC		✓	AEP Regulatory Forecast
PTC	✓		EIA Reference case
ITC	✓		EIA Reference case
State-mandated Renewable Portfolio Standards		✓	AEP Environmental
Reporting parameters; Peak/Off-Peak/NERC Holidays		✓	PJM/SPP/other RTO and/or internal guidelines
Transmission/links between Zones		✓	AEP Fundamentals

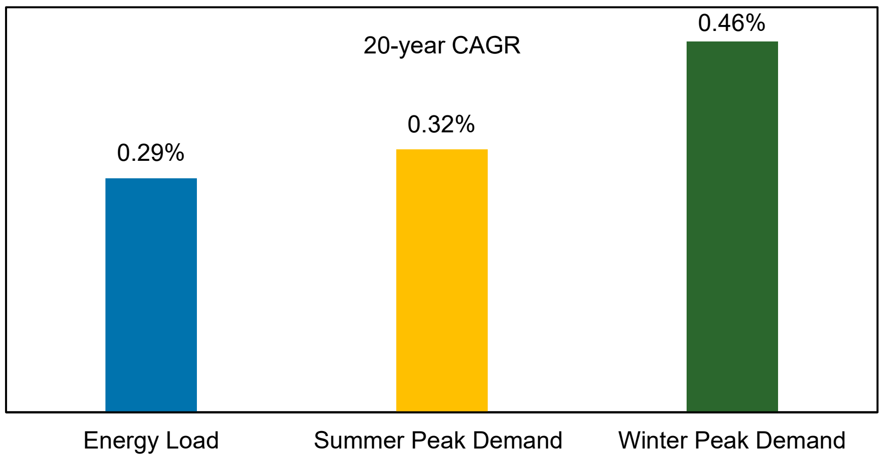
7.3. Reference Scenario Market Drivers and Assumptions

The Reference Scenario represents an expected view of how load growth, commodity prices, technology development and policy will evolve over time and contribute to the market conditions under which PSO will operate.

7.3.1. Reference Scenario Load

Under the Reference scenario, demand for energy in SPP is expected to grow by 0.29% per year over the 20-year forecast period (2022-2041). Peak summer demand is expected to grow at a rate of 0.31% per year, while peak winter demand grows more quickly at 0.46% per year. These figures are illustrated in Figure 46. The details of the analysis and the assumptions underlying the load forecast are discussed in Section 2 above.

Figure 46: Reference case SPP energy and seasonal peak demand growth rates (2022-2041)



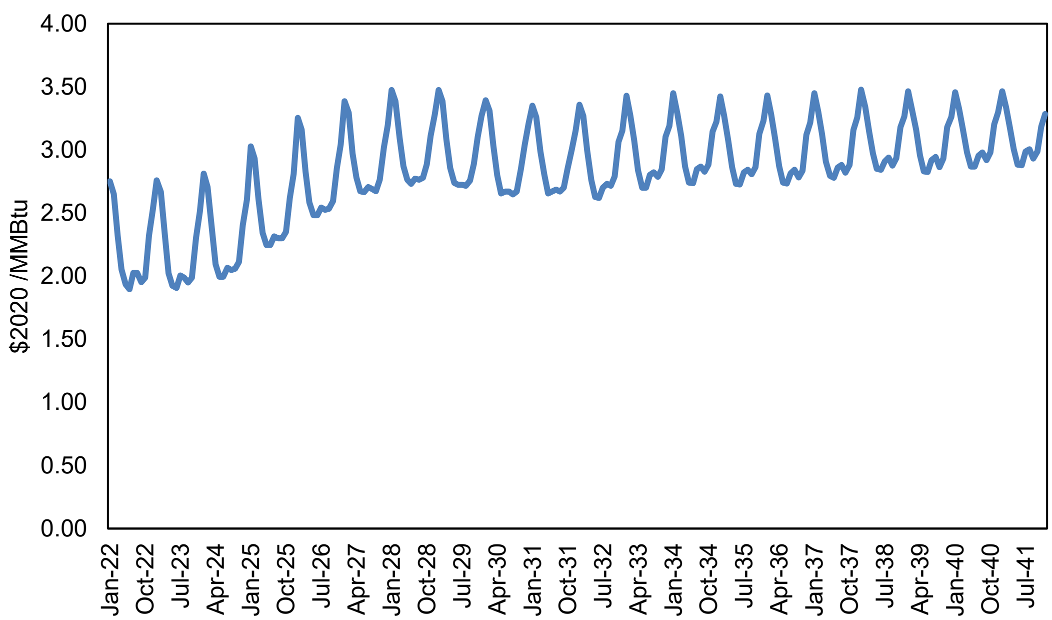
7.3.2. Reference Scenario Fuel & CO_2 Prices

The commodity price inputs to the Reference scenario reflect the "base" view from AEP's Fundamentals Forecast for natural gas, coal, and CO_2 emissions pricing. For the 2021 IRP Reference scenario, these "base" commodity price outlooks were used to represent the expected road conditions for the broader SPP market.

Natural Gas Prices

Figure 47 illustrates the monthly Panhandle Eastern TX-OK natural gas price forecast that was used for the SPP market modeling in the Reference scenario. This pricing point was selected for the report because it reflects the point used to supply PSO's units and is largely representative of gas prices in the region. Under the Reference scenario, prices rise from current levels through 2028 in real terms, after which, annual growth in prices is largely flat for the remainder of the forecast period.

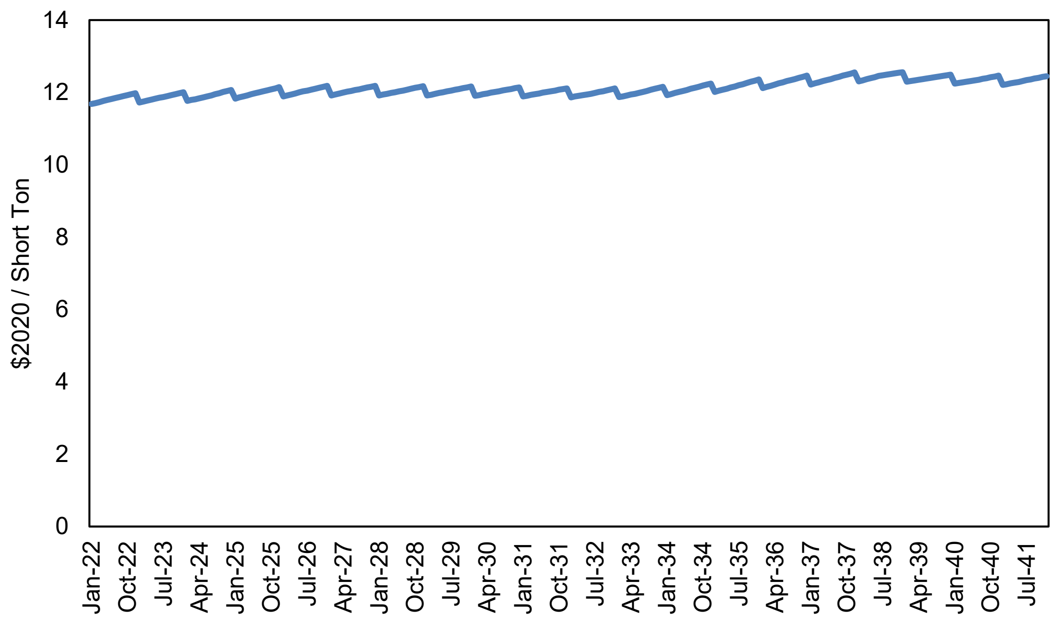
Figure 47: Panhandle Eastern TX-OK Natural Gas Prices (real $ / MMBtu)



Coal Prices

PSO also relied on the AEP Fundamentals Forecast for coal price inputs to the 2021 IRP. Figure 48 illustrates the monthly forecast of Powder River Basin ("PRB") coal prices at the point of purchase (i.e., exclusive of transportation costs) used in the Reference Scenario. While some coal-fired units in SPP burn coals other than PRB, this price reflects the outlook for the type of coal burned at PSO's Northeastern 3 facility. Unlike natural gas that exhibits a rise in prices over the forecast period, the forecast PRB price remains largely consistent through the mid-2030s in the Reference Scenario, but begins to rise slightly towards the end of the forecast period in real dollar terms.

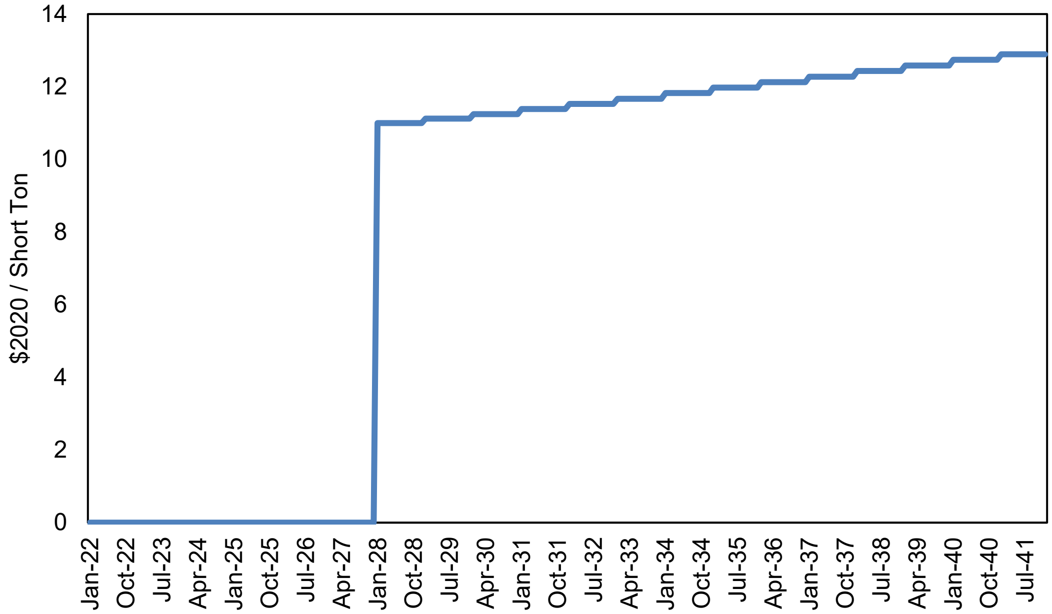
Figure 48: PRB 8,800 Coal Prices (real $ / ton, FOB origin)



CO_2 Prices

PSO assumes that policymakers enact a moderate CO_2 price starting in 2028 as part of the 2021 IRP Reference scenario. This price is assumed to start around $12 / Ton (in real $2020) and rises modestly throughout the forecast period, as illustrated in Figure 49. The CO_2 price increases the dispatch cost of all fossil-fired units in SPP based on the modeled emissions of the unit that, in turn, is a function of each unit's heat rate and carbon content of the fuel it consumes.

Figure 49: Moderate CO2 Price Forecast ($2020 / Short Ton)



7.3.3. Reference Scenario Reserve Requirements

PSO assumes that the Company will need to procure sufficient resources to meet expected load plus a planning reserve margin of 12%.

While the planning reserve margin percentage is not assumed to change over the course of the forecast period in the Reference Scenario, PSO does assume changes in the capacity contribution of different technology types, namely solar PV and 4-hour battery storage to reflect how incremental additions of these technologies are expected to shift peak load and reduce the Effective Load Carrying Capacity ("ELCC") of these resources. PSO relied upon studies performed by SPP to estimate the change in ELCC over time as penetration of these resources increases in the SPP footprint.[17,18] Section 7.4.2 discusses the assumed reduction in ELCC over time.

7.3.4. Reference Scenario Technology Assumptions

Cost and performance assumptions for supply-side technologies are discussed in Chapter 5. PSO assumes federal tax credits for new renewable generation in the Reference scenario, reflecting current law and the schedules enacted in the December 2020 COVID Relief Bill.

Cost and performance assumptions for demand-side technologies, including EE, DG, DR, and CVR were develop by AEP staff and the details of the demand-side resource assumptions are discussed in Chapter 6.

17 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

18 SPP Energy Storage Study Final Report. Astrape Consulting. November 2019. <https://spp.org/documents/61387/astrape%20spp%20energy%20storage%20study%20report.pdf>

7.4. IRP Scenario Inputs

PSO evaluated four market scenarios, in addition to the Reference scenario, that describe plausible futures that may develop over time and result in a materially different set of market conditions under which PSO will need to serve customer needs. Each scenario is driven by a set of thematically oriented fundamental market assumptions. These scenarios are used to test the boundaries of future market conditions. PSO dispatched the 2021 IRP candidate portfolios across the scenarios. The themes tested within and across scenarios reflect the priorities and key risks identified by PSO and its stakeholders and allow for a no or least regrets evaluation of options.

Focus on Resiliency ("FOR")

Under the FOR case, overall pressure on GHG emissions and fuel prices is similar to the Reference scenario, but the Company and its Stakeholders are increasingly concerned with the reliability of the electric grid. Under the FOR scenario, SPP is assumed to enforce both winter and summer reserve requirements on participating utilities. Furthermore, the peak credit value of solar and storage resources decreases more quickly over time in the FOR scenario than in the Reference scenario and additional dispatchable capacity is deployed across SPP.

No Carbon Regulation ("NCR")

Under the NCR case, natural gas prices remain low and no federal limits on carbon emissions are enacted during the forecast period. The resulting market conditions are similar to recent history and tend to be more favorable for natural gas and coal resources relative to the Reference scenario. The NCR case allows PSO to stress test candidate portfolios that rely more heavily on new renewable generation under conditions that are generally more favorable to gas-fired units and evaluate the impact on expected customer costs.

Clean Energy Technology Advancement ("CETA")

The CETA scenario is one of two in the 2021 IRP that test how an aggressive policy shift to decarbonize the electric sector could manifest in future market conditions. Under the CETA scenario, GHG reductions are achieved primarily through increased incentives for deployment of clean supply- and demand-side technologies. For example, under the CETA scenario PSO assumes that federal tax credits for renewable resources are extended and that investments in R&D drive cost improvements beyond the Reference scenario for new wind, solar, and storage units. The CETA case also incorporates more aggressive end-use electrification than the Reference scenario resulting in greater penetration of EVs and other technologies. This results in a higher load forecast and shift in customer demand patterns.

Enhanced Carbon Regulation ("ECR")

The ECR case is the other case that tests an aggressive policy shift to decarbonize the electric sector. Unlike the CETA case, reductions under the ECR scenario are achieved through a combination of actions that result in higher costs for emitting generation and restrictions on the future development of fossil fuels. Under the ECR scenario carbon emissions are regulated through a federal cap-and-trade program that results in a significant CO2 price and higher natural gas costs, relative to the Reference scenario.

Figure 50 summarizes the key drivers of each scenario in a matrix.

Figure 50: 2021 IRP Scenario Assumption Matrix

Scenario Concept	Load	Natural Gas	Carbon	Reserve Margin	New Resource Cost	Renewable Peak Credit
Reference	Base	Base	Moderate	Base	Base	Base
Focus on Resiliency (“FOR”)	Base	Base	Moderate	Summer & Winter Requirements	Base	Low
No Carbon Regulation (“NCR”)	Base	Low	No Price	Base	Base	Base
Clean Energy Technology Advancement (“CETA”)	High	Base	Moderate	Base	Low	Base
Enhanced Carbon Regulation (“ECR”)	Low	High	High	Base	Low	Base

7.4.1. Scenario Load

Two of the 2021 IRP scenarios, the FOR and NCR scenarios, use the same base case load forecast as the reference scenario (described in Section 2), while the CETA and ECR cases flex customer load higher and lower (respectively) to reflect changes in the broader economy and the expected impact of demand-side technologies.

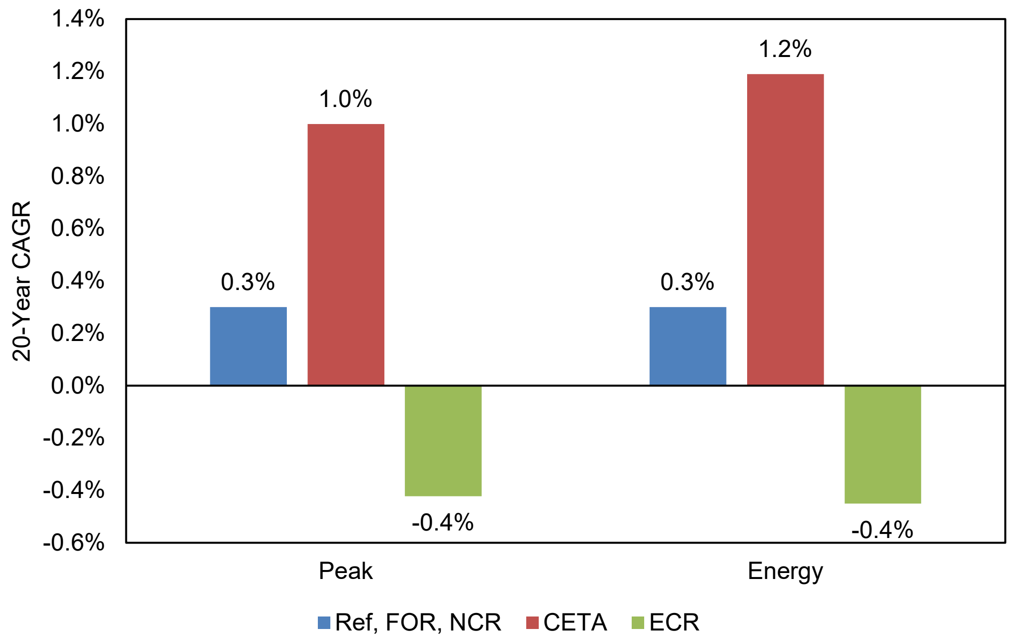
Under the CETA scenario, load grows more quickly than under the Reference scenario driven by increased economic growth, deployment of electric vehicles, and greater building electrification. Overall annual load growth for the SPP market in the CETA scenario is 1.19% per year, or approximately 0.9% higher than the Reference scenario. The accelerated adoption of EVs[19] and other end-use electrification applications also impact the load shape.

Under the ECR scenario, overall load levels in SPP fall over time driven by lower economic growth and adoption of distributed technologies by PSO’s customers. Under this case, annual load growth in SPP is forecast at -0.41% per year, or approximately 0.7% lower than the 20-year forecast of load growth from the Reference scenario.

Changes to annual energy for load across the SPP market are illustrated in Figure 51, below.

19 Incremental to the Reference scenario, the CETA scenario assumes an additional ~7-8 million EVs in the SPP region over 2022-2041 period. The incremental EV penetration assumption under the CETA scenario is scaled to SPP loads based on projections from the MISO MTEP 2020 study. < https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf>

Figure 51: SPP Load Growth 20-Year CAGR and Comparison with the Reference Scenario



7.4.2. Scenario Fuel & CO_2 Prices

Where the Reference scenario reflects an expected outlook for commodity prices and other fundamental market drivers, there are a number factors that may result in market conditions that produce higher or lower prices for natural gas and CO_2 permits.

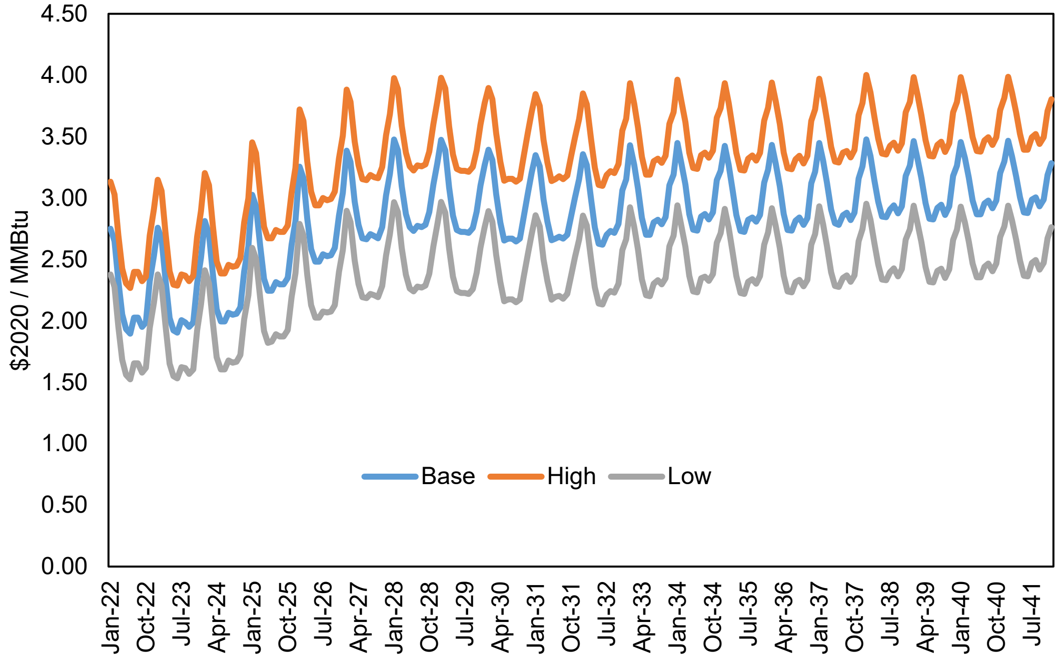
Natural Gas Prices

The same natural gas price view relied upon for the Reference scenario is also used in the CETA and the FOR scenarios when deriving the power price forecast for the SPP market. Under the ECR and NCR scenarios, natural gas prices are flexed upwards and downwards (respectively) reflecting different views of supply-side conditions for producers.

Under the ECR scenario, natural gas prices are assumed to be higher than in the Reference scenario despite lower overall demand. In this scenario, policymakers are enacting stricter federal regulations in an effort to reduce GHG emissions economy-wide. This results in a higher CO_2 price sooner, limits on access to natural gas supply (e.g., drilling bans), and higher production costs due to higher CO_2 prices and stricter environmental requirements. The result is that the natural gas price forecast is approximately \$0.50 / MMBtu higher than in the Reference scenario over the course of the forecast period. Under the NCR scenario, policymakers place less pressure on economy-wide GHG emissions than under the Reference scenario and natural gas prices are approximately \$0.50 / MMBtu lower.

Figure 52 below compares the high and low gas price forecasts relied upon in the ECR and NCR scenarios to the base view used for the remaining scenarios. All three forecasts are taken from AEP's Fundamentals Forecast.

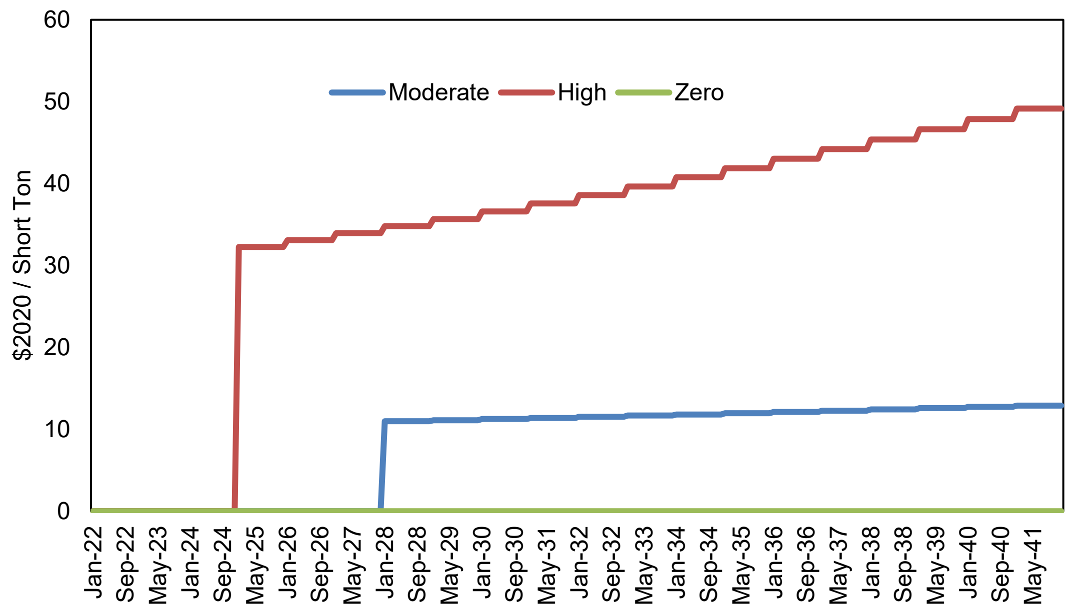
Figure 52: High and Low Panhandle Eastern TX-OK Natural Gas Price Forecasts (real $ / MMBtu)



CO_2 Prices

Under the Reference scenario policymakers enact measures that put moderate pressure on the economy to reduce greenhouse gas emissions in the form of a carbon price starting in 2028. Both the CETA and FOR scenarios use the same trajectory for CO_2 prices. However, there is the potential that future emissions reduction policy could occur sooner than expected and that the level of policy pressure could be materially higher, as represented in the high CO_2 price forecast used in the ECR scenario. Under this scenario, a national cap on carbon is instituted starting in 2025 with prices starting at approximately $32 / Ton in (in real $2020) and rising to around $49 / Ton by 2041. Under the NCR scenario, policymakers do not enact a price on CO2, and prices are assumed to be zero throughout the forecast period. Figure 53 below illustrates how the high and zero CO_2 prices in the ECR and NCR scenarios (respectively) compare to the moderate CO_2 price view used in the remaining three scenarios.

Figure 53: High and Zero CO2 Price Forecasts ($2020 / Short Ton)



7.4.3. Scenario Reserve Requirements

Summer Capacity Requirements

Currently, SPP requires LSEs to maintain sufficient firm capacity to meet a 12% planning reserve margin above summer peak demand to maintain system reliability. This summer planning requirement is observed in all five 2021 IRP scenarios.

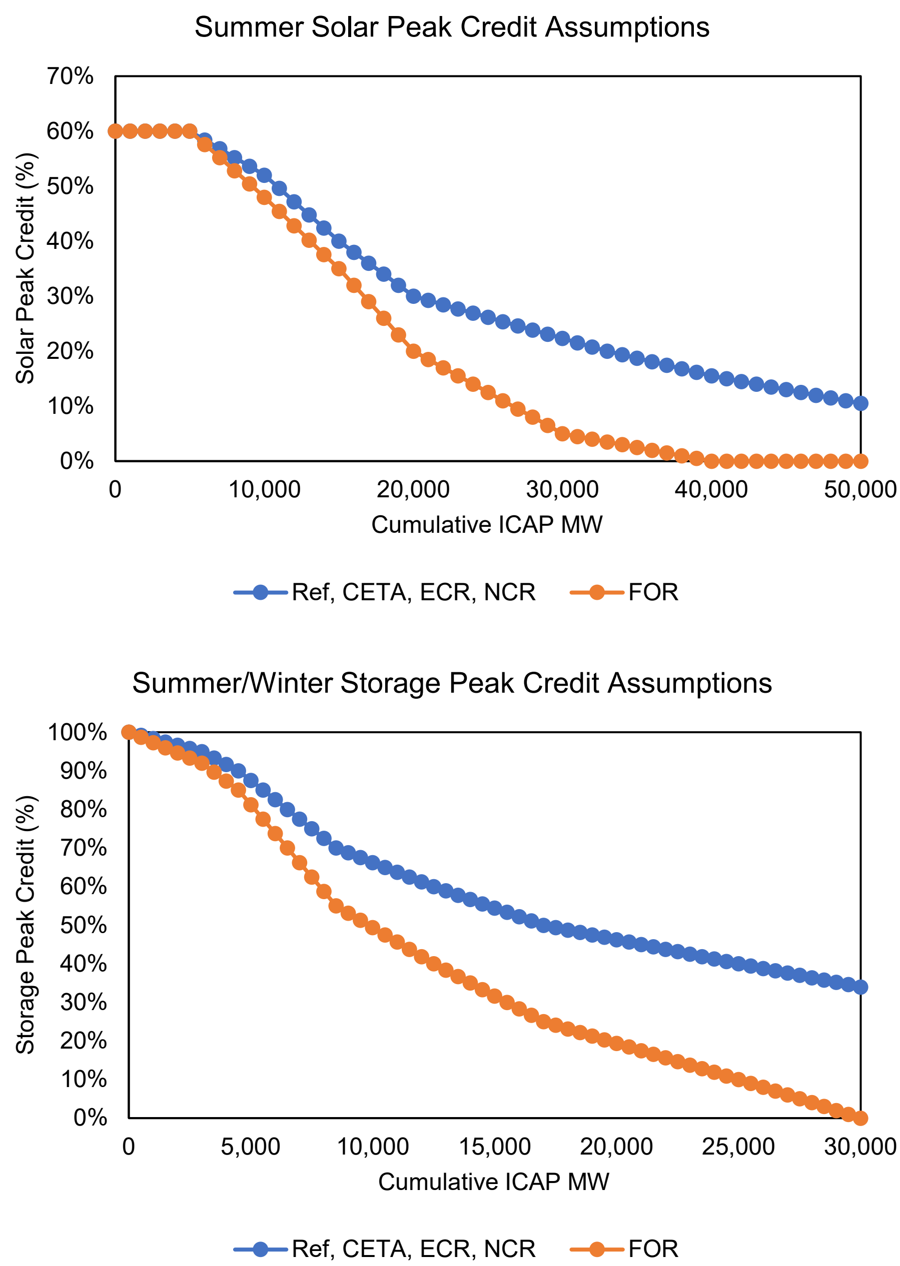
Increments of certain new resources, including some renewables and 4-hour battery storage, provide less additional capacity value as more of the resource is added to the system. That is, the amount of solar already installed on the system impacts how much ELCC the next increment provides. Figure 54 summarizes the reference and low ELCC views for select technologies used in the 2021 IRP scenarios. This figure summarizes the relationship between the installed nameplate capacity in the SPP market and the ELCC value received. It does not show the ELCC value awarded by year across scenarios, which is discussed in Section 7.5.2.

Under the FOR case, a lower outlook is used than in the other scenarios driven by changing SPP market rules for maintaining reliability. Again, the assumed ELCC values were informed by studies performed by SPP.[20,21]

20 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

21 SPP Energy Storage Study Final Report. Astrape Consulting. November 2019. <https://spp.org/documents/61387/astrape%20spp%20energy%20storage%20study%20report.pdf>

Figure 54: ELCC Assumptions for Select Resources by Cumulative Firm Capacity MW [22,23]



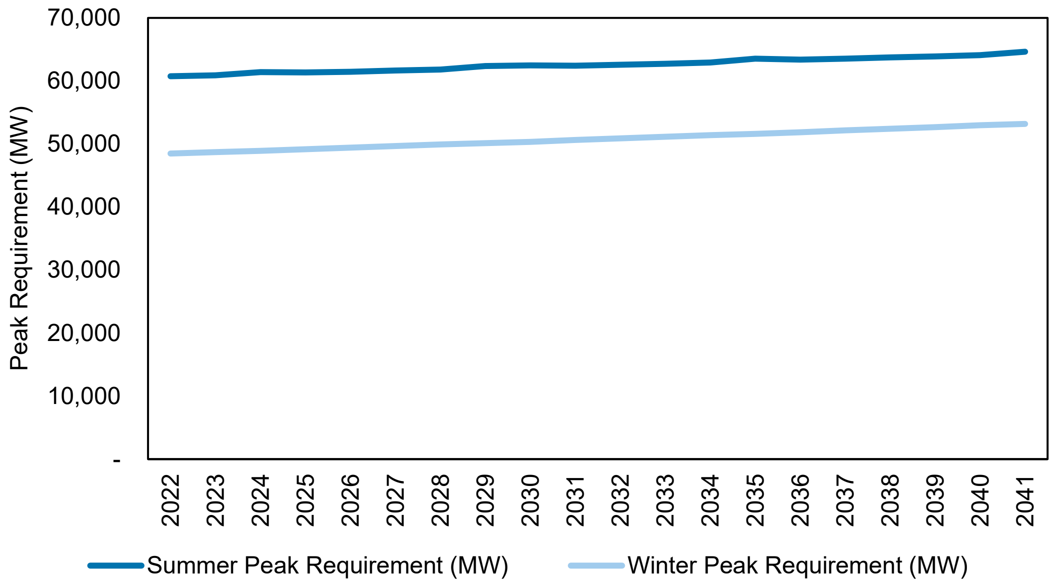
22 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

23 SPP Energy Storage Study Final Report. Astrape Consulting. November 2019. <https://spp.org/documents/61387/astrape%20spp%20energy%20storage%20study%20report.pdf>

Winter Capacity Requirements

Outside of the summer capacity requirements that are enforced for all five scenarios, in the FOR scenario, PSO enforces a 12% reserve margin requirement for the winter season as well. This scenario posits that the SPP market rules will evolve as the resource mix changes in SPP and maintaining reliability in the winter season becomes more challenging absent a planning requirement. Figure 55 below compares the annual forecast of winter peak requirements with peak summer requirements in the FOR case and shows how winter peak demand is growing more quickly than summer peak demand.

Figure 55: Comparison of FOR Scenario SPP Winter and Summer Peak Requirements (2022-2041)



To model winter requirements in the FOR case, it was also necessary to develop assumptions describing the peak contribution of different resource types in the winter season. Peak demand in winter typically occurs early in the morning. Some resources, particularly solar PV, may provide less load carrying capacity during winter peak periods than during summer peaks. Under this scenario solar resources are expected to perform materially different in winter than summer and their peak credits are modeled decline over time from 10% in 2022 to 2% in 2041. Storage peak credits are not assumed to differ from summer.

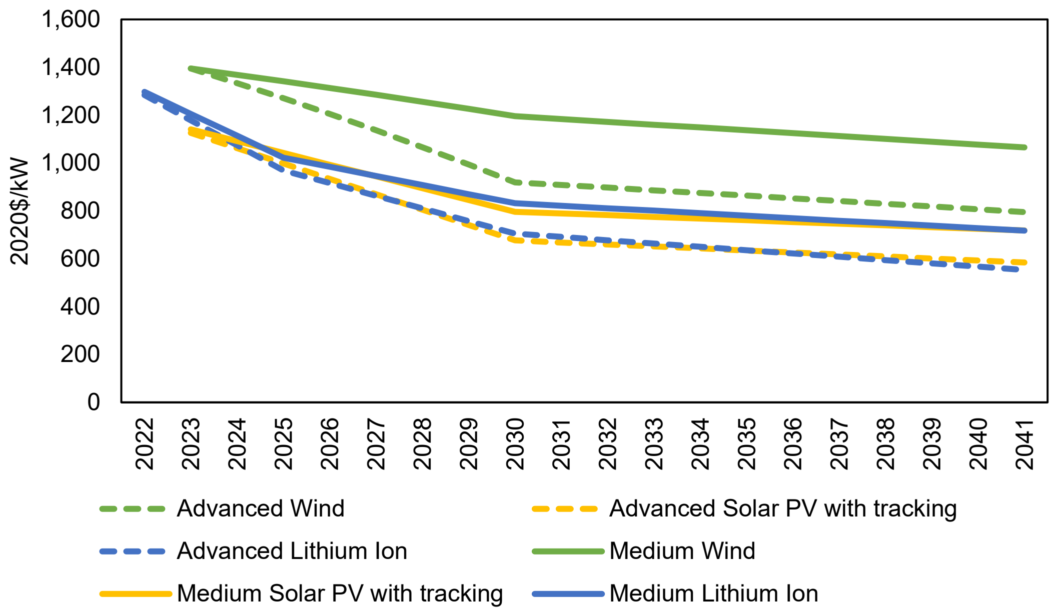
7.4.4. Scenario Technology Assumptions

PSO's 2021 IRP scenario flexed a number of technology-related assumptions including the expected capital cost, congestion costs, and federal tax benefits available to renewable units as part of the 2021 IRP scenarios.

Unit Capital Costs

As described in Section 5, PSO generally relies on technology cost assumptions from EIA's 2021 AEO report to establish the expected capital cost of new utility-scale resources. Those costs change over time based on the medium outlook from the NREL 2020 ATB. This outlook of new unit costs is used for three of the 2021 IRP scenarios: the Reference scenario, the FOR scenario, and the NCR scenario. However, under the ECR and CETA scenarios, rapid deployment of new renewable technologies combines with higher levels of policy support causing the cost of these technologies to decline more quickly. Capital costs follow the "advanced" NREL ATB case learning rates, resulting in costs that are materially lower throughout the forecast period. Figure 56 below compares the forecast of expected capital costs from NREL's advanced case used in the ECR and CETA scenario to the medium case costs used in the remaining three scenarios.

Figure 56: Comparison of Capital Costs Under Advanced and Medium Outlooks for Select Technologies (2022-2041 | $2020 / kw)

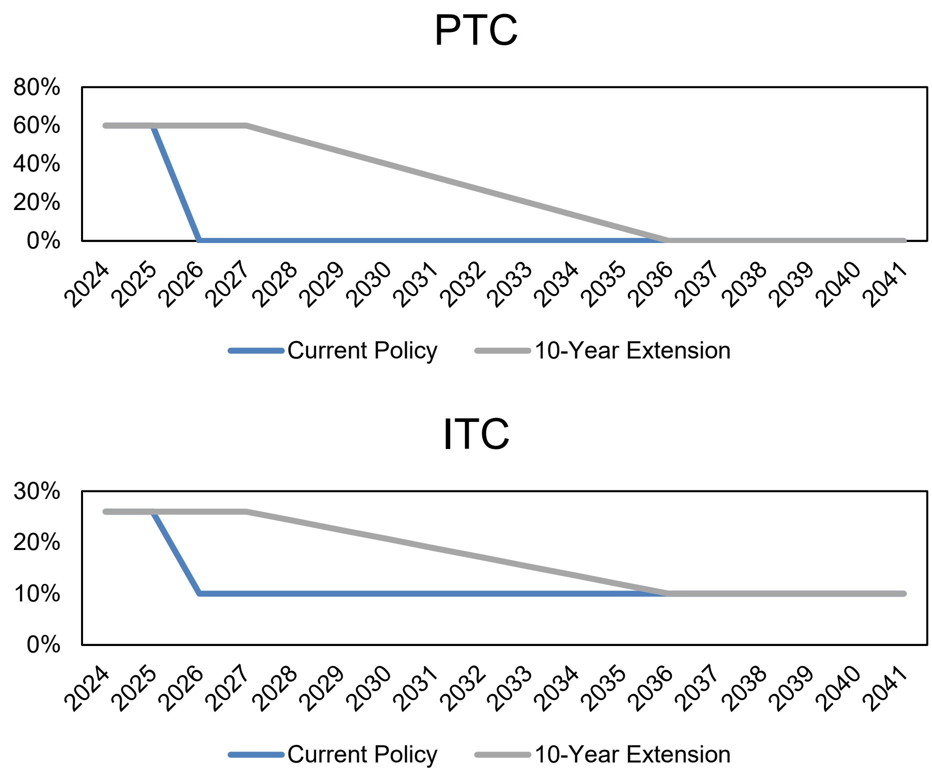


Federal Tax Credits for Renewable Energy

PSO considers how the benefits provided by federal tax credits for renewable energy may evolve under each scenario. As seen above in Figure 50, PSO modeled two different outlooks for federal tax policy as part of the 2021 IRP.

The current policy view reflects the level of benefit provided by the production tax credit ("PTC") and investment tax credit ("ITC") under current law, including the extensions approved in the December 2020 COVID relief bill. This view is adopted for the Reference scenario, as well as for the FOR, ECR, and NCR scenarios. Under the CETA scenario, it is assumed that these federal tax credits are extended for 10 years and decline gradually. This assumption is consistent with the theme of providing support for clean technologies as a method for achieving emissions reductions. Figure 57 below illustrates how these benefits are assumed to decline over time under the current policy and 10-year extension views used in the 2021 IRP. The PTC value in Figure 57 represents the multiplier applied to the statutorily defined value of the credit (e.g., in 2022 it is assumed that new wind units will receive 60% of the defined credit value). By contrast, the ITC value represents the percent of capital cost that can be recovered through the credit (i.e., in 2022 it is assumed that new solar received a 26% tax credit on capital costs).

Figure 57: Federal Tax Credit Assumptions Used in the 2021 IRP (2022-2041)



Congestion Charges

PSO's scenarios also include varying views on the future of the transmission system. Under the CETA scenario, congestion charges for these resources are expected to be higher than in the other cases because higher load growth coupled with lower net costs are expected to drive the highest amount of renewables. PSO has modeled a $5 / MWh congestion adder in the CETA scenario and a $2 / MWh adder in the other four scenarios.

7.5. Market Scenario Results

The load, technology, policy, and other assumptions for the five scenarios described above served as inputs into the AURORA model. Using the model's long-term capacity expansion ("LTCE") functionality, PSO developed scenario-specific forecasts of the SPP market. In the portfolio modeling stage, described below in Section 8, PSO developed an optimal candidate resource plan in each one of the five scenarios.

7.5.1. Capacity Expansion Results

PSO used the AURORA LTCE model to forecast the least-cost combination of resource additions and retirements in SPP using the assumptions for each market scenario. While the SPP market selections do not directly impact the resources that can be selected for the PSO portfolio, they are informative for describing how different resource types are likely to perform under certain conditions. Figure 58 and Figure 59 below illustrate the 2041 SPP capacity and generation mix (respectively) across all five market scenarios compared with the SPP resource mix in 2021.

Under the Reference scenario, much of the existing coal fleet is retired over the course of the forecast. Due to the combination of announced retirements and the modest CO_2 price that comes into effect in 2028, only 4 GW of coal are left by the end of the study period. To replace coal plant retirements and meet growing load, a combination of renewables, 4-hour battery storage, and new gas units are added over time. In total, approximately 16 GW of new wind, 24 GW of new solar, 20 GW of new storage units, 6 GW of new gas peakers, and 3 GW of new combined cycles are added by 2041. The gas units are installed primarily to meet firm requirements. Under the Reference scenario, solar and wind generators provide more than 75% of the total SPP generation by 2041. The result is that total CO_2 emissions in the SPP market drop by 70% in the Reference Scenario from 2021 to 2041.

Figure 58: Comparison of 2041 Nameplate Capacity by Technology in SPP w/ 2021 Resource Mix

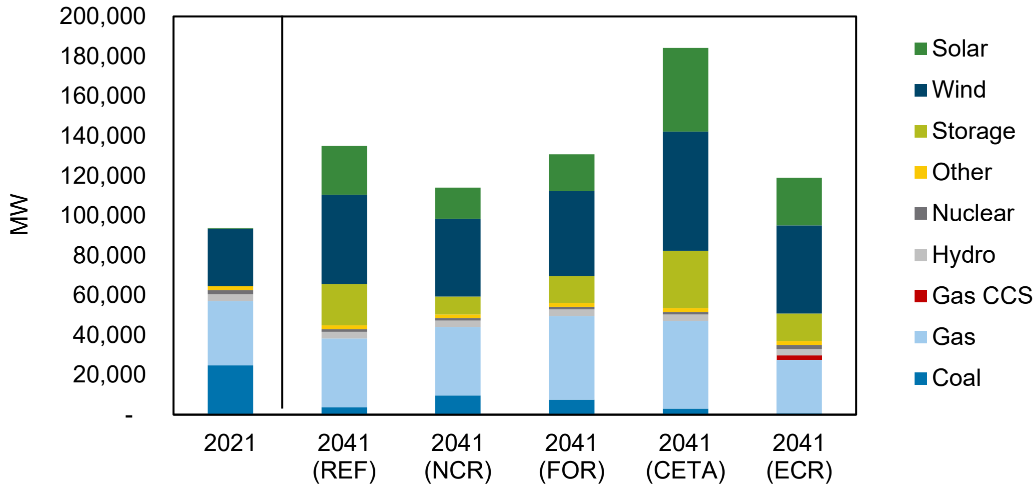
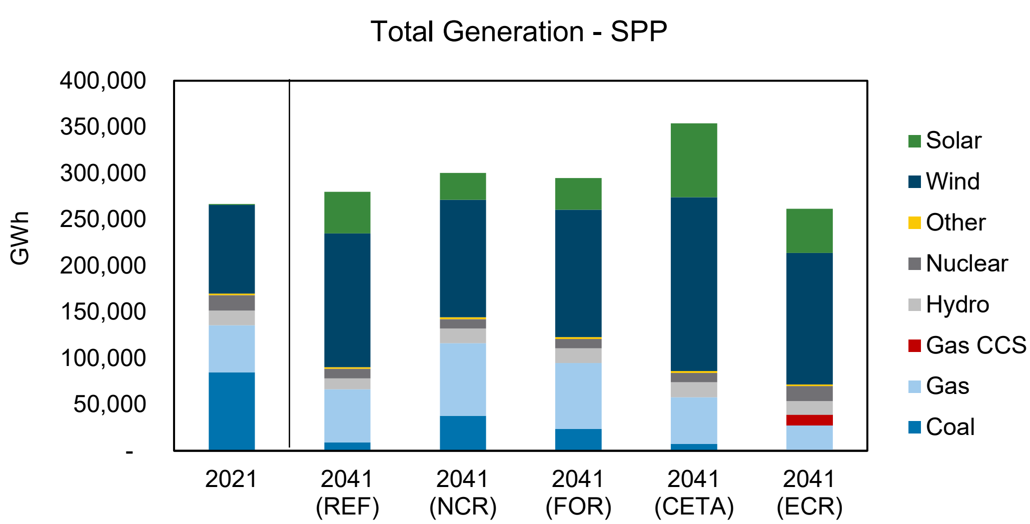


Figure 59: Comparison of 2041 Generation by Technology in SPP w/ 2021 Resource Mix



Under the NCR scenario, there is no economy-wide CO_2 price; however, natural gas prices are forecast lower than in the Reference scenario. The result is that more existing coal is able to remain competitive and approximately 10 GW of coal units are still operating by the end of the forecast period.

The overall build-out of new renewables in the NCR Scenario is lower than in the Reference scenario with approximately 10 GW of new wind, 15 GW of new solar, and 9 GW of new 4-hour battery storage added by 2041. Compared to the Reference scenario, there is a similar amount of total gas capacity, though it is weighted more heavily towards combined cycles in the NCR scenario due to the lower commodity price assumption that makes these units more competitive. The result is that renewable units comprise only about 50% of total SPP generation by 2041 in the NCR scenario, with natural gas units providing the majority of the remaining energy. Emissions fall in this scenario, but not as far as in the Reference scenario, down around 40% from 2021 levels by the end of the forecast period.

In the FOR scenario, commodity price conditions are similar to the Reference scenario, but the addition of the winter reserve margin requirement and the reduction in the peak contribution for wind and solar units result in a larger proportion of thermal dispatchable generation in the SPP market than under Reference scenario conditions. As a result, by 2041, there is approximately 4 GW more coal capacity remaining in the market and 7 GW of additional gas-fired generation relative to the Reference scenario by.

Deployment of renewable technologies is lower than in the Reference scenario due to the lower reserve margin value of these units. Approximately 18 GW of new solar, 14 GW of new wind, and 13 GW of new 4-hour battery storage are added by 2041. Renewable sources comprise just under 60% of SPP market generation in this year. SPP CO_2 emissions drop by approximately 50% from 2021 to 2041, compared to around 70% in the Reference scenario.

Under the CETA scenario, load growth is higher than in the Reference scenario and the cost of new renewable generation is lower due to a combination of faster learning rates and an extension of federal renewable tax credits. The combination of higher load and more affordable renewable technology leads to materially greater deployment of solar, wind and 4-hour battery storage than under the Reference scenario. By 2041, nearly 42 GW of new solar, 31 GW of new wind, and 29 GW of new 4-hour battery storage are added in SPP under the CETA scenario. Coal retirements are similar and there is slightly more gas generation in SPP under the CETA case than under the Reference scenario despite greater penetration of renewables due to the higher load forecast assumed in this scenario. Despite a higher installed capacity, gas units generate less in the CETA case than the Reference scenario due to greater competition from new renewable sources. Solar and wind units comprise more than 75% of total SPP generation by 2041, and CO_2 emissions fall by around 74% SPP-wide relative to 2021 levels.

In the ECR scenario, a lower load outlook for SPP is combined with a higher outlook for CO_2 and natural gas commodity prices. This results in accelerated coal retirements, relative to the Reference scenario, and nearly all coal units in SPP are retired by 2041. Natural gas-fired capacity also falls SPP-wide and approximately 2 GW of NGCCs are retrofits with carbon capture and storage over the forecast period. Due to the more favorable outlook for nuclear, the 770 MW Cooper plant is relicensed in 2034 under the ECR scenario. Gas units without CCS retrofits run at low capacity factors under the ECR scenario, while CCS-equipped gas units tend to run at higher capacity factors as carbon prices rise over the study period. SPP sees similar amounts of wind and solar deployment as the Reference scenario (around 24 GW and 15 GW respectively) and lower levels of 4-hour battery storage (around 13 GW). However, due to lower load growth, these resources make up a large proportion of the overall system, with wind and solar accounting for 75% of total SPP generation by 2041. SPP-wide CO_2 emissions are the lowest in this scenario and decline by 90% relative to 2021 levels by the end of the forecast period. To achieve these levels, renewable generation is supported by additional nuclear and CCS-equipped natural gas capacity relative to the Reference scenario.

7.5.2. Effective Load Carrying Capability (ELCC) Results

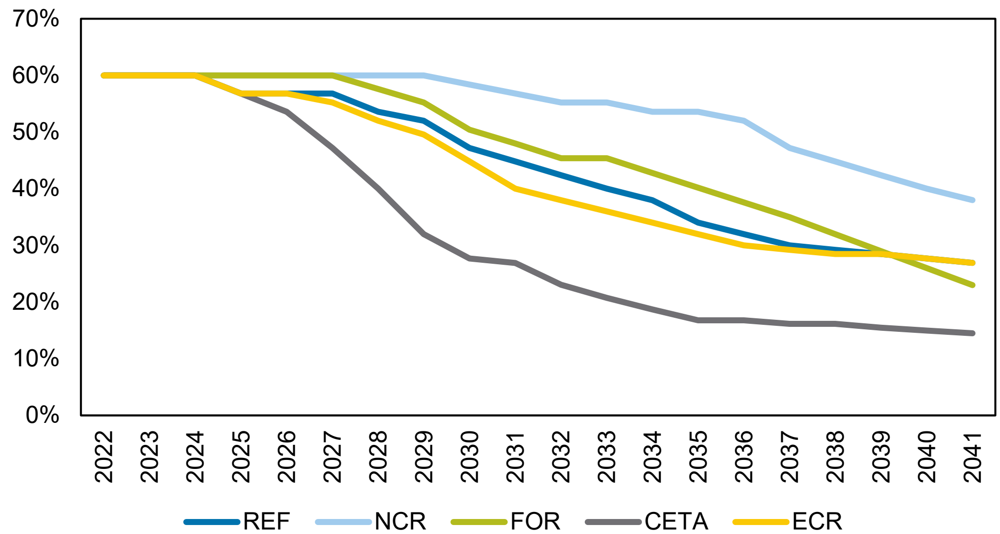
As described in Section 7.3.3 and Section 7.5.1, the PSO scenarios have produced a range of capacity expansion results using the AURORA LTCE model that result in different penetration levels of renewable and 4-hour battery storage. The ELCC value of the renewables and 4-hour battery storage are based on the amounts installed in each scenario.

While solar and storage credits vary by case, wind ELCC is assumed to stay constant at 14.7% informed by a SPP Study.[24]

Under the Reference, FOR, and ECR scenarios, solar ELCC values decline from the current 60% value to levels near 25% by 2041, with the capacity value falling over time in-line with the increments of new solar added in each case. Less solar is added in the NCR case driven by lower natural gas prices and the absence of an economy-wide CO_2 price, and solar ELCC declines to around 39% peak value by 2041. While the NCR scenario stretches towards an upper bound, the CETA case sets the lower bound. Under the CETA scenario capital costs are lower for renewable resources and tax credits are extended, leading to more and earlier additions. ELCC of incremental solar and storage falls more quickly in this scenario and settles at value of around 15% in summer during the second half of the forecast. Similar to solar, storage ELCC values vary across scenarios, ranging from 35% to 70% by 2041. The resulting solar and storage summer ELCC values are summarized in Figure 60.

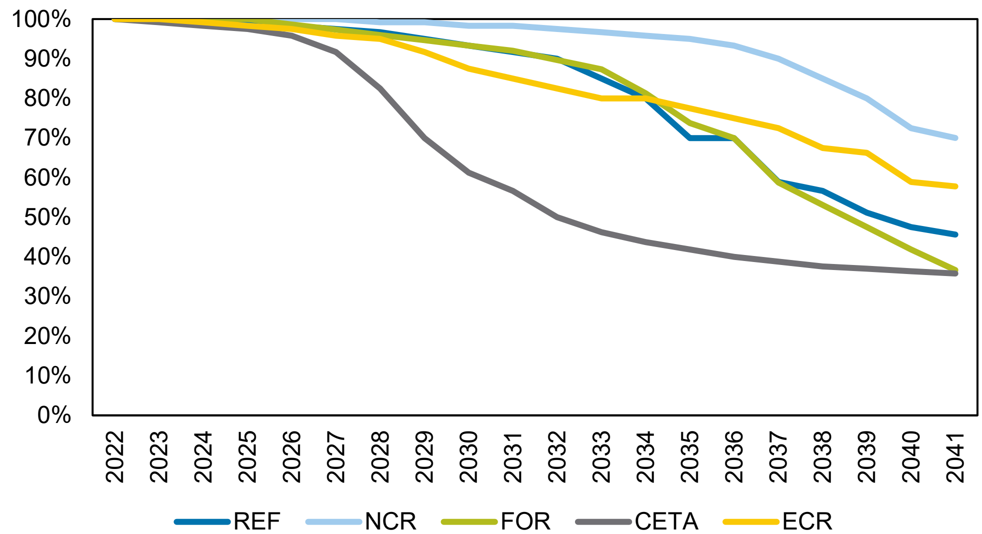
Under the FOR scenarios, solar winter ELCC values are assumed to decline from 10% in 2022 to 2% by 2041. Winter season reserve margin requirements were not enforced in the remaining market scenarios.

Figure 60: Comparison of Solar Summer Peak Credits by Scenario



24 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

Figure 61: Comparison of Storage Summer Peak Credits by Scenario



7.5.3. Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Figure 62 and Figure 63. Shown are all five market scenarios modeled in the 2021 IRP. These figures illustrate the wide but plausible range of energy prices that emerge from the scenario modeling step that were used to develop and select the Preferred Plan.

Figure 62: Annual On-Peak SPP South Hub Electricity Price ($2020 / MWh)

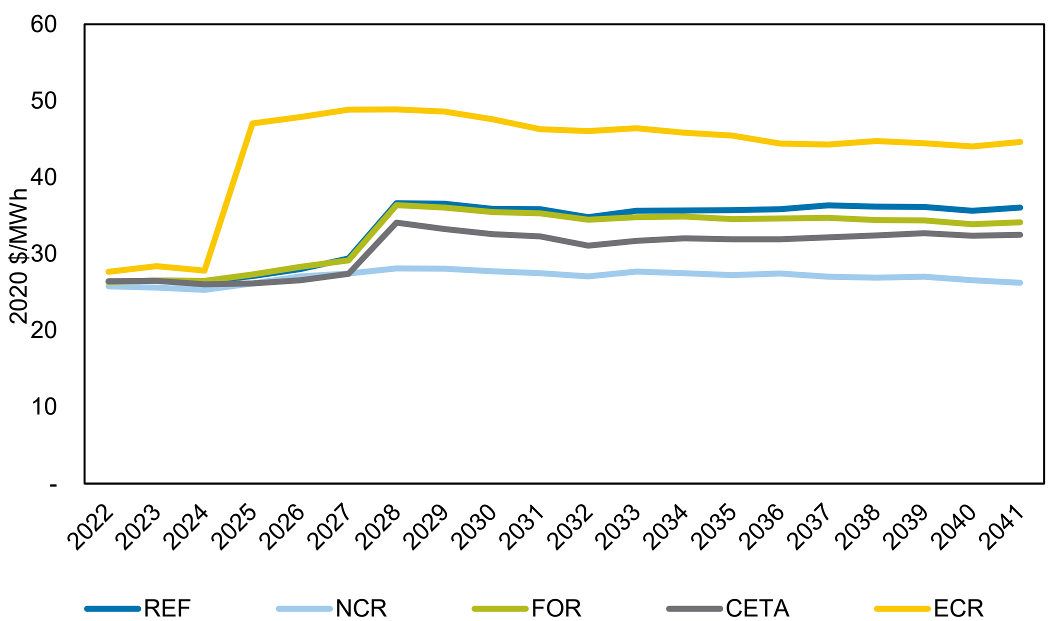
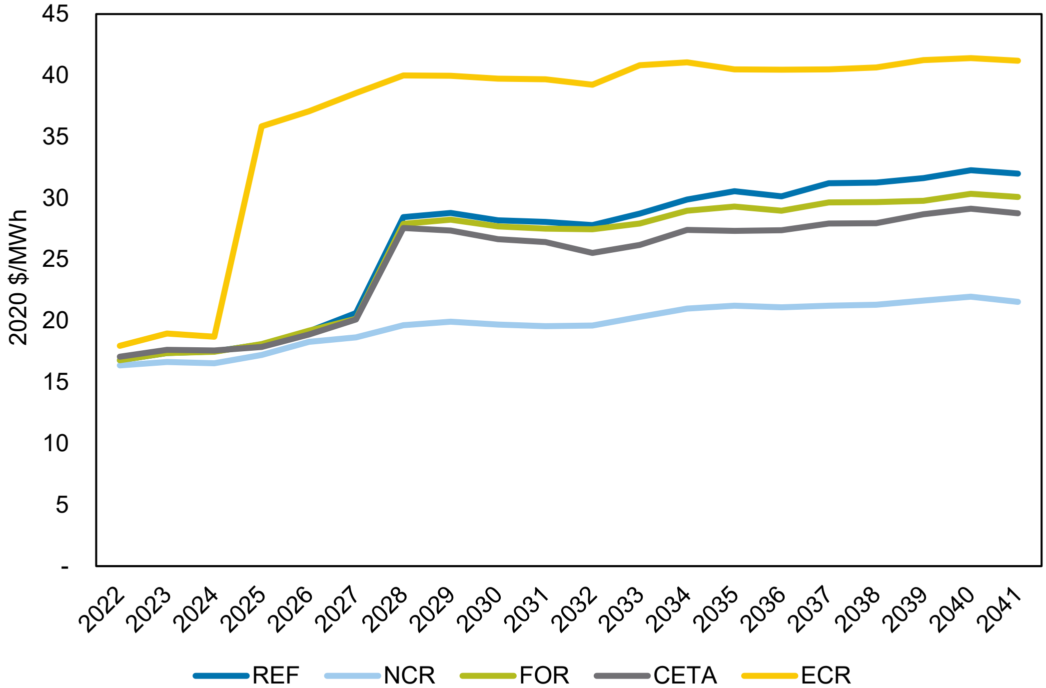


Figure 63: Annual Off-Peak SPP South Hub Electricity Price ($2020 / MWh)



Under the Reference scenario, on-peak energy prices in SPP South Hub rise gradually from around $26 / MWh ($2020 real) in 2022 to $29 / MWh by 2027 in large part due to the increase in natural prices over the period. There is approximately a $9 / MWh spread between on- and off-peak pricing over this same period, in real dollar terms. Starting in 2028 prices step up in both on- and off-peak periods by approximately $7 / MWh driven by the introduction of the CO_2 price in that year. There is little growth in on-peak pricing from 2029 onward even as CO_2 prices continue to rise due to the increasing penetration of renewable generation on the SPP system. Off-peak prices, however, rise more quickly due to increasing costs of thermal generation in periods of lower renewable output. This contributes to a narrowing of the spread between on- and off-peak prices over the forecast period, which declines to about $4 / MWh by 2041.

Under the FOR and CETA scenarios, SPP market prices are largely similar, though forecasted to be somewhat lower, than in the Reference scenario. This outcome is to be expected given that the same commodity prices were used in all three of these scenarios (i.e., base natural gas and moderate CO_2 prices). Under the FOR scenario, long term prices for both on- and off-peak energy are around $2 / MWh lower than under the Reference scenario due to the higher market-wide reserve margins. Under the CETA scenario, prices are between $2-4 / MWh lower than the Reference scenario over the long term despite faster load growth due to the high level of renewable penetration in the SPP market.

The ECR scenario sets the upper bound of SPP market prices. During the 2022-2024 period, both on- and off-peak prices are approximately $2-3 / MWh higher than in the Reference scenario due the higher natural gas price assumed in this scenario. In 2025, the high CO_2 price is introduced and SPP market prices rise by around $20 / MWh in both on- and off-peak periods. From 2025 onward, on-peak prices tend to fall modestly (in real terms) due to the lower load growth assumption in this scenario and the high penetration of renewable generation. Conversely, off-peak prices grow slightly from 2025-2041 due to the high cost of running thermal generation during periods of low renewable output. The result is that the spread between on- and off-peak prices falls to around $3.50 /MWh by 2041 in the ECR scenario when viewed on an annual average basis.

The NCR scenario sets the lower bound of SPP market prices. From 2022-2027, overall market prices are around $2-4 / MWh lower than in the Reference scenario due to the low natural gas prices forecast that is assumed in this scenario. After 2028, SPP prices in this case are materially lower than in the Reference scenario due to the lack of federal CO_2 pricing and lower outlook for natural gas prices that are assumed as part of the scenario. On-peak prices are largely steady from 2028 until the mid-2030s when they begin to decline modestly in real terms as additional renewable generation is added to the system. Off-peak pricing is flat through the early 2030's, after which prices grow slightly due to an increase in the forecasted coal prices and changing capacity mix in the SPP market. The spread between on- and off-peak prices therefore narrows to between $4-5 / MWh in this scenario on an annual basis.

7.6. IRP Stochastics Development

PSO's stochastic risk analysis attempts to address volatility and "tail risk" impacts to its generation portfolio that would not be included under "expected" or "weather normal" deterministic forecasts. The selected variables modeled for stochastic realizations –gas prices, power prices, and renewable output – are specifically selected to address portfolio performance under various market dynamics and generation availability outcomes.

As described in Section 8.2, rate stability is one of the key objectives for the preferred portfolio. The scorecard metric "Cost Risk" is defined as the NPVRR increase between the 95th percentile and 50th percentile portfolio cost observed under the set of stochastic distributions of variables. This metric captures the robustness of portfolio cost when subjected to a range of combinations of gas prices, power prices, and renewable output.

This analysis involves developing 250 combinations of stochastic gas prices, power prices, and renewable output, then determining the portfolio costs under each of the 250 iterations through portfolio dispatch in AURORA and the PERFORM financial module. The 95th and 50th percentile NPVRR among the set of portfolio cost realizations are identified to calculate the "Cost Risk" scorecard metric.

7.6.1. Gas and Power Prices Stochastics

Stochastic price paths for gas and power prices are developed using CRA's Moment Simulation Energy Price ("MOSEP") model. MOSEP is a regime-switching, mean-reverting[25] model that takes as input expected paths for gas and power, based on PSO's Reference scenario outlined in Section 7.3. MOSEP's Monte Carlo engine simulates random price deviations around the expected paths based on historical volatility and seasonal gas-power correlative relationships to yield "realized" price paths for both gas and power. While price paths are developed for the period 2021-2042, data from 2031 and 2041 are singled out for the portfolio cost analysis.

To reflect realistic market price behavior, historical daily average gas and power price data were gathered to observe key price characteristics and calibrate simulation model

25 The model simulates price behavior under different price regimes (e.g., normal price regime, spike price regime). Commodity prices have been found to exhibit a mean-reverting behavior after a sudden price jump. The model facilitates switching between different regimes via a Markov transition matrix. Given the current regime, the transition matrix specifies the probabilities of staying in the current regime or moving to a different regime. These probabilities are approximated based on historical data. For references, see the following paper, on which MOSEP is based - Higgs, H. & Worthington, A. "Stochastic price modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market." Energy Economics, 2008.

parameters. The key seasonal market price characteristics include, but are not limited to, the range of prices around a seasonal median price, standard deviation, magnitude and frequency of sudden price spikes, market heat rate, and correlation between gas and power. The specific pricing points used in this analysis are the daily natural gas spot index at ANR-SW and the day-ahead, around-the-clock SPPS price strip. The historical prices from the period January 1, 2016 to December 31, 2020 were used to summarize the relevant market price behavior and include only the most recent market dynamics.

Figure 64 and Figure 65 illustrate one sample iteration of gas and power daily prices in 2031 produced by MOSEP (red lines). The baseline forecasts are included in the same graphic (black lines) for comparison. As illustrated, the stochastic price paths exhibit more daily volatility as well as high-price and low-price risk than the deterministic Reference scenario forecasts.

Figure 64: Sample Iteration of Daily Natural Gas Price Simulation for 2031

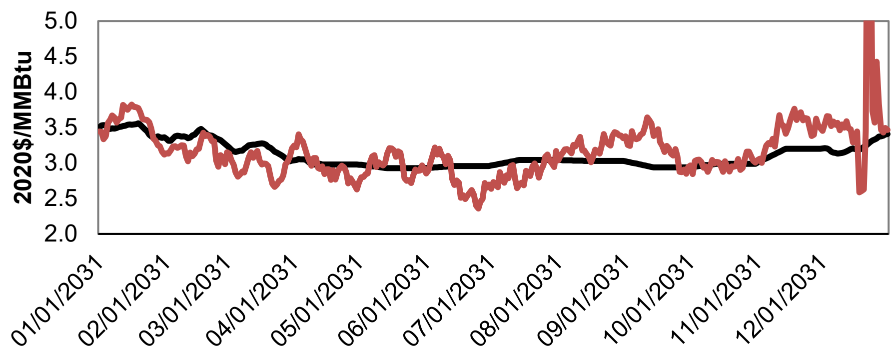
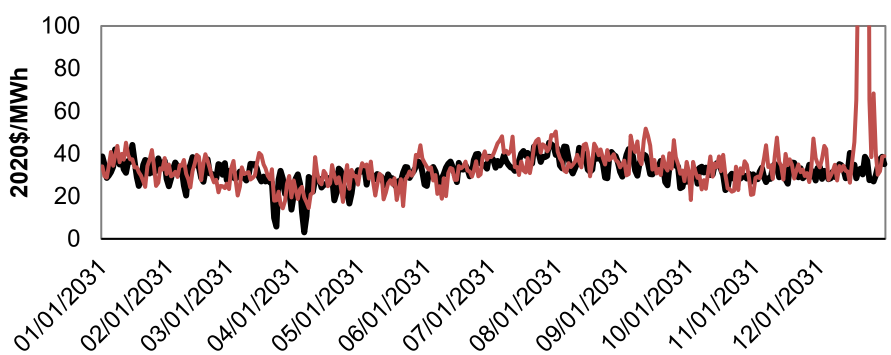


Figure 65: Sample Iteration of Daily Power Price Simulation for 2031



7.6.2. Renewable Output Stochastics

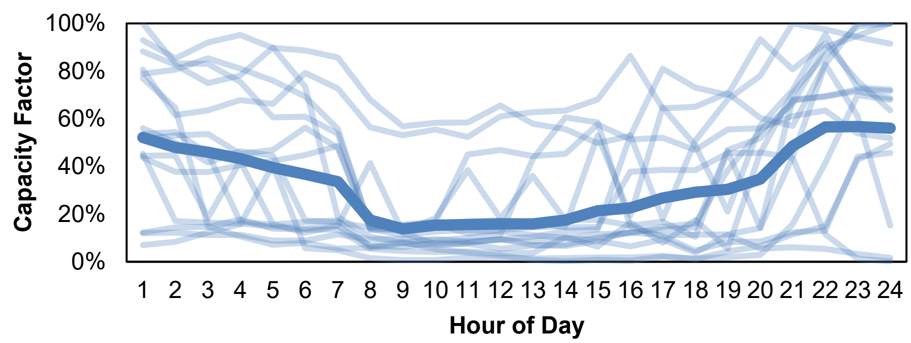
Renewable output uncertainty is integrated in PSO's stochastic analysis process to address the risks associated with energy market exposure. To widen the range of modeled renewable availability, historical weather data from NREL was used to proxy wind and solar availability using NREL's System Advisor Model ("SAM").

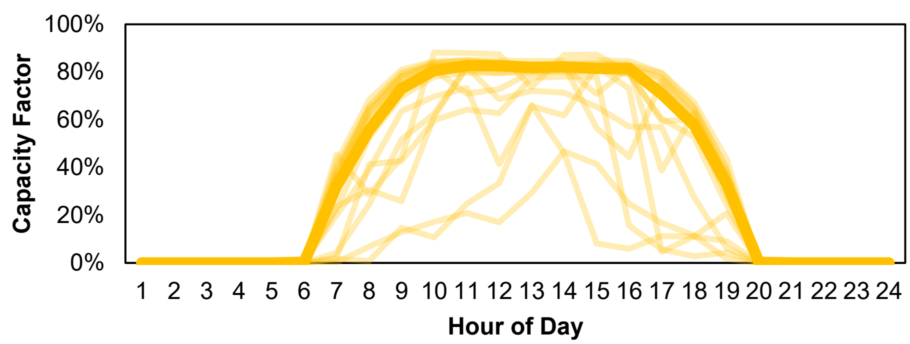
Historical hourly weather conditions for the years 2008 to 2012 (5 weather years) for counties across Oklahoma[26] were used as inputs into the SAM tool. Proxies for a farm of wind turbines and single-axis tilt solar panels were used in SAM to simulate hourly wind and solar power output, respectively. Adjustments to SAM power estimates were used to align with PSO's capacity factor assumptions for new wind and solar resources.

Figure 66 illustrates hourly capacity factor shapes for wind and solar in the month of July, with the monthly average capacity factor shape depicted in the bolded blue and yellow lines, respectively.

Each of the 250 commodity price paths are combined with renewable output data from one of the five historic weather years. For example, the first 50 iterations of gas and power prices are matched with wind and solar output based on historical weather year 2008 conditions.

Figure 66: Simulated Hourly Wind and Solar Capacity Factor for July



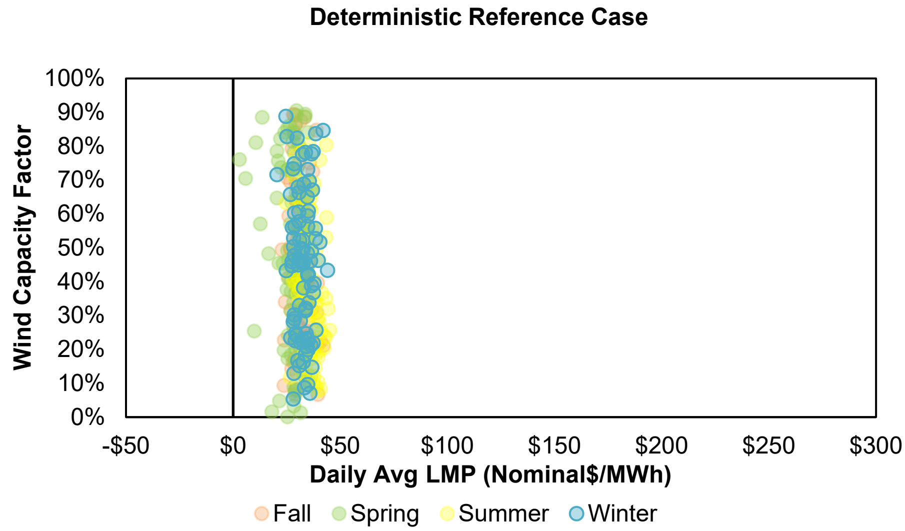


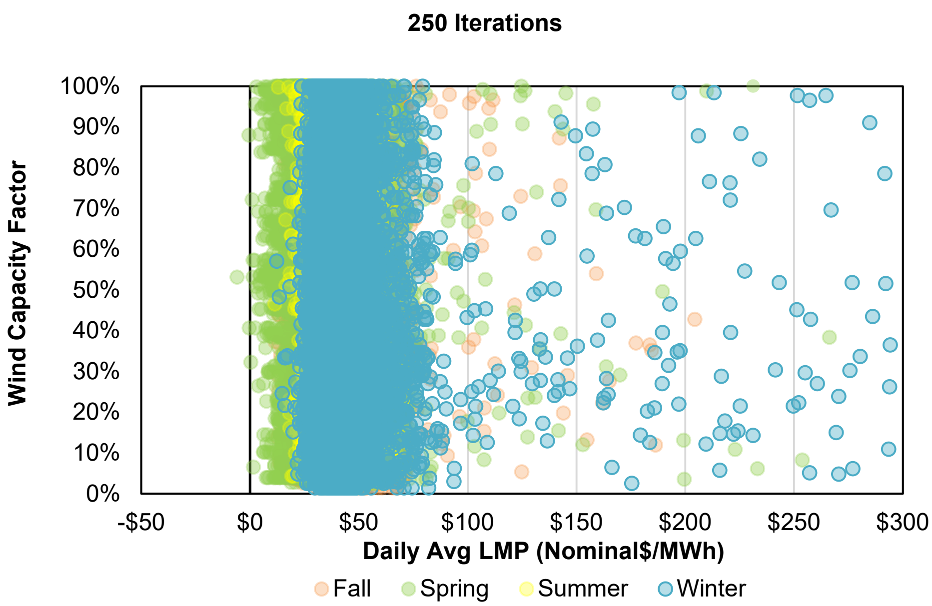
By incorporating stochastic renewable profiles and gas and power outputs, the combinations of renewable output and price paths cover a greater range than the Reference scenario. This is illustrated in Figure 67 that compares combinations of daily average wind capacity factors and the daily average power price across the deterministic Reference scenario versus the 250 stochastic iterations around the Reference scenario. From the first graphic, prices vary with renewable output, but there is limited variability in the overall market prices that are

26 Five geographically diverse counties across Oklahoma - Caddo, Cimarron, Dewey, Kay, and Kingfisher – were identified to determine a wind capacity factor shape. SAM simulated wind power output for each weather year, and the combined output across the five counties for a given weather year was used to define a single wind output shape. For solar, Caddo county data was used to define a solar output shape, as one would expect less volatility across geography for hourly solar output than wind.

reflected. By contrast, the stochastic modeling approach used by PSO tests many more hours and captures periods of high market prices and low renewable output, and vice versa.

Figure 67: Daily Average Wind Capacity Factor and Power Price, under Deterministic Reference Scenario vs. 250 Stochastic Iterations





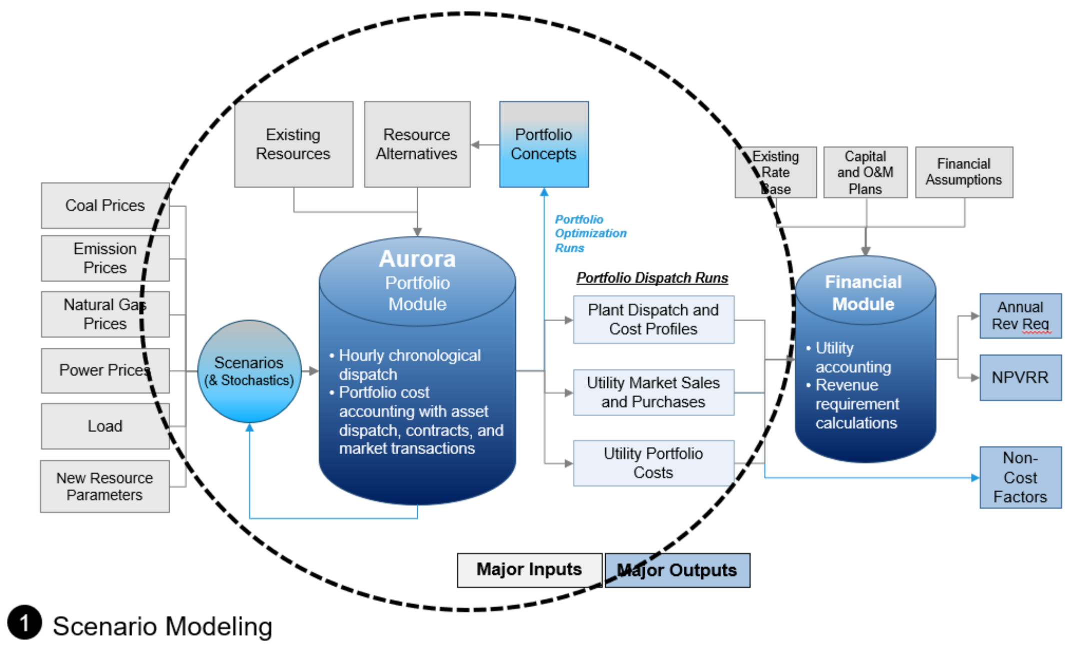
8. Portfolio Analysis

8.1. Introduction

The 2021 Portfolio Analysis began by reviewing the priorities and objectives of PSO and its Stakeholders, as well as key uncertainties and potential futures risks associated with the cost of serving PSO's customers described in the prior section. This process informed the analysis performed and the development of an IRP scorecard, a tool used to evaluate the potential trade-offs between different demand- and supply-side options that PSO may employ to meet customer future needs in the 2021 IRP. The 2021 IRP scorecard and metrics are detailed below in this chapter.

In terms of impact on the IRP analysis, the priorities and objectives informed the 2021 IRP by leading to the creation of five different market scenarios that reflect plausible, but different, combinations of outcomes across key related fundamental market drivers (e.g., load, fuel costs, seasonal requirements, level of environmental pressure, etc.) described in the prior section. These scenarios tested how the prices of energy, capacity, and other services changed across the SPP market under different combinations of these fundamental conditions. These scenarios were used to inform the development of six portfolio options using a combination of the capacity expansion model in AURORA and expert judgements to find "optimal" selections of resources under different market conditions. These five SPP market scenarios were also used to test the riskiness (or not) of the different candidate resource plans by subjecting them to a wide range of market outcomes that are materially different than scenario under which each plan is optimal.

Figure 68: 2021 IRP Modeling Framework



Further, concerns and risks raised by PSO leadership informed the cost metrics and broader risk analysis performed in the IRP. Leadership noted the market events of February 2021 in ERCOT and SPP, and set an objective for the Preferred Plan to provide reliable service for PSO customers during extended periods of extreme weather or broader system outages, and also the goal to protect customers from periods of unexpectedly high costs in the winter and summer seasons. The IRP therefore seeks to test market volatility and short-term extreme conditions through the stochastic analysis of power, gas, and renewable outcomes, and our risk metrics incorporate high cost outcomes to evaluate the potential impacts on total system costs under extreme or adverse SPP market conditions that may occur in both winter and summer.

8.2. Scorecard Metrics

In resource planning, a scorecard can be an effective tool in decision-making. "Scorecard" for resource planning purposes refers to a device that illustrates the performance of alternative resource plans across a set of Company-defined objectives, performance indicators, and metrics. A scorecard enables a utility to develop and consider resource decisions on the basis of how different plans score on the factors that matter to the utility and the customers it serves. It provides a simple and structured means of explaining how sometimes objectives align, while other times they can conflict and be traded off as part of reaching a reasonable decision that is in the best interest of customers.

The scorecard has three primary elements, illustrated in Figure 69:

- **Objectives** are overarching goals that align to PSO or stakeholder priorities. The four objectives of the 2021 PSO IRP Scorecard are:
    - Customer Affordability
    - Rate Stability
    - Maintaining Reliability
    - Local Impacts & Sustainability
- **Performance indicators** measure progress towards goals and serve as measurable categories across which portfolios can be compared. There are eleven performance indicators on the PSO Scorecard, these align to the four objectives and are detailed below.
- **Metrics** are the units in which the performance indicators are measured, often they include a time element (e.g., net present value, cumulative period, future test year) in addition to numerical value or calculation. With some exceptions, the PSO scorecard focuses on a 10-year outlook since this aligns with the IRP planning requirement.

Figure 69: Elements of the 2021 PSO IRP Scorecard

Objective	Performance Indicator	Metric
Customer Affordability	Short-term Rate Impact	5-year CAGR of customer rates
	Medium-term Portfolio Cost	10-year NPVRR and levelized rate
Rate Stability	Scenario Resilience	Range of cost from highest to lowest market scenario
	Cost Risk	Susceptibility to commodity shock risk (95th percentile minus 50th percentile)
	Market Exposure	Net market energy position (as % of load) in summer and winter
Maintaining Reliability	Planning Reserves	Excess capacity position in summer and winter
	Operational Flexibility	Dispatchable capacity and number of dispatchable units in portfolio
	Diversity	Percent generation by technology
Local Impacts & Sustainability	Local Impact	MW capacity and capital invested in service territory
	Carbon Emissions	Percent carbon reduction (2000 to 2031)

The details of objective, performance indicator, and metric is described in the following sections. The scorecard is found below as Figure 70.

8.2.1. Objective 1: Customer Affordability

Customer affordability is a primary goal for PSO. Affordable power and lowest reasonable rates were identified as key considerations for stakeholders who may be sensitive to increases in energy costs and may therefore object to certain resource plans if those plans are expected to result in higher rates. Further, this objective aligns with AEP's corporate vision, "We're redefining the future of energy and developing forward-thinking solutions that provide both clean and affordable energy to power the communities we serve."[27] For the PSO 2021 IRP, minimizing the expected cost to customers, to the extent reasonable when evaluated against other objectives, was a clear and obvious objective for the scorecard.

The PSO scorecard includes two performance indicators that track the customer affordability objective across different time scales.

Short Term: 5-yr expected growth in customer rates

Customers want affordable energy and are more likely to support resource plans that limit expected short term increases in customer rates. Portfolios with similar net present values over the longer term can have significantly different near-term impacts, which may be important to consider when selecting a Preferred Plan. This performance indicator allows PSO to assess that risk across portfolios and weigh short- and long-term cost considerations when selecting the Preferred Plan.

PSO measures and considers the expected percentage growth in retail rates over five years as the metric for the short-term customer affordability performance indicator. Near-term retail rate impact is measured using a 5-year Compound Annual Growth Rate ("CAGR") of expected system costs for the years 2022-2027.

Medium Term: 10-year net present value of revenue requirement

PSO expects a need for new capacity in the mid- to-late 2020s as Northeastern 3 is retired and contracts with existing thermal plants expire. Further, the 2021 IRP results are focused on the 10-year outlook throughout the body of the report. Having a 10-year performance indicator maintains consistency between the factors that management is reviewing and what is discussed and presented throughout this IRP report.

Net Present Value Revenue Requirement ("NPVRR") was selected as metric for this performance indicator. NPVRR is a representation of the total long-term paid by PSO's utility customers related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on and of capital related to power supply. NPVRR will be measured over the medium term using a 10-year period (2022-2031) and is expressed both in terms of total and levelized rate. The levelized rate is the fixed charge per MWh needed to recover the 10-year NPVRR.

8.2.2. Objective 2: Rate Stability

Rate stability is a key component of affordability for PSO's customers, a resource plan that performs well under expected conditions may expose ratepayers during periods of volatility, extreme weather events, or extended outages. PSO understands that market fluctuations in electric and fuel commodities and other uncertainties can adversely impact customer rates under a resource plan deemed to be the most affordable. This risk was recently highlighted during the Texas power crisis where an historic cold weather event led to rolling blackouts, forced generator outages, and high wholesale gas and electricity prices.

[27] Citation needed

The performance indicators of rate stability test how certain and robust the expected costs of each portfolio are by subjecting them to different market scenarios and to random shocks in power and gas prices, and renewable outputs. This assessment evaluates how portfolios perform under a wide range of market conditions, commodity prices, and policy outcomes and allows PSO to balance affordability under expected conditions with resilience to changes in the market.

The three performance indicators for rate stability are described below, they include an assessment of the potential change in rates across a wide range of scenarios, the amount of revenue requirement at risk under adverse or extreme conditions, and track the amount of seasonal reliance on the SPP energy market under each candidate plan.

Scenario Resilience: Range of 10-year NPVRRs across the 5 market scenarios

This performance indicator describes the range of total costs for a given portfolio when modeled across all five market scenarios. This allows management to compare the overall variability or consistency of costs for each candidate portfolio under the full range of market conditions considered in the IRP.

The metric for this performance indicator measures the range in cost of each portfolio option between its best and worst performing planning scenario. It is calculated by subtracting the 10-year NPVRR for a single resource plan in the (1) the market scenario under which total costs were for the resource plan were the lowest from (2) the market scenario under which the total costs to the resource plan were the highest.

Using a 10-year metric allows for all of the resource decisions made in the IRP to be reflected and maintains consistency between the scorecard and the IRP requirement. NPVRR is a representation of the total long-term annual costs paid by PSO's utility customers related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on and of capital related to power supply. NPVRR will be measured over the long term using a 10-year period (2022-2031) and is expressed both in terms of total and levelized rate.

Cost Risk: The revenue requirement increase when moving from the 50th to the 95th percentile of portfolio costs in 2031

Portfolios that perform similarly under expected conditions may perform differently when exposed to market volatility, extreme weather, or extended unit outages - such as the impacts of extreme weather observed in February 2021. This measure tests the robustness of portfolio costs when exposed to random combinations of gas prices, power prices, and renewable outputs, and allows PSO to compare the cost of the candidate portfolios under adverse market conditions, relative to the expected cost of the option under normal conditions. In other words, this metric measures the increase in the expected cost to serve customers under volatile or extreme conditions, relative to the expected case.

This metric measures the difference between the (1) total portfolio costs under 95th percentile conditions and (2) portfolio costs under median conditions across the stochastic distribution in the Reference scenario in 2031.This measure serves as a useful touch point for discussing portfolio risk with stakeholders and evaluating whether renewable-heavy portfolios that engage in market purchases and sales at different times of the day or year increase or decrease its cost risk.

2031 is selected as the test year to align with the other 10-year metrics and the IRP requirement.

Market Exposure: net purchases or sales as a % of summer and winter load in 2031

PSO has repeatedly expressed an interest in this IRP to track resource requirements seasonally to illuminate how different candidate portfolios may expose PSO customers to winter and summer market events that result in high (or low) wholesale energy prices.

This performance indicator allows PSO to evaluate the medium- and long term exposure of different resources options to conditions in the SPP energy markets by indicating the total portion of customer needs served by the market, or conversely, the reliance on market sales in certain periods of excess generation. PSO currently purchased between 30-50% of energy needed to serve load on an annual basis and there is an opportunity for the utility to supply more of the energy that its customers consume. This indicator allows management to measure progress towards that goal.

The metric for this performance indicator measures the magnitude of net purchases or sales made by each portfolio in model year 2031, distinguishing between market activity occurring during the summer (June, July, Aug, Sep) and winter (Dec, Jan, Feb, Mar) seasons. It is calculated by subtracting the volume of hourly gross energy sales from hourly gross purchases across the test months for each season, and then dividing the resulting value by total volume of energy demand served over those same months.

2031 is chosen as the test year to align with the 10-year outlook presented in the IRP report, and both winter and summer values are reported for this year.

8.2.3. Objective 3: Maintaining Reliability

"Safe, reliable power" is a key theme of the PSO mission statement and reliability is an important consideration for PSO's customers that are active in the stakeholder process. Understanding the role that SPP plays in maintaining broader system reliability, PSO has identified maintaining reliability as an important, fundamental objective to be included on the IRP scorecard. Reliability is an essential aspect of a utility's mission and has taken on even greater importance since the Texas and SPP energy event of winter 2021. PSO also noted the potential benefits to maintaining reliability of distributing a relatively larger number of smaller units across geographies that provide local benefits and relieve system constraints. Finally, PSO has been a leader in providing innovative technologies, such as AMI, to its customers and seeks to evaluate the level of innovation across candidate resource plans to evaluate progress towards these components of its corporate objectives.

Three performance indicators were selected to measure progress towards maintaining reliability. These cover the total capacity reserves, by season, maintained by PSO under each plan, the amount of capacity and number of dispatchable units included in each plan, and an indicator of the overall technology diversity and implementation of innovative technologies.

Planning Reserves: % of summer and winter capacity requirements served by the resource plan from 2022-2031

PSO seeks to track energy and capacity exposure separately in the 2021 IRP. This performance indicator measures PSO's expected reliance on the market (or excess capacity) for meeting summer and winter reserve margin requirements. This measure allows PSO to evaluate the seasonal exposure of different candidate resource plans to reliability events measured as the percent of seasonal reserve requirements contributed by owned resources (i.e., excluding any short-term purchases) towards meeting planning reserve margin requirements. This exposure is viewed as the average performance across all 5 market scenarios to capture the full range of load forecasts included in the 2021 IRP.

The metric for this performance indicator will be PSO's reserve margin measured as the ratio of firm supply to expected peak demand for *both* the summer and winter periods. For reporting purposes, the average reserve margin period over the 2022-2031 time period will be included in the scorecard. The period 2022-2031 is used because it reflects the results discussed in the IRP and allows PSO to evaluate the portfolios across the entire period instead of at a single point in time.

This metric is calculated by dividing the winter firm capacity of the resource plan by PSO's winter peak requirement and the summer firm capacity of the resource plan by PSO's summer peak requirement for years 2022-2031 across all five market scenarios. This results in 50 winter values and 50 summer values. These values are then averaged by season and reported on the scorecard.

Operational Flexibility: Dispatchable capacity in 2031

The increase in intermittent renewable resources across SPP may create the need for more flexible resources that can provide a reliability service and balance the system during periods of low output or extreme weather. Understanding each portfolio's ability to respond to system needs is an important factor for determining the Preferred Plan and can also be considered a as a measure of future ancillary services value, which is highly uncertain.

This performance indicator allows management to evaluate the amount of ramping capacity on its system and the potential to diversify those resources geographically measured as both the cumulative amount and number of dispatchable resources selected in the candidate portfolio 2031. Dispatchable resources include new gas peaking units (multiple configurations), new gas combined cycle units (with or without CCUS), new energy storage units, and new hydrogen-fired units.

The metrics for this performance indicator represent the (1) the total firm capacity provided by fast-ramping technologies, and (2) the total number of units added to the resource plan designated as "dispatchable" between 2022-2031. Multiple blocks of identical scalable technologies (such as battery storage) constructed within a single year will be considered as separate units, since no discount is being providing to represent benefits of collocating projects (i.e., the model does not see lower interconnection or land costs when building many of these units so they could be assumed to be located separately). The 2022-2031 period is selected to align with the results included in the IRP report and reflect PSO's position after filling the expected capacity gap emerging in the late 2020s.

Resource Diversity: Generation mix by resource in 2031

PSO is interested in maintaining a diverse set of resources as a method for maintaining reliability for its customers and in evaluating the role that new and innovate technologies can play to help customers reach their goals. This performance indicator will allow management to assess the overall diversity of its long-term resource plan as well as compare the performance of plans that rely on more traditional vs. more advanced technologies.

The metric for this performance indicator is a pie chart displaying the percentage of total generation provided by the different generating technologies selected in each candidate resource plan in model year 2031 and under the Reference scenario. The metric is measured in 2031 to capture the full range of replacement decisions over the IRP requirement timeline.

8.2.4. Objective 4: Local Impacts & Sustainability

Community partnership and local investment are key themes in the PSO mission statement and AEP corporate sustainability objectives. PSO has repeatedly indicated an interest in having a positive local impact within its service territory and highlighting the opportunities for customer-sited resources as part of the 2021 IRP. Further, AEP has defined corporate-level sustainability goals of reducing carbon emissions by 80% by 2030 and achieving net zero carbon emissions by 2050 across all operating companies.

PSO indicated interest in measuring the performance of alternative resource against those goals when selecting the Preferred Plan. This objective also allows PSO to evaluate the relative exposure of candidate resource plans under outcomes where significant reductions in GHG emissions are required in the power sector – a plausible outcome with potentially material impacts on the cost to PSO's serve customers.

Two performance indicators were selected to measure progress towards local impacts & sustainability. Local impacts are measured as the amount of new generation located in the PSO service territory and the amount of local investment associated with those projects.

Sustainability is measured through portfolio CO2 emissions, and the level of reductions achieved relative to the baselines use for the AEP corporate targets.

Local Impacts: Installed MW and Capital Invested inside PSO's Service territory

PSO has a continued interest in being a community partner and recognizes the importance of demonstrating the potential benefits of different candidate resource plans to its stakeholders and customers, including creating opportunities for customers interested in locating new generation on-site. This performance indicator allows management to compare the amount of total new installed resource likely to be constructed in regions that PSO serves and that may be candidates for customer sited projects over the 2022-2031 period. Further, this indicator allows management to evaluate the expected amount of local investment made under each candidate resource plan, which is a fair proxy for evaluating the relative local economic impacts of each plan.

There are two metrics associated with this performance indicator. (1) The cumulative nameplate MW of new capacity likely located within the PSO service territory from 2022-2031; and, (2) the cumulative capital invested in the PSO service territory from 2022-2031, calculated as the sum of capital spent over the period in current year (e.g., 2021) US dollars.

The 2022-2031 period was selected to align the scorecard to the portfolio modeling results that are presented in the 2021 IRP and to focus the evaluation on local impacts over the first 10 years of the overall resource plan.

CO2 Emissions: Percent reduction from 2000 in the Reference Scenario in 2031

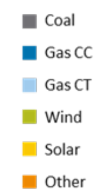
PSO's parent company, AEP, has defined corporate sustainability goals across all of their electric operating companies. Specifically, AEP has defined corporate-level sustainability goals of reducing carbon emissions by 80% by 2030 and achieving net zero carbon emissions by 2050 relative to a 2000 baseline.

This performance indicator allows PSO to evaluate progress towards those goals as one element of the Preferred Plan and also serves as a measure of comparing the relative exposure of candidate resource plans under outcomes where significant reductions in GHG emissions are required in the US power sector.

The metric for this performance indicator is the level of carbon emission reductions relative to PSO's total emissions in the year 2000. Carbon emissions are defined as the direct emissions from PSO's owned and contracted generating resources and the baseline year was selected to align with the AEP corporate targets. This metric is calculated by dividing the total PSO portfolio emission in 2031 by total PSO portfolio emission from the year 2000 and evaluating the percentage reduced. Despite AEP having announced targets in 2030 and 2050, the scorecard uses the test year 2031. This decision was made to maintain consistency with the 10-year outlook reflected in the IRP report. Further, it is PSO's view that portfolio emissions in 2031 are a reasonable proxy for progress towards AEP's 2030 aspirations.

Figure 70: 2021 IRP Scorecard

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *5-year Rate CAGR, Reference Case*	***Medium Term:*** *10-yr NPVRR, Reference Case*	***Scenario Resilience:*** *High Minus Low Scenario Range 10-yr NPVRR*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Purchases/ Sales as % of Total Portfolio Demand*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type*	***Local Impacts:*** *Nameplate MW & Total CAPEX Installed Inside PSO Territory*	***CO_2 Emissions:*** *Percent Reduction from 2000 Baseline - Reference Case*
Year Ref.	2022-2027	2022-2031	2022-2031	2031	2031	2022-2031	2031	2031	2022-2031	2031
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer | Winter	Summer | Winter	MW | #Units	%	MW | $MM	% Reduction
Reference Portfolio										
CETA Portfolio										
ECR Portfolio										
CC Portfolio										
NCR Portfolio										
Modified Reference Portfolio										



Note - Levelized Rates and NPVRR metrics are for generation component only. Metrics are for comparison only and do not represent the final costs which will apply to ratepayers.

8.3. Portfolio Considered

PSO used the AURORA model to select an optimal portfolio of resources to meet expected future customer needs under each of the five SPP market scenarios. The AURORA model uses an optimization technique to select the "least-cost" set of candidate resources that minimizes the net present value of revenue requirements subject to certain constraints and assuming the market scenario conditions including load, fuel and CO_2 prices, reserve requirements and technology assumptions including tax credits where relevant as discussed for each market scenario in Section 7. The candidate resources made available to the model includes supply-side resource and demand-side resource options, these inputs are discussed in Section 5 and Section 6 respectively, and the scenario parameters of which are discussed in Section 7.

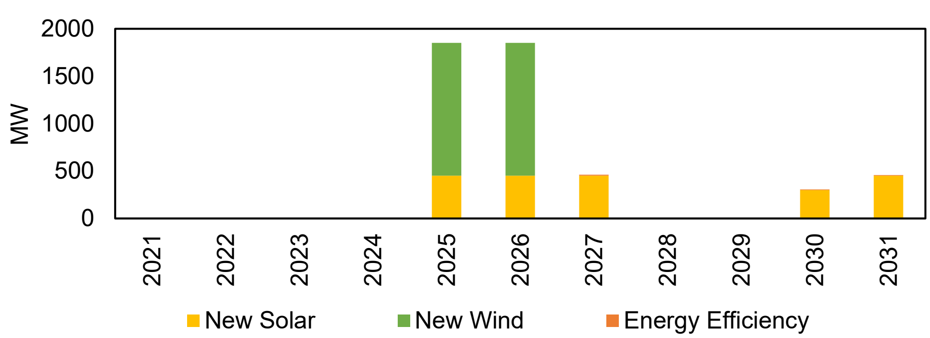
PSO used four of the resulting least-cost plans as candidate portfolios in the 2021 IRP. One duplicative plan was removed, and two new plans were created. The so-called "CC Portfolio" tests the impact of additional gas exposure on PSO customer costs because no plans that included a CC build resulted from the AURORA optimizations. The "Modified Reference" portfolio was added to address a short-term capacity gap that would otherwise emerge by mid 2020s in the Reference Portfolio.

Each of the six candidate portfolios was stress-tested under all five market scenarios as well as stochastic distributions of gas, power prices and renewable outputs (as discussed in Section 7) using a suite of resource planning tools, namely AURORA and a utility financial model known as PERFORM. AURORA produces projections of asset-level dispatch and the total variable costs associated with serving load. The AURORA output is then used by the PERFORM model to build up a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, tax credits, and financial accounting of depreciation, taxes, and utility return on investment. The PERFORM model produces annual and net present value estimates of revenue requirements over the planning horizon. The outputs from AURORA and PERFORM are then used to populate the 2021 IRP Scorecard to inform the selection of the preferred portfolio.

8.3.1. Resource Additions by Portfolio

Resource additions in each of the six portfolios considered are shown in Figure 71 to Figure 74 below.

Figure 71: Resource Additions in the Reference Portfolio

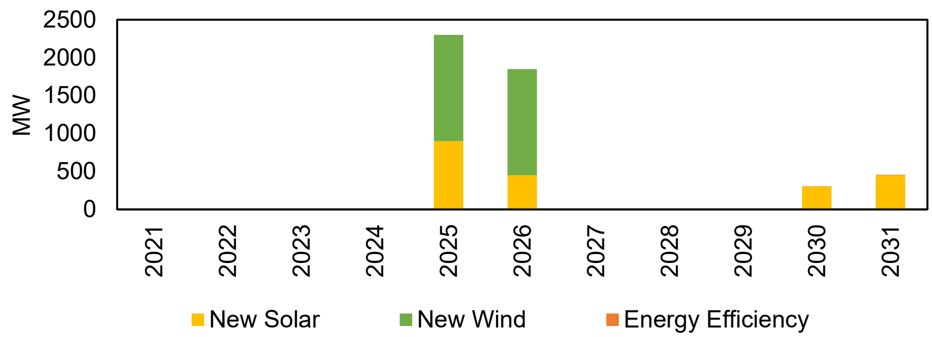


Note – Wind and solar additions in 2025 and 2026 occur on December 31 of the prior year to qualify for ITC/PTC, all other additions occur January 1 of year shown.

For the Reference portfolio, approximately 2.1 GW of new solar and 2.8 GW of new wind are added by 2031. Of the new solar and new wind added, 0.9 GW and 2.8 GW of new solar and wind, respectively, are added by the end of 2025 to take advantage of the ITC and PTC for customers.

In addition, demand-side resources including incremental DR, DG, CVR, and EE programs are pursued. The summer peak contribution of incremental DR rises from 5 MW in 2027 to 25 MW in 2031 while customer DG rises from 0.7 MW in 2022 to 4.5 MW in 2031. The contribution of incremental EE programs ranges from 16.5 MW – 68.1 MW depending on the year, with the peak of 68.1 MW registered in 2031. Selected incremental CVR contributes approximately 12 MW from 2028 onwards. In total, the summer peak contribution from incremental demand-side resources is 0.8 MW in 2022, rising to 123 MW in 2031.

Figure 72: Resource Additions in the Modified Reference Portfolio

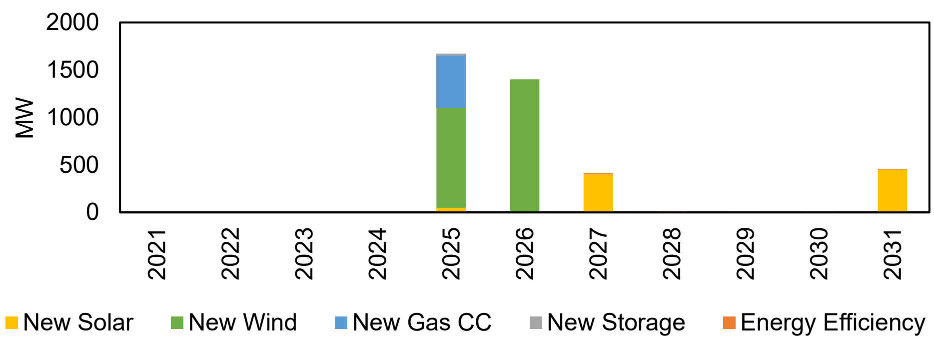


Note – Wind and solar additions in 2025 and 2026 occur on December 31 of the prior year to qualify for ITC/PTC, all other additions occur January 1 of year shown.

The Reference portfolio includes an addition of 450 MW of new solar in 2027, two years after the expiration of the ITCs. The Modified Reference portfolio was created to test the impact of accelerating that 2027 solar addition by two years to lock in the ITCs for PSO's customers and address a short-term capacity need in 2025.

When optimized in the FOR scenario, AURORA returns the same supply-side and demand-side resource additions as the Reference portfolio. This is because PSO's summer capacity peak requirement is materially higher than its winter capacity peak requirement, and the remaining market drivers (e.g., load, fuel price, etc.) are the same across these two cases. The least-cost capacity buildout needed to satisfy the Reference summer requirement provides sufficient capacity in winter to meet the 12% reserve margin requirement under the FOR scenario, even accounting for the reduction in the peak contribution for solar resources in winter. In other words, the winter reserve requirement was not binding when optimizing the PSO portfolios under the FOR scenario, and as a result, the resulting optimal capacity additions were identical to the Reference Portfolio. Therefore, PSO developed an additional CC portfolio, optimized under the Reference Scenario, to avoid duplicate resource plans in the 2021 IRP and test the impacts of additional gas exposure on expected customer costs.

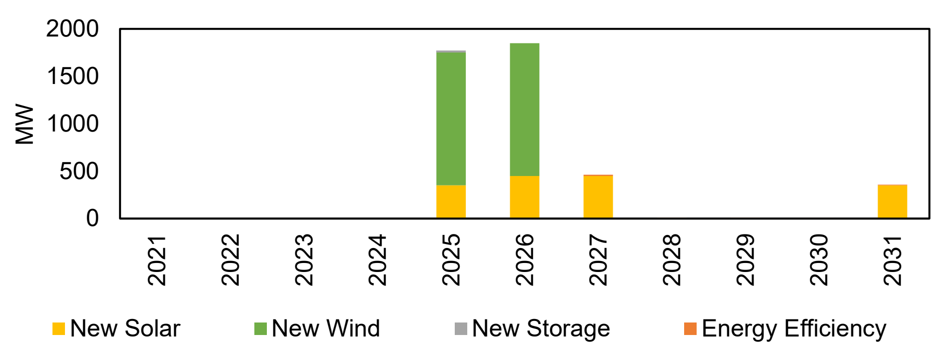
Figure 73: Resource Additions in the CC Portfolio



Note – Wind and solar additions in 2025 and 2026 occur on December 31 of the prior year to qualify for ITC/PTC, all other additions occur January 1 of year shown.

The CC portfolio includes the assumed addition of a 550-MW NGCC unit in 2025, then optimize the remaining resource selection under Reference Scenario conditions. This early addition of a baseload gas units results in lower capacity and energy requirements relative to the Reference portfolio, as such, the CC portfolio contains lower additions of new solar and wind relative to the Reference portfolio. Approximately 0.9 GW of new solar and 2.5 GW of new wind are added by 2031 in addition to the NGCC unit. The addition of the NGCC unit does not change the economics of demand-side resources, however, and the selection of demand-side resources in the CC portfolio are the same as in the Reference portfolio.

Figure 74: Resource Additions in the NCR Portfolio

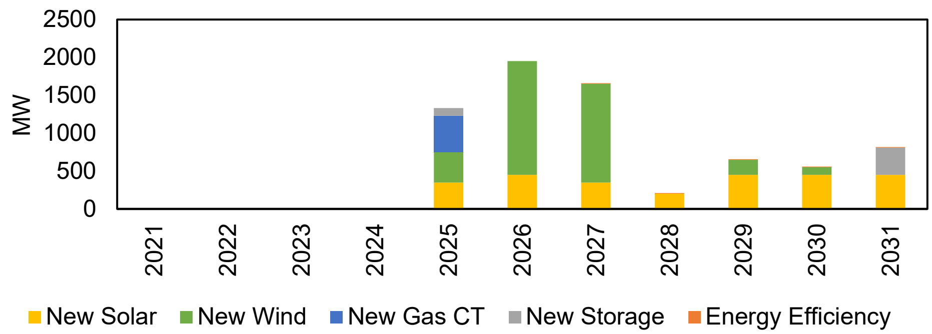


Note – Wind and solar additions in 2025 and 2026 occur on December 31 of the prior year to qualify for ITC/PTC, all other additions occur January 1 of year shown.

The NCR Scenario has lower natural gas prices and zero carbon prices that generally improve the economics of gas-fired generation relative to other scenarios. However, lower additions of renewables in the SPP region means that solar PV installed in the PSO portfolio has a higher ELCC, giving this technology higher capacity credit relative to other scenarios. The higher capacity credit of solar PV makes this resource more attractive in the NCR scenario relative to the other SPP market outlooks. As a result, AURORA selects more solar in the NCR portfolio despite low gas and carbon prices. By 2031, the portfolio adds 1.6 GW of new solar and 2.8 GW of new wind.

Lower gas and zero carbon prices result in limited deployment of demand-side resources in the NCR portfolio. No additional CVR tranches are selected, and the medium industrial and commercial EE bundle is not selected under this resource plan. In total, the contribution from incremental demand side resources is 0.8 MW in 2022, rising to 103 MW in 2031.

Figure 75: Resource Additions in the CETA Portfolio

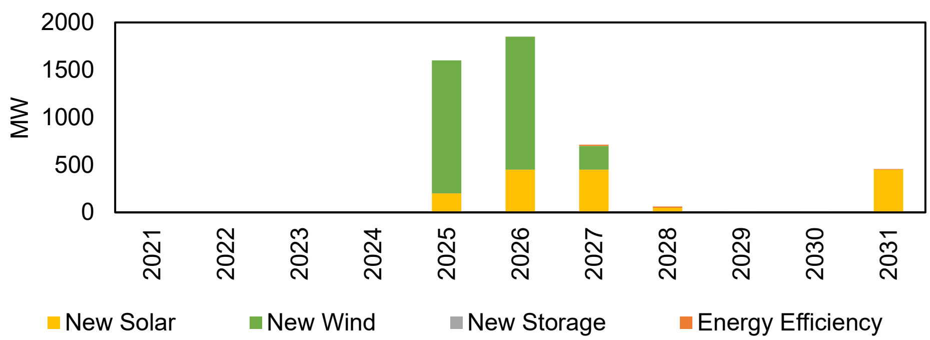


Note – Wind and solar additions in 2025 and 2026 occur on December 31 of the prior year to qualify for ITC/PTC, all other additions occur January 1 of year shown.

The CETA Scenario combines higher load and more affordable renewable technologies that result in faster decline in renewable technology costs and assumes an extension of federal renewable tax credits. As a result of higher load, the CETA portfolio has larger capacity additions. Due to the assumed changes in technology costs, these additions are predominantly renewables. Due to higher additions of solar PV elsewhere in the SPP region, solar PV has the lowest ELCCs compared to other scenarios. By 2031, approximately 2.7 GW of solar, 3.5 GW of wind, 0.5 GW of CTs, and 0.5 GW of storage units are added. Solar and wind additions are more evenly spread out over the period between 2024 and 2032 relative to the Reference portfolio, reflecting the impact of the federal tax credits extension. New CTs are added to meet firm capacity requirements.

On the demand-side, there is a two-year delay to the deployment of the medium industrial and commercial EE bundle relative to the Reference portfolio due to more competitive renewable resources in the Scenario. In total, the contribution from incremental demand-side resources is 0.8 MW in 2022, rising to 121 MW in 2031.

Figure 76: Resource Additions in the ECR Portfolio



Note – Wind and solar additions in 2025 and 2026 occur on December 31 of the prior year to qualify for ITC/PTC, all other additions occur January 1 of year shown.

The ECR Scenario combines lower load growth with high cost gas and carbon. Due to the lower load forecast, the ECR portfolio adds fewer resource overall relative to the other portfolios. Because of the high gas and carbon prices, the ECR portfolio predominantly adds new wind and solar units. By 2031, approximately 1.6 GW of solar and 3.1 GW of wind are added.

Three CVR tranches are selected in the ECR portfolio as CVR costs compare favorably to market prices in this market view relative to the other portfolios. In total, the contribution from incremental demand-side resources is 0.8 MW in 2022, rising to 143 MW in 2031.

8.4. Scorecard Results

8.4.1. Customer Affordability

PSO measures customer affordability across two time scales:

- Short-term affordability, measured as the 5-yr CAGR of growth in customer rates associated with the new demand- and supply-side resources selected under each portfolio
- Medium-term affordability, measured as the 10-year NPVRR of new demand- and supply-side resources selected under each portfolio

Short-term

Table 20 shows the portfolio performance under the Customer Affordability objective. As discussed in Section 8.2.1, the indicators for this objective include the expected annual growth in customer rates over the next five years and the NPVRR over the next 10 years, all measured under Reference Scenario market conditions.

Table 20: Portfolio Performance under Customer Affordability Metrics

Portfolio	5-Year Rate CAGR, Reference Scenario (%/annum)	10-Year NPVRR, Reference Scenario ($ Millions)
Reference	3.50	5,994
CC	3.60	6,043
Modified Reference	3.71	5,999
NCR	3.49	6,003
CETA	8.60	6,991
ECR	4.12	6,093

In the short-term, the Reference and NCR portfolios show that customer rates are expected to grow by around 3.5% a year over the next five years. The CC and Modified Reference portfolios are next best, with 3.6% and 3.7% short-term growth rates, respectively. The ECR portfolio is the next most expensive when measured over the short-term, with rates expected to grow by approximately 4.1% over this timeframe. Finally, the CETA portfolio shows the greatest increase in short-term rates, growing at a CAGR of 8.6% over the first five years of the forecast.

Medium-term

In the medium-term, the Reference, Modified Reference, and NCR portfolios all produce similar results – with NPVRRs over the next 10 years of approximately $6.0 billion. The CC and ECR portfolio are $50-100MM more expensive over this period relative to these three lower-cost portfolios. The CETA case is the most expensive, and the expected net present cost to customers over 10-years is nearly $1.0 billion more under the portfolio when compared to the best performing alternatives.

8.4.2. Rate Stability

PSO measures rate stability by evaluating:

- Scenario resilience as measured by the range of 10-year NPVRRs of each portfolio across the five market scenarios;
- Cost risk as measured by the NPVRR increase when moving from the 50^{th} to the 95^{th} percentile of portfolio costs in 2031; and
- Market exposure as measured by net sales in the summer and winter seasons as a percentage of load in 2031.

Scenario Resilience

Table 21 shows the 10-year NPVRRs across the five market scenarios and the difference between the highest and lowest NPVRRs of each of the five portfolios considered. The difference between the highest and lowest value is used to populate the Scenario Resilience indicator on the IRP scorecard.

Table 21: The 10-Year NPVRRs of the Portfolio Across Market Scenarios

Portfolio	Market Scenarios					
	Reference	FOR	NCR	CETA	ECR	High/Low Difference
Reference	5,994	5,964	5,933	6,084	5,600	484
CC	6,043	6,046	5,991	6,139	5,850	289
Modified Reference	5,999	5,987	5,838	6,103	5,578	525
NCR	6,003	5,995	5,931	6,086	5,639	447
CETA	6,991	6,986	6,999	6,038	6,501	961
ECR	6,093	6,087	6,044	6,073	5,675	418

Regarding overall cost of each portfolio across market scenarios, the Reference portfolio is the least costly in two scenarios. The Modified Reference Case is nearly the same cost as the reference scenario and is the least expensive under two other scenarios.

In general, the CETA scenario produces the highest expected 10-year portfolio NPVRRs under the candidate portfolios due to the higher load growth assumed in that scenario. The exception to this is the CETA portfolio that was optimized under these market conditions. Similarly, the IRP portfolios tend to report the lowest costs under the ECR scenario, because customer loads are assumed to be lower in this forecast than under the other SPP outlooks.

On this metric, the CC portfolio shows the lowest range in expected 10-year costs across the market scenarios. However, this result can be misleading when viewed in isolation. The primary reason that the range of costs is lower for the CC portfolio is that this resource plan tends to be more expensive under the ECR scenario and is unable to capture cost savings for customers under these conditions. As a result, the lower bound of portfolio costs tends to be higher under the CC portfolio and as a result to the total spread between high and low outcomes is less than under many other candidate portfolios. The CETA portfolio has the highest cost volatility due to reliance on electricity sales to balance customer demand.

Cost Risk

Figure 77 presents a summary of the stochastic results for each of the six candidate portfolios. This metric compares the distributions of net present revenue requirements in 2031 after applying 250 iterations of natural gas prices, power prices and renewable production profiles to the candidate portfolios under Reference Scenario market conditions. The cost risk is expressed as the difference between the median portfolio costs (i.e., 50th percentile) relative to portfolio costs under adverse conditions, represented as the 95th percentiles of revenue requirements observed. In the figure below, the median value is represented as the center of each box, with the top of relevant line indicating costs at the 95th percentile. Table 22 shows a summary of the cost risk across each candidate portfolio.

Figure 77: Distribution of Revenue Requirements Based on Stochastic Analysis

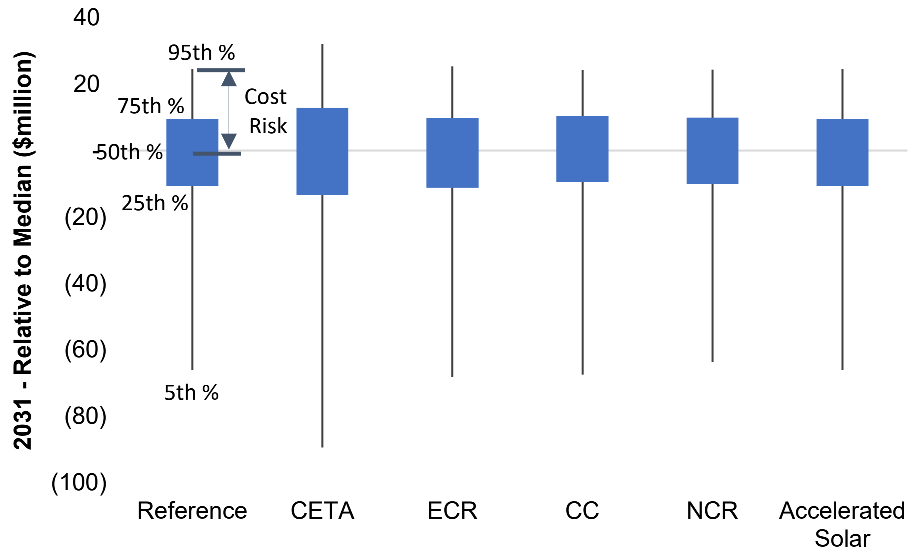


Table 22: Cost Risk - 50th to 95th Percentile Distribution Range for 2031 by Portfolio ($million)

Portfolio	2031
Reference	24.6
CC	24.3
Modified Reference	24.6
NCR	24.4
CETA	32.1
ECR	25.4

All portfolios except for CETA show similar cost risk in 2031, with 95th percentile costs estimated to be approximately $25 million than 50th percentile costs. This result reflects the similarity in build out across most the non-CETA portfolios. The CC portfolio is more gas-heavy and relies less on new renewables than the non-CETA resource plans, but produces a similar cost risk outcome due to ability to ramp down the CC's generation output more than other portfolios when market conditions become unfavorable. The CETA portfolio is the riskiest by this measure because it is more reliant on energy sales to balance generation with customer requirements. As such, the CETA portfolio is more exposed to short-term volatility in power prices, gas prices, and renewable output.

Market Exposure

Table 23 shows the net energy sales as a percentage of portfolio load, distinguishing between market reliance in the summer and winter seasons. The percentages shown are the average net purchases (-) or sales (+) across all five market scenarios.

Table 23: Average Net Energy Sales as % of Portfolio Load Across All Scenarios

Portfolio	Summer		Winter	
	2022	2031	2022	2031
Reference	*-24%*	3%	*-25%*	21%
CC	*-24%*	2%	*-25%*	17%
Modified Reference	*-24%*	3%	*-25%*	21%
NCR	*-24%*	-3%	*-25%*	16%
CETA	*-24%*	22%	*-25%*	42%
ECR	*-24%*	1%	*-25%*	22%

PSO currently relies on market purchases to meet customer's energy requirements in both the summer and winter seasons. By 2031, all portfolios evaluated in the 2021 IRP close this gap, with the CETA portfolio relying more heavily on market sales to balance customer requirements. The remaining five portfolios show a relatively balanced net energy position in the summer season, with net sales +/- 3% of expected customer load in summer. Due to lower seasonal demand, all portfolios tend to have a net sales position in the winter. The CETA portfolio is the outlier owing to the greater amount of capacity added to meet faster load growth in the CETA Scenario. As a result, the CETA portfolio shows greater reliance on market sales in the summer and winter, relative to other candidate portfolios.

8.4.3. Maintaining Reliability

PSO measures each portfolio's contribution to maintaining reliability by evaluating:

- Planning reserves measured as the ratio of firm supply to expected peak demand for *both* the summer and winter periods, averaged over the period between 2022 and 2031;
- Operational flexibility measured as (1) the total firm capacity provided by fast-ramping technologies, and (2) the total number of units added to the resource plan designated as "dispatchable" between 2022-2031; and
- Resource diversity measured as the percentage of total generation provided by each technology in model year 2031 under Reference Scenario conditions.

Planning Reserves

Table 24 shows the summer and winter planning reserves, averaged over the period between 2022 and 2031 across all market scenarios for each candidate portfolio.

Table 24: Planning Reserves Between 2022 and 2031 by Portfolio

Portfolio	Summer	Winter
Reference	12%	47%
CC	13%	58%
Modified Reference	13%	47%
NCR	11%	48%
CETA	23%	62%
ECR	10%	42%

PSO assumed that each candidate portfolio would need to meet a SPP planning reserve margin of 12% above summer peak load when optimizing each candidate portfolio in its native market scenario. This approach can result in capacity short-falls or extra capacity when candidate portfolios are evaluated in non-native scenarios due to differences in load forecasts and resource ELCC value. For example, the NCR scenario solution showed lower overall deployment of solar SPP-wide in response to low gas prices and zero CO_2 price. AURORA then selected the amount of solar needed to balance customer load in the NCR portfolio under NCR scenario conditions. When run in other scenarios with greater solar penetration and lower solar ELCCs, this portfolio tends to be short capacity and rely on market purchases to meet firm requirements. The opposite is true in the CETA portfolio. Higher deployment of solar SPP-wide in the CETA scenario results in lower solar ELCCs. As a result, the CETA portfolio tends to be overbuilt when run under market conditions that award more capacity contribution to solar resources.

The Reference, CC, and Modified Reference portfolios all meet or slightly exceed the average summer planning reserves of 12% when averaged across the market scenarios. The CETA cases tends to be long in summer by this measure, owing the difference in solar ELCCs across scenarios and the tendency to build more new resource in this portfolio to meet faster load growth.

Both the NCR and ECR portfolios fall short of the 12% requirement in the summer when viewed across all five SPP market scenarios. For the ECR portfolio, the result is driven by the fact that lower rates of load growth result in the fewest capacity additions relatively to other portfolios. For the NCR portfolio, the result is driven by the difference in solar ELCC values, which tend to higher in the NCR Scenario due to the lower deployment SPP-wide. When this portfolio is solved in other market scenarios with lower ELCCs, the planned build-out tends to leave the portfolio short in summer.

Operational Flexibility

Table 25 shows the number of dispatchable units and their capacity in 2031 in each of the candidate portfolios considered.

Table 25: The Amount of Dispatchable Capacity and Units in 2031 by Portfolio

Portfolio	Dispatchable Capacity (MW)	Dispatchable Units
Reference	2,923	13
CC	3,493	15
Modified Reference	2,923	13
NCR	2,943	14
CETA	3,863	20
ECR	2,923	13

The Reference, NCR and ECR portfolios score similarly under this metric with approximately 2.9 GW of dispatchable capacity provided by 13-14 dispatchable units owned by PSO.

The CETA and CC portfolios both show greater amounts of operational flexibility. Under the CC portfolio, this increase is due to the assumption that a 550 MW NGCC unit will be added to the portfolio in 2025, even if it is not least-cost. Under the CETA portfolio, the overall higher amount of new resource additions needed to meet higher load growth results in the greatest operational flexibility, with almost 4.0 GW of dispatchable capacity across 20 different units included as part of this resource plan.

Resource Diversity

Figure 78 displays the PSO generation mix by technology in 2021 and Figure 78 shows pie charts that display the percentage of total generation provided by existing resources as well as the generating resources selected by each candidate resource plan in model year 2031 under Reference Scenario market conditions.

Figure 78: 2021 Generation Mix by Technology (MWh)

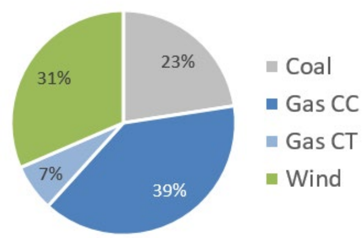
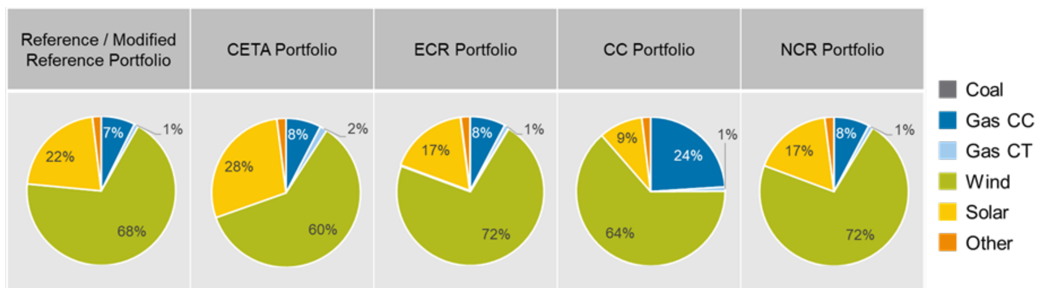


Figure 79: 2031 Generation Mix by Technology and Portfolio (MWh)



In general, new resource additions are dominated by wind and solar across all candidate portfolios. Despite assumed improvements in technology costs over time, no advanced generation technologies are selected across any portfolios.

The CC portfolio scores best by this metric, owing to the assumption that this resource will be added despite the fact that it is not least-cost. The ECR portfolio has the highest reliance on wind, followed by the Reference and Modified Reference portfolios. The CETA and NCR portfolios tend to score somewhat better, have more evenly split generation from wind and solar, but still exhibit outcomes where solar and wind resources provide nearly 90% of all energy in 2031. NGCTs are primarily used as peaking resources. Therefore, those portfolios that show an increase NGCT deployment tend to score similarly to alternative resource plans that rely more heavily on other resource types.

8.4.4. Local Impacts and Sustainability

PSO compares portfolio performance across the local impacts and sustainability objective by evaluating:

- Local impacts measured as (1) the total new installed nameplate capacity inside PSO's service territory, and (2) the total amount of capital invested inside PSO's service territory between 2022 and 2031; and
- The percentage reduction in CO_2 emissions in 2031 from owned resources relative to the baseline year 2000 in the Reference Scenario.

Local Impacts

Table 26 compares the total new installed nameplate capacity and total expected CAPEX invested inside PSO's territory between 2022 and 2031 for each candidate portfolio.

Table 26: Local Impacts Metrics by Portfolio

Portfolio	New Nameplate Capacity Between 2022 and 2031 (MW)	Total CAPEX Invested Inside PSO's Territory ($ Millions)
Reference	2,000	1,556
CC	1,470	1,196
Modified Reference	2,000	1,538
NCR	1,620	1,281
CETA	2,580	2,273
ECR	1,600	1,251

The CETA portfolio scores best by this metric, primarily owing to the greater deployment of new resources under this case to meet faster growth in customer load. The Reference and Modified Reference portfolios are next-best, installing 2 GW each of new capacity in the service territory with a total expected investment of approximately $1.5 billion over the 10 years in the PSO service territory.

The ECR and NCR portfolios produce similar results despite being run in very different market scenarios. Both show around 1.6 GW of new resources are expected to be installed in the PSO territory with CAPEX spend of approximately $1.3 billion in PSO territory over the next 10 years. The CC portfolio has the lowest level of local impacts due to the addition of the 550 MW NGCC unit in 2025, which delays and displaces solar deployment over the 2022-2031 period covered by this performance indicator.

CO_2 Emissions

Table 27 compares the CO_2 emissions in million short tons of CO_2 from PSO-owned and contracted resources in 2031 under Reference Scenario conditions for each candidate portfolio with PSO's baseline emissions from the year 2000.

Table 27: CO_2 Emission Reductions by Portfolio

Portfolio	Level of Emissions in 2000 ($mtCO_2$)	Level of Emissions in 2031 ($mtCO_2$)	% reduction in 2031 relative to 2000
Reference	13.6	0.7	95%
CC	13.6	2.2	84%
Modified Reference	13.6	0.7	95%
NCR	13.6	0.7	95%
CETA	13.6	0.7	95%
ECR	13.6	0.7	95%

Total CO_2 emissions from PSO owned- and contracted plants was approximately 13.6mt in year 2000. CO_2 emissions from the PSO portfolio have declined considerably since 2000 and are now forecast to be around 6.4mt in 2022.

All of the resource plans considered in the 2021 IRP put PSO on a pathway to meet or exceed the 2030 CO_2 emissions reduction targets announced by AEP. Further reductions are driven largely by retirement of the Northeastern 3 coal unit in 2027 as well as the renewable additions over this time frame.

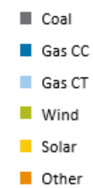
8.5. Evaluating of the 2021 IRP Scorecard

The 2021 IRP Scorecard is displayed below in Section 8.5.1. The key results from the scorecard are summarized below:

- The Reference and the Modified Reference portfolios perform similarly across all scorecard metrics as best or near-best alternatives. The difference is that the Modified Reference portfolio results in slightly higher expected costs to customers in the near term and less in the intermediate term.
- The CETA portfolio is a clear outlier when measured against the customer affordability objective. While lowest cost under CETA Scenario conditions, the CETA portfolio exposes customers to higher costs if load growth does not accelerate and federal tax credits are not extended.
- The CETA portfolio is the least affordable and relies heavily on market sales to balance customer demand. However, the additional resources added in this plan cause it to perform better relative to other options across the planning reserves and operational flexibility indicators.
- The CC portfolio performs similarly to other lower-cost plans across the customer affordability and reliability metrics and provides a high degree of operational flexibility. However, this portfolio is unable to capture cost savings for customers under certain conditions, has more exposure to a future carbon burden and less able to take advantage of potential new renewable incentives and does not put PSO on a path to meet AEP's announced 2050 CO_2 reduction targets.
- The ECR and NCR portfolios, while relatively affordable, do not perform well on reliability metrics. The summer planning reserves for both portfolios are below the 12% reserve margin requirement for SPP and require PSO to purchase additional firm capacity to meet seasonal reserve requirements across most market scenarios in order to ensure that customer needs are met in peak periods.

8.5.1. Full Scorecard Results

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *5-year Rate CAGR, Reference Case*	***Medium Term:*** *10-yr NPVRR, Reference Case*	***Scenario Resilience:*** *High Minus Low Scenario Range 10-yr NPVRR*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside PSO Territory*	***CO2 Emissions:*** *Percent Reduction from 2000 Baseline - Reference Case*
Year Ref.	2022-2027	2022-2031	2022-2031	2031	2031	2022-2031 Avg.	2031	2031	2022-2031	2031
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer | Winter	Summer | Winter	MW | #Units	%	MW | $MM	% Reduction
Reference Portfolio	3.50	5,994 $42.3	484 $1.4	24.6	3% | 21%	12% | 47%	2,923 | 13		2,000 | $1,556	95%
CETA Portfolio	8.60	6,991 $49.3	961 $8.6	32.1	22% | 42%	23% | 62%	3,863 | 20		2,580 | $2,273	95%
ECR Portfolio	4.12	6,093 $43.0	418 $2.0	25.4	1% | 22%	10% | 42%	2,923 | 13		1,600 | $1,251	95%
CC Portfolio	3.60	6,043 $42.6	289 $1.3	24.3	2% | 17%	13% | 58%	3,493 | 15		1,470 | $1,196	84%
NCR Portfolio	3.49	6,003 $42.3	448 $1.3	24.4	-3% | 16%	11% | 48%	2,943 | 14		1,620 | $1,281	95%
Modified Reference Portfolio	3.71	5,999 $42.3	525 $1.6	24.6	3% | 21%	13% | 47%	2,923 | 13		2,000 | $1,538	95%



Note - Levelized Rates and NPVRR metrics are for generation component only. Metrics are for comparison only and do not represent the final costs which will apply to ratepayers.

8.6. Preferred Portfolio

The IRP Scorecard does not select a Preferred Plan on its own. Each candidate resource plan considered in the 2021 IRP represents a trade-off between the objectives defined by PSO. The CETA portfolio, for example, provides the greatest level of seasonal reliability, but has the highest expected costs to customers. Conversely, the NCR portfolio is the least expensive alternative, on an NPVRR basis, but relies more on market purchases to meet customer energy needs and may not provide the seasonal reserves that PSO needs to meet SPP requirements, depending on future market conditions. It also relies upon an external assumption that there is no carbon regulation and cannot take as much advantage of any new renewable incentives. The purpose of the Scorecard is therefore to provide PSO management with a structure tool that illustrates these trade-offs and enables the selection of the best path forward for PSO's customers.

PSO selected the Reference Portfolio with an accelerated solar deployment as the Preferred Plan for the 2021 IRP. PSO selected the Modified Reference portfolio because it scores best or near-best across all four of PSO's IRP objectives, as measured on the Scorecard. In this section, PSO reviews the detailed outputs of the Preferred Plan, and discusses its performance relative to the other candidate portfolios considered as part of the 2021 IRP.

8.6.1. Details of the Preferred Portfolio

PSO determined that the Modified Reference provides the best combination of supply- and demand-side resources to meet PSO's future customer needs. The plan maintains affordable and stable rates for PSO customers, is expected to maintain reliability across seasons, and creates opportunities for local development all while reducing GHG emissions in line with AEP corporate targets. Details of the annual capacity additions in the Preferred Plan, on a nameplate basis, are displayed below in Figure 79.

Figure 80: Annual Capacity Additions in the 2021 IRP Preferred Plan

Utility-Scale New Build Additions by Year (Nameplate MW)				
Year	New Solar	New Wind	New Gas CT	New Storage
2022				
2023				
2024	900.0*	1,400.0*		
2025	450.0*	1,400.0*		
2026				
2027				
2028				
2029				
2030	300.0			
2031	450.0			
Total	2,100.0	2,800.0	0.0	0.0

Demand Side Additions by Year (Peak Credit MW)					
Year	Demand Response	Energy Efficiency	Distributed Generation	CVR	Total + 12%
2022			0.7		0.8
2023			1.2		1.3
2024			1.7		1.9
2025			2.2		2.5
2026			2.8		3.1
2027	5.0	16.5	3.5		28.0
2028	10.0	32.3	3.8	11.8	64.8
2029	15.0	44.0	4.2	12.1	84.3
2030	20.0	58.0	4.2	11.8	105.3
2031	25.0	68.1	4.5	11.8	122.5

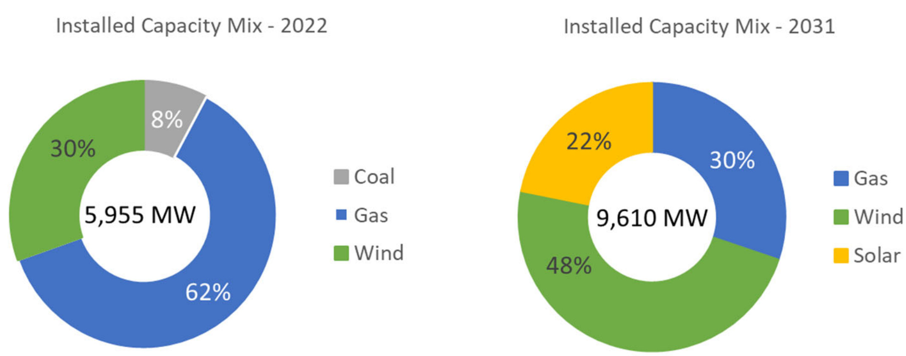
** These resources are added 12/31 of given year due to tax incentive deadlines*

Under the Preferred Plan, PSO adds approximately 109 MW of demand-side resource to the portfolio that reduce total need for new utility-scale resources by approximately 123 MW by

2031.[28] In addition to these demand-side resources, PSO proposes to add 2,100 MW of new solar PV and 2,800 MW of new wind to the portfolio between 2022-2031 under the Preferred Plan. When viewed in isolation, these additions may appear to result in a situation where PSO is largely relying on intermittent resources to meet peak requirements. However, when viewed in the context of PSO's existing generating fleet, displayed below in Figure 82, it shows that approximately 70% of firm customer capacity requirements are met by the existing gas resources in the PSO portfolio. Further, PSO tested the Preferred Plan across multiple market scenarios with differing outlooks of resource capacity contribution. When averaged across these scenarios for the 2022-2031 period, the Preferred Plan maintains or exceeds the 12% planning reserve margin required by SPP.

Additionally, Figure 81 illustrates a comparative supply-side installed capacity mix of resources in the Company's portfolio between 2022 and 2031. The Preferred Plan maintains a balance of capacity resources while meeting the broad set of objectives and metrics illustrated in the comparative scorecard in Section 8.5.1.

Figure 81: Installed Plan Nameplate Capacity Mix



The Preferred Plan is informed by an optimized analysis to meet SPP minimum reserve margins. However, this plan is based on an uncertain future regarding events that can impact the Company's capacity position, including uncertainty around intermittent resources contribution to reserve margins, load growth and existing unit performance. Consequently, the Company will continue to evaluate its capacity position relative to these risks and may consider adding additional resources in the future to the plan (e.g., 3-5%) to ensure sufficient capacity length that remains in compliance with SPP's summer capacity reserve requirement.

8.6.2. The Preferred Plan Best Achieves PSO's IRP Objectives

Customer Affordability

When measured against the customer affordability objective, the Modified Reference portfolio was among the most affordable resource plans evaluated in the 2021 IRP. In the short-term, the overall rate impacts of the Preferred Plan are in the cluster of lower-cost plans that were evaluated in the 2021 IRP. Though it is slightly more expensive that the lowest cost portfolio, the magnitude of this difference is small. The higher cost portfolios, such as the CETA

[28] Note that "nameplate" additions of load-reducing resources are grossed up by 12% when determining the peak contribution to meeting PSO's seasonal reserve requirements, as reflected in Figure 80.

portfolio, show 5-yr rate impacts that more than double the expected rate impact of the Preferred plan.

In the medium-term, the Preferred Plan is among the lowest cost plans evaluated in the 2021 IRP, within $5MM or 0.1% of the lowest cost plan evaluated on the 10-year metric. Again, the IRP analysis illustrates that costs can be materially higher, as much as $1 billion or 16% higher by this measure.

This result is consistent over the long-term. The Preferred plan shows a 20-year expected cost with 0.3% of the lowest-cost alternative, while providing greater benefits towards maintaining reliability, providing local opportunities for PSO customers, and providing similar levels of CO_2 reductions.

Rate Stability

When measured against the rate stability objective, the scenario resilience indicator shows that expect costs under the Preferred Plan varied little across the fundamental market scenarios compared to the CETA and ECR portfolios, but slightly more than the NCR and CC portfolios. Note that the lower cost range for the CC portfolio may be misleading. The lower-bound of costs in the CC portfolio is higher than in the other resource plans because this portfolio has fewer opportunities to capture cost savings for customers.

The cost risk measure shows that five of the six portfolios, including the Preferred Plan, have similar increases in customer costs when exposed to market volatility and extreme weather. The CETA portfolio exhibits the greatest risk by this measure, indicating that portfolio costs vary more under this resource plan. The Preferred plan was among the lowest-risk bundles by this measure in both 2031 and 2041.

The seasonal market exposure of the Preferred Plan is limited in summer with only a small amount of net sales needed to balance customer loads. Owing to lower load in winter, there is greater reliance on sales in this season under all plans.

Maintaining Reliability

The Preferred Plan ties with other plans to provide the greatest summer planning reserves outside the CETA portfolio, which overbuilds relative to customer load in all non-CETA scenarios. While the overall score in winter is somewhat lower than in the CC and NCR portfolios, the Preferred Plan is more than sufficient to meet expected winter needs over the next decade with an average reserve margin of 47%, even accounting for lower solar contribution in the winter season.

The Preferred Plan results in somewhat lower operational flexibility scores when compared with other candidate portfolios, though outcomes are similar to the REF, NCR, and ECR resource plans. The CETA and CC plans score best on this metric, owing to the greater number of total units deployed under the CETA portfolio and the decision to force in a new gas combined cycle in the CC portfolio. However, both the CETA and CC portfolios have a higher expected cost to PSO customers over the medium- and long-term.

The resource diversity indicator shows similar levels of concentration across all portfolios by 2041, with the exception of the CC portfolio that scores highest by this metric. The ECR portfolio is the most concentrated of the 2021 IRP resource plans. The Preferred Plan is middle-of-the-pack by this measure.

Local Impacts & Sustainability

The Preferred Plan scores among the highest on the local impact indicator across the portfolio alternatives. The Reference portfolio is nearly identical, and only the CETA case is expected to provide materially greater local benefits due to the larger number of units built under that portfolio to meet faster load growth.

All of the resource plans considered in the 2021 IRP put PSO on a pathway to meet or exceed the 2030 CO_2 Emissions reduction targets announced by AEP, in part owing the high level of emissions in the 2000 PSO baseline. By 2041, all plans except the CC portfolio are on track to achieve the 2050 target. The Preferred Plan's score is among the highest measured on this indicator.

8.6.3. Testing the Robustness of the Renewable Additions in the Preferred Plan

PSO relied on the 2021 AEO and NREL ATB assessment to estimate the future cost of the solar and wind units selected under the Preferred Plan. These capital costs start at around $1,100 / kw and $1,400 / kw for new solar and wind units respectively, and then decrease over time, as described in Section 5 above. Recent indications are that potential inflationary and supply pressure may result in the actual costs for these resources that is higher than EIA estimates in the 2024-2026 timeframe. The same period that PSO plans to add significant quantities of these units under the Preferred Plan.

In order to assess the potential impact of higher short-term renewable costs on the optimal selection of new resources, PSO evaluated a one-off "higher-cost" sensitivity using AURORA's portfolio optimization function. To perform this sensitivity, PSO assumed that capital costs for new wind and solar resources would be 20% higher than assumed to develop the Preferred Plan when determining PSO's least-cost portfolio, making no other changes to the Reference Scenario market conditions.

This higher-cost sensitivity reflects a reasonable worst case view for PSO wind and solar additions because the cost of these resources is assumed to be higher for PSO without any corresponding change to the broader SPP market prices. In other words, PSO evaluated a least-cost portfolio under conditions where the capital cost of wind and solar was 20% higher *solely for PSO*, but not for other market participants. This sensitivity also did not increase the cost of other resource options due to inflationary or other price pressure.

Even when view from this worst-case perspective, the results of the 2021 Preferred Plan are robust. The optimal plan selected by AURORA using higher capital costs for PSO's resources under Reference Scenario conditions led to the same amount of solar selected by 2027. The results of the wind buildout were almost identical, with 2,750 MW of new wind selected by 2026 even under higher-cost conditions, compared with 2,800 MW in the Preferred Plan. These outcomes are displayed below in Table 28.

Table 28: Comparison of Short-term Resource Selection under Reference Conditions and Higher Cost Sensitivity than Increase Renewable Capital Costs by 20%

	Preferred Plan	Higher-Cost Sensitivity	Difference
2022-2027 Solar Additions	1,350 MW	1,350 MW	0 MW
2022-2027 Wind Additions	2,800 MW	2,750 MW	-50 MW

The higher-cost sensitivity results illustrate that new solar and wind resources are preferred over alternatives (i.e., new gas) over the next five years even under outcomes where the realized cost of renewable resources turn out materially higher than the Reference Scenario assumptions used in the 2021 IRP.

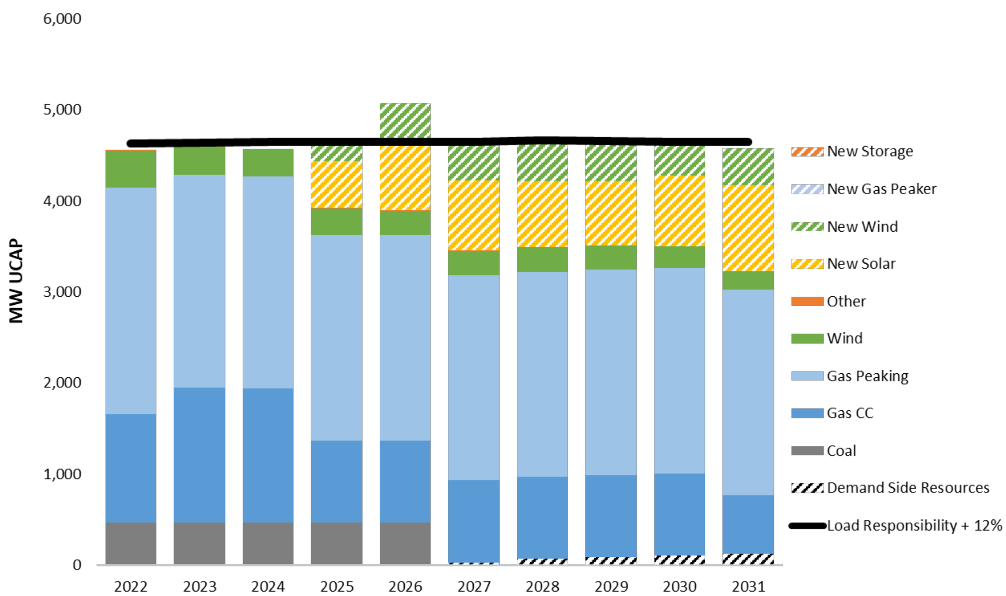
9. Conclusion

PSO selected the Reference Portfolio with an accelerated solar deployment as the Preferred Plan for the 2021 IRP because it best meets the objectives of providing affordable, reliable electricity for customers while also maintaining rate stability and achieving AEP sustainability targets.

9.1. Preferred Plan Summary

Figure 82 below summarize the additions to the PSO portfolio over the 2022-2031 under the Preferred Plan. It shows how a combination of new supply- and demand-side resources meet expected customer needs over the coming decade and maintains or exceeds the 12% planning reserve margin required by SPP. In total, the Preferred Plan adds 1,350 MW of new Solar PV, 2,800 MW of new wind, and more than 100 MW of new demand-side resources over the next 10 years.

Figure 82: 2021 IRP Preferred Plan Summer Capacity Position (MW firm capacity)



9.2. Five-Year Action Plan [PSO]

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

- Continue the planning and regulatory actions to implement cost effective energy efficiency and demand response programs that reduce energy use and peak demand for PSO customers.
- Continue to investigate opportunities to incorporate advanced technologies related to a DER technology to provide both capacity relief and improved reliability
- Conduct a Request for Proposals (RFP) to explore opportunities to add cost-effective renewable generation in the near future to take advantage of the Federal Tax Credit.
- Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

The Preferred Plan is informed from an optimized analysis to meet SPP minimum reserve margins including forecasted resource ratings to meet this margin, which are both subject to change. Based on this uncertainty, the Company will continue to evaluate its capacity position relative to potential changes in SPP's reserve margin requirements and the Company's overall SPP capacity position. The Company may consider adding additional firm resources (e.g., 3 to 5%) to the Preferred Plan optimized resources in the future to ensure adequate additional capacity length and to manage resource performance risk associated with SPP's summer capacity reserve requirement and the uncertainty around intermittent resources contribution to reserve margins, load growth and other factors.

Appendix

Exhibit A: Load Forecast Tables

Exhibit A-1
Public Service Company of Oklahoma
Annual Internal Energy Requirements and Growth Rates
2018-2031

	Residential Sales		Commercial Sales		Industrial Sales		Other* Energy Requirements		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual										
2018	6,452	---	5,004	---	6,120	---	2,380	---	19,957	---
2019	6,273	-2.8	4,958	-0.9	6,156	0.6	2,388	0.4	19,775	-0.9
2020	6,117	-2.5	4,673	-5.8	5,713	-7.2	2,279	-4.6	18,782	-5.0
Forecast										
2021	6,367	4.1	4,853	3.9	6,004	5.1	2,265	-0.6	19,490	3.8
2022	6,363	-0.1	4,725	-2.6	6,386	6.4	2,323	2.6	19,797	1.6
2023	6,372	0.1	4,736	0.2	6,409	0.4	2,338	0.7	19,856	0.3
2024	6,380	0.1	4,760	0.5	6,423	0.2	2,335	-0.1	19,899	0.2
2025	6,378	0.0	4,757	-0.1	6,541	1.8	2,342	0.3	20,018	0.6
2026	6,360	-0.3	4,730	-0.6	6,641	1.5	2,351	0.4	20,082	0.3
2027	6,340	-0.3	4,710	-0.4	6,693	0.8	2,351	0.0	20,094	0.1
2028	6,331	-0.1	4,700	-0.2	6,729	0.5	2,367	0.7	20,127	0.2
2029	6,344	0.2	4,706	0.1	6,762	0.5	2,346	-0.9	20,158	0.2
2030	6,320	-0.4	4,694	-0.3	6,798	0.5	2,345	-0.1	20,157	0.0
2031	6,303	-0.3	4,687	-0.1	6,841	0.6	2,343	-0.1	20,175	0.1

*Other energy requirements include other retail sales, wholesale sales and losses.
Note: 2021 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
2018-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2018	07/20/18	4,107	---	01/17/18	3,193	---	4,107	---	19,957	---	55.5
2019	08/12/19	4,104	-0.1	03/04/19	2,902	-9.1	4,104	-0.1	19,775	-0.9	55.0
2020	08/10/20	3,884	-5.4	02/14/20	2,671	-8.0	3,884	-5.4	18,782	-5.0	55.2
Forecast											
2021		4,266	9.8		3,129	17.1	4,266	9.8	19,490	3.8	52.0
2022		4,289	0.6		2,909	-7.0	4,289	0.6	19,797	1.6	52.7
2023		4,302	0.3		2,921	0.4	4,302	0.3	19,856	0.3	52.7
2024		4,304	0.1		2,931	0.3	4,304	0.1	19,899	0.2	52.8
2025		4,307	0.1		2,939	0.3	4,307	0.1	20,018	0.6	52.9
2026		4,307	0.0		2,946	0.3	4,307	0.0	20,082	0.3	53.2
2027		4,301	-0.2		2,946	0.0	4,301	-0.2	20,094	0.1	53.3
2028		4,309	0.2		2,956	0.3	4,309	0.2	20,127	0.2	53.3
2029		4,310	0.0		2,956	0.0	4,310	0.0	20,158	0.2	53.2
2030		4,299	-0.2		2,956	0.0	4,299	-0.2	20,157	0.0	53.5
2031		4,299	0.0		2,950	-0.2	4,299	0.0	20,175	0.1	53.6

Notes: 2021 data are six monts actual and six months forecast. The winter 2020/21 peak occurred on February 14, 2021.

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
2021	9.2	9.6	7.4
2022	18.2	12.8	8.7
2023	39.1	13.8	9.4
2024	58.4	15.4	10.6
2025	78.2	19.4	12.9
2026	99.5	23.8	15.5
2027	126.0	29.8	19.4
2028	128.3	30.3	23.0
2029	129.1	30.5	19.8
2030	130.3	30.8	20.0
2031	131.2	31.0	20.2
*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	Long-Term
Industrial	Long-Term
Other Retail	Long-Term

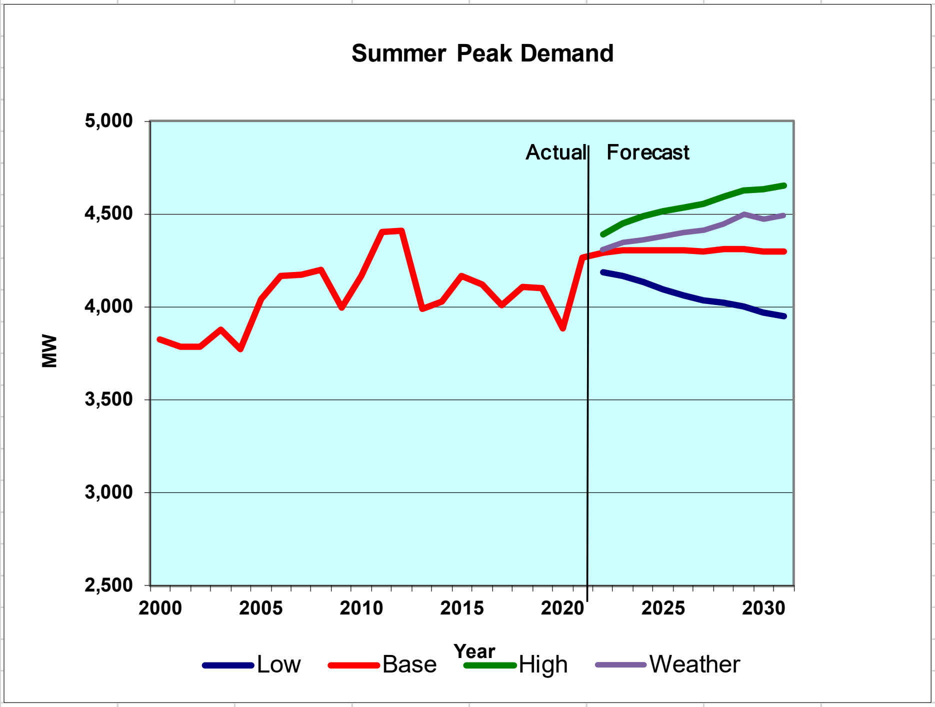
Exhibit A-5
Blending Illustration

Month	Short-term Forecast	Weight	Long-term Forecast	Weight	Blended 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**
2022	2,839	2,909	2,979	4,185	4,289	4,392	19,317	19,797	20,272
2023	2,827	2,921	3,022	4,165	4,302	4,451	19,222	19,856	20,543
2024	2,813	2,931	3,055	4,131	4,304	4,486	19,099	19,899	20,740
2025	2,795	2,939	3,080	4,097	4,307	4,514	19,041	20,018	20,976
2026	2,781	2,946	3,103	4,065	4,307	4,536	18,952	20,082	21,147
2027	2,763	2,946	3,120	4,034	4,301	4,554	18,847	20,094	21,280
2028	2,761	2,956	3,153	4,025	4,309	4,597	18,800	20,127	21,468
2029	2,747	2,956	3,173	4,005	4,310	4,627	18,732	20,158	21,638
2030	2,730	2,956	3,188	3,972	4,299	4,637	18,620	20,157	21,738
2031	2,709	2,950	3,192	3,947	4,299	4,652	18,524	20,175	21,828

Exhibit A-7
Public Service Company of Oklahoma
Range of Forecasts



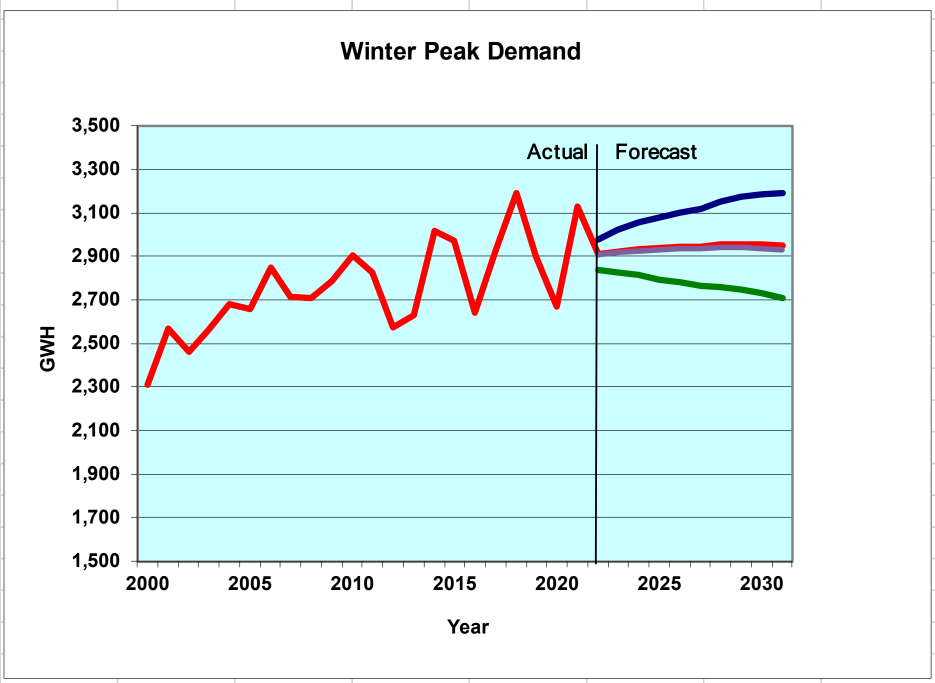


Exhibit B: Detailed Generation Technology Modeling Parameters

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Heat Rate Btu/kWh	First Available Year
Coal and Gas	ULTRA-SUPERCRITICAL COAL WITH 90% CO2 CAPTURE, 650 MW	5,821	11.03	59.85	12,507	2024
	COMB TURBINE H CLASS, COMB-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW	2,428	5.87	27.74	7,124	2023
	COMB TURBINE H CLASS, 1100-MW COMBINED CYCLE	882	1.88	12.26	6,370	2023
	COMB TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW	1,004	2.56	14.17	6,431	2023
	COMB TURBINE F CLASS, 240-MW SIMPLE CYCLE	654	0.61	7.04	9,905	2022
	COMB TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE	1,079	4.72	16.38	9,124	2022
	INTERNAL COMBUSTION ENGINES, 20 MW	1,763	5.72	35.34	8,295	2022
	NG CC CCS Retrofit	869	1.23	19.64	17.2% Penalty	2020

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Capacity Factor %	First Available Year
Renewable	Wind	1,395	0.00	26.47	44.0%	2023
	Solar PV with tracking	1,190	0.00	14.70	26.6%	2022

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Heat Rate Btu/kWh	First Available Year
Hydrogen and Nuclear	PEM Electrolyzer + 10 Hr Storage PSO	1,715	0.50	46.39	60% Efficiency	2020
	H2 CT	1,576	0.61	7.04	9,655	2020
	SMR	6,485	3.02	95.48	10,455	2028

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Efficiency %	Self-discharge rate % per day	Depth-of-Discharge Limit %	Duration Years	Asset Life Years	First Available Year
Storage	Compressed Air	1,771	0.00	17.19	52%	0.1%	100%	20	25	2020
	Flow Battery	3,798	0.00	11.30	70%	1.0%	100%	20	15	2020
	Pumped Thermal	3,295	0.00	51.16	65%	1.0%	100%	20	20	2020
	Lithium Ion	1,389	0.00	25.37	85%	0.3%	80%	4	10	2021

Exhibit C: Capacity, Demand and Reserves - "Going-in"

Public Service of Oklahoma

Capability, Demand, and Reserve Forecast

2021-2031

CAPABILITY

	Plant Capabilities	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	COMANCHE 1	220	220	220	220	220	220	220	220	220	220	220
	NORTHEASTERN 1	422	422	422	422	422	422	422	422	422	422	422
	NORTHEASTERN 2	434	434	434	434	434	434	434	434	434	434	434
	NORTHEASTERN 3	465	465	465	465	465	465					
	RIVERSIDE 1	448	448	448	448	448	448	448	448	448	448	448
	RIVERSIDE 2	448	448	448	448	448	448	448	448	448	448	448
	RIVERSIDE 3	72	72	72	72	72	72	72	72	72	72	72
	RIVERSIDE 4	72	72	72	72	72	72	72	72	72	72	72
	SOUTHWESTERN 1	56	56									
	SOUTHWESTERN 2	79	79	79	79							
	SOUTHWESTERN 3	311	311	311	311	311	311	311	311	311	311	311
	SOUTHWESTERN 4	74	74	74	74	74	74	74	74	74	74	74
	SOUTHWESTERN 5	75	75	75	75	75	75	75	75	75	75	75
	TULSA 2	164	164	164	164	164	164	164	164	164	164	164
	TULSA 4	158	158	158	158	158	158	158	158	158	158	158
	WELEETKA 4	47	47									
	WELEETKA 5	49	49									
1	**TOTAL**	**3,594**	**3,594**	**3,442**	**3,442**	**3,363**	**3,363**	**2,898**	**2,898**	**2,898**	**2,898**	**2,898**
	Adjustments to Plant Capability											
	Ft Sill Solar		6	6	6	6	5	5	5	5	3	2
	North Central	18	107	115	108	108	108	108	108	108	108	101
2	**TOTAL**	**18**	**114**	**121**	**114**	**114**	**113**	**113**	**113**	**113**	**111**	**103**
3	**Net Plant Capability (1 + 2)**	**3,612**	**3,708**	**3,563**	**3,556**	**3,477**	**3,476**	**3,011**	**3,011**	**3,011**	**3,009**	**3,001**
	Sales Without Reserves											
4	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases Without Reserves											
	CALPINE	260	260	260	260	260	260	260	260	260	260	
	WEATHERFORD WIND	28	28	25	24	24						
	SLEEPING BEAR WIND	6	6	16	15	15	15	15	15	15	15	14
	BLUE CANYON V WIND	16	16	17	16	16	16	16	16	16		
	ELK CITY WIND	13	13	17	16	16	16	16	16	16		
	MINCO WIND	16	16	17	16	16	16	16	16	16	16	
	BALKO WIND	82	82	34	32	32	32	32	32	32	32	30
	GOODWELL WIND	91	91	34	32	32	32	32	32	32	32	30
	SEILING WIND	53	53	34	32	32	32	32	32	32	32	30
	EXELON GREEN COUNTRY	519	289	582	569							
5	**TOTAL**	**1,083**	**853**	**1,035**	**1,011**	**442**	**418**	**418**	**418**	**418**	**387**	**104**
6	**Total Capability (3 - 4 + 5)**	**4,695**	**4,561**	**4,598**	**4,567**	**3,919**	**3,894**	**3,429**	**3,429**	**3,429**	**3,396**	**3,105**

	DEMAND	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A	**Peak Demand Before Passive DSM**	**4,275**	**4,302**	**4,316**	**4,320**	**4,327**	**4,331**	**4,330**	**4,340**	**4,341**	**4,330**	**4,330**
B	**Passive DSM**											
	APPROVED DSM PROGRAMS	7	8	5	2	1						
	VOLT-VAR OPTIMIZATION (VVO)	2	4	9	14	19	24	24	24	24	24	24
	AMI (METERING (DLC/TOU)	12	12	12	12	12	12	12	12	12	12	12
	TOTAL	**22**	**25**	**26**	**27**	**31**	**36**	**36**	**36**	**36**	**36**	**36**
C	**Peak Demand (A - B)**	**4,254**	**4,277**	**4,290**	**4,292**	**4,295**	**4,295**	**4,295**	**4,304**	**4,305**	**4,295**	**4,295**
D	**Active DSM**											
	APPROVED DR PROGRAMS	54	54	54	54	54	54	54	54	54	54	54
	SPECIAL CONTRACT (ABOVE FIRM)	24	24	24	24	24	24	24	24	24	24	24
	TOTAL	**78**	**78**	**78**	**78**	**78**	**78**	**78**	**78**	**78**	**78**	**78**
E	**Firm Demand (C - D)**	**4,176**	**4,200**	**4,213**	**4,215**	**4,218**	**4,218**	**4,217**	**4,227**	**4,228**	**4,217**	**4,217**
F	**Other Demand Adjustments**											
	DIVERSITY	27	25	32	27	26	25	25	25	32	26	26
	TOTAL	**27**	**25**	**32**	**27**	**26**	**25**	**25**	**25**	**32**	**26**	**26**
7	**Native Load Responsibility (E - F)**	**4,149**	**4,174**	**4,181**	**4,188**	**4,192**	**4,192**	**4,192**	**4,201**	**4,195**	**4,191**	**4,191**
	Sales With Reserves											
8	**TOTAL**	**0**	**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	39
9	**TOTAL**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**
10	**Load Responsibility (7 + 8 - 9)**	**4,110**	**4,135**	**4,142**	**4,149**	**4,153**	**4,153**	**4,153**	**4,162**	**4,156**	**4,152**	**4,152**
	RESERVES	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
11	**Reserve Capacity, MW (6 - 10)**	**585**	**425**	**457**	**418**	**-234**	**-259**	**-724**	**-733**	**-727**	**-756**	**-1,047**
12	**% Reserve Margin ((11/10) * *100*)**	**14.2**	**10.3**	**11.0**	**10.1**	**-5.6**	**-6.2**	**-17.4**	**-17.6**	**-17.5**	**-18.2**	**-25.2**
13	**% Capacity Margin (11/(6) * *100*)**	**12.5**	**9.3**	**9.9**	**9.2**	**-6.0**	**-6.7**	**-21.1**	**-21.4**	**-21.2**	**-22.3**	**-33.7**
14	**Reserve Above 12% Reserve Margin, MW**	**91**	**(71)**	**(40)**	**(80)**	**(733)**	**(758)**	**(1222)**	**(1233)**	**(1226)**	**(1254)**	**(1545)**

Exhibit D: 2021 PSO Fuel Supply Portfolio and Risk Management Plan

Public Service Company of Oklahoma

2021 Fuel Supply Portfolio and Risk Management Plan

May 15, 2021

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Introduction

Organized in Oklahoma in 1913, Public Service Company of Oklahoma ("PSO" or "the Company") is engaged in the generation, transmission and distribution of electric power to approximately 565,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO owns 3,728 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2020, PSO had 1,023 employees. Among the principal industries served by PSO are paper manufacturing, oil and gas extraction, petroleum and coal products manufacturing, transportation equipment and pipeline transportation. PSO is a member of the Southwest Power Pool ("SPP"), and is part of AEP's Vertically Integrated Utilities segment.

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.

PSO is a member of the 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.

The SPP Integrated Market Place ("IM") is a wholesale power market that consists of Day-Ahead, Real-time, and Ancillary Service markets. 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 the 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 overall 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 natural gas power plants, wind resources and one coal-fired unit, as summarized in Exhibit 1.

Exhibit 1: Plant Capacity

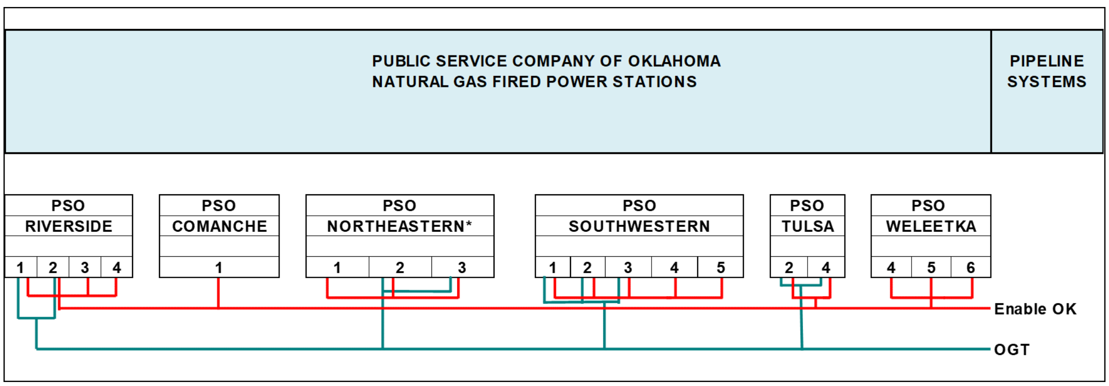
ıame	Fuel Type	aximum Capacity (MW)
·e	Wind	90.5*
k	Wind	130.6*
he	Natural Gas	248
e	Natural Gas	1,061
·stern	Natural Gas	621
	Natural Gas	325
a	Natural Gas	100
;tern, Units 1 and 2	Natural Gas	904
;tern, Unit 3	Coal†	469
		3,949

Central Energy Facilities ("NCEF") project figures reflect only the 45.5 percent owned by PSO. The NCEF t wind project with Southwestern Electric Power Company ("SWEPCO") that includes Sundance (199 ɔjected in-service date is April 2021), Maverick (287 MW; projected in-service date is December 2021), ⁄erse (999 MW; projected in-service date is early 2022).

ın also use natural gas to operate Northeastern Unit 3 at partial load in the event of coal curtailments or ıted 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



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.

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 2021, 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, and the Dogwood Energy Facility in Pleasantville, Missouri. The associated megawatts and start dates are listed in Exhibit 3 below.

Exhibit 3: PP Contracts

PSO 2021 Purchased Power Contracts	Contract Maximum Quantity (MW)	Contract Start	Contract End
(1) GREEN COUNTRY I	530	June 2012	February 2022
(2) ONETA	260	June 2016	May 2031
(3) DOGWOOD	80	June 2016	May 2021
Total	**870**		

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 2021, PSO estimates that approximately 24 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. Exhibit 4 below offers a comparison of the total generation resource mix in 2019 and 2020.

Exhibit 4: Resource Percentage Comparison

ation Resource (MWh Basis)	2019	2020
Natural Gas	21.4%	20.5%
Coal	14.2%	7.5%
Purchased Power	42.8%	49.8%
Wind Energy	21.6%	22.2%
Fuel Oil	<0.01%	<0.01%

In 2020, PSO's total average delivered cost of fossil fuel varied from a low of $1.87 per MMBtu in June to a high of $2.39 per MMBtu in November. The Company experienced decreases in the percentage of Coal (-6.7%) and Natural Gas (-0.9%) while Wind (0.6%) and Purchased Power saw an increase (7.0%) year over year.

2020 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 2020 were made pursuant to transportation arrangements with UP and BNSF, respectively. Exhibit 5 summarizes the contracts used by PSO to purchase coal in 2020.

Exhibit 5: List of Coal Contracts in Effect in 2020

PUBLIC SERVICE COMPANY OF OKLAHOMA
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BOUNDLESS ENERGY

Northeastern Generation Station

Vendor	greement Number	ons Purchased
dy COALSALES, LLC	08-81-18-4M4	624,994
dy COALSALES, LLC	08-81-19-4M1	183,759
dy COALSALES, LLC	08-81-19-4M2	153,301

Oklaunion Generation Station (Total Plant Basis)*

Vendor	greement Number	ons Purchased
dy COALSALES, LLC	08-81-18-4M4	467,149

nion Retired in September 2020

2020 Natural Gas Procurement Summary

Throughout 2020, PSO's natural gas generating units were dispatched on-line and off-line by SPP on relatively short notice resulting in natural gas demand that was highly variable. The mode of system operation and unit dispatch required a flexible procurement strategy in a dynamic marketplace.

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. Refer to Exhibit 2 for an illustration of the pipeline connections at each plant.

2020 Purchased Power Summary

On an energy basis, purchased power, including wind purchases, accounted for 72 percent in 2020, an increase of 7.6 percent from the prior year. On average, year-over-year SPP IM prices were lower in 2020 versus those experienced in 2019. The average SPP IM day-ahead market prices for SPP South Hub for 2019 and 2020, shown in Exhibit 6 below, are based on the daily trading results as reported by Platts.

Exhibit 6: 2019 through 2020 Average SPP South Hub Prices

Month	rage On-Peak ($/MWh)	rage Off-Peak ($/MWh)	Month	rage On-Peak ($/MWh)	rage Off-Peak ($/MWh)
Jan 19	$28.55	$21.55	Jan 20	$20.04	$15.84
Feb 19	$27.49	$20.59	Feb 20	$21.70	$13.76
Mar 19	$31.42	$22.38	Mar 120	$18.45	$10.13
Apr 19	$24.78	$12.87	Apr 20	$17.37	$8.45
May 19	$29.00	$18.06	May 20	$19.45	$11.76
Jun 19	$27.63	$17.78	Jun 20	$21.80	$11.34
Jul 19	$33.68	$20.46	Jul 20	$26.45	$17.44
Aug 19	$30.74	$18.56	Aug 20	$28.60	$18.52
Sep 19	$30.10	$15.99	Sep 20	$23.77	$14.40
Oct 19	$23.22	$12.44	Oct 20	$26.88	$12.27
Nov 19	$25.25	$16.98	Nov 20	$23.24	$12.46
Dec 19	$22.44	$15.43	Dec 20	$22.89	$16.81
) Monthly Average	$27.86	$17.76	)20 Monthly Average	$22.55	$13.60

II. 2021 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. Exhibit 7 below illustrates PSO's forecasted energy source mix for 2021, which will help drive purchases of fuel and other sources of power.

Exhibit 7: Energy Source Percentages

Generation Resource (MWh Basis)	2021
Natural Gas	13.7%
Coal	9.4%
Wind	24.3%
Purchased Power	16.1%
SPP Market Purchases	36.5%

1. Demand Forecast

PSO's 2021 peak native load responsibility is forecast to be 4,158 MW, as compared with PSO's actual weather normalized peak of 4,147 MW realized in 2020.

2. Fuel

PSO's fuel planning forecast 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 uses sub-bituminous coal from the Powder River Basin in Wyoming that typically has a heat content of 8,500 to 8,900 Btu per pound. Projections of coal supply needs must consider railroad delivery constraints and cycle time performance. Currently, PSO has an arrangement with the UP to deliver coal to Northeastern. PSO expects its 2021 delivered costs for Northeastern to remain relatively stable and comparable to coal costs incurred in 2020.

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").

According to the EIA's March 2021 Short-Term Energy Outlook, the price of natural gas is expected to increase approximately 55% in 2021 compared to 2020 due to lower production and rebounding demand. Weather, generating unit availability, economic power purchase opportunities, and the SPP IM will all impact natural gas purchases for 2021.

3. Purchased Power

Conventional Purchased Power

SPP IM market prices decreased from 2019 to 2020 in both the on-peak and off-peak hours. The change in market prices did not significantly impact PSO's market optimization activities. SPP IM market prices and the overall percentage of purchased power are expected to remain relatively unchanged in 2021. 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. Exhibit 8 below shows PSO's wind resources that are in effect during 2021.

Exhibit 8: Wind Contracts

PSO 2021 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 ENERGY	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 competitively 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.

The UP delivers coal to Northeastern under a long term rail transportation agreement that is set to expire at the end of 2023.

PUBLIC SERVICE COMPANY OF OKLAHOMA

An AEP Company

BOUNDLESS ENERGY

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 inception of the SPP IM. In addition to daily purchases, monthly baseload agreements will be considered and pursued in 2021. 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 2021, the decision to obtain monthly supply will depend on 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 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 2021, PSO has a firm transportation agreement with Enable OK that can serve all of PSO's natural gas units. This agreement expires on December 31, 2023. As the previous firm transportation agreement expired on December 31, 2020, in early 2020, PSO solicited competitive bids for firm transportation over a three-year period beginning in January 2021, with the business awarded to Enable OK. PSO closely followed the Oklahoma Corporation Commission rules throughout the entirety of the RFP process. In addition, PSO has interruptible transportation agreements with both Enable OK and OGT. If the economics are favorable, PSO will explore the possibility of procuring seasonal firm transportation from OGT during the peak summer months.

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 current natural gas transportation contract 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 $1.36 per MMBtu of incremental cost above the related natural gas commodity costs. PSO's 2020 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

Due to lack of utilization, environmental risk and the degradation of plant equipment while consuming fuel oil, PSO made the decision to eliminate the use of fuel oil at the Riverside Plant. The remaining fuel oil inventory will be sold using a competitive bidding program.

Purchased Power Plan

The purchased power plan for 2021 will have a diverse mix of transactions with a wide range of counterparties. For example, the Green Country, Oneta and Dogwood PPAs, along with PSO's wind REPAs, 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. 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 ("HCl") mitigation.

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

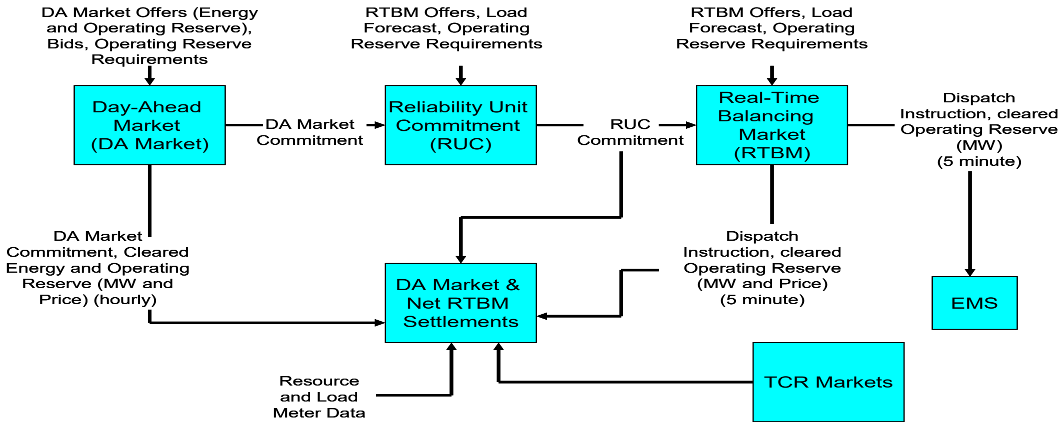
The primary objective of PSO's fuel hedging strategy is to reduce fuel and purchased power cost volatility experienced by customers. In many respects, a fuel hedging strategy is similar to insurance. A successful hedging program can effectively mitigate the risk of fuel cost volatility, but it also comes 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 2021 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.

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 9 illustrates the process design relationship between the market processes in which AEPSC participates on behalf of PSO.

Exhibit 9: Integrated Marketplace Process Design Relationships[29]



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 operating day. The Real-Time Balancing Market is a financially and operationally binding market clearing every 5 minutes with a purpose of ensuring that market resources committed through the RUC process are dispatched according to Real-Time load requirements. 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 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.

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29 "EMS" stands for Energy Management System

PSO continues to experience 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. AEPSC is tasked with optimizing source-sink path selections in the TCR market in order to financially hedge day-ahead congestion and reduce the net congestion costs charged to PSO.

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. 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 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. This includes the Demand Portfolio programs most recently approved by the Commission in Cause No. PUD 201800073. PSO completed full deployment of Advanced Metering Infrastructure ("AMI") in 2016. Enabled by AMI, PSO is able to offer 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. In 2018, PSO introduced a residential pre-pay program called Power Pay to provide payment convenience and daily notifications. PSO also offers a range of customer programs 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. PSO is deploying Conservation Voltage Reduction technology across circuits to manage voltage and lower energy consumption for customers.

A complete listing of PSO's DSM programs can be found in Exhibit 10 below.

Exhibit 10: PSO Demand Side Management Programs

Residential	Commercial & Industrial
Weatherization	family
Rebates	ess Rebates
y Saving Products	ervation Voltage Reduction
r Hours	Performers
ervation Voltage Reduction	
ioral Modification	
tion	
family	

b. Retail Energy Usage and Cost Projections

Exhibit 11 below provides monthly bill projections for summer 2021 and winter 2021, as well as the previous year's information.

Exhibit 11: Monthly Bill Projections

PUBLIC SERVICE COMPANY OF OKLAHOMA
An AEP Company
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Winter Bill

Customer Class and Usage**	Bill* 2020	Price–¢/kWh 2020	Projected Bill* 2021	Projected Price–¢/kWh 2021	Projected % Change Per kWh
Residential- 1070 kWh	$98.83	9.24	$96.10	8.98	-2.77%
Small Commercial- 1760 kWh	$146.99	8.35	$141.11	8.02	-4.00%

Summer Bill

Customer Class and Usage**	Bill* 2020	Price–¢/kWh 2020	Projected Bill* 2021	Projected Price–¢/kWh 2021	Projected % Change Per kWh
Residential- 1450 kWh	$134.47	9.27	$148.81	10.26	10.66%
Small Commercial- 2300 kWh	$192.52	8.37	$212.39	9.23	10.32%

*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.

PUBLIC SERVICE COMPANY OF OKLAHOMA
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Contact Information

For questions or additional information, please contact:

Fairo Mitchell
Regulatory Consultant Principal
Regulatory Services-Oklahoma
1601 North West Expressway
Suite 1400
Oklahoma City, OK 73118-1116
(405) 841-1310

Exhibit E: Portfolio Annual Revenue Requirement

Annual Revenue Requirement
($000)

	Reference Portfolio	CETA Portfolio	ECR Portfolio	CC Portfolio	NCR Portfolio	Mod. Reference Portfolio
2022	787,957	787,957	787,957	787,957	787,957	787,957
2023	817,902	817,902	817,902	817,902	817,902	817,902
2024	841,033	841,328	841,057	841,171	841,043	840,991
2025	843,250	833,487	842,697	794,251	841,826	844,245
2026	866,854	997,538	872,086	848,326	864,603	876,634
2027	951,054	1,209,641	979,876	955,741	950,672	960,909
2028	925,716	1,238,817	960,707	959,055	927,849	919,517
2029	867,312	1,174,727	899,842	907,409	869,798	862,851
2030	821,543	1,150,187	860,219	874,158	833,459	818,028
2031	766,915	1,111,094	792,861	812,374	771,355	764,600
2032	749,558	1,094,801	776,647	794,369	758,996	748,336
2033	761,410	1,095,006	792,495	822,443	763,629	760,620
2034	761,312	1,094,737	770,349	804,111	762,510	760,656
2035	926,743	1,130,731	929,497	934,791	907,395	926,240
2036	1,168,458	1,210,348	1,171,830	1,178,222	1,152,427	1,168,049
2037	1,221,272	1,236,959	1,219,445	1,225,233	1,196,885	1,221,014
2038	1,249,177	1,235,049	1,243,359	1,248,692	1,227,954	1,249,086
2039	1,256,618	1,226,201	1,247,977	1,245,513	1,221,449	1,256,667
2040	1,282,013	1,244,028	1,272,693	1,280,499	1,261,612	1,282,195
2041	1,258,322	1,225,661	1,261,999	1,261,327	1,255,800	1,258,651

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Exhibit F: Draft Renewable RFP's

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DRAFT

American Electric Power Service Corporation

as agent for

Public Service Company of Oklahoma

Request for Proposals for up to 1,350 MW
of Solar Energy Resources

The Solar Energy Resources requested via this RFP will be acquired via Purchase and Sale Agreements for purchase of 100% of the equity interest of the Project's limited liability company at Mechanical Completion.

RFP Issue Date: November 17, 2021

RFP Proposals Due: January 13, 2022

RFP Web Address: www.psoklahoma.com/rfp

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Solar Resource Analysis / Study....Appendix F
AEP Requirements for Connection of Facilities....Appendix G
Project Land Lease / Decommissioning Costs / Auxiliary Load....Appendix H
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1. Background

Public Service Company of Oklahoma ("PSO" or the "Company") is pursuing additional generation resources via two separate Wind and Solar Request for Proposals ("RFPs") to satisfy the need for additional generation resources as identified by its updated Integrated Resource Plan[30].

This **Solar RFP** seeks up to 1,350 MW of Solar Energy Resources via multiple Purchase and Sale Agreements ("PSA") for purchase of 100% equity interest in the project companies selected.

The Wind RFP for up to 2,600 MW of Wind Energy Resources may be found at www.psoklahoma.com/rfp.

The Company will evaluate each of the RFPs, individually and collectively, to determine the portfolio of projects that it elects to move forward with.

2. Introduction

American Electric Power Service Corporation ("AEPSC") and PSO are subsidiaries of American Electric Power Company, Inc. ("AEP").

AEPSC is administering this RFP on behalf of PSO who is seeking competitively priced Solar Energy Resources (each a "Project" or "Solar Project" and collectively the "Projects" or "Solar Projects") solely on a turnkey basis through its acquisition of the ownership interests in one or more projects.

Affiliates of the Company will not participate as Bidders in this RFP.

AEP is one of the largest electric utilities in the United States, delivering electricity and custom energy solutions to nearly 5.4 million regulated retail customers in 11 states. AEP owns the nation's largest electricity transmission system, a more than 40,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP also operates 224,000 miles of distribution lines. AEP ranks among the nation's largest generators of electricity, owning approximately 26,000 megawatts of generating capacity in the U.S. AEP also supplies approximately 4,300 megawatts of renewable energy to customers. AEP's utility units operate as AEP Ohio, AEP Texas,

30 The Company's Integrated Resource Plan is expected to be submitted to the Oklahoma Corporation Commission on October 29, 2021.

Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, PSO and SWEPCO (in Arkansas, Louisiana and east Texas). AEP's headquarters is in Columbus, Ohio. More information about AEP can be accessed by visiting www.aep.com.

PSO serves approximately 560,000 customers in 232 cities and towns across 30,000 square miles of eastern and southwestern Oklahoma. PSO is headquartered in Tulsa, Oklahoma, with regulatory and external affairs offices in Oklahoma City. The Company's distribution operations are organized into three districts: Tulsa, Lawton and McAlester. PSO has 3,771 MW of owned generating capacity, 1,109 MW of natural gas PPA capacity and has executed long-term Renewable Energy Purchase Agreements ("REPAs") with wind generation resources totaling 1,137 MW. Additional information regarding PSO can be accessed by visiting www.psoklahoma.com.

3. RFP Overview

3.1. General. PSO is pursuing up to 1,350 MW of Solar Projects that can achieve a Commercial Operation Date ("COD") of December 15, 2024, or alternatively, December 15, 2025. Projects must interconnect to the Southwest Power Pool ("SPP") and be located in the state of Oklahoma.

3.2. PSA Proposals. The Solar Energy Resources requested in this RFP will be acquired via PSAs for purchase of 100% of the equity interest of the Project's limited liability company ("Project LLC") at Mechanical Completion[31]. Proposals that do not meet these criteria, including proposals for REPAs, will not be considered by the Company.

3.3. Base Proposal. A Base Proposal for a Solar Project "only" is required by Bidders to participate in this RFP. Bidders may include an Alternate Proposal for a Solar Project with a battery energy storage system ("BESS"). Standalone BESS proposals will not be accepted in this RFP.

3.4. ITC Value. PSO is seeking Solar Projects that will qualify for the Federal Investment Tax Credit ("ITC"). While qualifying for these Federal Tax credits is not an Eligibility and Threshold Requirement (§9.1) for participating in the RFP, the value brought to the Proposals in buying down the cost of energy by utilization of these tax credits is significant, and is included in the Company's Economic Analysis (§9.2.1) and ranking of each of the respective Proposals.

[31] Mechanical Completion means the Project has been mechanically completed, assembled, erected and installed in accordance with the terms and conditions of the PSA.

3.5. Timing. The time period between the receipt of Proposals and the time required for the Company's evaluation, due diligence, selection, negotiation and the execution of definitive agreements is anticipated to be seven to eight months (see RFP Timeline (§6.1)). The Company anticipates filing for regulatory approval with the Oklahoma Corporation Commission ("OCC") in Q3-2022 and receiving regulatory approvals in Q2-2023.

3.6. Regulatory Approvals. The Company's decisions regarding the results of this RFP will be subject to its receipt of regulatory approvals from the OCC and the Federal Energy Regulatory Commission. Definitive agreements between the Company and Bidders for selected Projects will be conditioned upon the Company receiving the regulatory approvals described in the preceding sentence that are in form and substance satisfactory to the Company in its sole discretion. The Company plans to submit a portfolio of Projects to the regulatory commissions described above for approval. In the event the entire portfolio is not approved, the Company may reduce the size of the portfolio accordingly by eliminating Project(s) from the portfolio.

3.7. Notice to Proceed. Upon obtaining regulatory approvals for the Projects selected by the Company as described in §3.6, the Company would issue a Notice to Proceed ("NTP") for the Bidders to proceed with the construction of selected Projects. The Form PSA (Appendix D) contains additional information regarding the conditions and timing for NTP issuance. The Company may issue NTP for selected Projects that it prefers over other selected Projects, if some, but not all, approvals are received.

3.8. Reservation of Rights. The Company reserves the right, without qualification, to select or reject any or all Proposals and to waive any formality, technicality, requirement, or irregularity in the Proposals. In addition, the Company reserves the right to utilize a Bidder's completed Appendices and any supplemental information submitted by the Bidder in any of its regulatory filings.

3.9. Non-Binding. This RFP is not a commitment by the Company to acquire any Project LLC and it does not bind the Company or its affiliates in any manner. The Company in its sole discretion will determine which Bidders, if any, it wishes to engage in negotiations with that may lead to definitive agreements for the acquisition of a selected Project.

3.10. RFP Questions. All questions regarding this RFP should be submitted by email to:

PSO2021RFP@aep.com

Questions and answers that are determined to be pertinent to Bidders will be posted to the RFP webpage. All questions must be submitted by the Q&A Deadline noted in the RFP Timeline (§6.1).

4. Product Description and Requirements

4.1. Completed Project. Each Project at its COD must be a complete, commercially operable, integrated solar-powered electric generating plant, including all facilities that are necessary to generate and deliver energy into SPP.

4.2. Commercial Operation Deadline. The Company is pursuing Projects that can achieve the Commercial Operation Deadline of December 15, 2024, or alternatively, December 15, 2025.

4.3. Size. This RFP is seeking a total of up to 1,350 MW nameplate rated Solar Generation Resources. The minimum acceptable Project size is 50 MW.

4.4. Interconnection. Each Project must be interconnected to the SPP.

4.5. Solar Project Location. Solar Projects must be located in Oklahoma. PSO has a preference for Projects located in its service territory or interconnected to its transmission system.

4.6. Project Development.

4.6.1. Site Control. Bidder must have established substantial site control of the proposed Project. Site control must be in the form of direct ownership, land lease, land lease option or easement for at least 35 years. A letter of intent will not be an acceptable form of demonstrated site control.

4.6.2. AEP Solar Generation Facility Standards. Each Project must satisfy the requirements of the AEP Solar Generation Facility Standard (see Appendix E, Specification Number GEN-4550). The AEP Solar Generation Facility Standard requires a minimum facility design life of 30 years, includes listings of approved module and inverter manufacturers, and detailed requirements for an operations and maintenance ("O&M") Building. Project's module and inverter manufacturers must be included in the AEP Solar Generation Facility Standard or will not qualify for consideration in this RFP.

4.6.3. Solar Resource Analysis/Study. Bidders are required to submit all required Solar Resource Information (Appendix F).

4.6.4. Alternate Proposal (w/ BESS). Bidders may include in their proposals, as an option, a Bid Price for a Solar Project with a BESS. The optional BESS must be 1) no larger (MW) than 40% of the nameplate rating (MWac) of the Solar Project and, 2) for 4 and/or 8 hours of capacity. BESSs must satisfy the AEP Battery Energy Storage System Technical Specification and Design Criteria (Specification Number GEN-4570) and AEP Design Criteria for Battery Energy Storage Systems Fire Safety (Document Number: DC-FP-BATT) (See §6.5 for instructions to obtain these documents).

4.6.5. AEP Requirements for Connection of Facilities. Project substation and interconnection facilities must conform to the AEP Requirements for Connection of Facilities (Appendix G).

4.6.6. Small and Diverse Suppliers. Bidder and/or its EPC-BOP contractor shall use reasonable efforts to utilize and adopt a subcontracting plan to use small and diverse suppliers as subcontractors for work.

4.7. Interconnection / Delivery Point.

4.7.1. The Proposal must identify the Project's proposed transmission interconnection point(s) within SPP, including any studies, applications, line extensions and system upgrades identified as part of the interconnection approval process.

4.7.2. The Bidder is responsible during the Project start-up period for following the established SPP, NERC, and transmission operator policies and procedures that are in effect regarding facility interconnection and operation associated with a utility's transmission system.

4.7.3. Each Project must be active in SPP Queue Cluster 2017-002 or earlier. Projects in later queue clusters will not be able to participate in this RFP.

4.8. Congestion / Deliverablity. The Company is seeking Projects in locations that are not currently experiencing, or anticipated by the Company to experience, significant congestion or deliverability constraints which are likely to result in adverse Project economics.

5. Bid Price and Structure

5.1. The Proposal Bid Price shall be the "total" price the Company will pay to the Bidder via three separate payments at Mechanical Completion, Substantial Completion (also referred to as COD), and Final Completion, as further described in the Form PSA.

5.2. The Proposal Bid Price must be for the Company's acquisition of a turnkey Project that is a complete and commercially operable integrated solar-powered electric generating plant designed for a minimum of a 30-year life.

5.3. The Project shall include, but is not limited to, solar modules, tracking system, balance of plant equipment, O&M Building, SCADA and all facilities required to deliver energy into SPP. In addition, pricing must include costs associated with ALTA/title insurance and construction financing.

5.4. In addition to §5.2 and §5.3, Proposal Bid Pricing must include the costs associated with the following:

- a minimum of a two-year comprehensive warranty from a creditworthy entity for all equipment including design, labor and materials, and fitness for purpose;
- post-commercial operation testing activities and associated costs; and
- transmission and interconnection facilities required for the Project, including system or network upgrades, as required by SPP for the Project to interconnect to SPP.

6. RFP Schedule and Proposal Submission

6.1. The following schedule and deadlines apply to this RFP. The Company reserves the right to revise this schedule at any time in its sole discretion.

RFP Timeline	
Draft RFP Posted Online	September 15, 2021
Bidders Technical Conference	November 3, 2021
RFP Issued	November 17, 2021
Notice of Intent	November 29, 2021
Q&A Deadline	January 5, 2022
Proposal Due Date	January 13, 2022
Final Project Selection and Negotiation	March 15, 2022
Execute Definitive Agreements	August 15, 2022
File for Regulatory Approvals	September 1, 2022

Required Regulatory Approvals	May 1, 2023
Notice to Proceed	June 1, 2023
Commercial Operation Date	No later than December 15, 2024 or December 15, 2025

6.2. Bidder Technical Conference. A Bidder Technical Conference (teleconference) will be held on November 3, 2021 at 2:00 p.m. EST (1:00 p.m. CST). Prospective Bidders may request details and sign up for the pre-bid conference by sending an email request to:

PSO2021RFP@aep.com

Include the name of your company, email address, company representative name(s), and the following in the subject line of your email: **PSO BIDDER TECHNICAL CONFERENCE**.

AEPSC will use this information to communicate any updates regarding this RFP to potential Bidders. In addition, any updates regarding the RFP will be posted at the RFP website.

6.3. Notice of Intent. PSO requests that Bidders provide a Notice of Intent (“NOI”) to PSO by the Notice of Intent Date defined in the RFP Timeline (§6.1). The NOI shall include the project(s) name, technology, location, size (MW), and SPP Queue number. The NOI shall be made via email to the following address:
PSO2021RFP@aep.com

6.4. Proposals must be complete in all material respects and be received no later than 4:00 p.m. EST (3:00 p.m. CST) on the Proposal Due Date at AEPSC’s Columbus, Ohio location as defined in Section 7 of the RFP. Proposals should be as comprehensive as possible to enable the Company to make a definitive and final evaluation of the Proposal’s benefits to its customers without further contact with the Bidder.

6.5. Bidders will be required to sign a Confidentiality Agreement (“CA”) prior to receiving the following documents:

- Form PSA (Appendix D)
- AEP Solar Generation Facility Standard (Appendix E)
- SolarEnergyInputSheet_2021.xls (Appendix F)
- Project Land Lease, Decommissioning Cost, and Auxiliary Load spreadsheet (Appendix H)
- Project Technical Due Diligence Material (Appendix I)
- AEP Battery Energy Storage System Technical Specification and Design Criteria (Specification Number GEN-4570) (§4.6.4)

- AEP Design Criteria for Battery Energy Storage Systems Fire Safety (Document Number: DC-FP-BATT) (§4.6.4)

6.6. Bidders should request PSO's Form CA by emailing (PSO2021RFP@aep.com) and including the following documentation:
- Supporting documentation of Bidder's experience in developing, engineering, procuring equipment, constructing and commissioning solar powered electric generation facilities (> Project bid size) in the United States or any portion of Canada and/or otherwise have demonstrated appropriate experience,
- Documentation that the Project is active in SPP Queue Cluster 2017-002 or earlier.

6.7. The Company reserves the right to solicit additional information or Proposals and the right to request additional information from Bidders during the Proposal evaluation process.

6.8. Proposals and Bid Pricing must be valid for at least 180 days after the Proposal Due Date at which time Proposals shall expire unless the Bidder has been notified that its Proposal has been included in Final Project Selection.

7. Proposal Submittal

One hard copy of Bidder's Executive Summary and Appendix A and two electronic thumb drive copies of the Bidder's complete Proposal shall be submitted by the Proposal Due Date to:

American Electric Power Service Corporation
Attn: PSO Solar Energy 2021 RFP Manager
1 Riverside Plaza (25th Floor)
Columbus, OH 43215

8. Proposal Content

Bidders must submit the following information for Proposals for new Projects or expansion of existing projects. All electronic versions of the Appendices shall be individual files.

8.1. A completed Appendix K (Proposal Content Check Sheet).

8.2. An executive summary of the Project's characteristics and timeline, including any unique aspects and benefits.

8.3. Summary documentation demonstrating how the Project will qualify for the ITC for Solar Projects under Section 48 of the Internal Revenue Code of 1986, as amended.

Bidder shall provide a detailed plan regarding the steps taken to date and future actions required to satisfy IRS start of construction requirements.

8.4. A completed Appendix A (Solar Project Summary).

8.5. Detailed information regarding equipment (e.g. solar module, inverter, and BESS (if applicable)) warranty offerings including parts and labor coverage.

8.6. The identity of all persons and entities that have a direct or indirect ownership interest in the Project.

8.7. A completed Appendix B (Bidder's Credit-Related Information).

8.8. A completed Appendix C (Bidder Profile). Bidders must provide a general description of its (including its affiliates) background and experience in the development and construction of at least three large-scale solar projects similar to the Projects sought by the Company in this RFP. In addition, Bidders should provide at least three third-party references for such projects.

8.9. Any exceptions to the terms and conditions contained in the Form PSA (Appendix D).

8.10. Any exceptions to the AEP Solar Generation Facility Standards (Appendix E).

8.11. All required Solar Resource Analysis / Study information (Appendix F).

8.12. Bidder's Proposal shall include a completed Appendix H, which requires the following information:

- Expected Land Lease Costs (annual) for at least a 35-year operating period. The Land Lease costs will be used in the Company's Economic Analysis (§9.2.1);
- Estimated decommissioning costs (including salvage value). In addition, Bidder shall provide any completed decommissioning studies;
- Expected Auxiliary Load (Station Power) the Project expects to consume for a typical year on a monthly basis.

8.13. Bidder and/or its EPC-BOP contractor shall provide its plan to use reasonable efforts to utilize and adopt a subcontracting plan to use small and diverse suppliers as subcontractors for work (§4.6.6).

8.14. Bidder shall provide basic project technical due diligence material (Appendix I).

8.15. OPTIONAL: Bidders may provide a separate O&M services proposal (Appendix J).

8.16. Battery Energy Storage System (BESS) Option: Bidders providing an Alternate Proposal for a Solar Project with a BESS shall provide this option separate from the Base

Proposal. This Alternate Proposal shall include all applicable information from this Section 8 in addition to technical, operating, performance, and warranty details associated with the BESS.

9. Proposal Evaluation & Selection

The evaluation process will be conducted in three phases:

Section 9.1 Eligibility and Threshold Requirements

Section 9.2 Detailed Analysis

Section 9.3 Final Project Selection

9.1. Eligibility and Threshold Requirements. A preliminary screening of each Proposal will be undertaken by the Company to determine if the Proposal is eligible to proceed to the Detailed Analysis phase. Bidders and their associated Proposals must satisfy the following Eligibility and Threshold Requirements:

9.1.1. Base Proposal must be for a Purchase and Sale Agreement for a Solar Project (§3.2, 3.3);

9.1.2. Project must have demonstrated a clear path toward constructability (land rights, permits, etc.) and be capable of achieving commercial operation by the Commercial Operation Deadline (December 15, 2024 or alternatively December 15, 2025) (§4.2);

9.1.3. Project's minimum name-plate rating is 50 MW (§4.3);

9.1.4. Project must be interconnected to SPP (§4.4), be active in SPP Queue Cluster 2017-002 or earlier (§4.7.3), and remain active in the queue process with the demonstrated ability to achieve commercial operation of any interconnection for the full output of the Project by the Commercial Operation Deadline;

9.1.5. Project must be physically located in Oklahoma (§4.5);

9.1.6. Bidder has substantial Project site control (§4.6.1);

9.1.7. Project must have a minimum design life of at least 30 years (§4.6.2);

9.1.8. Project's module and inverter manufacturers must be included in the AEP Solar Generation Facility Standard (§4.6.2);

9.1.9. Bidder must have completed the development, construction, financing, and commissioning of a similar-sized solar project in the United States or Canada and/or otherwise have demonstrated appropriate experience;

9.1.10. Bidder's exceptions to the Form PSA, considered individually or in the aggregate, are minimally acceptable to the Company as a basis for further discussions.

The Company reserves the right to reject any Proposal which proceeded to the Detailed Analysis phase but which is subsequently determined by the Company not to satisfy the Eligibility and Threshold Requirements.

9.2. Detailed Analysis. Proposals meeting the Eligibility and Threshold Requirements in §9.1 will move to the Detailed Analysis phase, which is comprised of the Economic Analysis and the Non-Price Factor Analysis set forth below. The Economic Analysis will constitute 90% and the Non-Price Factor Analysis 10% of the overall evaluated value of each Proposal.

The Company's evaluation and Final Project Selection (§9.3) will be based on the Base Proposals.

9.2.1. Economic Analysis. The Economic Analysis will result in a Levelized Net Revenue Requirement, which will constitute 90% of the overall evaluated value of the Proposal in its Final Project Selection. The Levelized Net Revenue Requirement will be calculated as follows:

9.2.1.1. The Company will first determine a Levelized Adjusted Cost of Energy ("LACOE") by adding together (a) the Levelized Cost of Energy ("LCOE") associated with each Proposal as calculated by the Company and (b) the cost of Transmission Congestion as determined by the Company's Transmission Screening Analysis. The Transmission Screening Analysis will evaluate (i) cost of transmission congestion and losses to the AEP West load zone and/or (ii) cost of deliverability / curtailment risk mitigation that the Company calculates to ensure that the resources can be designated as firm resources to meet Company's Capacity requirements.

9.2.1.2. The Company will then calculate the Levelized Net Revenue Requirement by taking the difference between (a) the levelized expected SPP revenues for the Proposal's energy in the SPP market and (b) the LACOE for each Proposal.

9.2.2. Non-Price Factor Analysis. The Non-Price Factor Analysis, which will constitute 10% of the overall evaluated value of the Proposal will be comprised of the following factors:

9.2.2.1. Project's (including associated transmission and interconnection facilities) impact on wildlife, the environment and identified cultural resources;

9.2.2.2. Project's (including associated transmission and interconnection facilities) location on or proximity to tribal or government lands;

9.2.2.3. Bidder's exceptions to the Form PSA (Appendix D);

9.2.2.4. Bidder's exceptions to the AEP Solar Generation Facility Standards (Appendix E);

9.2.2.5. Development status of the Project including, but not limited to, permitting, transmission and interconnection facilities and constructability;

9.3. Final Project Selection. Based upon the results of the Economic Analysis and the Non-Price Factor Analysis described above, the Company will determine which Projects will be included in the final selection. The Company will notify Bidders whether or not their Proposal has been selected and negotiation of definitive agreements will commence with Bidders whose Proposals have been selected.

10. Confidentiality

The Company will take reasonable precautions and use reasonable efforts to maintain the confidentiality of the Proposals. Bidders should clearly identify each page of information considered to be confidential or proprietary. The Company reserves the right to release any Proposals to agents or consultants for purposes of Proposal evaluation. The Company's disclosure policies and standards will be binding upon its agents and consultants. Regardless of such confidentiality, all such information may be subject to review by the appropriate state authority or any other governmental authority or judicial body with jurisdiction relating to these matters and may be subject to legal discovery. Under such circumstances, the Company will make all reasonable efforts to protect Bidder's confidential information.

11. Bidder's Responsibilities

11.1. It is the Bidder's responsibility to comply with the deadlines specified in this RFP.

11.2. Bidders are responsible for the timely completion of the Project by the Commercial Operation Deadline (§4.2) and are required to submit proof of their financial and technical wherewithal to ensure the successful completion of the Project.

11.3. Bidders are responsible for costs incurred by them in the preparation of their Proposal.

12. Reservation of Rights

A Proposal will be deemed accepted only when the Company and the successful Bidder have executed definitive agreements for the Company's acquisition of the Project. The Company has no obligation to accept any Proposal, whether or not the stated price in such Proposal is the lowest price offered, and the Company may reject any Proposal in its sole discretion and without any obligation to disclose the reason or reasons for rejection.

BY PARTICIPATING IN THE RFP PROCESS, EACH BIDDER AGREES THAT ANY AND ALL INFORMATION FURNISHED BY OR ON BEHALF OF THE COMPANY IN CONNECTION WITH THE RFP IS PROVIDED WITHOUT ANY REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, AS TO THE USEFULNESS, ACCURACY, OR COMPLETENESS OF SUCH INFORMATION, AND NEITHER THE COMPANY NOR ITS AFFILIATES NOR ANY OF THEIR PERSONNEL OR REPRESENTATIVES SHALL HAVE ANY LIABILITY TO ANY BIDDER OR ITS PERSONNEL OR REPRESENTATIVES RELATING TO OR ARISING FROM THE USE OF OR RELIANCE UPON ANY SUCH INFORMATION OR ANY ERRORS OR OMISSIONS THEREIN.

The Company reserves the right to modify or withdraw this RFP, to negotiate with any and all qualified Bidders to resolve any and all technical or contractual issues, or to reject any or all Proposals and to terminate negotiations with any Bidder at any time in its sole discretion. The Company reserves the right, at any time and from time to time, without prior notice and without specifying any reason and, in its sole discretion, to (a) cancel, modify or withdraw this RFP, reject any and all Proposals, and terminate negotiations at any time during the RFP process; (b) discuss with a Bidder and its advisors the terms of any Proposal and obtain clarification from the Bidder and its advisors concerning the Proposal; (c) consider all Proposals to be the property of the Company, subject to the provisions of this RFP relating to confidentiality and any confidentiality agreement executed in connection with this RFP, and destroy or archive any information or materials developed by or submitted to the Company in this RFP; (d) request from a Bidder information that is not explicitly detailed in this RFP, but which may be useful for evaluation of that Bidder's Proposal; (e) determine which Proposals to accept, favor, pursue or reject; (f) reject any Proposals that are not complete or contain irregularities, or waive irregularities in any Proposal that is submitted; (g) accept Proposals that do not provide the lowest evaluated cost; (h) determine which Bidders are allowed to participate in the RFP, including disqualifying a Bidder due to a change in the qualifications of the Bidder or in the event that the Company determines that the Bidder's participation in the RFP has failed to conform to the requirements of the RFP; (i) conduct negotiations with any or all Bidders or other persons or with no Bidders or other persons; and (j) execute one or more definitive agreements with any Bidder.

13. Contacts

All correspondence and questions regarding this RFP should be directed to:

PSO2021RFP@aep.com

Appendix A

Solar Project Summary

Company Information

Bidder (Company):		
Contact Name:		
Contact Title:		
Address:		
City:	State:	Zip Code:
Work Phone:	Cell Phone:	
Email Address:		
Is the Proposal being submitted through a partnership, joint venture, consortium, or other association? ______ If so, please identify all partners, joint ventures, members, or other entities or persons comprising same.		

General Project Information

Project Name:	
Project site location (County, Oklahoma):	
Percentage of Federal Investment Tax Credit that the Project will qualify for:	
Expected Commercial Operation Date:	
Module Manufacturer / Model:	Annual Degradation (%):
Configuration (Fixed Tilt / Single Axis):	Design Life (years):
Inverter Manufacturer / Model:	
Solar Project Nameplate (MWac): Solar Project Nameplate (MWdc): Battery Energy Storage System (MWac) (optional)	Expected Annual Availability (%):
Bidder must identify its choice in Approved Module Manufacturer and Approved Inverter Manufacturer associated with the bid and provide the applicable production data (Expected Annual Energy, Capacity Factor. Bidder shall attach module and inverter warranty information with its proposal.	

Proposal Bid Pricing (Base Proposal)

Expected COD by	Module Mfg.	Expected Annual Energy	apacity Factor	Bid Price, $M
12/15/24				

12/15/25				
If Bidder has not finalized Module Manufacturer, they must identify the module (& inverter) options and provide the applicable design information including layout, production data (Expected Annual Energy, Capacity Factor) for each module / inverter mfg. Bidder shall attach module warranty information with its proposal.				

Alternate Proposal Bid Pricing (Base Proposal with BESS Option)

Expected COD by	Module Mfg.	Expected Annual Energy	apacity Factor	Bid Price, $M
12/15/24				
12/15/25				
Confirm Bid Price includes an O&M Bldg:			(Y/N)	

Interconnection (SPP)

ueue #:	tion Name / Voltage:
n Impact Study Complete (Y/N):	n Impact Study Report Date:
of Interconnection with :	
terconnection Status (describe):	
attach a copy of all interconnection studies and/or the expected completion date(s).	

BESS (If applicable)

Use Case:	Integrator:
Battery Manufacturer:	Type of Battery:
Battery Model Number:	Cycles per Day:
Nameplate (MWac):	Ramp Rate:
Nameplate (MWdc):	Charge Time:
Duration (hours):	Maximum Charge Rate:
Energy (MWh):	Round Trip Efficiency:
Aux Load:	Aux Power Source:
Overbuild (MW):	Overbuild Years:

PCS Unit Power (kW):	PCS Minimum Voltage:
Qty PCS:	PCS Maximum Voltage:
Inverter Manufacturer / Model:	
Fire Suppression System (wet / pre-action):	
EMS Manufacturer / Model:	

Site Information

Site Legal Description:		
Address:		
City:	State:	Zip Code:
County	Longitude:	Latitude:
Site Control (lease, own, site purchase pending, etc.):		
Site Acres:		
Is there potential for expansion (Y / N):	If Yes; acres available:	

Permits

Have you contacted all required permitting agencies regarding this project and identified all necessary permits?

City (Y / N):

County (Y / N):

State (Y / N):

Federal (Y / N):

USF&W (Y / N):

Other (Y / N)

On an additional sheet, list and describe all city, county, state and federal permits required for this project. Include: status, duration, planned steps, critical milestones and timeline.

Preliminary Site Questions[1] (Y/N)

Has the site been assessed for any environmental contamination? Describe any known environmental issues. If necessary, please describe on a separate attachments	
Are there any Tribal Lands or Tribal mineral ownership rights within Project boundary or vicinity?	
Are there any Federally or State owned or controlled lands within Project boundary or vicinity?	
Is the site adjacent or near an Environmental Justice or Fenceline community?	
Has TNC or any other non-governmental organizations been engaged?	
Are there CRP, WRP or other conservation easements within the Project boundary or vicinity?	

Attachments Required

- Site Layout: Attach a diagram identifying anticipated placement of major equipment and other project facilities, including transmission layouts and Point of Delivery.
- Leases: Attach (electronic version only) a copy of all leases, easements or other ownership documentation.
- Permit Matrix: Attach a comprehensive permit matrix and status of all required permits, including, but not limited to Federal (USFWS, FAA), State, County, City, etc.
- Decommissioning Studies: Provide available decommissioning studies and cost estimates.
- Environmental Report Summary: The initial Proposals shall include a summary of all environmental and other reports associated with the site. (See Note 1 for reports to summarize)

Note 1: As applicable, the following reports will be requested: Tier I / II Site Characterization Report, Environmental Work / Survey Plan, Bat Acoustic Survey Report, Avian Use Survey Report, Raptor Nest Survey Report, Prey-base Survey Report, Wetland, Waters and Playa Survey / Assessment Report, Whooping Crane Habitat Assessment Report, Lesser Prairie Chicken Survey / Assessment Report, Phase I Environmental Site Assessment Report, Historical and Cultural Resource Survey / Assessment Report, All Other Species and Environmental Resource Survey and Study Reports, Record and Notes of all Federal or State Resource Agency Correspondence and Meetings, Turbine and Environmental Resource Shapefiles (.kmz format), and Bird and Bat Conservation Strategy and Eagle Conservation Plan (if available).

Solar Projects Completed

e a summary of all solar projects ($\geq$ 20 MWac) that Bidder has successfully developed and com-
in the United States or Canada. For each project, describe the Bidder's specific role in the project.

Project	Location	MW	Bidder's Role
	Total MW =		

BESS Projects Completed

e a summary of all battery energy storage projects ($\geq$ 5 MWac) that Bidder has successfully de-
d and completed in the United States or Canada. For each project, describe the Bidder's specific
the project.

Project	Location	MW	Bidder's Role

	Total MW =		

Please provide a summary of the operating history of previously built solar projects ($\geq$20 MW), if necessary, provide in a separate attachment.

Appendix B

Bidder's Credit-Related Information

egal Name of the Bidder:
Bidder Entity (corporation, partnership, etc.):
's Percentage Ownership in Project:
egal Name(s) of Parent Corporation: 1. 2. 3.
Providing Credit Support on Behalf of Bidder (if applicable): e: ess: Code:
of Relationship:
nt Senior Unsecured Debt Rating: 1. S&P: 2. Moodys:
References & Name of Institution:
Contact: e: ess:

'ode: e Number:
Proceedings: As a separate attachment, please list all lawsuits, regulatory proceedings, or arbitra- which the Bidder or its affiliates or predecessors have been or are engaged that could affect the 's performance of its bid. Identify the parties involved in such lawsuits, proceedings, or arbitra- nd the final resolution or present status of such matters.
ial Statements: Please provide copies of the Annual Reports for the three most recent fiscal years arterly reports for the most recent quarter ended, if available. If available electronically, please e link:

Appendix C

Bidder Profile

list Bidder’s affiliate companies: 1. 2. 3. 4.
attach a summary of Bidder’s background and experience in Solar Energy projects.

References

1. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

2. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

3. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

4. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

Appendix D

Form Purchase and Sale Agreement

See Section 6.5 for instructions to obtain the applicable Form Purchase and Sale Agreement.

Appendix E

AEP Solar Generation Facility Standard

See Section 6.5 for instructions to obtain the AEP Solar Generation Facility Standard.

Appendix F

Solar Resource Information

See Section 6.5 for instructions to obtain any of the documents identified below:

1. Proposal must provide the source and basis of the solar irradiance data used in the development of energy projections for the Project. Explain all assumptions used in forecasted generation calculations.

2. Bidder must populate the data required in the Company's "SolarDataReviewForm_PSO" spreadsheet.

3. Bidder must attach an 8760 calendar year hourly energy forecast, net of all losses using the Company's form spreadsheet (SolarEnergyInputSheet_2021.xls).

4. Bidder must supply the Project Layout along with the contour and elevation data in CAD format.

Appendix G

AEP Requirements for Connection of Facilities

Please follow the link below to access the AEP Requirements for Connection of Facilities ("Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System").

https://www.aep.com/assets/docs/requiredpostings/TransmissionStudies/Requirements/AEP_Interconnection_Requirements_Rev2.pdf

Appendix H

Projected Land Lease / Decommissioning Costs / Auxiliary Load

See Section 6.5 for instructions to obtain the spreadsheet for Projected Land Lease Costs, Decommissioning Costs, and Auxiliary Load.

Information to be provided in the Appendix H spreadsheet shall include:

- Expected Land Lease Costs by year for at least a 35-year operating period. The Land Lease costs will be used in the Economic Analysis (§9.2.1);
- Estimated decommissioning costs (including salvage value). In addition, Bidder shall provide any associated decommissioning studies;
- Expected Auxiliary Load (Station Power) the Project expects to consume for a typical year on a monthly basis.

Appendix I

Project Technical Due Diligence Material

See Section 6.5 for instructions to obtain the Project Technical Due Diligence Material list.

This list will include basic technical due diligence material that the Company will require to perform an initial technical due diligence of the Project.

Appendix J

O&M Services Scope of Work (OPTIONAL)

Bidders may request the O&M Services Scope of Work via email at:

PSO2021RFP@aep.com

PUBLIC SERVICE COMPANY OF OKLAHOMA
An AEP Company
BOUNDLESS ENERGY™

Appendix K

Proposal Content Check Sheet

Section	Item	Com-pleted
8.2	Executive Summary	
8.3	Documentation demonstrating Project will qualify for % ITC	
8.4	Appendix A (Solar Project Summary) - Company Information - General Project Information - Proposal Bid Pricing - Interconnection - BESS Information (if applicable) - Site Information - Permits - Preliminary Site Questions - Solar Projects Completed - BESS Projects Completed	
8.5	Manufacturer's Warranty Offerings	
8.6	Identity of all person and entities that have a direct or indirect ownership interest in the project.	
8.7	Appendix B (Bidder's Credit-Related Information)	
8.8	Appendix C (Bidder Profile)	
8.9	Appendix D (Form PSA exceptions (if any))	
8.10	Appendix E (exceptions to AEP Solar Generation Facility Std)	
8.11	Appendix F (required Solar Resource Analysis / Study Info)	
8.12	Appendix H (Land Lease Cost, Decommission Cost, Aux Load)	
8.13	Bidder's plan to use small and diverse suppliers	
8.14	Appendix (I) Project Technical Due Diligence Material	
8.15	O&M Services Proposal (optional)	
8.16	Alternate Proposal (w/ BESS Option) information	

PUBLIC SERVICE COMPANY OF OKLAHOMA

An AEP Company

BOUNDLESS ENERGY™

DRAFT

American Electric Power Service Corporation

as agent for

Public Service Company of Oklahoma

Request for Proposals for up to 2,600 MW of Wind Energy Resources

The Wind Energy Resources requested via this RFP will be acquired via Purchase and Sale Agreements for purchase of 100% of the equity interest of the Project's limited liability company at final completion.

RFP Issue Date: November 17, 2021

RFP Proposals Due: January 13, 2022

RFP Web Address: www.psoklahoma.com/rfp

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Bidder's Credit-Related Information .... Appendix B
Bidder Profile .... Appendix C
Form Purchase and Sale Agreement .... Appendix D
AEP Wind Generation Facility Standards .... Appendix E
Wind Resource Analysis / Study .... Appendix F
AEP Requirements for Connection of Facilities .... Appendix G
Project Land Lease / Decommissioning Costs / Auxiliary Load .... Appendix H
Project Technical Due Diligence Material .... Appendix I
O&M Services Scope of Work .... Appendix J
Proposal Content Check Sheet .... Appendix K

14. <u>Background</u>

Public Service Company of Oklahoma ("PSO" or the "Company") is pursuing additional generation resources via two separate Wind and Solar Request for Proposals ("RFPs") to satisfy the need for additional generation resources as identified by updated Integrated Resource Plan[32].

This **<u>Wind RFP</u>** seeks up to 2,600 MW of Wind Energy Resources via multiple Purchase and Sale Agreements ("PSA") for purchase of 100% equity interest in the project companies selected.

The Solar RFP for up to 1,350 MW of Solar Energy Resources may be found at www.psoklahoma.com/rfp.

The Company will evaluate each of the RFPs, individually and collectively, to determine the portfolio of projects that it elects to move forward with.

15. <u>Introduction</u>

American Electric Power Service Corporation ("AEPSC") and PSO are subsidiaries of American Electric Power Company, Inc. ("AEP").

AEPSC is administering this RFP on behalf of PSO who is seeking competitively priced Wind Energy Resources (each a "Project" or "Wind Project" and collectively the "Projects" or "Wind Projects") solely on a turnkey basis through its acquisition of the ownership interests in one or more projects.

Affiliates of the Company <u>will not</u> participate as Bidders in this RFP.

AEP is one of the largest electric utilities in the United States, delivering electricity and custom energy solutions to nearly 5.4 million regulated retail customers in 11 states. AEP owns the nation's largest electricity transmission system, a more than 40,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP also operates 224,000 miles of distribution lines. AEP ranks among the nation's largest generators of electricity, owning approximately 26,000 megawatts of generating capacity in the U.S. AEP also supplies approximately 4,300 megawatts of renewable energy to customers. AEP's utility units operate as AEP Ohio, AEP Texas,

32 The Company's Integrated Resource Plan is expected to be submitted to the Oklahoma Corporation Commission on October 29, 2021.

Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, PSO and SWEPCO (in Arkansas, Louisiana and east Texas). AEP's headquarters is in Columbus, Ohio. More information about AEP can be accessed by visiting www.aep.com.

PSO serves approximately 560,000 customers in 232 cities and towns across 30,000 square miles of eastern and southwestern Oklahoma. PSO is headquartered in Tulsa, Oklahoma, with regulatory and external affairs offices in Oklahoma City. The Company's distribution operations are organized into three districts: Tulsa, Lawton and McAlester. PSO has 3,771 MW of owned generating capacity, 1,109 MW of natural gas PPA capacity and has executed long-term Renewable Energy Purchase Agreements ("REPAs") with wind generation resources totaling 1,137 MW. Additional information regarding PSO can be accessed by visiting www.psoklahoma.com.

16. RFP Overview

16.1. General. PSO is pursuing up to 2,600 MW of Wind Projects that can achieve a Commercial Operation Date ("COD") of December 15, 2024, or alternatively, December 15, 2025. Projects must interconnect to the Southwest Power Pool ("SPP") and be located in the state of Oklahoma.

16.2. PSA Proposals. The Wind Energy Resources requested in this RFP will be acquired via PSAs for purchase of 100% of the equity interest of the Project's limited liability company ("Project LLC") at the Project's final completion. Proposals that do not meet these criteria, including proposals for REPAs, will not be considered by the Company.

16.3. Base Proposal. A Base Proposal for a Wind Project "only' is required by Bidders to participate in this RFP.

16.4. PTC Value. PSO is seeking Wind Projects that will qualify for the Federal Production Tax Credit ("PTC"). While qualifying for these Federal Tax credits is not an Eligibility and Threshold Requirement (§9.1) for participating in the RFP, the value brought to the Proposals in buying down the cost of energy by utilization of these tax credits is significant, and is included in the Company's Economic Analysis (§9.2.1) and ranking of each of the respective Proposals.

16.5. Timing. The time period between the receipt of Proposals and the time required for the Company's evaluation, due diligence, selection, negotiation and the execution of definitive agreements is anticipated to be seven to eight months (RFP Timeline (§6.1)). The Company anticipates filing for regulatory approval with the Oklahoma Corporation Commission ("OCC") in Q3-2022 and receiving regulatory approvals in Q2-2023.

16.6. Regulatory Approvals. The Company's decisions regarding the results of this RFP will be subject to its receipt of regulatory approvals from the OCC and the Federal Energy Regulatory Commission. Definitive agreements between the Company and Bidders for selected Projects will be conditioned upon (a) the Company receiving the regulatory approvals described in the preceding sentence that are in form and substance satisfactory to the Company in its sole discretion. The Company plans to submit a portfolio of Projects to the regulatory commissions described above for approval. In the event the entire portfolio is not approved, the Company may reduce the size of the portfolio accordingly by eliminating Project(s) from the portfolio.

16.7. Notice to Proceed. Upon obtaining regulatory approvals for the Projects selected by the Company as described in §3.6, the Company would issue a Notice To Proceed ("NTP") for the Bidders to proceed with the construction of selected Projects. The Form PSA (Appendix D) contains additional information regarding the conditions and timing for NTP issuance. The Company may issue NTP for selected Projects that it prefers over other selected Projects if some, but not all, Commission approvals are received.

16.8. Reservation of Rights. The Company reserves the right, without qualification, to select or reject any or all Proposals and to waive any formality, technicality, requirement, or irregularity in the Proposals. In addition, the Company reserves the right to utilize a Bidder's completed Appendices and any supplemental information submitted by the Bidder in any of its regulatory filings.

16.9. Non-Binding. This RFP is not a commitment by the Company to acquire any Project and it does not bind the Company or its affiliates in any manner. The Company in its sole discretion will determine which Bidders, if any, it wishes to engage in negotiations with that may lead to definitive agreements for the acquisition of a selected Project.

16.10. RFP Questions. All questions regarding this RFP should be submitted by email to:

PSO2021RFP@aep.com

Questions and answers that are determined to be pertinent to Bidders will be posted to the RFP webpage. All questions must be submitted by the Q&A Deadline noted in the RFP Timeline (§6.1).

17. Product Description and Requirements

17.1. Completed Project. Each Project at its COD must be a complete, commercially operable, integrated wind-powered electric generating plant, including all facilities that are necessary to generate and deliver energy into SPP.

17.2. Commercial Operation Deadline. The Company is pursuing Projects that can achieve the Commercial Operation Deadline of December 15, 2024, or alternatively, December 15, 2025.

17.3. Size. The PSO RFP is seeking a total of up to 2,600 MW nameplate rated Wind Generation Resources. The minimum acceptable Project size is 100 MW.

17.4. Interconnection. Each Project must be interconnected to the SPP.

17.5. Wind Project Location. Wind Projects must located in Oklahoma. PSO has a preference for Projects located in its service territory or interconnected to its transmission system.

17.6. Project Development.

17.6.1. Site Control. Bidder must have established substantial site control of the proposed Project. Site control must be in the form of direct ownership, land lease, land lease option or easement for at least 30 years. A letter of intent will not be an acceptable form of demonstrated site control.

17.6.2. AEP Wind Generation Facility Standards. Each Project must satisfy the requirements of the AEP Wind Generation Facility Standards (see Appendix E, Specification Number GEN-4560), which includes at a minimum:

- the use of only GE, Siemens-Gamesa, or Vestas wind turbine generators,
- inclusion of a Cold Weather Package (ability to operate to a minimum of -30 deg C and be capable of operating under an ice operation mode),
- a minimum facility (including turbines) design life of 30 years, and,
- specifications for the required operations and maintenance ("O&M") Building.

17.6.3. Wind Resource Analysis/Study. Each Project shall include a robust wind resource analysis/study prepared by an independent consultant, which shows the expected energy output from the Project utilizing the turbines that will be used for the Project. Such analysis should include P50, P75, P90, P95 and P99 output with 1-year, 5-year, 10-year, 20-year and 30-year estimates. During the Company's evaluation process, Bidders will be required to provide additional site information including raw meteorological data and met tower maintenance records to the Company for use by the Company's independent wind resource consultant.

17.6.4. AEP Requirements for Connection of Facilities. Project substation and interconnection facilities must conform to the AEP Requirements for Connection of Facilities (Appendix G).

17.6.5. Small and Diverse Suppliers. Bidder and/or its EPC-BOP contractor shall use reasonable efforts to utilize and adopt a subcontracting plan to use small and diverse suppliers as subcontractors for work.

17.7. Interconnection / Delivery Point.

17.7.1. The Proposal must identify the Project's proposed transmission interconnection point(s) within SPP, including any studies, applications, line extensions and system upgrades identified as part of the interconnection approval process.

17.7.2. The Bidder is responsible during the Project start-up period for following the established SPP, NERC, and transmission operator policies and procedures that are in effect regarding facility interconnection and operation associated with a utility's transmission system.

17.7.3. Each Project must be active in SPP Queue Cluster 2017-002 or earlier. Projects in later queue clusters will not be able to participate in this RFP.

17.8. Congestion / Deliverablity. The Company is seeking Projects in locations that are not currently experiencing, or anticipated by the Company to experience, significant congestion or deliverability constraints which are likely to result in adverse Project economics.

18. Bid Price and Structure

18.1. Proposal pricing must be for the Company's acquisition of a turnkey Project that is a complete and commercially operable integrated wind-powered electric generating plant designed for a minimum of a 30-year life. The Project shall include, but is not limited to, wind turbine generators, balance of plant equipment, O&M Building, SCADA, and all facilities required to deliver energy into SPP. In addition, pricing must include costs associated with ALTA/title insurance and construction financing.

18.2. In addition to §5.1, Proposal pricing must include the costs associated with the following:

- a minimum of a two-year comprehensive warranty from a creditworthy entity for all non-turbine balance of plant equipment including design, labor and materials, and fitness for purpose;
- post-commercial operation power curve testing activities and associated costs, including the installation / removal of any temporary test met towers;
- transmission and interconnection facilities required for the Project, including system or network upgrades, as required by SPP for the Project to interconnect to SPP.

19. RFP Schedule and Proposal Submission

19.1. The following schedule and deadlines apply to this RFP. The Company reserves the right to revise this schedule at any time in its sole discretion.

RFP Timeline	
Draft RFP Posted Online	September 15, 2021
Bidders Technical Conference	November 3, 2021
RFP Issued	November 17, 2021
Notice of Intent	November 29, 2021
Q&A Deadline	January 5, 2022
Proposal Due Date	January 13, 2022
Final Project Selection and Negotiation	March 15, 2022
Execute Definitive Agreements	August 15, 2022
File for Regulatory Approvals	September 1, 2022
Required Regulatory Approvals	May 1, 2023
Notice to Proceed	June 1, 2023
Commercial Operation Date	No later than December 15, 2024 or December 15, 2025

19.2. Bidder Technical Conference. A Bidder Technical Conference (teleconference) will be held on November 3, 2021 at 2:00 p.m. EST (1:00 p.m. CST). Prospective Bidders may request details and sign up for the pre-bid conference by sending an email request to:

PSO2021RFP@aep.com

Include the name of your company, email address, company representative name(s), and the following in the subject line of your email: **PSO BIDDER TECHNICAL CONFERENCE**.

AEPSC will use this information to communicate any updates regarding this RFP to potential Bidders. In addition, any updates regarding the RFP will be posted at the RFP website.

19.3. Notice of Intent. PSO requests that Bidders provide a Notice of Intent ("NOI") to PSO by the Notice of Intent Date defined in the RFP Timeline (§6.1). The NOI shall include the project(s) name, technology, location, size (MW), and SPP Queue number. The NOI shall be made via email to the following address:
PSO2021RFP@aep.com

19.4. Proposals must be complete in all material respects and be received no later than 4:00 p.m. EST (3:00 p.m. CST) on the Proposal Due Date at AEPSC's Columbus, Ohio location as defined in Section 7 of this RFP. Proposals should be as comprehensive as possible to enable the Company to make a definitive and final evaluation of the Proposal's benefits to its customers without further contact with the Bidder.

19.5. Bidders will be required to sign a Confidentiality Agreement ("CA") prior to receiving the following documents:
- Form PSA (Appendix D)
- AEP Wind Generation Facility Standard (Appendix E)
- WindEnergyInputSheet_2021.xls (Appendix F)
- Project Land Lease, Decommissioning Cost, Auxiliary Load spreadsheet (Appendix H)
- Project Technical Due Diligence Material (Appendix I)

19.6. Bidders should request PSO's Form CA by emailing (PSO2021RFP@aep.com) and including the following documentation:
- Supporting documentation of Bidder's experience in developing, engineering, procuring equipment, constructing and commissioning wind powered electric generation facilities (> Project bid size) in the United States or any portion of Canada and/or otherwise have demonstrated appropriate experience, and

- Documentation that the Project is active in SPP Queue Cluster 2017-002 or earlier.

19.7. The Company reserves the right to solicit additional information or Proposals and the right to request additional information from Bidders during the Proposal evaluation process.

19.8. Proposals and Bid Pricing must be valid for at least 180 days after the Proposal Due Date at which time Proposals shall expire unless the Bidder has been notified that its Proposal has been included in Final Project Selection.

20. Proposal Submittal

One hard copy of Bidder's Executive Summary and Appendix A and two electronic thumb drive copies of the Bidder's complete Proposal shall be submitted by the Proposal Due Date to:

American Electric Power Service Corporation
Attn: PSO Wind Energy 2021 RFP Manager
1 Riverside Plaza (25th Floor)
Columbus, OH 43215

21. Proposal Content

Bidders must submit the following information for Proposals for new Projects or expansion of existing projects. All electronic versions of the Appendices shall be individual files.

21.1. A completed Appendix K (Proposal Content Check Sheet).

21.2. An executive summary of the Project's characteristics and timeline, including any unique aspects and benefits.

21.3. Summary documentation demonstrating how the Project will qualify for the PTC for Wind Projects, under Section 45 of the Internal Revenue Code of 1986, as amended. Bidder shall provide a detailed plan regarding the steps taken to date and future actions required to satisfy IRS start of construction requirements.

21.4. A completed Appendix A (Wind Project Summary).

21.5. Detailed information regarding the turbine manufacturer's warranty offering including parts and labor coverage, warranted turbine availability levels, power curve warranty, liquidated damages and other key terms.

21.6. The identity of all persons and entities that have a direct or indirect ownership interest in the Project.

21.7. A completed Appendix B (Bidder's Credit-Related Information).

21.8. A completed Appendix C (Bidder Profile). Bidders must provide a general description of its (including its affiliates) background and experience in the development and construction of at least three large-scale wind projects similar to the Projects sought by the Company in this RFP. In addition, Bidders should provide at least three third-party references for such projects.

21.9. Any exceptions to the terms and conditions contained in the Form PSA (Appendix D).

21.10. Any exceptions to the AEP Wind Generation Facility Standards (Appendix E).

21.11. All required Wind Resource Analysis / Study information (Appendix F).

21.12. Bidder's Proposal shall include a completed Appendix H, which requires the following information:

- Expected Land Lease Costs (annual) for at least a 30-year operating period. The Land Lease costs will be used in the Company's Economic Analysis (§9.2.1);
- Estimated decommissioning costs (including salvage value). In addition, Bidder shall provide any completed decommissioning studies;
- Expected Auxiliary Load (Station Power) the Project expects to consume for a typical year on a monthly basis.

21.13. Bidder and/or its EPC-BOP contractor shall provide its plan to use reasonable efforts to utilize and adopt a subcontracting plan to use small and diverse suppliers as subcontractors for work (§4.6.5).

21.14. Bidder shall provide basic project technical due diligence material (Appendix I).

21.15. OPTIONAL: Bidders may provide a separate O&M services proposal (Appendix J).

22. RFP Proposal Evaluation & Selection

The evaluation process will be conducted in three phases:

Section 9.1 Eligibility and Threshold Requirements

Section 9.2 Detailed Analysis

Section 9.3 Final Project Selection

22.1. Eligibility and Threshold Requirements. A preliminary screening of each Proposal will be undertaken by the Company to determine if the Proposal is eligible to proceed to the Detailed Analysis phase. Bidders and their associated Proposal must satisfy the following Eligibility and Threshold Requirements:

22.1.1. Proposal must be for a Purchase and Sale Agreement for a wind energy resource (§3.2, 3.3);

22.1.2. Project must have demonstrated a clear path toward constructability (land rights, permits, etc.) and be capable of achieving commercial operation by the Commercial Operation Deadline (December 15, 2024 or alternatively December 15, 2025) (§4.2);

22.1.3. Project's minimum name-plate rating is 100 MW (§4.3);

22.1.4. Project must be interconnected to SPP (§4.4), be active in SPP Queue Cluster 2017-002 or earlier (§4.7.3), and remain active in the queue process with the demonstrated ability to achieve commercial operation of any interconnection for the full output of the Project by the Commercial Operation Deadline;

22.1.5. Project must be physically located in Oklahoma (§4.5);

22.1.6. Bidder has substantial Project site control (§4.6.1);

22.1.7. Project's wind turbine generators must be manufactured by GE, Siemens-Gamesa, or Vestas; and include a Cold Weather Package (§4.6.2);

22.1.8. Project must have a minimum design life of at least 30 years (§4.6.2);

22.1.9. Bidder must have completed the development, construction, financing, and commissioning of a similar-sized wind project in the United States or Canada and/or otherwise have demonstrated appropriate experience;

22.1.10. Bidder's exceptions to the Form PSA, considered individually or in the aggregate, are minimally acceptable to the Company as a basis for further discussions.

The Company reserves the right to reject any Proposal which proceeded to the Detailed Analysis phase but which is subsequently determined by the Company not to satisfy the Eligibility and Threshold Requirements.

22.2. Detailed Analysis. Proposals meeting the Eligibility and Threshold Requirements in §9.1 will move to the Detailed Analysis phase, which is comprised of the Economic Analysis and the Non-Price Factor Analysis set forth below. The Economic

Analysis will constitute 90% and the Non-Price Factor Analysis 10% of the overall evaluated value of each Proposal.

22.2.1. Economic Analysis. The Economic Analysis will result in a Levelized Net Revenue Requirement, which will constitute 90% of the overall evaluated value of the Proposal in its Final Project Selection. The Levelized Net Revenue Requirement will be calculated as follows:

22.2.1.1. The Company will first determine a Levelized Adjusted Cost of Energy ("LACOE") by adding together (a) the Levelized Cost of Energy ("LCOE") associated with each Proposal as calculated by the Company and (b) the cost of Transmission Congestion as determined by the Company's Transmission Screening Analysis. The Transmission Screening Analysis will evaluate (i) cost of transmission congestion and losses to the AEP West load zone and/or (ii) cost of deliverability / curtailment risk mitigation that the Company calculates to ensure that the resources can be designated as firm resources to meet Company's Capacity requirements.

22.2.1.2. The Company will then calculate the Levelized Net Revenue Requirement by taking the difference between (a) the levelized expected SPP revenues for the Proposal's energy in the SPP market and (b) the LACOE for each Proposal.

22.2.2. Non-Price Factor Analysis. The Non-Price Factor Analysis, which will constitute 10% of the overall evaluated value of the Proposal will be comprised of the following factors:

22.2.2.1. Project's (including associated transmission and interconnection facilities) impact on wildlife, the environment and identified cultural resources;

22.2.2.2. Project's (including associated transmission and interconnection facilities) location on or proximity to tribal or government lands;

22.2.2.3. Bidder's exceptions to the Form PSA (Appendix D);

22.2.2.4. Bidder's exceptions to the AEP Wind Generation Facility Standards (Appendix E);

22.2.2.5. Development status of the Project including, but not limited to, permitting, transmission and interconnection facilities and constructability;

22.2.2.6. Credentials of the Bidder's independent consultant used to prepare the Wind Resource Analysis/Study (Appendix F) for the Project as described in §4.6.3.

22.3. Final Project Selection. Based upon the results of the Economic Analysis and the Non-Price Factor Analysis described above, the Company will determine which Projects will be included in the final selection. The Company will notify Bidders whether or not their Proposal has been selected and negotiation of definitive agreements will commence with Bidders whose Proposals have been selected.

23. Confidentiality

The Company will take reasonable precautions and use reasonable efforts to maintain the confidentiality of the Proposals. Bidders should clearly identify each page of information considered to be confidential or proprietary. The Company reserves the right to release any Proposals to agents or consultants for purposes of Proposal evaluation. The Company's disclosure policies and standards will be binding upon its agents and consultants. Regardless of such confidentiality, all such information may be subject to review by the appropriate state authority or any other governmental authority or judicial body with jurisdiction relating to these matters and may be subject to legal discovery. Under such circumstances, the Company will make all reasonable efforts to protect Bidder's confidential information.

24. Bidder's Responsibilities

24.1. It is the Bidder's responsibility to comply with the deadlines specified in this RFP.

24.2. Bidders are responsible for the timely completion of the Project by the Commercial Operation Deadline (§4.2) and are required to submit proof of their financial and technical wherewithal to ensure the successful completion of the Project.

24.3. Bidders are responsible for costs incurred by them in the preparation of their Proposal.

25. Reservation of Rights

A Proposal will be deemed accepted only when the Company and the successful Bidder have executed definitive agreements for the Company's acquisition of the Project. The Company has no obligation to accept any Proposal, whether or not the stated price in such Proposal is the lowest price offered, and the Company may reject any Proposal in its sole discretion and without any obligation to disclose the reason or reasons for rejection.

BY PARTICIPATING IN THE RFP PROCESS, EACH BIDDER AGREES THAT ANY AND ALL INFORMATION FURNISHED BY OR ON BEHALF OF THE COMPANY IN CONNECTION WITH THE RFP IS PROVIDED WITHOUT ANY REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, AS TO THE USEFULNESS, ACCURACY, OR COMPLETENESS OF SUCH INFORMATION, AND NEITHER THE COMPANY NOR ITS AFFILIATES NOR ANY OF THEIR PERSONNEL OR REPRESENTATIVES SHALL HAVE ANY LIABILITY TO ANY BIDDER OR ITS PERSONNEL OR REPRESENTATIVES RELATING TO OR ARISING FROM THE USE OF OR RELIANCE UPON ANY SUCH INFORMATION OR ANY ERRORS OR OMISSIONS THEREIN.

The Company reserves the right to modify or withdraw this RFP, to negotiate with any and all qualified Bidders to resolve any and all technical or contractual issues, or to reject any or all Proposals and to terminate negotiations with any Bidder at any time in its sole discretion. The Company reserves the right, at any time and from time to time, without prior notice and without specifying any reason and, in its sole discretion, to (a) cancel, modify or withdraw this RFP, reject any and all Proposals, and terminate negotiations at any time during the RFP process; (b) discuss with a Bidder and its advisors the terms of any Proposal and obtain clarification from the Bidder and its advisors concerning the Proposal; (c) consider all Proposals to be the property of the Company, subject to the provisions of this RFP relating to confidentiality and any confidentiality agreement executed in connection with this RFP, and destroy or archive any information or materials developed by or submitted to the Company in this RFP; (d) request from a Bidder information that is not explicitly detailed in this RFP, but which may be useful for evaluation of that Bidder's Proposal; (e) determine which Proposals to accept, favor, pursue or reject; (f) reject any Proposals that are not complete or contain irregularities, or waive irregularities in any Proposal that is submitted; (g) accept Proposals that do not provide the lowest evaluated cost; (h) determine which Bidders are allowed to participate in the RFP, including disqualifying a Bidder due to a change in the qualifications of the Bidder or in the event that the Company determines that the Bidder's participation in the RFP has failed to conform to the requirements of the RFP; (i) conduct negotiations with any or all Bidders or other persons or with no Bidders or other persons; and (j) execute one or more definitive agreements with any Bidder.

26. <u>Contacts</u>

All correspondence and questions regarding this RFP should be directed to:

PSO2021RFP@aep.com

Appendix A

Wind Project Summary

Company Information

Bidder (Company):
Contact Name (Title):
Contact Title:
Address:
City: State: Zip Code:
Work Phone: Cell Phone:
Email Address:
Is the Proposal being submitted through a partnership, joint venture, consortium, or other association? ______ If so, please identify all partners, joint ventures, members, or other entities or persons comprising same.

General Project Information

Project Name:	
Project Location: [ ] County, Oklahoma	
Wind Project Size (MW):	Source of wind energy forecast:
Percentage of Federal Production Tax Credit that the Project will qualify for:	%
Turbine Specific Site Suitability Report completed & included in proposal?	
Bidder confirms that it has substantial Project site control	
Independent wind report / analysis completed and included in proposal?	

Proposal Bid Pricing[1]

Expected COD by	Turbine Manufacturer	Expected Annual Energy	Capacity Factor	Bid Price, $M
12/15/2024				
12/15/2025				

Note 1: Optional size(s) provided <u>*cannot*</u> *be contingent on Bidder selling the remaining portion of the Project to another party via a sale of a portion of the project company or a power purchase agreement.*

Turbine Manufacturer (GE/SiemensGamesa/Vestas)			
Nameplate (MW)			
# of Turbines			
Model #		Design Life (Years)	
Expected Capacity Factor (%)			
Expected Annual Energy (MWh)			
Year 1 Capacity Factor (%)[2]			
Year 1 Expected Annual Energy[2]			

Note 1: Bidder is required to identify the Turbine Manufacturer and associated data above for their bid.

Note 2: Year 1 production data is required to account for potential lower Year 1 production due to routine maintenance associated with the break-in period.

Interconnection and Point of Delivery

SPP Queue #:	Substation Name / Voltage:
System Impact Study Complete (Y/N):	System Impact Study Report Date:
Feasibility Study Complete (Y/N):	Feasibility Study Report Date:
Point of Interconnection with :	
SPP Interconnection Status (describe):	
electronic copies of all interconnection studies and/or the expected completion date(s).	

Site Information

Site Legal Description:		
Address:		
City:	State:	Zip Code:
County	Latitude:	Longitude:
Site Control (lease, own, site purchase pending, etc.):		
Site Acres:		
Is there potential for expansion (Y / N):	If Yes; acres available:	

Permits

Have you contacted all required permitting agencies regarding this project and identified all necessary permits?
City (Y / N):
County (Y / N):
State (Y / N):
Federal (Y / N):
USF&W (Y / N):
Other (Y / N)
On an additional sheet, list and describe all city, county, state and federal permits required for this project. Include: status, duration, planned steps, critical milestones and timeline.

Preliminary Site Questions[1] (Y/N)

Has the site been assessed for any environmental contamination? Describe any known environmental issues. If necessary, please describe on a separate attachments	
Are there any Tribal Lands or Tribal mineral ownership rights within Project boundary or vicinity?	
Are there any Federally or State owned or controlled lands within Project boundary or vicinity?	
Is the site adjacent or near an Environmental Justice or Fenceline community?	
Has TNC or any other non-governmental organizations been engaged?	
Are there CRP, WRP or other conservation easements within the Project boundary or vicinity?	

Attachments Required

- Site Layout: Attach a diagram identifying anticipated placement of major equipment and other project facilities, including transmission layouts and Point of Delivery.
- Leases: Attach (electronic version only) a copy of all leases, easements or other ownership documentation.
- Permit Matrix: Attach a comprehensive permit matrix and status of all required permits, including, but not limited to Federal (USFWS, FAA), State, County, City, etc.
- Decommissioning Studies: Provide available decommissioning studies and cost estimates.
- Environmental Report Summary: The initial Proposals shall include a summary of all environmental and other reports associated with the site. (See Note 1 for reports to summarize)

Note 1: As applicable, the following reports will be requested: Tier I / II Site Characterization Report, Environmental Work / Survey Plan, Bat Acoustic Survey Report, Avian Use Survey Report, Raptor Nest Survey Report, Prey-base Survey Report, Wetland, Waters and Playa Survey / Assessment Report, Whooping Crane Habitat Assessment Report, Lesser Prairie Chicken Survey / Assessment Report, Phase I Environmental Site Assessment Report, Historical and Cultural Resource Survey / Assessment Report, All Other Species and Environmental Resource Survey and Study Reports, Record and Notes of all Federal or State Resource Agency Correspondence and Meetings, Turbine and Environmental Resource Shapefiles (.kmz format), and Bird and Bat Conservation Strategy and Eagle Conservation Plan (if available).

Wind Projects Completed

le a summary of all wind projects (> 100 MW) that Bidder has successfully developed and com-
in the United States or Canada. For each project, describe the Bidder's specific role in the project.

Project	Location	MW	Bidder's Role
	Total MW =		

Appendix B

Bidder's Credit-Related Information

ɛgal Name of the Bidder:
Bidder Entity (corporation, partnership, etc.):
·'s Percentage Ownership in Project:
ɛgal Name(s) of Parent Corporation: 4. 5. 6.
Providing Credit Support on Behalf of Bidder (if applicable): ɛ: ɛss: Code:
of Relationship:
ıt Senior Unsecured Debt Rating: 3. S&P: 4. Moodys:
References & Name of Institution:
Contact: ɛ: ɛss:

;ode: e Number:
Proceedings: As a separate attachment, please list all lawsuits, regulatory proceedings, or arbitra- which the Bidder or its affiliates or predecessors have been or are engaged that could affect the 's performance of its bid. Identify the parties involved in such lawsuits, proceedings, or arbitra- nd the final resolution or present status of such matters.
ial Statements: Please provide copies of the Annual Reports for the three most recent fiscal years arterly reports for the most recent quarter ended, if available. If available electronically, please e link:

Appendix C

Bidder Profile

list Bidder's affiliate companies: 5. 6. 7. 8.
attach a summary of Bidder's background and experience in Wind Energy projects.

References

5. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

6. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

7. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

8. Company
    a. Contact Name:
    b. Contact Number:
    c. Project:

Appendix D

Form Purchase and Sale Agreement

See Section 6.5 for instructions to obtain the applicable Form Purchase and Sale Agreement.

Appendix E

AEP Wind Generation Facility Standard

See Section 6.5 for instructions to obtain the AEP Wind Generation Facility Standard.

Appendix F

Wind Resource Analysis / Study

Required Information

- Attach the independent wind energy report
    - Wind report shall also include P50, P75, P90, P95 and P99 production estimates with 1, 5, 10, 20 and 30 year timeframes
    - Independent consultant information (resume, contact information) if not included in the wind energy report.
- Describe on-site meteorological campaign including:
    - Number of met towers
    - Height of met towers
    - Remote sensing (lidar and/or sodar)
    - Number of years of data for each tower / remote sensing device.
- Identify any wind direction sector management or other operation restriction requirements.
- Experience of developer in Oklahoma. Identify the number of projects, years each project has been operating, turbine models and capacity rating.
- Source and basis of the wind speed data used in the development of energy projections for the project. Explain all assumptions for wake losses, line losses, etc. and the location where the data was measured.
- Wind turbine power curve adjusted for the site's specific air density.
- Provide a description of the system intended to provide real-time telemetry data.
- Attach an 8760 calendar year hourly energy forecast, net of all losses (See attached Excel spreadsheet (***Energy Input Sheet***).
- Bidders shall provide a summary of representative wind data with measurement height referenced and any extrapolations used to estimate the wind speeds at the proposed hub height. (This item shall be provided in the electronic (CD, flash drive, etc.) version of the Proposal only.)

llowing information should be available upon request; however, is not required with the submis-f the Proposal.

- Project boundary (shape files, kmz files, or pdf on USGS topographic map)
- Land control, broken down by leased land, likely to be leased land, likely NOT to be leased land, and indeterminate status (shape files, kmz are best)
- Setbacks/exclusions (shape files preferred),
- Met tower installation commissioning sheets and all subsequent maintenance documents
- Raw data files for all on-site met towers
- If applicable, sodar or lidar documentation and raw data files
- Proposed turbine locations (shape file, kmz file, Excel file with coordinates, including map datum (e.g., WGS84, NAD83)

Appendix G

AEP Requirements for Connection of Facilities

Please follow the link below to access the AEP Requirements for Connection of Facilities ("Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System").

https://www.aep.com/assets/docs/requiredpostings/TransmissionStudies/Requirements/AEP_Interconnection_Requirements_Rev2.pdf

Appendix H

Projected Land Lease / Decommissioning Costs / Auxiliary Load

See Section 6.5 for instructions to obtain the spreadsheet for Projected Land Lease Costs, Decommissioning Costs, and Auxiliary Load.

Information to be provided in the Appendix H spreadsheet shall include:

- Expected Land Lease Costs by year for at least a 35-year operating period. The Land Lease costs will be used in the Economic Analysis (§9.2.1);
- Estimated decommissioning costs (including salvage value). In addition, Bidder shall provide any associated decommissioning studies;
- Expected Auxiliary Load (Station Power) the Project expects to consume for a typical year on a monthly basis.

Appendix I

Project Technical Due Diligence Material

See Section 6.5 for instructions to obtain the Project Technical Due Diligence Material list.

This list will include basic technical due diligence material that the Company will require to perform an initial technical due diligence of the Project.

Appendix J

O&M Services Scope of Work (OPTIONAL)

Bidders may request the O&M Services Scope of Work via email at:

PSO2021RFP@aep.com

Appendix K

Proposal Content Check Sheet

New Build Projects

Section	Item	Com-pleted
8.2	Executive Summary	
8.3	Documentation demonstrating Project will qualify for %PTC	
8.4	Appendix A (Wind Project Summary) - Company information - General Project Information - Proposal Bid Pricing - Turbine Manufacturer Options - Interconnection & Point of Delivery - Generation Collection System (>100 kV) - Site Information - Permits - Preliminary Site Questions - Wind Projects Completed	
8.5	Manufacturer's warranty offerings	
8.6	Identity of all person and entities that have a direct or indirect ownership interest in the project.	
8.7	Appendix B (Bidder's Credit-Related Information	
8.8	Appendix C (Bidder Profile)	
8.9	Appendix D (Form PSA exceptions (if any)	
8.10	Appendix E (exceptions to AEP Wind Generation Facility Std)	
8.11	Appendix F (required Wind Resource Analysis / Study Info)	
8.12	Appendix H (Land Lease Cost, Decommission Cost, Aux Load)	
8.13	Bidder's plan to use small and diverse suppliers	
8.14	Appendix (I) Project Technical Due Diligence Material	
8.15	O&M Services Proposal (optional)	

Exhibit G: Attorney General Comments on 2021 DRAFT IRP

In the Matter of the Triennial Integrated)
Resource Plan of Public Service Company)
of Oklahoma for 2021)

ATTORNEY GENERAL'S COMMENTS

John O'Connor, the Attorney General of Oklahoma, on behalf of the utility customers of this State, hereby submits his Comments in the matter referenced above. The Attorney General reminds the reader that integrated resource plans ("IRPs") are not approved under Oklahoma law. Further, PSO has not adequately explained its load forecasts; its natural gas forecasts are opaque; and it does not consider existing natural gas generation facilities that may be available at lower cost than new construction.

I. Oklahoma law does not grant any approval or determination of prudency with respect to integrated resource plans submitted under OAC 165:35-37.

The integrated resource planning process offers stakeholders an important and valuable opportunity to review and provide input on regulated electric utilities' generation plans. Nevertheless, the Attorney General would remind readers that such planning processes do not take place in full proceedings before the Oklahoma Corporation Commission ("Commission") governed by discovery rules, nor do stakeholders enjoy the procedural protections of such proceedings.[1] The utility's statements supporting IRPs are not made under oath, nor do they constitute evidence. Further, the Commission itself does not vote on or approve IRPs.[2] The completion of the IRP process does not carry the effect of making utility actions reasonable or prudent. The IRP rules themselves impose on the utility a duty to consider stakeholder comments,[3] meaning stakeholders may not appeal or challenge a final IRP.

[1] *See* OAC 165:35-37-5.
[2] *See* OAC 165:35-37-5(h)
[3] *See* OAC 165:35-37-5(d) (requiring utility to "take into account" comments and make changes that "seem reasonable").

The limitations of the integrated resource planning process are important to keep in mind where, as here, PSO forecasts growing customer bills by 3-4 percent per year on average.[4] The concerns addressed in the remainder of these comments raise concerns about the analysis done to support PSO's significant customer bill increases.

II. PSO does not consider existing natural gas generation facilities available in the Tulsa area.

As is often the case with IRPs, PSO's modeling relies extensively on the cost of new construction for additional generation facilities.[5] The draft IRP contains no analysis of using existing generation facilities in or near PSO's service territory to meet capacity obligations over the IRP's planning horizon, even though such generation options may be much more affordable for customers. The Commission recognized the lower costs of using existing generation facilities, either through purchased power agreements or asset purchases, in a recent case involving PSO's request for preapproval for new construction.[6]

There are many existing generation providers that could meet the capacity needs of PSO's customers. The U.S. Energy Information Administration's Form 860 shows at least two natural gas independent power producers in the Tulsa area alone. If such producers have capacity available, they may be able to bid into a competitive bidding process at a more cost-effective level than new construction of any fuel type.

Further, Southwest Power Pool market data shows that it "continues to have significant excess capacity at peak loads."[7] During each of the last seven years from 2014 to 2020, SPP has

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[4] Public Service Company of Oklahoma, Draft 2021 IRP Working Document 113 [hereinafter "Draft IRP"].
[5] Draft IRP at 53–70.
[6] Final Order, Order No. 718,758, at 7–8, *Pub. Serv. Co. of Okla. Facilities at Ft. Sill*, No. PUD 202000097 (Okla. Corp. Comm'n June 7, 2021).
[7] SPP Market Monitoring Unit, State of the Market 2020, at 2 (Aug. 12, 2021); SPP Market Monitoring Unit, 2020 Annual Report Highlights 12 (Aug. 25, 2021).

had over 30 percent more capacity available at peak times than actual peak loads.[8] Since capacity requirements are imposed on load serving entities based on peak load, this overabundance of capacity implies that there should be significant opportunities to place existing generation resources under contract that are not currently under contract or needed by other load serving entities in the market.

PSO's action plan should commit to open and non-restrictive competitive bidding processes that allow it to make use of existing generation resources in the market rather than simply building new facilities.

III. PSO has not adequately explained the increase in its load forecast, which is discontinuous with its past load data and leads to the large capital expenditures proposed by PSO.

A key element not explained in PSO's draft IRP is the increase in its load forecast. The issue can be visually observed on page 21 of the draft IRP, which shows a notable discontinuity between previous data and PSO's forecast in future years.[9] The higher load forecast and discontinuity in load expectations contributes to a significant capacity shortfall forecast by PSO for upcoming years.[10] These capacity expansion plans are directly tied to the concerning rate increases forecasted by PSO. Without this anomalous increase in load, it is likely that some portion of the rate increases planned by PSO would not be necessary.

While PSO may claim that the discontinuity is explained primarily by the global coronavirus pandemic that began in 2020, this would be inaccurate. The chart on page 21 does show a slight reduction in weather normalized peak demand in 2020, but the higher forecasted amount nevertheless appears higher than normalized peak demand in 2018 and 2019. PSO should

[8] *Id*.
[9] Draft IRP 21, Figure 8.
[10] *See id.* at 45, Figure 21 (showing capacity shortfalls before 2025).

be required to provide more detailed explanations for why its load forecast has increased and why there is a discontinuity between recent weather normalized peak usage and PSO's expectations for the next several years.

IV. PSO's natural gas forecasts are opaque.

PSO's draft IRP relies on a forecast of natural gas prices, among other forecasts, to help generate PSO's preferred plan.[11] The natural gas forecast used in an integrated resource plan has significance due to its high impact on market prices for electricity, affecting the economics of all generation resources. Generally, the direction of this impact is for higher natural gas price forecasts to make non-natural gas resources, such as the wind and solar renewable facilities favored by PSO,[12] more attractive, while lower natural gas price forecasts tend to make natural gas facilities themselves appear more attractive.

While PSO's draft IRP states that it developed its natural gas forecast using publicly available information from the U.S. Energy Information Administration,[13] it also notes that some adjustments are made to result in the AEP Fundamentals Forecast.[14] PSO's natural gas forecast lacks transparency by showing a price chart for a single hub in western Oklahoma[15] rather than backing out prices to the Henry Hub and explaining the assumed pricing "basis" or difference between the Henry Hub and Oklahoma markets. Further, the chart uses volatile monthly pricing[16] rather than annual estimates typical for long-run charts, and it adjusts the data into a "real" price that disguises the underlying long-term price trends of the forecast.

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[11] *Id.* at 77, 79.
[12] *Id.* at 122.
[13] Draft IRP at 78, Figure 45.
[14] *See id.*at 77–78.
[15] *Id.* at 79.
[16] *See id.*

While some of the information in PSO's charts can be helpful, the Attorney General finds the changes relative to common long-term price forecast charts concerning. PSO should provide typical information about its natural gas forecasts, such as a long-term annual price in nominal terms for the Henry Hub, and then provide additional information as helpful, such as monthly price swings and the pricing basis to relevant hubs in Oklahoma.

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Exhibit H: 2021 Technical Conferences Transcripts

- September 21, 2021 Technical Conference Transcript
- October 19, 2021 Technical Conference Transcript

PUBLIC SERVICE COMPANY OF OKLAHOMA

INTEGRATED RESOURCE PLAN

TECHNICAL VIDEOCONFERENCE

Tuesday, September 21, 2021

APPEARANCES

FAIRO MITCHELL, Host

GREGORY SOLLER, Manager, Resource Planning

MATTHEW HORELED, Vice-President, Regulatory and Finance

JAMES McMAHON, Vice President

JONATHAN PAINLEY, Senior Associate

CHAD BURNETT, Director, Economic Forecasting

ROBERT KAINEG, Principal

TUESDAY; SEPTEMBER 21, 2021; 9:00 A.M.

PUBLIC SERVICE OF OKLAHOMA

INTEGRATED RESOURCE PLAN

TECHNICAL VIDEOCONFERENCE

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MR. SOLLER: Hello, everybody. I'm Greg Soller. I'm with AEP's Resource Planning Group and associated with PSO today. I appreciate you joining us to -- for our technical conference.

I want to -- I'd like to go through -- hi, Ishmael. All right. So, I'd like to initiate a few opening comments with regards to how we would like to facilitate the session today, this presentation for today.

I'd like to ask that everybody stay on mute while the presentation is going on. The -- we will periodically be opening up the discussion for additional Qs & As.

We would ask that if you do have a question throughout the presentation that you use the chat feature of Webex. You can -- you can get to that at the bottom right-hand side of your screen to type in your questions.

That will allow us to be able to read those and be able to address those periodically with the intent to try to keep up with those throughout the presentation.

If the opportunity exists we will also have the chance to come off mute and engage in some dialogue, as well. Throughout the presentation it's our intent to share not only what we have done and where we've -- what we've accomplished through this process, but also to get your feedback and listen to the comments that you have, as well.

So, for the presentation I would like -- for this presentation I would -- I would appreciate at least one who advised for this presentation, we have a court reporter that will be transcribing the discussion.

But in support of that we are also intending to record the presentation and to give her a little bit of back up. If there is a concern, please advise through the chat. We can take that into account.

The court reporter notes are intended to be the information that we will include with the record of this discussion in our IRP process.

At the end of the presentation we will continue to have some discussion and open up for additional questions and answers. And we look forward to a good meeting today, and we hope you'll have an active participation.

It's important to us and to not only share what we have done, but also to hear -- hear from our stakeholders.

So, at this point, just a brief summary of the agenda that we will talk, and then I would like to bring on Matt Horeled to add some opening remarks. We will open up for some discussions after with Matt talking about what we have done and some of the steps we have taken since the 2018 IRP.

We will -- we will discuss about the -- the remaining part of our process, and then we will turn it over to start talking about the -- the process we followed, the IRP development in terms of the -- the inputs, the scenarios that we have tested and also -- and then we will take a small break. That should take us about midway through the session today.

After break we would like to get right into the discussion of the portfolio development we talked -- we have done over the past few months, talk about the information, the results that we have seen and ultimately discuss the Preferred Plan for PSO's IRP, at which time we will certainly have, as I mentioned, several opportunities for -- for questions and answers. And then we will close with some final remarks with Matt Horeled.

So, that's the plan for today. We're looking forward to a good conversation with you folks. Appreciate your time.

And at this point I would like to turn it over and give Matt Horeled a chance to have some opening remarks, okay?

MR. HORELED: All right, Greg. Good morning, everyone. My name is Matthew Horeled. I'm the vice-president of regulatory and finance for Public Service Company of Oklahoma. And I just want to welcome you to this -- this year's 2021 Integrated Resource Plan for PSO.

We're excited to talk about our modeling and our results and get the feedback from you to this process. And just looking at the -- a quick introduction of who we have, our PSO leadership team, of course, is Peggy Simmons, our president and chief operating officer; myself, vice-president of regulatory and finace; Mary Williamson, director of regulatory services; Joann Worthington, counsel; Fairo Mitchell, regulatory consultant principal and Jeff Brown, manager of EE and consumer programs.

We also have joining with us today -- we brought in -- we brought in all the best experts we could, everybody, so we're excited to introduce them and bring them onto this conversation, as well, too. We have a full -- full team on here to help address any concerns and questions.

With our internal Integrated Resource Planning team we have Kelly Pearce, managing director of resource planning and strategy; Mark Becker, managing director of resource planning and grid solutions. Scott Fisher and Greg Soller are both managers of resource planning. Greg had the honor of kind of kicking us off a moment ago.

We have Chad Burnett, director of economic forecasting -- many of you are familiar with him -- talking about our ecomomic forecasting in the past. Connnie Trecazzi, as well, economic forecast staff.

And then we have Charles River Associates, CRA, team is joining us for this IRP this year to help with the modeling and -- and the scenarios. They have a whole wealth of experience and background in other -- other jurisdictions and in other states. They've worked here with Empire, as well, here in Oklahoma.

We have James McMahon, vice-president; Patrick Augustine, vice-president, as well as Robert Kaineg, Jonathan Painley and Abigail Sah joining us today, as well, too.

So, like I said, we have a full roster of experts to walk us through our IRP today. Next slide, Greg. Perfect.

So, the past is prologue, right? So, we always like to see where we come from and where we're going, and so, we thought it would be appropriate to look at a quick five year action plan view from our last IRP, which as you all know, happens every three years here in Oklahoma. So, our last 2018 IRP, what were the action items that we had from that -- that session.

And the first one kind of looking at the update around our energy efficiency program, we're continuing to plan, implement and report on energy efficiency and demand response programs.

Our most recent DSM program for twenty-two to twenty-four was just recently approved by the Commission. We are also -- we also are looking at how can we best utilize adding cost effective wind -- wind generation to take advantage of the Federal production tax credit.

And many of you are aware, I'm sure, about our -- our RFP we issued in 2019 which led to the development and purchase of the North Central Energy facilities, our -- our new wind facilities that we're very proud of and very excited to bring those on-line to serve our PSO customers.

The first two facilities, Sundance and Maverick, are operational, and PSO expects a final facility, Traverse, to reach commercial operation early next year in 2022.

And additionally the company is planning to release an RFP for wind resources to be operational by the end of -- of 2024 and 2025, as well.

Now in tandem with the wind options, we've been looking at the utility scale solar resources, as well, too, and that was something that was in our previous IRP.

In coordination with the wind RFP mentioned above, we're planning to release an RFP for solar resources to be operational by the end of twenty-four and twenty-five, as well.

And then there are a couple items here on -- on how to replace existing thermal PPAs, which created a capacity need in our previous IRP view in 2018, looking at a need we had in 2022 and also just looking at intermittent resources on our system and how to evaluate options for short-term capacity related to those -- those additions.

And a status update on that item is the company secured short-term paper capacity resources in 2020 to meet that capacity need in twenty-two, twenty-three and twenty-four.

And then, of course, just like with our action plan from this year's IRP, we'll -- we'll check and adjust the plan and adjust it as -- as we need to going forward.

And most importantly today is we want this to be a collaborative conversation with the stakeholders. You know, our main intent is to inform, listen and consider as -- as this slide is talking about here.

We want to increase stakeholders' understanding of the IRP process, the assumptions we used in our modeling and challenges that -- that -- that we face in our long-term planning.

We -- we want to hear from you, hear what your concerns and objectives are, as well, too and other stakeholders throughout the whole process and then ultimately take into account your feedback and look at different ways that we can inform our decision-making going forward.

And part of that process was publishing the draft last week, having this very important stakeholder meeting today, then ultimately preparing the final report for submission on October 1st.

And I think at this point, Greg, I'm going to kick it back over to you or to Jim.

MR. SOLLER: Yeah. I'll pick up. I'll do a quick introduction, and then I'll turn it over to Jim McMahon, who's with Charles River Associates. We worked with them today or throughout this process to -- really to develop this IRP.

And I would like to introduce Jim McMahon from Charles River and let him pick up from here. So, Jim?

MR. McMAHON: Thanks, Greg. Thanks, Matt. I appreciate it.

I'm Jim McMahon. I lead the advisory services business within our energy practice at CRA. Our energy practice is about seventy-five professionals within a company of about a thousand consultants. If you are not familiar with CRA, we have been around since 1965.

We have been -- have had a substantial energy practice since the early '80s, probably three decades of working utility resource planning across most U.S. states, all the major energy markets, including SPP and PJM and MISO and CAISO, you know, just some of our current or previous clients in resource planning to give you a sense of the work that we have done include Northern Indiana Public Service Company, NPSCO, Alliance Energy, Southern Company, Dominion Energy, Infinite, as Matt referenced Empire District, who has jurisdiction in four different states, including Oklahoma.

And then we have also worked with public power clients, Great River Energy, Hoosier Energy, CPS Energy, Oglethorpe Power to give you a sense. So, it's a pretty broad set of clients we've worked for often on similar questions to what we have -- we have been working on with PSO.

So, today I'll provide you an overview -- a fairly brief overview of the process that we -- we went through in this -- in this IRP, the AEP PSO teams and then turn it over to my colleagues, a couple of them that were referenced on the prior slide, Jonathan Painley and Robert Kaineg, to go through the -- the detailed results and findings.

So, on this slide gives you a high level view, and I'll start on the right side of this in terms of the steps that we went through, and the left side talks more about the teaming between ourselves and AEP and PSO.

So, on the right side the five steps -- the first step was defining the objectives and making sure those are aligned to the customer needs. The second step in the process was to look at market scenarios within the broader SPP market to test future risk, a lot of these -- a lot of these variables.

Then in step three we look to optimize a set of portfolios for these different market conditions that are described in step two. And then these -- these portfolios consist of supply and demand side solutions.

Step four we -- we test those optimized portfolios against the full set of market scenarios that we talked about in step two. And we also run stochastics, which is a different way of looking at risk. And we will talk through all of this in much more detail today.

And then finally in the final step we -- we look at the results against the -- the set of objectives that we set up-front and consider the trade-offs between the objectives to the extent we need to balance and -- and then select the Preferred Plan on that basis. So, we will walk through on how we did that.

Now, on the left side of the graphic it really shows the responsibility and that this was a team effort, you know. Certainly, CRA has played a substantial role in modeling in -- in modeling and a lot of the analytics.

But PSO played a -- and AEP more broadly played a really important role in definition up-front in terms of the objectives, but also the selection on the back end, of course, to the Preferred Plan.

Also, AEP-PSO provided fundamental price forecasts that went into scenarios that -- that we developed. But in the middle there at CRA where we developed the supply side assumptions, we modeled market scenarios and the -- the models to produce the -- the optimal resource portfolios in step three to the right there.

And then we populated a scorecard. We will talk about the scorecard, but it's a representation of these objectives. And -- and that allowed the PSO team to make an informed decision about the preferred portfolio in the -- in the final step.

So, with that let me move to the next slide, Greg. So, PSO identified four overall objectives. This is the first step I referenced on the prior slide. These four objectives actually branch into ten different metrics, which we will discuss in much more detail on the slides to follow.

But the first one to give you a high level view of this is customer affordability, which was measured based on short and medium-term costs on a net present value basis.

The second was rate stability, which was measured in a few different ways, including how the -- the net present value of the portfolio varied by scenario and how much market exposure a portfolio has.

The third was -- was maintaining reliability, which was measured by the amount of operating reserves, dispatchable capacity and how much resource diversity in the particular portfolio that we have -- that we had that we were comparing.

The fourth is the local impacts and sustainability. So, local impacts were measured by the expected Capex impacts in the service territory, and sustainability was measured by the reduction in carbon emissions.

You'll see all these represented in a bit on the broader scorecard, so -- so the metrics for each one of these four objectives, again, several metrics per objective.

But -- but these objectives overall were really central to driving all the steps with the analysis, how we thought about scenarios, the -- the evaluation of different resource types, the types of risks we assessed in the stochastic analysis. And -- and -- and then again these all manifest in the scorecard, which we will discuss in a little bit.

Next slide, Greg. So, this slide represents the going-in position, starting position, for -- for PSO. And just to orient you to what we're looking at here, those are the years along the -- the horizontal axes, the megawatts, the u-cap along the vertical axes.

And the -- the stacked bars show the capacity contribution by resource type over time. So, that's -- that's the stacked bars, and you can see the resources off to the right side of them, looking down to the right side.

The solid line shows the -- the peak load plus a reserve margin, which is how much must be procured or -- or retained in -- in the portfolio to meet the -- the reliability standards set out by -- by SPP.

So, as you can see in the -- the capacity position starts to open up over time with the retirement of Northeastern in 2026 and then some smaller gas units, as well as the -- the expiration of some PPAs, which include some gas contracts and smaller wind contracts.

And so, we have a -- a fairly substantial open position as we go out in time. And that's a lot about what this -- this IRP is about, how to fill -- optimally fill that -- that open position.

Let's go to the next slide, Greg. And I'll say a little bit about the Preferred Plan, and then we're going to get into the details after this -- after this slide and basically walk you back to this, how we got here.

But basically a high level, the Preferred Plan adds about twenty-eight hundred megawatts of wind, twenty-one hundred megawatts of solar and just over a hundred megawatts of DSM and -- and demand response, all starting in that 2025 time frame, you know, really filling the gap that I -- that I illustrated on the prior slide.

The -- the -- you know, in addition to -- to being the best balance of -- of performance across all four objectives as judged by the PSO leadership the Preferred Plan is lowest cost or near lowest cost in just about every scenario that we ran.

So, we will talk about that in a lot -- lot more detail in the slides that follow, and my colleagues are going to walk you back to this -- these finding, if you will.

So, from here I'm going to turn it over to Jonathan Painley. He's going to get into much more detail for you on -- on the -- the steps here that we have -- we started talking in the -- the market scenario piece. John?

MR. PAINLEY: Thank you, Jim. Good morning, everyone. As Jim briefly introduced, my name is Jonathan Painley. I'm with the Charles River Associates modeling team and have been working closely with AEP and PSO this year to develop this.

I'll be introducing today the scenarios, so as we discussed a bit earlier, scenario modeling is used as part of the IRP to study plausible but materially different long-term views of the SPP market where PSO operates.

The scenario themes shown on this slide reflect different outlooks for fuel, load, environmental and tax policies, market rules and technology costs. And we have studied various combinations of these inputs in the form of integrated scenarios.

And the point of integrated scenarios is to study a broad range of outputs which will then be used to evaluate various PSO portfolio decisions.

The five themes that emerged during the scenario development phase are shown on this slide, the first being the reference scenario, which is intended to reflect a middle of the road expected case view of the key inputs.

In addition to the reference, there are four other market scenarios that stress test a lot of these key inputs, starting with the clean energy technology advancement case which studies more rapid deployment of new clean energy technology.

The enhanced carbon regulation case studies rapid carbon policy implementation with high emission prices. The focus on resiliency case includes both a summer and winter planning reserve margin enforced in SPP, and the no carbon regulation case tests lower gas prices and zero carbon regulation in the immediate future.

Next slide, so diving in just a bit more, this slide presents a high-level overview of the assumptions for each scenario with the main market drivers shown across the top of the table, being load, natural gas, carbon, et cetera.

So, in the reference scenario we adopt the expected case or base yield, and all of the other scenarios show changes relative to the reference case. So, I'll go through those quickly.

For the CETA case, again, this is a clean energy adoption case, so we see more rapid decline of technology costs, and we also see a ten-year PTC-ITC extension at current subsidy levels. And then last we have rapidly growing load reflecting higher electrification and faster underlying economic growth.

Just a quick aside, this is not exactly the same as the proposed clean energy performance program, but it is in a similar story line, and it does test a lot of those -- those elements that have been proposed through that program.

As we continue on, the ECR case, we see the high gas and carbon prices. We also see faster decline in technology costs, and we have lower load, reflecting higher adoption of distributed technologies and lower underlying economic growth.

In the FOR case, we see the winter reserve margin requirements, and then we also have low renewable P credits associated with this case. And last for NCR we see lower natural gas prices and no carbon prices.

So, the next few slides will go into more specifics for each market driver. So, I will hand the presentation off to Chad Burnett, unless we need to pause for a moment.

(Pause.)

MR. BURNETT: All right. Looks like no questions, Greg.

MR. SOLLER: No. I was just going to say let's -- I don't have any questions in the chat, so we will continue forward. Thank you, Chad.

MR. BURNETT: Well, everyone, it's great to see you again. Again, my name is Chad Burnett, and as mentioned earlier, I lead the -- the economic forecasting team for AEP.

I wanted to kind of just real quickly touch base on what we are using for the load forecasts as the input into this IRP process. For those of you that have already read the report, you know, Section 2.1 goes into a lot of detail, so I'm just going to really hit the highlights here, and -- and then if we have any questions we can go a little further into it if we need to.

But what you can see on this page when you look in the chart in the upper left, this is showing our peak demand forecast. The black diamonds are the actuals. The red line represents a weather normalized view of our historical, and then you can see the green line represents what our projections are going forward again for our base forecast.

And so, you can see over the next decade our -- our load is expected to be relatively flat, growing at about one-tenth of a percent per year.

But while that seems like a fairly boring story to tell, what is interesting is that we are seeing a little bit of a mix in our -- or a shift in the mix of our sales.

And so, to the chart in the upper right, these are the major retail classes that make up our load. And what's interesting here is seeing how much industrial is -- is starting to take over, and, you know, by the end of the forecast period will be the dominant class in terms of sales for PSO's service territory, whereas historically it's been the residential class.

So, you know, there's a -- there's a number of factors that are driving that. But the important thing is to realize that PSO's sales mix is, in fact, shifting over time. I think we can go on to the next slide.

This is just -- I want to point out the fact that we do have -- we do a lot of load scenarios within our shop, looking at multiple different features, different things that could influence the load forecasts going forward.

What we did focus on in the IRP though are really our base forecasts and then the high and the low, because those really capture kind of the universe of all the different options that we can think about.

And so, while we have -- we have done an extreme weather forecast at different assumptions about appliance efficiencies and codes and standards and those sorts of things, those are still generally well within the high economic and low economic scenarios.

And so, as a result, that -- that's ultimately what we'd be handing off to the IRP optimization. And you can -- you can kind of see here I've given the range of those.

The high would be looking at a load growth of about one point one percent per year. Our low economic would be a decline in our load of a half a percent per year, and you can see it in the base forecast at times, what the difference roughly between those two.

So, on the next slide in addition to the specific load scenarios, we also have done some analysis on -- on several new emerging technologies or disruptions that are happening that we want to kind of make our stakeholders aware of, because I know in the last several jurisdictions that we have done these, these tended to be of -- of interest to a lot of stakeholders.

So, let's start out talking about electric vehicles. So, we get this data off -- from the vehicle registration database, and it -- it captures -- what we're able to do here is look at how many electric vehicles are actually registered in the PSO service territory.

So, we're looking at data at a ZIP code level. We match that up with our customers' billing data set to find out which ZIP codes are ours and looking at the number of electric vehicles that are registered here.

And so, the most recent data we have is as of the end of the first quarter of this year. And you can see that we're just under two thousand electric vehicles registered in PSO's service territory, which is roughly about -- well, it's less than two-tenths of one percent of a market share. In total we've got about one point three million vehicles registered.

However, so we are expecting that to grow at a -- roughly about thirty percent per year, and that's fairly consistent with what we've seen over the last three years.

So, the growth is strong, but at this point it's still a relatively small piece of the puzzle, and so it is not going to have a dramatic influence at least in the near term but over the next ten years on our load projections.

So, we just want to make sure the stakeholders are aware that we are thinking about electric vehicles, and we're projecting them. But they are still going to be well within the high and low bands that we would be describing in this IRP optimization.

On Slide 16, the other kind of big technical disruption that's happening across the country that we wanted to make sure our stakeholders are aware of has to do with the idea of distributed generation. And specifically we're looking a lot at the rooftop solar that is -- that's installed.

So, as of the end of last year, we had just over six thousand of our customers that had installed DG. That's roughly about one point one percent of all of our customers. And, you know, we kind of look as you can project those going out, you can see that by the end of 2030 we're expecting roughly about four percent of our customers will have installed DG at their facilities.

And so, what's really been exciting for me -- and I know this may sound a little bit nerdy, but one of the -- the opportunities that has opened up after the Commission allowed us to install AMI metering was the ability to really dig deeper into some of the issues to see what impact some of these technologies like distributed generation are having on our load shape. And that helps us again when we think about planning for the future.

So, on the next slide, this is an analysis that we recently completed where we're looking again at AMI data for customers that had installed a distributed generation facility at their premise.

And we wanted to get -- to narrow the sample down to customers that we had a full year -- at least a year of AMI data before they installed the DG on their system, as well as a year after so that we could really capture what is the impact that distributed generation is having on our customers' load obligations.

And so, you know, this is pretty interesting. What we're seeing here is -- the vertical axis is the daily usage for these customers, and the horizontal axis here represents what the average daily temperature was.

So, again, you wouldn't think -- and I'm not -- not suggesting that solar is a function of temperature, but the reason we wanted to look at this is because we certainly know that customer usage is highly influenced by -- by temperatures.

And so, you can kind of see the typical load shape that -- you know, it kind of bottoms out and -- and the base degrees of -- and the average temperatures between around fifty-five and sixty-five. That's kind of our base load.

And then when the average daily temperature gets above sixty-five or below fifty-five, that's when we start to see the heating and cooling loads kick in. And so, that's just your typical shape that you would see here.

What we're seeing here though on this particular chart, the blue dots represent what the customers usage was before they installed the DG, and the -- the orange dots represent what their usage was after.

And one of the things that was pretty interesting for us is to realize, you know, that, you know, DG -- and this is probably not a surprise, but at least the data referring to this has a much bigger impact in the summer months when there's, you know, more exposure to the sun than it does in the winter.

So, for instance, during the summer months we saw an impact of nearly fourteen percent compared to about a four percent impact in the winter months.

And so, on an annual basis when you pull it all together, roughly customers that had DG had lowered their customer usage by almost eleven percent.

So, let me just pause there to see if there were any questions about the forecasts, and, if not, I think I will hand it back to John.

MR. SOLLER: Right now, Chad, we don't have any questions in our chat sessions, so, you know, folks, if there is something that comes up on your mind, please -- please enter those in the chat. We can always get back to that. But for now thank you, and, Jonathan, we will turn it back to you.

MR. PAINLEY: Thank you, Greg. On -- so, on slide eighteen here we have got the fundamental gas price and carbon price inputs that we use for the scenario modeling. So, I'll walk through those quickly.

For natural gas on the left we relied on the AEO 2020 reference case for the base trajectory with the higher and lower trajectories differing by about forty to fifty cents around the base trajectory.

And we're showing here the eastern Texas, Oklahoma hub, which you can see the axis is in real dollars, so we are showing some real price growth from 2022 through about 2028.

And then the long-term forecast stabilizes around three dollars real, which is just shy of about six dollars nominal by 2041. So, there is, you know, inflation growth, but we have removed that for the purpose of these charts.

We can also see the seasonality of the gas prices with the winter spikes being approximately fifty to seventy-five percent higher than the non-winter months.

And then lastly this hub, this area, maintains about a thirty percent discount to Henry Hub, so cheaper than the main forecast that you might see published for Henry Hub.

On the right-hand side for the carbon price inputs you see we can -- we're testing three different trajectories with the base case outlook characterized as a moderate carbon price starting around twelve dollars per ton in real dollars in 2028 and growing slightly faster than inflation.

We also stress test this by having two other carbon trajectories, so we have first a zero carbon price which is used in the NCR case, and then we also have a high carbon price which is used for the ECR case.

And the high trajectory is assumed to start earlier in 2025, and there's also much more rapid growth to about fifty dollars per ton real in 2041, which is equivalent to about eighty dollars a ton in nominal terms.

The next slide -- so, this slide here is showing the planning reserve and some of the technology inputs. So, for determining the appropriate summer peak credit associated with solar and for our storage, we have utilized studies performed by SPP in the 2019 accreditation study.

And the peaks associated with the SPP study are shown by the blue lines and the graphs to the right. And those are used in all but the FOR scenario.

The main take-away is that with low penetration of these technologies the peak credit remains high, but as more and more capacity is installed across SPP the credit for both technologies declines. And this is not strictly a decision that PSO can control. So, a lot of it depends on what all of the other participants are doing, as well.

But we know that there could be some uncertainty for how the peak credit would evolve over time, so part of the focus on resiliency case was to evaluate a lower peak credit assumption.

So, we constructed the lower outlook shown by the orange lines on the graphs, and relative to the other cases you would just get less peak credit for the same market-wide installed capacity for either solar or four-hour storage.

And then in addition to the lower peak credit assumptions or the FOR case in that scenario we also do enforce a winter planning reserve margin requirement of twelve percent. And that's the same as summer.

And we note that solar has a lower peak credit in the winter than it does in the summer due to a dual peaking winter load shape in the morning and the late evening.

So, the -- the capacity credit that's used for winter solar was ten percent declining to five percent. And you can see that that's significantly lower than the summer credits, which start at around sixty percent and decline from there.

I think we can move to the next slide. So, this slide here illustrates the cost ranges for the technologies of wind, solar and four-hour storage. And these are the ones that are varying by scenario. We have some additional detail for all the other technologies in the appendix and also in the draft IRP, which has been issued.

But I think what I'll focus on here is the -- first the base trajectory, which is shown by the blue lines as used in the reference scenario, the FOR scenario and the NCR scenario.

And these are based on EIA 2021 projection, and also they utilize the NREL moderate cost decline curve to estimate how the capital costs will evolve over time.

And then for the CETA and ECR cases I have outlined that both of those have more rapid technology cost declines. And so, what we used to develop those was the NREL advanced technology decline curves, and that generates the orange lines that are shown on each graph.

And those are really stress testing what would happen if there are more rapid advancements or cheaper technology costs in the future.

And the last point I'll make is that the cost assumptions shown here are prior to any tax incentives that the project would be eligible for. So, the final costs that we would model would also take those into account.

This is just kind of an index for the costs prior to any of those incentives. Checking the chat, still no questions, and so we will keep moving.

The -- this slide here sort of wraps up the scenario input section, and we can transition to some of the outputs that we have observed through modeling these five scenarios.

The only point I'll make before we get there is that by combining all these different market inputs in the way that we have, we're producing fundamentally different views of the SPP market for each scenario.

And we think that that is quite valuable because we get fundamentally different resource additions and retirements across each case, and we can study a -- a broad range of how the SPP market itself will evolve over time.

And so, the next few slides we will talk through some of the outputs that actually are used as we move into the modeling of the PSO portfolio.

So, first on this slide here we show the supply mix changes, so on the left-hand side we show the nameplate capacity of installed resources across SPP. And on the right-hand side we're showing the total generation.

The first bar in each graph shows the state of the market in 2021, and then the other bars show how that -- how the market evolves by each scenario in 2041.

So, in terms of nameplate capacity we see that there's much less installed coal across all scenarios. We see about the same amount of gas capacity, but mostly we see large build-outs of wind, solar and storage across SPP.

And in the reference case over the modeling horizon we see about twenty gigawatts of coal retiring, and that's actually replaced with about sixty gigawatts of new wind, solar and storage.

And then in the CETA case where load is actually growing rapidly and renewables are cheaper, we see as much as one hundred gigawatts of new wind, solar and storage installed across SPP. So, that's a quite significant amount.

And then even in the NCR case with no carbon policy and a lower gas price we still see a large build-out of about thirty-five gigawatts of wind, solar and storage. And many of these builds are actually occurring in the near term due to the tax incentives that are in place.

So, moving to the right-hand side of this graph -- sorry, Greg. Back up one. Yeah. I'll just touch on the total generation, as well. So, looking across all scenarios we see more than fifty percent renewable generation in all cases by 2041.

And the reference scenario shows about seventy percent renewable generation by 2041. So, we do see a large evolution away from fossil generation to a lot of renewable generation with firming resources on the back end.

We can move to the next slide now. So, looking at the market prices by scenario, we see all cases with relatively flat prices in the immediate term, the next year or two. We see the reference, CETA and FOR cases that assume the moderate carbon policy.

They have a price jump in 2028 when that policy starts. And you can see that that is a moderate jump in power prices. I think it's about a seven dollar increase from where they were.

On the high end the green lines show the ECR case where carbon comes in in 2025, and that's the -- the high carbon policy. And we see the prices jump significantly due to that policy.

So, on peak the prices go up by about twenty dollars, and off-peak they go up by about eighteen dollars. So, that's quite a big impact to the prevailing price of market power.

And then on the low end the blue lines show the NCR case, which has a mostly flat outlook for market prices since there is no carbon and it has the lowest natural gas trajectory.

And then in terms of the spread -- so, if we look at the difference between on-peak prices and off-peak prices in recent history we have observed an eight to twelve dollar spread between on-peak and off-peak, depending on the season and some of the other market forces.

But I think what we're seeing across all cases is a convergence between peak and off-peak, and that's largely due to the solar coming in and influencing the peak price.

So, in all scenario forecasts we see about an average of a four dollar spread by 2041. So, we see that peak/off-peak spread actually cut in half or even lower across all cases, which is quite interesting.

And the last point I'll make here is that this is just -- these are just the annual price summaries, but what we actually do is take the hourly market prices that we get from our modeling, and we carry them forward to the portfolio modeling section, and they are used as inputs to evaluate the PSO portfolio.

So, this is -- these are the market prices directly that we use and -- yeah, I think that is the main point with the prices. So, we can move to the last slide here.

This is the last output for the scenarios. So, what we're showing here is actually how the solar and storage capacity credit evolves over time. A few slides ago I -- I talked about the assumption for how much would get -- how much credit would be associated with different build-outs across SPP, and this is what we see when we actually evaluate those build-outs.

So, just as we discussed, there is -- in the CETA case we see the yellow lines. There's a much more rapid build-out of solar and storage in those cases, and as a result we see the capacity credit fall much more rapidly.

So, you can see that in some cases where the solar credit might still be close to sixty percent, we're seeing in that case solar credited closer to forty percent. And that's reflective of all of the market participants.

So, if PSO were to add solar in that case, you know, you -- you might end up with less credit than you would initially anticipate it, or you would get if other market conditions were at play.

So, this is really how we're evaluating the uncertainty of, you know, what a solar or battery storage resource will count as in the future.

Alternatively, with the blue lines we see the no carbon regulation case have higher peak credits due to less penetration of renewables. And then we see the other three cases being somewhere in the middle.

And I think the last point I'll make here is that this again is carried over into the portfolio modeling section. So, when we evaluate the PSO portfolio, we will interpret resource decisions with these appropriate credit amounts, and then the portfolios will have to plan with that in mind.

So, it does give us a -- a bit broader analysis and -- and more confidence with the new resource decisions evaluating these ranges as opposed to just one set assumption or what the credit will be in the future.

I think this brings us to the end of the scenario modeling section, so I guess I want to take a pause and turn it back to Greg to continue the presentation.

MR. SOLLER: Yeah. Thank you, Jonathan. We -- we don't have any messages in our chat for additional questions at this point, and we were planning to take a break at this point in our presentation to really put a demarcation separation between the main parts of our -- our discussion.

And I'd like to go forward with maybe a ten-minute break and -- and maybe ask everybody to return at the top of the hour.

When we get back we will have more discussion continuing, but it will really be now taking with the foundation that we just tried to walk everybody through in the -- the development of -- of the front end of the IRP process to now we will go into the back end of the IRP process as we start to do the portfolio modeling and start seeing some of the outputs of what the model has -- has led us to assess and analyze in order to get to a Preferred Plan.

So, we look forward to showing that and sharing that with you in a few minutes. But for now let's take a small break and return at the top of the hour. So, thanks, everyone.

(Recess taken.)

MR. SOLLER: Well, welcome back, everybody. I hope you were able to reconnect and start in the second half of our presentation.

As I mentioned, we will get into a more deep discussion around the actual portfolio development that came from the front end work that -- to develop the criteria and the inputs, critical inputs, key inputs for the IRP effort that we did this year.

I would like to introduce Mr. Robert Kaineg with Charles River Associates to lead us through the -- the effort as we went through to develop the various portfolios and test those and run those through the model to see what the analysis led us to.

And at this point I'll turn it over to Robert and just keep reminding we appreciate any questions that you might have throughout this discussion. And if you have an opportunity to send those through the chat, we'd be glad to receive those and pause to make sure we can keep everybody's questions answered.

So, thank you. Robert, I'll turn it over to you and let you start this -- this part of the presentation.

MR. KAINGER: Okay. Thank you very much, Greg. I hope everyone can hear me okay.

So, I'll start this section just describing how PSO developed the candidate portfolios for the 2021 Integrated Resource Plan. Then we'll talk a little bit about what was in the Preferred Plan and the other portfolios that were considered.

And once that is done, we will talk about how those portfolios were tested and evaluated and then how that evaluation is represented on the scorecard.

So, you'll see here on the left-hand side of this slide the five scenarios that Jonathan just spoke to in the prior section.

So, the approach that PSO took as part of the IRP was to select an optimal portfolio in each five of these scenarios, each one of the five scenarios. And those optimal portfolios essentially were a mix of demand and supply side resources that could be used to meet future customer needs.

On the demand side we considered energy efficiency, demand response, distributed generation, as well as conservation voltage reduction.

On the supply side we considered a host of new generating technologies, including wind and solar PV, gas-fired units, different configurations of storage, as well as advanced low carbon technologies like carbon capture retrofits and hydrogen-fired -- dedicated hydrogen-fired CTs, as well as advanced nuclear.

So, what we did was use Aurora to select a least cost portfolio -- when we say optimized, we really mean these costs -- in each of these scenarios, given this menu of options, both demand and supply side. And we did that for all five scenarios.

So what I'll do first is talk a little bit on the next slide about where we landed on the Preferred Plan and what's included in that plan, and then I will go through the other scenarios that were selected or considered at least in the 2021 IRP.

So, on this slide we see a little more detail of the slides that Jim shared earlier at the front of the presentation. Again it showed the firm capacity need in the black line there for the PSO portfolio going out through 2031 and that how that firm summer capacity need is being met through existing resources.

And you can see that the existing portfolio of gas generation and gas contracts does provide a lot of capacity going out into the next ten years.

And then you can see how the units that were selected or the resources, I should say, that were selected as part of the Preferred Plan support that.

On the bottom you can see that the hashed black line -- those represent the demand side resources. So, that's a combination of all the different elements that I described on the prior slide, including energy efficiency, DG, CVR and GR.

On then on the top you can see the hashed yellow and green bars. These show the new wind and new solar that were added into the portfolio over time and how they contribute to meeting the summer peak requirement.

I think you'll note when you look at this slide that there wasn't a selection of new storage or new gas-fired units as part of the Preferred Plan. I mean, these units were not optimal from the portfolio modeling perspective. We preferred to fill that gap with additions of wind and solar.

Moving to the next slide, please. So, where the prior slide gave an overview from a firm capacity perspective, this slide is showing us a lot of the same information about looking at a nameplate capacity perspective.

So, starting on the right-hand side we can see the demand side resources that were selected as part of the PSO Preferred Plan. It included some amount of demand response, selections of energy efficiency bundle, deployment of distributed generation and then incremental CVR.

And all of those together provide quite a bit of capacity portfolio. You'll notice on the right-hand side we have a total plus twelve percent column. And that's because these resources are located at the load. They're located at the customer site.

And so, as a result they -- they also obviate the need for that additional planning reserve margin that you would have on top of a generated resource, so you are actually getting a little more bang for your buck with the demand side addition.

On the utility scale side, which is the left-hand side of the chart, you can see that there were nine hundred megawatts of solar added in 2024, and keeping in mind this is the end of 2024, so really available and in service to provide energy to the portfolio in 25 and then another four hundred and fifty megawatts selected in -- in 2025.

Over that same period we see significant wind addition of fourteen hundred megawatts again in twenty-four and twenty-five. And really we see the model selecting these units early in the -- in the period because they are able to get the full benefit or as much benefit as they can from the existing PTC and ITC, the existing PTC and ITC credit.

Out over time there is some additional solar that is added to the portfolio down in the 2030 and 2031 period. This coincides with the roll-off of some of the existing wind PPAs and, of course, the load growth that we expect in the portfolio.

So, go to the next slide. The next slide is going to give us a little more of a flavor of the other portfolios that we considered as part of the 2021 Integrated Resource Plan but that weren't ultimately selected as the Preferred Plan.

So, just as a -- as a note here, if you go across the top of this table you'll see that these mostly correspond to the scenarios that we discussed in the prior section. So, we have a reference or a modified reference portfolio. We have the CETA portfolio, an ECR portfolio and NCR portfolio.

But you'll notice that there is no FOR portfolio, or focus on resiliency portfolio. And that's because the focus on resiliency case had very similar inputs as in the reference case.

So, we have the same natural gas price, same load forecast, same carbon pressure. The main difference between the FOR case and the reference case was -- was first that we -- we required a twelve percent planning reserve margin above winter peak in the same way that SPP requires a twelve percent planning reserve margin above summer peak.

And we also de-rated particularly solar unit more in that season -- more in the winter season to reflect the fact that they tend not to produce as much energy during the early morning when we tend to see peaks in the winter.

But even despite these changes the -- just because the summer peak demand in the PSO territory is materially higher than the winter peak demand we actually end up with the same selection of resources that we saw in the reference case.

So, for that reason PSO determined that it would be better to -- instead of having a duplicate portfolio to test additional gas exposure. So, we created what we're calling the CC portfolio.

And in that case what we did was to asssume that a new combined cycle unit five hundred and fifty megawatts would be added to the portfolio in 2025 under reference case conditions and then optimized around that, so essentially select a natural gas combined cycle and then allow them to take everything else and find the least cost solution.

We also made a modified reference portfolio. So, in our initial modeling we included a four hundred and fifty megawatt annual limit on new solar addition in the reference case modeling.

And the result of this was that there was a capacity gap that opened up in the PSO portfolio following the roll-off of the green country PPA. But the model was not finding that it was optimal to fill that gap with a permanent resource. Instead it was opting to allow short-term purchases to fill that gap for just one year.

Because we felt that that was not a tenable solution going forward, we made a modified reference portfolio where some of the solar which was built in 2027 was accelerated to meet that capacity gap that was opening up in 2025 and fill that. But, otherwise, it is identical to the optimized solution in the reference scenario.

So, what we're looking at in the -- in the circles here or in the pie chart are the generation mix in 2031 across the portfolio. So, this is just a total amount of generation from all of PSO's existing and new additional units, as well as contracts.

So, you can see that generally wind was selected across all of our portfolios. A significant amount of wind is added to the portfolio really under all the different marketing conditions that we looked at.

But you'll see that the amount of solar varies quite a bit between portfolios, and this really has to do with the -- a lot to do with the amount of capacity credit which is awarded to solar, which again is a function of how the broader market solves -- how the broader SPP market solves in each of our scenarios, as Jonathan explained in the prior section.

So under scenarios where there was more solar added SPP wide than the amount of capacity value that solar provides to the PSO portfolio is lower and vice-versa.

So -- so, this shows that from a total megawatt hour perspective, but I think the next slide is very useful, as well, where we can see it from a nameplate capacity perspective and how the different portfolios selected different mixes of technologies.

MR. SOLLER: Hey, Robert, let me do a quick check. Susie shared with me on a break, so for the court reporter. So, Susie is -- is this a little better for you?

(Discussion off the record.)

MR. SOLLER: Thank you. We'll get you to the next slide.

MR. KAINEG: Greg, can we advance? So, where the prior slide showed the selections across the different candidate portfolios from a generation perspective, on this slide we're really focused on how those selections were different from a capacity perspective. And also you can see how the timing of additions was different across the different portfolios.

So, starting in the upper left-hand corner we can see how the solar PV additions varied across the different candidate portfolios that were studied as part of the 2021 IRP.

And as you can see, under most conditions the model selected about as much solar as we would allow it subject to that four hundred and fifty megawatt annual limit that I discussed on the prior slide.

You can also see here in the modified reference case how this portfolio is somewhat unique in allowing to accelerate just a little more solar into the early period to meet that capacity gap that I described before.

I think that the one portfolio that stands out here in my mind is the CC portfolio, which is -- which does not add any additional solar, at least not out until 2027.

And the reason for this is recall that we have added or told the model that there's going to be a new natural gas combined cycle built in 2025 in this case. And as a result there just is not an energy need for the solar in this period. And so, it is delayed, the construction.

Moving down to the cumulative gas addition, you'll actually notice that new gas resources are only added in two of the five or six portfolios that we evaluated.

The first is the CC portfolio. And recall that that was actually a non-economic addition that we added to the model to test further exposure to natural gas to see what it would do to total portfolio costs.

But under the CETA portfolio, which is the clean energy technology advancement case, the model actually does pick additional gas early in the -- early in the modeling period.

And the reason for this is that in the CETA portfolio we're looking at a world with faster overall load growth than in the other portfolios or scenarios.

As a result, the model is anticipating the need for the future firm capacity and building additional gas capacity early, even though we are stressing clean energy technology in this case.

If we go to the upper right-hand corner and evaluate wind, I think that's the -- you see a similar outcome where many of the portfolios are building about as much as they can get in the first two or three years when the full PTC or the high value PTC is available.

One of the interesting outliers here is actually the CETA portfolio where we see the delay in wind by one or two years. And now this is really a function of that PTC extension that Jonathan was talking about.

So, under this portfolio and scenario the tax credits don't expire as quickly, and as a result the model has more time to essentially capture the full value of the tax credit. And as a result it pushes back a little bit more of the wind addition.

Finally, we will go down to the bottom right-hand corner and look at the cumulative solar -- excuse me -- storage addition. My apologies. Four-hour storage addition.

And in this case you can see that storage is not -- was not a preferred strategy really for any of our portfolios. There is quite a bit added in the CETA portfolio, particularly towards the end of the modeling period.

But the rest of our portfolios really did not select -- did not select storage as a preferred capacity resource. You'll note some small amount added in the no carbon regulation case.

Moving onto the next slide -- so, in the same way that we compared the supply side or utility scale addition in the prior slide, this slide is evaluating how the demand side selection, so that is the energy efficiency, CVR, DER, et cetera, were selected and -- by scenario or portfolio, I should say.

So, what we will note here is that the selection of these resources tends to be highly dependent on the broader energy prices in the SPP market.

So, under the higher cost cases generally such as the ECR portfolio, we tend to see more of these demand side additions. Conversely, under the NCR case, which has low SPP-wide market prices, we see a lot fewer demand side additions than we did in the other portfolios.

Now, outside of these extremes the rest of our candidate portfolios really came in a very tight band of demand side resources with a little bit of difference in the -- in the timing of the selection of energy efficiency bundles.

So, in some cases the timing might be delayed by one or two years, but overall the selection was quite similar across the portfolios.

Moving on, so just a -- take a few take-aways from those slides, I know there's a lot of information that we have condensed into really just a few pictures.

The natural gas combined cycle wasn't selected as the least cost or optimal solution in any of our market scenarios, even those featuring low natural gas prices and zero CO2 prices.

So, just to reiterate, even our NCR scenario the model is not selecting a new base load gas resource as an optimal least cost solution.

The next thing that we will note is that PSO was really able to satisfy peak requirements really without adding too much more gas or storage in most of our portfolios.

And that's because there's just a significant amount of existing gas and existing gas contracts in the portfolio that persist after Northeastern 3 is retired that provide almost seventy percent of the firm capacity of that unit over the period.

Again, the CETA portfolio was the outlier here, but that really has to do with the accelerated load growth in that portfolio.

As I mentioned previously, the level of solar addition is highly dependent on the capacity value provided by these units. So, we do tend to see that the scenarios that resulted in higher solar ELCCs then in turn resulted in portfolios where more solar was selected.

And this is really because solar and wind in many ways are -- are both competing resources in this analysis. And generally wind provides more energy than solar, but less capacity.

But when that capacity -- relative capacity benefits between the wind and the solar resources that's produced, then the -- the additional energy from the wind becomes more attractive, and as a result we see more prevalence of wind in portfolios where -- where solar capacity is lower.

Finally, as I mentioned previously, we did offer the model a large number of advanced technologies, including carbon capture and storage, dedicated hydrogen-fired combustion turbins, nuclear unit and then long duration storage options, such as flow batteries.

Under the current assumptions that we have for those technologies, the current costs of performance assumptions, as well as the markets that we evaluated them in, none of these technologies were selected for the PSO portfolio.

But, obviously, both sides of that equation could change in the future where either the information about the technology changes such that they become less expensive or perform better, or, alternatively, market conditions could change to be more supportive.

So, we certainly don't want to close the door on the idea that these could be selected in the future, but for the purpose of the 2021 IRP none of these advanced technologies were selected.

So, with that, I will just stop for a moment and see, Greg, if there are any questions before I get into how the portfolios were tested and evaluated.

MR. SOLLER: Robert, at this time we don't have any questions in the chat. Nothing is coming through to see. So, I think I'll advance our slides for us, and we will get into some of the actual analysis that -- that was done, so --

MR. KAINEG: Great. Thank you, Greg.

So, on this slide I just want to take it to the next step. So, the last section that we just went through really talked about how the candidate portfolios were constructed and gave a flavor of what was in each of these candidate portfolios that we evaluated.

So, in this section we're going to talk about how we stress tested or evaluated each of those candidate portfolios to determine how they performed against the different objectives that PSO defined at the front of the process, the four objectives that Jim laid out at the front of his presentation.

So, we really did this through two different methods. The first was what we'll call scenario analysis. And this is where we would run each of the portfolios that were created under every scenario, every market scenario that we looked at, even the ones where they weren't considered optimal.

And this really allows you to test what happens if you make an investment decision and then fundamental market conditions change. So, you sort of locked in a plan, and then the market doesn't turn out the way you expected at a fundamental level.

And I think that's a -- a pretty straightforward concept, so basically you can imagine each portfolio that I just described dispatched in every scenario, and we have the outputs from that that help populate the scorecard.

The other step that we took is what we call stochastic analysis or uncertainty analysis where we actually test the portfolios under volatile inputs, distributions of input, that combine random draws of natural gas, power prices, solar output and wind output to see how these portfolios would perform under short-term high-impact market events like extreme weather and also how they would perform when exposed to sort of daily market volatility and -- and the sort of price swings that we sometimes see in the commodity market, as well as unit outages. So, that's the stochastic analysis.

So, we go to the next slide, and I'm going to explain just a few -- few slides, explaining the stochastic analysis because it is, I think, a little bit different than what -- what many of us might be familiar with.

So, when we perform the stochastic analysis we essentially run each portfolio under two hundred and fifty random combinations of market conditions and compare how the costs in those portfolios is higher under -- under bad or adverse market conditions than under normal or expected market conditions.

So, the right-hand side of the slide really illustrates that. So, you can see here at least notionally how if you were to develop these two hundred and fifty iterations you would end up with a band of -- of expected costs under that portfolio that represents the -- the distance between the top and the bottom of the bar here.

And what we're really looking at when we're evaluating the risk of each portfolio is how much more it would cost a customer under the ninety-fifth percentile outcome, the most expensive ninety-fifth percentile of outcome, versus the fiftieth percentile or expected median outcome.

And the four variables as I alluded to in the prior slide that we projected -- that we used to create these two hundred and fifty iterations were first hourly power prices in SPP, natural gas prices, again at the hourly basis, wind and solar output, again at the hourly basis, so essentially how could these random combinations of power prices, natural gas prices, wind and solar outputs combined to lead to volatile market conditions.

And just as a note, we do account for the correlation between power prices and natural gas prices as part of this step. So, those two variables are -- are highly correlated, and that's accounted for in our analysis.

So, I know that that description is somewhat abstract, so on the next two slides I just want to provide a visual example of what we're talking about here when we're talking about performing stochastic analysis.

So, on this first slide, slide thirty-five, we're looking at how the deterministic forecast, which is the forecast that was used in the scenario modeling, compares to the stochastic iteration.

And here we're just looking at ten of the two hundred and fifty random iterations in gray, and you can see that the stochastic iterations provide a -- both a wider band of prices, so you can see on the left-hand side, for example, gas prices rising over five dollars in MMBtu and on the right-hand side power prices rising over one hundred dollars MMbtu and then going negative.

So, we're getting a wider band of overall prices than the -- than the scenarios would return. And we're also able to capture some of those market spikes and volatility that we know can expose rate-payers to cost, just like the event that we saw back in February of 2021 with the cold snap in ERCOT and SPP.

So, the next slide is a similar presentation, but we're just looking at the other stochastic variables that were included as part of the analysis. On the top side we have got wind in both winter and summer.

And, again, the thick -- thicker line represents sort of an average view or how the output of these units might look when you're viewing it from a scenario or deterministic perspective so you can see how when you look at it from sort of a stochastic view that there's a lot of variation in the hour-to-hour output of each unit that depends on wind speed, weather and other factors.

And to populate that, to generate these iterations, we relied on NREL's wind tool kit and national solar resource database. This is actual weather data that was used to simulate how these units would perform.

And the bottom part of the slide really shows the same thing, but for solar output. So, you can see again how the central tendency is -- is relatively stable, but from hour to hour there can be a lot of variation in the output of these units.

And because the PSO portfolios tended to select a lot of new wind and new solar, as we discussed in the -- the prior section, we felt that it was very important and PSO felt that it was very important to evaluate this -- this risk explicitly about the output of these -- these renewable units.

So, with that I have described the -- how the portfolios were evaluated or how they were tested. The results of that testing ultimately end up on the scorecard.

Now, I know the scorecard has a lot of elements on it, and -- and for right now you don't need to read each and every one of these because I'm actually going to go through each one of the four objectives, define the indicators that were used and then describe how the portfolios compared across those indicators.

And once that's done, then we are going to bring it all the way to back to a populated scorecard that allows you then to look across objectives and how the portfolios compared.

But the purpose of this slide I think is really two-fold. First it just illustrates how the four objectives that we defined at the front of the process -- customer affordability, rate stability, maintaining reliability and having a positive local impact and sustainability -- were -- were reflected in these indicators.

So, short-term and long-term costs, scenario resilience and all the other factors that occur on the scorecard.

Also, just a little bit of a language primer, because throughout the next part of the presentation I'll be discussing the performance indicators, which are the categories that we measured and then the metrics which are the -- essentially the numbers that are used to show the performance under each category or indicator.

So, with that, we will move to customer affordability. So, the customer affordability indicators test how the portfolios are expected to cost or what -- what the expected costs to customers of each portfolio is under reference case conditions.

So, if you assume the expected outcome in the broader SPP market, how much is this portfolio likely to cost your customers. When we look at this over two different time scales, the first is a five-year compound annual growth rate, or CAGR, and that covers the expected growth and system costs over the first five years of the forecast which cover 2022 through 2027.

In general a lower number is better. That indicates that there's less growth in the costs to serve customers and that overall rate growth is likely to be lower under this portfolio under expected conditions.

We also take a longer view on these -- on this metric, as well. So, we also look at the costs of the portfolios over ten years. And for this indicator the metric is the net present value revenue requirement, essentially the total present cost of serving customer load over that next ten years.

And that cost includes all of the costs associated with supplying power to PSO's customers. So, that's the ongoing costs of existing -- excuse me -- the operating costs of existing units and then the capital costs and operating costs of the new units that are added to the portfolio.

What this number does not include would be the sort of sunk capital associated with the existing PSO unit. So, with that -- oh, sorry. Before I move on -- and again a lower number is better.

So, a lower number indicates that there's essentially less cost on a present value basis to meet customer requirements over the next ten years.

So we will start by looking at the short-term output. So, if you look in the left-hand column here you can see that we have five portfolios that all ended up within twenty cents of each other -- or twenty point -- sorry -- let me rephrase that -- point two percent of each other over the first five years. So, we call this the cluster of lower cost portfolios.

And the modified reference portfolio, which is the Preferred Plan, was among them -- in this group. So, all very similar load growth across -- excuse me -- similar rate growth across the reference, CC, NCR and modified reference portfolios.

We did have two outliers that were higher cost in this case. The first was the ECR portfolio, which was the portfolio that was constructed under the enhanced carbon regulation scenario and then the CETA portfolio, which was again the portfolio constructed under the CETA scenario.

Really, the CETA portfolio stands out here as being more than double the costs of any of the other portfolios we considered. And really this is a function of the additional resource that's added in this case and also the fact that the PTC extension that was assumed in the CETA scenario does not carry over to the reference scenario when we're looking at the costs to serve customers under reference or expected conditions.

If we look to the right-hand side here, we can see that over the longer term these results are largely consistent where we have a lower cost cluster of portfolios of which the reference and modified reference case are the lowest, followed by the no carbon regulation, enhanced carbon regulation and CC portfolios.

CETA again is the highest cost, which is expected, given that we have got simply more resources added in this portfolio than in the other portfolios that we considered.

So, moving onto customer affordability, so the next metric -- excuse me -- objective that I will cover is rate stability.

Under rate stability we have three indicators. The first is scenario resilience, which looks at the range of portfolio costs over ten years when you run the portfolio under every market scenario, so -- but differently if you look at, for example, the reference case under all five scenarios, what is the the difference between the lowest cost return and the highest cost return. That's what that resilience metric tells you.

Now, generally a lower number is better here, indicating that there's less range in the -- in the -- excuse me. There's lower range in costs across many different market conditions.

But as we will see when we get into the details of -- of this analysis, that can also be a little bit deceptive because you can have a portfolio which is, for example, higher costs in all cases, but the range of those costs is somewhat lower, which, in fact, is what we found in the PSO analysis.

The next metric that we used was the cost risk metric. This was the metric that was informed by the stochastic analysis that I described in the prior section.

So, it compares the difference between the expected costs of the portfolio and the costs of the portfolio under the ninety-fifth percentile of high costs in both -- in 2031.

And so, this really shows the amount of increase in customer costs that could occur under volatile market conditions or extreme weather events. And again, generally a lower number is better. You don't want your costs to customers to increase a lot when exposed to market volatility.

The last metric that we use is a metric we're calling market exposure, which looks at how the net sales of the portfolio balance in the summer and winter season.

So, essentially if you look over the -- the month June, July, August, which covers the summer season for this metric, and you add up all of the sales in the portfolio and subtract from that all the purchases from the portfolio from the broader market, you end up with a net sale. So, that's what we're looking at.

And then we do the same thing in winter, which in this metric is covering December, January, February. So, generally closer to zero indicates less reliance on the market to meet customer needs, but doesn't necessarily indicate a better portfolio because the level of market exposure I think is a matter of selection or -- or really a matter of preference for PSO management.

So, there can be benefit, for example, to having portfolios that sell back to the market if they can provide cost benefits for your customers. So, we will see that when we get to the -- to the details on the next block.

So, starting with scenario resilience, you'll see that the NCR, reference, modified reference and ECR portfolios all score very similarly by this metric.

So, they have a range of between four hundred and five hundred million dollars across those scenarios, where the CC portfolio, I think, was a -- was a bit surprising -- had the lowest range.

So, even though this was the portfolio that included the -- the gas unit that I discussed when we were talking about the construction, the range of outputs was actually somewhat lower in this portfolio than in some of the other portfolios.

Now, as you'll see in the subsequent slide, which we're not going to get to yet, that result is misleading because it -- that really was the case because the CC portfolio simply wasn't able to save customers money in conditions where the other portfolios were able to.

So, they are essentially the -- the lower bound of this portfolio was higher than some of the other portfolios we considered. As a result the -- the range was somewhat smaller.

The -- the highest cost range that we saw here was the CETA portfolio. And really this again is to be expected, given that the portfolio was constructed under a high load forecast, and we're running it under every scenario, including scenarios with the moderate and low load outlook.

Then when you have a unit which is -- excuse me -- a portfolio which has been optimized for celebrated load growth and you run that portfolio, the low load growth scenario tends not to perform well.

On the cost risk metric we see a very similar range of cost risks actually across the portfolios outside of CETA.

So, there really isn't a material difference between the level of cost risk that we're exposing customers to, whether we're relying heavily on new renewable generation or gas-fired generation to meet customer needs.

So, you can see that the CC portfolio scores very similarly to the reference and modified reference case, even though the construction of those portfolios is quite different.

Again, we see the CETA portfolio having the greatest risk by this metric. And that's again because this portfolio relies more on market sales and purchases, as you can see on the -- excuse me -- market sales, as you can see in the right-most column here.

And so, when -- when the power prices and other factors fluctuate, then this -- this portfolio can be more exposed to -- to, I guess, unfavorable prices and unfavorable market conditions.

Finally, if we look at the market exposure metric to the right-hand side, we can see that most of the portfolios are -- are basically meeting or very close to meeting customer requirements in summer or matching customer requirements in summer within three percent of the energy sales and summary, there being plus or minus depending on whether you are looking at the NCR portfolio or a few of the other portfolios.

But the -- the CETA portfolio is the outlier here, really relying more in summer on market sales to balance customer loads, which I think is why we see, for example, that cost risk metric that I just described, I'm seeing it a bit broader for this portfolio.

In winter all the portfolios are long with the modified and reference portfolio being very similar to the other cases and the -- the CETA portfolio being the longest for the reasons I have already described as just more generation built in that portfolio.

Moving on, so as I mentioned before, the outcome of the CC portfolio in the scenario resilience metric was a bit of a -- a head scratcher for us when we first were looking at the results.

And so, what this -- what this does is try to shed a little light on what we're seeing there and why the range of the CC portfolio appears to be, you know, quite a bit lower than what we saw in the Preferred Plan.

So, just to orient you on this slide, on the left-hand side what we're seeing is each line represents one of the portfolios that we ran in our IRP analysis. So, the black line is the reference portfolio, and the orange dashed line is the Preferred Plan. The yellow line is the CETA portfolio, and the gray line is the CC portfolio and so on.

And then if you look at the -- along the bottom there we have the scenarios listed, so you can kind of imagine each of these columns is comparing what the levelized cost of energy was, levelized rate, across all the portfolios in each scenario. So, basically it's comparing the costs across this scenar- -- portfolio in each scenario.

So, there's really two things that I think jump off the chart for me that I would like to share with you or discuss with this group.

The first is that just if you look at the position of the Preferred Plan on the chart you can see that it is the lowest or near lowest cost in every scenario that we considered.

So, there really weren't any scenarios where we felt that this portfolio or -- or PSO felt that this portfolio was exposing customers relative to the other options that we considered.

And the second is the CC portfolio, which tended to score somewhat better by the scenario resilience metric, really did so because it was unable to capture some of those cost savings for customers that I described.

So, the only scenario actually where the CC portfolio was less pre- -- was less costly than the Preferred Plan was in the no carbon regulation case that combines zero CO2 price and low natural gas prices.

But even under those conditions the Preferred Plan is very competitive with the CC portfolio. I mean, the difference is very small, as you can see here on this chart.

So, I think this really speaks to the resilience of the Preferred Plan and -- and how PSO sort of -- one of the -- one of the factors that led PSO to reach a decision to the proceed with the portfolio.

Moving onto the next. So, the next objective that we -- that was included as part of the 2021 IRP is maintaining reliability, and there were three different indicators that we used to compare the -- a candidate plan across this objective.

The first was looking at the planning reserves in each of the seasons across every portfolio and every scenario. So, essentially it's an average of how the -- how well the summer and winter peak requirements are covered under a wide range of market conditions.

And instead of looking at a single year because the selection of one unit can make -- can make a very big difference on this if you only look at it one year, for example, just 2031 or just 2027, we averaged this over the forecast period.

So, you get a sense of over the longer term how this portfolio is providing firm -- the firm energy needed to meet peak customer requirements in winter and in summer.

Generally a higher number is better here, indicating that you've got more reserves on hand to meet peak requirement. But you -- there also could be too much of a good thing where if you are well over the peak requirement you -- you just might have excess capacity that has little value in the broader market.

So, while a higher number is generally better, you know, you want to make sure -- you don't necessarily want to be so long that -- that you -- in a position of -- the more generation your customers need.

The next metric that we looked at or indicator that we looked at is operational flexibility. And this indicator compared the total amount on a megawatt basis of dispatchable generation in the portfolio, which includes coal, natural gas combined cycle, natural gas combustion turbin, storage and other technologies that could be ramped up or down.

And we also compared the -- the number of units, so in addition to the -- the total megawatts in each portfolio we just have the number of dispatchable units, which could be an indicator of your -- of your risk to outages at that specific unit -- outages of that specific unit in your portfolio.

Generally a higher number is better here, indicating that you have more dispatchable resources available to follow load or react to market conditions. And having a greater number of -- of generators in the portfolio leads to a broader diversity and a lower risk of -- sort of an individual unit causing problems to your system.

(Clarification.)

MR. KAINEG: I was just saying in general a higher number is better because it indicates that you've got less reliance on any single unit to provide the firm capacity that you need.

So, if you have more -- a higher number of dispatchable units, then you've got less risk associated with the outages in any one unit.

Finally, the last metric or indicator that we evaluated here was the resource diversity metric. This looks at the proportion of total generation that is provided in each portfolio by each technology type, so natural gas, wind, solar, et cetera.

In general a lower -- a less concentrated portfolio is better because it means that you've got less reliance on a single technology and you are less exposed if the conditions for that technology become unfavorable.

So, an example would be like a spike in gas prices or a day with very little solar output. This would be an example where concentration in your portfolio can expose your customers to risk, and a less exposed -- a less concentrated portfolio is generally better.

Moving on, so when we look at the planning reserve metric on the left -- left column here, we see that the Preferred Plan puts PSO in a good position to meet its summer requirements throughout the forecast period averaging about thirteen percent reserve margin in summer.

But it comes out just a little bit better than the reference portfolio, even though these portfolios are very similar because that solar is accelerated from 2027 to 2025. So, because there's a duration associated with this metric it scores just a little better in summer.

You can see that both the ECR and NCR portfolios potentially exposed customers to capacity shortfalls in the summer season. This really has to do with the difference in the -- the units that were selected in each of these portfolios and then also the interplay between the capacity credit that was awarded to the solar capacity in these portfolios when they were constructed versus when they were run in -- in other scenarios where -- where maybe the capacity credit for solar can be a bit lower.

The CETA portfolio actually scores very well here in the summer having twenty-three percent planning reserve margins relative to summer peak. But, again, we discussed maybe having too much of a good thing where you are -- you're really maybe having more resources than your customers really need and exposing them to higher costs to cov- -- to cover more summer peak requirement than you have.

From a winter perspective, as I mentioned when I was describing the construction of the CC portfolio, the -- the peak requirement in winter is just materially lower for PSO than the summer requirement.

And as a result, all of these portfolios tend to be quite long in winter.

So, there really wasn't any -- any portfolio which appears to be particularly risky in winter, and the reference and modified reference portfolio are very middle of the pack by this metric.

From an operational flexibility perspective, which is the middle column here, we see that most of the portfolios are -- are very similar with the stand-outs being the CC and CETA portfolios.

I think it is sensible that the CC portfolio has a little more operational flexibility than some of the other portfolios that we considered because we do add that natural gas combined cycle in 2025, which you can see they are reflected in the -- in the megawatt metric, roughly being five hundred and fifty megawatts more than we see in the other -- other portfolios.

And again in CETA this was a -- this was a portfolio optimized under a high load outlook, and as a result there's simply more resource built, including dispatchable resources. So, it has the greatest amount of megawatts.

And then the larger number of units on the right-hand side is really a function of that storage that gets added towards the end of the -- the -- the forecast period. So, those units -- there -- there tends to be a -- they are smaller in size so you get more of them, and you end up with many more dispatchable units in your portfolio.

From a resource gener- -- excuse me -- resource diversity perspective, which are the pie charts on the right-hand side, we see that the portfolios were quite similar in the sense that they almost all rely on mostly wind generation to meet energy needs. There is a -- a difference in proportion, certainly, but every single one of them is over fifty percent wind generation by 2031.

Now, as I mentioned before, the -- the proportion of solar varies somewhat by case, depending on, you know, the cost assumptions that were used for those units, as well as the solar capacity value that was awarded.

And there really wasn't a major difference in the thermal output across the cases, with the exception of the CC portfolio, which does have more gas exposure than the other cases, owing to the addition of that combined cycle in 2025.

And then the last objective that we will discuss today is the local impact and sustainability objective.

Under the fifth objective we have two performance indicators. The first is the total amount of nameplate megawatts, as well as the total amount of capital expenditure inside the PSO service territory by 2031, so essentially how much PSO is investing in the service territory from both a dollar and a megawatt perspective over the next ten years.

Generally, a higher number is better, indicating more opportunities for customer side of resources and more local spending by PSO.

On the CO2 emission indicator we are comparing the 2031 emissions to the two thousand base line emissions and calculating the percent reduced. So, a higher number is better, indicating that you have reduced your emissions more relative to that two thousand base line -- two thousand emissions base line.

So, when we look at the outcomes on -- across these indicators on the following slides we see that the modified reference portfolio is among the best scores from a local impact perspective.

In terms of megawatts installed, the only portfolio which meets it is the CETA portfolio, but again we have already seen how this portfolio can be higher cost to customers and expose customers to more risk because you have got more units constructed.

From a -- from a dollar's perspective it is also among the best outside again of the CETA portfolio which simply builds more resources, and as a result you have more investment inside the service territory.

When you look at the level of CO_2 emissions, many of these portfolios score similarly by this metric with ninety-five percent reductions relative to the two thousand base line across the -- really all portfolios except for the CC portfolio, which has -- which has more gas exposure because of that natural gas combined cycle.

So, really, all of these portfolios put PSO on target to achieve the 2030 aspirations which have been defined by AEP, as well as all portfolios outside the CC portfolio puts PSO on track for that 2050 net zero target again, which has been announced by AEP, so really the portfolio scoring very well here by this metric.

So where I've gone through each of these objectives sort of in a vacuum or individually, once you put them on the scorecard it allows you to see not only how they rank within each objective -- how these portfolios rank within each objective, but how it compares across objectives.

And so, this was really the -- the tool that was used to help inform the discussion that PSO had to select the Preferred Plan, and they -- that the plan that has the best balance of meeting these objectives that were set out for the 2021 IRP.

So, with that, Greg, I will turn it back to you to discuss any questions, as well as wrap it up here.

MR. SOLLER: Thank you, Robert, for our stakeholders and really the audience. That's a tremendous amount of information that Robert just went through after the break, hoping it was informative to really summarize the analysis that we have all been working with Charles River and PSO and AEP to get to this Preferred Plan.

And we exposed this at the front end just to give you some insights to what we will be talking to. And I think -- I'll make a couple of comments to the Preferred Plan, and if there is any other questions we're happy to take those.

And then after that I would like to bring Matt Horeled back on to make some closing comments as we -- we wrap up the -- the call today.

But as we went through, there's a tremendous of information and a tremendous amount of analysis that -- that came into the selection of this portfolio as our Preferred Plan.

And -- and what we were reassured by, I think, was we did the optimized portfolio under the reference case, is by and large what this represents. The -- the company found an opportunity and we saw an opportunity that by bringing forward one trunk -- or chunk of -- of some solar that was originally selected in twenty-seven -- by bringing that forward and modifying that reference case in that one situation, it allowed the company to take advantage of the tax credits that are available to us and effectively be able to pass those on to rate-payers.

That is the adjustment we did, and it caused us to call this a modified reference plan. And it is -- really is, in fact, that Preferred Plan to push forward. It still retains the -- a lot of that gas and that peaking dispatchable amount of resources in our portfolio.

It leverages the -- the tax benefits and still meets our obligations to serve the SPP market and our -- and our customers. So, those are my comments, and I'm open to -- if there are any other questions, I appreciate offering those.

I don't see any yet, and -- but I'll give a moment if people want to digest this a little bit. And if not, then I'll bring on Matt Horeled to make some closing comments.

(Pause.)

MR. SOLLER: So, Matt, we don't have any other comments coming in, questions. And so, I think what I'd like to do is give folks, you know, the opportunity to really digest this.

I'll bring Matt Horeled back on, and if you certainly have questions or comments that you want to share with us afterwards, we'd love to hear from you and appreciate the feedback.

And we encourage you to reach out and talk to Fairo Mitchell, and we'll -- we'll get all those assembled and try to get responses back to you.

So, Matt, let me bring you up and see if you want to offer some closing comments to our -- our folks.

MR. HORELED: Greg, I think Montelle Clark had a question.

MR. SOLLER: Certainly.

MR. CLARK: Thank you.

MR. SOLLER: Yeah. Matt -- Montelle, if you would like to come off mute, feel free to, and we'd love to hear from you.

MR. CLARK: Thank you, sir. Can you hear me all right?

MR. SOLLER: Yes, sir. Nope. You're good.

MR. CLARK: Great. Thank you. Just a couple of clarifications, and these are more derived from the report, which I did have a time -- I did have time to go through once, not so much the slides, although I'm sure they correspond.

But one of the -- one of the items you mentioned in the report is the integration -- I'll read the quote.

It says integration of additional transmission connected generation capacity within the SPP zone will likely require significant transmission upgrades.

Is -- is that equally applicable to both wind and solar resources?

MR. SOLLER: I -- I'm not sure how best to answer that. I would suspect so. I -- I --

MR. CLARK: Well, the reason I ask is that, obviously, solar may have different preferable locations or ideal locations, or it might even be more available in eastern Oklahoma, whereas wind tends to be more concentrated in western Oklahoma.

And I'm thinking about congestion curtailment issues there that -- maybe just wondering if solar has any advantages in that regard.

MR. SOLLER: Yeah. And I think, you know, I'll offer a little commentary on it, and maybe if some of my -- my peers want to chime in.

But, you know, from a location -- a specific location, certainly, you know, we really didn't drill into where a solar might be sited, where transmission might ultimately be sited for sure. That's -- that's a much more localized and detailed process.

So, you know, we do have some congestion cost assumptions in -- in our models for that. I know primarily there is some for wind. And I'd have to go back in and be specific about what we have identified in the report on -- on congestion charges possibly for -- for the solar.

MR. CLARK: That's what I was wondering about. Thank you.

MR. SOLLER: Yeah.

MR. CLARK: Give me just a moment here --

MR. SOLLER: Yeah.

MR. CLARK: -- let me look through my notes.

MR. SOLLER: Yeah.

MR. CLARK: So, on Page 24 of the report it states that Exhibit A-8 details the impacts of the approved EE programs included in the load forecast.

I couldn't find an exhibit labeled A-8. I don't know if that's just a -- an oversight or maybe I totally missed it. If I did, I apologize.

There's -- the last exhibit in the report might be what you're referring to there, but I just wanted to make certain. If you could clarify that for me, for -- that Exhibit A-8 is on the --

MR. SOLLER: I appreciate Montelle bringing that. I -- I don't have the report in front of me in detail, but I'll look into it and make sure that the final report -- that, you know, we'll be including the stakeholder presentation and some new -- some additional information.

I'll make sure that we find A-8, and we can reach out to you on that. Again, I apologize.

MR. CLARK: No, that's all right. And -- and if I missed the -- it may have been just in tiny print and I just didn't see it initially, not looking at the right table.

Again, on a clarification issue on Page 123, it says that PSO proposes to add thirteen hundred and fifty megawatts of new solar PV and twenty-eight hundred megawatts of new wind between 2022 and 2031.

And I -- that confused me a little bit because I think you've had a higher number for -- by 2031, so I wondered if maybe that -- that's supposed to say between 2022 and 2025 or -- or something.

MR. SOLLER: Yeah.

MR. CLARK: Maybe he's got a slide that -- that shows it.

MR. SOLLER: I think this would --

MR. CLARK: There he shows it --

MR. SOLLER: Yes.

MR. CLARK: Yeah.

MR. SOLLER: This would be what's in the Preferred Plan in terms of new resource additions. So, I think the -- the -- there really wasn- -- I would go with this, what's on here, and I think I can go back in and look on Page 123, Montelle, to -- to make sure that it does coincide with this, because this is, in fact, what's -- what's in the Preferred Plan --

MR. CLARK: That's -- that's perfect. I -- when I saw that slide I thought that that confirmed, that it's just a date correlation there, twenty-one hundred and twenty-eight hundred by 2031.

Finally, I just wanted to thank you for the pie charts showing your resource mix, your generation mix. Those are helpful to have just as a visual.

This is a lot of dense information, so those pie charts are a really good, quick way to compare the -- the --

MR. SOLLER: Exactly.

MR. CLARK: Those up there that you have on the screen are very helpful for those of us that get challenged by plowing through all this data.

I also appreciated the -- the -- I guess it was a table or something that showed where your total carbon emissions reductions will be versus your two thousand base line.

Given the potential for carbon constraints going forward, it's really helpful for me as a stakeholder for OSM to be able to see where you're -- where you're headed with this. So, thank you for providing both of those.

MR. SOLLER: Certainly. It's a tremendous amount of information densely packed into a two-hour discussion for certain. So, I appreciate the -- the questions you're able to even raise at this point and, you know, even bringing to light some of the -- the points in our report that maybe we need to further review.

So, all very -- very much appreciated and -- and respectfully tremendous amount of information today, so thank you.

MR. CLARK: That's all I have. Thanks for your time -- for your time today.

MR. SOLLER: All right. If there is anyone else, I -- I -- we have a couple minutes, and I'll encourage you if you want -- would like to come off of mute and ask a particular question, we do have a little bit more time from what we allotted, and we -- we could take those now.

(Pause.)

MR. SOLLER: All right. Okay. So, Matt, maybe I'll bring you back onto the platform here and turn it -- turn it over to you to -- to make some final comments then.

MR. HORELED: Great, Greg. Thank you. I'm trying to pull up my -- just to -- just to reiterate again, thank you, everyone, for your time and attention.

I really appreciate you coming to meet with us today, just to walk through our IRP plan and technical conference and just -- just to reiterate why we think our Preferred Plan is -- is the Preferred Plan overall and is aptly named, meaning that it scores the best or near best across all four of -- of our -- our measures on our scorecard.

And -- and I think our -- our team feels also that we really like the scorecard innovative process of looking at evaluating the different options, and the Preferred Plan came out as -- as the best or -- or near best score on -- on all four of those -- those measures.

And as -- as we say here on -- I wanted to close -- make some closing comments on Page 48, you know, it -- it really maintains affordable and stable rates for PSO customers and is expected to maintain reliability across all seasons and create opportunities for local development, all while reducing greenhouse gas emissions.

So, I know Greg and the team really touched on that already, but I thought it was -- that was worth mentioning yet again, our overall -- overall conclusion.

And at this point I -- I'd like to offer -- offer up that if parties have additional questions or concerns, please reach out to Fairo Mitchell on our team, and we will be happy to -- to field any of your requests and address any additional questions you may have and ultimately just want to thank -- thank our team for walking through the presentation.

Appreciate all of our experts being available to discuss this with the stakeholders, and more importantly -- or most importantly I do appreciate all the stakeholders attending, as well, and having this conversation with us at this conference. So, thank you, everyone.

MR. SOLLER: All right. Well, I appreciate it. Thank you, Matt. And with that, we will adjourn for today's call and we'll continue to wrap up our -- our process here. Thanks, everybody, for attending.

* * * * * *

(Whereupon, the above proceedings were adjourned at 11:15 a.m., Tuesday, September 21, 2021.

STATE OF OKLAHOMA   }
                          } ss:
COUNTY OF OKLAHOMA COUNTY}

C E R T I F I C A T E

I, Carol S. Dennis, Registered Professional Reporter, Certified Shorthand Reporter of the State of Oklahoma, do hereby certify that on September 21, 2021, the preceding hearing was taken by me in machine shorthand and was thereafter reduced to typewritten form by me. The foregoing transcript is a true and accurate record of the hearing to the best of my understanding and ability.

Whereupon, I have set my hand and seal.

____
CAROL S. DENNIS, RPR, CSR
OFFICIAL COURT REPORTER
OKLAHOMA CORPORATION COMMISSION

PUBLIC SERVICE COMPANY OF OKLAHOMA

INTEGRATED RESOURCE PLAN

TECHNICAL VIDEOCONFERENCE

Tuesday, October 19, 2021

P R E S E N T E R S

FAIRO MITCHELL, Host

GREGORY SOLLER, Manager, Resource Planning

MATTHEW HORELED, Vice-President, Regulatory and Finance

JAMES McMAHON, Vice President

JONATHAN PAINLEY, Senior Associate

CHAD BURNETT, Director, Economic Forecasting

ROBERT KAINEG, Principal

CONNIE TRECAZZI, Economic Forecasting Staff

TUESDAY; OCTOBER 19, 2021; 10:00 A.M.

PUBLIC SERVICE OF OKLAHOMA

INTEGRATED RESOURCE PLAN

TECHNICAL VIDEOCONFERENCE

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MR. SOLLER: I'd like to ahead and kick things off. I know that there will be -- may be a few more folks that will be joining us here in the next couple minutes. But I'll give a little bit of an introduction and talk about the format for today.

My name is Greg Soller. I'm with AEP and with the Resource Planning Group. We have worked over the past several months to develop the 2021 IRP and -- for this conversation today's talk -- conference about the results of that effort and to -- for us to really explain the process, the -- the information and the insights that we have gained and that really have culminated in the IRP that we have released the draft to.

So, I'd like to proceed with a couple of little ground rules to help talk about how we can facilitate today's call. And hopefully while -- while the -- during the presentation we would appreciate if everybody could stay on mute to minimize the disruptions for the information that we have prepared.

But during the presentation we're interested in your feedback, your questions, and we intend to stop periodically, try to level set and bring together these questions and -- and have a good dialogue throughout the conference call today.

For your questions we are asking that you use the chat feature of the WebEx. You can see that in the bottom right-hand corner. There will be a -- a display, an image there that says chat.

Just simply select that, type your question in, and I will work to get that integrated into the meeting so we can stay up on those and listen to your thoughts and your questions and -- and make sure this is a fully engaged process.

So, periodically -- as we said, periodically throughout this presentation at the end if there is additional questions that we need to get back to, we're happy to -- we'll be doing that, as well.

All in the interests of time, we're going to do our best to stay within the allocated time frame. It is not going to be too rigid, but we do want to try to respect everybody else's schedules, as well.

So, with that I'd like to proceed. And I'd like to introduce Matt Horeled and maybe talk a little bit about -- well, actually, I'll -- I'll introduce the agenda here, and we will talk a little bit about introduction.

We'll have Matt Horeled speak with us a little bit, and then we will turn it over to Jim McMahon, who is with Charles River and Associates. And we have -- we've engaged them to help us with this IRP.

We will work in the first half of the conference call really talking about the inputs and the IRP development that we went through, the process we went through.

We will take a -- a brief break and then spend the second half of the presentation and the conference call really about the portfolio results, some of the insights and then the effect of Scorecard that looked at the various -- compared the various portfolios to help us identify a Preferred Plan for this particular IRP.

So, that's the -- the broad structure of our prepared presentation today. We're looking forward to an engaged process with you, and we appreciate you spending time with us today. So, with that, I will turn it over to Matt Horeled to have him offer some opening remarks.

So, Matt, if you want to come off mute.

MR. HORELED: Absolutely, Greg. Can you hear me okay?

MR. SOLLER: Yes, sir.

MR. HORELED: All right. Excellent. Good morning, everyone. My name is Matthew Horeled. I'm the vice-president of regulatory and finance for Public Service Company of Oklahoma. And as Greg said, welcome to our exciting 2021 Integrated Resource Plan Technical Conference.

We're happy to do this again. We had a little bit of a scheduling issue with the prior conference. Some parties weren't able to make it. So, we're -- we're happy to -- to run through this again a second time and to solicit your feedback and conversation about our -- our long-range planning.

As far as the introductions go, our PSO leadership team, Peggy Simmons, our President and Chief Operating Officer. I don't believe she'll be able to join us this morning, but she's certainly involved in a lot of our planning and -- and discussion certainly.

Mary Williamson, our Director of Regulatory

Services, will be on the phone joining us, as well; Joann Worthington, senior counsel; Fairo Mitchell, who I know many of you are familiar with, our regulatory consultant principal; and Jeff Brown, Manager of our EEN Consumer Programs.

And then a roster of internal experts that will be joining us today and help with this Integrated Resource plan are Kelly Pearce, Managing Director of Resource Planning and Strategy; Mark Becker, Managing Director of Resource Planning and Grid Solutions; Scott Fisher, Manager of Resource Planning; Greg Soller, Manager of Resource Planning who you met just a moment ago; and Chad Burnett, who I know many of you are familiar with, our Director of Economic Forecasting. He'll have some -- some load forecasts updates for us throughout this conversation. And then Connie Trecazzi's Economic Forecasting Staff, as well, who helped a lot of our modeling, also.

And this year we're -- we're taking a little bit of a different approach. A lot of this has been done traditionally in-house with our Integrated Resource Planning team, who I just introduced. And they have been fully involved in this process.

But we have also brought in some outside help, as well, to help us with some of these modeling scenarios. And that's Charles River Associates, the CRA team. There's James McMahon, Jim McMahon, Vice-President; Patrick Augustine, Vice-President, as well as Robert Kaineg, principal; Jonathan Painley, senior associate, and Abigail Sah, consulting associate, as well, too.

And we're excited about the input they have been able to -- to bring to this process with some of the scenario planning, some of the modeling associated with the Scorecard. I think -- I hope you agree with us and with me that it's -- it's a very innovative, exciting approach to our Integrated Resource Plan. And we're looking forward to -- to walking -- walking you through that process a little bit later today.

I'm sure CRA will add some additional details to their background, as well, too, but they have a lot of experience in our state, as well, helping -- helping Empire with some of their -- their IRP planning, as well, in the past.

Moving onto the next slide, you know, kind of looking at, you know, at the past of what we have done with our -- our previous five-year action plan from our 2018 IRP, the -- the first bullet point here is -- was essentially a take-away to continue the planning and regulatory action necessary to implement economic, you know, energy efficiency programs here in Oklahoma.

And -- and I'm happy to report that PSI continues to plan, implement and report on our energy efficiency and demand response programs. And our most recent portfolio for 2022 to '24 was recently approved by this Commission, so thank you for your continued support on that and on that journey for energy efficiency with us.

Looking at the second bullet point, the take-away from our action plan 2018 was to conduct -- conduct an RFP to explore opportunities to add cost effective wind generation in the near future, to take advantage of the Federal Production Tax Credit.

And we issued an RFP in 2019 which led to the development and purchase of the North Central Wind facilities. I'm sure many of you remember that case. We're very excited to announce that Sundance and Maverick, the first two facilities of the three, are operational. And we expect the final facility, Traverse, to reach commercial operation in early 2022.

We're very excited about those opportunities to -- to utilize this resource to serve our customers and to allow those -- those Federal Production Tax Credits to go to work for our customers, as well, too.

And, additionally, the company -- we're planning to release an RFP for wind resources to be operational by the end of 2024 and 2025.

The third bullet take-away from last time was to consider conducting an RFP to explore adding cost effective utility-scale solar resources, as well.

And in coordination with the RFP that I mentioned above with the wind resources, we're planning to release an RFP later this year for solar resources to be operational by the end of -- of '24 and '25, as well, too, because you'll see looking forward now into our 2021 plan that wind and solar show up as -- as preferred resources to serve our customers in that time frame to help fill the capacity need.

Additional take-aways from last time were to initiate the RFP process to evaluate PSO's options for replacing existing thermal PPAs when they expire and also with adding variable intermittent resources, consider conducting an RFP to evaluate for PSO's options for short-term capacity needs related to the incremental intermittent resource additions.

And we did secure short-term paper capacity resources in 2020 to meet the capacity need in '22, '23 and '24, essentially our short-term need to help get us to -- to the period of time of this '24, '25, '26 that we will be talking about quite a bit in today's presentation, as well.

And ultimately, you know, we're always trying to adapt and achieve here at PSO, and we're always ready to -- to adjust our action plan and future IRP planning to reflect changing circumstances.

So, if -- if we may move onto the next slide. You know, what -- what are we here -- what are we here today to do and what are we hoping to achieve today?

And really our stakeholder process objectives really focus on -- on being informed, listening and -- and considering the feedback that we get from all of you. This is, you know, an important part of the process for us.

We really want to -- to kind of lay out the key assumptions that we used in our IRP planning, the challenges that we face in serving our customers and then listening to the feedback that we receive from all of you with your resource planning concerns and objectives and provide, you know, a forum for -- for feedback and information to -- to flow back and forth between us to help -- help inform our -- our decision-making and serving our customers.

We published the initial draft back in mid- -- mid-September, September 15th. We had that initial meeting on September 21st, and now we're having the follow-up meeting approximately a month later on October 19th.

And we're going to -- you know, in the meantime we'll be listening to your feedback, preparing the report which will then be submitted to the Commission no later than October 29th, 2021.

So, we're really looking forward to a -- to a good conversation today and walking through all the details. And I think at this point I'm going to stop my M.C. duties for a moment, Greg, and kick it back to you to introduce the -- the CRA team.

MR. SOLLER: Certainly. Thank you, Matt. Appreciate that. Hopefully, that really sets the tone for what we want to converse about today and making sure we don't lose sight of where we were, but reallly looking where we want to get to.

At this point I'd like to bring on and introduce Mr. Jim McMahon with Charles River Associates. And -- and we have really worked with Charles River this -- this year or in this process, and they have done a great job working with us.

But I'm going to have Jim really explain the process that we walked through with them to identify all the right inputs and the necessary information in order to be successful with this IRP.

So, Jim, at this point if you don't mind, if you could maybe come off mute, and I'll -- I'll turn the -- turn it over to you at this point.

MR. McMAHON: Thanks, Greg. Thanks, Matt. Jim McMahon here again, vice-president in Charles River Associates. I lead the advisory services business within our energy practice.

Our energy practice is a team of about seventy-five individuals, as a company, if you are not familiar with us, about a thousand consultants overall across a number of different practices in the energy space.

We have had about three decades of utility resource planning experience across most U.S. states, major energy markets in the U.S. Certainly we have a -- our practice is divided between Europe and -- and the U.S., North America.

But we have worked across all U.S. markets, including is SPP, PJM, MISO, CAISO, ERCOT. Matt alluded to some of the clients that we have worked with in the past, including Empire District with operations and SPP.

Other clients include Northern Indiana Public Service Company, or NIPSCO, Alliance Energy, two -- the two companies or two utilities within Alliance Energy; Southern Company, Dominion Energy and then a range of public power clients, as well, including Great River Energy, Hoosier, CPS, Oglethorpe, so a lot of -- a lot of experience in resource planning as a firm, and we have been around as a firm for over fifty years.

So, I'm going to provide a brief overview of the process, then turn it over to my colleagues who are on the line today: Jonathan Painley and Robert Kaineg, who are going to go through many more of the details, the results and the findings, but then all of the inputs, as well.

So, on this slide that we have up here describes really the IRP process that we went through, and I'll start on the -- the right side of this slide.

The -- the first step here we have five steps defined. The first step is defining the set of the objectives that are aligned to customer needs. The -- the second step was looking at -- at market scenarios within the broader SPP market to test future risk. And most of these were beyond the utility's control.

And then in step three we look to optimize portfolios for these different market conditions that were described here in step two. And these portfolios consist of supply and demand solutions in combination.

And then in step four we test the optimized portfolios against the -- the full set of market scenarios, and we also run stochastics, which is really a different way of looking at risk. And we will get into a lot of this in detail here shortly.

And then finally we look at the results against the set of objectives and -- and consider the trade-offs between the objectives and then select a Preferred -- Preferred Plan.

The -- the left side of the graphic is really showing the responsibility and that it was a team effort between ourselves and PSO and -- and AEP more broadly. PSO and AEP set the objectives and the performance criteria and provided the fundamental commodity price forecasts.

CRA's primary role was in supplying the supply-side assumptions, the -- the modeling of the market scenarios and developing the portfolios. And then PSO was responsible for reviewing the outcomes, selecting the Preferred Plan and then developing a short-term -- term action plan.

So, like I said, we will go through this whole process here over the next couple of hours, and I'm sure that we will have points where we're going to have lots of questions to those who will be presenting on the specifics.

Move to the next slide, please, Greg. So, first I just want to talk about the objectives. PSO identified four overall objectives that branch into ultimately ten metrics, which we will discuss in a bit.

The first is customer affordability, which is measured based on short and medium-term costs on a -- on a net present value basis. The second, rate stability, which was measured in a few different ways, including how the -- the net present value of the portfolios cost varied by portfolio and then how much market exposure a given portfolio has.

The third objective was to maintain reliability, which was measured by the amount of operating reserves, dispatchable capacity and -- and resource diversity.

And then the fourth was around local impacts and sustainability. The local impacts were measured by the expected CAPEX impacts on the service territory, and sustainability was measured by the reduction in carbon emissions. We will show a break-out of this in -- in detail coming up here shortly.

But these -- these objectives were really central to driving all steps of the analysis, how we thought about the scenarios, the evaluation of the different resource types and the types of risks that were -- were assessed in the stochastic analysis. And -- and these all ultimately manifest in a Scorecard, which we will discuss here shortly.

Next slide, Greg. So, this slide illustrates what the title says, Going in Position. The stacked bars show the capacity contribution by resource type over time. And the solid line shows the peak load plus a reserve margin, which -- which is how much must be procured or retained in the portfolio to meet the -- the minimum reliability standards that SPP sets out.

So, as you can see, there's a capacity position that opens up in the 2026 time frame with the retirement of Northeastern and some smaller gas units, as well as the expiration of several PPAs, which include a couple of large gas contracts and some smaller wind contracts that we can talk about specifically in -- in a bit. So, that's the going in position.

And then to round things out and complete the executive summary portion of -- of the presentation, the Preferred Plan, so the Preferred Plan adds twenty-eight hundred megawatts of wind, twenty-one hundred megawatts of solar and just over a hundred megawatts of DSM and -- and demand response, starting in the 2025 time frame.

The -- the Preferred Plan utilizes Scorecard objectives that I mentioned a bit ago to -- to choose a plan that's the best overall fit for the company. And -- and the Preferred Plan is really the best balance of performance across all four --

all of the -- the four objectives.

And the Preferred Plan is lowest cost or near lowest cost in just about every scenario that we ran, which we'll talk about pretty extensively here coming up.

So, with that introduction and -- and summary, we're now going to get into the details and sort of walk you back to how we got to these results. And I believe I'm going to hand off to Jonathan Painley from -- from CRA's shop to -- to talk you through the next section. Jonathan?

MR. PAINLEY: Yes. Thank you, Jim. So, as Jim briefly introduced, we utilized scenario modeling as part of the IRP process to study plausible but materially different long-term views of the SPP market where PSO operates.

The scenario themes that are shown on this slide reflect different outlooks for fuel, load, environmental and tax policies, market rules and technology costs. And we have studied various combinations of these inputs in the form of integrated scenarios.

The point of integrated scenarios is to study a broad range of outputs which will then be used to evaluate various PSO portfolio decisions. So, the five themes that emerged during the scenario development process that was a joint effort between AEP and CRA -- they are shown here on the slide.

The first scenario is the Reference Scenario, which is intended to reflect a middle-of-the-road expected case view of the key inputs. In addition to the Reference, there are four other market scenarios that stress test the key inputs.

So, as we go down, we have the Clean Energy Technology case, which we will call CETA or CETA. That case study is more rapid deployment of new clean energy technology.

The Enhanced Carbon Regulation or ECR case studies rapid carbon policy implementation with a high emission price. The Focus On Resiliency case, or FOR, will include both the summer and winter planning reserve margin enforced across SPP. And the No Carbon Regulation case or NCR will test lower gas prices and zero new carbon regulation.

I think we can move to the next slide.

SCOTT NORWOOD: This is Scott Norwood. Can I get one quick question in right here or -- on the -- the report has some verbiage about testing extreme weather event conditions. Where does that come in under your scenarios?

MR. PAINLEY: Yeah, that's a good question. So, the scenarios themselves test weather normal conditions, but we do test a sort of stochastic environment where we have random natural gas and power price shocks, as well as random iterations of renewable output based on historical development.

And so, we are able to stress test portfolio decisions under what you refer to as kind of weather volatility and that environment, and that actually shows up as one of the columns on the Scorecard which we call cost risk.

Does that answer your question?

SCOTT NORWOOD: Well, I mean, is that -- is that -- do you talk about in the report anywhere explicitly what that means, how -- how high you would let, for example, natural gas energy prices get, as, you know, we have recently seen in February?

Do -- do you have anything that sort of tries to simulate that or test that or see how the overall portfolio responds to that?

MR. PAINLEY: Yeah, we do. So, we actually test two hundred and fifty different paths or iterations. And this is based on history. We have looked at historical volatility for both natural gas and power and also for the different -- volatility of different renewable output, how often do wind and solar contribute under certain conditions.

And so, yeah, I don't think we report individual iterations because it's quite a lot of data, but I can tell you that many of the iterations have multiple days where the power prices are consistent with what we might have seen in, you know, this latest winter storm or other storms in the last -- I think we look at about a decade of history.

So, we do have that type of volatility built in.

SCOTT NORWOOD: Is -- is that talked about anywhere? I mean, do you have a technical appendix or anything in the report that says, you know, this is how we looked at that and this is how the -- the various plans and portfolios responded to that?

And by that I mean the extreme -- you know, the extreme energy price excursion type events.

MR. PAINLEY: Yes. So, the -- the way that we have measured this and looked at it is when we run all individual iterations, what we're looking at is kind of the price impact that the highest case or the ninety-fifth percentile iterations have on the different portfolio options relative to the median.

So, we do report that in the -- in the Scorecard under the cost risk column, and I think we provide more detail in the report about just some of the outputs.

But we are -- we don't actually report individual iterations like the impact, just because there's so much data that it would get really tricky to kind of separate what is impactful and what is kind of helping to drive a portfolio decision versus what is just a -- you know, one individual iteration doing.

So, I think we kind of do report that information, but I think if there's additional information we can provide, we can discuss what you'd like to see.

SCOTT NORWOOD: Okay. Great.

MR. SOLLER: Jonathan, I -- and I'll just jump in here real quick. So, Scott, thank you. That's a good -- good starting conversation for some of the questions.

One thing is if there is something specific that you would like for us to take into account or consider, one of the effective ways, since we -- we have to meet virtual, if you're able to type your specific request into the chat, it's an opportunity for us to make sure we get it correct, right?

The dialogue is helpful. But if there is a specific request, I'll just please encourage you to type that into the chat so we won't -- we don't misunderstand something, as well, so . . .

But thank you for that.

SCOTT NORWOOD: Yeah. My -- my thinking -- and I'm sure it's more complicated than this -- but, you know, we just had this February event. It's all fresh on our mind, and we're still fighting about it.

And -- and, you know, your fuel supply portfolio says well, we have got all this -- we have got this, you know, diversified mix, and we're doing all these great things to hedge on gas prices and all.

And -- and what I would like to see is, you know, even a small technical appendix that tests that, because it looks like to me the scenario results, you know, in terms of overall difference in present value, if you look at the dollars they're pretty -- pretty tight, they are pretty close.

So, if there's one of these that performs better against, you know, this hundred-year event or whatever it is, you know, it would be nice to know that in some way. And I -- and I don't know that -- is that a huge study or -- or what.

But it seems like it would be comforting to customers to know that the performance here you think is matching the words and the -- the fuel supply portfolio, and -- and we do have some hedge -- additional hedge coming out of this new plan.

MR. SOLLER: Yeah. So, here's what I'd offer, Scott. Keep that question in the back of your mind through the rest of the presentation because certainly we'll -- we'll finish up the first half of this. We will go through the inputs and some of the assumptions in terms of load forecasts and some -- the fundamentals.

But as we get into the portfolio results and the -- the range of results that we -- we have, I think there's an opportunity to re- -- reconnect on this particular question testing, you know, challenging essentially really what we did test and how that aligns with some of your -- your thoughts, especially from a long-range type of planning perspective, more so than even the short-term planning, so -- because, you know, this past winter's event was -- was certainly something for us all to take notice to.

But from a long-range perspective we also need to keep that -- keep our thoughts balanced on that, as well, so -- but thank you for that, Scott.

MR. PAINLEY: Yeah. My colleague will actually go through that directly on Slide 41. So, I think at that point if there are additional questions, we can talk through it some more.

SCOTT NORWOOD: All right. Thank you.

MR. PAINLEY: Is there anything else before we get moving again to address?

MR. SOLLER: Not at this time, Jonathan. I'll just turn it over to you.

MR. PAINLEY: Okay. All right. So, picking back up, this slide falls on the scenario themes that we introduced on the prior slide. It gives a little bit more detail on how the individual scenarios handle each of the key drivers.

So, I think across the top of the table we have got those key drivers that I mentioned before: load, natural gas, carbon, et cetera. And as I mentioned in the Reference scenario, we adopt kind of a base or moderate view, middle-of-the-road type expected outlook for all the key drivers. And then the other scenarios we show here differences relative to the Reference.

So, for CETA -- this is a Clean Energy adoption case, so we see more rapid decline of technology costs. And we also have a ten-year PTC and ITC extension. And we also have rapidly growing load, reflecting higher electrification and faster underlying economic growth.

For the third scenario, ECR, we see high gas and high carbon prices. We see faster decline in technology costs relative to the Reference case. We have also low load, which reflects higher adoption of distributed technologies and lower economic growth in the SPP-wide market.

Then the Focus On Resiliency case we see winter reserve margin requirements and we also include low renewable peak credits associated with this case. And finally for NCR we see the lower natural gas price and no carbon prices shown here.

We're actually going to walk through every one of these drivers, and there will be more information to follow. And so, I guess if there are no specific high-level questions at this time, I'll turn it back over to Greg to introduce Chad, who's going to go through the load forecast section.

MR. SOLLER: All right. Thank you. Chad, yeah, I'll bring you up here, Chad. Bring your slide up. And I'll turn it over to you to really talk now about the key input here, which is -- is the load forecast. So, Chad, I turn it over to you.

MR. BURNETT: Okay. Good morning, everyone. I hope you can hear me okay. So, what you can see here on the Slide 13, I think it is, the chart to the left shows kind of what our -- our peak demand forecast looks like.

The -- the black diamonds here are showing what the actual historical peak demands have been. The red line represents from weather normal that -- so you can kind of see under normal weather conditions where our peaks have been lining up.

And you can see that really aligns fairly well with our load projections, which is shown as the green line here.

I just want to point out Section 2.1 has a lot of detail on the Reference case that we're showing you here. Generally speaking, we have got a customer count of growth assumption of about three-tenths percent per year over the forecast horizon.

The sales forecast is assumed to grow at about two-tenths percent per year. So, relatively speaking, a little bit of growth, but it's a relatively flat forecast overall.

But where there is a little bit more interest or excitement happening is when you look in the -- to the right of the slide, because we are seeing kind of a dynamic situation with regards to our sales mix.

And so, here to the right you can see the line chart is showing how our residential, commercial and industrial sales are trending. And we are seeing a bit of a shift here. So, you're -- you're seeing the green line there represents our industrial sales. And, again, if you were to go back to around the -- the 2010 time frame, they were among the lowest of those three classes.

And then going forward, and we have a brief episode right before the pandemic where they had reached this level, as well, but projecting going forward they will be the dominant class for PSO sales.

And so, you can kind of see the two donut charts below that show, you know, how the -- what was PSO's sales mix a decade ago versus what it's projected to be ten years from now.

And you can see again industrial is -- is becoming a little bit more dominant, and the residential and commercial will have a little bit less of an influence here.

Moving onto the next slide, again, that was really talking about the Reference case, but we also have done a number of load scenarios. And you saw some of this on the -- the earlier slide that Jonathan was talking about with the various scenarios that are out there.

But, you know, I want to point out here that even though what we show and that was a high and a low load forecast, the reality is we have done a number of other load scenarios that are within those upper bounds to account for various changes in technology, operating conditions, all of those things that all would be within those bounds.

And so, from -- from an IRP perspective, you know, we can keep having iterations after iterations of all these various load scenarios, but at the end of the day if you are planning a portfolio that can lead both the Reference case, as well as the -- the high and low extremes or -- in different scenarios, it's fairly safe to say you covered all of the various future states that could happen from this.

And so, again we have got a high economic, which you'll see is the green line, which has got a much faster growth rate over one percent per year in the high economic forecast.

Down at the bottom the red line is our low economic. In that one you can see it's projected to decrease at about a half a percent per year. And then again, that compares with our base forecast, which is, you know, slight but modest growth here in the long term.

So, you know, we have got several scenarios here with regards to energy efficiency, with extreme weather, and there was a discussion earlier about, you know, in the near term, hourly, daily, the impact it would have.

But we have done some -- some longer term impacts of a -- of a very rapid or extreme weather scena- -- warming scenario based on the study that the Purdue University had done several years back.

So, we've -- we've done a lot of different ones, as well as different changes, assumptions around energy efficiency standards that might be in future legislation that's not already accounted for.

So, in addition to these scenarios, on the next slide you'll see we have also got some scenarios with regard to electrification, specifically electric vehicles. And I didn't read the whole question, but I think there may have just been a question in the chat that was regarding this. So, I'm hoping this will help address that question.

You can see here for, you know, what -- currently at in terms of total EVs that are registered within our footprint. And where we get this from is we have got a data source that captures all vehicles that are registered in our service territory.

We match that up with our billing customer data to make sure that we're -- we're capturing all of the customers in our service territory. But roughly -- we've got just under two thousand electric vehicles to date. And that represents a -- a market share of about point one five percent of the total one point three million vehicles that we have in the PSO territory.

We -- we've got a projection -- we have been monitoring for the last several years, but we are assuming roughly about a thirty percent per year increase in that. And again, over the last three years that has tracked very well with that projection.

So, we -- we -- you know, we kind of have a number of scenarios, but we have also done a high adoption, as well as a lower adoption around that base EV projections, just planning for what could happen with this base.

But it's clearly something that we're keeping an eye on, but just at this point it's still a relatively small driver for -- for the load.

SCOTT NORWOOD: Do -- do you have any feel for what this translates into in terms of peak demand and energy growth? In other words, if --

MR. BURNETT: Yeah --

SCOTT NORWOOD: Yeah.

MR. BURNETT: Yeah. You know, I mean, there's -- there's going to be lots of factors on that, you know, depending on what -- how often is the vehicle charged, what time of day is it going to be charged, and how it's going to be charged: Is it going to be charged, you know, just a regular plug into the wall? Is it going to be a -- you know, a high-speed level one, level two, level three chargers?

And so, those will all have an influence on what the demand requirements will be with -- associated with these different scenarios. And so, you know, we have got -- we kind of base it on, you know, market research and what's out there in the industry today, you know, what we think it's going to be.

But -- but, clearly, there's a lot of uncertainty around that, as well.

SCOTT NORWOOD: Okay. Just -- just a rough feel for -- are we talking about in the high range -- what kind of growth are we looking at with the high range of the projection?

MR. BURNETT: You know, Scott, let me -- I -- I'll need to double-check on -- on that. The -- the reality of -- the big point of all of this is to recognize that it is still a very, very small -- again, we're talking point one five percent, so not even two-tenths of a percent yet.

And so, it's still -- at this point it's very, very small. So, while it is growing very rapidly, in terms of the impact that it's going to have on PSO's load, especially in the near term, it's -- it's relatively -- it's going to be relatively small until it reaches a critical mass.

And so, that could take again several years before you'll get to a component where it's going to actually -- I won't say show up on the radar, but before it's -- it becomes a critical mass that's going to have a dramatic impact or a significant impact on PSO's load.

SCOTT NORWOOD: Okay. Thank you.

MR. BURNETT: So, Greg, I think on the next slide there's another disrupture that is happening out there that has the offsetting impact of electrification, and that is with distributed generation.

These tend to be -- as you're aware, there would be a load reducer. And so, at the end of last year we had just over six thousand customers with an installed DG system. That's roughly one per- -- just over one percent of our customers. Based on the latest projections we've got here, that is expected to grow to about four percent of our customers by 2030.

Again, there is -- this is still relatively small, but it -- it will have an impact that will again offset some of that growth that we're seeing and projecting with electrification.

But what's really cool -- one thing I wanted to share with this group on the next slide, Greg, is because of the -- the AMI data that we now have access to with the meters that have been installed, it really helps us to dig a little deeper to understand what the impacts of DG is on our system in terms of a load reducer, because it's not -- as we have learned, it's not going to be the same across all eighty-seven sixty hours of the year.

And so, what we have done with this study was we looked at the -- a sample of the customers that had full AMI deployment a year before they installed their DG system and then a year after so that we could kind of get a -- a comparison apples -- apples to apples of what they were like before and after they installed the system.

In this instance the blue dots here represent daily energy of these customers at different temperatures. So, you can see the horizontal axis is the average daily temperature, and it's got, you know, the traditional load shape that you would expect where, you know, around the fifty-five to sixty-five range is kind of where there's not a lot of weather, that's more like the base load, if you want to think about that for a residential customer.

But as temperatures get hotter, you're going to see that the load starts to go up. And similarly when you get cooler than fifty-five, you start to see the load go up.

And so, just a couple of interesting observations here. What we noticed is that you see the greatest separation between the orange and the blue at higher temperatures. And again, this is not rocket science.

It makes sense that when -- when we have hotter temperatures that's generally in the summer, and that's when the sun is going to be the brightest. So, that's when you are going to get the biggest impact from these distributed generation systems.

And then conversely if you look at lower temperatures, a lot of times in the winter time that's when it's going to be cloudy or overcast, and so, you don't see nearly as big of an impact on these systems.

And so, on an annual basis, you know, for the study that we -- we looked at here these DG systems tended to lower customer usage by just under eleven percent. And so, this is something we will continue to monitor.

But again, this is the sort of analysis that the AMI technology has enabled us to do that really helps us kind of put a finer point in terms of making assumptions regarding what would be the impact of DG going into the future.

So, Greg, if there are no other questions, I think I can turn it back to you or Jonathan at this point.

MR. SOLLER: Yeah. Thanks, Chad. I -- I'll just bring Jonathan back on to pick back up for this part of the presentations. Jonathan?

MR. PAINLEY: Thanks, Greg. I'll continue walking through the remainder of the scenario inputs. Then we will get into some of the outputs, and that will lead us to a short break.

So, here on Slide 18 we are showing the natural gas and carbon inputs that we are using for the scenario modeling. On the left-hand side we have got the fundamental price ranges for natural gas.

The process for natural gas is we're relying on the AEO 2020 Reference case for the base Henry Hub forecast. And then the AEP fundamentals team forecasts the basis differentials from Henry Hub.

So, here on this hub -- here on this slide we're showing the Eastern Texas-Oklahoma natural gas hub, which maintains about a thirty cent discount to Henry Hub.

We show the base trajectory in blue, and then the higher and lower trajectories, which are about forty to fifty cents different around the base trajectory.

So, when we look at the prices, there's some real price growth. The axis is in real dollars per MMBtu. So, there's some real price growth from 2022 through 2028 with the long-term forecast kind of stabilizing with the base case around three dollars real 2028 and onward.

Inflation adjusted, this is about four dollars nominal in 2031 and five dollars nominal in 2041. You can also see we're showing monthly here so you can see the seasonality of the gas prices, the winter prices being about fifty to seventy-five percent higher than non-winter.

And then one thing I think I'll kind of comment on is that we've been observing the recent natural gas price movements. And while we're seeing high prices for spot markets and prices this winter elevated for a number of different reasons, we do still see futures returning to the four dollar range by next year and then the three dollar range by 2023 and 2024.

So, I think, you know, there's been a lot of discussion recently about the uptick in natural gas and even oil prices. But I think we're still looking at this as being more of a near-term disturbance. And I think it highlights the importance of stress testing a range of long-term prices.

And then I think the last point is that we will keep observing the natural gas fundamentals market and incorporating changes as they -- you know, as their impacts are no longer into the future.

So, I think for the right-hand side of the slide we show the carbon inputs, which vary by scenario, as well. So again, we test three different trajectories with the base case outlook characterized as a moderate carbon price.

That starts at around twelve dollars a ton in real dollars in 2028, and it grows slightly faster than inflation, but it's overall pretty flat in terms of the long-term trajectory.

And we stress test this moderate carbon price by having a zero carbon price, which is used in the NCR case. It's kind of hard to see on the axis, but it's zero for the foreseeable future. And then we also have a high carbon price which is used in the ECR case.

And this high trajectory is assumed to start earlier in 2025, and it also incorporates more rapid growth to about thirty-eight dollars a ton in nominal terms by 2031, which is about fifty dollars a ton in nominal terms and ultimately grows to about eighty dollars a ton in nominal terms.

So, it's quite a bit steeper than we have in the Reference case. And we will see in a couple slides the effect that this has on the SPP market. I'll pause here, Greg. Is -- is -- are there any questions before we move on?

SCOTT NORWOOD: I -- I have one quick question. The -- I know like over in Virginia where they have the -- you know, the zero carbon legislation or close to that by 2045.

Where -- where does this carbon price have to be to in essence incent that? Have you all looked at that? In other words, at what point does it switch over and solar and wind is the -- you know, is the resource of -- of choice that would --

MR. PAINLEY: Yeah. I'll -- I'll start, and then I -- maybe some of my colleagues can add a little bit of color, as well. But I think that, you know, first off, we are not modeling out to 2045. We kind of end the analysis at 2041, which is a twenty-year time horizon.

At this point it's really speculative to get into that level of decarbonization. Our highest gas pri- -- or our highest carbon price, the orange trajectory, it does get to about eighty to maybe ninety percent carbon-free in the SPP market by 2041.

But I think when we look beyond that it's -- it's -- there's a lot of other factors, including, you know, reliance on technologies which are fairly new and really difficult to look at what the prices will be that far out.

But I think we have seen in a lot of our modeling work that the eighty dollar per ton and maybe up to a hundred dollar per ton is enough to kind of incentivize some of that last level of decarbonization, but it is very speculative at this point, given that it's twenty to twenty-five years out.

SCOTT NORWOOD: Okay. And -- and one other question. The -- in a number of your recent IRPs -- and by "your" I'm talking about AEP -- that I've seen capacity price forecasts which are extremely low for many years.

And are you going to -- are you going to talk about that? Is that in your IRP, and have you looked at and modeled that, and, if so, how -- how have you incorporated that? The ability --

MR. PAINLEY: I think I'm going to turn it over to Connie --

SCOTT NORWOOD: Okay.

MR. PAINLEY: But, yeah, I will say that the AEP fundamentals team does forecast the capacity prices, although I don't think that we are looking at fundamental paper capacity as being a long-term resource option, so for that reason we're not -- you know, we're not long-term -- we don't have a PSO portfolio saying we're going to rely on capacity purchases long-term because the supply and the demand across the SPP market is uncertain.

And I think -- I guess with that I'll turn it over to Connie maybe to explain the capacity price forecasts a bit more.

MR. SOLLER: Connie, do you want to come off mute? I mean, I think Jonathan is -- is right in the context. It's -- we're not looking at paper capacity, Scott, in terms of a long-term solution. But we really are going to be looking at our -- our capacity relative to how it plays out in our fundamental analysis.

And I think Connie might be able to offer a little bit more insight into how that gets derived.

MS. TRECAZZI: Yes. The reported capacity price included with our fundamentals forecast is a model output that reflects the cost to keep the incremental unit in the supply mix, in the stack.

So, what's changed between forecasts is new build retirements. Those are two -- two of the primary contributors. We also by using the EIA inputs have introduced a new change to what our models produce.

So, those are the -- those are the differences from the -- the previous capacity price forecast. But even in those forecasts it was a model to output, based on the input assumptions that were used.

SCOTT NORWOOD: Okay. Is the -- following up on that that the -- when you go out for resources identified in this IRP, go out for bids, the short-term capacity is available then and it's cheaper, you'll -- you'll do that and -- I mean, you're not -- you're not actually locked into looking at investing in new resources over the next five years if -- if there is cheaper capacity resources available?

MR. SOLLER: Let me bring Matt Horeled in to -- to maybe comment more specifically to that question, Scott. I mean, that's -- that's certainly something that we want to get informed through the RFP process. But, you know, Matt, is that something that you might be able to address with Scott directly here?

And I do want to check with -- one thing with Mr. Montelle Clark before we get into the rest of the presentation. Matt, are you able to get off mute and maybe talk to that some more directly with Scott on his -- his inquiry?

If I can find Matt. I don't know if Matt is there. So, Scott, maybe -- maybe if -- if Matt is -- doesn't seem to be available at the moment, then maybe we can reconnect with you.

But, you know, I think -- you know, this is an

IRP, so I don't know that we're making any final decisions, is probably my best answer to you --

SCOTT NORWOOD: Yeah.

MR. SOLLER: -- with regards to this for sure. I mean, we've got the RFP process, and that's -- that's going to be a -- a key input for some of the actual decisions we -- we move forward on this -- this process really tells us in terms of capacity some of the short-term and long-term needs that we want to go and how we -- you know, strategies on how we can look to solve those, so --

SCOTT NORWOOD: Okay.

MR. HORELED: Greg, I -- yeah, Greg, I -- I think that's right. Sorry. This is Matt Horeled. I'm just having a hard time reconnecting, but I'm back on, everybody.

Yeah. I -- I think that, you know, we always look to what resources are indicated by -- by the IRP that helps influence what we look for in our -- our mid- -- middle to long-term planning for our RFP.

And that's -- we think the results of this IRP are going to help influence what we look for, which is primarily going to be renewables at this point for -- for twenty-four and twenty-five time frame to fill that capacity need that we have, and we'll just have to look and see what those -- those results are in that -- in that process and weigh that against other options, as well.

MR. SOLLER: Okay. Thank you, Matt. And before we go on, I'd like to just connect back with Montelle Clark. You've -- you'be writ- -- you've written a question into the chat. Thank you for that. And I just want to make sure -- I think we might have addressed it during Chad's discussion on the load forecast and information.

But the question is -- says what about electrification trends for residential, commercial sales, including transportation, are they entirely offset by gains in appliance and HVAC efficiency?

You know, Matt -- or Montelle, do you mind coming off mute and seeing if -- through the discussion that Chad provided if that really addressed your question, or is there a follow-up that you would like to -- to pose at this time?

MONTELLE CLARK: Thanks, Greg. Can you hear me?

MR. SOLLER: Yes, sir.

MONTELLE CLARK: Yeah. You -- you -- you

answered my question on the transportation part of electrification. I -- I was just surprised from the IRP that you project declining or somewhat declining sales in the residential, commercial sector between a half a percent and a one percent decline. And I -- that's what I was asking about.

Is that -- does that reflect the potential for transportation electrification but also other types of electrification like hot water, heating -- hot water and space heating, et cetera, that the -- that electrification trends is what I was addressing.

MR. SOLLER: Chad, is there -- is that an opportunity maybe to do a -- a quick touch-point to Montelle's follow-up?

MR. BURNETT: Yeah. No, I think that's a good point. Again, the reference point that -- the reference forecasts that we talked about we really aren't seeing much of a trend of electrification at this point.

In fact, when we look at our residential appliance surveys that we do every three to four years, the last couple of months we have seen more of a gasification trend than electrification trend. I will point out that we're getting ready to do another one here recently, so it's possible, you know, if we see some changes.

But the important thing, Montelle, that you -- you mentioned is I think that it would -- that -- what you describe is something that is in one of these load scenarios that we talked about.

And so, we're -- when we do the IRP analysis and as Charles Rivers goes through the rest of the Scorecard, they are going to show you, you know, different scenarios of future states of the world, and one of those does include electrification as a much higher rapid pace.

And I guess where we're going with this is even in -- in that world we have given, you know, through that high economic load scenario, we're going to have captured the impact of any of that electrification that would -- that might happen.

So, even though we may not necessarily say that in the reference case, we're going to see that fast of adoption of electrification. We have also developed a scenario that will capture that, and we're -- we're going to model this IRP to account for that possible future, as well.

MONTELLE CLARK: That's perfect. Thank you for that response.

MR. SOLLER: Thank you, Chad. So, in the interests I'll -- I'll -- we'll keep pushing forward. I'd like to bring Jonathan back up and maybe continue on now with talking about some of our technology inputs. So, Jonathan?

MR. PAINLEY: All right. So, we'll keep moving through the key inputs. This slide here shows the reserve margin and peak credit inputs.

So, for determining the appropriate summer peak credit associated with solar and four-hour storage, we have utilized studies performed by SPP in the 2019 accreditation study.

The peak credits associated with the SPP study are shown by the blue lines in the charts to the right. And those are used in all but the Focus On Resiliency case. The main take-away is that with low penetration amounts for either solar or storage across SPP the peak credit would remain high, but as more and more of those resources get installed market-wide the credit for both technologies declines.

So, we note that there would be some uncertainty in terms of timing, also the amount of that decline. And that's part of the reason why we incorporate the orange trajectory, which is a bit more of a pessimistic view on how much either solar or four-hour storage would count in the future, mostly due to market rules and the effect of it including a winter reserve margin credit and, you know, the other assumptions included with the Focus On Resiliency case.

And then in addition to the lower peak credit assumptions, the Focus On Resiliency case also enforces the winter planning reserve margin requirement of twelve percent, same as the summer.

We note that in the wintertime solar has a significantly lower peak credit, and that's due to the different load shape being kind of morning and evening peaking both mostly before and after the sun goes -- is up in the wintertime.

So, the value that we used for winter solar credit in the FOR case was ten percent, declining to around five percent.

I think we can move to the next slide. So, this slide here shows the technology cost ranges that we studied. And basically the base trajectory is -- the blue line is used in the Reference case, the FOR case and the NCR case. And it's based on EIA 2021 starting costs --

SCOTT NORWOOD: This is Scott --

MR. PAINLEY: It's based on the EIA 2021 starting costs and then utilizes the NREL moderate costs decline curve to generate the long-term view on how the costs would change.

So, the CETA and ECR cases we mentioned -- I mentioned earlier that they have more aggressive cost declines. And so, those cases are actually relying on the NREL advanced technology cost decline curve. And that's used to generate the orange lines that we see here.

The last point is that these new resource costs are prior to any tax incentives that the project would be eligible for. So, the final costs we would model would also take tax credits into account. This is just kind of a pre-tax credit view. And most of the cases utilize the current law for PTC and ITC eligibility.

But I did mention before and I'll reiterate that the CETA case tests a ten-year extension to PTC and ITC, so we are incorporating a lot of different variable costs and uncertainty as it relates to these wind, solar and four-hour storage capital costs in the future.

SCOTT NORWOOD: This is Scott Norwood, just a couple of quick ones. Why is solar -- is there not more solar being selected when it has a lower capital cost, a higher capacity credit -- much higher capacity credit, lower O&M costs than wind?

MR. PAINLEY: Well, I think we will get into some of the observations across the SPP market in a couple slides. This is just talking about the cost inputs.

SCOTT NORWOOD: Okay. And a second question is, is storage being selected by the model, or are you plugging that in? Because I haven't seen storage -- I mean, I haven't -- I haven't noticed any storage being economic in studies that I've seen recently.

MR. SOLLER: Jonathan --

SCOTT NORWOOD: A stand-alone resource.

MR. SOLLER: Jonathan, I think -- and, Scott, if you don't -- I would appreciate if we could actually hold that question until we get into some of the results, because I think it goes right to the -- the heart of what we want to talk about in the second half.

To the extent -- I think if we start talking about some of the results in the -- of the portfolio modeling at this point we -- we start to confuse or intermix some of the key messaging we're trying to communicate at the front end of this.

We're certainly going to get into the portfolio results, Scott. So, you know, if -- if you'd be okay, I'd --

SCOTT NORWOOD: Sure.

MR. SOLLER: I'd like to defer your question, because I don't want to lose the question. I think that would be the other reason we want to make sure we -- we try to get these typed in to the chat, if you're able -- if you're able to do it.

I don't want to lose the question. I just want to make sure that we can address it at the right time with the rest of the material.

SCOTT NORWOOD: All right. And then one other quick one while I'm thinking about it, while it's fresh in my mind. The previous slide showed ten thousand megawatts of solar being where the capacity credit dropped off or roughly.

Is that an SPP number, or is that -- what is that number?

MR. PAINLEY: Yeah. That is from the SPP solar and wind ELCC accreditation study. I think they did one -- it's labeled 2019. I think it was released in 2020. And then they did another one in 2020 that was released, I believe, in June or July of this year --

SCOTT NORWOOD: Okay. So, that's not a PSO limitation. You're looking at the -- the market as a whole?

MR. PAINLEY: That's right.

SCOTT NORWOOD: And there's some projection in your model, I assume, going forward what solar is going to be and sort of takes us --

MR. PAINLEY: Yeah. We actually use the market-wide build-out to kind of figure out where we are on this curve at different points in time, so --

SCOTT NORWOOD: Okay, okay.

MR. PAINLEY: You can think about the market will select resources, and then you'll say where are we on this curve, and then that will be the ELCC value.

SCOTT NORWOOD: Okay. Great. Thank you.

MR. PAINLEY: All right. I think we can go to the next slide. Yeah. So, this is kind of a -- wrapping up the key inputs.

So, the thing I'll -- the point I'll reiterate here is that, you know, all of these different assumptions grouped together in various combinations, you know, results in five very fundamentally different views of the SPP market.

And we get -- you know, what we will do is we set up all these inputs. We run kind of a long-term study that will simulate economic retirements across SPP and new resource additions and then come up with a supply and demand mix over time that kind of optimizes under all these conditions and gives us a market price expectation for each of these five scenarios.

And so, all of that information is then kind of used as we move forward into the portfolio modeling section, which my colleague, Robert, will go into.

But I think a lot of this kind of ties back into PSO because, you know, PSO isn't specifically responsible for how the market will respond and how the market will evolve. And so, you know, external states of the world do have some impact, so it's important to kind of consider how those different states of the world might evolve.

I think with that, you know, we will get into a couple of the output slides at the scenario level, and then we will probably have time to cover any questions and then take a break.

So, here on Slide 22 this is illustrating the different capacity and -- and generation mixes that we observed by scenario. So, the first bar in each of the two charts shows kind of what the market looks like today or as of 2021.

And then each of the other bars show how the market will have changed by 2041 under each of the five scenarios that we have run.

In terms of nameplate capacity, we see the bright blue bar for coal going down under all market scenarios. What we are observing across all of the market scenarios in terms of nameplate capacity is large build-outs of wind, solar and storage.

And again, these are all selected by the model in order to optimize and -- and solve for the lowest cost under that scenario. So, whatever build-outs are shown here are not -- you know, we're not putting them in or it's not like we're selecting storage. The model is saying this is -- these resources help to minimize the costs at the market level.

So, for the Reference case over the modeling horizon we see about twenty gigawatts of coal that retires, and that's replaced by sixty gigawatts of new wind, solar and storage.

And then the CETA case, the tallest bar, load is growing more rapidly, and renewables are quite cheap, so as much as a hundred gigawatts of new wind, solar and storage is installed across SPP.

And even in the NCR case with no carbon policy and a lower gas price we still see a build-out of about thirty-five gigawatts of new wind, solar and storage. So, this is becoming a theme.

We also note that a lot of these resources actually do get added in the near term, you know, the next five-year time horizon, mostly due to tax incentives.

On the right-hand side for the generation we're seeing all cases exceed the fifty percent renewable generation by 2041. The Reference case shows about seventy percent renewable generation, and I think on the high end the CETA case exceeds eighty percent, and the ECR case is actually getting closer to ninety percent.

So, we do see significant decarbonization and generation from renewables across most of the cases.

SCOTT NORWOOD: This is Scott. I don't want to slow things down, but is this the place to talk about why the model is selecting wind over solar?

MR. PAINLEY: Yeah. I'll touch on it briefly. So, I -- I would say that the model is selecting both resources quite heavily. So, you know, there is already a large build-out of wind in SPP, but we do see that to continue.

And then I think we are seeing a lot of solar coming into the model to the market, as you suggested, due to, you know, a few factors. It does have high capacity credit, at least in the near to medium term. And it does provide energy in a kind of peak period when prices tend to be higher.

So, that is part of the reason why we see solar. And then, you know, as the solar capacity or capital costs decline over time, the resource itself does look attractive throughout most of the time horizon when we look across the different cases and through time.

Does that help answer your question?

SCOTT NORWOOD: Well, not exactly. I mean, I -- I'm just wondering is it a tax credit issue or -- I just have -- you know, forgive me for being dense, but it's got a higher capacity factor, higher on peak energy production, higher capacity credit, lower capital costs, lower O&M costs. What -- what's left?

Why -- why is it -- it's still selecting more wind than solar investment, and I don't -- I don't see this -- I'm not -- you know, I'm not trying to be a conspiracy theorist or anything like that --

MR. PAINLEY: It has a much higher capacity factor overall. I think we see forty to forty-five percent as the capacity factor for wind. So, when you -- with the production tax credits there's a quite large subsidy for new wind, and that continues through current policy through 2025. And then in the CETA case it continues to some extent through 2035.

So, we -- I mean, we tested different levels, and the model itself is balancing all the different attributes, the generation component, the capacity component, the reserve margin, all those things.

MR. SOLLER: Yes. Scott, I -- I think -- keep challenging the question. I think we will continue to try to address it. There are some -- some -- some opportunities certainly to explore the portfolio results.

But I think this -- I don't know that it's necessarily the wrong timing to ask the question, but appreciate it, and we will continue to try to give you the best answers we -- as we understand the information.

Jonathan, do you want to proceed then?

MR. PAINLEY: Yeah. We'll -- I think we can move to the next slide, second to the last in this section here.

MR. SOLLER: And I -- just a quick note. Montelle has a question. Montelle, we see it, and I'll make sure we address it. We will get through some of the additional information, though.

MR. PAINLEY: Okay. We can advance to Slide 23.

MR. SOLLER: Sure.

MR. PAINLEY: So, taking all of these different supply mixes into account, you know, the model will solve for a market price. So, we're showing here the SPP market prices on-peak and off-peak for the five different scenarios that we model.

You know, loo- -- when looking at the -- the Reference case and the CETA and FOR cases -- those are the three kind of grouped in the middle -- all three of those assume the moderate carbon policy that comes into effect in 2028. And we see about a seven dollar jump in power prices due to that policy mostly.

On the high end for the ECR case shown in green, that case has a carbon policy coming into effect sooner, so in 2025, and also the price is higher. So, we actually see that case in 2025 market prices jump by about twenty dollars on-peak and eighteen dollars off-peak.

And then on the low end in blue we have the No Carbon Regulation case, and this case has a mostly flat outlook since there is no carbon burden or no carbon tax being assessed, and it has the lowest natural gas trajectory, as well. So, across all of these cases we have, you know, a pretty good range of different outcomes.

The other point I'll make here is that, you know, in recent history we have seen somewhere between an eight and twelve dollar spread between peak and off-peak prices, but we will note that as we go through time we're actually seeing significant convergence between on-peak and off-peak.

You may be able to tell kind of that as a lot of the on-peak prices are kind of flat and declining after they kind of jump up. And then the off-peak prices tend to kind of gradually rise over time.

So, we will note that I think a lot of this is due to solar becoming a larger factor in the SPP market. And we do observe kind of across all scenarios that that eight to twelve dollar price spread that we see kind of in recent history and in the near term that converges to about four dollars.

So, we -- we are seeing a lot of, you know, price convergence across the different time periods.

And then the last point I'll make here is that, you know, this is just an annual level, but our model does forecast the prices at an hourly level, and the hourly forecasts are what we use to kind of move over to the portfolio modeling side and stress test all of the PSO portfolio decisions. So, they get run against these prices for the kind of second half of this presentation. That's -- that's where all the price tests come from.

I think we have one more slide, if there aren't any specific questions here. Okay. We can move.

So, the last scenario output slide that we've got here shows kind of what was alluded to a bit earlier. This is what the actual solar and storage capacity credits ended up being through time by the different scenarios.

So, as we discussed, you know, there is a rapid build-out of solar and storage across the SPP market. And when we look at how fast or when that build-out occurs and what the effective ELCC or peak credit would be for the technologies, we see the kind of most pessimistic or lowest capacity credit being in the CETA case. And that's the yellow line in both of these graphs.

And that case really has much more rapid deployment of both solar and storage. And you can see how the peak credit that would be used for PSO decisions how that declines faster, and it -- you know, it kind of levels off, but it's materially lower than the other cases.

The other cases will have -- you know, the -- the NCR case has the lowest renewable penetration, mostly due to no carbon assumption and the lowest natural gas price. So, that case kind of maintains a bit higher capacity credit for both solar and storage.

And then somewhere in the middle are the other three cases, which for varying reasons have, you know, pretty similar amounts of resource, or in the case of FOR it's got less resource, but the credit assigned to it would be less, so -- but overall I think this does give us a -- a good range of different capacity credits through time since these -- the credit that would -- could be assumed for either of these technologies is highly dependent on what the other market participants are doing.

So, you know, this is kind of unique, but this is the way that we're capturing that kind of uncertainty in our analysis.

SCOTT NORWOOD: What -- what does the wind capacity credit curve look like?

MR. PAINLEY: Yeah. The -- the wind capacity credit is assumed to stay constant at fourteen point seven percent.

SCOTT NORWOOD: Okay.

MR. PAINLEY: This is -- you know, we are relying on the SPP ELCC publications for this, as well, and also, you know, there's a lot more wind in the market so we kind of can observe what has happened.

And we think that fourteen point seven number is reflective of the current wind in the market and also how that wind would be applied and how it would be credited going forward. So, we thought that the constant value was pretty reasonable.

MR. SOLLER: All right. So, thank you, Jonathan. Before we go into break, we -- there is a few more minutes from the -- from the agenda timeline. I know that Montelle has one question -- we'll look back where it's listed.

So, the model doesn't select -- he's asking if -- if the model is not selecting DSM, and, you know, Montelle, feel free to come off and, you know, converse with me.

But, you know, I don't know if that maybe is a misunderstanding. What we had talked about earlier in the slides were the supply slide resources. In fact, the modeling is able, and it is -- we are letting the model select various DSM resources, whether it's DR, energy efficiency, CER resources.

So, the model is selecting that or has the option to select relative to supply sides. Just maybe -- Montelle, does that clarify where your question might be stemming from?

MONTELLE CLARK: Yes. And -- and perhaps the DSM resource is small enough that it doesn't show up on your graphic. And so, if -- if that's the case, forgive me, but I just didn't see it listed --

MR. SOLLER: Yeah.

MONTELLE CLARK: -- in that previous graphic up there. And then also, you know, the -- the challenging part with DSM is it's generally treated as an -- as an energy resource and not a capacity resource, and it's hard to figure out what is the capacity cost associated with DSM savings.

So, I wondered if you had a -- is there a number you're working with on the -- the cost of a saved kilowatt with DSM? How -- how do you determine that, or are you simply limiting it by the perceived restrictions on spending from the Commission rules?

So, can -- can you -- can you address a little bit of that for me?

MR. SOLLER: I want to make sure I understand your question a little bit. In terms of the costs for our energy efficiency resources, for instance, demand, what is the -- that relative capacity cost? Is that --

MONTELLE CLARK: Correct.

MR. SOLLER: You know, we -- so, the -- the capacity cost would still essentially be tied to some of the fundamentals forecasts that we have in terms of, you know, saved capacity.

So, that -- that's how I -- I would answer you in terms of, you know, avoided, and, you know, with regards to the energy efficiency and the cost of those or the other supply -- or demand side resources, you know, that will come up, and we will show the -- the numbers aren't -- or at least the capacities for the different DSM resources, you'll see that in the upcoming slides as far as how the cumulative totals of -- relative to the other supply side resources.

So, in -- in essence, they are not a large, large number, and they typically aren't, but they're -- they're not insignificant at the same point. So, it's -- it's important that we still let them compete for the relative solution.

So, let me pause and see if you want to do some follow-up or do some more questions you want to talk about.

MONTELLE CLARK: Yeah. And I don't want to go too far into the weeds on this, and -- and, you know, Jeff Brown and I can talk about it.

But I'm trying to get a sense of if -- if -- aside from restrictions based on spending limitations from the Commission, if DSM was simply treated as a selectable resource, a capacity resource, not just an energy resource, where would it fall on this scenario and -- and what price are you using, if we -- we have a sense of the price, you know, per kilowatt hour, you know, of solar and wind, et cetera, combustion turbines.

But do you have a price that you use for treating DSM as a potential selectable capacity resource, and how does that compare with the prices that are -- that we're seeing for the other resources?

MR. SOLLER: Jonathan, you want to -- I -- I don't know if you're able to talk. It -- it is selected as a -- a capacity essentially in some of these, not the --

MR. PAINLEY: I'll make maybe a quick clarification. So, I think there's a distinction between the SPP market scenarios that we model versus the PSO portfolio.

So, at the PSO portfolio level DSM can be selected, and it will be selected based off of its energy and capacity contributions. So, we take both into account.

I think we will get into that in future slides, and if not, we maybe can look up a bit more on that at -- at the break.

But I think at the market scenario side we're testing different wholesale growth rates across SPP, and I guess the assumption would be that DSM is folded into some of those different growth rates, but we wouldn't allow DSM or we don't model DSM at the SPP level because it's too specific to, you know, different types of load and different programs that utilities might run.

And I -- I don't know that that's a -- it wouldn't kind of make enough of an impact to kind of change the outlooks, I don't think, at the scenario level, but when we get to the portfolio side I think we can describe more about what we do for PSO.

MONTELLE CLARK: Okay. Thanks for helping with that.

SCOTT NORWOOD: One more really quick question. These capacity credit curves -- those are derived, or are those -- is that from some study, or is that what you input, or is that a derivation of your runs?

MR. PAINLEY: Yeah. It is derived as part of a model output from our modeling. So, you know, the input is kind of the -- the credit that would be assigned to different levels of capacity, and then the output would be, you know, what capacity gets installed and how much would it end up counting towards the, you know, market-wide reserve margin target.

SCOTT NORWOOD: Okay. So, it's based on basically how much it's supplying on-peak and applying that to the SPP criteria or --

MR. PAINLEY: Yeah --

SCOTT NORWOOD: -- formula or whatever? Okay.

MR. SOLLER: Okay. Thank you, Jonathan. So, at this point I don't see any more questions in our chat. And we are right on schedule, frankly, so I appreciate the dialogue we've had.

It's been healthy for us to -- to hopefully keep everybody engaged and clear up to this point. I'd like to extend -- and let's take a break for fifteen minutes. We'll come back at a quarter till the hour. And we will -- we'll start getting into the -- the actual portfolio results.

And, Scott, I hope we will have an opportunity to answer some of the questions that are popping up in your head, and we can delve deeper into those as

-- as we need to.

So, let's -- we will break now, and we'll return in about fifteen minutes. So, thank you.

(A recess was taken from 11:30 a.m. to 11:45 a.m.)

MR. SOLLER: All right. So, it's about fifteen minutes before the hour, and I would like to proceed. I hope everybody is -- is back with us at this point.

We will move into the next half of our discussion, which really is about the portfolio, the development process, the -- and the -- the results that we -- we learned from this -- this IRP.

So, I'd like to introduce Mr. Robert Kaineg of Charles River Associates. He will walk us through the next half of the discussion today. And, Robert, if you want to come on -- come off mute, I think this is the best time, and we will let you pick up from here.

MR. KAINEG: Okay. You can hear me okay, Greg?

MR. SOLLER: Yes, sir.

MR. KAINEG: Great. Thank you all for having us today and for joining us. So, where

Jonathan spent the last section of the presentation discussing the scenarios that were run, which are the views that the broader SPP market that PSO is going to have to operate its system in in the future, I'm going to talk a little bit about the portfolio development, which is how we developed alongside PSO and the AEP team a set of candidate portfolios using those five scenarios and the analysis that we did to evaluate what the Preferred Plan might be for PSO going forward in this Integrated Resource Plan.

So, there's a lot going on on this slide. But just to start, on the upper left-hand side here you can see the five scenarios that were referenced by Jonathan in the prior section. And each of those scenarios produced a set of market conditions, forecasted market conditions that included the power prices, technology costs, the load outlook and ELCC and puts all those elements that we were talking about.

And what -- what -- the next step that we took was to evaluate in each one of those scenarios an optimal supply mix that was using Aurora's portfolio model to select from a set of demand and supply side resources to find the -- the optimal or lowest costs set of resources to meet expected customer needs, you know, subject to a set of constraints, making sure, for example, that you are meeting your peak requirements and there's limits on how long you can go in the market and that type of thing, but in general that's the approach.

On the demand side we looked at four different resources that could be selected. The first was energy efficiency. The second was demand response. The third was distributed generation. And the fourth was conservation voltage reduction.

And so, what we did in this case were to offer the model different bundles, in the case of energy efficiency at different cost levels, and those would have a certain amount of energy and demand that they supply to the peak demand that they supply to the portfolio and a cost. And, actually, some of those costs are summarized on Slide 54 in response to a comment from an earlier -- earlier stakeholder comment.

So, there's a -- there are tranches available or bundles available that -- that increase in cost and provides more of that service, more energy and more peak demand than the model could select from the -- separately the model had an option of supply side resources that it could choose from, the new generation. This included wind and solar units, gas-fired CTs and combined cycles, four-hour battery storage, retrofits -- carbon capture retrofits on existing units, new hydrogen-fired or dedicated hydrogen CTs and then finally a -- a set of advanced nuclear and storage technology that it could select from.

And so, what Aurora does, is it selects the least cost combination new resources, so it's minimizing the costs of meeting the objective. And it does that for each five scenarios -- for each of the five scenarios and get us a set of candidate portfolios to evaluate.

So, what we did with that set of candidate portfolios was first to look at the five overall optimal solutions, and then make a few adjustments to those -- from those solutions to cover areas that weren't necessarily captured via the least-cost balances.

And the reason for doing this is that, as Jim alluded to at the front of the presentation, there's -- there's more than just lowest cost. There's more to the objectives in this IRP beyond simply lowest costs.

So, even while we want to be certainly mindful of costs in evaluating the least-cost solution, we want to be -- perform the analysis in a way that speaks to the other objective, including rate stability, maintaining reliability, providing positive local impact and -- and achieving sustainability targets, making sure that we're covering all those -- all those bases.

That was the process that we took and then from those -- from that process we selected or PSO selected a preferred portfolio.

Go to the next slide, please. So, the preferred portfolio -- I believe we shared this with you earlier in the -- the executive summary, but taking another look at it.

This is the preferred portfolio, which is a variation, a modification of the Reference portfolio that accelerated a little over to the solar deployment that we were seeing in that optimal solution to, I guess, in a way allow a little more earlier in the process to meet a capacity gap that was -- that was opening up.

So, what we can see when you take away from this -- or what you take away when you look at this is really I think three things. First, you can see on the bottom the hashed black lines. That's the demand side resource that's being selected by the model, and you can see that it becomes non-trivial by the end of the modeling period.

It's a hundred and twenty -- a hundred and nine or a hundred and twenty-two megawatts depending on how you are measuring it. And then the -- you can see then the wind and solar, a lot of the new additions, which are the hashed on top are -- are wind and solar.

So, the model suddenly choosing under the Reference case conditions really to rely on -- on new wind and solar resources to both meet energy needs and also fill that last bit of capacity gap, which is sensible in our view because there's a lot of existing capacity still in the portfolio.

So, you can see that even as we're getting out into 2030, the existing gaps that's -- that's in the portfolio provide almost seventy percent of the total firm capacity that's needed. So, we are able to fill that -- that last gap then with the -- that last twenty to thirty percent then with the -- the new solar and -- and wind resources providing that extra support. And I think those are the two key elements I'll -- I'll draw on this slide, and we can sort of come back to this at the end if there is any further questions about the -- the resource selection here.

SCOTT NORWOOD: Just -- just very quick, where is storage?

MR. KAINEG: So, storage is not selected in the Preferred Plan.

SCOTT NORWOOD: Okay. Why -- why is that?

MR. KAINEG: Well, it wasn't part of the least-cost solution, so it was not -- the model was finding that it didn't require storage to meet its reserve requirements. It was able to meet that in combination with stand-alone solar and wind resources, so they're simply more economic.

SCOTT NORWOOD: Okay.

MR. KAINEG: So, this -- what I showed previously with the stats bar which included the existing resources, this slide is a table that just -- or two tables, I should say, that just include the -- the details of the -- the resources that were selected, the incremental resources on top of the existing portfolio.

So, starting on the right-hand side you can see that there was a fair amount of demand response, energy efficiency, distributed generation and CVR, all selected as part of the Preferred Plan. And those total a hundred and twen- -- twenty-two megawatts.

That's a little more than a hundred and nine we showed in the first slide because we're -- we're grossing that up here to account for the fact that these -- these resources are located at the load centers, so they don't require that twelve percent reserve planning margin that SPP requires. So, that's the difference between the hundred and nine we showed in the first slide, and then a hundred and nine is the nameplate, and then the hundred and twenty-two is what their effective contribution, considering that they don't need to be covered with that planning reserve margin.

On the left-hand side we see the nameplate additions of the utility scale builds. You can see that there is a large plug of solar and wind resources that are built in twenty-four and twenty-five, with the model really concentrating on those years to take advantage of the ITC and PTC, the production tax credits and the investment tax credits which is available to the units in those years.

The PTC in particular is -- is quite important for the wind units. That's because it adds to the -- essentially the amount of value that they generate every megawatt hour so they can really -- really have a lot of impact over time.

And then that puts -- those early additions put PSO in a good position to meet its reserve margin requirements for some time until we start to see some additional contracts rolling off later in the -- in the modeling period as some additional new solar built out in 2030 and 2031 to meet that capacity gap and also provide energy to the portfolio.

SCOTT NORWOOD: Real quickly, any limits in the modeling on amount of capacity that could be added or types of capacity that could be added?

MR. KAINEG: Yeah. So, we did include a four hundred and fifty annual limit, four-fifty megawatt annual limit on the amount of solar that could be built per year. So, the original model solution which is today the Modified Reference case was to build four and hundred fifty megawatts in 2040 -- excuse me -- 2024, 2025, and then four and hundred and fifty more just a year or two later.

And so, the decision was made to modify that to bring some of that later optimal solar earlier to both capture the ITC and avoid what would be a short-term capacity gap earlier in the modeling period, and it obviously remains to be seen whether all of that can be sourced.

But based on the amount of deployment which is -- which is potentially available in ITC, we think that's a realistic number.

SCOTT NORWOOD: What is the thought --

MR. KAINEG: On the wind side is the fourteen hundred -- fourteen hundred megawatt limit annually.

SCOTT NORWOOD: Yeah. What is the thought behind that, is it, i.e., limit solar and -- why do you limit wind?

MR. KAINEG: So, I'm going to defer to the -- well, first of all, there's I think some practical limit to just how much can be installed in any given year, which you want to reflect, and then subsequently those numbers were developed by the AEP team, so maybe I will turn that over to Greg to provide a -- an answer to that.

MR. SOLLER: Yeah, Scott. I -- maybe I'll -- I'll offer it this way. These -- the annual limits are something we -- we typically see when we do the RFPs in terms of, you know, the responses we get from RFPs, how much is in the market ready to go.

So, that's -- that's a big source of input for us to consider, and we have got the RFP that's ongoing now, so that will -- this nine hundred that's in the Preferred Plan we will talk more about that.

We will -- we'll continue to validate that through the RFP process, but that's -- that's a big part of it, is -- is how much is really in the market ready to support these plans, as well.

MR. KAINEG: And then for the second part of your question, Scott, there were some other limits on some of the advanced technologies, so, for example, we didn't allow new nuclear to be selected by the model until later in the modeling period, 20- -- 2028 or 2030, I think it's tucked in in the RFP, just reflects that tech- -- technology is still being developed, and also some of the dedicated hydrogen resources not available until later -- later in the modeling period.

SCOTT NORWOOD: Okay. I haven't read all the details --

(Clarification.)

MR. KAINEG: No worries. So, we were just saying that the -- the nuclear SMR, which is the small medium reactor, isn't available until later in the modeling period because that technology is still being developed, and then similarly dedicated hydrogen CT was also -- hydrogen CT was also not made available until later in the modeling to reflect that that technology is being developed.

I'm sorry, Scott. You are -- were you asking another question?

SCOTT NORWOOD: Just -- just very quickly if you know, then the -- the RFP is not going to limit to these amounts. If you get fifteen hundred megawatts of really good solar offers, you'd -- you would go ahead and add those and -- I mean, you are not -- you are not going to restrict the RFP to these quantities, I take it.

MR. KAINEG: No --

MR. SOLLER: Let me -- let me jump in here a little bit. The RFP isn't restricted to what the IRP says for sure, Scott. I think we have the opportunity to flex based on what the RFP results do come in at.

We're -- you know, the IRP really is identifying, you know, from a Reference case maybe an optimal solution, you know, mathematical solution based on some -- some parameters we have got to, you know, place in the model, and then we make some other judgment decisions that supports PSO's objectives, which is part of what -- what you're seeing in this case, for instance, the annual -- that is Preferred Plan is a -- and we will get more into it, Scott, the -- the Reference case, the optimal solution, because of the limited four fifty was selected.

But, you know, there is that opportunity potentially if the RFP comes back very strong, you know, that -- that we're looking -- we could do flex all the -- you know, maybe double that amount and, you know, support a few other initiatives or support those objectives and still maintain a very cost effective plan.

SCOTT NORWOOD: Okay.

MR. SOLLER: All right. Robert?

MR. KAINEG: Moving onto the next slide, I think we have covered the key elements here.

MR. SOLLER: Okay.

MR. KAINEG: So, where we were showing you the detail of the Preferred Plan from a capacity perspective on the prior slide, here we're switching in two different ways, one we're moving to a generation view, so where we were looking at capacity before now we're looking at the total generation provided across the portfolio in year 2031, and we're also now looking across more of the portfolio.

So, where previously we were looking at the left-most circle here and focused on that area, now we're introducing some of the other portfolios that were solved as part of our portfolio development process.

So, just going left to right, you can see the Reference and the Modified Reference portfolio are represented by this -- this single chart. That's because the only difference between these two portfolios is whether some amount of solar is added in 2027 or 2024. And so, by 2030 they are identical. So, that's -- that's the mix that you see there.

You can see that by that time almost ninety percent of the energy generated in the portfolio is from renewable sources with a balance primarily being made up by gas units with a little bit of other there being the energy efficiency and the other sources that we discussed, the demand side sources.

The CETA portfolio shows a similar outcome. This was optimized under the CETA scenario, and we have a subtly different mix of solar and -- and wind here, but the general outcome is quite similar from the portfolio perspective, at least in proportion, with a little bit more solar in this case as the ITC and PTC are extended out in time and the load that's expected to grow more rapidly in this case.

There's just more room for some of that midday energy that's provided by the solar resources, and then, of course, the -- Jonathan showed the ELCC associated with solar somewhat lower in those cases, and so you tend to have a little bit more of it to end up with the same amount of capacity.

In the ECR portfolio, which is the high carbon case combined with high gas price, again, a roughly similar outcome with ninety percent of total generation by 2031 coming from primarily renewable sources with a slightly -- a slight preference for wind in this case with the -- you know, the -- the -- the combination of the richer energy price really helping those units because they have a higher capacity factor than solar units.

The CC portfolio you notice has the star. This is the next portfolio that we made some extra judgment on. So, there weren't any natural gas combined cycles that were selected as an optimal solution in -- in any of the scenarios that we ran.

So, even when we combined no CO2 prices with low gas prices in the NCR portfolio, as you see, we still didn't have the selection of a new base load gas resource.

And so, in an effort to try to tease out the trade-off between a more renewable heavy portfolio and a more gas heavy portfolio we thought it was wise to include a CC portfolio at least on the Scorecard as a point of comparison and also to see if maybe it did perform more -- or better, I guess, against some of the non-cost objectives.

And then the other -- the other justification here was that I mentioned before how we had optimized a portfolio in each scenario. And if you recall from the scenario metrics, the only difference between the FOR, the Focus On Resiliency scenario, and the Reference scenario was the SPP capacity constructs.

So, we incorporated a winter requirement -- winter planning requirement and then also reduced the -- the capacity value that was awarded to certain resources.

And because in -- in PSO's case the difference between summer and winter peaks is so great, you -- you actually end up with a very similar, almost identical portfolio to the Reference case, even when you apply this -- this winter requirement. And so, the CC portfolio also has the impact of removing a duplicative portfolio from our consideration.

And then finally we see the NCR portfolio over to the right-hand side. This was the portfolio optimized in the No Carbon Regulation case which combined both low gas prices and zero CO2 price.

You can see even in this case the renewable resources are still preferred because they have just a lower cost overall, and the capacity value which is awarded to solar in this case actually tends to be higher than in the other portfolios simply because this scenario solves for less solar SPP-wide.

And so, it tends to provide a little more capacity in the -- in the PSO portfolio than when run in that scenario.

SCOTT NORWOOD: You may have just told me this, but the -- is the model selecting combined cycle over CTs?

MR. KAINEG: So, the model did not select any new combined cycles in any of the scenarios that we ran. We did see a new gas selection, which we will get to on the next slide, actually, in the CETA portfolio, which is the Clean Energy Technology Advancement case.

And, really, that has to do with the greater load growth that's projected in that world, and so, with that additional load growth there was a need for more permanent capacity.

So, even though it's a -- a clean energy case, we actually see a -- an additional gas build there. And, actually, the next slide would be a great --

SCOTT NORWOOD: Okay.

MR. KAINEG: -- alternative to -- that illustrates it. So, I think -- this breaks out, I think, a little bit easier, getting at your question. So, Scott, if you look at the bottom left-hand corner, you can see what was selected from new gas resources across all the cases.

You can see there were only two cases that showed a -- any new gas resource selected. The CC portfolio, which is where we actually force it in, and then the CETA portfolio where it was actually selected as a -- as the lowest cost optimal solution. But that was a CT -- a gas-fired CT that was selected in that case.

So, moving upward from that where the prior slide showed the energy view of the portfolios, this shows a capacity view. And so, each of these charts here is the nameplate capacity addition, cumulative number over the course of the forecasts in each of the portfolios we were just discussing.

So, we just discussed gas on the bottom left-hand side. Moving up to the top left-hand side, you can see that the results in terms of the solar build-out was remarkably consistent across nearly all the cases that we looked at.

So, in general, the model was choosing to build as much solar as we made available, and when it was ITC enabled. The only real outlier here would be the -- the NGCT portfolio, and that's because we had actually, you know, forced in a natural gas combined cycle, which just reduced the both capacity and energy needs of the portfolio, so we don't see any selected there.

You can see here also how the Modified Reference case ends up with the same level of solar overall as the Reference case, so that's the orange and the black. It's just we allowed four hundred and fifty to come in just a bit sooner in the Modified Reference case. So, that's just the -- the only difference between those two portfolios.

Moving to the right-hand side on the top right we see wind, so what you see here is actually to see how the extension of the PTC for wind results in slightly -- a slight delay in the build in the CETA portfolio.

So, you might recall that in the CETA scenario we allowed a -- we had a -- included a tax credit extension of ten years. And so, we do see that when -- when that is relaxed a bit and the model has more time to get a high PTC value when it does tend to wait a year. Obviously, you can see that there in the results.

But, otherwise, it's very consistent across portfolios to get about as much wind as you can get. So, the model does like to pick that -- those fourteen hundred -- excuse me -- fourteen hundred megawatt plugs in twenty-four and twenty-five with remarkable consistency, regardless of the condition.

We already talked about gas, so I'll just move down to the bottom right-hand corner which shows storage. And so, we do see some storage constructed in our portfolios, so we weren't without storage builds. But these are primarily occurring in two cases.

So, the first -- the CETA portfolio -- and recall in this case that we have lower overall costs for these storage units, so they are more competitive in this case, and also there's that faster load growth.

So, those two factors combined to bring in some storage resource starting in 2025 and then some more later in the 2030s when the technology costs get quite low and it becomes more competitive actually than -- than gas in this -- in this portfolio.

And then finally in the -- the No Carbon Regulation case counterintuitively maybe we do see some small amount of storage built, and again, this is a result of that ELCC difference.

So, because the units are -- are higher valued in this portfolio over time from a capacity perspective, it just makes sense to -- to bring them on, even though the power price is just somewhat low in this case and there's no carbon price.

SCOTT NORWOOD: And these are -- these are carbon capacity credit numbers, or are they name- --

MR. KAINEG: These are nameplate. These are nameplate.

SCOTT NORWOOD: These are nameplate. Okay.

MR. KAINEG: Cumulative nameplate numbers, yeah.

SCOTT NORWOOD: Okay. And -- okay.

MR. KAINEG: So, the same way that there was -- oh, go ahead, Scott.

SCOTT NORWOOD: One other quick one, the -- the last -- the last frame. Why are we -- you have the capacity credit curves earlier. Why are we not seeing a need generated from that at some point?

MR. KAINEG: Well, you are, actually. So, if we can go up to two -- two slides, I think, to the Preferred Plan -- still up more -- yeah. So, there's no solar -- sorry, yeah, the one that has the bars on it.

So, there's -- there's no additional resource which is being built between 2026, let's call it, and 2030, but you can actually see if you look at the chart closely that that amount of capacity which is being provided by solar is getting a little smaller from year to year.

SCOTT NORWOOD: Yeah.

MR. KAINEG: Right? And that's the effect of that ELCC curve. So, you have the same nameplate in twenty-seven, twenty-eight, twenty-nine, but if you can look at the chart carefully you can see that that actually -- that wedge of -- is shrinking a little bit, and that's the effect of the ELCC.

SCOTT NORWOOD: Okay.

MR. KAINEG: It's just beating that out by that DSM being selected. Okay. So, moving to the next --

(Clarification.)

MR. KAINEG: No -- no problem. So, where the prior slide was comparing the difference in the supply-side selection by portfolio, this slide is comparing the demand side selections. So, you can see that there was variation in what was selected across the portfolio that -- that we evaluated.

And for the most part we see that these portfolios are coming in at a relatively stable level. That middle group there which includes the

Reference, CETA and CC portfolios, there's a little bit of variation there which is primarily caused by a one- or two-year delay in the timing of the selections.

But overall they are clustering around that -- sort of that amount of DSM being selected with the outliers being the ECR and NCR cases, which are highest and lowest power price cases, respectively, which is sensible I think that in the scenarios where we are seeing much higher power prices, more of our DSM and EE is getting selected, and in the cases where we're seeing much lower power prices less of it is getting selected.

So, I think that these results make sense and -- and illustrate the different selections of the model across these different scenarios from a demand side perspective.

Moving on, so up until now we have just talked about what was selected by the model, and so I have a few key take-aways which really relate to that. So, we will get down to what PSO prefers in a minute, but just when we looked at the overall portfolio results and started to develop some insights I think a few things came out.

The first is a point that I hit on a few times already, but it's that, you know, new natural gas combined cycles were just not optimal under any of the wide side of market conditions that we evaluated, including those with no CO2 price and a low gas price.

So, I think it was clear that that was not a preferred strategy, at least from a lowest cost perspective.

The second was this capacity question that -- that Scott has alluded to a few times, I think. But it's that, you know, because there's so much existing gas in the portfolio, existing units, you really are able to meet that going forward capacity need with the addition of solar and storage units so that those are able to -- even though they don't provide -- they only provide a fraction of their nameplate as a firm capacity resource, having that existing gas in the portfolio allows you to meet the gas primarily with these renewable resources.

The next insight that we -- we noted, looking across these portfolios, was that the level of solar resource was highly dependent on the capacity value that it was awarded.

So, we had a few different scenarios which ended up with similar levels of energy prices as we saw it previously, but the difference in that ELCC value did swing how the portfolio selected solar, so clearly that -- getting that extra capacity value for the solar is important.

And that really has to do with the fact that it's competing with wind at the end of the day. So, wind provides just more energy to the portfolio overall than solar does.

And so, the solar is relying then on that additional capacity value to give it an edge up in many ways over the wind. I mean, that's a simplification, but it -- it certainly, I think, comes out of the -- the results that we have seen.

SCOTT NORWOOD: I mean, in terms of --

MR. KAINEG: And the top -- and --

SCOTT NORWOOD: Very quickly, in terms of competing, solar has lower capital costs, lower O&M costs, more on-peak energies. So, why -- why is it a slam-dunk that wind is the selection, the capacity value --

MR. KAINEG: So, there's -- there's two factors, Scott. One, I -- I don't think it's fair to characterize wind as a slam-dunk. I think what they are is they are in competition with each other. And there's two -- there's two elements to consider.

The first is winter, right? So, even though solar provides a lot of on-peak energy in summer, if you have a winter peak at 7:00 a.m. in January, your solar doesn't provide a lot, but your wind is still giving you fifteen percent.

So, there is value in holding onto wind from a capacity perspective during certain seasons. And then separately wind just provides more energy and it's being built in a time when it's eligible for a production tax credit. So, that's a lot of additional revenue that's generated by those units. So, that's what I was talking about --

SCOTT NORWOOD: So, the solar -- the solar tax credit is going away in the modeling, and the PTC is continuing; is that -- is that --

MR. KAINEG: Well, the investment tax credit only applies when you build the unit. The production tax credit continues into the future. You continue to generate production tax credits as you continue to generate energy.

SCOTT NORWOOD: Okay. So, you're assuming whoever is the owner is not going to pass through that cost advantage or it is not going to be a -- not going to be reflected in -- but the company won't own solar assets or --

MR. KAINEG: I mean, solar is getting selected up until the limit that we put on the model. So, I don't --

SCOTT NORWOOD: Yeah, okay.

MR. KAINEG: I don't know that it's characterized as not being selected.

SCOTT NORWOOD: Yeah, okay. All right.

MR. KAINEG: And then I guess just a final insight very briefly was that we did offer the model, and there's -- the IRP, I think, spends a lot of time discussing the various advanced technologies, including different types of long-term storage, SMR reactors, hydrogen-fired solutions.

We did offer all those technology options to the portfolio model, but they just weren't selected using this set of assumptions that we have used. Obviously, there's a lot that's still there to learn about these technologies, and the costs could turn out different than we see them right now.

But given the -- the market conditions that -- that we forecast and the assumptions that we used, these just weren't an optimal solution.

SCOTT NORWOOD: Let -- let me ask one

other thing. The -- the first bullet, it -- now that's a little bit surprising to me, but if that's true, what is -- is that reflected in the gas price forecast? I mean, is that -- does EIA understand that? Or I guess they do.

But, I mean, if you are not building any more combined cycle units, what's -- what's the demand of gas -- for gas?

MR. KAINEG: Well, we are using the low natural gas price in this case, right? So --

SCOTT NORWOOD: For the base?

MR. KAINEG: -- we gave it a --

SCOTT NORWOOD: For the --

MR. KAINEG: So -- so, in the NCR portfolio -- excuse me -- the NCR scenario we have zero CO2 price and a low gas price. Remember there were three gas prices on the board.

So, we combined the zero CO2 price with the low gas price.

SCOTT NORWOOD: Right.

MR. KAINEG: And even in that world it doesn't make sense for PSO to build new natural gas.

SCOTT NORWOOD: Wow. Interesting.

MR. SOLLER: All right. So, yes, and --

and thanks, Scott. And I think I want to just keep pushing forward. I know we have a lot more to get through, so we want to make sure we get into some of the results that -- that tie into some of your earlier questions, as well, Scott.

So, if it's okay, we will -- maybe we can continue to push forward.

MR. KAINEG: Let's go to the prior slide, please, just quickly. So, in terms of we talked about the generation of the portfolios and what is in each of the portfolios, but now we are going to talk about how we tested them and put them on the Scorecard.

So, to sort of perform the uncertainty analysis or the portfolio analysis, we chose two different methods. The first is a scenario analysis. So, we have a set now of six candidate portfolios that we discussed.

And we dispatched each of those portfolios in all of the market scenarios to evaluate how they performed and compared the performance across all the scenarios.

So, this approach is a what-if type of approach that answers the question what if the fundamental outlook for these commodity prices and load and all these fundamental market drivers that are external to -- to PSO change after capital is committed, right?

So, the -- or essentially you -- you've made a decision to build something because you have one view of the future, the future turns out very differently, what happens. That's what -- that -- that's what's covered on the left side here.

Then on the right-hand side we have the stochastic analysis, which I think gets to the question you had earlier, Scott, about the weather uncertainty.

So, under the stochastic analysis we do it would be different. So, instead of looking at what happens if all the fundamental drivers go a different direction, we introduced volatility and randomness into the key fundamental drivers, including natural gas prices, power prices and renewable output.

And this allows us to capture high-cost, low probability events like extreme weather that -- that creates tail risks for the portfolios, so the -- the risk that customers will face very high costs under bad conditions.

And so, we test that explicitly under the stochastic analysis. And I'm going to spend just a few slides talking through that because it's a little more complex than the scenario analysis which I think most of us can wrap our heads around that have been doing this for a while.

So, go to the next slide, please. So, to perform the stochastic analysis, we first selected our stochastic variables. So, those are the -- the elements that we were going to make random going into the model, the -- how the outcomes would change. And those were power prices at the hourly level, natural gas prices at the daily level, and then hourly and solar/wind outputs.

So, these cover, I think, key risks that they give those portfolios. First, that power prices could spike -- short-term power prices could spike, creating exposure for customers. Certainly natural gas prices spiking could also create exposure for customers, particularly in hours of low renewable output.

And then -- and finally I think that we're all aware that intermittent resources like solar and wind don't always perform exactly when you need them or may over-perform in hours when you don't.

So, we actually look at historical weather data and create a set of two hundred and fifty random combinations of these factors, which is applied -- which in each of our portfolios is actually dispatched in each of those two hundred and fifty random combinations. So, it creates quite a wide distribution of results.

And then moving to the right-hand part of the slide here, what we're looking at again today and what we're measuring is -- is the difference between the ninety-fifth percentile and the median, so essentially asking the question how much higher will costs be than the expected case under these extreme conditions.

So, when you're looking at your ninety-fifth percentile bad case, how much more does that cost you than your median case or your -- your fifth percentile case.

And so, that's a good relative metric for showing how much higher costs could be when exposed to these factors across these portfolios. We will see that on the Scorecard when we get down there.

So, just to illustrate that, the next two slides that I'll go through very quickly because we're getting short on time, and they are really just illustrations.

So, the black lines on these charts illustrate the power price in our deterministic modeling, so our scenario model. And then the gray line are just ten examples of the iterations that I have described where we are looking at random fluctuations in gas and power prices. Then you can see that they get quite spiky.

So, on gas, for example, we have many days where the gas price is above five dollars in this example, and then on the power price we have similar days where power prices are well above a hundred dollars a megawatt hour and go quite a ways up. And so, we are really looking at these short-term high-cost events.

The next slide just shows the same type of distribution, but for the wind and the solar outputs. So, again, the thick line or the dark bolded line is these deterministic tendencies, so what is the average view of -- of solar and wind output in -- in January and in July case. And then the lighter colors show how within a day those variations could be quite wide.

And so, what we did were to -- to look at cases where, you know, we're getting those types of spiky ups and downs in the wind and the solar output and how that impacts the portfolio.

You can see it obviously for solar there's no solar at night. That's why that goes down to zero, starting right around hour nineteen or twenty in both cases and running through the evening.

And these were developed based on historical weather data that was sampled on different locations in the service territory.

Moving on, so what I've described previously was the framework for how we evaluated the different portfolios to determine their objectives against this Scorecard. So, at the end of the day we have the four objectives that we opened the call with: customer affordability, rate stability, maintaining reliability, local impacts and sustainability.

So, there's a lot on this slide. You don't need to memorize all these. I'm going through them here in a minute. But I think the main take-away is that we tried to make measurable performance indicators under each one of these objectives and assigned them with metrics that we can evaluate to try and see how the portfolios rank relative to one another towards meeting these objectives.

And it's a key -- a key thing to take away from this and a point I want to make is that the Scorecard does not add up to the answer. It doesn't create a composite number at the end of the day that tells you what the Preferred Plan ought to be.

The purpose of the Scorecard is really to illustrate the trade-off between these different objectives which have already been defined as important to the company and its customers so that you could have an informed discussion about what you're giving up and what you're getting when you are choosing different selections of resources that you might choose for the Preferred Plan.

So, what I'll do then on the next slide is talk through each of the objectives, the scoring of those metrics and then how they scored.

So, for customer affordability we have two different indicators that we're using. The first is a short-term five-year CAGR or Compound Annual Growth Rate, which shows how much power supply costs are increasing on a percentage basis across the different portfolios over the first five years of the forecast.

So, this only accounts for, you know, the operational costs of existing resources and then all the costs of new resources. So, any ongoing capital, for example, existing resources, are not reflected in this rate. It is just the no fur- -- the -- resource selection that was made, how fast is that rate growing.

And then we have also a medium-term indicator which looks at the net present value of system costs over the full ten years that we evaluated.

So, essentially, if you are looking at the full costs of operating the system, including all the resource selections that I just described over ten years and look at that from a present value perspective, how do they compare.

So, both of these are relatively straightforward. A lower number is better, indicating that you've got slower road -- slower growth -- excuse me -- in customer rates and less overall net present costs of -- of your portfolio.

So, going to the next slide, so on this slide we are just ranking then the key portfolios, candidate portfolios against just these two performance indicators.

You can see that over the short term most of our portfolios perform quite similarly within twenty cents of each other -- or twenty percent --

two-tenths -- excuse me -- of a percent of each other.

So, the Reference Modified portfolio, which was the Preferred Plan, is in this lower cost cluster. Then there are also two portfolios which turned out materially higher costs from a short-term perspective. Those were the Enhanced Carbon Regulation and ECR portfolios.

And you just have a few more resources being built earlier in these portfolios, and as a result you see higher costs, and that's really exacerbated actually in the CETA portfolio because of -- that was optimized in a world where load was growing very quickly.

Over the medium term we see again a real clustering of the portfolio costs with the Reference portfolio and the Modified Reference portfolio being almost identical as the least cost options from this affordability metric, with the ECR and CC portfolios being somewhat more expensive and the CETA portfolio being the most expensive, again because we just have more resource built out in this case.

So, I'm going to move on to the customer -- excuse me -- the rate stability metric, unless there's any questions about that.

So, under rate stability we are looking at three different indicators. The first is scenario resilience, which is how much does the ten-year costs -- net present costs of this portfolio change when it's subjected across every one of the scenarios that we ran, so what it was its lowest cost scenario, what was its highest cost scenario and what is the difference between those two numbers.

Generally a lower number is better here, indicating that you have less variation across different futures. But that can be a bit misleading if all those numbers are high, which we will see when we get to the next slide or -- or two slides from now.

And then the next metric that we looked at was cost risk. This is the stochastic metric that we discussed a few slides ago where we were evaluating how much higher portfolio costs could be in 2031 when exposed to high price events or extreme weather events.

Again, a lower number is better, indicating that there's less difference between your expected costs and the ninety-fifth percentile costs for this portfolio under those conditions.

And then the last metric that we looked at here was market exposure, which is a seasonal metric which looks at how much net purchases or sales you had in the winter or summer season in 2031.

So, closer to zero in this case indicates less reliance on the market to meet customer needs, but it isn't necessarily better or worse since there can be benefits to customers of selling energy into the market.

But it is a good indicator for -- for your -- your relative length in each season and how much you might rely on the market or not to balance your load.

So, move to the next slide. So, starting with the scenario resilience indicator, you'll see that the CC portfolio, the combined cycle portfolio, actually has the lowest score here, which is a bit of a surprise to us.

But the reason that it has such a low score is that it actually scores poorly in a lot of cases, and as a result it's not able to capture savings for customers under conditions where other portfolios can capture savings for customers. And we'll -- we'll see that illustrated here on the next slide.

From a cost risk perspective, which is the increase due to the stochastic risk, you can see that all the portfolios are pretty similarly risky, except for the CETA portfolio, which is materially higher, and as it's the higher, exposes customers more when the situation -- the market situation is -- is unfavorable, which we think is sensible because as we see, there's quite a bit more energy sales in that portfolio.

So, moving over to market exposure, you can see it -- it's twenty-two percent net long in the summer and forty-two percent net long in the winter, and as a result it just is -- is more exposed to variations in the market.

And then since I have already cued that up, we will over to market exposure. You can see that the Reference portfolio and the Modified Reference portfolio are very similar here, both being pretty close to their net summer requirement, just three percent long in summer and roughly twenty percent long in winter.

The other portfolios scored similarly here, I think the only stand-out being the No Carbon Regulation portfolio, which tends to actually rely a little bit on market purchases in the summer. As you can see there, it's a little short.

So, go down to the next slide. I want to dig into the scenario resilience metric a little bit, because I think that the result that we found with the CC portfolio having the lowest range was interesting.

And so, to unpack that a bit, what we're looking at here is a -- each line represents one of our portfolios and how it scored in each scenario. So, if we just follow the yellow line, for example, that's the CETA portfolio. That has lots of additional builds in it.

And you can see that under the CETA scenario it is the lowest cost, and that's because in that scenario we have combined faster load growth with PTC-ITC extension. So, it performs really well in that world.

So, when it's taken out of that framework, when it's not in a world with fast load growth combined with PTC-ITC extension, it gets very expensive. So, you can see that when it's run in the other four scenarios, it is the highest cost portfolio across the board.

Now, when we look at the Preferred Plan, which is the orange hashed line here, you can see that it is lowest cost or near lowest cost in every single scenario that we ran. So, even -- and in -- and in cases when it's not lowest cost, it's very, very close to lowest cost.

And then finally we just wanted to call the CC portfolio out here because you can see that while the range between the higher and lower values is tighter than for some of the other portfolios, it's really because it's not able to capture cost savings under the CETA, ECR and FOR scenarios.

So, when those market outcomes -- this is a very costly portfolio for customers where all -- most all the portfolios we looked at would save them money. So, that's kind of an interesting result.

So, I'll move onto the next set of metrics. Maintaining reliability -- so, again, we have three indicators for reliability. The first is planning reserves. So, here we're looking at the average level of planning reserves above peak requirement in the summer and winter season separately across the entire forecast period from 2022 to 2031.

We thought it was important to use an average across the period, as opposed to a single point value so we don't distort the outcomes by looking at just what's happening in 2031, for example.

The next thing that we loo- -- and -- and generally a higher number is better, so you want to have more planning reserves, that means more coverage for your customers. Otherwise, there can be lift to that if you have just got way more planning reserves than your customers need. That may not benefit them.

Finally -- or excuse me -- not finally. Next, operational flexibility. This is the number and -- of dispatchable units in your portfolio, as well as the total nameplate capacity of those units. So, in general, a higher number is better from a nameplate perspective -- perspective, indicating that you've got more rampable generation that you control.

And similarly having more units is generally better than having fewer units because it exposes you less to performance risk at any one location. If you have one large prime mover, for example, and that goes down, that can really expose you. If you have many small prime movers and one goes down, you are less exposed. So, that's why a lower number -- or excuse me -- a higher number is better in both of those cases.

And then the last metric that we looked at here was resource diversity, which is the proportion of generation provided by each technology type in 2031. And in general a less concentrated portfolio is better because overreliance on a single technology exposes customers to risks when the conditions for that technology are bad.

So, the example would be if you're heavy into solar and the sun doesn't shine for two or three days in a row, you can be in trouble. If you're heavily into gas and gas prices are elevated for two to three days, you could be in trouble, right? So, having a more diverse portfolio protects you from those one-off attempts.

So, moving to the scores themselves, so starting with the planning reserves we find that the Preferred Plan really meets summer requirement throughout the forecast, thirteen percent, and current planning reserve margin is twelve percent and -- and also put PSO on track to easily exceed any winter requirements that might be imposed by SPP, even keeping in mind that we do de-rate the solar units and -- more in winter, so this accounts for that, so good coverage across both seasons.

The CETA portfolio you can see has much higher numbers than the other portfolios. Again, this is a result of just having more build-outs in that case.

And then the ECR and NCR portfolios -- they -- they mostly cover customers, but do have the potential to leave customers exposed in summer over the long term. So, you know, obviously we don't know exactly how ELCC buys will turn out, but based on the analysis that we did those portfolios may be a little short in summer over the longer term.

In terms of operational flexibility, the CC portfolio was -- was among the best here because you have that additional combined cycle which is forced in.

The CETA portfolio also does very well because you simply have more units in that case, and a lot of new storage units come on towards the end of the -- the forecasting cycle. And because they are relatively small, you can kind of run up the score, as well, on the number of units.

The Reference portfolio was very similar to what we see in the NCR and the ECR cases, so generally good coverage there.

And then finally on the resource diversity mix I think one thing that -- that comes off this slide to me is how similar in many ways a lot of these portfolios are. I think that's because we are using this least cost optimization approach as the basis for generating at least our initial set of candidates.

And so, we do see a difference in reliance on the amounts of wind with the ECR portfolio and the NCR portfolio tending to rely more than the other portfolios on new wind resources, and the CETA portfolio tends to rely more than other portfolios on solar resources, but generally a good mix of both. And then as I mentioned before, it's really only the CC portfolio where we see a lot of gas representation. And that is because we told the model that it had to build that unit.

So, the last metric that we'll look at or the last set of indicators we'll look at is local impacts and sustainability. For local impacts we're looking at two different indicators.

The first is the total amount of net -- nameplate megawatt hours that are installed in the service territory. And the second piece is how much CAPEX is associated with those megawatts.

So, that's just an indication of essentially how much spending PSO may do in the service territory and potentially how many opportunities there might be for customer side in programs or customer located generators, because they are able to be in the service territory.

And then the second indicator that we looked at here was CO_2 emissions. And we're looking at the percentage reduction from the 2000 emissions level by 2031.

So, this aligns closely with a 2030 corporate target that AEP has announced, and in general the higher number is better, indicating a greater level of emissions reductions relative to that 2000 baseline.

So, going to the next slide, so in terms of scoring the Reference and Modified Reference portfolios were among the best scores in the local impacts category. The only portfolio that really does materially better was the CETA portfolio, just owing to the larger amount of resources which get built in that case.

And then from a CO_2 emissions perspective we see that most of the cases end up with quite high levels of emissions reductions, so ninety-five percent below 2000 levels by 2031, with the CC portfolio lagging behind a bit, owing to the additional gas exposure in that case, but still achieving eighty-four percent emissions reductions relative to the 2000 levels by 2031.

So, really, any of these cases I think put PSO on track to achieve the 2030 AEP corporate targets, and -- and all but the CC portfolio puts them on track to achieve the longer-term 2050 AEP corporate targets, as well, but not a lot of variation across the cases on this basis.

So, I have gone through now each of the objectives in detail, and that all culminates in the Scorecards. So, where previously we were looking at each of these objectives as a silo, now we can start to see the trade-off between the -- between the cases across the objectives.

So, with that I think we will leave it here and -- and open the questions, since you've already gone into the -- the details.

SCOTT NORWOOD: I have a couple of questions real quick. On the diversity slide, again, we're looking out through 2031, but I suspect as we go farther out we're going to have more renewable and more wind. And not so long ago seventy percent of wind on-line that would scare me to death, and the question is: Is your model accounting for, you know, regulation and all this cost to back up wind when the wind quits blowing?

MR. KAINEG: So, the SPP model scenarios themselves have to meet planning requirements, so they are -- the -- the scenarios themselves are -- are meeting the same requirements in SPP. And we're addressing the risks that the wind doesn't blow explicitly with our stochastic analysis where we look at hours where they -- it just doesn't show up. So, yeah, that's what we're capturing.

SCOTT NORWOOD: At some point you've got to build new conventional generation, I think, because you've got to have something to back it up when the wind quits blowing, unless you have got excess reserve across the region that somehow can -- through diversity can pick that up.

But do -- do you all think about that? Is that something you're missing by truncating at 2030 and '31 on the economics, or is it -- is that a concern? It -- that -- that scares me to death, but, you know, maybe not -- maybe not you.

But if you are not building any more gas and you have got a bunch of old gas units and you're shutting down your coal units, at -- at what point are you sort of exposed on the renewables?

MR. SOLLER: Robert, let me step in a little bit and maybe address some of the -- the concerns, Scott, because -- and I'll go back to really the next slide that -- you know, for the IRP we're really looking at that ten-year window from a planning horizon.

And -- and certainly we're going to have more IRPs to go through that -- that further evaluate the risk as -- as more renewables come on-line, not only on our portfolio, but, you know, the whole SPP portfolio.

This -- what I'm showing here I'm certain we have a lot of dispatchable gas resources that still remain as our total portfolio in this next ten years.

And how we -- how our decisions ultimately get made, you know, in the next subsequent IRP based on whatever regulations or incentives get imposed or introduced, that's -- that's yet for us to determine.

I would suggest that for this IRP and what we're hoping we have really tried to walk folks that are in attendance today through is the analysis we did, given the current environment, the current regulations.

I think, you know, to your point it's -- we have got dispatchable resources, and I -- and I think many other utilities do. But we still have an obligation to pay attention to the -- the -- the broader, I guess, environment here for our -- our rate-payers.

The -- the renewable resources do offer some -- some value in terms of costs, in terms of total portfolio costs. And that's what we're trying to get introduced in part with this plan.

So, I don't think I can really address your question in terms of what do we think is going to happen in twenty years here and, you know, how worried are we on the dispatchable versus non-dispatchable.

It's -- it's just a -- a constant question that we have to manage amongst many different, you know, inputs. So, I offer that as a feedback --

SCOTT NORWOOD: Yeah. I'm just not used to seeing IRPs that ignore the last ten years. Most of them look twenty years and, you know, obviously give more value to the near term.

But they at least know the answer on the last ten years, and this looks somewhat unsustainable to me. That's just a comment.

MR. SOLLER: Okay.

SCOTT NORWOOD: The second issue I want to be sure I understand the -- the tax credits because I -- I probably didn't listen well enough or write it down. But the PTCs you're assuming continue and are a credit for wind. The ITCs you're assuming go away for solar; is that correct?

MR. KAINEG: Scott, that's not precisely correct.

SCOTT NORWOOD: Okay.

MR. KAINEG: So, the ITC and the PTC both expire, right? So, your eligibility for those credits expires in both cases and on track with the current law in the Reference case.

SCOTT NORWOOD: Okay.

MR. KAINEG: What I'm hearing is the way that it works is once you are installed, if you're PTC eligible, you will continue to generate PTCs --

SCOTT NORWOOD: For ten years.

MR. KAINEG: Right, as you operate.

SCOTT NORWOOD: So, as a practical matter the way you've -- you've looked at ten years, the wind is going to have the PTCs throughout the study. And what about solar? What is the ITC?

How does that come in?

MR. KAINEG: So, wind built in 2027, for example, would not get PTC in our study.

SCOTT NORWOOD: Okay. So, '27 is when it rolls off?

MR. KAINEG: I believe that's right. I can look at the exact numbers, but yes. So, PTC and ITC eligibility both roll off. So, it's one of the reasons the model prefers to select resources earlier in the modeling period, because it can -- it's eligible for those PTC-ITCs.

If it waits longer, it won't get that. It just happens to be the case that the way the PTC is constructed, units that are built that are PTC eligible will continue to generate tax credits over time, but an ITC unit is going to get its benefit in the year that it's built, and that's it.

SCOTTD NORWOOD: Okay. And this eleven hundred and ninety dollars kilowatt number for solar, that's with ITCs, or is that --

MR. KAINEG: Exclusive of ITCs. So, the tax credits are assessed separately from the installed cost of the units.

SCOTT NORWOOD: Okay, okay. All right. That's all I have. Interesting presentation.

MR. SOLLER: And real quick, I know Montelle has -- has posed a question in the chat as far as confirm the generation mix charge, the CO2 emissions tables, that's inclusive of the contracted resources. The mix charts are inclusive, I believe. This is -- let me make sure we're talking to the same thing, Montelle. Well, let me ask you, Montelle, maybe I can -- before I assume it.

Can you come off mute and maybe clarify which charts you're referring to and make sure we're talking from the -- to the same points?

MONTELLE CLARK: I think you understand what I'm asking. I -- I'm not sure exactly which slide it is, but it's -- it's the one you have up there, I suppose.

MR. SOLLER: From the -- the pie charts?

MONTELLE CLARK: Yeah. That's generation mix. That's -- no, that's resource diversity. You had one that showed -- it's more of a horizontal. I've got your IRP document, not the slides, so I don't know which one it is.

But it basically showed that you're going to be around ninety percent renewable energy mix, generation mix, and it's ninety-five percent reduction in CO2 emissions from your twenty -- year 2000 baseline, I think.

And I just want to make certain that that included any contracted generation that you all have.

MR. SOLLER: Yeah. So, the generation mix that we're -- we're including would be the full portfolio as it -- as it's dispatched to the model. So, I think to the extent that, you know, we have got contracted renewable resources, I'd -- and I'd have to follow up specifically as far as the emissions from any contracted gas resources or others to be completely sure of that answer.

MR. PAINLEY: Greg, we -- for gas contracts we assign those emissions to the PSO portfolio.

MR. SOLLER: Okay. So, Montelle, I think that to give you -- yes, it incl- -- it's the mixed charts that you're looking at would be inclusive of the contracted resources involved then.

MONTELLE CLARK: Okay.

MR. SOLLER: So, hopefully, that helps, Montelle. And -- and I'll -- I'll make a couple comments here just to reinforce this slide up. And then I would like to turn it over -- unless there's other questions -- to let Matt Horeled make a few closing remarks.

But our objective was really to illustrate the -- the process, describe it, explain and -- and -- and be as transparent as possible in the -- in the time we have on the inputs, the assumptions we made, the analysis we did. And that led us to the decisions for this Preferred Plan.

And, you know, we -- we hope that it resonated with you. We hope there's lots of questions that were able to get answered or at least substantiated. We'll certainly take more information.

And at this point, Matt, let me bring you back into the fold and see if you want to add more comments to the stakeholders for -- for our steps to proceed.

MR. HORELED: Thank you, Greg, and our entire team for the presentation and also thank you, Scott, Montelle, and others for your -- for your comments and feedback. We really do appreciate this and the dialogue that we have all shared today, kind of walking through our modeling.

And, Greg, you did such a great job kind of wrapping this up that you didn't leave me much to do, which is always a good place for me to be in, I feel like. So, thank -- thank you for that. I really appreciate it.

But just to re-emphasize here on Page 48, you know, our -- our Preferred Plan conclusions, essentially our Preferred Plan scored that at or near best across all four of -- of our objectives measured in our Scorecard.

And I -- I think personally that the Scorecard is a really interesting way of laying out the information, and I -- I think it's a very helpful view, as well. And I hope you share in that thought, as well.

And the Preferred Plan maintains affordable and stable rates for our PSO customers, and it's expected to maintain reliability across seasons and create opportunities for local development by having locally owned and operated assets, while also reducing greenhouse gas emissions, as well, too.

And overall I just wanted to say once again thank you for all the feedback. Thank you for all the good dialogue. And if you have any additional questions, please -- please, send them to Fairo

Mitchell on our team. Send them over to Fairo, and we will -- we will address them as they -- as they come up.

But thank you all for your -- for your time and attention today. I appreciate it.

MR. SOLLER: All right. Well, with that, with no other comments we will adjourn today, and again, greatly appreciate everybody giving us the time and the feedback that you've provided for this particular IRP. Have a great rest of your day, folks. Thank you.

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(The above proceedings were concluded at 12:53 p.m., Tuesday, October 19, 2021.)

STATE OF OKLAHOMA }
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COUNTY OF OKLAHOMA COUNTY}

C E R T I F I C A T E

I, Carol S. Dennis, Registered Professional Reporter, Certified Shorthand Reporter, Official Court Reporter for the State of Oklahoma, do hereby certify that on October 19, 2021, the above proceedings were taken by me in machine shorthand and thereafter reduced to typewritten form by me. The foregoing transcript is a true and accurate record of the proceedings given to the best of my understanding and ability.

Whereupon, I have set my hand and seal.

____
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