SOUTHWESTERN ELECTRIC POWER COMPANY

An AEP Company

2023 Integrated Resource Plan Report
to the
Louisiana Public Service Commission

February 13, 2024

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Executive Summary

This Integrated Resource Plan ("IRP" or "Report") is submitted by Southwestern Electric Power Company ("SWEPCO" 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.

To meet its customers' future energy requirements, SWEPCO will continue the operation of, and ongoing investment in, its existing fleet of generation resources including its efficient base-load coal plants, its newer combined cycle and combustion turbine plants, its growing renewable resources and certain older gas-steam plants. In addition, SWEPCO's IRP considers the impacts of the evolving SPP resource adequacy requirements and the emergence of new technologies and renewable energy resources, both large-scale and distributed.

Keeping all of the multiple considerations discussed above in mind, SWEPCO has identified various future Scenarios and developed and analyzed corresponding generation portfolios that are forecasted to provide adequate supply and demand resources to reliably and safely meet its peak load obligations, while giving consideration to reducing or minimizing the costs to its customers, including energy costs, for the next twenty years.

For this IRP, SWEPCO identified four objectives aligning to customer and corporate priorities including: customer affordability, rate stability, maintaining reliability, and sustainability. The candidate resource portfolios are evaluated against these four objectives using the IRP Scorecard to consider merits between each portfolio.

Louisiana IRP Stakeholder Process

As part of the IRP Process, the Company held a stakeholder meeting as outlined in the LPSC IRP Process Schedule of Events #3 on March 29, 2022. In this meeting the Company discussed initial data assumptions and expected Scenarios and Portfolios to be modeled. A 2nd Stakeholder meeting was held on July 20, 2022 to provide an update of assumptions and inputs planned for the IRP. Stakeholders provided feedback that the Company considered in this IRP. Additional written questions provided outside of the Stakeholder meetings were submitted to the Company that were also considered as part of this IRP.

Following the release of the Draft IRP in March 2023, the Company held an additional stakeholder meeting on August 29, 2023 where the draft results were reviewed. Written feedback was received from this meeting. Stakeholder feedback from all meetings is also summarized, along with the Company's responses in the Appendix as Exhibit G.

Key dates as defined by the LPSC IRP Process Schedule of Events are shown in Table 1:

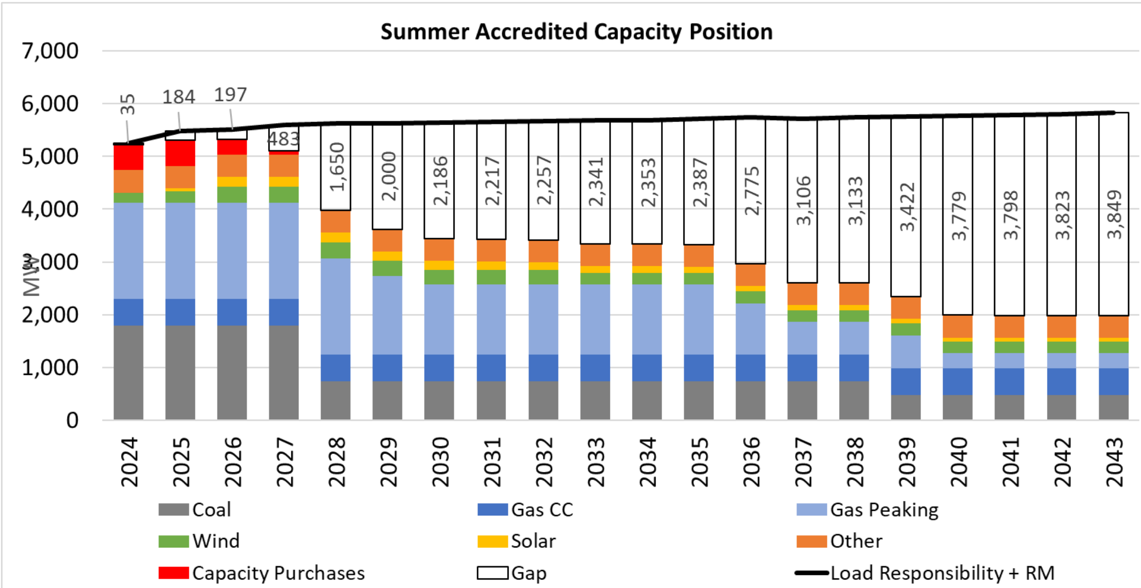
Table 1 LPSC IRP Process Schedule of Events

Event	Description	Number of Months from IRP Filing Date	Date
1	Utility submits its request to initiate the IRP process, which should specify dates in accordance with this schedule of events, and a non-disclosure agreement.	At filing date (IRP Cycle Date)	December 29, 2021
2	Utility files data assumptions to be used in the IRP and a description of studies to be performed.	1	January 31, 2022
3	Utility holds first Stakeholder Meeting.	2	March 29, 2022
4	Stakeholders may file written comments.	4	April 28, 2022
	SWEPCO provided Optional 2nd Stakeholder Meeting		July 20,2022
5	Draft IRP Report published.	15	March 2023
6	Utility holds second (third) Stakeholder Meeting.	20	August 29, 2023
7	Stakeholders may file comments about the draft IRP Report.	22	October 24, 2023
8	Staff files comments about draft IRP Report.	23	November 2023
9	Final IRP Report filed by the utility.	26	February 13, 2024
10	Stakeholders submit list of disputed issues and alternative recommendations.	28	April 9, 2024
11	Staff submits recommendations to the Commission including whether or not a proceeding is necessary for the resolution of disputed issues.	29	May 7, 2024
12	Commission Order acknowledging the IRP or setting disputed issues for hearing.	31	July 2024

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 deliver on customers' expectations while balancing the four IRP objectives. In this IRP, SWEPCO started from evaluating a known "going-in" capacity position that shows the forecasted load need and the current expectations about existing and planned owned resources and contracts. Figure 1 illustrates the starting summer capacity needs of SWEPCO through 2043. As of March 2023, the Company has obtained what it projects to be sufficient resources to meet SPP's minimum 15% summer planning reserve margin (PRM) requirement for the capacity years beginning June 1, 2023, and June 1, 2024. As part of this IRP, the Company also evaluated optimized Portfolios to meet a minimum planning reserve margin of at least 26% above the Company's winter peak load. To ensure adequate supply, the Company also included an additional 7% reserve margin above the aforementioned PRMs. This assumption is further discussed in Section 3.5. The going-in capacity position shown in Figure 1 includes recently approved solar and wind resources,[1] as well as the continued operation of the Arsenal Hill unit 5 and Lieberman gas-steam units 3 & 4 through May 31, 2029. With these assumptions, the Company identifies a capacity need beginning June 1, 2025. The need grows in 2028 when SWEPCO's Welsh 1 & 3 units cease burning coal and are removed from the going-in assumptions and in 2030 with the planned retirement of the Wilkes 1 gas-steam unit.

Figure 1 SWEPCO Summer Going- In Capacity Position



SWEPCO 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 this IRP includes Energy Efficiency ("EE") options that could be selected alongside, or as an alternative to, new utility-scale resources when meeting customer needs.

Furthermore, the Company explicitly considers a scenario where a separate and higher winter reserve requirement is imposed to analyze the winter reliability of electricity supply to customers. The relative going-in winter capacity position is shown in Figure 2 and is discussed further in Section 8.3 in the associated portfolio winter analyses.

[1] Planned resources include company owned resources of the Diversion Wind project planned in 2025 (201MW), Wagon Wheel Wind Project planned in 2026 (598MW) and the Mooringsport Solar project planned in 2026 (200MW) along with the Rocking R Solar PPA project planned in 2025 (73MW). Recent developments have delayed the in service date for Mooringsport.

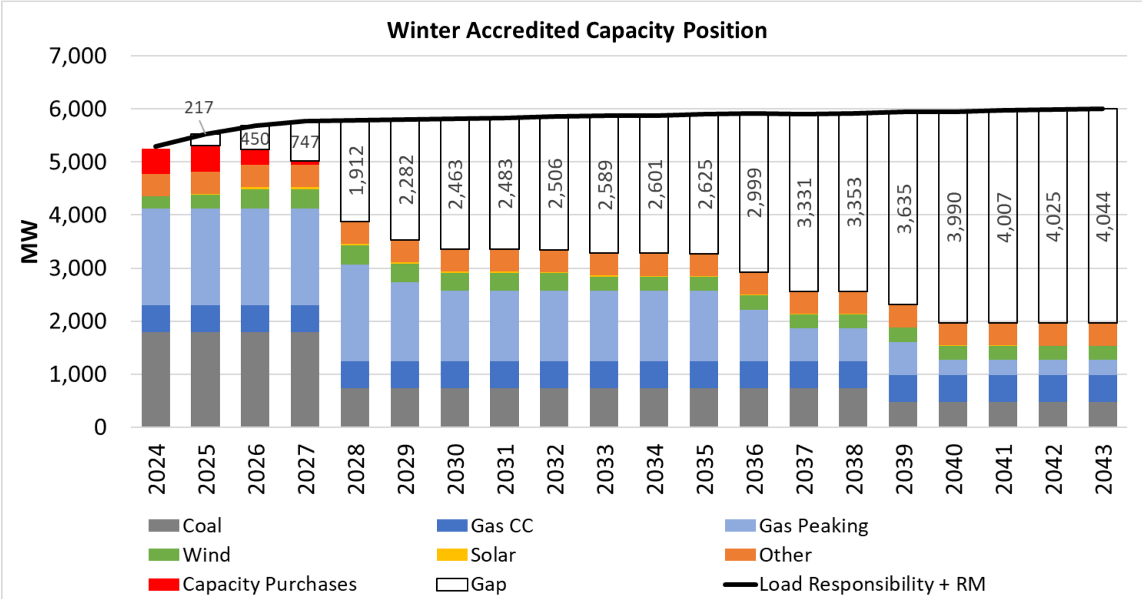


Figure 2 SWEPCO Winter Going-In Capacity Position

Responsive to Changing Customers' Needs

SWEPCO considered how customers' needs could change under five different market scenarios that consider different outcomes of fundamental factors that drive the demand for electricity as well as changes in customer preferences and end-use technologies that affect SWEPCO customer load patterns. SWEPCO 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 SWEPCO's customers over the 20-year IRP forecast period.

Over the next 20 years, under base case conditions (i.e., the "Reference case"), SWEPCO is projected to see customer count grow at a rate of 0.2% per year. Retail sales are also expected to grow at 0.3% over this period as stronger growth from the residential and industrial customer classes offsets a modest decline in commercial sales. SWEPCO's peak demand is also expected to increase at an average rate of 0.3% per year through 2043.

SWEPCO considered conventional and advanced supply options alongside demand-side resources to evaluate the best way to meet future customer needs. SWEPCO considered emerging supply-side technologies such as hydrogen and small modular nuclear reactors, as well as long-duration storage technologies as solutions to meet customer requirements under different market conditions.

Empowering Customers with Choices

SWEPCO's customers already benefit from existing demand-side programs that include DSM and EE measures. Nonetheless, SWEPCO continues to explore the potential to further implement demand-side programs to the benefit of its customers. This IRP considers EE measures that could be selected alongside new utility-scale resources.

Planning for Uncertain Futures

SWEPCO knows the importance of reliability to its customers and set an objective to the extent practicable, to mitigate risks of high costs during unexpected or adverse market conditions. This IRP includes two methods for evaluating cost risks:

- The first approach is a scenario analysis where SWEPCO 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 SWEPCO 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 resource output to observe how the candidate portfolio performed from a cost perspective.

SWEPCO Preferred Plan

SWEPCO was informed by the different least-cost portfolios modeled to develop the Preferred Plan that includes a diverse set of dispatchable and renewable generation resources that bring a broad set of benefits to customers. Collectively, the resources support numerous objectives identified in the IRP Scorecard in a holistic manner including maintaining a diverse portfolio of resources that supports an expected seasonal capacity obligation construct within SPP while mitigating potential cost risks to ratepayers in the event future market conditions change.

Shown in Figure 3 and Figure 4, the Company's Preferred Plan adds:

- 700 MW of solar and 600 MW of wind eligible for federal tax credits and providing low-cost energy
- 400 MW of dispatchable storage resources supporting the potential energy needs when renewable resources might be unavailable and diversifying the Company's capacity resources
- 3.36 GW of dispatchable natural gas combustion turbines (NGCT) offsetting planned retirements of existing company resources
- Includes the Welsh 1 & 3 conversions in 2028 providing valuable firm capacity during the 10-year period.
- Leverages near-term capacity purchases to provide a bridge until firm resources can be acquired by the Company to mitigate a long-term requirement for this type of resource
- The plan also includes Energy Efficiency resources with a peak contribution of around 80 MW in 2028.

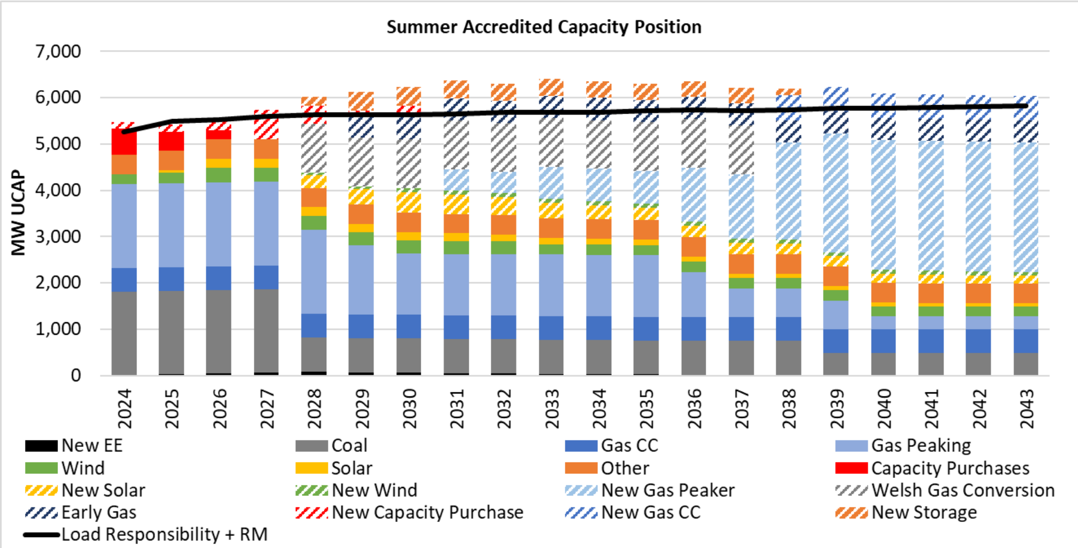


Figure 3 SWEPCO Summer Accredited Capacity Position – Preferred Plan

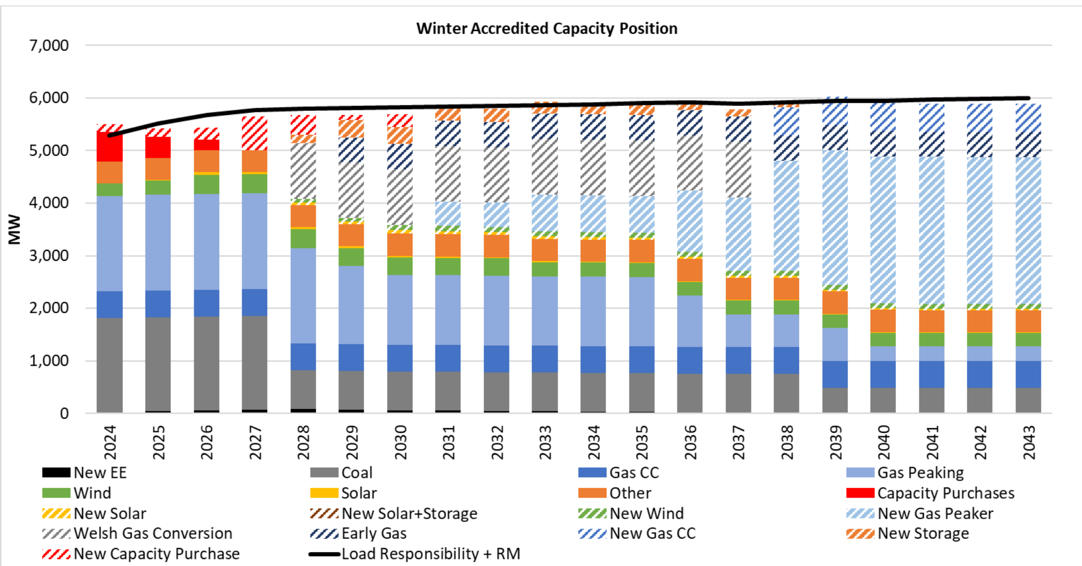


Figure 4 SWEPCO Winter Accredited Capacity Position – Preferred Plan

Five-Year Action Plan (2024 to 2028)

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

- Issue an All-Source RFP in Q12024 to identify resources in support of the Company's capacity needs.
- Seek Commission approval for 2024 RFP resources to meet company obligations to reliably serve load
- Monitor and evaluate the changes to SPP Resource Adequacy requirements as more information becomes available and issue subsequent RFPs as needed to meet final requirements
- Given the timeframe to add new generation in the SPP and considering the transmission interconnection queue process, SWEPCO will continue to evaluate and implement steps as necessary to ensure a sufficient pipeline of resources consistent with the Preferred Plan that are needed beyond the five-year period.
- Remain committed to closely following developments related to environmental regulations and update our analysis of compliance options and timeliness when sufficient information becomes available.

1. Introduction

This Report presents the 2023 Integrated Resource Plan ("IRP") for Southwestern Electric Power Company ("SWEPCO" 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 over the 20-year IRP planning period.

For this IRP, SWEPCO 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 based in Washington DC, Boston, New York, London, and Toronto. CRA advises clients on a range of issues including resource 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. Integrated Resource Plan Process

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 SWEPCO.

These objectives and performance indicators were used to inform the assumptions and steps taken in the IRP analysis to create and evaluate candidate resource plans.

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

- **Customer affordability** by considering a broad range of resource options including renewables to take advantage of tax credits for the Company's customers, and demand-side measures including EE;
- **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 volatility and risks to customers;
- **Maintaining reliability** by considering SWEPCO's portfolio performance against seasonal reserve margins and adverse system events and,
- **Local impact & sustainability** through inclusion of renewable and advanced generation technologies as resource options to enable a greener future for all as well as considering economic impacts for new resources to SWEPCO communities.

The details of the 2023 IRP portfolio analysis framework and the scorecard elements are discussed in Section 8.

This Report covers the processes, assumptions, results, and recommendations required to develop the Company's IRP. It uses the best available information at the time of preparation, but changes that may affect its results can, and will, occur. Therefore, commitments to specific resources and actions remain subject to further review and consideration as needed.

This IRP includes assumptions related to the Company's Load Forecast, Commodity Forecast and Technology costs.

1.2. IRP Process

The IRP process for SWEPCO includes the following components/steps:

- Evaluate the Company’s current situation and create the framework for the resource planning process;
- Evaluate future customer needs and how those needs are likely to change over the 20-year IRP forecast period. (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 (Chapter 3);
- Review transmission and distribution system integration in meeting future customer needs (Chapter 4);
- Identify a list of resources that could be selected by the portfolio model to meet future customer needs. Resources include both supply-side (Chapter 5) and demand-side options (Chapter 6);
- Assess sources of future risks and uncertainties, and devise market scenarios and stochastic analysis to represent those risks as part of portfolio optimization (Chapter 7)
- Define the objectives or targets that the preferred resource plan should achieve, and evaluate all resource options to identify the portfolio options (Chapter 8);
- Engage with stakeholders and consider feedback (Appendix Exhibit G); and
- Utilize resource modeling results in formulating the preferred resource plan and the associated five-year action plan (Chapters 8 & 9).

1.3. Introduction to SWEPCO

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

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

The two AEP operating companies in the Southwest Power Pool (SPP), SWEPCO and Public Service Company of Oklahoma (PSO) collectively serve a population of about 4.25 million, which includes over 1 million retail customers in a 36,000 square mile area in parts of Arkansas, Louisiana, Oklahoma, and Texas.

SWEPCO’s customers consist of both retail and sales-for-resale (“wholesale”) customers located in the states of Arkansas, Louisiana, and Texas (see Figure 5). Currently, SWEPCO serves approximately 550,000 retail customers in those states; including approximately 125,000, 234,000 and 190,000 in the states of Arkansas, Louisiana and Texas, respectively. The peak load requirement of SWEPCO’s total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. SWEPCO’s historical all-time highest recorded peak demand was 5,554 MW, which occurred in August 2011; and the highest recorded winter peak was 4,919 MW, which occurred in January 2014. The most recent 2023 actual SWEPCO summer peak demand was 4,886 MW occurring on August 24th. SWEPCO’s 2022/23 winter peak demand occurred on December 23, 2022, with a value of 4,918 MW.

SWEPCO service territory is highlighted in Figure 5.

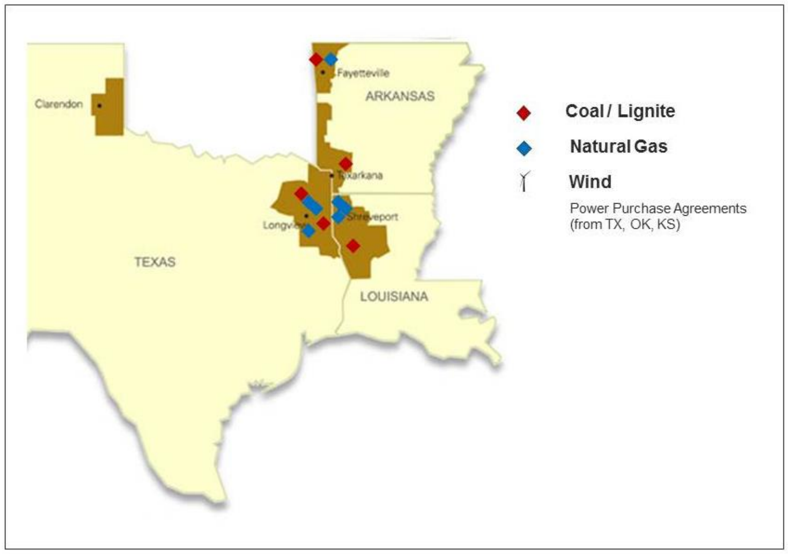


Figure 5 SWEPCO's Service Territory

2. Load Forecast and Forecasting Methodology

2.1. Overview

The SWEPCO load forecast was developed by AEP's Economic Forecasting organization and completed in June 2023.[2] The final load forecast is the culmination of a series of underlying forecasts that build on 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 20-year period (2024-2043)[3], SWEPCO's service territory is expected to see population and non-farm employment experience similar growth of 0.4% and 0.3% per year, respectively. SWEPCO is projected to see customer count growth at a rate of 0.2% per year. Over the same forecast period, SWEPCO's retail sales are projected to grow at 0.3% per year with stronger growth expected from the residential class (0.2% per year) while the commercial class remains relatively flat and the industrial class experiences modest increases (0.7% per year) over the forecast horizon. The projected change in SWEPCO's internal energy over the next 20 years is for requirements to increase by 0.4% per year. Finally, SWEPCO's peak demand is also expected to increase at an average rate of 0.3% per year through 2043.

2.2. Forecast Assumptions

2.2.1. Economic Assumptions

The load forecasts for SWEPCO and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in December 2022. Moody's Analytics projects moderate growth in the U.S. economy during the 2023-2042 forecast period, characterized by a 2.1% annual rise in real Gross Domestic Product ("GDP"), and moderate inflation as well, with the implicit GDP price deflator expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's index of industrial production, is expected to grow at 1.7% per year during the same period. Moody's projected regional employment growth of 0.3% per year during the forecast period and real regional income per-capita annual growth of 1.3% for the SWEPCO 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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[2] The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of connected load, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning

[3] 20 year forecast periods begin with the first full forecast year, 2024

2.2.3. Specific Large Customer Assumptions

SWEPCO's customer service engineers are in frequent touch with industrial and commercial customers about their needs and activities. From these discussions, expected load additions or reductions are relayed to the Company.

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. Energy Efficiency (EE) and 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. As highlighted in sections 2.4.4 and 2.4.5, the Company uses Statistically Adjusted End-Use (SAE) models developed by Itron as well as time-series based econometric models developed by the Company to produce the long-term load forecast. The SAE models are used to develop energy sales forecasts for the residential and commercial classes and incorporate trends in energy efficiencies consistent with the federal government's codes and standards. Impacts to the load forecast caused by the adoption of these codes and standards are computed by taking the difference between the Energy Efficiencies' 2023 scenario, which keeps EE standards and trends at 2023 levels for residential and commercial equipment, and the base forecast.

In addition to general trends in appliance efficiencies, the Company also administers 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, EE Resources through 2023 are in the load forecast.

These new company sponsored DSM programs are incorporated into the load forecast as post-model adjustments. The resulting energy forecast reductions included in the load forecast are provided in Exhibit A-12 and shown in Figure 14.

2.3. Overview of Forecast Methodology

SWEPCO's load forecasts are based mostly on econometric, state-of-the-art 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.

SWEPCO utilizes two sets of econometric models: 1) a set of monthly short-term models, which extend for approximately 24 months and 2) a set of monthly long-term models, which extend 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 SWEPCO'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.

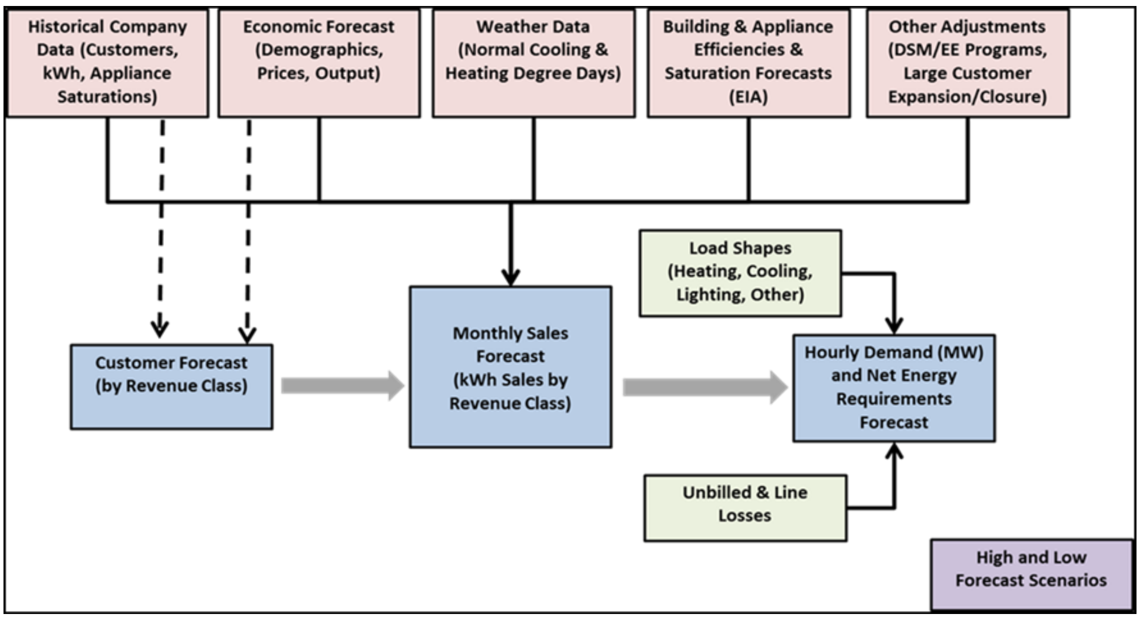


Figure 6 SWEPCO Internal Energy Requirements & Peak Demand Forecasting Method

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

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

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to affect 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 based on monthly information 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 SWEPCO'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.

There are separate models for the Arkansas, Louisiana, and Texas Jurisdictions of the Company. The estimation period for the short-term models was January 2015 through January 2023.

Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

Industrial Energy Sales

Short-term industrial energy sales are forecast separately for 20 large industrial customers in SWEPCO and for the remainder of industrial energy. These short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables for each of the Company's jurisdictions. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 20 large industrial customers and the forecasts for the remainder of the manufacturing customers. Customer service engineers also provide input into the forecast for specific large customers.

All Other Energy Sales

The “All Other Energy Sales” category for SWEPCO includes public street and highway lighting (or other retail sales) and sales to municipalities. Current SWEPCO wholesale requirements customers include the Cities of Bentonville, Hope and Prescott in Arkansas, City of Minden in Louisiana, and Northeast Texas Electric Cooperative, located in Texas. Wholesale loads are generally longer term, full requirements, and cost-of-service based contracts, although SWEPCO does have a partial requirements wholesale customer that owns generation resources by this customer.

Both the other retail and municipal models are estimated using ARIMA models. SWEPCO's short-term forecasting model for Public Street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale model includes binaries, heating and cooling degree-days, lagged error terms and lagged energy sales.

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast, as they are not requirements load or part of 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 monthly heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the SWEPCO 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 1995-2022, with some variation in the estimation period for the various models. The long-term energy sales forecast is developed by blending 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, several supporting models are used, including a natural gas price model for SWEPCO’s Arkansas, Louisiana, and Texas service areas. These models are 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 “*2023 Annual Energy Outlook*”. The natural gas price model is based upon 1980-2022 historical data.

Residential Energy Sales

Residential energy sales for SWEPCO 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 SWEPCO'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 models are estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2023. It is important to note, as will be discussed later in this document, that this modeling has incorporated the reductive effects of the Energy Policy Act of 2005 (EPAct), the Energy Independence and Security Act of 2007 (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.

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

Separate residential SAE models are estimated for the Company's Arkansas, Louisiana, and Texas jurisdictions.

Commercial Energy Sales

Long-term commercial energy sales are also forecasted using a SAE model. These models are similar to the residential SAE models, where commercial usage is a function of Xheat, Xcool and Xother variables.

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from EIA's *2022 Annual Energy Outlook*. Billing days and electricity prices are developed internally. The commercial output measure is either service gross regional product, service area real personal income per capita or service area commercial employment from Moody's Analytics. The equipment stock and square footage information are for the West South Central Census Region.

The SAE is a linear regression for the period, which is typically January 2000 through January 2023. As with the residential SAE model, the effects of EPAct, EISA, ARRA and EIEA2008 are captured in this model. Separate commercial SAE models are estimated for the Company's Arkansas, Louisiana, and Texas jurisdictions.

Industrial Energy Sales

The Company uses a combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, service area manufacturing employment, FRB industrial production indexes, service area industrial electricity prices and state industrial natural gas price. 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. Separate models are estimated for the Company's Arkansas, Louisiana, and Texas jurisdiction. The last actual data point for the industrial energy sales models is January 2023.

All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales to either service area employment or service area population and binary variables.

The municipal energy sales model is specified linear with the dependent and independent variables in linear form. Wholesale energy sales are modeled relating energy sales to economic variables such as service area gross regional product, employment, population, 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 2023 and 2024 are taken from the short-term process. Forecast values for 2025 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 of 2024, 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.

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 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 significantly different from the model results, then additional factors may be used to reflect those large changes that are different from those from the forecast models' output.

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 premises is measured as the average ratio of all FERC revenue class energy sales measured at the premises' 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 SWEPCO 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 (SPP), 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 SWEPCO's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other retail and wholesale sales, as well as losses) on an actual basis for the years 2013-2022. 2023 data are six months actual and six months forecast and on a forecast basis for the years 2024-2043. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding retail sales information for the Company's Arkansas, Louisiana and Texas retail service areas is given in Table A-2.

Figure 7 provides a graphical depiction of weather normal and forecast Company residential, commercial, and industrial sales for 2002 through 2043.

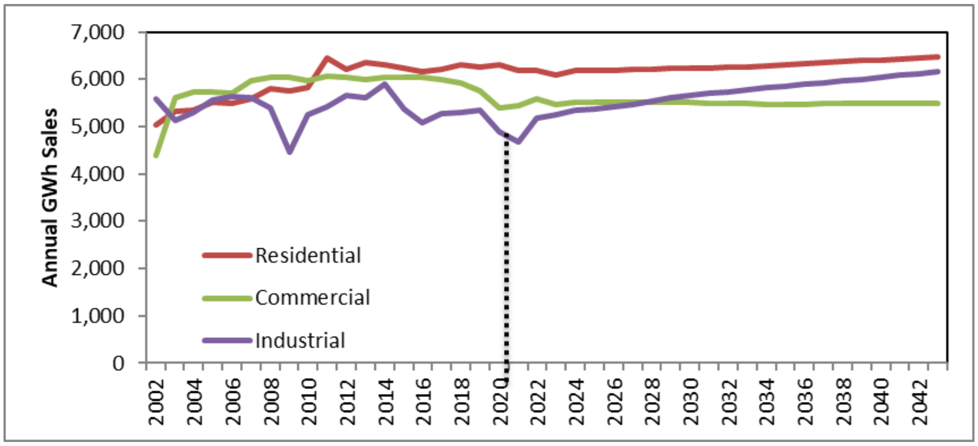


Figure 7 Weather Normalized History and Forecast of SWEPCO's Sales by Category

2.5.2. Peak Demand and Load Factor

Table A-3 provides SWEPCO's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2013-2022. 2023 data are six months actual and six months forecast and on a forecast basis for the years 2024-2043. The table also shows annual growth rates for both the historical and forecast periods.

Figure 8 presents actual, weather normal and forecast SWEPCO peak demand for the period 2000 through 2043.

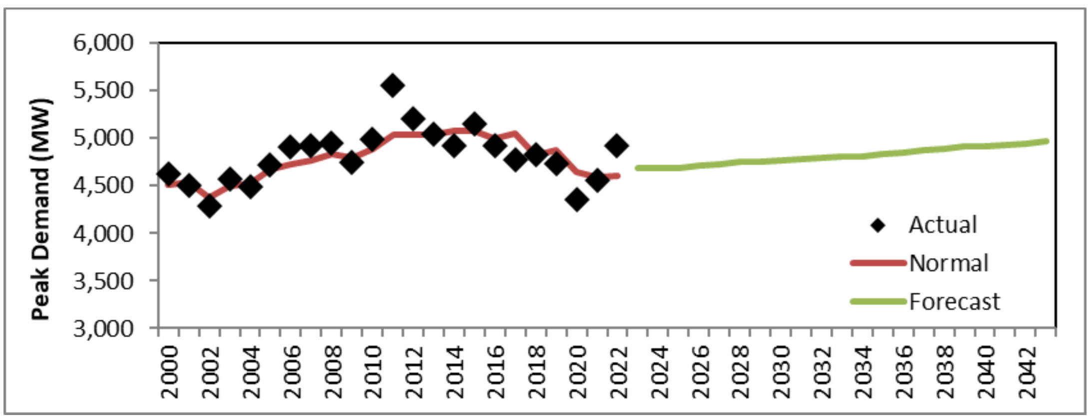


Figure 8 SWEPCO's Peak Demand Between 2000 and 2043

2.5.3. Monthly Data

Table A-4 provides historical monthly sales data for SWEPCO by customer class (residential, commercial, industrial, other retail and wholesale) for the period January 2013 through June 2023. Table A-5 provides forecast SWEPCO monthly sales data by customer class for July 2023 through December 2043.

2.5.4. Prior Load Forecast Evaluation

Table A-6 presents a comparison of SWEPCO's energy sales and peak demand forecasts in the 2019 IRP with the actual and weather normal data for 2019, 2020, 2021and 2022. The major source of forecast error was the impacts of the COVID-19 Pandemic. As explained in more detail below, the commercial and industrial sectors were most affected by the economic shutdown, resulting in decreased load across those classes. Otherwise, load forecast performed well. For example, the 2019 retail sales were under forecast by only 0.9%. However, there is a constant monitoring of the modeling process to seek improvement in forecast accuracies. Table A-7 provides the impact of demand-side management on the 2019 IRP.

2.5.5. 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.

2.5.6. Significant Determinant Variables

Table A-8 provides significant economic and demographic variables incorporated in the various residential long-term energy sales models for the Company. Table A-9 provides significant economic variables utilized in the various SWEPCO jurisdictional commercial energy sales models. Table A-10 presents significant economic variables that the Company employed in its jurisdictional industrial models. Table A-11 depicts the significant economic variables the Company incorporated in its other retail and wholesale energy sales models.

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 SWEPCO'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 1.4% per year while the Commercial usage grew by 2.1% per year. Over the next decade (2001-2010), growth in Residential usage slowed to 0.5% per year while the Commercial class usage increased by 0.9% per year. For the most recent decade (2011-2020) Residential usage declined at a rate of 0.6% per year while the Commercial usage also fell by an average of 1.4% per year. The COVID-19 Pandemic had a significant impact on commercial usage. With more people at home, Residential usage increased by 0.7% in 2020. Meanwhile, with the economy shutdown, Commercial usage declined by 5.8% in 2020. Efficiency gains are expected to continue over the next seven years (2024-2030), with residential usage declining by 0.2% per year and commercial usage declining by 0.3% per year.

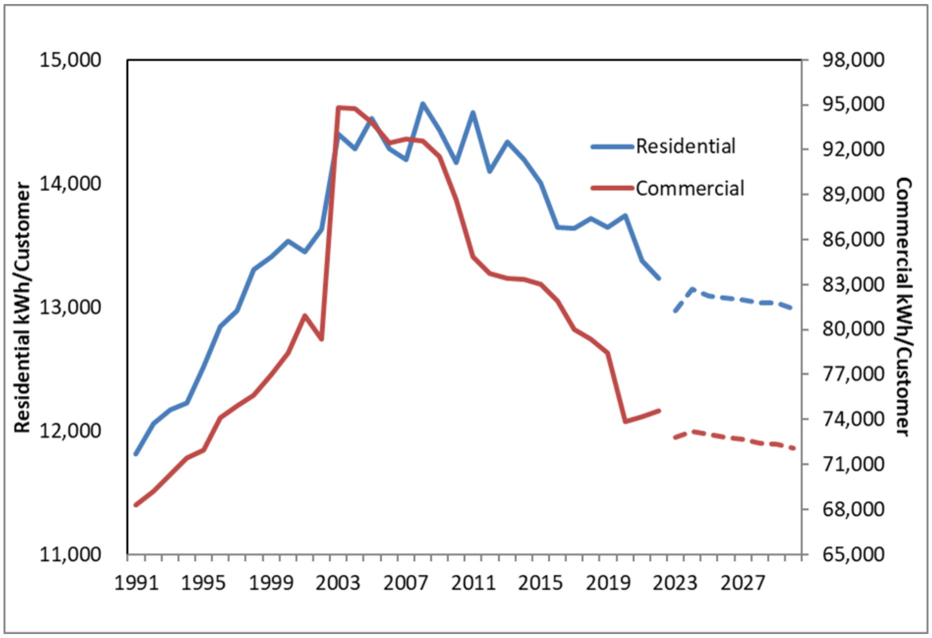


Figure 9 SWEPCO's Normalized Usage Per Customer by Customer Type

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 the various enacted federal policy 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 below 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 11.78 in 2010 to nearly 15.29 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units as well. Figure 11 shows similar improvements in the efficiencies of lighting and refrigerators over the same period. However, there are not many additional efficiency gains expected from lighting for residential customers, as consumers have adopted the newer technologies and moved away from incandescent lighting.

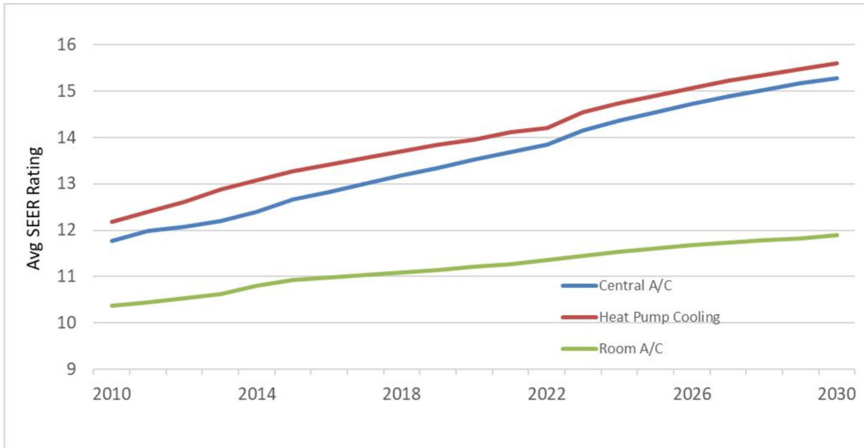


Figure 10 Projected Changes in Cooling Efficiencies, 2010 - 2030

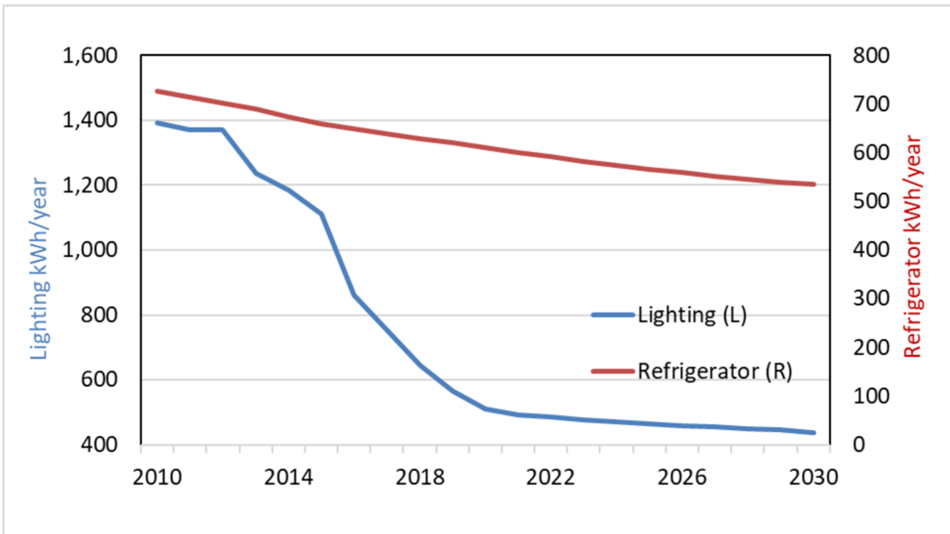


Figure 11 Projected Changes in Lighting & Refrigerator Efficiencies, 2010-2030

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 of SWEPCO residential customers are provided.

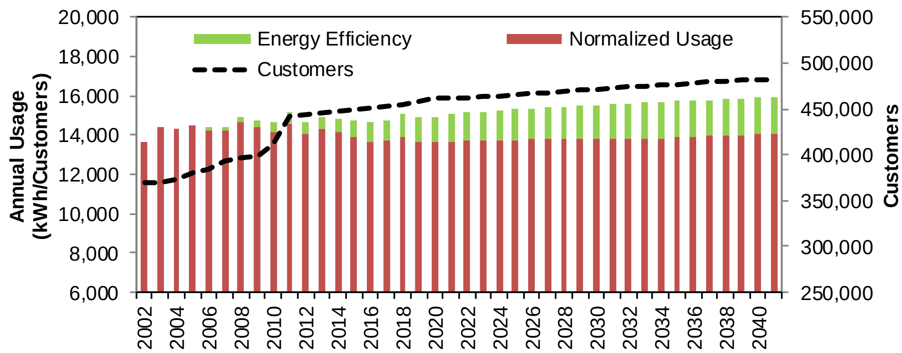


Figure 12 Residential Usage and Customer Growth, 2002 - 2042

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

Table A-12 provides the DSM/EE impacts incorporated in SWEPCO's load forecast provided in this report. Annual energy and seasonal peak demand impacts are provided for the Company and its Louisiana jurisdiction.

2.6.3. Losses and Unaccounted for Energy

Actual and forecast losses and unaccounted for energy are provided in Table A-13. See Section 2.4.4 for a discussion of loss estimation. At this time, the Company does not have any planned loss reduction programs.

2.6.4. Interruptible Load

The Company has 19 customers with interruptible provisions in their contracts. The aggregate on-peak capacity available for interruptions is 35MW. 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, or during system emergencies, such as the 2021 winter storm. As such, estimates for "demand response" impacts are reflected by SWEPCO in determination of SPP-required resource adequacy (i.e., SWEPCO's projected capacity position).

2.6.5. 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. Table A-14 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, seven of the nine wholesale forecasts utilize the long-term forecast model results and the other two uses the blended model results.

In general, forecast values for 2023 and 2024 were typically taken from the short-term process. Forecast values for 2025 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 2025 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 Table A-15). 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.

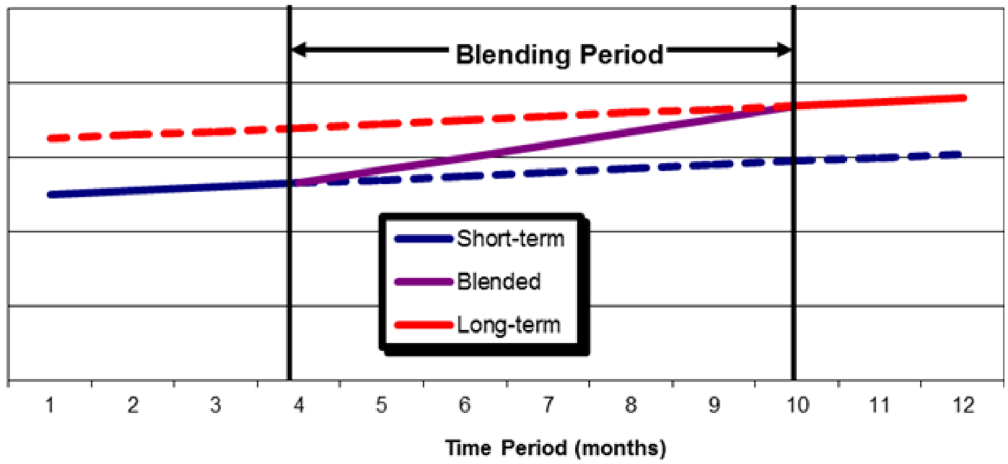


Figure 13 Load Forecast Blending

2.6.6. 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.

2.6.7. Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs. For the purposes of this IRP, the wholesale customer contracts are assumed to continue through the forecast period. Concurrently, any self-generation provided by those wholesale customers that is appropriately "assumed" by SWEPCO for purposes of its long-term resource planning is also retained through the forecast period.

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.

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 2023 *Annual Energy Outlook*. While other factors may affect load growth, this analysis focuses on 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 SWEPCO are tabulated in Exhibit A-16.

For SWEPCO, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2043, represent deviations of respectively, 14.9% below and 14.2% above 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.

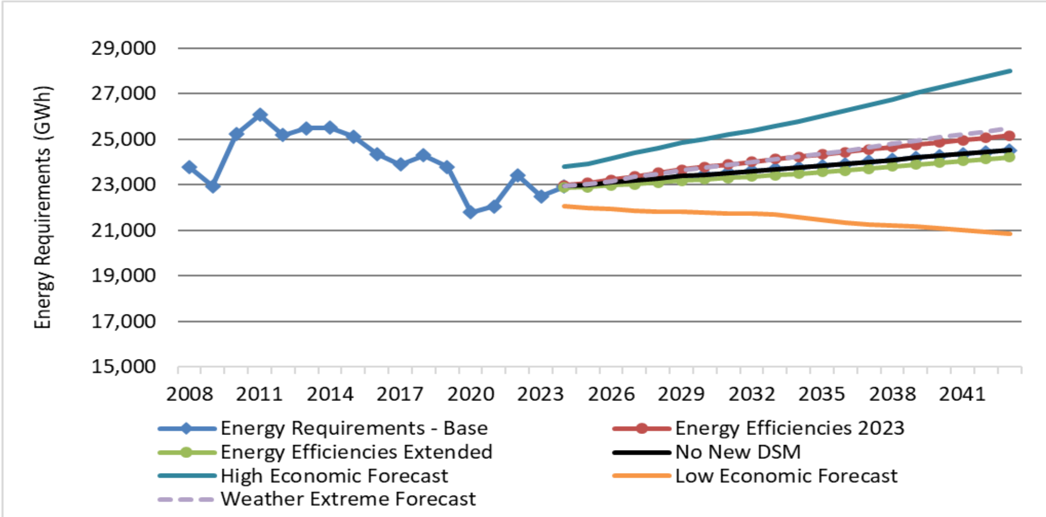


Figure 14 SWEPCO's Load Forecast Scenarios

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 2022 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 Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial equipment.

The weather extreme forecast assumes increased average daily temperatures for both the winter and summer seasons, which results in diminished heating degree-days in the winter and increased cooling degree-days in the summer. This analysis is based on a potential impact of climate change developed by Purdue University. This scenario results in increased load in the summer and diminished load in the winter, with the net result being a higher energy requirement forecast. Exhibit A-17 provides graphical displays of the range of forecasts of summer and winter peak demand for SWEPCO along with the impacts of the weather scenario for each season.

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 and distributed generation in the load forecast, it does continually monitor the adoption rate and will address the issue as it becomes more significant. At this time, SWEPCO has not seen a high penetration of electric vehicles in its service territory or an excessive percentage of DER penetration relative to its peak load; however, the Company anticipates that these activities will grow in the coming years. For EV growth, the Company has developed high, low, and base scenarios on adoption in the service area through 2030. These scenarios are presented graphically in Figure 15 and in Appendix Exhibit A-18 for SWEPCO's three state jurisdictions. Figure 16 illustrates the Company's projections for DG growth for the Company's three state jurisdictions, which is also shown in Appendix Exhibit A-19.

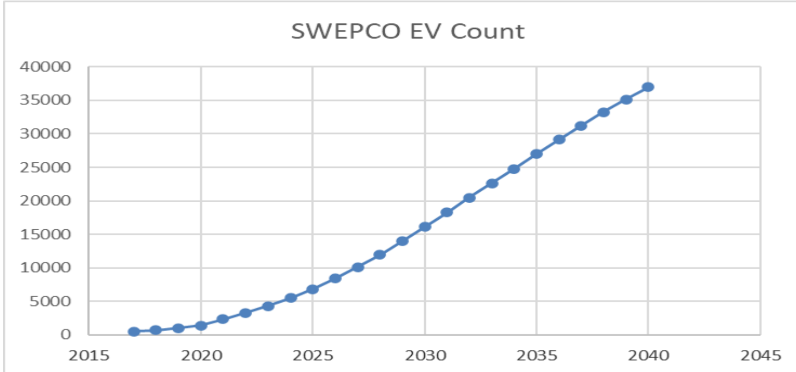


Figure 15 Electric Vehicle Growth Projections

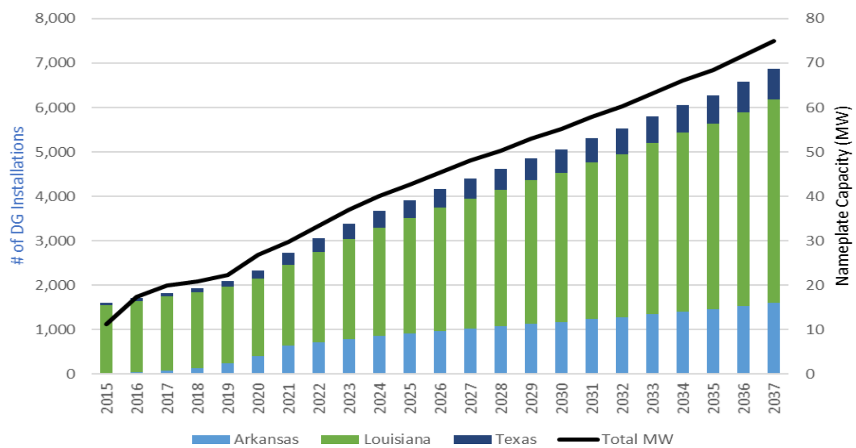


Figure 16 Distributed Generation Projections

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. Note that 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.

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 0.18. For comparison, the estimated long-term elasticity for gasoline is 0.6 while the elasticity for restaurant meals is 2.3[4].

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

3. Current Resource Evaluation

3.1. Introduction

SWEPCO'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 supply-side resources include a mix of wind and fossil-fired resources. The demand-side resources include active demand response ("DR") and EE programs. Customers wishing to generate their own energy can also participate in SWEPCO's distributed generation ("DG") program.

3.2. Existing SWEPCO Generation Resources

The SWEPCO fleet of existing resources includes a diverse mix of owned and contracted resources. Table 2 identifies the current owned SWEPCO generating resources and Table 3 identifies the current and planned contracted resources assumed in the going-in position.

Table 2 SWEPCO's Generation Assets as of March 2023

Unit Name	Primary Fuel Type	C.O.D.[1]	Rating (MW) [2]	Location	Retirement Date
Arsenal Hill 5	Gas Steam	1960	108	LA	5/31/2029
Flint Creek 1	Coal	1978	258	AR	1/1/2039
Harry D. Mattison 1	Gas (CT)	2007	70	AR	1/1/2053
Harry D. Mattison 2	Gas (CT)	2007	71	AR	1/1/2053
Harry D. Mattison 3	Gas (CT)	2007	71	AR	1/1/2053
Harry D. Mattison 4	Gas (CT)	2007	71	AR	1/1/2053
J Lamar Stall	Gas (CC)	2010	511	LA	1/1/2051
John W. Turk, Jr. 1	Coal	2012	477 (3)	AR	1/1/2068
Knox Lee 5	Gas Steam	1974	335	TX	1/1/2040
Lieberman 3	Gas Steam	1957	109	LA	5/31/2029
Lieberman 4	Gas Steam	1959	108	LA	5/31/2029
Welsh 1	Coal	1977	525	TX	3/1/2028
Welsh 3	Coal	1982	528	TX	3/1/2028
Wilkes 1	Gas Steam	1964	162	TX	1/1/2030
Wilkes 2	Gas Steam	1964	352	TX	1/1/2036
Wilkes 3	Gas Steam	1964	350	TX	1/1/2037
Sundance	Wind	2021	109 (4)	OK	2051
Maverick	Wind	2021	156 (4)	OK	2051
Traverse	Wind	2022	544 (4)	OK	2051
Diversion	Wind	2025	201	TX	2054
Wagon Wheel	Wind	2026	598	OK	2055
Mooringsport	Solar	2026 (5)	200	LA	2060

(1) Commercial Operation Date
(2) Peak net dependable capability (Summer) as of filing.
(3) SWEPCO's share
(4) Installed capacity; Represents SWEPCO's 54,5% ownership stake
(5) Recent developments have delayed the in service date for Mooringsport.

Table 3 SWEPCO's Contracted Generation Assets

Contracted Resource	Primary Fuel	Contract Expiration (SPP Planning Year)	Rating (MW)
Majestic	Wind	2029	79.5
High Majestic	Wind	2032	79.6
Canadian Hills	Wind	2032	201
Flat Ridge	Wind	2032	108.8
Rocking R	Solar	2045	72.5

In addition to these long-term resources, SWEPCO currently has short-term contracts to provide capacity during the period between June 1, 2023 and May 31, 2027. The amounts currently under contract are 482 MW for DY 2024/2025, 485MW for DY 2025/2026, 278 MW for DY 2026/2027 and 78MW for DY 2027/2028.

Based on the assessment of the current resources, planned retirements and peak demand projections, a capacity needs assessment can be established that will determine the amount and timing of capacity resources for this IRP. This is discussed further in Section 3.5.

For the Company's existing resources, a supplemental analysis was conducted at Staff's request as captured in the Stakeholder feedback summarized in Appendix, Exhibit G. This analysis is included in Confidential Appendix Volume 2, Exhibit J.

3.2.1. Fuel Inventory and Procurement Practices

SWEPCO plans to have adequate fuel supplies at its generating units to meet burn requirements in both the short-term and the long-term. SWEPCO's primary objective is to assure the availability of an adequate, reliable supply of fuel at the lowest reasonable delivered cost.

Procurement Process - Coal

American Electric Power Service Corporation (AEPSC), acting as agent for SWEPCO, is responsible for the procurement and delivery of coal to SWEPCO's coal generating stations, Flint Creek, Turk and Welsh. AEPSC is also responsible for establishing each plant's coal inventory targets and managing those levels.

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. SWEPCO's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases that are primarily made through a competitive Request for Proposal process. Long-term contracts (greater than 1 year) support a relatively stable and consistent supply of coal, but often do not provide the required flexibility to meet changes in demand for coal fired generation in a low gas price and/or low power demand scenario. Spot purchases are used to provide additional flexibility to accommodate changing market conditions.

All coal purchased for Flint Creek, Turk and Welsh, originate from the Powder River Basin in Wyoming. The coal is transported via rail to the plants in railcars owned and/or leased by SWEPCO and the other AEP Operating companies as part of the AEP System Railcar Use Agreement. As of January 1, 2023, SWEPCO has six long-term coal supply agreements with three suppliers. Additionally, SWEPCO has three spot agreements several committed spot contracts with two suppliers that contribute to fulfilling the supply requirements. Any remaining supply requirements will be met with purchases that are not yet committed.

Procurement Process – Natural Gas

Given the variable and uncertain operation of SWEPCO's natural gas power plants, spot market purchases continue to be an integral part of the supply portfolio. However, SWEPCO also has a long-term supply agreement, which supplies a nominal percentage of daily requirements. Additionally, SWEPCO purchases monthly and seasonal baseload natural gas supply to further mitigate price volatility that may be experienced in the spot market. SWEPCO relies on both firm and interruptible transportation agreements to optimize the costs of delivery of natural gas.

Forecasted Fuel Prices

SWEPCO specific forecasted annual fuel prices, by unit, for the period 2023 through 2052 are displayed in Confidential Appendix Volume 2, Exhibit H.

3.3. Current Demand-Side Programs

Demand-Side programs, also known as Demand-side Management (DSM) collectively includes utility programs aimed at influencing both the level of, and timing of, customer use of grid supplied electricity. These types of programs are structured to counter the ongoing need for increased supply resources through customer energy conservation or direct intervention in how customers use electricity. Typically, customer influence is achieved through some form of monetary or product enticement either through utility rebates or electric bill credit payments. Several demand-side programs typically available including Energy Efficiency (EE), Demand Reduction (DR), and Distributed Generation (DG).

Generally, EE programs pay rebates directly to customers that are designed to encourage either end-use conservation or energy use reduction through the installation of or upgrade to more efficient end-use technologies. Some EE programs do not pay a cash rebate but instead encourage customers to reduce their annual energy consumption, or better manage their cost of electricity. Other types of EE programs seek to influence the manufacture and supply of more efficient end-use technologies through upstream rebate payments to end-use technology providers that reduce the technology cost to end-use customers. EE programs provide both energy and demand savings. Energy savings are accounted for as an around-the-clock energy reduction impact while demand savings are accounted for in terms of their point-in-time, peak coincident use reduction on an hourly basis. SWEPCO currently has EE programs in place in its Arkansas, Louisiana, and Texas service territories. SWEPCO forecasts EE measures will reduce peak demand in 2023 by 7.1 MW and reduce 2023 energy consumption by approximately 32 GWh.

Generally, DR programs offer electric bill credits through tariff pricing mechanisms to elicit point-in-time energy use reductions (also known as demand, or coincident peak demand reductions). DR programs require specific action to monitor and control electricity use during periods of peak usage. Direct load control (DLC) programs allow utility control over customers' end use loads to achieve the specific peak period use reduction. Other types of DR programs allow customers to reduce use during peak periods on their own accord and pay bill credits based on the actual level of usage during peak period events. Demand response programs primarily provide peak coincident demand impacts but can provide energy impacts as well depending upon the extent of use reduction that occurs. For this IRP, incremental DR programs were not modeled however, the Company will continue to review opportunities to offer a program for its customers.

DG typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. Two of SWEPCO's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at a full or reduced retail rate. For this IRP, incremental DG resources were assumed to be captured within the Company's load forecast as discussed in section 2.6.1.

3.4. Environmental Compliance

It should be noted that the following discussion of environmental regulations is based on the requirements currently in effect and those compliance options viewed as most likely to be implemented by the Company and 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 alter the requirements set forth by these regulations. While such activities have the potential to materially change the compliance options available to the Company 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 Clean Air Act (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 National Ambient Air Quality Standards (NAAQS) and the development of State Implementation Plans (SIPs) to achieve any 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 Standard (MATS) rule, (d) implementation and review of Cross-State Air Pollution Rule (CSAPR), which is designed to eliminate significant contributions from sources in upwind states to non-attainment 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 the Company's operations are discussed in the following sections.

3.4.2. National Ambient Air Quality Standards (NAAQS)

The CAA requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. Revisions tend to increase the stringency of the standards, which in turn may require the Company to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated.

In January 2023, the EPA announced its proposed decision to strengthen the primary (health based) annual $PM_{2.5}$ standard.

SWEPCO cannot currently predict if any changes will be finalized or what such changes may be but will continue to monitor this issue and any future rulemaking.

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 initial SIP required certain eligible facilities to conduct an emission control analysis, known as a Best Available Retrofit Technology (BART) analysis, to evaluate emissions control technologies for nitrogen oxides (NO_{X}), sulfur dioxide (SO_{2}) 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 megawatts 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. Arkansas Regional Haze

Arkansas has an approved SIP for implementation of the Regional Haze Rule's Planning Period I. On August 2, 2022, ADEQ submitted the state's Regional Haze Plan for Planning Period II to EPA for approval on August 8, 2022, and on August 18, 2022, the EPA determined the submission was complete. The proposed Regional Haze Plan for Planning Period II imposes no requirements on SWEPCO facilities.

3.4.4. Louisiana Regional Haze

Louisiana has an approved SIP for implementation of the Regional Haze Rule's Planning Period I. That SIP does not impose any requirements on SWEPCO facilities. Louisiana has proposed rules that would constitute the state's Regional Haze Plan for Planning Period II. Those proposed rules do not impose any requirements on SWEPCO facilities. Those rules have not been approved by Federal EPA.

3.4.5. Texas Regional Haze

Texas submitted its first planning period Regional Haze SIP to Federal EPA for review in 2009. The rulemaking history surrounding the Texas Regional Haze rule has been convoluted. Federal EPA disapproved a portion of Texas's original plan in 2012. In 2017, Federal EPA proposed to require source-by-source BART controls for SO2 emissions from covered sources. Federal EPA never finalized this proposal. Instead, in 2017 (and again in 2020), Federal EPA promulgated an intrastate trading program to govern SO2 emissions from Texas power plants, based on a finding that the program would achieve greater reasonable progress than source-by-source BART even though the program would allow for increases in SO2 emissions instead of emission reductions. On May 4, 2023, Federal EPA proposed withdrawing the intrastate trading program and promulgating source-by-source BART emission limits for covered sources in Texas. In addition, Federal EPA proposed that these changes to the Texas plan, if finalized, would allow Federal EPA to once again reaffirm that the CSAPR program remains a viable BART alternative for the states subject to CSAPR. Federal EPA also proposed to deny an outstanding petition seeking to end these States' longstanding reliance on the CSAPR program to satisfy their BART obligations for power plants. The proposal has not yet been finalized. If finalized, the proposal would require Welsh Unit 1 to meet the rule's BART limits for SO2 five years after the rule's effective date. The Welsh unit is required to cease coal combustion by October 17, 2028, as part of its compliance obligations with the CCR and ELG Rules; consequently, compliance with the rule's proposed BART limit, if finalized as proposed, is not a concern.

The Regional Haze rules for the first planning period are subject to several legal challenges that have been consolidated before the U.S. Court of Appeals for the District of Columbia Circuit. Those appeals are being held in abeyance pending Federal EPA's review of Texas' most recent Regional Haze rulemakings.

SWEPCO is currently complying with the SO_2 intrastate trading program.

On June 30, 2021, TCEQ adopted the 2021 Regional Haze SIP Revision to meet the Regional Haze Rule's requirements for the second planning period. TCEQ has submitted its rules to Federal EPA for approval.

3.4.6. Cross-State Air Pollution Rule (CSAPR)

CSAPR is a regional trading program designed to address interstate transport of emissions that contribute significantly to non-attainment and maintenance of the 1997 ozone and PM NAAQS in downwind states. CSAPR relies on SO_2 and NO_X allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted basis.

In January 2021, the EPA finalized a revised CSAPR rule, which substantially reduces the ozone season NO_X budgets in 2021-2024. Management believes it can meet the requirements of the rule in the near term, and is evaluating its compliance options for later years, when the budgets are further reduced. In addition, in February 2023, the EPA Administrator finalized the denial of 2015 Ozone NAAQS SIPs for 19 states, including Arkansas, Louisiana and Texas.

In March 2023, the EPA finalized a FIP, the Good Neighbor Plan (Plan), for the 2015 Ozone NAAQS for those states where SIPs were denied. The Plan is designed to increasingly reduce the cap on NO_X emission allowances annually from 2023 through 2029. The Plan redefines states participating in the Group 2 and Group 3 OSN_X allowance program. Specifically, five states, which include Arkansas and Texas, will transition from Group 2 to Group 3. However, numerous challenges to the EPA's disapproval of several states' SIPs have led to a number of federal courts issuing stays of the disapprovals pending the resolution of the litigation. Without a disapproval of a SIP, there is no legal basis for EPA to issue a FIP. Consequently, EPA has issued interim rules to stay the applicability of the Good Neighbor Plan in those states where the SIP denial has been stayed. This includes Arkansas, Louisiana, and Texas.

Collectively, the installed SCR and FGD systems' respective emission reductions of NO_X and SO_2, the use of allocated NO_X and SO_2 emission allowances in conjunction with adjusted banked allowances, and the purchase of additional allowances as needed through the open market position SWEPCO well moving forward for compliance with CSAPR.

3.4.7. Climate Change, CO_2 Regulation and Energy Policy

In May 2023, EPA proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants (GHG). The new proposed GHG regulations set limits for new gas-fired combustion turbines, existing coal, oil and gas-fired steam generating units, and certain existing gas-fired combustion turbines. If finalized in their current form, the regulations would require existing steam generating units to be retired by December 31, 2031 or extend the retirement date by either adopting a stringent annual capacity factor or natural gas co-firing. If an existing steam generating unit is planned to operate in 2040 and beyond, the unit will be required to meet a standard of carbon capture and storage (CCS) at a 90% capture rate. Likewise, for the new and existing gas fired combustion turbines affected by the regulations, the units would need to utilize either CCS or hydrogen blending at up to a 96% blend rate. EPA is currently considering comments submitted on the regulatory proposals, with final action expected by June 2024. Under EPA's rulemaking process, publication of the final rule will trigger a two-year time period for states to formulate state implementation plans (SIPs) to implement the regulation. Assuming the final rule is published in June 2024, SIPs would be required by June 2026. Further, upon being finalized, litigation is likely. With these caveats in mind, under the GHG rule as proposed, sources not slated for imminent or near-term retirement would need to have the Best System of Emission Reductions (BSER) designed, installed and operational by January 1, 2030. The cost and operational implications of the proposed EPA regulations cannot be known at this time. We are far from having any certainty regarding the scope and timing of any CO2 regulations, as well as any implications of the rules on fossil-fuel fired generation. SWEPCO continues to monitor these rulemaking activities.

Aside from GHG rulemaking activities, the Company has taken action to reduce CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline over the next decade due to the retirement of 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

The EPA's CCR rule regulates the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The rule applies to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers.

In 2020, the EPA revised 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 EPA. In late 2020, SWEPCO filed two applications under the second option, committing to cease coal combustion at the Pirkey plant by October 17, 2023 and at the Welsh Plant by October 17, 2028. Neither application has been acted upon.

The Company retired the Pirkey plant in March of 2023 and ceased coal combustion as a component of its plan for compliance with the CCR rule. Physical closure of Pirkey's west bottom ash pond was certified in December 2022. The east bottom pond was closed by October 2023. As a result, the Pirkey Plant application is moot.

At Flint Creek, the Company completed the plant modifications required for compliance with the CCR rule in March of 2023 and is no longer using water to handle the ash produced by coal combustion. The subsequent work to close Flint Creek's ash impoundments was completed in August of 2023.

The Turk plant does not use water to transport or store coal combustion byproducts, and therefore is not subject to CCR compliance investments.

Because SWEPCO currently uses 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.

In January 2022, the EPA proposed to deny several extension requests filed by the other utilities based on allegations that those utilities are not in compliance with the CCR Rule (the January Actions). In November 2022, the Federal EPA finalized one of these denials. The Federal EPA's allegations of noncompliance rely on new interpretations of the CCR Rule requirements. The January actions of the Federal EPA have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit as unlawful rulemaking that revises the existing CCR Rule requirements without proper notice and without opportunity for comment. Management is unable to predict the outcome of that litigation.

In May 2023, the EPA proposed revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities ("legacy CCR surface impoundments") as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land ("CCR management units"). No revisions have been finalized but SWEPCO continues to track this rulemaking closely.

3.4.9. Clean Water Act Regulations

The EPA's Effluent Limitation Guidelines (ELG) rule for generating facilities establishes limits for FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility's wastewater discharge permit. In 2020, EPA revised the ELG rule to establish additional options for reusing and discharging small volumes of bottom ash transport water, an exception for retiring units, and an extension to the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. SWEPCO has implemented changes and has achieved compliance with the 2020 ELG Rule requirements. The Company assessed technology additions and retrofits to comply with the 2020 rule and in January 2021, permit modifications to incorporate the 2020 ELG Rule's requirements were filed for affected facilities. The Pirkey and Welsh Plants opted to comply with the 2020 ELG Rule by committing to cease coal combustion by 2023 and 2028, respectively.

On March 7, 2023, the Federal EPA proposed further revisions to the ELG Rule which, if finalized, would establish a zero-discharge standard for flue gas desulfurization wastewater and bottom ash transport water, and more stringent discharge limits for combustion residual leachate. The Flint Creek plant does not generate flue gas desulfurization wastewater and already meets the zero discharge requirements proposed for bottom ash transport water but will be subject to the new leachate limits. The Turk Plant will also only be subject to the leachate requirements as it was designed and built with a dry scrubber and dry ash handling systems. SWEPCO is still evaluating how the proposed combustion residual leachate limits will impact these plants.

On January 18, 2023, the EPA and the Army Corps of Engineers published a final rule revising the definition of "waters of the United States", which became effective on March 20, 2023. On May 25, 2023, the Supreme Court issued a decision in the case of *Sackett v. EPA* which made clear that certain aspects of the 2023 rule are invalid. Consequently, in August of 2023, the agencies announced a new rule to conform the definition to the Supreme Court's decision. The new rule expands the scope of the definition, which means that permits may be necessary where none were previously required and issued permits may need to be reopened to impose additional obligations. SWEPCO is evaluating what impact the revised rule will have on operations.

As a result of ongoing litigation on the January 2023 Rule, the agencies are implementing the January 2023 Rule, as amended by the conforming rule, in 23 states, the District of Columbia, and the U.S. Territories. In the other 27 states – including Arkansas, Louisiana and Texas -- and for certain parties, the agencies are interpreting "waters of the United States" consistent with the pre-2015 regulatory regime and the Supreme Court's decision until further notice. SWEPCO will continue to monitor developments in rule making and litigation for any potential impact to operations.

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 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.

3.5. Capacity Needs Assessment

As a member of SPP, SWEPCO (together with PSO) and other member utilities have an obligation to maintain a minimum level of generating capacity under SPP's Resource Adequacy construct. If a utility falls short of these obligations, SPP may assess non-compliance charges. The current *minimum* SPP Planning Reserve Margin (PRM) as of June 1,2023 requires a reserve capacity of 15% above SWEPCO's coincident summer peak load.

There are currently numerous initiatives at SPP which are expected to increase the minimum capacity requirement even further. These include potential further increases to the current summer PRM requirement, the expected addition of a winter seasonal requirement beginning in SPP Planning Year 2025/26 in response to recent extreme winter events, and SPP's implementation of a Performance-Based Accreditation (PBA) methodology for thermal resources which will reduce the amount of accredited MWs SPP will recognize from capacity resources compared to the historic values.

For this IRP, the Company evaluated portfolios that target a SPP summer PRM of 22% and a winter PRM of 33%. These values include added contingency that is intended to mitigate risks related to complying with the quickly changing SPP initiatives mentioned above and other sources of forecast uncertainty. The resulting target values are reasonable given recent SPP studies indicating a need based upon the 1 day in 10 years Loss of Load Expectation target reliability metric used to determine the minimum PRM. The 33% target winter value assumes a required winter reserve margin of 26% and 7% contingency. As of the date of this report, SPP has provided some indications that the new winter reserve margin requirement, which is expected to be binding for the winter of 2026/27, could even be greater than this planning value.[5]

The target PRMs provide an appropriate confidence level for SWEPCO to comply with SPP's 15% minimum PRM, or potentially higher summer PRM, given increasingly stringent and still evolving SPP resource adequacy requirements, as well as further requirements by SPP for planning for winter events.

SWEPCO also notes that it has historically had surplus capacity that exceeds the Company's current planned contingency of 7%, which equates to approximately 340 MW. For example, for the 8-year period from 2015 through 2022, SWEPCO's average capacity surplus above SPP's requirement was approximately 630 MWs. This was considered prudent considering it could be used as a contingency against a unit outage.

SWEPCO notes that the 7% additional target surplus of approximately 340 MWs is not fully unit contingent for SWEPCO. SWEPCO has several units shown in Table 2 that exceed this contingency. Consequently, even if (a) the final SWEPCO load peak requirement does not exceed what is forecast herein; (b) SPP's accredited capacity for all of SWEPCO's units is no less than forecasted herein; and, (c) SPP's capacity requirements, which currently have a high degree of uncertainty, all occur precisely as forecasted and SPP does not impose higher requirements, an extended unplanned outage of any unit that exceeds 340 MWs could still result in SWEPCO being short on its commitment.

Figure 17 and Figure 18 illustrate the resulting summer and winter capacity needs respectively of SWEPCO through 2043. The Company has obtained what it projects to be sufficient resources to meet SPP's minimum summer PRM requirement for the capacity year beginning June 1, 2024. The Company's Arsenal Hill unit 5 and Lieberman gas-steam units 3&4 are also now planned to continue operation through May 2029. Beginning with the delivery year which starts on June 1, 2025, the Company expects additional capacity will be required. The needs further widen in 2028 when SWEPCO's Welsh 1 & 3 units cease burning coal and are removed from the going-in resource assumptions along with planned retirement of the Wilkes 1 gas-steam unit in 2030.

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.

[5] (https://www.spp.org/Documents/70415/SAWG%20Meeting%20Materials%2020231106.zip,, 2023 LOLE Study Results_November SAWG_V3)

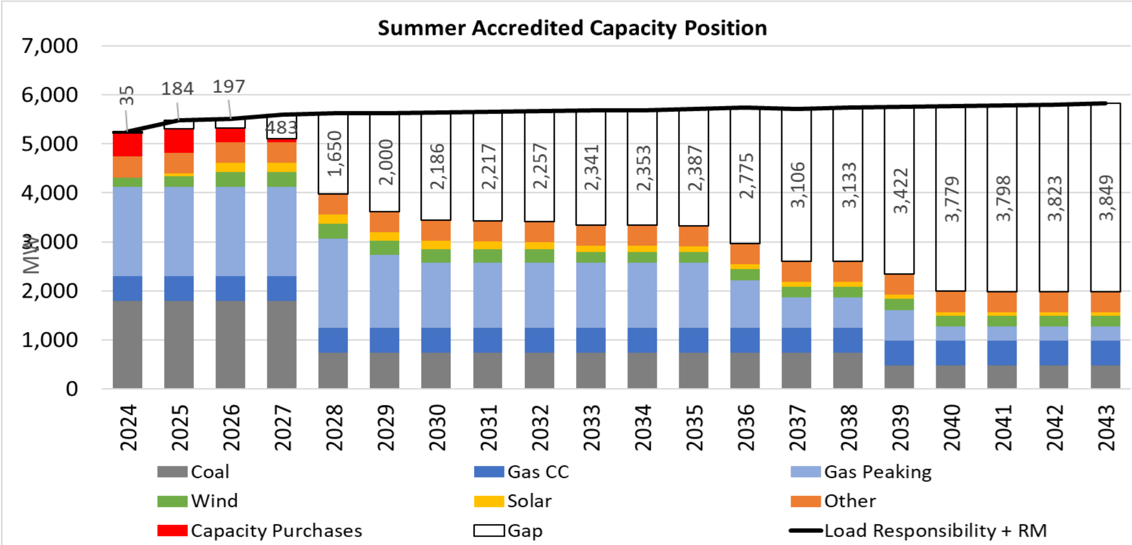


Figure 17 SWEPCO "Going-In" SPP Summer Capacity Position and Obligation

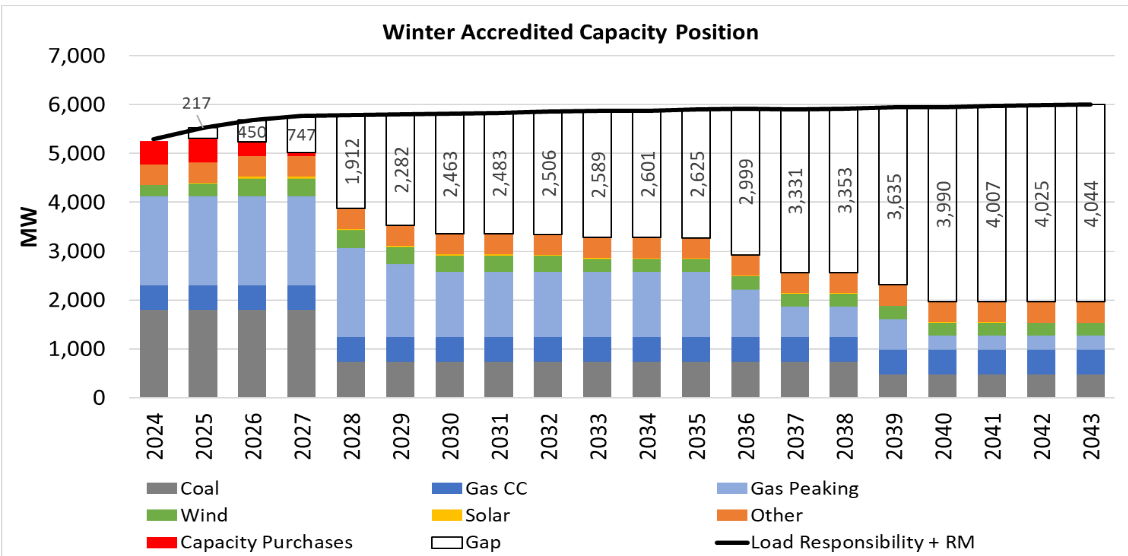


Figure 18 SWEPCO Winter Going- In Capacity Position

4. Transmission and Distribution Evaluation

4.1. Transmission System Overview

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 thirteen other companies at over 90 interconnection points, of which over 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.

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. 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 sometimes constrained when generation is dispatched in a manner substantially different from the original design of utilizing local generation to serve local load. However, since becoming an RTO in 2004, many bulk transmission upgrades within SPP have greatly improved SPP's ability to dispatch generation in a more economic and flexible manner while maintaining reliability, and more such upgrades continue each year.

SPP has made efforts to solve seams issues, and SPP and MISO have engaged in a coordinated study process to identify transmission improvement projects which are mutually beneficial. The latest effort was the Joint Targeted Interconnection Study which started in 2020. The study was focused on identifying projects needed for generator interconnections near the SPP-MISO seams. Projects deemed beneficial by both RTOs will be pursued with joint funding.

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 SPP Transmission Expansion Plan ("STEP"). The STEP is a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. 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 2023 STEP summarizes 2022 activities, including expansion planning and long-term SPP Open Access Transmission Tariff ("OATT" or "Tariff") 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. Requests pursuant to Attachment AQ
4. Integrated Transmission Planning (ITP)
5. Balanced Portfolio

6. High Priority Studies
7. Sponsored Upgrades
8. Interregional Coordination
9. Integrated Transmission Planning 20-Year Assessment, and
10. Generation Retirement

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 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
- Zonal-Sponsored – Projects sponsored by facility owner with no Project Sponsor Agreement.

The 2023 STEP[6] identified 343 transmission network upgrades with a total cost of approximately $3.28 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 71% of the total cost in the 2023 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 ITP resulted in a recommended portfolio of transmission projects for comprehensive regional solutions, local reliability upgrades, and the expected reliability and economic needs. Upgrades that require a financial commitment within the next four years receive Notification to Construct ("NTC") letters issued by SPP.

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

[6] The 2023 STEP is available at: https://www.spp.org/Documents/56611/2023%20SPP%20Transmission%20Expansion%20Plan%20Report.pdf

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. Recently approved SPP transmission solutions that improve reliability or reduce congestion

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

- Chisholm – Woodward/Border tie 345 kV line. This project, located in western Oklahoma, will increase bulk transfer capability from west to east across the west Texas/Oklahoma area. This project is estimated to provide between $102 million and $123 million in economic benefits over 40 years.
- Minco – Pleasant Valley – Draper 345 kV line and new station. This project creates a new Pleasant Valley 345/138 kV substation which ties into the existing Cimarron to Draper 345 kV line. A new line from Minco to Pleasant Valley and a second 345 kV line from Pleasant Valley to Draper. Overall, there is approximately 48 miles of new 345 kV transmission. The project increases transfer capability by bypassing congestion in the Oklahoma City area. This project is estimated to provide between $286 million to $804 million in economic benefits over 40 years.
- Sooner – Wekiwa 345 kV line build. This approximately 76-mile project will increase transfer capability and is estimated to provide between $17 million and $465.6 million in economic benefits over 40 years.
- South Shreveport – Wallace Lake 138 kV line rebuild. This project will improve reliability in the Shreveport / Bossier City area and will strengthen the transmission system between SPP and the Cleco area of MISO.
- 36th & Lewis – 52nd & Delaware Tap 138 kV rebuild. This 0.97-mile project was approved to address NERC TPL-001-4 criteria.
- Osage – Webb City Tap – Shidler 138 kV rebuild. This project was approved to address NERC TPL-001-4 criteria. The project includes the rebuild of 24.9 miles. The project is expected to provide up to $44.37 million in economic benefits over 40 years. The project greatly increases the west to east flow across the SPP system.
- Cleveland – Cleveland 138 kV bus tie rebuild. This tie between the SPP and AECI systems west of Tulsa has become one of the most congested points on the SPP system. This project is estimated to provide between $138.7 million and $225.3 million in economic benefits over 40 years.
- Pine & Peoria Tap – 46th Street Tap – Tulsa North 138 kV rebuild. The project includes the rebuild of 5.7 miles of 138 kV between Pine & Peoria Tap and Tulsa North. This project is estimated to provide between $390 million and $532.7 million in economic benefits over 40 years.
- Fitzgerald Creek – Kenzie 138 kV line tap at Valley. This project is located 30 miles north of Oklahoma City. The project addresses congestion between the Kenzie station owned by OG&E and the Kenzie station owned by GRDA. This project is estimated to provide between $65.1 million and $125.3 million in economic benefits over 40 years.
- Matthewson – Redbud 345 kV new line. This project assists in transferring renewable energy from western Oklahoma towards the larger load centers further to the east. The

project is a new 38-mile path between the existing Matthewson and Redbud stations. This project is expected to provide between $138.6 million and $225.3 million in economic benefits over 40 years.

- **Northwest Arkansas**: The Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line has been upgraded to a larger conductor with improved thermal capacity. The terminal equipment upgrades were approved to further increase the rating of the path. These upgrades relieve constraints for west to east flow and improve reliability.
- **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. SWEPCO Distribution System Overview

SWEPCO serves approximately 552,000 customers across 20,701 square miles of Arkansas, Louisiana, and Texas. This includes approximately 470,000 residential, 75,000 commercial, 6,900 industrial, and 600 “other” customers. SWEPCO’s Distribution Operations organization includes five districts: Longview, Fayetteville, Texarkana, Shreveport, and Valley. SWEPCO’s distribution system includes approximately 21,717 overhead circuit miles and approximately 3,580 underground circuit miles. SWEPCO’s distribution system includes approximately 19,999 primary miles and 5,297 secondary miles.

4.5.1. Distribution Investments

SWEPCO’s Distribution Operations organization includes five functional support departments: Engineering, Region Operations, Vegetation Management, Distribution Systems and Continuous Improvement. These departments are responsible for distribution system engineering and design activities, resource planning and contracting activities, vegetation management, construction and maintenance, and the operation of the distribution electrical system for the entire SWEPCO service territory.

In SWEPCO’s most recent rate case filings, SWEPCO has proposed investments to its distribution grid of approximately $301.96M in capital investment in SWEPCO’s distribution grid over the next five years.

Table 4 provides an overview of this plan.

Table 4 SWEPCO Grid Transformation and Infrastructure Program

Project Type	Estimated Spend (Millions $)
Capacity Assurance	92.79
Grid Modernization	39.91
Reliability Enhancements	62.43
Asset Renewal	106.83
Total	301.96

4.5.2. Microgrids

Microgrids are small scale power systems that can operate independently or in tandem with a large-scale electrical grid. They typically make heavy use of renewables such as photovoltaic systems and wind turbines, along with other sources as needed, to generate enough energy to use with a specific building or community without adding demand to the wider electric network. Microgrids are generally designed to be self-sufficient and can help fill the gap on an overstressed network as well as insulate a large urban area from power failure or potential blackout because of a natural disaster and physical or cyber-attacks. They may connect to the wider network during certain times of stress as needed to either take energy from, or supply energy to, the grid.

The Company is completing the development of a microgrid community solar project with storage in Shreveport, Louisiana. At this time, the project is under construction and commissioning of the project is expected to be completed and the system to be brought online in the first quarter of 2024. The Company looks forward to the addition and the opportunity to learn how the operation will impact the Company's peak load.

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 baseload 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 obsolete 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 SWEPCO in this IRP fall into six categories: base / intermediate alternatives, peaking alternatives, renewable alternatives, advanced generation alternatives, long-duration storage alternatives, and short-term market purchases.

Unless stated otherwise, SWEPCO relied on EIA's 2023 *Annual Energy Outlook* ("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 2023 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("NREL ATB 2023") report.[7] 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. Capital Costs shown are in nominal dollars starting from a base year of 2022, reflecting the Producers Price Index for Energy (PPI).

The Company included annual and cumulative capacity modeling limits for different resources informed through its analysis of the SPP queue and responses to Company RFPs. To establish the modeling limits, the Company first reviewed the potential amount of resources that might be available through the analysis of the resources submitted in the SPP Queue. It further assumed, that of the total resources in the SPP Queue, only 20% might actually be available to the open market for development. The Company then considered the total responses to recent RFPs to substantiate the estimate of potential resources that might be available to the Company to transact. In its recent RFPs, the Company received a larger number of responses for solar resources than wind resources. The Company further refined its estimates from the SPP Queue analysis to reflect market-informed levels of potential resources it might have the opportunity to transact.

All new resources also included an assumption for additional transmission network and interconnection upgrade costs. For this IRP, a proxy cost of $32/kW was included in the cost of thermal resources informed from a study by Lawrence Berkley National Laboratory on SPP Interconnection costs through 2023[8]. Wind resources included a capital cost of $113/kW and solar resources included a capital cost of $157/kW. These costs were informed from responses to the Company's 2021 RFP and are used as a proxy for potential costs of future resources.

Fixed costs for all new gas resources included an additional firm gas reservation fee of $0.2441/MMBtu based on gas distribution company published transmission rate. This cost is applied as a proxy for ensuring the availability of an adequate and reliable fuel supply.

5.2. Base / Intermediate Alternatives

Baseload electricity is the minimum level of electricity demand in the system. Traditionally, baseload electricity demand is met by baseload power plants designed and optimized for

[7] NREL Electricity Annual Technology Baseline (ATB)

[8] https://emp.lbl.gov/publications/generator-interconnection-cost-0

continuous running. Baseload plants include coal and nuclear plants which are generally not designed to vary their outputs over a wide range quickly on a frequent basis. However, the electricity supply mix is changing with increased intermittent renewable generation. Furthermore, regulations and changing customers' needs have made new coal and nuclear plants economically infeasible. As such, coal without carbon capture and storage and traditional nuclear are not part of supply-side resource options in this IRP.

Intermediate power plants adjust outputs as electricity demand fluctuates. This role has been traditionally met by older, smaller and relatively less efficient power plants. But as these power plants retire, new capacity is needed. Natural gas combined cycle power plants have slowly become the typical generation resource option for intermediate power plants and they are included in this IRP.

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

Modern NGCCs have moderate capital costs, high generating efficiency, relatively low carbon emissions (per MWh) compared to older fossil fuel units, and the ability to load follow over a significant range of operation. These characteristics make the technology desirable for baseload and intermediate applications.

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 418 MW capacity and the H-class turbine multi-shaft configuration with 1,100 MW capacity. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for SPP interconnection request approvals, regulatory approvals, permitting siting, engineering, and construction.

Overnight capital cost assumptions for NGCC options are shown Figure 19. The first operating year variable operations and maintenance cost ("VOM"), the fixed operations and maintenance cost ("FOM"), firm gas reservation fees and heat rate assumptions are shown in Table 5.

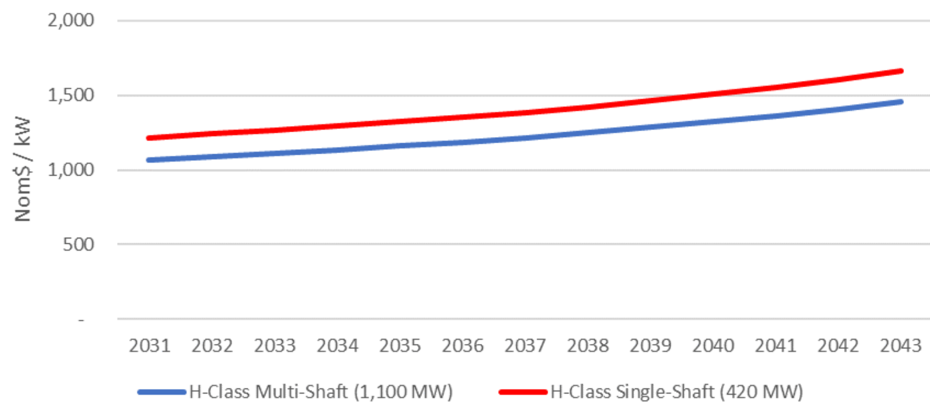


Figure 19 Capital Cost Assumptions for NGCC

Table 5 Operating Cost and Heat Rate Assumptions for NGCC

		H-Class Multi-Shaft (1,100 MW)	H-Class Single Shaft (420 MW)
VOM	$ / MWh	2.33	3.18
FOM	$ / kW-yr	14.96	17.29
Gas Transmission rate	$ / kW-yr	16.09	16.25
Heat Rate	Btu / kWh	6,370	6,431

5.3. Peaking Alternatives

Peaking sources have traditionally provided top-up generating capacity during demand peaks that may typically occur from a few days to several weeks 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. In this IRP, four new peaking sources considered are simple cycle combustion turbines, aeroderivatives, reciprocating engines, and lithium-ion batteries. Additionally, the conversion of the Company's existing Welsh 1 and Welsh 3 units from coal to gas-steam were included as a resources for economic selection.

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 for use in a steam cycle. 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.

In addition, turbine manufacturers are developing the ability of new gas turbines to burn increasing volumes of hydrogen in the gas stream. Recent turbines can burn up to 30% hydrogen by volume[9] in the gas stream and can potentially be retrofitted to burn 100% hydrogen when the hydrogen supply chain is sufficiently developed. Section 5.5.3 provides further detailed on the modeling 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

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

configuration is available for AURORA to select, the 240 MW F-Class unit. This generic resource is made available in the model with a first operating year of 2031, reflective of the anticipated period required for SPP interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction. The maximum annual capacity addition is 720 MW.

Additionally, the Company included an earlier NGCT alternative, up to 480MW that would be available by 2029. This resource is assumed to be developed on an existing company site where additional Company options might be available to support bringing a resource online sooner than the generic option.

The NGCT overnight capital cost assumptions are shown in Figure 20. The first operating year FOM, VOM, firm gas reservation fees and heat rate assumptions are shown in Table 6.Table 6

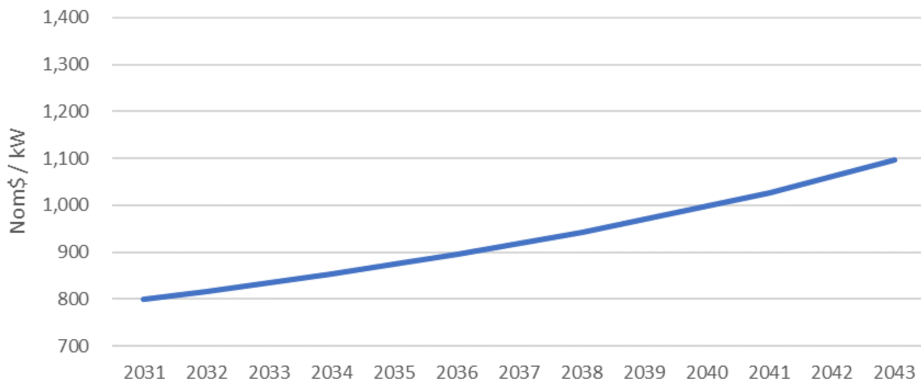


Figure 20 Capital Cost Assumptions for NGCT

Table 6 Operating and Heat Rate Assumptions for NGCT

		F-Class CT (240 MW)
VOM	$ / MWh	5.98
FOM	$ / kW-yr	8.88
Gas Transmission Rate	$ / kW-yr	25.02
Heat Rate	Btu / kWh	9,905

5.3.2. Aeroderivatives (AD) Turbines

Aeroderivative turbine units are based off of aircraft jet engine designs and are modified for the use in power generation. Their operating characteristics make them well suited for high renewable penetration as they can quickly respond to significant shifts 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 on a dollar per kW unit costs than NGCTs.

AD units are modeled in AURORA in 105 MW units as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for approval, siting, engineering, and construction. The maximum annual capacity addition is 210 MW.

The AD overnight capital cost assumptions are shown in Figure 21. The first operating year FOM, VOM, firm gas reservation fees and heat rate assumptions are shown in Table 7.

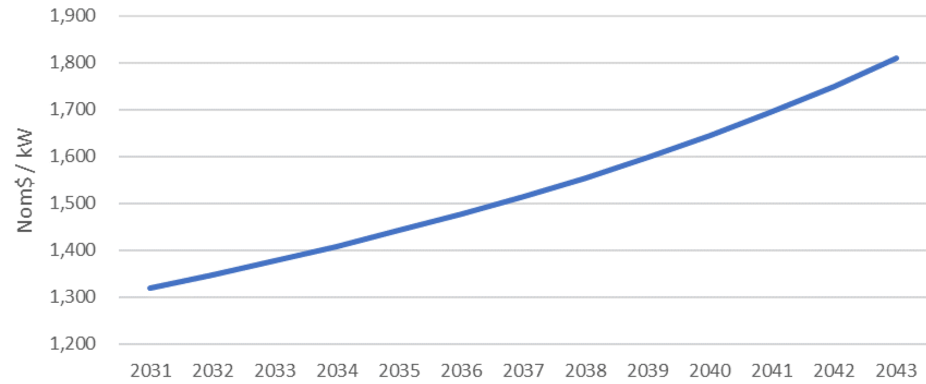


Figure 21 Capital Cost Assumptions for AD

Table 7 Operating and Heat Rate Assumptions for AD

		AD (100 MW)
VOM	$ / MWh	6.25
FOM	$ / kW-yr	20.69
Gas Transmission Rate	$ / kW-yr	23.05
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 within piston chambers 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 efficiently at partial load as individual RE units within the generating set can be shut down to reduce output while allowing remaining units to run at full load. Unlike NGCTs or ADs, RE units can be started multiple times in a day without incurring substantial additional maintenance costs. These characteristics make RE units well suited for power systems that require frequent but short-duration dispatches.

REs are modeled in AURORA in 21 MW units as a standard dispatch resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for approval, siting, engineering, and construction.

The RE overnight capital cost assumptions are shown in Figure 22.The first operating year FOM, VOM, firm gas reservation fees and heat rate assumptions are shown in Table 8.

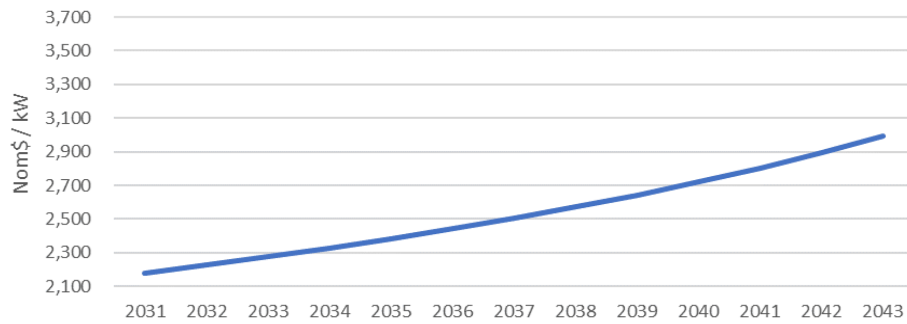


Figure 22 Capital Cost Assumptions for RE

Table 8 Operating and Heat Rate Assumptions for RE

		RE (20 MW)
VOM	$ / MWh	7.56
FOM	$ / kW-yr	44.61
Gas Transmission Rate	$ / kW-yr	20.96
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 regulation, 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 first made available in AURORA from 2028 and are modeled as an energy storage option with durations of four, six and eight 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 0.2% per day. 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 14-70% by 2043 for the four-hour duration, 24-93% for the six-hour duration and 27-97% for the eight-hour duration, depending on the scenario (see section 7.3). Li-ion batteries are made available in a configuration of 50 MW. The maximum annual capacity addition is 200 MW distributed across 4, 6 and 8 hour alternatives in annual amounts of 50, 100 and 50 MWs respectively. The cumulative maximum is 1,800 MW.

The overnight capital cost assumptions for Li-ion batteries are shown in Figure 23. 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 2032. After 2032, ITC tax credits reduce to 22.5%, 15% and 0% of their value in 2033, 2034, and 2035, respectively.[10]

Figure 24 shows the assumed FOM for a Li-ion battery built in each specific year.

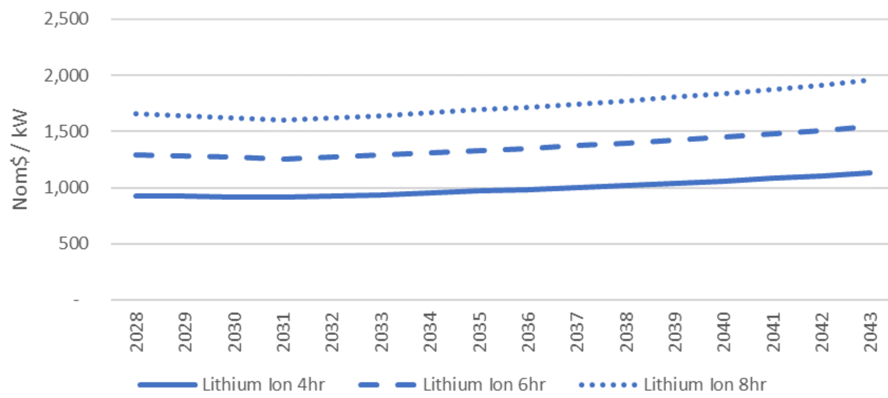


Figure 23 Capital Cost Assumptions for Li-Ion

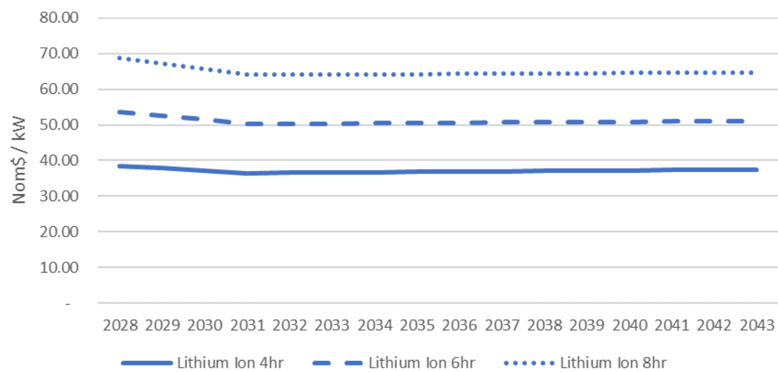


Figure 24 FOM Assumptions for Li-Ion

5.3.5. Welsh Unit Conversions

The Company's existing Welsh 1 and Welsh 3 coal units were included as separate resources available in 2028 for conversion from coal-fired to gas-fired. The conversion of these units allows the Company to take advantage of existing infrastructure and retain a reliable resource to provide capacity and energy at low costs to SWEPCO customers.

Each unit was modeled with a capital cost assumption of $271/kW.

The first operating year FOM, VOM, firm gas reservation fees and heat rate assumptions are shown in Table 9.

Table 9 Operating and Heat Rate Assumptions for Welsh Unit Conversions

		Welsh Cnvsn (525MW)
VOM	$ / MWh	$
FOM	$ / kW-yr	$18

[10] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

Gas Transmission Rate	$ / kW-yr	$23.0
Heat Rate	Btu / kWh	10,600

5.4. Renewable Alternatives

Renewable generation alternatives provide an opportunity to deliver affordable clean energy to address future electricity needs, consistent with SWEPCO's aim of enabling a greener future for all when cost effective. These renewable 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.

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

5.4.1. Wind

Wind energy is based on utilizing 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 in 2028. It is modeled as a generation resource dispatching according to a generic production profile representative of the region with an average capacity factor of 44%. The capacity credit for wind is evaluated based on its Effective Load Carrying Capability (ELCC), consistent with SPP's methodology used for accrediting the capacity credit for wind resources. Based on SWEPCO's analysis of wind ELCC, wind resources are credited with 13-19% capacity value depending on the scenario in the IRP analyses. Both the hourly production profile and average capacity factor are estimated based on recent market data obtained by AEP through the 2021-22 RFP process and are assumed to be a reasonable representation of the production and performance characteristics of a typical new wind resource in the region.

Wind resources are made available in a configuration of 100 MW. Two pricing tiers, Tier 1 and Tier 2, were modeled to reflect the range of potential pricing for wind resources in the marketplace. Because wind generation resources tend to be located electrically further from load centers, a congestion and loss cost adder of approximately $16/MWh was assumed. The maximum annual capacity additions were informed through the level of responses to the Company's RFPs and included 400 MW for lower cost Tier 1 sites and 400 MW for Tier 2 sites. The assumed cumulative maximum is 1,200 MW.

Capital costs were informed from responses to the Company's 2021 RFP and are used as a proxy for potential costs of future resources. The cost reduction projection from NREL ATB 2023 is applied to the capital cost to project the capital costs through the study period and beyond, as shown in Figure 25 below.

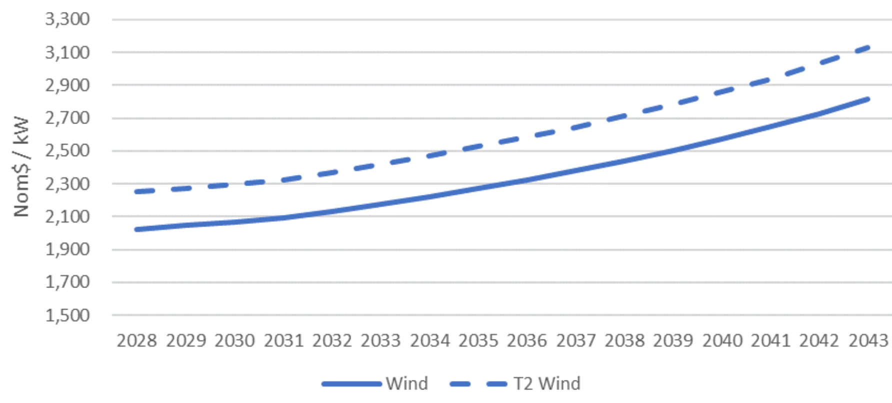


Figure 25 Capital Cost Assumptions for Onshore Wind

Figure 26 illustrates the FOM cost assumptions for onshore wind.

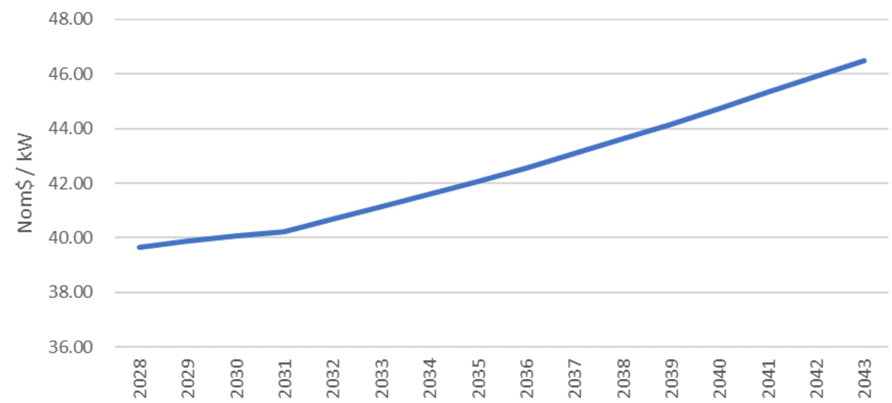


Figure 26 FOM Assumptions for Onshore Wind

Pursuant to the Inflation Reduction Act (IRA) of 2022, projects whose construction begins by the end of 2032 are eligible for a Production Tax Credit ("PTC"), added to the project value at a rate of 100% of the PTC, or $25/MWh[11], which is implemented in AURORA as a negative variable cost adder. After 2032, PTC tax credits were assumed to be reduced to 75%, 50% and 0% of their value in 2033, 2034, and 2035, respectively.[12]

5.4.2. Solar

Solar photovoltaic ("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 2028. 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 around 25% assuming a single-axis tracking configuration. Solar capacity credit for summer is estimated at a percentage of ICAP.

[11] In 2021 dollars; 10 year tax credit; PTC eligibility declines to zero for projects in service for 2035 and beyond. There is potential for several years extension through safe harbor provisions.

[12] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

This capacity credit is discussed further in section 7.3.3. The percentage capacity credit is modeled at 69% in 2028 and then declines to 12% by 2043, depending on the scenario (see Section 7.4.2). The hourly production profile and average capacity factor are based on production estimates for solar resources within SPP. Solar is made available in a configuration of 50 MW. The maximum annual capacity additions were informed through the level of responses to the Company's RFPs and included 600 MW for lower cost Tier 1 sites and 600 MW for Tier 2 sites. Similar to wind resources, a congestion and loss adder was also included. For solar resources, a cost of approximately $1/MWh was assumed initially, rising to approximately $3/MWh by 2033. The cumulative maximum available additions over the planning horizon were modeled as 3,600 MW.

Hybrid 3:1 solar+storage systems are available in 200 MW blocks (150 MW solar plus 50 MW of 4-hour duration storage), up to 400 MW annually.

Capital costs were informed from responses to the Company's 2021 RFP and are used as a proxy for potential costs of future resources. The overnight capital cost assumptions for solar PV are shown in Figure 27.

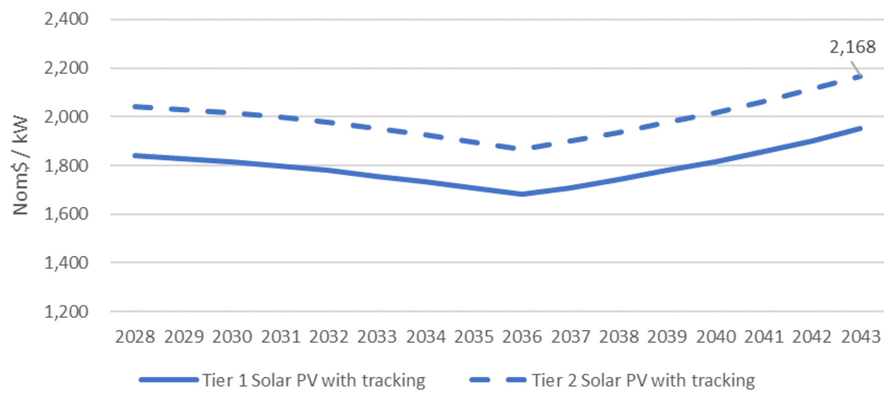


Figure 27 Capital Cost Assumptions for Utility-Scale Solar PV

As with wind resources, under the terms of the IRA, solar projects whose construction begins by the end of 2032 are eligible for a PTC, added to the project value at a rate of 100% of the PTC. Solar PTCs were modeled similarly to the wind resource option described in the previous section.

Figure 28 Figure 28 shows the FOM cost assumptions for solar PV.

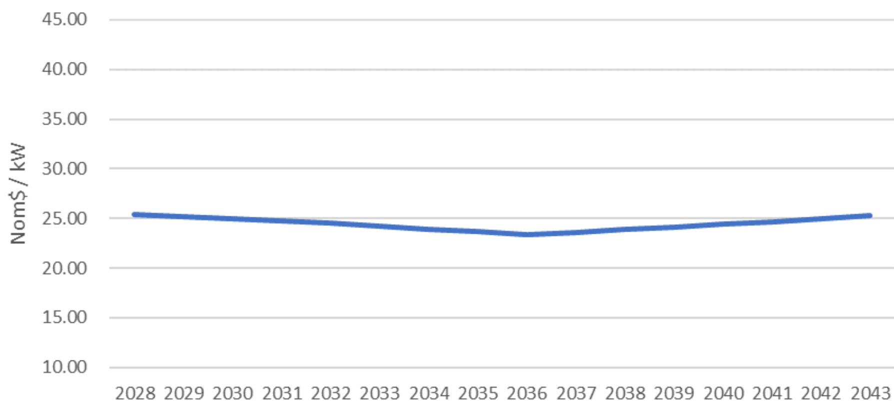


Figure 28 FOM Assumptions for Utility-Scale Solar PV

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 SWEPCO 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 plan that minimizes technology risks and allows SWEPCO 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 (SMR) 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 footprint;
- 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.

Recently, the LPSC has asked the Idaho National Laboratory (INL) to support their efforts to examine opportunities for advanced nuclear energy. The effort will focus on economic development and is intended to create an approach that addresses value propositions for the state and private sector. While this endeavor is in the very early stages, the Company looks forward to engaging with the parties to advance this opportunity.

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 taken from the EIA AEO 2022. 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[13]. 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. It is assumed that SMR will not be available for commercial deployment until 2035 in a block size of 600MW. Figure 29 below shows the assumed overnight capital cost of SMR cost over time. The first operating year FOM, VOM assumptions are shown in Table 10.

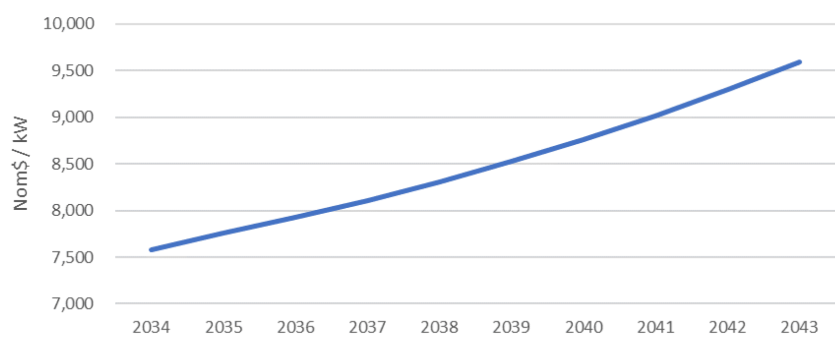


Figure 29 Capital Cost Assumptions for SMR

Table 10 Operating and Heat Rate Assumptions for SMR

		SMR
VOM	$/ MWh	4.21
FOM	$ / kW-yr	133.26
Heat Rate	Btu / kWh	10,443

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 form 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. Section 45Q legislation provides a tax credit of $94/short-ton of CO_2 sequestered in 2031, applied for the first 12 years of operation. This incentive is implemented in AURORA as a negative variable cost adder, improving dispatch economics.

13 Department of Energy (2013), Small Modular Nuclear Reactors: Parametric Modeling 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 380 MW H-class combined-cycle natural gas turbine with 90% carbon capture. Coal CCS is assumed available in 2033 and natural gas CCS in 2031.

The assumptions on overnight capital costs for new build CCS are shown in Figure 30. The first operating year FOM, VOM, and heat rate assumptions are shown in Table 11 below.

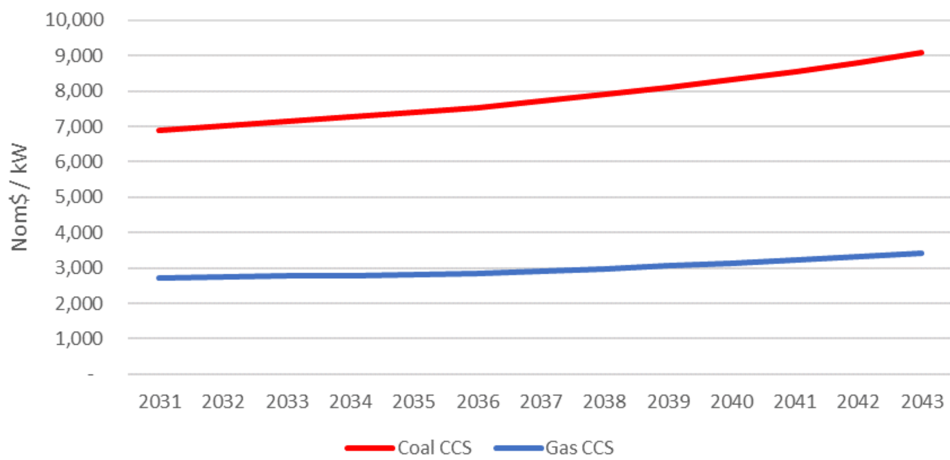


Figure 30 Capital Cost Assumptions for New Build CCS

Note – Coal CCS represents a 650 MW ultra-supercritical unit with 90% capture rate; Gas CC CCS represents a 380 MW single shaft CCGT with 90% capture rate

Table 11 Operating and Heat Rate Assumptions for New Build CCS

		Coal	Gas
VOM	$ / MWh	14.68	6.90
FOM	$ / kW-yr	76.95	31.62
Gas Transmission Rate	$ / kW-yr		18.00
Heat Rate	Btu / kWh	11,341	6,696

Retrofit Options

It is also possible for AURORA to choose to retrofit 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 12 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	$2021 / kW post-retrofit capacity	881
Incremental FOM	$2021 / kW post-retrofit capacity	19.9
Incremental VOM	$ / kWh	1.24

The cost and performance parameters for retrofit coal units are taken from the Environmental Protection Agency's ("EPA") modeling assumptions in its power sector modeling platform[14]. The applied parameters vary based on the capacity and heat rate of the coal unit as shown in Table 13 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 13 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 (%)
400	9,000	2,595	36.9	18.2	33.6	50.6
	10,000	2,960	41.2	19.7	37.3	59.5
	11,000	3,373	46.1	21.3	41.0	69.6
700	9,000	1,852	23.7	14.9	19.2	23.7
	10,000	2,071	26.1	15.6	21.3	27.0
	11,000	2,302	28.6	16.4	23.4	30.6
1000	9,000	1,625	19.7	13.9	13.4	15.5
	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 transporting and storing CO_2. The parameters in Table 14 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. 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 14 Carbon transport and storage schedule ($2021 / tCO_2)

	Louisiana	Texas	Oklahoma	Kansas	Arkansas	Missouri
Storage Cost	5.10	5.10	5.10	5.10	5.10	-
Transport Cost	44.32	49.28	28.10	42.94	19.42	35.41
Total Cost	**49.42**	**54.38**	**33.20**	**48.04**	**24.52**	**35.41**

5.5.3. Hydrogen (H_2)

Two key components that make up a "green" hydrogen system[15] are the polymer electrolyte membrane ("PEM") electrolyzer and the hydrogen gas combustion turbine ("H_2 CT").

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

- **Energy density**: H_2 is 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;

[14] 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

[15] Green hydrogen is made with electrolyzers powered by non-carbon emitting resources. Other types of hydrogen production, for example "blue" hydrogen, is made from reforming methane with CCS of the CO_2 byproduct.

- **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 reduction curve, and efficiency assumptions for the PEM electrolyzer are developed based on a compilation of various sources including PNNL[16], IEA[17], EPRI[18], DOE[19] and the International Council on Clean Transportation[20]. 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 31, FOM for electrolyzer in Figure 32, efficiency for electrolyzer in Figure 33. Other first operating year parameters shown in Table 15 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 the same with the EIA AEO 2022 estimate for NGCT, reflecting additional costs for maintaining a system with high levels of water and steam injection for emission control.

[16] 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

[17] 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

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

[19] 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

[20] 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 31 Capital Cost Assumptions for PEM Electrolyzer and H2 CT Components

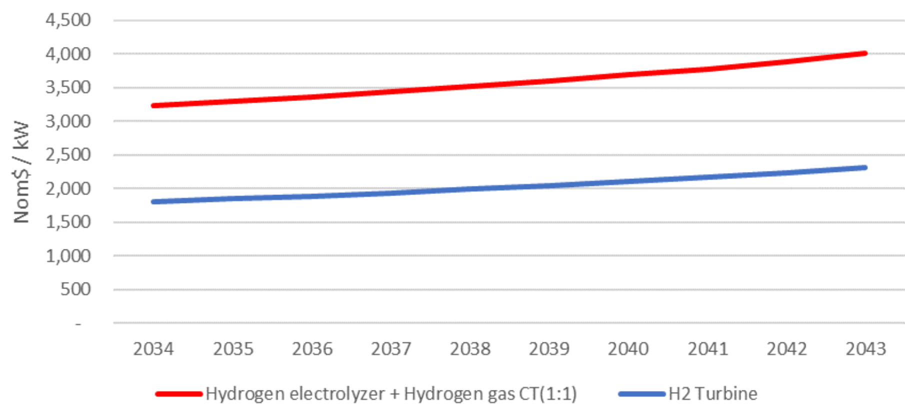


Figure 32 FOM Assumptions for PEM Electrolyzer and H2 CT Components

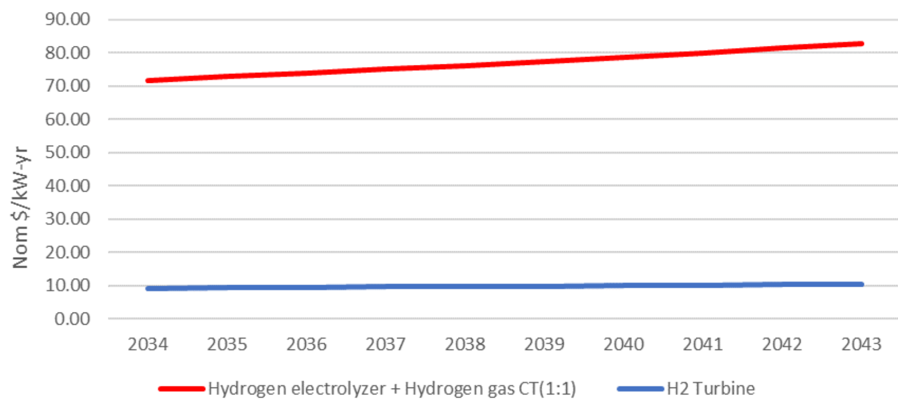


Figure 33 Efficiency Assumptions for PEM Electrolyzer

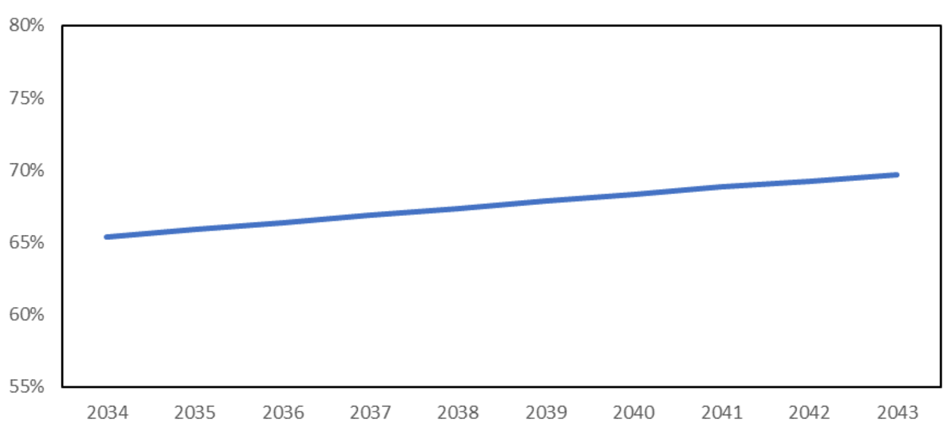


Table 15 Operating and Heat Rate Assumptions for PEM Electrolyzer and H_2 CT

		PEM Electrolyzer	H_2 CT
VOM	$ / MWh	0.62	6.31
FOM	$/ kW-yr	Figure 32	Figure 32
Efficiency/Heat Rate	Btu / kWh	Figure 33	9,655

Projects whose construction begins by the end of 2032 are eligible for a PTC. This is applied as a discount to the price of hydrogen fuel in AURORA at a rate of $3/kg[21].

Hydrogen is made available in AURORA starting in 2032, based on statements by various major power equipment providers committing to provide 100% H_2 CTs by 2030 and a best estimate of when market supply of hydrogen could be reliably available.

Hydrogen resources are offered in AURORA assuming third-party H_2 supply, whereby only the H_2 CT is assumed to be utility owned, thus the modelled costs comprise the capital cost, FOM, VOM of H_2 CT only, and fuel prices represented by 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. The supply of H_2 is assumed to be available on demand. The H_2 CT is then modeled as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

5.6. Long Duration Storage Alternatives

For the purposes of this IRP, long-duration storage refers to storage that can provide 20 hours' or more 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 SWEPCO'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 any new sites may be subject to a potentially long permitting process. Consequently 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 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 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.

21 While the amount of the credit varies based on the CO_2e per kg of emissions of the hydrogen production process, the ten-year hydrogen PTC is for up to $3 per kg (in 2022 dollars and inflated over time).

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. PTES is made available in a configuration of 25 MW. The maximum annual capacity addition is 250 MW and the cumulative maximum of 500 MW.

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 34 and Figure 35 below.

Figure 34 Capital Cost Assumptions for 20-hour duration PTES

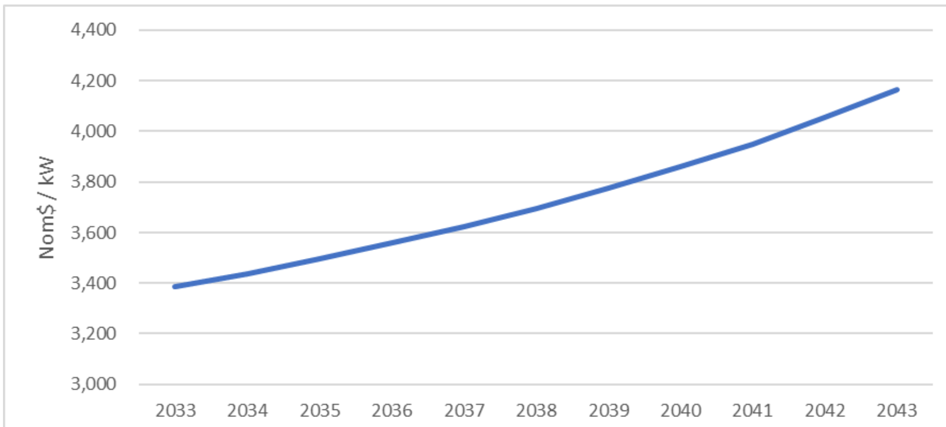
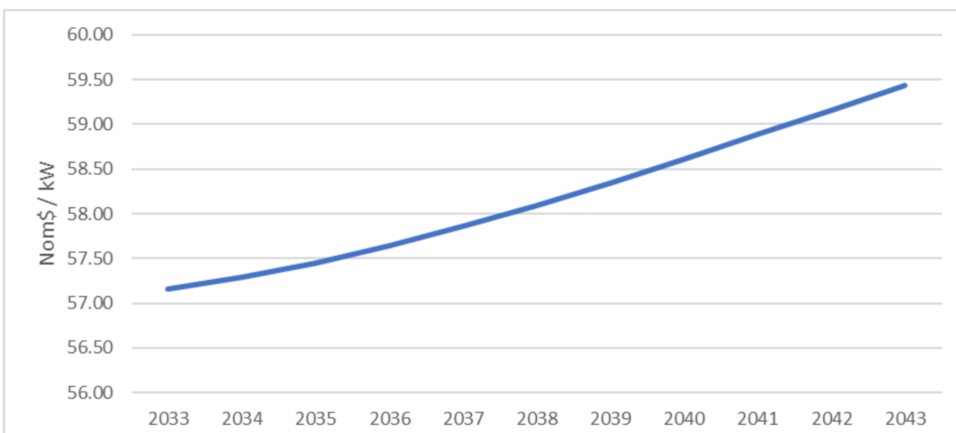


Figure 35 FOM Assumptions for 20-hour duration PTES



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 2032. After 2032, ITC tax credits reduce to 22.5%, 15% and 0% of their value in 2033, 2034, and 2035, respectively.[22]

[22] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

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. VFB is made available in a configuration of 50 MW. The maximum annual capacity addition is 200 MW and the cumulative maximum is 500 MW. The first available year for operation is 2033.

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 36 and Figure 37 below.

Figure 36 Capital Cost Assumptions for 20-hour duration VFB

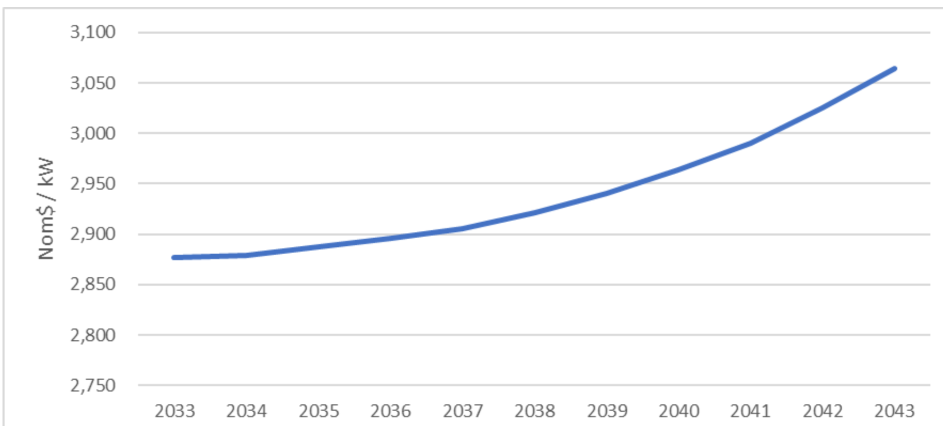
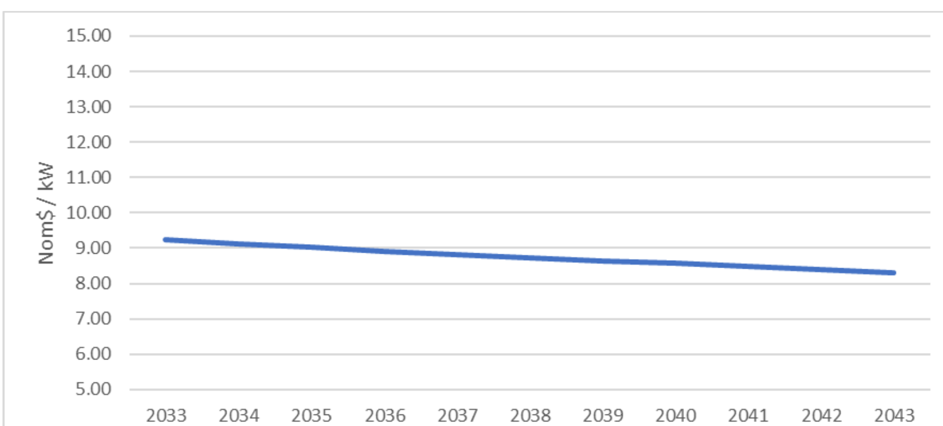


Figure 37 FOM Assumptions for 20-hour duration VFB



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 2032. After 2032, ITC tax credits reduce to 22.5%, 15% and 0% of their value in 2033, 2034, and 2035, respectively.[23]

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. CAES is made available in a configuration of 25 MW. The maximum annual capacity addition is 250 MW and the cumulative maximum is 500 MW. The first year available for operation is 2033.

The forecasted CAES overnight capital cost is based on a survey of recent project development activity, whereas FOM is based on an average of a wide range of sources including reports from DOE, PNNL, BEIS and academic studies. 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 2032.

5.7. Short-Term Market Purchase (STMP)

Short-Term Market Purchase alternative capacity resources were made available to the model for selection during the development of the optimal plans. This resource is assumed to have no energy associated with it and a contract term of one year. The purpose of adding this resource was to allow the model an option to include a short-term capacity resource as a bridge to mitigate abrupt capacity shortfalls. At this time, due to the Company's understanding of the availability of third-party capacity purchases, with no energy value, it is appropriate to limit the availability of this resource option to the 2027-2028 period to a maximum of 150 MW/year.

Although the Company has seen a limited supply of near-term resources, a capacity expansion portfolio sensitivity was run in response to stakeholder feedback to evaluate the results of mid- and long-term portfolio resource selections if more near term resources were available. For this sensitivity, the Company modeled a 3 year, 400MW capacity resource available for selection in 2026, 2027 or 2028 and available for renewal in 2029 for an additional 3 years.

[23] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

6. Demand-side Resource Options

6.1. Introduction

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

6.2. Energy Efficiency (EE) Measures

This IRP considers incremental EE programs as resource options to meet future capacity needs. These incremental EE programs, starting from 2024, are in addition to the existing demand-side programs that run until 2023 and are discussed in Section 2.2.5.

6.2.1. EE Cost and Performance Assumptions

The cost and performance parameters for the incremental EE programs evaluated are based on input from SWEPCO'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 SWEPCO 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 16 provides a list of current and anticipated EE measures for both the residential and commercial sectors.

Table 16 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 of 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

SWEPCO 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 0.5% of the total system load. This is to ensure that each bundle represents a significant energy resource option for AURORA to select when compared against other energy resource options, such as new generating units.

Table 17 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 17 Energy Efficiency Bundles Statistics

	LCOE ($ / MWh)			2024 Gross Total Energy Savings Potential (MWh)	Energy Saving as % of Total 2023 Load
	Min	Mean	Max		
Residential					
Low	3	16	29	248,817	2.1%
Medium	33	45	53	108,858	0.9%
High	72	104	159	213,786	1.8%
Commercial					
Low	3	5	10	59,837	0.5%
Medium	12	21	36	182,509	1.6%
High	54	709	1,274	299,322	2.4%

Table 18 provides incremental gross average yearly energy savings potential for each bundle overtime.

Table 18 Incremental Gross Average Yearly Energy Savings

	Time Period (MWh / Year)		
	2024-2028	2029-2033	2034-2038
Residential			
Low	49,577	4,320	2,008
Medium	25,685	5,606	8,121
High	50,975	9,245	6,303
Commercial			
Low	11,709	0	0
Medium	37,047	0	0

Each EE bundle has a unique 8760 hourly load shape, allowing AURORA to consider 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 19 shows the composition of individual EE measures comprising the low-cost bundle for residential sector for 2024-28 and 2029-33. The individual EE measures are from four electricity end-uses: residential heating, residential cooling, lighting, and other.[24] The load shape for this bundle is the weighted average shape of the four 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.

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

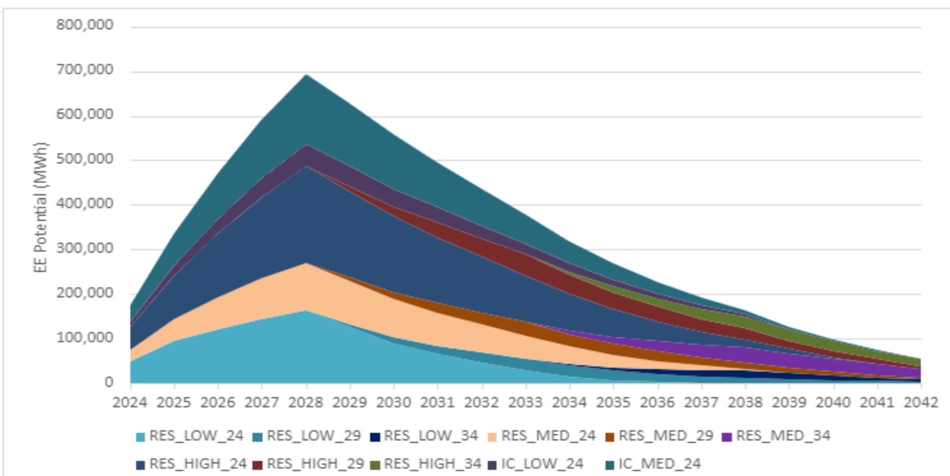
Table 19 Composition of Individual EE measures in Low Residential Bundle by Year

Individual EE measure	Electricity End Use	Gross Incremental Energy Savings Potential (MWh) 2028	2033
Low Flow Showerheads	Other	18,286	1,346
Faucet Aerators	Other	4,360	321
Screw-In – Halogen to LED	Lighting	15,928	1,246
Duct Insulation	Heating + Cooling	9,871	1,976
Pipe Insulation	Other	10,409	766
Energy Star Television	Other	53,097	9,038
Smart Thermostats	Heating + Cooling	59,021	14,506
Behavioral Program	All	66,277	1,344
Energy Star Refrigerator	Other	10,635	1,715
Total		**247,884**	**32,258**

Each bundle is made available in AURORA 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 38 shows net annual energy savings potential across all EE bundles made available to AURORA. The figure assumes that all EE bundles would be selected in the first year of each selection period. At its peak in 2028, net annual energy savings potential available to AURORA accounts for 6% of total energy demand in the year.

Figure 38 Net Annual Energy Savings Potential Across EE Bundles



7. Planning Scenarios and Uncertainties

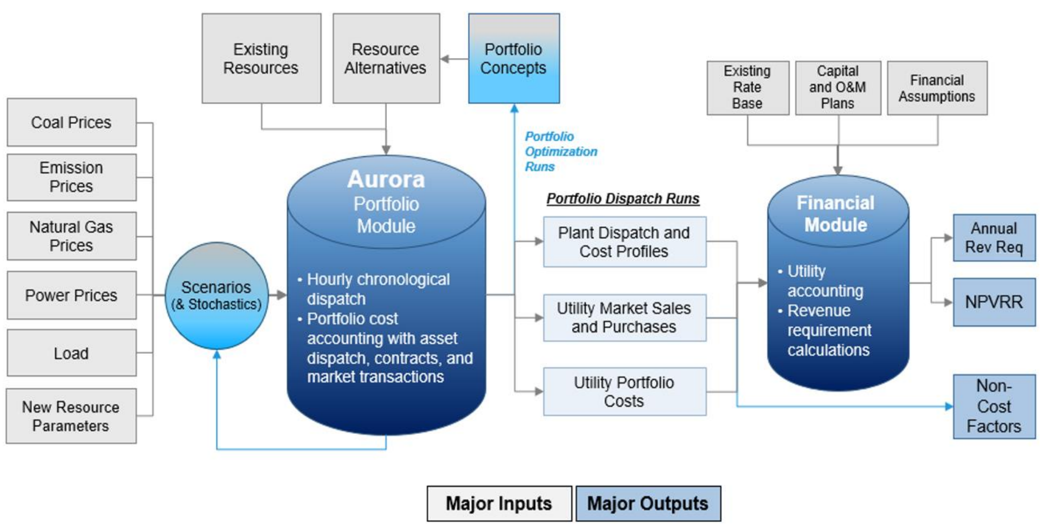
7.1. Introduction

Rate stability and maintaining reliability are two of SWEPCO's objectives for the 2023 IRP. In the context of rising future uncertainties, this section explains how the 2023 IRP analysis captures the key uncertainties and planning risks facing the SWEPCO 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 SWEPCO's customers. SWEPCO evaluates uncertainty and risk using two different methods as part of the 2023 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, SWEPCO developed four additional market scenarios that test the boundaries of expected long-term outcomes. 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 7.2 that combine to reflect a specific theme or "what-if" narrative. The key categories of assumptions used to develop the 2023 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 2023 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 39.

Figure 39 2023 IRP Modeling Framework



The second method subjected the candidate portfolios to a large number of randomly drawn market simulations in the 2023 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. SWEPCO 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

CRA produced a fundamental forecast for key market assumptions including prices for natural gas, coal, and CO_2 based on information from Wood Mackenzie, EIA, and CRA's proprietary market models.

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. AURORA's vendor Energy Exemplar also incorporates the most recent transmission topology for SPP including flow limits between its zones. These are informed by power flow cases, reliability reports and other ISO Planning documents.

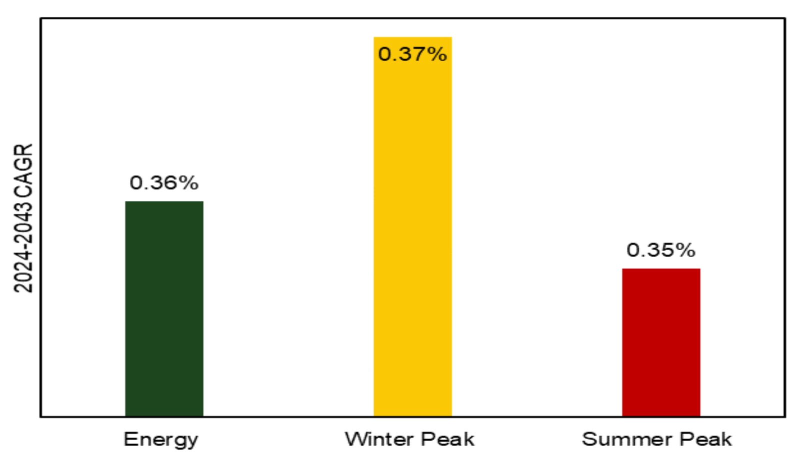
7.2.1. Reference Scenario Market Drivers and Assumptions

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 SWEPCO will operate.

7.2.2. Reference Scenario Load

Under the Reference Scenario provided by AEP Economic Load Forecasting, demand for energy in SPP is expected to grow by 0.36% per year over the 20-year forecast period (2024-2043). Peak summer demand is expected to grow at a rate of 0.35% per year, while peak winter demand grows slightly more quickly at 0.37% per year. These figures are illustrated in Figure 40. The details of the analysis and the assumptions underlying the load forecast are discussed in Section 2 above.

Figure 40 Reference case SPP energy and seasonal peak demand growth rates (2024-2043)



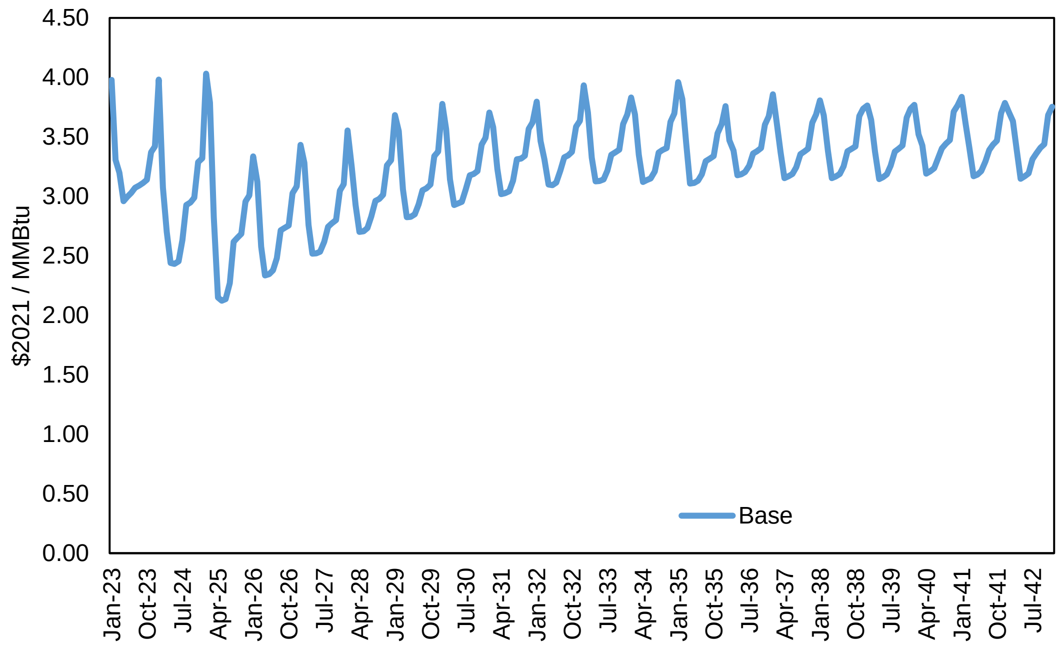
7.2.3. Reference Scenario Fuel & CO_2 Prices

The commodity price inputs to the Reference scenario reflect the "base" view for natural gas, coal, and CO_2 emissions pricing. For the 2023 IRP Reference Scenario, these "base" commodity price outlooks were used to represent the expected conditions for the broader SPP market.

Natural Gas Prices

Figure 41 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 SWEPCO's units and is largely representative of gas prices in the region. Under the Reference Scenario, prices fall from current levels through 2026 in real terms, after which annual growth in prices is modest for the remainder of the forecast period.

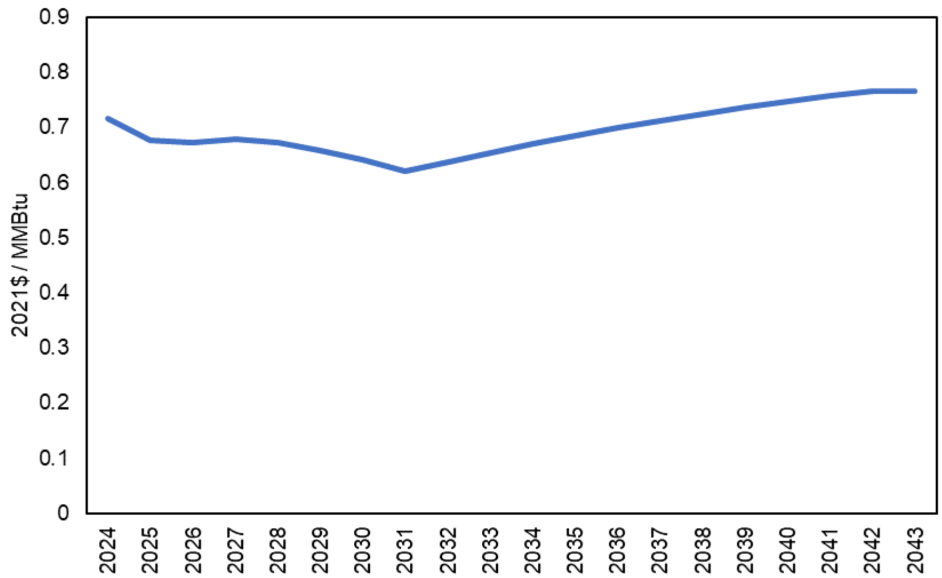
Figure 41 Panhandle Eastern TX-OK Natural Gas Prices (real $ / MMBtu)



Coal Prices

SWEPCO used a coal price forecast from Wood Mackenzie as inputs to the 2023 IRP. Figure 42 below illustrates the monthly forecast of Powder River Basin ("PRB") coal prices at the point of purchase (i.e., exclusive of transportation costs) that were 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 SWEPCO's solid fuel facilities. In the Reference Scenario, similar to natural gas, the PRB forecast exhibits a shorter-term decline in prices from current levels then remains largely constant through the end of the forecast horizon to 2043.

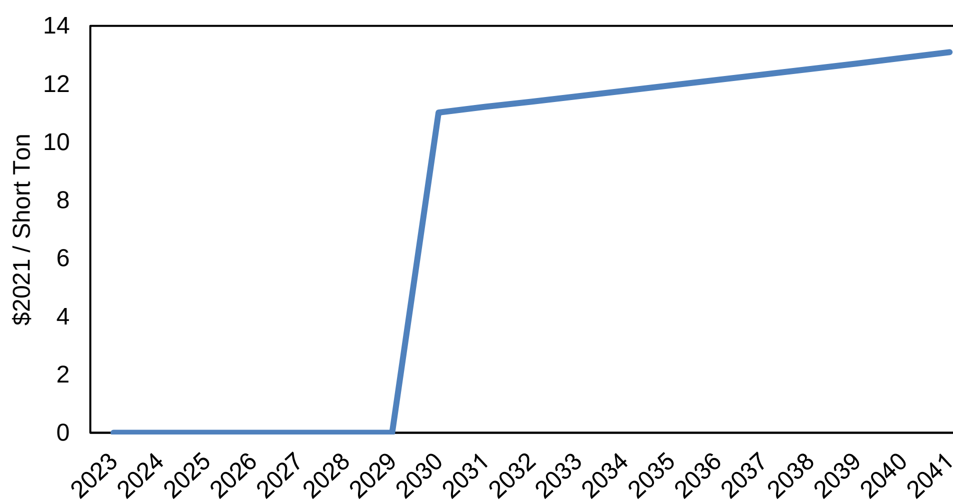
Figure 42 PRB 8,800 Coal Prices (real $ / MMBtu, FOB origin)



CO_2 Prices

SWEPCO assumes that policymakers enact a moderate CO_2 price starting in 2030 as part of the 2023 IRP Reference Scenario. This price is assumed to start around $13 / Ton (in real $2021) and rises modestly throughout the forecast period, as illustrated in Figure 43. 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 43 Moderate CO_2 Price Forecast ($2021 / Short Ton)



7.2.4. Reference Scenario Reserve Requirements

SWEPCO assumes that SPP will need to procure sufficient resources to meet expected load plus a summer planning reserve margin of 15%.

While the planning reserve margin percentage is not assumed to change over the course of the forecast period in the Reference Scenario, SWEPCO does assume changes in the capacity contribution of different technology types, namely solar PV and 4, 6 and 8-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. SWEPCO relied upon studies performed by SPP to estimate the change in ELCC over time as penetration of these resources increases in the SPP footprint.[25,26] Section 7.3.3 discusses the assumed reduction in ELCC over time.

7.2.5. Reference Scenario Technology Assumptions

In general, SWEPCO relied on EIA's 2023 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 2023 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("ATB") report.[27] SWEPCO assumed federal tax credits for new renewable generation, hydrogen, CCS, and grid energy storage under all scenarios to reflect current law and the schedules enacted in the Inflation Reduction Act (IRA) of 2022.

Cost and performance assumptions for demand-side technologies, including EE were developed by AEP staff and the details of the demand-side resource assumptions are discussed in Section 6.

7.2.6. Federal Tax Credits for Renewable Energy

The Inflation Reduction Act of 2022 ("IRA") provides federal tax credits for clean energy, energy storage, clean hydrogen, and CCS. SWEPCO modeled IRA tax benefits as part of the 2023 IRP.

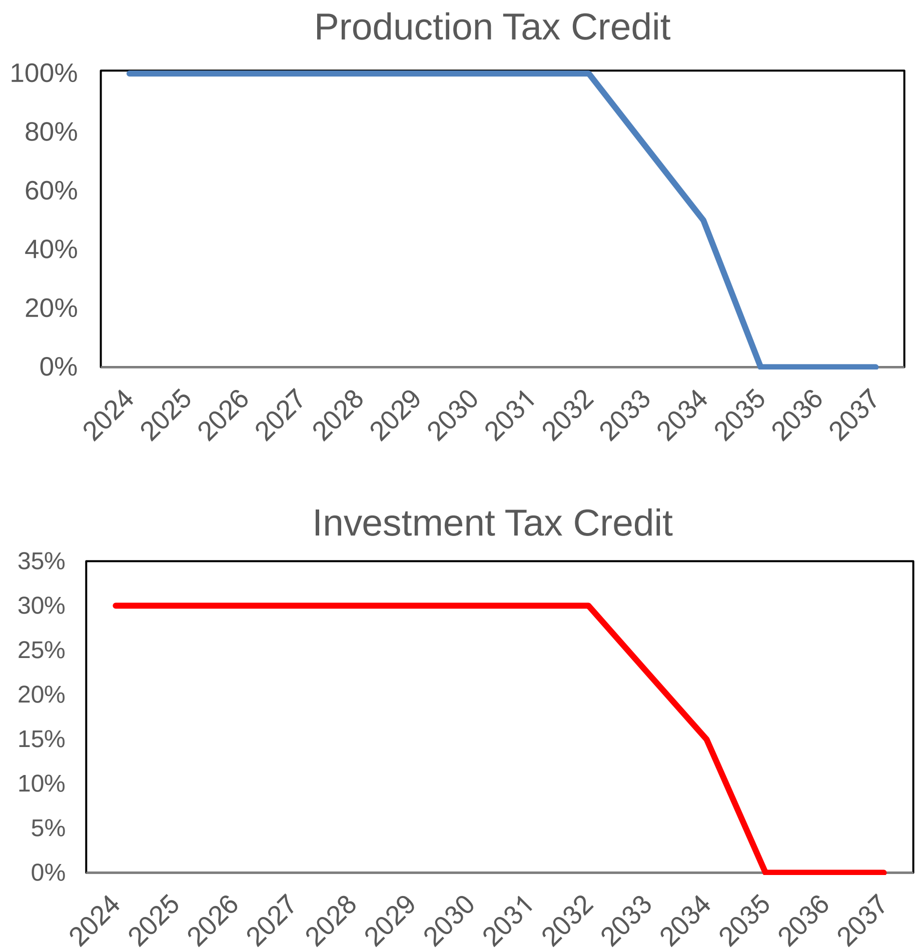
The primary provisions under the IRA are made available through the PTC and ITC. These benefits are adopted for all scenarios. Figure 44 below illustrates how these benefits are assumed to decline over time. The PTC value in Figure 44 represents the multiplier applied to the statutorily defined value of the credit (e.g., in 2024 it is assumed that new wind units will receive 100% of the defined credit value). By contrast, the ITC value represents the percent of capital cost that can be recovered through the credit (e.g., in 2024 it is assumed that new solar will receive a 30% rebate on capital costs).

[25] 2020 SPP Solar & Wind ELCC Accreditation. SPP. November 2022. < https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf>

[26] SPP Energy Storage Study Final Report. Astrape Consulting. November 2019. – Appendix Added September 2021<https://spp.org/documents/65977/astrape%20spp%20energy%20storage%20study%20report%20updated%20winter%20results.pdf >

[27] NREL Electricity Annual Technology Baseline (ATB) 2022. <https://atb.nrel.gov/electricity/2022/data>

Figure 44 Federal Tax Credit Assumptions Used in the 2023 IRP (2024-2037)



7.3. IRP Scenario Inputs

SWEPCO 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 SWEPCO 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. SWEPCO dispatched the 2023 IRP candidate portfolios across the scenarios. The themes tested within and across scenarios reflect the priorities and key risks identified by SWEPCO and its stakeholders and support the analysis of the evaluation of options.

Clean Energy Technology Advancement ("CETA")

The CETA scenario is one of two in the 2023 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 deployment of clean supply- and demand-side technologies. For example, under the CETA scenario SWEPCO assumes 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 a 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 CO_2 price and higher natural gas costs, relative to the Reference Scenario. The CO_2 program also incentivizes reductions in energy loads due to faster adoptions in distributed energy resources.

Focus on Resiliency ("FOR")

Under the FOR case, overall pressure on GHG emissions and fuel prices is similar to the Reference Scenario, but regulators 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. For this IRP, SWEPCO assumed a 26% Planning Reserve Margin for winter informed by the SPP study discussed in Section 3.5. Further, 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 fully-dispatchable capacity is deployed across SPP.

No Carbon Regulation ("NCR")

Under the NCR case, natural gas prices are assumed to be lower than the other scenarios accompanied by no federal limits on carbon emissions 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 SWEPCO 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.

The following table summarizes the key drivers of each scenario in a matrix.

Table 20 2023 IRP Scenario Assumption Matrix

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

7.3.1. Scenario Load

The FOR and NCR Scenarios, use the same base case load forecast as the reference scenario above (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.

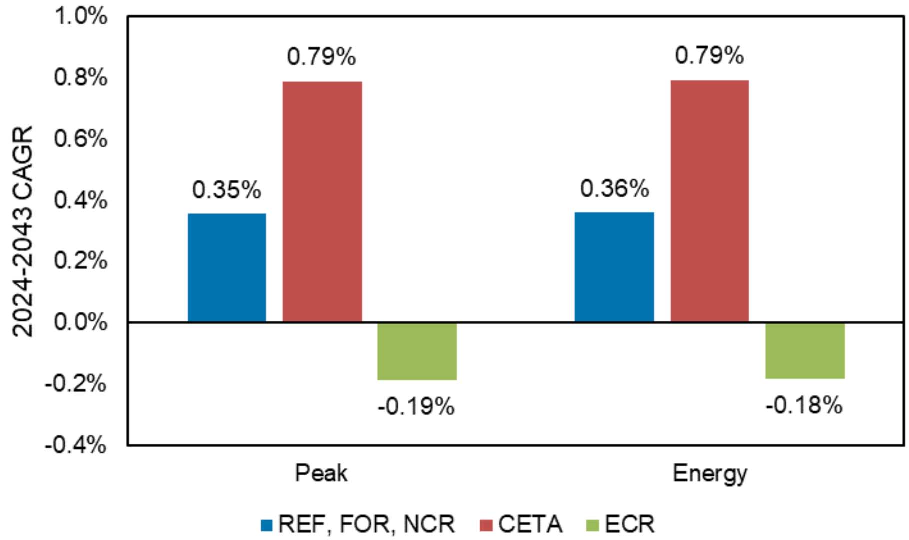
Under the CETA scenario, load grows more quickly than under the Reference Scenario driven by increased economic growth, deployment of electric vehicles, and greater building electrification. Overall annual load growth for the SPP market in the CETA scenario is 0.8% per year between 2024-2043, or approximately 0.5% higher than the Reference Scenario. The accelerated adoption of EVs 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 SWEPCO’s customers. Under this case, annual load growth in SPP is forecast at -0.18% per year, or approximately 0.5% lower than the forecast of load growth from the Reference Scenario during the 2024-2043 period. SWEPCO relied on the AEP Load Forecast Fundamentals for this estimate.

Changes to annual energy for load across the SPP market are shown in Figure 45, below.

Figure 45 SPP Load Growth 2024-2043 Compound Annual Growth Rate ("CAGR")

and Comparison with the Reference Scenario



7.3.2. 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 of factors that may result in market conditions that produce higher or lower prices for natural gas and CO_2 permits.

Natural Gas Prices

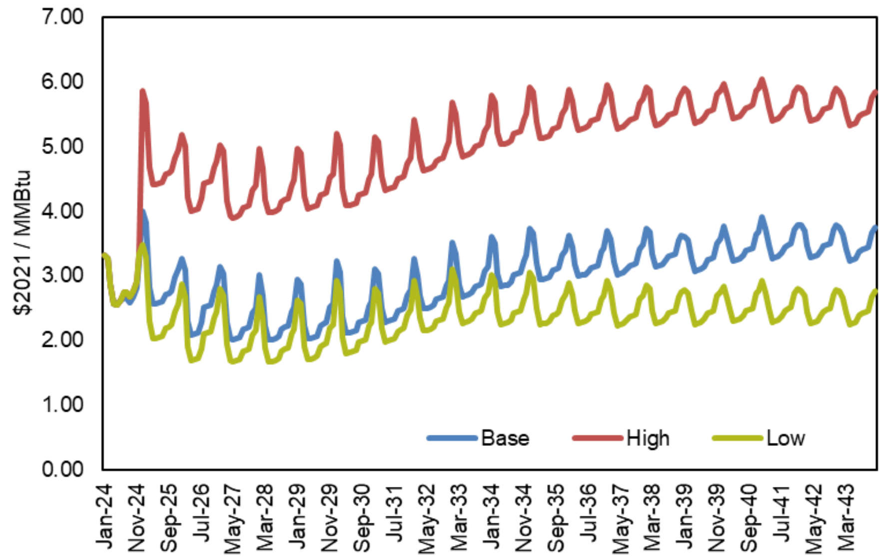
The same natural gas price view relied upon for the Reference Scenario is also used in the CETA and the FOR scenarios when deriving the power price forecast for the SPP market. Under the ECR and NCR Scenarios, natural gas prices are flexed upwards and downwards (respectively) reflecting different views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

Under the ECR case, 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) a higher CO_2 price sooner, (b) limits on access to natural gas supply (e.g., drilling bans), and (c) higher production costs due to higher CO_2 prices and stricter environmental requirements. The result is that the natural gas price forecast is approximately $2.00/ MMBtu (in real 2021$) higher than in the Reference Scenario over the 2024-2043 period. Under the NCR case, policymakers place less pressure on economy-wide GHG emissions than under the Reference Scenario and natural gas prices are approximately $0.58/ MMBtu (in real 2021$) lower.

Figure 46 below compares the high and low gas price forecasts relied upon in the ECR and NCR cases respectively to the base view used for the remaining scenarios. All three forecasts benchmark against EIA AEO 2023 forecasts for Henry Hub by using three cases: the AEO 2023 Reference Case, the High Oil and Gas supply case and the Low Oil and Gas supply case. In the AEO 2023 Reference case for the gas price, U.S, natural gas production increases through 2050 with more than 35% of gross additions exported.

According to the details provided by EIA, the oil and gas supply cases illustrate the relationship between LNG exports and production. The Low Oil and Gas Supply case assumes higher costs with less resource availability resulting in an increase of natural gas prices. In this case, LNG exports begin to decline in the mid-2030s. In the High Oil and Gas Supply case, that assumes lower natural gas prices, LNG exports grow twice as fast compared to the Reference case, leveling off during the mid-2040s.[28]

Figure 46 High, Base and Low Panhandle Eastern TX-OK Natural Gas Price Forecasts (real 2021$ / MMBtu)



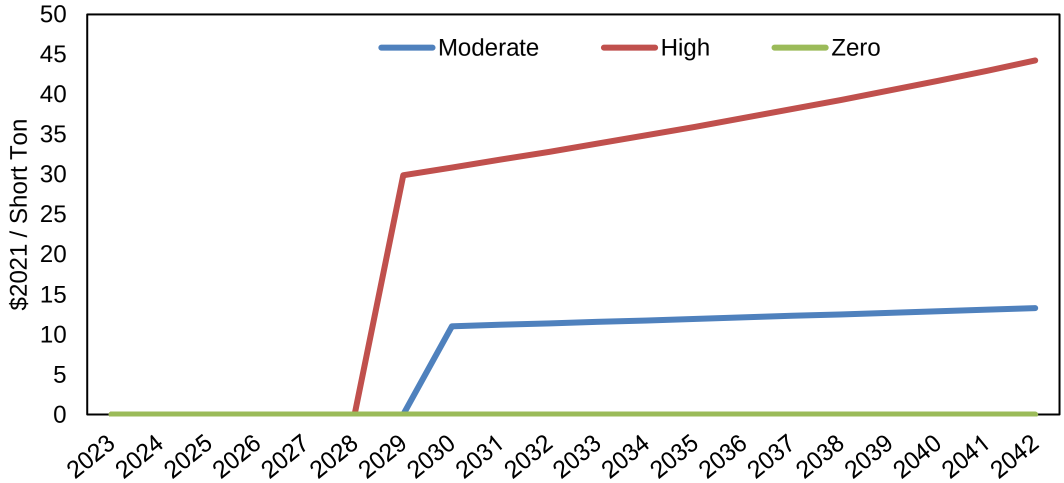
CO_2 Prices

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 2030. 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 2029 with prices starting at approximately $30/Ton (real $2021) and rising to around $45/Ton by 2042. Under the NCR Scenario, policymakers do not enact a price on CO_2, and prices are assumed to be zero throughout the forecast period. Figure 47 below illustrates how the high and zero CO_2 prices in the ECR and NCR Scenarios respectively compared to the moderate CO_2 price view used in the remaining three scenarios.

28 https://www.eia.gov/outlooks/aeo/narrative/production/sub-topic-01.php

Figure 47 High and Zero CO_2 Price Forecasts ($2021 / Ton)



7.3.3. Scenario Reserve Requirements

Summer Capacity Requirements

SPP recently announced it will require LSEs to maintain sufficient firm capacity to meet a 15% planning reserve margin[29] above summer peak demand to maintain system reliability. SPP also continues to review their resource adequacy requirements for LSEs such that the Company considers this a risk.

Increments of certain new resources, including some renewables and various duration 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 Effective Load Carrying Capability (ELCC) the next increment provides. Figure 48 summarizes the reference and low ELCC views for select technologies used in the 2023 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 7.4.2.

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 or for SPP.[30,31]

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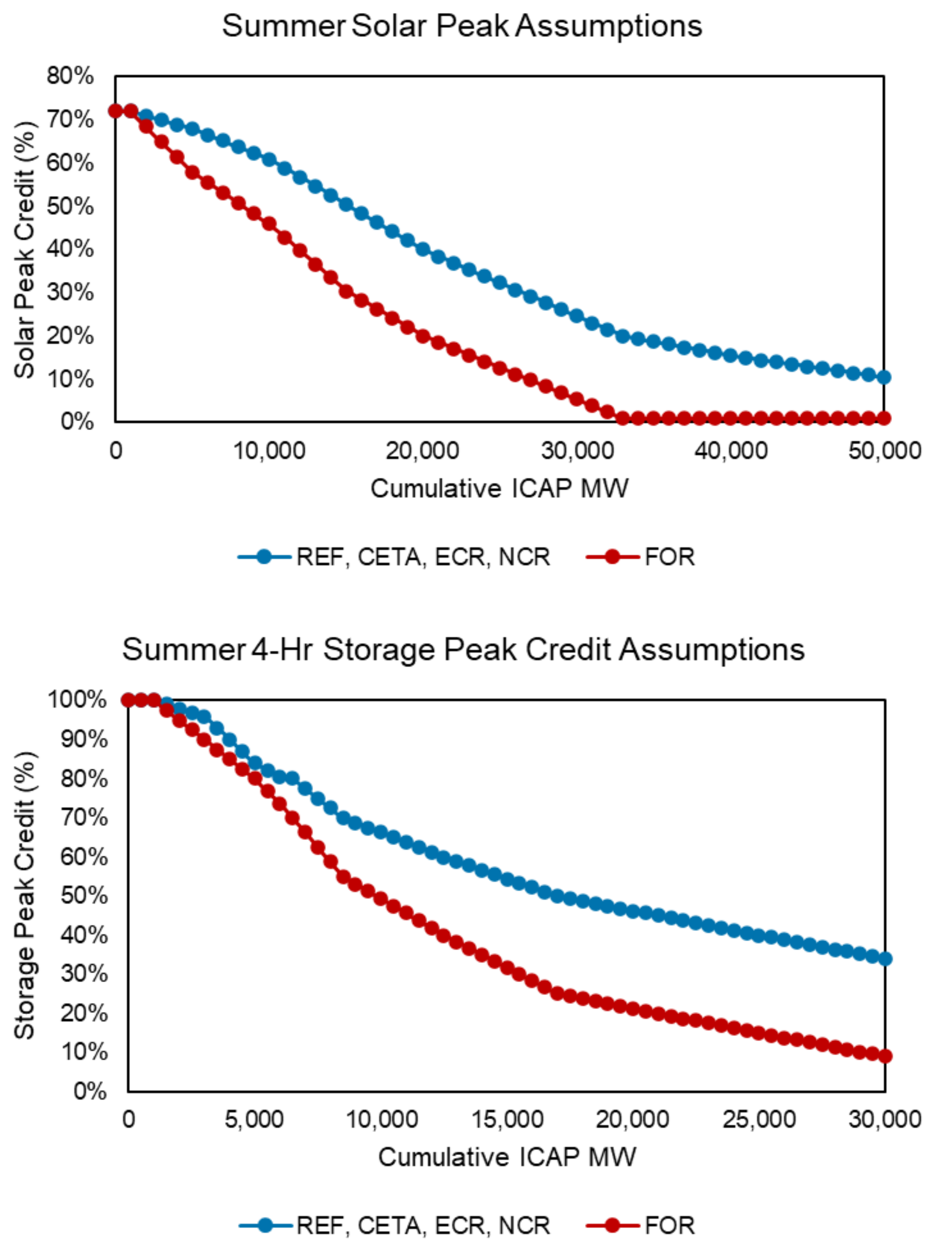
29 https://www.rtoinsider.com/articles/30538-spp-board-regulators-side-with-staff-over-reserve-margin

30 https://www.spp.org/documents/65169/2020%20elcc%20wind%20and%20solar%20study%20report.pdf

31 https://spp.org/documents/65977/astrape%20spp%20energy%20storage%20study%20report%20updated%20winter%20results.pdf

Figure 48 ELCC Assumptions for Select Resources by Cumulative ICAP MW [32,33][34]



Winter Capacity Requirements

Outside of the summer capacity requirements that are enforced for all five scenarios, in the FOR scenario, SWEPCO modeled a 26% reserve margin requirement for the winter season as well.

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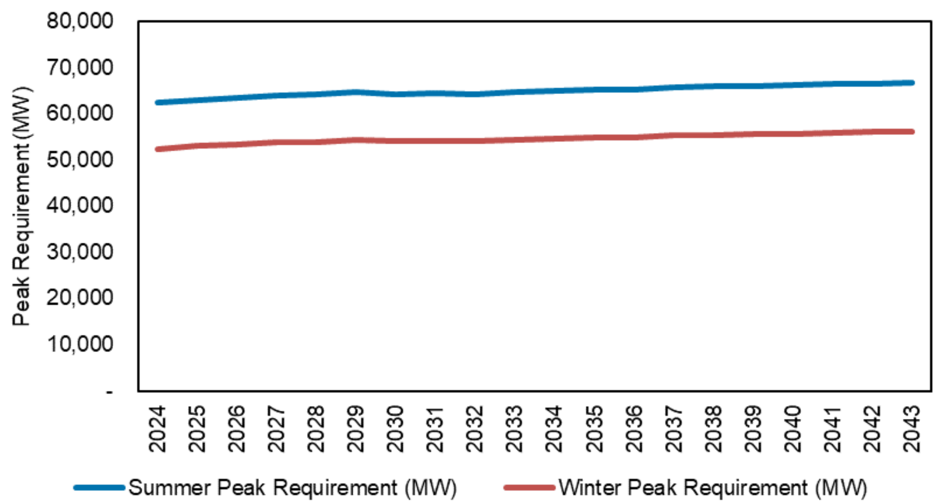
32 2020 SPP Wind and Solar Study Report. SPP. July 2021. <https://www.spp.org/documents/65169/2020%20elcc%20wind%20and%20solar%20study%20report.pd

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

34 2022 ELCC ESR Study Report. SPP. February 2023. <https://www.spp.org/documents/68930/2022%20elcc%20esr%20report.pdf>

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. This is discussed further in Section 3.5. Figure 49 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 similarly to summer peak demand. SWEPCO relied on AEP Load Forecasting Fundamentals for the winter load estimates.

Figure 49 Comparison of FOR Scenario SPP Winter and Summer Peak Requirements (2024-2043)



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, are expected to provide less load carrying capacity during winter peak periods than during summer peaks. Under this scenario solar resources perform materially different in winter than summer and their peak credits are modeled to decline over time from 19% in 2024 to 1% in 2043. The net load peaks in SPP during the winter are fairly flat across the day. Because of this, batteries are not able to provide as much capacity value as they do during the summer. For winter, it was assumed the capacity peak credits for 4-, 6- & 8-hour batteries to decline from 80% to around 18%, 28% and 31% respectively in 2043.

7.3.4. Scenario Technology Assumptions

In general, SWEPCO relied on EIA's 2022 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 moderate case of the 2022 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("ATB") report.[35] SWEPCO assumes that under all scenarios federal tax credits for new renewable generation and grid energy storage reflect current law and the schedules enacted in the Inflation Reduction Act (IRA) of 2022.

SWEPCO's 2023 IRP scenario flexed a number of technology-related assumptions including the expected capital cost and federal tax benefits available to renewable units as part of the 2023 IRP scenarios.

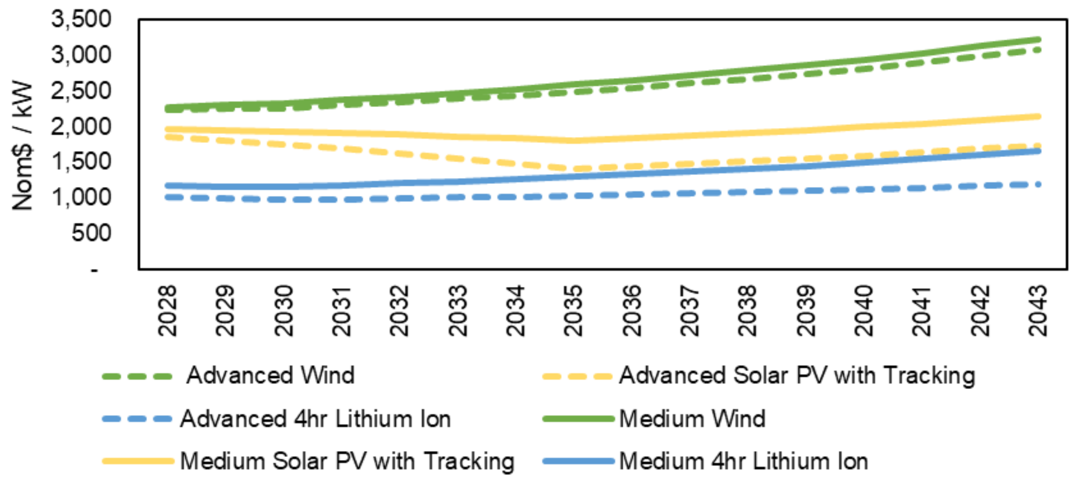
Unit Capital Costs

As described in Section 5, SWEPCO generally relies on technology cost assumptions from EIA's 2023 AEO report to establish the expected capital cost of new utility-scale resources. Those

[35] NREL Electricity Annual Technology Baseline (ATB) 2022. https://atb.nrel.gov/electricity/2022/data

costs change over time based on the medium outlook from the NREL 2022 ATB. This outlook of new unit costs is used for three of the 2023 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 50 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 50 Comparison of Capital Costs Under Advanced and Medium Outlooks for Select Technologies (2025-2043 | Nom$ / kW)



7.4. 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, SWEPCO developed scenario-specific forecasts of the SPP market. In the portfolio modeling stage, described below in Section 8, SWEPCO developed an optimal candidate resource plan for each of the five scenarios.

7.4.1. Capacity Expansion Results

SWEPCO 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 SWEPCO portfolio, they are informative for describing how different resource types are likely to perform under certain conditions. Figure 51 and Figure 52 below illustrate the 2043 SPP generation capacity and energy mix respectively across all five market scenarios compared with the forecasted SPP resource mix in 2024.

Under the Reference Scenario, much of the existing coal fleet is retired over the course of the forecast as shown in Figure 53. Due to the combination of announced retirements and the modest CO_2 price that comes into effect in 2030, only 1 GW of coal are left by the end of the study period. By 2043, 7 GW of aging gas resources are also projected to be phased out. To replace coal and gas plant retirements and meet growing load, a combination of renewables, battery storage, and new gas units are added over time. In total, approximately 11 GW of new wind, 30 GW of new solar, 20 GW of new storage units, 10 GW of new gas peakers, and less than 1 GW of new combined cycles are added by between 2024 and 2043. The gas units are installed primarily to meet firm requirements and mostly enter the market beyond 2030. Under the Reference Scenario, solar and wind generators provide more than 65% of the total SPP generation by 2043. The result is that total CO_2 emissions in the SPP market drops by 76% in the Reference Scenario from 2024 to 2043.

Figure 51 Comparison of 2024 and 2043 Nameplate Capacity by Technology in SPP

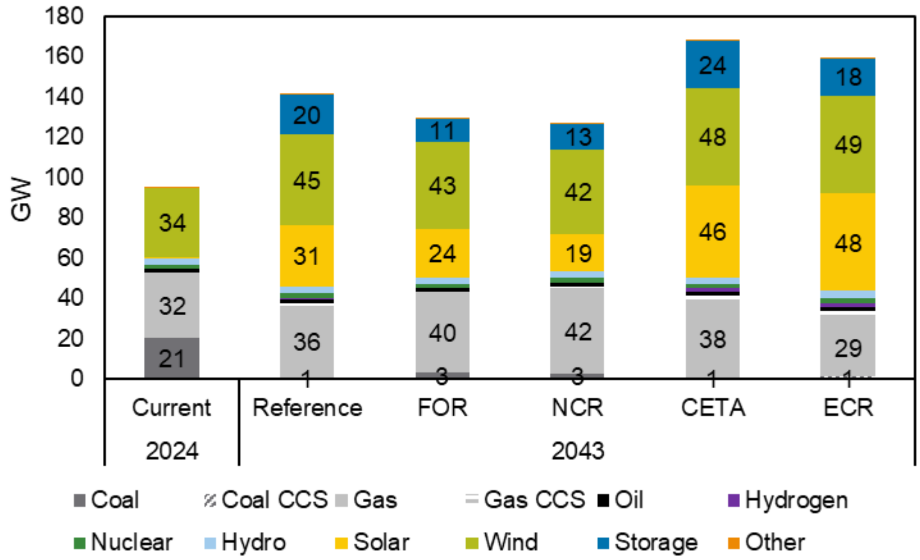
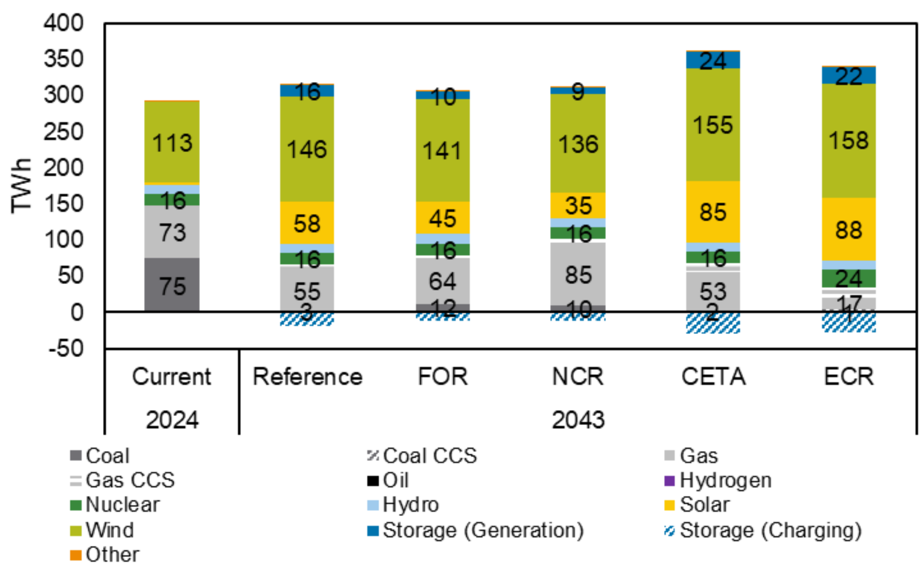


Figure 52 Comparison of 2024 and 2043 Generation by Technology in SPP



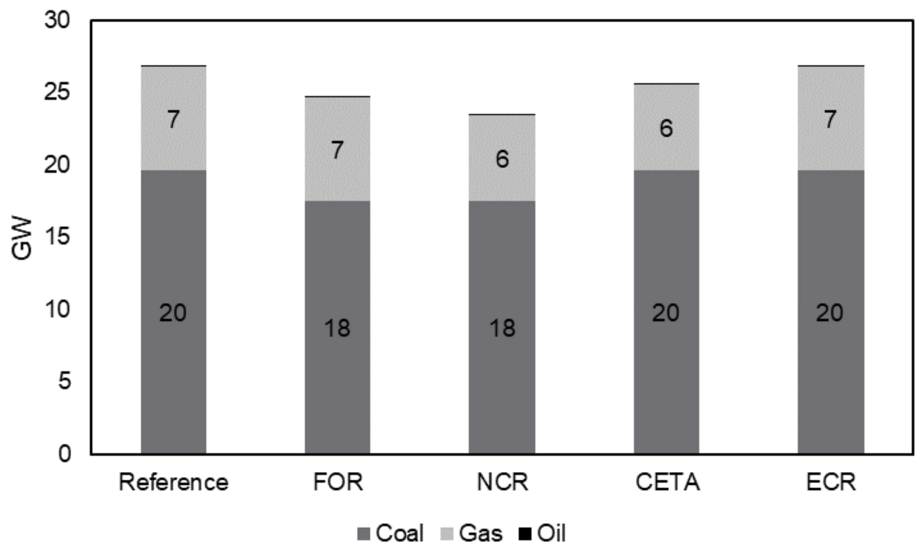


Figure 53 Summary of 2024-2043 Firm and Economic Retirements by Scenario

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 8 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 7.8 GW of new wind, 17.8 GW of new solar, and 12.5 GW of new short and long duration battery storage added by 2043. On the retirements side, approximately 2 GW of existing coal and 1 GW of gas resources remain in the system without the carbon burden under this scenario. 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 wind and solar resources comprise only about 57% of total SPP generation by 2042 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 57% from 2024 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 2043, there is approximately 2 GW more coal capacity remaining in the market and 3.9 GW of additional gas-fired generation relative to the Reference Scenario by 2043. Deployment of renewable technologies is lower than in the Reference Scenario due to the lower capacity credit value of these units. Approximately 23 GW of new solar, 9.4 GW of new wind, and 11 GW of new battery storage are added by 2043. Renewable sources comprise just under 63% of SPP market generation in this year. SPP CO_2 emissions drop by approximately 64% from 2024 to 2043, compared to around 76% 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 faster learning rates. The combination of higher load and more affordable renewable technology leads to materially greater deployment of solar, wind and battery storage than under the Reference Scenario. By 2043, nearly 44.8 GW of new solar, 13.7 GW of new wind, and 23.8 GW of new energy storage of various duration are added in SPP under the CETA Scenario. Furthermore, approximately 2.1 GW of NGCC capacity with carbon capture and storage is installed or retrofitted. Despite higher load, gas generation across SPP under CETA remains similar to the Reference Scenario due to greater penetration of renewables. In terms of retirements, a similar amount of coal resources exit the system. Solar and wind units comprise more than 72% of total SPP generation by 2043, and CO_2 emissions decline by around 77% SPP-wide relative to 2024 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 2043. Natural gas-fired capacity also falls SPP-wide and approximately 3.4 GW of NGCCs are retrofits with carbon capture and storage over the forecast period. The ECR Scenario also indicates a more favorable environment for existing nuclear resources. 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 slightly higher amounts of wind and solar deployment as the Reference Scenario (around 48 GW and 48 GW respectively) and lower levels of various duration battery storage (around 18 GW). However, due to lower load growth, these resources make up a large proportion of the overall system, with wind and solar accounting for 78% of total SPP generation by 2043. SPP-wide CO_2 emissions are the lowest in this scenario and decline by 92% relative to 2024 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.

7.4.2. Effective Load Carrying Capability (ELCC) Results

As described in 7.4.1, the SWEPCO scenarios have produced a range of capacity expansion results using the AURORA LTCE model that result in different penetration levels of renewable and battery storage. The ELCC value of the renewables and 4-hour battery storage are based on the amounts installed in each scenario. The resulting differences are illustrated by the curves in Figure 48. While solar and storage credits vary materially by case, wind ELCC stays relatively constant in the 14-16% range informed by a SPP Study.[36]

Under the Reference, FOR, and ECR scenarios, solar ELCC values decline from the current 72% value to levels near 25% by 2043, 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 44% peak value by 2043. 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 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, 4-hour storage ELCC values vary across scenarios, ranging from 36% to 70% by 2042. The resulting solar and storage summer ELCC values are summarized in Figure 54 and Figure 55.

Under the FOR scenarios, solar winter ELCC values are assumed to decline from 19% in 2024 to 1% by 2043. Winter season reserve margin requirements were not enforced in the remaining market scenarios.

[36] 2020 SPP Solar & Wind ELCC Accreditation. SPP. November 2022. < https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf

Figure 54 Comparison of Solar Summer Peak Credits by Scenario

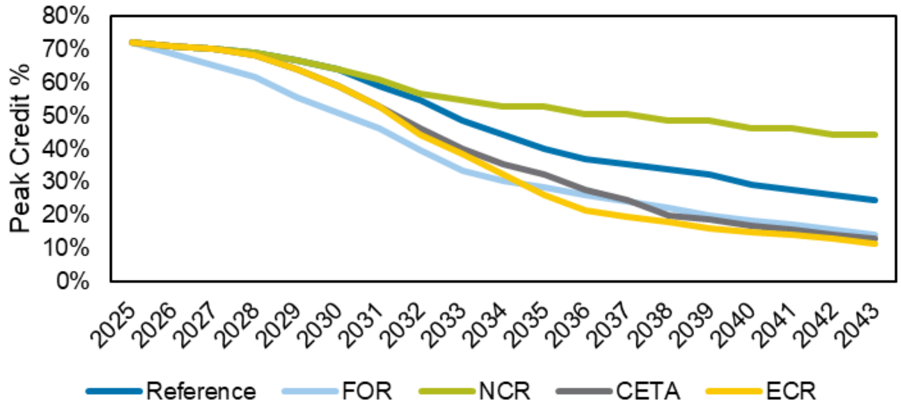
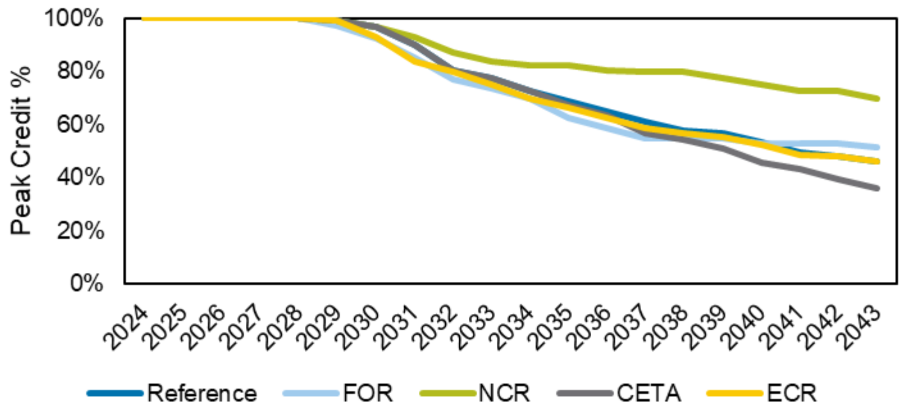


Figure 55 Comparison of 4-Hour Storage Summer Peak Credits by Scenario



7.4.3. Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Figure 56 and Figure 57. Shown are all five market scenarios modeled in the 2023 IRP. These figures illustrate the wide but plausible range of energy prices that emerge from the scenario modeling step.

Figure 56 Annual On-Peak SPP South Hub Electricity Price ($2021 / MWh)

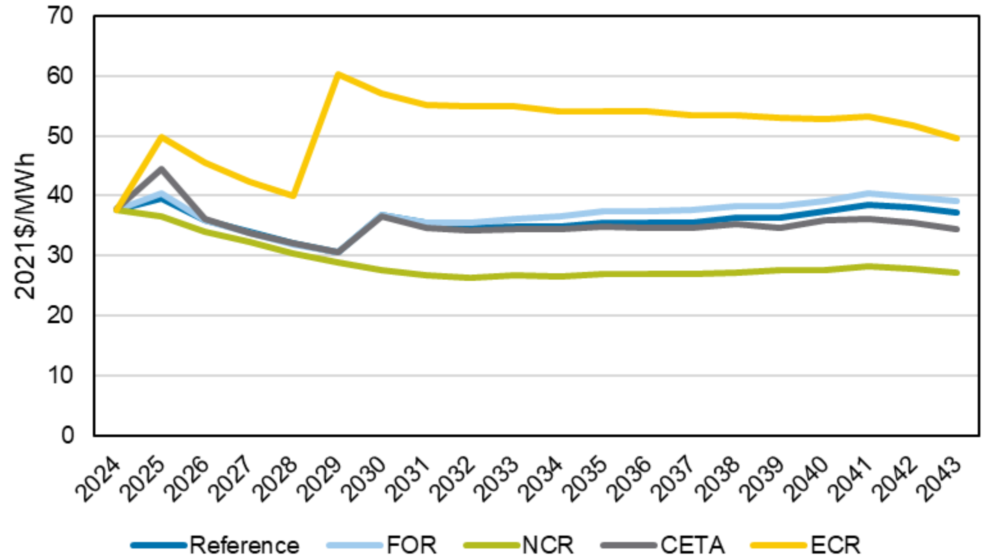
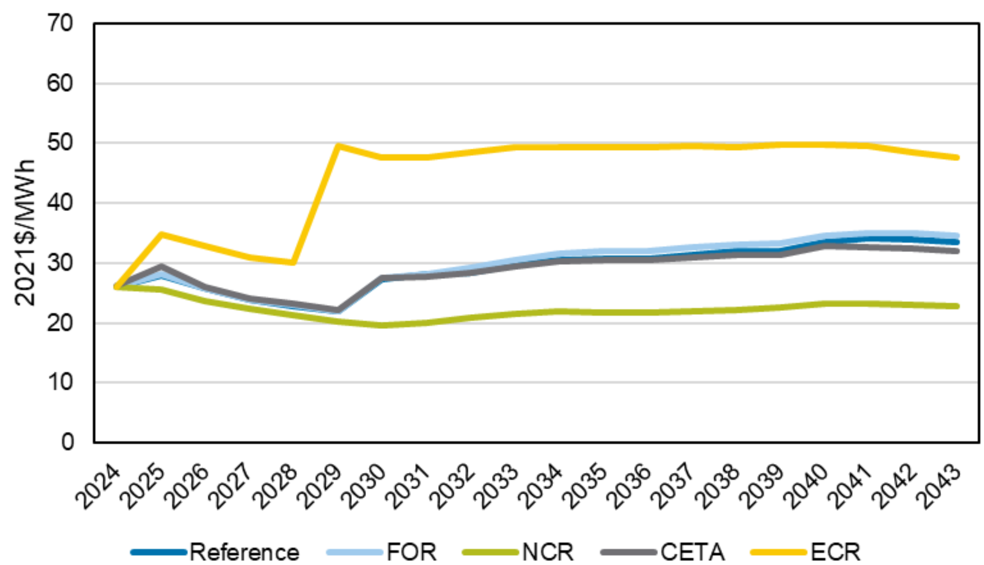


Figure 57 Annual Off-Peak SPP South Hub Electricity Price ($2021 / MWh)



Under the Reference Scenario, on-peak energy prices in SPP South Hub decline gradually from around $37.74 / MWh ($2021 real) in 2024 to $30.5 / MWh by 2029 in large part due to the decrease in natural gas prices over the period. There is approximately an average of $10/MWh spread between on- and off-peak pricing over this same period, in real dollar terms. Starting in 2030 prices step up in both on- and off-peak periods by approximately $6/MWh driven by the introduction of the CO_2 price in that year. There is a slight decline in on-peak pricing from 2030 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, remain relatively flat 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 $3/MWh by 2043. Overall, similar to the rest of the scenarios, the passage of the Inflation Reduction Act enables additional amount of renewable and energy storage generation to enter the SPP market. SWEPCO considered the impacts of the IRA in all scenarios.

Under the FOR and CETA Scenarios, SPP market prices are largely similar, though forecasted to be somewhat lower, especially under the CETA Scenario, 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 CETA Scenario, prices are between \$0.5 and \$2.5/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 2024-2028 period, both on- and off-peak prices are approximately \$7-10/MWh higher than in the Reference Scenario due the higher natural gas price assumed in this scenario. In 2029, the high CO_2 price is introduced and SPP market prices rise by around \$20/MWh in both on- and off-peak periods. From 2029 onward, on-peak prices remain flat (in real terms) due to the lower load growth assumption in this scenario and the high penetration of renewable generation offset the progressively increasing cost of carbon. Conversely, off-peak prices grow slightly from 2029-2043 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/MWh by 2043 in the ECR scenario when viewed on an annual average basis.

The NCR Scenario sets the lower bound of SPP market prices. From 2024-2029, overall market prices are around \$1-3/MWh lower than in the Reference Scenario due to the low natural gas prices forecast that is assumed in this scenario. After 2029, 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 assumed as part of the scenario. On-peak prices are largely steady from 2029 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 2030s, 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 from around \$9 to \$11/MWh to between \$4 to \$6/MWh in this scenario on an annual basis by the end of the study period.

7.5. IRP Stochastics Development

SWEPCO'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 8.1, rate stability is one of the key objectives. The scorecard metric "Cost Risk" is defined as the Net Present Value Revenue Requirement ("NPVRR") increase between the 95^{th} percentile and 50^{th} 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 outputs.

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

7.5.1. 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[37] model that takes as input expected paths for gas and power prices, based on SWEPCO's Reference Scenario outlined in Section 7.2. 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 2024-2043, data from 2033 and 2043 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 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, 2018 to July 13, 2023 were used to summarize the relevant market price behavior and include only the most recent market dynamics.

Figure 58 and Figure 59 illustrate one sample iteration of gas and power daily prices in 2033 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.

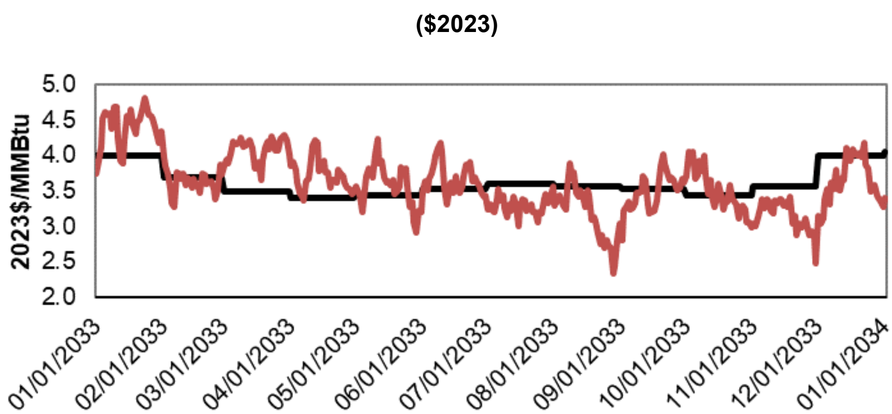


Figure 58 Sample Iteration of Daily Natural Gas Price Simulation for 2033 ($2023)

[37] 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 modeling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market*." Energy Economics, 2008.

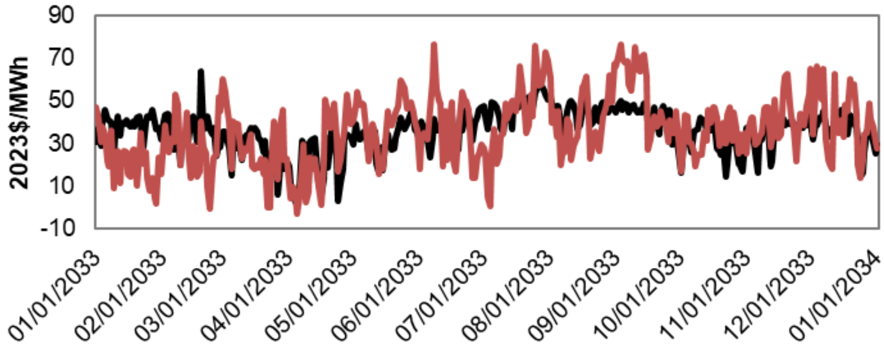


Figure 59 Sample Iteration of Daily Power Price Simulation for 2033 ($2023)

7.5.2. Renewable Output Stochastics

Renewable output uncertainty is integrated in SWEPCO'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 2007 to 2014 (8 weather years) for counties across Oklahoma[38] were used as inputs into the SAM tool for wind, and weather conditions for years 1998 to 2022 (25 weather years) for one central county in Oklahoma were used as inputs into the SAM tool for solar. 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 SWEPCO's capacity factor assumptions for new wind and solar resources.

Given the fact that the weather years sampled had a narrower distribution of average capacity factor over the course of the year, extra variability was induced on certain capacity factor profiles to simulate outcomes from more extreme weather data. The appropriate degree of variability was determined by determining a theoretical distribution of average annual capacity factors based on historical data. To induce such variability, a cumulative distribution function was created using the original data, and multipliers were applied to specific portions of the data to replicate a similar distribution. The multipliers were constrained such that this new distribution maintains the physical constraints of a solar/wind system (e.g., roughly half the hours of the year have no sun). An example of a cumulative distribution function for the original set of hourly capacity factors versus adjusted values is displayed in Figure 60.

[38] 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.

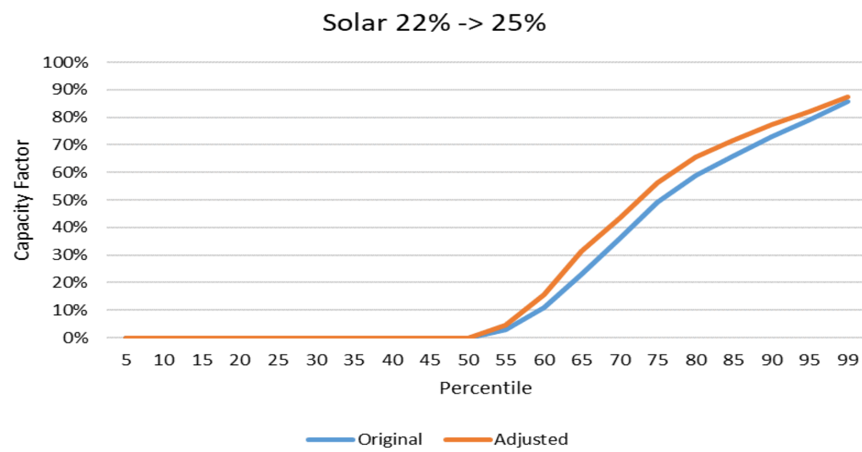


Figure 60 Example of Capacity Factor Adjustment

Figure 61 and Figure 62 illustrate 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 between 2007-2014. For example, the first 50 iterations of gas and power prices are matched with wind and solar output based on historical weather year 2007 conditions.

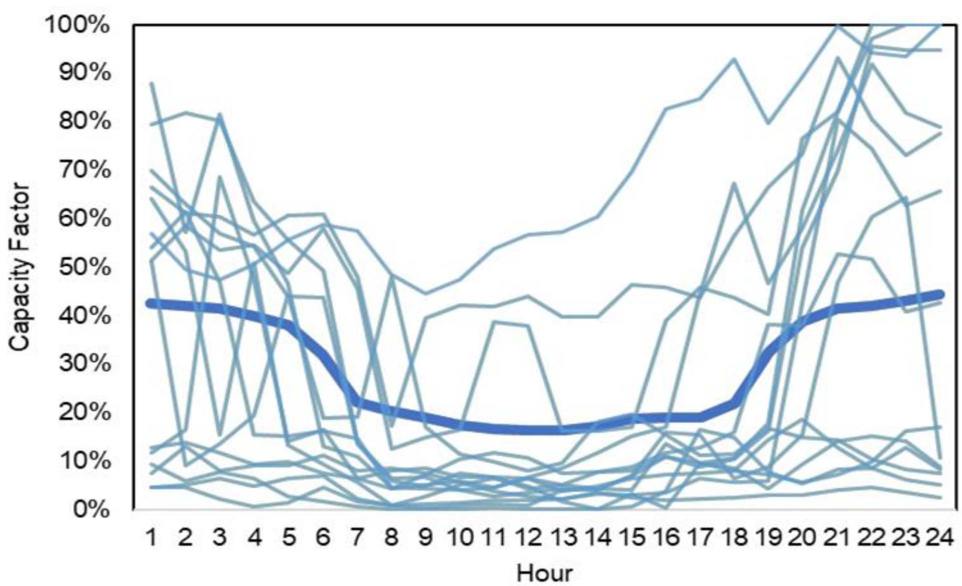


Figure 61 Simulated Hourly Wind Capacity Factor for July

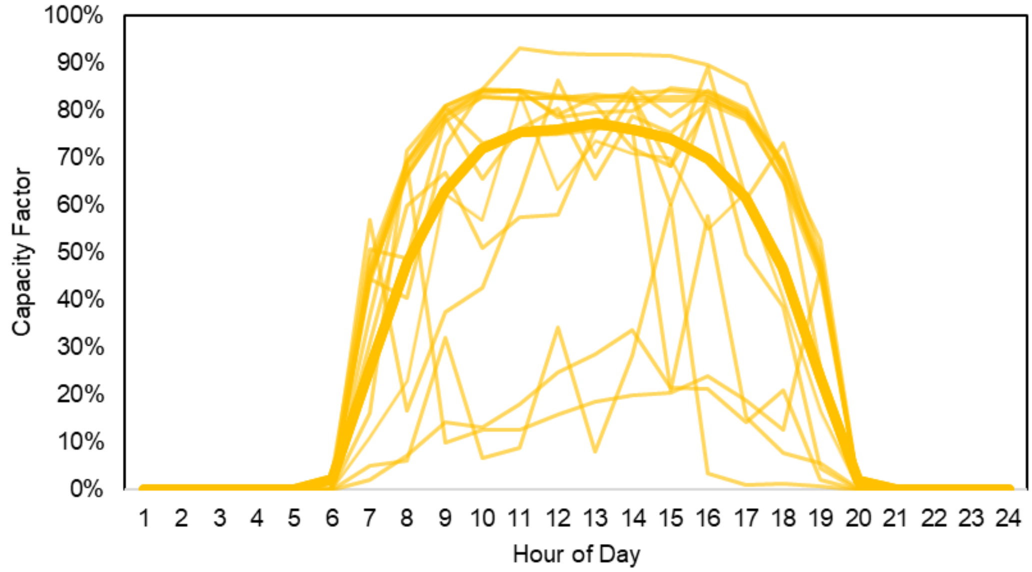


Figure 62 Simulated Hourly Solar Capacity Factor for July

By incorporating stochastic renewable profiles and gas and power prices, the combinations of renewable output and price paths cover a greater range than the Reference Scenario. This is illustrated in Figure 63 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 reflected. By contrast, the stochastic modeling approach used by SWEPCO tests many more hours and captures periods of high market prices and low renewable output, and vice versa.

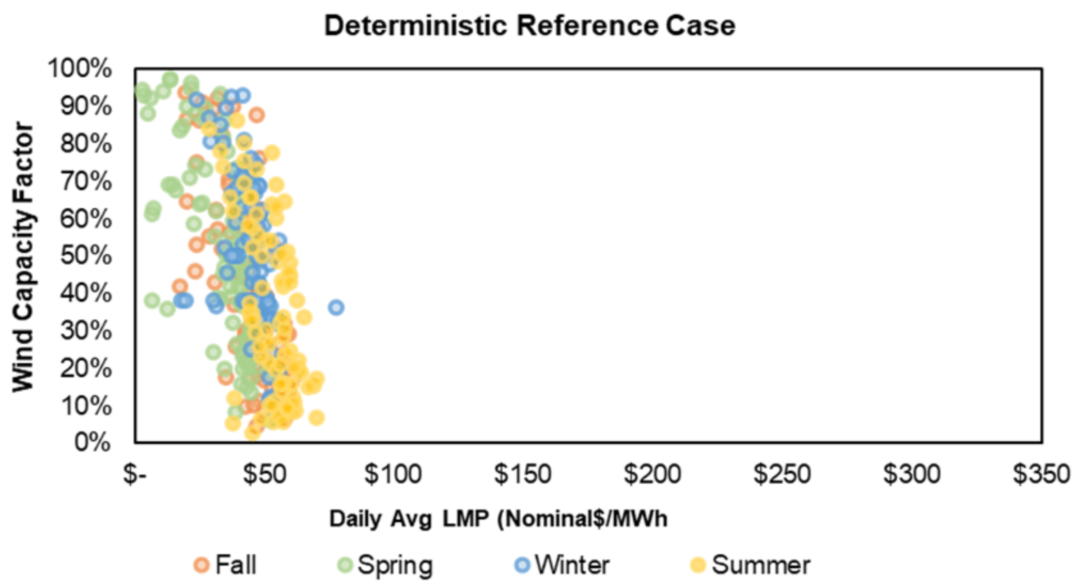
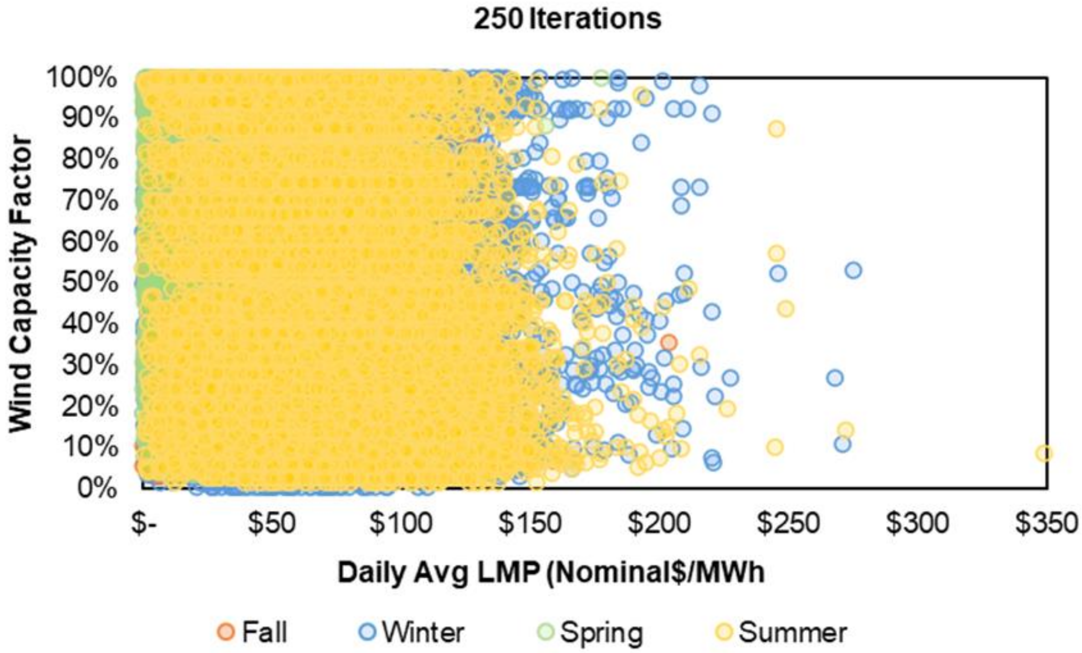


Figure 63 Daily Average Wind Capacity Factor and Power Price, Under Deterministic Reference Scenario vs. 250 Stochastic Iterations


250 Iterations
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Wind Capacity Factor
$-
$50
$100
$150
$200
$250
$300
$350
Daily Avg LMP (Nominal$/MWh
Fall
Winter
Spring
Summer

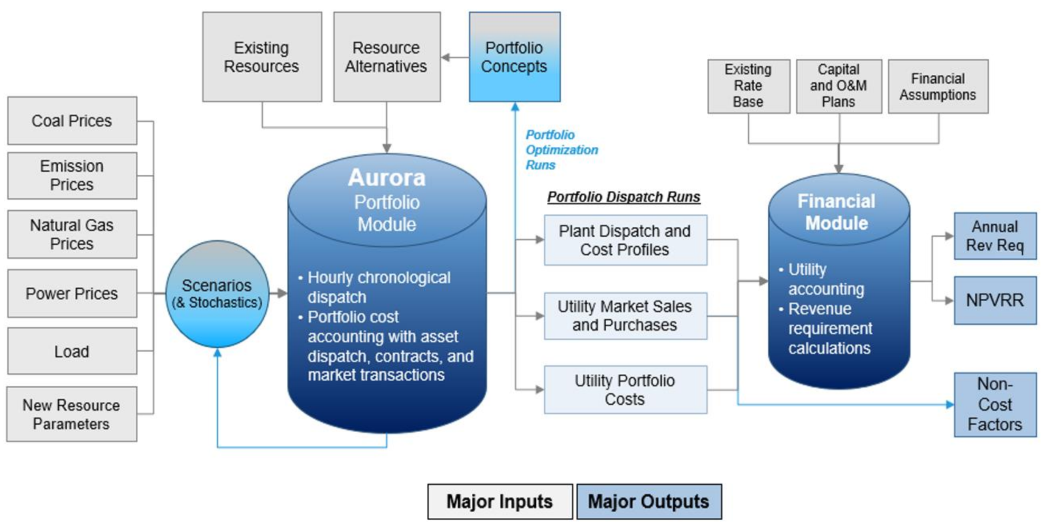
8. Portfolio Analysis

8.1. Introduction

The IRP Portfolio Analysis began by reviewing the priorities and objectives of SWEPCO and its Stakeholders, as well as key uncertainties and potential futures risks associated with the cost of serving SWEPCO's customers described in the prior section. This process informed the analysis performed and the development of an IRP scorecard. The scorecard is a tool used to evaluate the potential trade-offs between different demand- and supply-side options that SWEPCO may employ to meet customer future needs in the 2023 IRP. The IRP scorecard and metrics are detailed below in this chapter.

In terms of impact on the IRP analysis, the priorities and objectives informed the 2023 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 changed across the SPP market under different combinations of these fundamental conditions. One portfolio was developed under each of the five scenarios (under FOR, REF and NCR both a winter and summer portfolio was developed) using the portfolio optimization feature in AURORA to find "optimal" selections of resources under different market conditions. These five SPP market scenarios were also used to test the robustness 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 64 2023 IRP Modeling Framework



SWEPCO set an objective to provide reliable service for customers while also guarding 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. The 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 for each of the Portfolios.

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 support 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 65:

- **Objectives** are overarching goals that align to SWEPCO or stakeholder priorities. The four objectives of the 2023 SWEPCO 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 ten performance indicators on the SWEPCO 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.

Figure 65 Elements of the 2023 SWEPCO IRP Scorecard

Objective	Performance Indicator	Metric
Customer Affordability	NPVRR	Total long-term Annual Costs paid by ratepayers
	Near-Term Rates	Near-term impact of resource decisions
Rate Stability	Scenario Resilience	Range of cost from highest to lowest market scenario
	Cost Risk	95^{th} percentile of cost risk
	Market Exposure	Amount of net purchase or sales from SPP market
Maintaining Reliability	Reserve Margin	Excess capacity position
	Operational Flexibility	Dispatchable capacity included in portfolio
Local Impacts & Sustainability	Local Impacts	New Investment in utility service territory
	Carbon Emissions	Percent carbon reduction

The details of objective, performance indicator, and metrics are described in the following sections.

8.2.1. Objective 1: Customer Affordability

Customer affordability is a primary goal for SWEPCO. 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."[39] For the SWEPCO 2023 IRP, minimizing the expected cost to customers, to the extent reasonable when evaluated against other performance indicators, was a clear and obvious objective for the scorecard.

The SWEPCO scorecard includes two performance indicators that track the customer affordability objective across the short- and long-term.

[39] From AEP corporate website on planning for clean energy future: <https://www.aep.com/about/ourstory/cleanenergy>

Short Term: 5-year expected growth in customer rates

Customers need affordable energy over the long term. However, many customers may tend to prefer 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, along with long term costs, when selecting a preferred plan. This performance indicator allows SWEPCO to assess that risk across portfolios and weigh short- and long-term cost considerations when selecting the preferred plan.

SWEPCO 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 7-year Compound Annual Growth Rate ("CAGR") of expected system costs for the years 2024-2031

Long Term: 20-year net present value of revenue requirement

Portfolios that perform well in the short- and medium-term may be expensive over the longer term. Further, portfolios that perform similarly in the short- to medium-term may look very different over the long term under varying market conditions.

This performance indicator allows SWEPCO to evaluate the risk of higher costs when viewed further into the future and weigh short- and long-term cost considerations.

NPVRR was selected as the metric for this performance indicator. NPVRR is a representation of the total long-term annual costs paid by SWEPCO'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 20-year period (2024-2043) and is expressed both in terms of total and levelized rate. The levelized rate is the fixed charge per MWh needed to recover the 20-year NPVRR.

8.2.2. Objective 2: Rate Stability

Rate stability is a key component of affordability for SWEPCO's customers. A resource plan that performs well under expected conditions may expose ratepayers during periods of volatility, extreme weather events, or extended outages. SWEPCO 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 2021 Texas power crisis where a historic cold weather event led to rolling blackouts, forced generator outages, and high wholesale gas and electricity prices. While SPP was shielded from long-term outages in its service territory during this event, SWEPCO's customers were exposed to high wholesale gas and electricity prices.

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, renewable outputs and to random rapid changes in near term power and gas prices. This assessment evaluates how portfolios perform under a wide range of market conditions, commodity prices, and policy outcomes and allows SWEPCO 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 20-year NPVRRs across the 5 market scenarios

This performance indicator describes the range of total long-term 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 30-year NPVRR for a single resource plan in the (1) the market scenario under which total costs for the resource plan were the lowest from (2) the market scenario under which the total costs to the resource plan were the highest.

The 20-year NPVRR is selected because SWEPCO's going in position shows a need for replacements in the 2020s and later in the 2030s. Using a long-term metric allows for all of the resource decisions made in the IRP to be fully reflected and maintains consistency in the affordability performance indicators on the scorecard. NPVRR is a representation of the total long-term annual costs paid by SWEPCO'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 20-year period (2023-2043) 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 years 2033 and 2043

Portfolios that perform well (or similarly) under expected conditions may perform poorly 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 SWEPCO 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.

The metric for this performance indicator 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 for years 2033 and 2043. 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.

2033 and 2043 are selected as the test dates to align with the reported customer affordability metrics and enables SWEPCO to distinguish between the impact of decisions made in the 2020s and 2030s to meet known capacity gaps. These test years also align to the 10-year and 20-year results presented in the IRP report and appendix, respectively.

Market Exposure: net purchases or sales as a percent of summer and winter load in 2033

This performance indicator allows SWEPCO 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. SWEPCO can purchase significant amounts of energy needed to serve load on an annual basis and there is an opportunity and potential benefit 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 2033, distinguishing between market activity occurring during the summer (June, July, Aug) and winter (Dec, Jan, Feb) 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.

2033 is chosen as the test year to illustrate the long-term differences in market exposure across the candidate portfolios. 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 SWEPCO mission statement and reliability is an important consideration for SWEPCO’s customers that are active in the stakeholder process. Understanding the role that SPP plays in maintaining broader system reliability, SWEPCO 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. SWEPCO 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.

Three performance indicators were selected to measure progress towards maintaining reliability. These cover the total capacity reserves, by season, maintained by SWEPCO under each plan, the amount of dispatchable capacity included in each plan, and an indicator of the resource generation diversity in each candidate portfolio.

Planning Reserves: percent of summer and winter capacity requirements served by the resource plan from 2024-2043

SWEPCO seeks to track energy and capacity exposure separately in the 2023 IRP. This performance indicator measures SWEPCO’s expected reliance on the market (or excess capacity) for meeting summer and winter reserve margin requirements. This measure allows SWEPCO 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 five market scenarios to capture the full range of load forecasts included in the 2023 IRP.

The metric for this performance indicator will be SWEPCO’s reserve margin measured as the ratio of accredited capacity supply to expected peak demand for *both* the summer and winter periods. For reporting purposes, the average reserve margin period over the 2024-2043 time period will be included in the scorecard. The period 2024-2043 is used to evaluate SWEPCO’s average exposure across the portfolios over time.

This metric is calculated by dividing the winter UCAP of the resource plan by SWEPCO’s winter peak requirement and the summer UCAP of the resource plan by SWEPCO’s summer peak requirement for years 2024-2043 across all five market scenarios. This results in 100 winter values and 100 summer values. These values are then averaged by season and reported on the scorecard.

Operational Flexibility: Dispatchable capacity in 2033 and 2043

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 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 measured as the cumulative amount of dispatchable capacity selected by the candidate portfolio in 2033 and 2043. Dispatchable resources include new gas peaking units (multiple configurations), new gas combined cycle units (with or without CCS), new energy storage units, and new hydrogen-fired units.

The metrics for this performance indicator represent the total capacity (nameplate) provided by fast-ramping technologies in years 2033 and 2043. 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 provided 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 10- and 20-year reporting period is selected to align with the results included in the IRP report and reflect SWEPCO's position after filling the expected capacity gap emerging in the late 2020s and into the 2030s.

Resource Diversity: Generation mix by resource in 2043

SWEPCO 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 versus 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 2043 and under the Reference Scenario. The metric is measured in 2043 to capture the full range of replacement decisions and because it is expected that many advanced technologies may not become economic until the 2030s and therefore a shorter term (e.g., 10-year) metric may provide little or no information to support SWEPCO's evaluation. Wedges of qualifying advanced technologies are emphasized using the color palette to compare the relative level of new or innovative technologies selected by each resource plan.

8.2.4. Objective 4: Local Impacts & Sustainability

Community partnership and local investment are key themes in the SWEPCO mission statement and sustainability objectives. SWEPCO has repeatedly indicated an interest in having a positive local impact within its service territory and highlighting the opportunities for resources located within the SWEPCO service territory as part of the 2023 IRP. Furthermore, this metric integrates awareness to sustainability measures through an assessment of carbon reduction estimates in each portfolio.

SWEPCO indicated interest in measuring the performance of alternative resources against those goals. This objective also allows SWEPCO 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 serve SWEPCO's customers.

Two performance indicators were selected to measure progress towards local impacts and sustainability. Local impacts are measured as the amount of new generation located in the SWEPCO service territory and the amount of local investment associated with those projects. Sustainability is measured through portfolio CO_2 emissions and the level of reductions achieved relative to a 2005 baseline.

Local Impacts: Installed MW and capital invested inside SWEPCO's service territory

SWEPCO 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. This performance indicator allows management to compare the amount of total new installed resources likely to be constructed in regions that SWEPCO serves over the 2024-2033 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 SWEPCO service territory from 2024-2033; and (2) the cumulative capital invested in the SWEPCO service territory from 2024-2033, calculated as the sum of capital spent over the period in current year (e.g., 2023) US dollars.

The 2024-2033 period was selected to align the scorecard to the portfolio modeling results that are presented in the 2023 IRP and to focus the evaluation on local impacts over the first 10 years of the overall resource plan.

CO_2 Emissions: Percent reduction from 2005 in the Reference Scenario in 2033 & 2043

This performance indicator allows SWEPCO to evaluate progress towards reducing carbon emissions 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 SWEPCO's total emissions in the year 2005. Carbon emissions are defined as the direct emissions from SWEPCO's owned and contracted generating resources. This metric is calculated by dividing the total SWEPCO portfolio emission in the test year (2033 or 2043) by total SWEPCO portfolio emission from the year 2005 and evaluating the percent reduction. The scorecard uses the test years 2033 and 2043 to maintain consistency with the 10- and 20-year outlooks reflected in the IRP report and appendix.

The final Scorecard template is found below as Figure 66.

Figure 66 2023 IRP Scorecard

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *7-yr Rate CAGR, Reference Case*	***Long Term:*** *20-yr NPVRR, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 20-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 SWEPCO Territory*	***CO2 Emissions:*** *Percent Reduction from 2005 Baseline - Reference Case*
Year Ref.	2024-2031	2024-2043	2024-2043	2033 | 2043	2033	2024-2043	2033 | 2043	2043	2024-2033	2033 | 2043
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer | Winter	Summer | Winter	MW % of Peak Demand	%	MW | $MM	% Reduction
Reference Portfolio										
REF-Wint Portfolio										
CETA Portfolio										
ECR Portfolio										
FOR - Summer Portfolio										
FOR-Winter Portfolio										
NCR Portfolio										
NCR-Wint Portfolio										
Preferred Plan										

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

8.3. Portfolios Considered

SWEPCO 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. It assumes the market scenario conditions including load, fuel and CO_2 prices, reserve requirements and technology capacity accreditation assumptions discussed for each market scenario in Section 7 as appropriate.

The candidate resources made available to the model include various supply side resources discussed in Section 5 and demand-side resource options discussed in Section 6 The market scenario parameters are discussed in Section 7.

SWEPCO evaluated eight candidate portfolios including five under the current SPP Peak Summer capacity obligations and three additional portfolios, REF-Winter, NCR-Winter and FOR-Winter, under an anticipated SPP Peak Winter capacity obligation. To model winter requirements in these scenarios, 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, provide less load carrying capacity value (see Section 7.4.2) during winter peak periods than during summer peaks.

Each of the eight candidate portfolios were stress-tested under all five market scenarios and were also stress tested under stochastic distributions of gas prices, power prices, and renewable outputs (as discussed in Section 7.5) using a suite of resource planning tools, namely AURORA and the PERFORM utility financial model. AURORA produces projections of asset-level dispatch and the total variable costs associated with serving load. The AURORA output is then used by CRA's PERFORM model to build 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 NPV estimates of revenue requirements over the planning horizon. The outputs from AURORA and PERFORM are then used to populate the 2023 IRP Scorecard to inform the Company for the identification of the Preferred Plan.

8.3.1. Resource Additions by Portfolio

Resource additions in each of the eight portfolios considered are shown in Figure 67 to Figure 73 below. Tables of specific resource amounts in each portfolio are also included in Appendix F.

Reference Portfolio

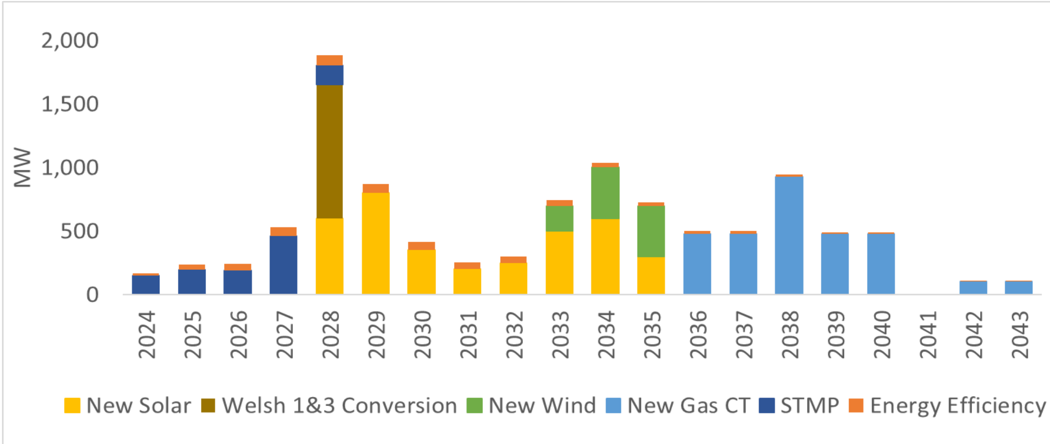


Figure 67 Annual Resource Additions in the Reference Portfolio

For the Reference portfolio, approximately 3.6 GW of new solar, 1.0 GW of new wind and 3.0 GW of new NGCTs are added by 2043. All of the new solar and new wind are added by the end of 2035 to take advantage of the ITC and PTC for customers from the Inflation Reduction Act. New NGCT and NGCC units are installed primarily from 2036 onward, to replace retiring existing units to meet firm requirements. The Welsh 1 & 3 conversions are selected in 2028.

In addition, demand-side resources including incremental EE programs are pursued. The contributions of incremental EE programs occur from 2024 – 2043, with the peak MW contribution of 78.8 MW in 2028.

REF-Winter Portfolio

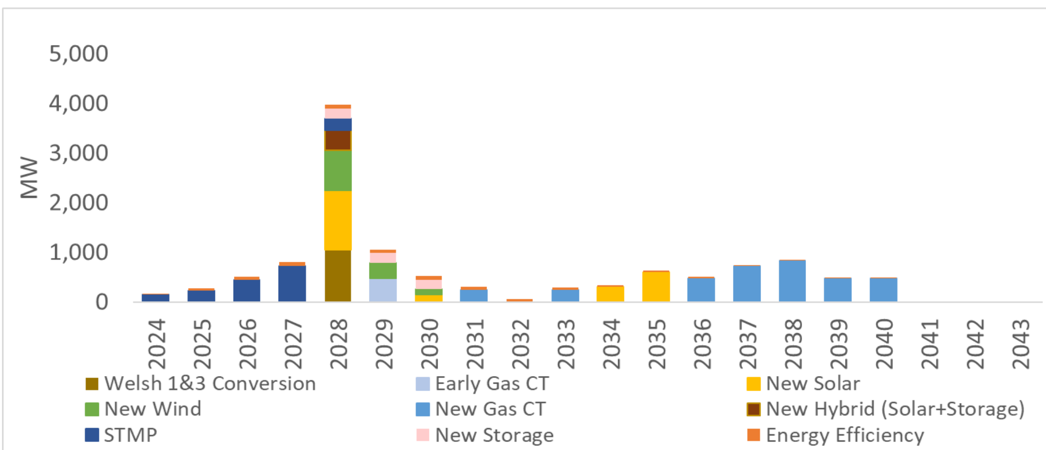
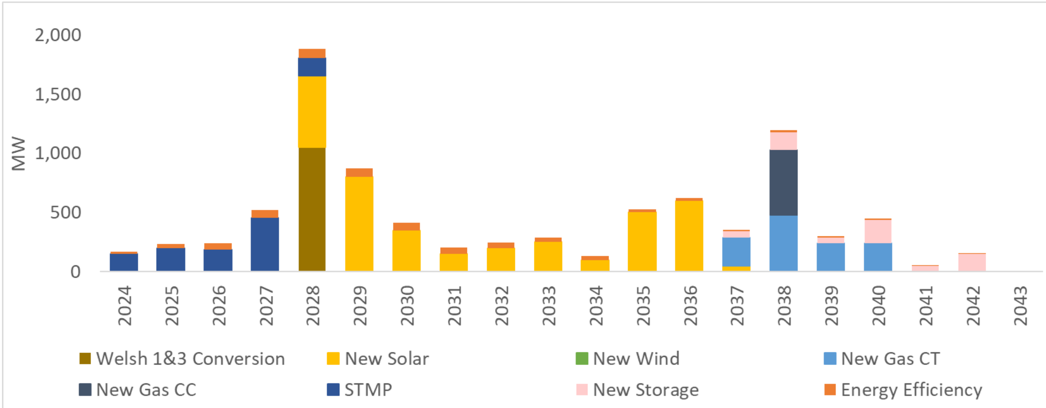


Figure 68 Annual Resource additions in the REF-Winter Portfolio

The REF Winter portfolio adds 2.3 GW of solar, 1.2 GW of wind, 3.5 GW of NGCT, 600 MW of storage, 400 MW of solar with storage hybrid and 480 MW of early NGCT. The significant amount of the new renewable resources selected in 2028 were to support a large capacity need for the Company more than from an economic basis by the model. Similar with the REF Summer portfolio, the Welsh 1 & 3 gas conversions provide valuable firm capacity during the 10-year period until it is mostly replaced by new NGCTs and New Gas Aeroderivatives in 2038. Additionally, the model selected 480MW of the new early gas CT in 2028 as described in section 5.3.1. On the demand-side, the need for resources results in the procurement of energy efficiency throughout the study period with a peak contribution of around 78.8 MW in 2028.

NCR Portfolio

Figure 69 Annual Resource Additions in the NCR Portfolio



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 this portfolio has a higher ELCC, given this technology's 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. In addition, the lack of a carbon program reduces the competitiveness of energy rich resources like wind and this portfolio des not add any new wind during the study period. By 2043, the NCR portfolio adds 3.6 GW of new solar, 650 MW of new storage, 1.2 GW of new NGCTs, and 550 MW of NGCC. The Welsh 1 & 3 conversions are also selected in 2028.

NCR-Winter Portfolio

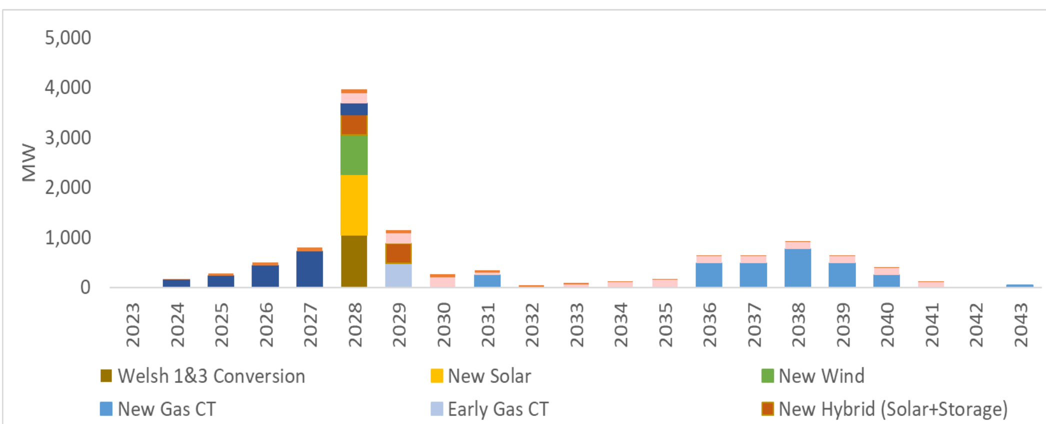
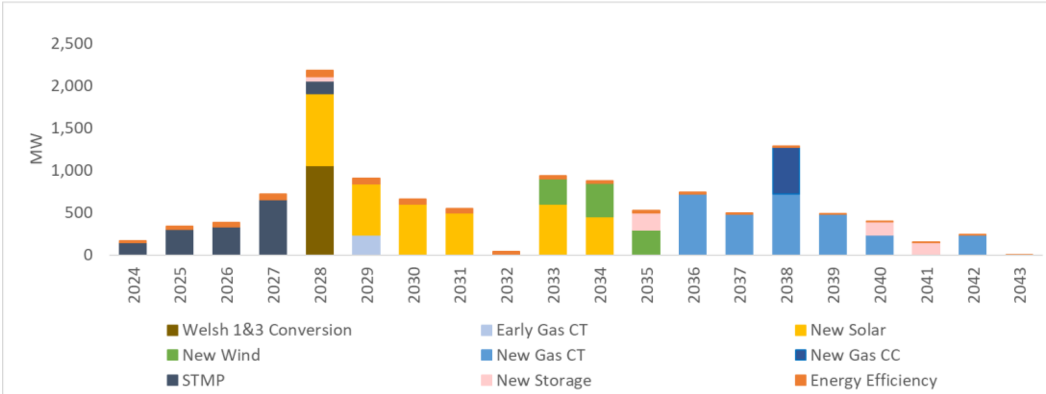


Figure 70 Annual Resource Additions in the NCR-Winter Portfolio

The NCR Winter portfolio adds 1.2 GW of solar, 800 MW of wind, 2.7 GW of NGCT, 1.8 GW of storage, 800 MW of solar with storage hybrid and 480 MW of the early NGCTs. This portfolio adds 800 MW of hybrid solar with storage mostly due to the capacity accreditation of storage. Similar with the other portfolios, the Welsh 1 & 3 conversions providing valuable firm capacity during the 10-year period until it is mostly replaced by new NGCTs and New Gas RICE in 2038. The model also selected 480MW of new early gas CT in 2028 as described in section 5.3.1. On the demand-side, the need for resources results in the procurement of energy efficiency throughout the study period with a peak contribution of around 78.8 MW in 2028.

Clean Energy Technology Advancement (CETA) Portfolio

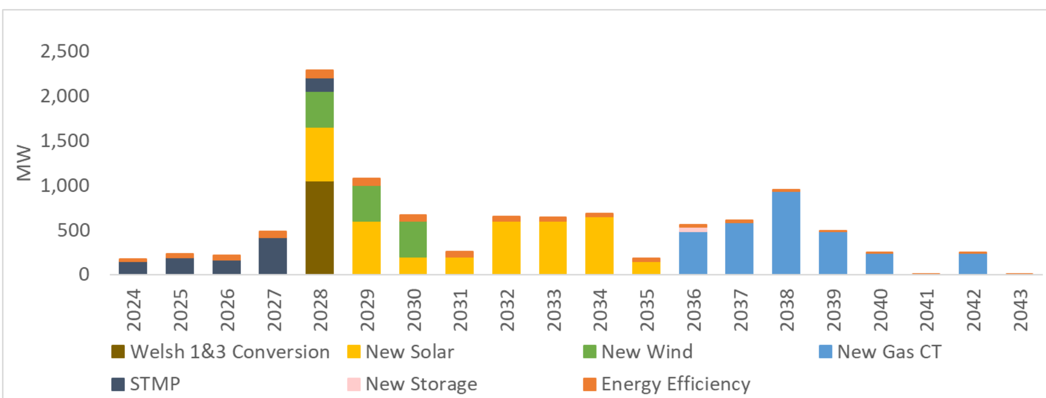
Figure 71 Annual Resource Additions in the CETA Portfolio



The CETA Scenario combines higher load and more affordable renewable technologies that result in faster decline in renewable technology costs. As a result of higher load, the CETA portfolio has larger capacity additions than all summer optimized portfolios. 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. In order to meet firm capacity requirements given the low ELCCs for solar PV, the CETA portfolio adds proportionately less solar PV and more new wind and storage units. By 2043, approximately 3.6 GW of solar, 1.0 GW of wind, 2.9 GW of NGCTs, 550 MW of NGCC, 240 MW early NGCT and 550 MW of storage units are added. Similar to the other portfolios, the Welsh 1 & 3 conversions are selected in 2028. In total, the peak contribution from incremental demand side resources is 78.8 MW in 2028.

Enhanced Carbon Reduction (ECR) Portfolio

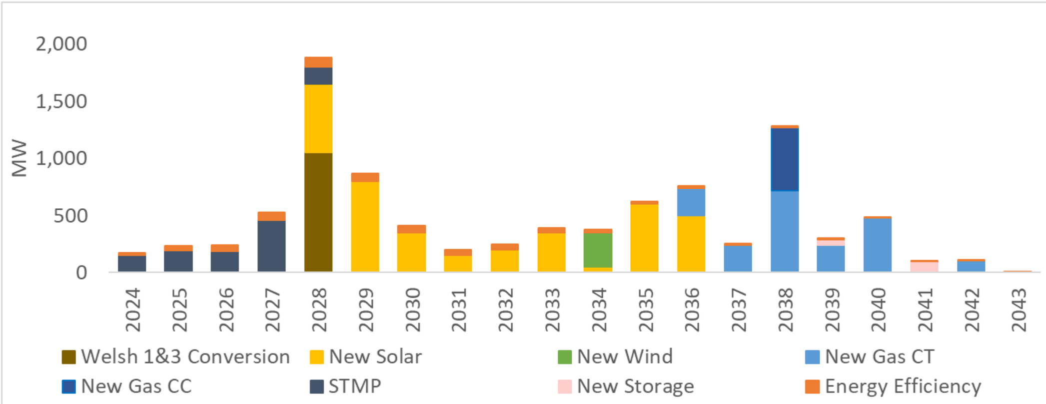
Figure 72 Annual Resource Additions in the ECR Portfolio



The ECR Scenario combines lower load growth with high-cost gas and carbon. Due to the lower load forecast, the ECR portfolio adds fewer resources overall relative to the other portfolios. Because of the high gas and carbon prices assumed for the Scenario, the ECR portfolio prefers adding new storage units over NCGTs to meet firm requirements. By 2043, approximately 3.6 GW of solar, 1.2 GW of wind, 2.96 GW of NGCTs, and 1.6 GW of storage units are added. The amount of new wind added is about 1 GW higher than the level in the Reference portfolio due to the higher carbon price beyond 2029. The Welsh 1 & 3 conversions are selected in 2028 to provide valuable firm capacity. The contributions of incremental EE programs occur from 2024 – 2043, with the peak MW contribution of 78.8 MW registered in 2028.

Focus On Resiliency (FOR) Portfolio

Figure 73 Annual Resource Additions in the FOR Portfolio



For the FOR portfolio, approximately 3.6GW of new solar, 300 MW of new wind, 2.0 GW of new NGCTs, 550 MW of NGCC and 150 MW of storage are added by 2043. All of the new solar and wind units are added before the end of the ITC and PTC from the Inflation Reduction Act. New NGCT and NGCC units are installed primarily from 2036 onward, to replace retiring existing units to meet firm requirements. The Welsh 1 & 3 conversions are selected in 2028. The contributions of incremental EE programs occur from 2024 – 2043, with the peak MW contribution of 78.8 MW in 2028.

Focus On Resiliency Winter (FOR-Winter) Portfolio

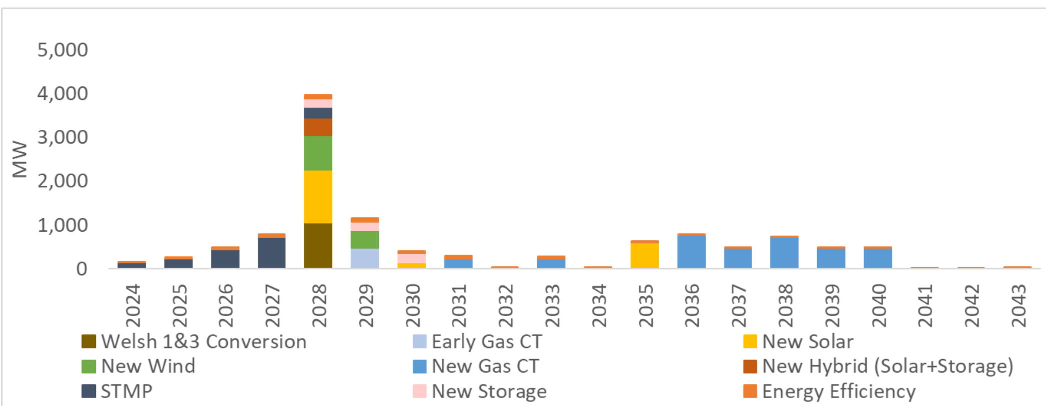


Figure 74 Annual Resource Additions in the FOR-Winter Portfolio

Under the FOR scenario, solar resources are expected to perform materially different in winter than summer and their peak credits are modeled with a decline over time from 19% in 2024 to 5% in 2043. The net load peaks in SPP during the winter are fairly flat across the day. Because of this, batteries are not able to provide as much capacity value as they do during the summer. For winter, SWEPCO assumed the capacity peak credits for 4-hour, 6-hour and 8-hour batteries to decline from 83% in 2024 to around 16%, 41% and 55% respectively in 2043.

The FOR-Winter portfolio adds 2.0 GW of solar, 1.2 GW of wind, 3.38 GW of NGCT, 600 MW of storage, 480 MW of early NGCT and 400 MW of solar with storage hybrid. Similar with the rest of the portfolios, the Welsh 1 & 3 conversions provide valuable firm capacity during the 10-year period until it is mostly replaced by new NGCTs and New Gas Aero in 2038. This portfolio adds about 400 MW of hybrid solar with storage mostly due to the capacity accreditation of storage. On the demand-side, the need for resources results in the procurement of energy efficiency throughout the study period with a peak contribution of around 78.8 MW in 2028.

Early Capacity Sensitivities

The Company also received Stakeholder feedback suggesting an analysis where resources might be available within 1 to 2 years. Although the Company has limited confidence it can reliably identify such resources in SPP, negotiate and finalize terms, and gain Commission approval in this short period of time, capacity expansion sensitivities were conducted to evaluate how the near-term capacity needs might be affected if such capacity were able to be acquired. Summer and winter sensitivities were conducted on the Reference and NCR Portfolios. All parameters and available resources made available in these Portfolios were the same except for the change in the Market Capacity resources. In the original portfolio analysis, Market Capacity resources were made available up to 150MW/year for a duration of 1 year at the SPP CONE price. In the capacity sensitivities, a 3-year, 400MW market capacity resource was made available at $13.35/kW-month[40] beginning in 2026 (within 2 years) and this resource was available for renewal in 2029.

The analysis identified a mix of results depending on a summer or winter capacity obligation. More specifically, under summer optimized portfolios when solar resources retain a higher ELCC, similar solar resources were selected although the timing of these resources were delayed. The summer analysis suggests solar resources would continue to be reasonable for meeting the Company's summer capacity obligation if they were available and responded to the Company's RFP. Figure 75 and Figure 76 illustrate the change in resource selections in the summer optimized capacity sensitivity portfolios.

[40] The Company informed the capacity sensitivity price from recent studies indicating capacity prices are escalating due to inflation. (https://www.rtoinsider.com/57681-miso-pra-cone-inflation-auction/)

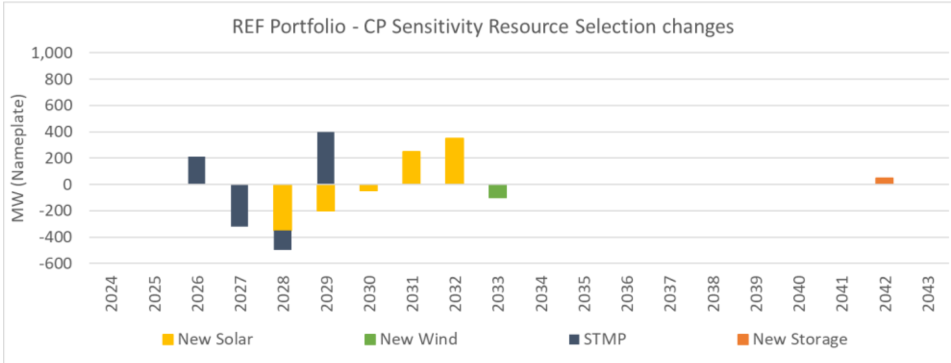


Figure 75 REF Portfolio – CP Sensitivity Resource Selection Changes

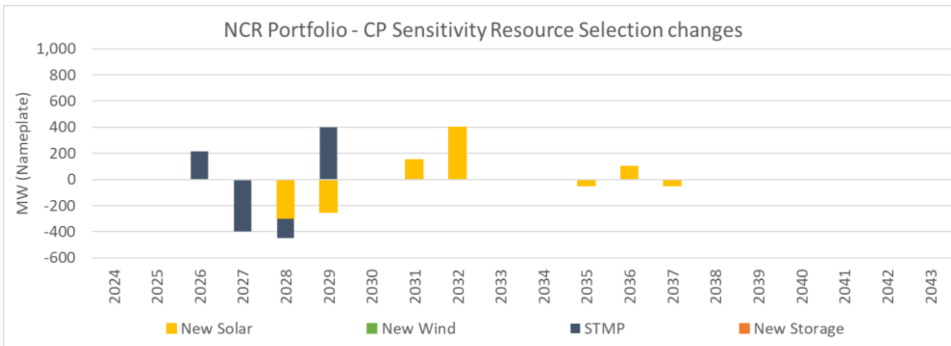


Figure 76 NCR Portfolio – CP Sensitivity Resource Selection Changes

In the winter capacity obligation sensitivities, the selection of a large number of renewable resources in 2028 to support the winter capacity obligation is replaced with a firm capacity resource. The results support the earlier analysis indicating the 2028 resource selections in the winter analysis is largely for the capacity value they bring to the portfolio. The selection of solar resources in the winter analyses was materially different in the REF-Winter Portfolio and the NCR-Winter Portfolio with the NCR-Winter Portfolio not selecting the solar resources later in the planning horizon as they were in the REF-Winter Portfolio. The NCR-Winter Portfolio relied on more NGCT resources over the longer planning horizon. Figure 77 and Figure 78 illustrate the change in resource selections in the winter optimized capacity sensitivity portfolios. Figure 77 and Figure 78 illustrate the change in resource selections in the winter optimized capacity sensitivity portfolios.

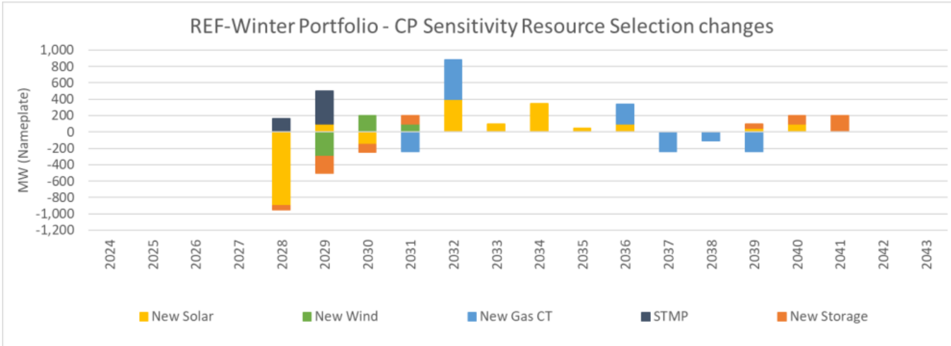


Figure 77 REF-Winter Portfolio – CP Sensitivity Resource Selection Changes

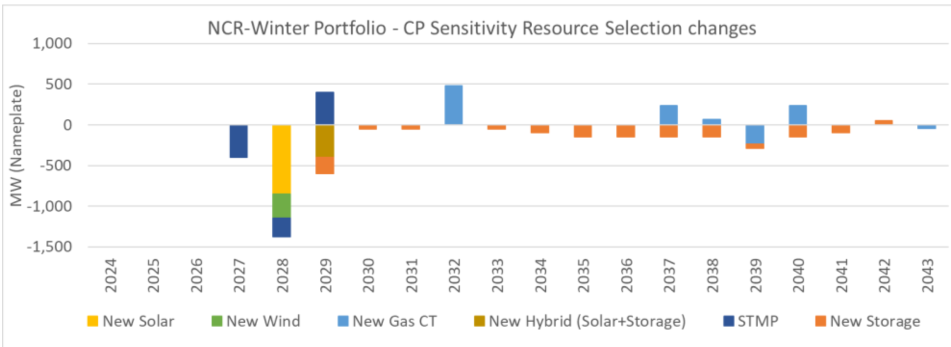


Figure 78 NCR-Winter Portfolio – CP Sensitivity Resource Selection Changes

8.4. Scorecard Results

8.4.1. Customer Affordability

SWEPCO measures customer affordability across two time scales:

- Short-term affordability, measured as the 7-year CAGR of growth in customer rates associated with the new demand- and supply-side resources selected under each portfolio; and
- Long-term affordability, measured as the 20-year NPVRR of new demand- and supply-side resources selected under each portfolio.

Short-Term

Table 21 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 revenue requirements over the next 30 years expressed on both an NPVRR basis and a levelized rate basis, all measured under Reference Scenario market conditions.

Table 21 Portfolio Performance under Customer Affordability Metrics

Portfolio	7-Year Rate CAGR, Reference Scenario (%/annum)	20-Year NPVRR, Reference Scenario ($ Millions)	20-Year Levelized Rate, Reference Scenario ($/MWh)
Reference	1.53%	15,851	67.2
REF-Winter	3.83%	17,817	75.4
CETA	1.90%	16,371	69.3

ECR	1.83%	16,126	68.3
FOR-Summer	1.49%	15,630	66.2
FOR-Winter	3.99%	17,705	74.9
NCR	1.49%	15,582	66.0
NCR-Winter	3.92%	18,271	77.3

Over the next seven years, the variation in the expected growth of customer rates is driven by the differences in near-term resource additions across the portfolios. The FOR Summer and NCR portfolios have the smallest amount of capacity additions in this period – primarily driven by the availability of low-cost, reliable gas units – and as a result, these portfolios exhibit the slowest rates of growth at 1.49% per year. Conversely, the FOR Winter portfolio has the highest rate of growth at 3.99% per year, owing to the greater amount of new resources added to the portfolio over this period to meet winter capacity requirements. The remaining portfolios fall between these two extremes, with CETA having the highest rate growth across summer portfolios at 1.90% and the winter portfolios having growth rates in the range of 3.83-3.99%, significantly higher than the summer portfolios in the range of 1.49-1.90%.

Long-term

In terms of revenue requirements over the next 20 years, the Reference, FOR Summer, and NCR portfolios perform similarly on both the NPVRR and the levelized rate bases. Overall, the NCR portfolio has the lowest expected cost to customers due to a combination of economic baseload gas generation, lower capex resource types, and lower O&M. The FOR Summer portfolio is next best and only slightly higher cost compared to the NCR portfolio due to similar build schedules. The next least expensive is the Reference portfolio with $15.6 billion, followed by the ECR portfolio with $16.1 billion.

Of the summer portfolios, the CETA portfolio has the highest long-term revenue requirement and levelized rate of $16.4 billion and $69.3/MWh, respectively when compared with the other summer portfolios. This is driven largely by the high load scenario under which the portfolio was optimized, resulting in nearly 1,600 MW more new capacity than the ECR portfolio and nearly 3,300 MW more than the NCR portfolio. Overall, the winter portfolios have the highest long-term revenue requirements and levelized rates due to a greater amount of capacity additions in order to meet winter capacity requirements. Of the winter portfolios, NCR Winter has the highest revenue requirement over 20 years with $18.3 billion, followed by the REF Winter and FOR Winter portfolios with $17.8 billion and $17.7 billion, respectively.

8.4.2. Rate Stability

SWEPCO measures rate stability by evaluating:

- Scenario resilience as measured by the range of 20-year NPVRR of the portfolio across the five market scenarios;
- Cost risk as measured by the NPVRR increase when moving from the 50th to the 95th percentile of portfolio costs in years 2033 and 2043; and
- Market exposure as measured by net sales in the summer and winter seasons as a percentage of load in 2043.

Scenario Resilience

Table 22 shows the 20-year NPVRRs across the five market scenarios and the difference between the highest and lowest NPVRRs of each of the six portfolios considered. The difference between the highest and lowest value is used to populate the Scenario Resilience indicator on the IRP scorecard.

Table 22 The 20-Year NPVRRs of the Portfolio Across Market Scenarios ($Million)

	Market Scenarios					
Portfolios	**Reference**	**CETA**	**ECR**	**FOR**	**NCR**	**High/Low Difference**
Reference	15,851	15,745	16,351	15,819	15,055	1,296
REF-Winter	17,817	17,610	18,039	17,805	16,977	1,062
CETA	16,371	16,208	16,777	16,319	15,585	1,192
ECR	16,126	15,992	16,165	16,077	15,482	682
FOR-Summer	15,630	15,531	16,493	15,610	14,704	1,789
FOR-Winter	17,705	17,557	18,036	17,704	16,831	1,205
NCR	15,582	15,439	16,506	15,571	14,619	1,887
NCR-Winter	18,271	17,956	18,747	18,289	17,255	1,492

In general, the various portfolio costs under the Reference scenario and the ECR scenario produce the highest expected 20-year portfolio NPVRRs, though the portfolio costs under these market scenarios are not significantly higher compared to the others. While the Reference scenario assumes base technology costs, the ECR scenario assumes faster technology cost declines. Base costs in the Reference scenario combined with large buildouts of new resources leads to higher overall NPVRR values. Despite quickly declining costs in the ECR scenario, an economically inefficient situation arises as new gas capacity is required to meet strict capacity requirements, but the gas resources have limited dispatch due to high carbon costs. The IRP portfolios tend to report the lowest costs under the NCR scenario due to the economic competitiveness of gas resources in the absence of a restrictive carbon price.

The ECR portfolio is the most resilient under the five market scenarios with an NPVRR range of approximately $682 million – a fraction of the next smallest NPVRR range. The REF Winter and CETA portfolios rank second and third in terms of resiliency with NPVRR ranges of $1,062 million and $1,192 million, respectively.

The NCR and FOR Summer portfolios are least resilient by this measure with an NPVRR range of greater than $1.7 billion when solved under different fundamental conditions. The NCR portfolio was optimized without a carbon tax, so under market conditions with enhanced carbon regulation, this portfolio performs poorly. As a result, the NPVRR of the NCR portfolio under the ECR scenario is the highest. The FOR Summer portfolio was optimized to a market scenario which requires reliability, typically afforded by new gas generation. As a result, this portfolio sees a large buildout of NGCC and NGCT resources. Under the ECR scenario, this portfolio performs worst due to high carbon taxes, and thus customers are at highest risk from regulatory changes.

Cost Risk

Figure 79 and Figure 80 present a summary of the stochastic results for each of the six candidate portfolios. This metric compares the distributions of net present revenue requirements in 2032 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. Figure 79 shows a summary of the cost risk across each candidate portfolio.

Figure 79 Distribution of Revenue Requirements Based on Stochastic Analysis (2033)

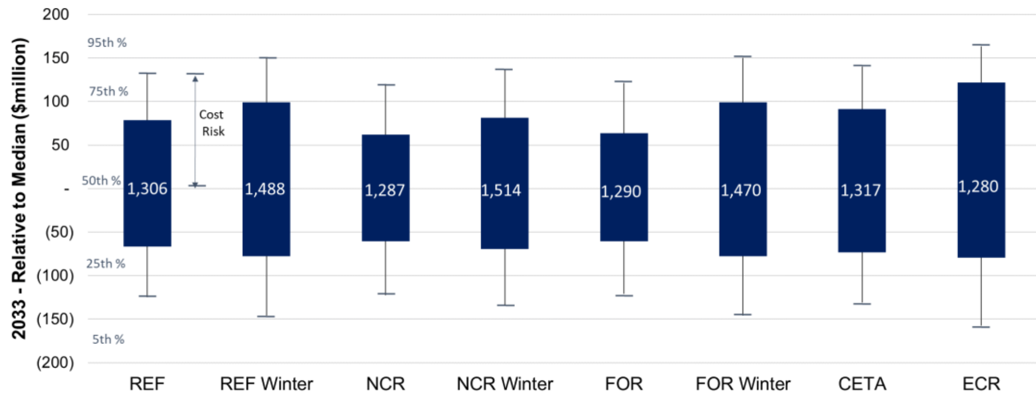


Figure 80 Distribution of Revenue Requirements Based on Stochastic Analysis (2043)

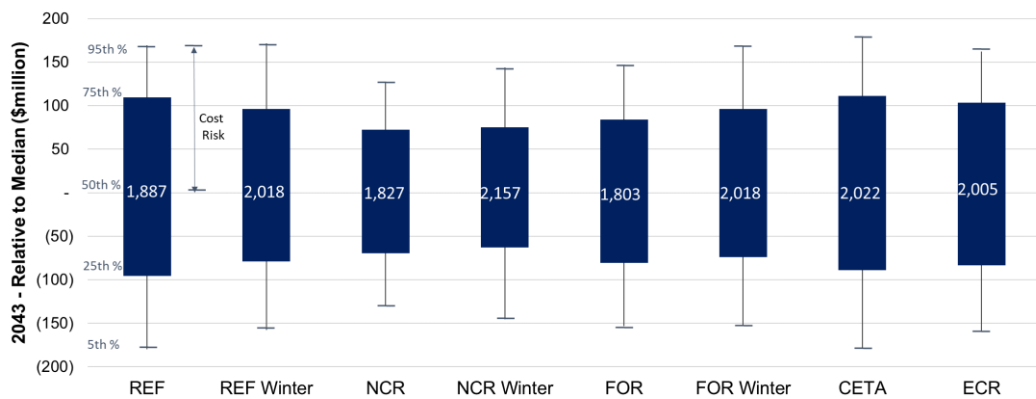


Table 23 Cost Risk - 50th to 95th Percentile Distribution Range ($Million)

Portfolio	2033	2043
Reference	133.1	169.5
Reference - Winter	150.4	171.8
CETA	140.2	178.4
ECR	163.7	162.4
FOR	121.5	146.5
FOR Winter	150.4	169.0
NCR	120.1	127.1
NCR Winter	137.1	144.2

The highest cost risk portfolios are the ECR Portfolio in 2033 and the CETA Portfolio in 2043, thus making them more exposed to short-term volatility in power prices, gas prices, and renewable output. The NCR portfolio has the lowest cost risk, with a much narrower distribution of outcomes.

Market Exposure

Table 24 shows the net energy sales as a percentage of portfolio load split by summer and winter. The percentages shown are averaged across all market scenarios.

Table 24 Average Net Energy Sales as % of Portfolio Load Across All Scenarios

(Negative is net purchases and positive values are net off system sales)

Portfolio	**Summer**			**Winter**		
	2023	**2033**	**2043**	***2023***	**2033**	**2043**
Reference	17%	-5%	45%	21%	-20%	11%
REF-Winter	17%	-1%	49%	21%	-9%	7%
CETA	17%	2%	61%	21%	-14%	25%
ECR	17%	8%	45%	21%	4%	15%
FOR-Summer	17%	-11%	38%	21%	-27%	8%
FOR-Winter	17%	-1%	44%	21%	-9%	5%
NCR	17%	-12%	21%	21%	-28%	-2%
NCR-Winter	17%	-8%	22%	21%	-19%	-13%

Generation from SWEPCO's current portfolio is expected to exceed demand in the short-term resulting in a long energy position. This is mainly driven by robust thermal dispatch and a higher market heat rate environment.

By 2033, all portfolios evaluated in the 2023 IRP show a tendency for reduced net sales in summer relative to 2023 with only CETA and ECR maintaining net energy sales. For ECR this is due to lower projected load assumed for that portfolio. In winter, all portfolios also tend to reduce their share of net sales by 2033 as a percent of customer load and other than ECR rely on market purchases to meet demand compared with 2023 levels. The ECR Portfolio relies most heavily on market sales to balance customer requirements while the NCR portfolio has the least reliance on market in 2033.

The summer net sales position of most portfolios tends to increase between 2033 and 2043 primarily due to later additions of new solar resources. Net sales in summer tend to grow more between 2033 and 2043 relative to the winter season. This is explained, in part, by the fact that many portfolios include more thermal resources by year 2043 to make up for reduced production from solar in the winter months, leading to lower generation from the winter portfolio.

8.4.3. Maintaining Reliability

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

- Planning reserves measured as the ratio of firm (i.e., Accredited Capacity) supply to expected peak demand for *both* the summer and winter periods, averaged over the period between 2024 and 2043;
- Operational flexibility measured as the total firm capacity (Accredited Capacity) provided by fast-ramping technologies in years 2033 and 2043; and
- Resource diversity measured as the percentage of total generation provided by the different generating technologies selected in each candidate resource plan in model year 2043 under the Reference Scenario.

Planning Reserves

Table 25 shows the summer and winter planning reserves, averaged over the period between 2023 and 2043 and across all market scenarios.

Table 25 Planning Reserves Between 2024 and 2043 by Portfolio

Portfolio	Summer	Winter
Reference (Summer)	24%	18%
REF-Winter	40%	34%
CETA (Summer)	33%	25%
ECR (Summer)	25%	19%
FOR (Summer)	20%	15%
FOR-Winter	36%	34%
NCR (Summer)	17%	11%
NCR-Winter	40%	33%

As discussed in Section 3.5, SWEPCO assumed that each candidate summer portfolio assumed a planning reserve margin of 22% above summer peak load by 2025 when optimizing each candidate portfolio in its native market scenario. The Company also assumed that each candidate winter portfolio included a planning reserve margin of 33% above its winter peak load by 2025 when optimizing each candidate portfolio to its native market scenario.

This approach results 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 have a large surplus when run under market conditions that award more capacity contribution to solar resources.

When viewed as the average across all scenarios, the FOR Summer, NCR Summer and ECR Portfolios fall short or are close to the 22% reserve margin target in the summer. For the ECR portfolio, the result is driven by the fact that it has the smallest capacity additions relatively to all other portfolios as the portfolio is optimized for low load growth. For the FOR Summer and NCR Portfolio, the result is driven by the portfolios adding just enough capacity to meet its load obligations and relying on market purchases to meet energy shortfalls. The CETA portfolio has an average summer reserve margin of 33% by this measure, about 10% higher than the target planning reserve margin. This is driven by greater capacity additions in this portfolio in anticipation of high load growth, and the greater ELCC value awarded to solar resources in any of the non-CETA Scenarios.

Operational Flexibility

Table 26 shows the capacity of dispatchable units in 2033 and 2043 in each of the portfolio considered. The Company considers dispatchable resources all technologies except solar and wind.

Table 26 The Amount of Dispatchable Capacity in 2033 and 2043 by Portfolio

Portfolio	2033 Dispatchable Capacity (MW)	2043 Dispatchable Capacity (MW)
Reference	3,624	4,331
REF-Winter	5,184	5,816
CETA	3,914	5,491
ECR	3,624	4,276

FOR-Summer	3,624	3,996
FOR-Winter	5,184	5,732
NCR	3,624	3,671
NCR-Winter	5,044	6,275

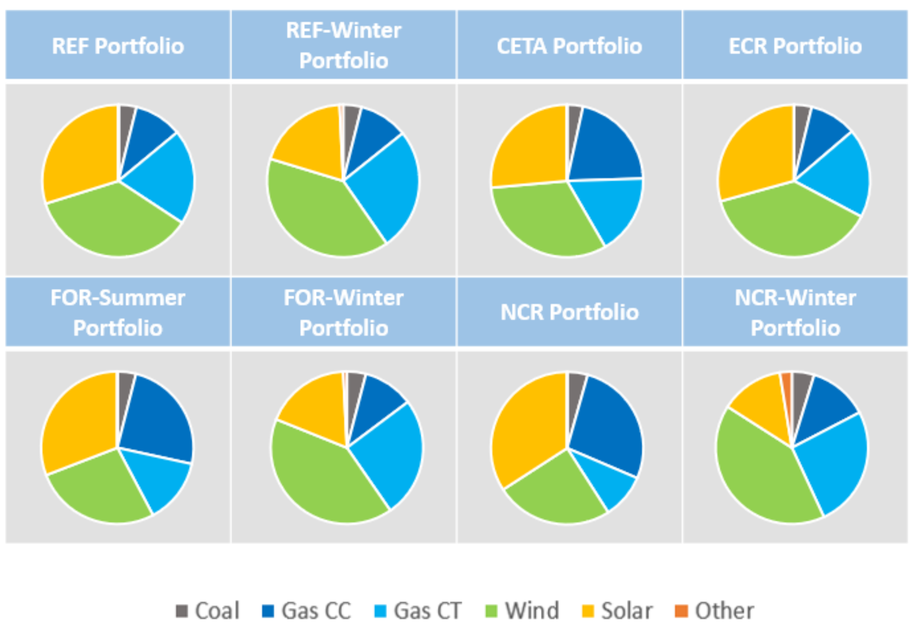
The REF-Winter, FOR-Winter and NCR-Winter portfolios tend to score highest on this metric, particularly over the first 10 years, owing to the overall higher amount of new thermal resources constructed in anticipation of reduced production from solar resources in the winter resulting in greater operational flexibility. The CETA portfolio performs second best due to higher amount of new resource additions due to higher customer loads. The Reference, FOR-Summer, ECR and NCR portfolios tend to score less due to greater reliance on solar.

All portfolios except the NCR tend to have higher amounts of dispatchable capacity in 2043 compared to 2033. This is due to the addition of greater amounts of dispatchable thermal resources including NGCTs and a 550 MW NGCC in the later years. The NCR portfolio makes the least of these additions in the later years.

Resource Diversity

Figure 81 shows pie charts displaying the percentage of total generation provided by existing resources as well as the different generating resources selected by each candidate resource plan in model year 2043 under Reference Scenario market conditions.

Figure 81 2043 Generation Energy Mix by Technology and Portfolio (percent)



All portfolios primarily rely on gas, wind and solar generation along with smaller amounts of coal, demand-side resources and storage. Despite assumed improvements in technology costs over time, no advanced generation technologies are selected across any portfolios.

The REF and ECR portfolios are most diverse, with similar proportions of energy provided by gas, solar and wind units. FOR-Summer, CETA and NCR portfolios score similarly on this metric but are slightly more gas-heavy than the REF and ECR portfolios. Finally, the REF-Winter, FOR-Winter and NCR-Winter portfolios are the least diverse, with wind dominating total portfolio generation in 2043.

8.4.4. Local Impacts & Sustainability

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

- Local impacts measured as (1) the total new installed nameplate capacity inside SWEPCO service territory, and (2) the total amount of capital invested inside SWEPCO service territory between 2024 and 2033; and
- The percentage reduction in CO_2 emissions in 2033 and 2043 from owned resources relative to the baseline year 2005 in the Reference Scenario.

Local Impacts

Table 27 compares the total new installed nameplate capacity and total expected CAPEX invested inside SWEPCO service territory between 2024 and 2033 for each candidate portfolio. This includes an assumption of particular assets being located within SWEPCO's territory. For this metric, informed by the current SPP queue, all thermal and storage resources as well as 35% of solar resources are included while all wind resources are excluded. The Company will, however, continue to explore opportunities to locate resources within and outside of SWEPCO's territory if they are beneficial to SWEPCO customers.

Table 27 Local Impacts Metrics by Portfolio

Portfolio	New Nameplate Capacity Between 2024 and 2033 (MW)	Total CAPEX Invested Inside SWEPCO Territory ($ Millions)
Reference	1,998	1,610
REF-Winter	3,086	2,322
CETA	2,446	1,866
ECR	2,033	1,608
FOR-Summer	1,911	1,514
FOR-Winter	3,086	2,286
NCR	1,876	1,477
NCR-Winter	2,893	2,358

The REF-Winter, For-Winter and NCR-Winter portfolios score best by the MW metric and by the dollar metric, owing to the greater deployment of new thermal resources under this case to compensate for lower generation from solar in the winter. The CETA portfolio scores second best by the dollar metric and second best by the MW metric due to its greater deployment of new resources to meet faster growth in customer load. The Reference and ECR portfolios are third-best in the capacity metric with 1,988 MW and 2,033 MW installed in the territory and a total expected investment of approximately $1.6 billion over the 10 years which ranks third across the portfolio options. The FOR-Summer and NCR portfolios score similarly by this measure and result in approximately $1.5 billion in new investment in the SWEPCO territory over the next 10 years.

CO_2 Emissions

Table 28 shows the levels of carbon emissions in 2033 and 2043 in the Reference Scenario by portfolio and expresses the reduction in carbon emissions relative to the level of emissions to 2005 in percentage terms. Total CO_2 emissions from both SWEPCO owned plants and contracted output was 21.9 million tons (mt) in year 2005. Emissions have since declined to around 13.9 million tons in 2023.

Table 28 CO_2 Emission Reductions by Portfolio under Reference Scenario

Portfolio	Level of Emissions in 2005 ($mtCO_2$)	Level of Emissions in 2033 ($mtCO_2$)	% reduction in 2033 relative to 2005	Level of Emissions in 2043 ($mtCO_2$)	% reduction in 2043relative to 2005
Reference	21.9	2.7	88%	5.6	75%
REF-Winter	21.9	3.1	86%	6.5	70%
CETA	21.9	2.8	87%	6.9	68%
ECR	21.9	2.7	88%	5.4	75%
FOR-Summer	21.9	2.7	88%	5.9	73%
FOR-Winter	21.9	3.1	86%	6.3	71%
NCR	21.9	2.7	88%	5.1	77%
NCR-Winter	21.9	3.0	86%	5.7	74%

By 2033, all portfolios have similar levels of CO_2 emissions between 2.7 and 3.1mt.

By 2043, the CETA, REF-Winter and FOR-Winter have similar levels of CO_2 emissions between 6.3 and 6.9mt due to greater thermal additions in these portfolios to meet faster customer load growth in the CETA scenario and compensate for lower solar generation in the winter scenarios.

8.4.5. Evaluating the 2023 IRP Scorecard

The fully populated scorecard is shown in Figure 82. The key results from the scorecard are summarized below:

- The Reference Portfolio scored strong in the Affordability metrics but was an underperformer in the Planning Reserves and Operational Flexibility metrics. Conversely, the REF-Winter Portfolio scored well in the Operational Flexibility metrics while incurring high Affordability metrics due to the increased resources required. Similar scorecard metrics were realized between the NCR and FOR Portfolios compared to their corresponding winter portfolios.
- The CETA and ECR Portfolios modeled under summer capacity obligations had high short-term and long-term affordability cost metrics. For Rate Stability, although the Scenario Range metrics for these portfolios scored well among all the portfolios, higher cost risks were realized,
- Winter portfolios scored the strongest in the Reliability metrics with all winter portfolios having dispatchable capacity capable of serving SWEPCOs peak loads in 2033 and 2043. Additionally, summer optimized portfolios were unable to meet expected SPP winter capacity obligations.
- Winter Portfolios scored the strongest in Local Impacts given the need to obtain more resources to meet expected SPP winter capacity obligations.
- This scorecard also shows the results of the Preferred Plan which is described in the next section.

Figure 82 Populated 2023 IRP Scorecard

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & Sustainability	
Portfolio	***Short Term:*** *7-yr Rate CAGR, Reference Case*	***Long Term:*** *20-yr NPVRR, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 20-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 SWEPCO Territory*	***CO2 Emissions:*** *Percent Reduction from 2005 Baseline - Reference Case*
Year Ref.	2024-2031	2024-2043	2024-2043	2033 | 2043	2033	2024-2043	2033 | 2043	2043	2024-2033	2033 | 2043
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer | Winter	Summer | Winter	MW % of Peak Demand	%	MW | $MM	% Reduction
Reference Portfolio	1.53	15,851 $67.2	1,296 $9.61	133.1|169.5	-5% | -20%	24% | 18%	3,624 | 4,331 76% | 91%		1,998 | 1,610	88% | 75%
REF-Wint Portfolio	3.83	17,817 $75.4	1,062 $9.19	150.4|171.8	-1% | -9%	40% | 34%	5,184 | 5,816 109% | 122%		3,086 | 2,322	86% | 70%
CETA Portfolio	1.90	16,371 $69.3	1,192 $9.35	140.2|178.4	2% | -14%	33% | 25%	3,914 | 5,491 79% | 106%		2,446 | 1,866	87% | 68%
ECR Portfolio	1.83	16,126 $68.3	682 $7.01	163.7|162.4	8% | 4%	25% | 19%	3,624 | 4,276 80% | 101%		2,033 | 1,608	88% | 75%
FOR - Summer Portfolio	1.49	15,630 $66.2	1,789 $11.71	121.5|146.5	-11% | -27%	20% | 15%	3,624 | 3,996 76% | 84%		1,911 | 1,514	88% | 73%
FOR-Winter Portfolio	3.99	17,705 $74.9	1,205 $9.79	150.4|169.0	-1% | -9%	36% | 34%	5,184 | 5,732 109% |120%		3,086 | 2,286	86% | 71%
NCR Portfolio	1.49	15,582 $66.0	1,887 $12.13	120.1|127.1	-12% | -28%	17% | 11%	3,624 | 3,671 76% |77%		1,876 | 1,477	88% | 77%
NCR-Wint Portfolio	3.92	18,271 $77.3	1,492 $11.28	137.1|144.2	-8% | -19%	40% | 33%	5,044 | 6,275 106% | 131%		2,893 | 2,358	86% | 74%
Preferred Plan	3.00	16,774 $71.0	2,724 $16.21	137.4|146.2	-16% | -29%	29% | 33%	5,224 | 5,581 110% | 117%		2,898 | 1,526	86% | 67%

(0% wind, 35% solar, 100% gas, storage)

Coal
Gas CC
Gas CT
Wind
Solar
Other

8.5. Preferred Plan

The Company identified the Preferred Plan (PP) based on insights from the different portfolio analyses discussed in Section 8. The PP includes resources supporting an estimated SPP Winter Planning Reserve Margin (PRM) of 26% plus additional reserve to account for the uncertainty in the final future peak load, the final accredited capacity values of the resources, and the actual SPP minimum reserve margin that will ultimately be adopted. The Company does not yet know the specific SPP winter capacity minimum reserve margin obligation. The winter optimized portfolios analyzed in this IRP required the most resources needed to meet anticipated future SPP PRM obligations due to SWEPCO's winter peak and the anticipated range of winter PRM. The Company's Preferred Plan (PP) was identified to balance the need and costs to meet SPP's expected winter reserve margin while also recognizing value from resources selected in the summer optimized plans. Figure 83 and Figure 84 illustrate the Company's capacity position given the PP new resources in both a Summer and anticipated Winter capacity obligation view.

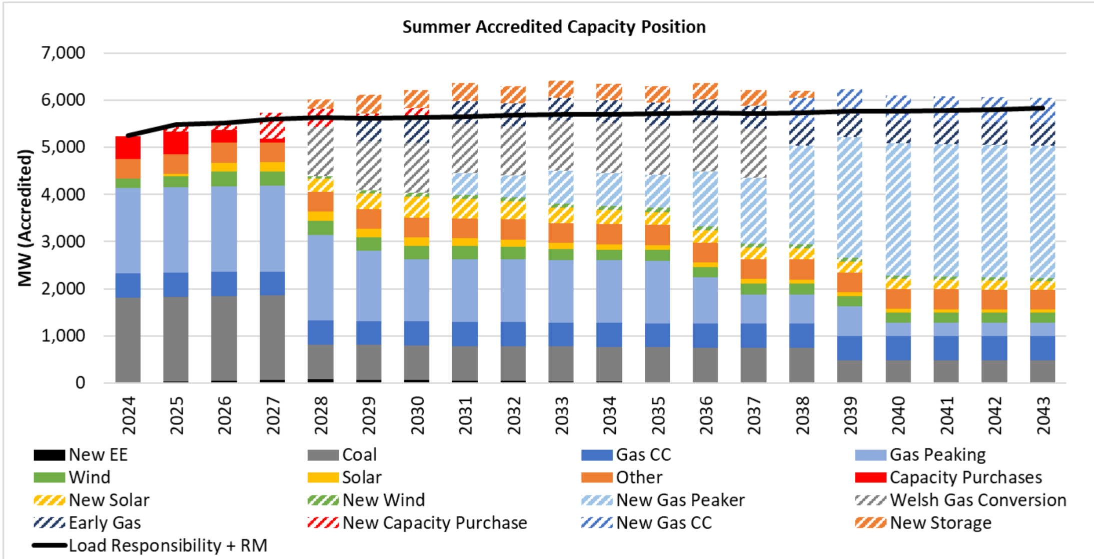


Figure 83 SWEPCO Summer Accredited Capacity Position – Preferred Plan

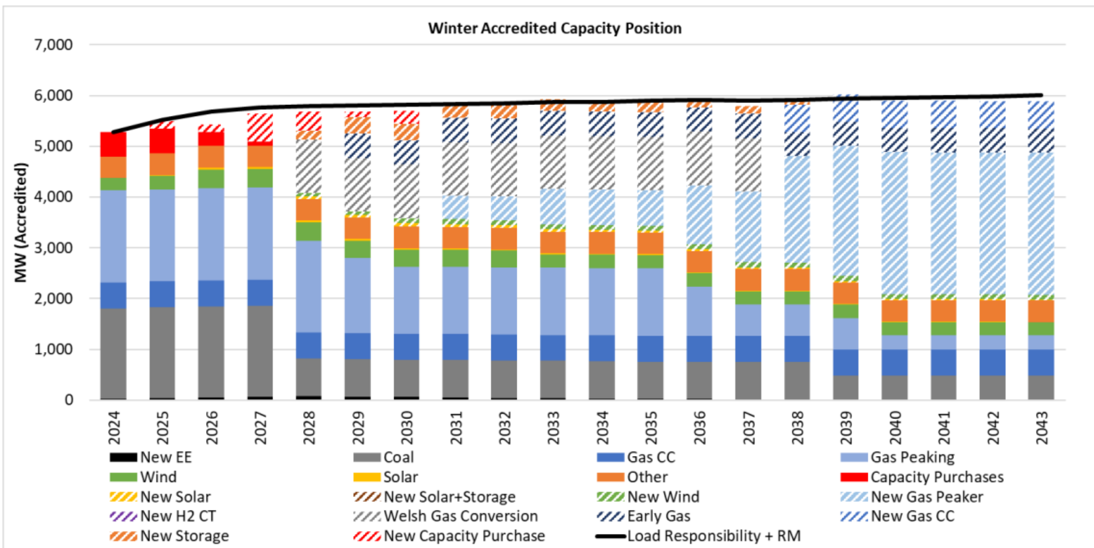
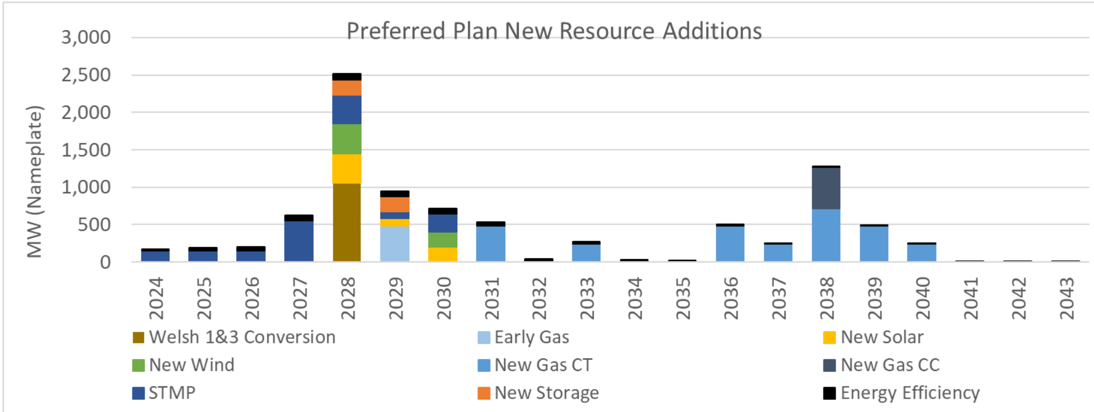


Figure 84 SWEPCO Winter Accredited Capacity Position – Preferred Plan

The Company's PP adds 700 MW of solar, 600 MW of wind, 3.36 GW of NGCT, 400 MW of storage and 480 MW of early NGCT shown in Figure 85. The plan also includes the Welsh 1 & 3 conversions in 2028 providing valuable firm capacity during the 10-year period. After the 10-year period, the model selects new gas resources. On the demand-side, the need for resources results in the procurement of energy efficiency throughout the study period with a peak contribution of around 78.8 MW in 2028.

The Company notes that the winter capacity position above indicates a slight deficit for the winter of 2026/27 based on the assumed target PRM. This position will be monitored and adjusted as additional information becomes available from SPP. Additional resources will be sought as necessary.



New Build Additions by Planning Year (Nameplate MW)											
Planning Year (ICAP)	New Solar (T1/T2)	New Wind (T1/T2)	New Gas (CT/Aero/Rice)	New Storage (4/6/8)	New Solar + Storage	New Gas CC	Pirkey CT	Welsh 1&3 Gas Cnvrsn	Optional Capacity Purchases (MW/yr.)	Summer Reserve Margin	Winter Reserve Margin
2024									150	22%	30%
2025	*72.5	**200							150	20%	27%
2026	*200	**600							150	22%	27%
2027									557	25%	30%
2028	400	400		50/100/50				1053	380	31%	30%
2029	100			50/100/50			480		100	33%	30%
2030	200	200							250	35%	30%
2031			480							37%	34%
2032										35%	32%
2033			240							37%	34%
2034										36%	33%
2035										34%	32%
2036			480							35%	33%
2037			240							31%	29%
2038			720			550				31%	31%
2039			480							31%	34%
2040			240							28%	31%
2041										27%	30%
2042										26%	30%
2043										26%	29%
Total	**973 (700 new)**	**1,400 (600 new)**	**2,880**	**400**		**550**	**480**	**1,053**			

Figure 85 Preferred Plan New Resource Additions

From a capacity expansion analysis, commonalities were realized in all portfolios modeled including the assumed economic selection of both Welsh units 1&3 in 2028. SWEPCO customers will benefit from the opportunity to repurpose these two existing units. Additionally, the early CTs were selected in each of the winter optimized portfolios.

Affordability

The Preferred Plan total revenue requirement compared to all other portfolios is shown in Figure 86. The Preferred Plan results in a 20-year NPVVRR that is the lowest compared to portfolios that meet the anticipated winter capacity planning reserve requirement discussed in Section 3.5.

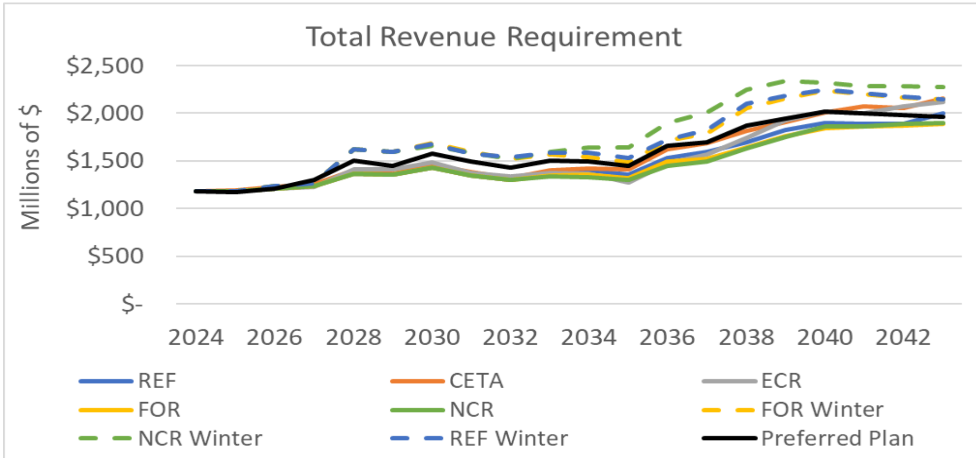


Figure 86 Portfolio 20-year NPVRR Comparison

Rate Stability

Given the uncertainty in SPP what the final expected winter PRM requirements will be, the PP includes resources that support both seasonal optimization resource selections and balances customer rate stability risks when considering the associated metrics for this objective. Table 29 shows the Preferred Plan results in nearly the lowest 20-year NPVRR when evaluated across all future potential market scenarios. Shown in Figure 87, the PP encompasses a levelized rate range that is within 1.1% of the upper range and lower than any of the lower ranges of potential costs of the winter portfolios while also realizing a potential low-end cost that is within 3% of the REF Portfolio low range.

Table 29 Preferred Plan 20-Year NPVRR Across Market Scenarios ($Million)

	Market Scenarios ($MM)					
Portfolio	**Reference**	**CETA**	**ECR**	**FOR**	**NCR**	**High/Low Difference**
Preferred Plan	$16,774	$16,770	$18,243	$16,821	$15,519	$2,724

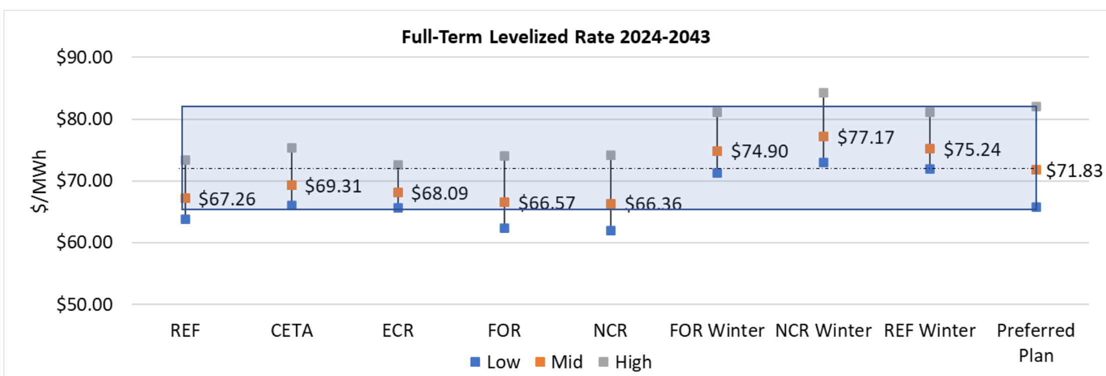


Figure 87 Preferred Plan Rate Stability

Maintaining Reliability

As shown in the Scorecard, the PP includes resources to maintain a market exposure risk to both summer and winter optimized portfolios less than 30% while also supporting the Company's energy adequacy ability through the inclusion of dispatchable resources capable of providing energy to meet the Company's summer and winter peak loads in adverse market conditions.

The PP scores well in the Maintaining Reliability metrics meeting both the summer and winter projected minimum SPP PRMs. Specifically, the plan includes a mix of resources identified in summer and winter optimizations that meets an expected SPP winter reserve margin while also maintaining a prudent reserve relative to the Company's summer peak capacity obligations.

The PP includes dispatchable resources comparable to the winter portfolios that scored well in both the summer and winter Operational Flexibility metric. The PP includes a mix of dispatchable resources capable of providing energy to meet SWEPCOs peak demand in both, 10-year and 20-year forecasts, providing a hedge to unmitigated market energy prices. The PP provides as much or more of this operational flexibility than any other portfolio analyzed.

The plan also includes a mix of diverse resources including new renewable and storage resources eligible for federal tax benefits for SWEPCOs customers while also providing low-cost energy as well as dispatchable resources capable of serving customers in a more predictable and controlled manner.

Local Impacts & Sustainability

Under the Local Impacts and Sustainability metrics, the PP includes one of the largest amounts of new resource capacity assumed to be installed within SWEPCO jurisdictions. The PP also estimates 67% reduction in CO_2 emissions by 2043 compared to the Company's 2005 baseline from energy generated to serve its customers.

8.5.1. Rate Impact Discussion

The Company evaluated the Preferred Plan for the potential rate impact assuming an average residential customer monthly load of 1,128 kWh. The Preferred Plan was compared to both the Reference and Reference-Winter Portfolio rate impacts. The Preferred Plan compares favorably to these different portfolios when considering the risks related to changing reserve requirement obligations the Company is faced with.

Figure 88 illustrates the comparable rate impact of the Preferred Plan to the Reference and Reference-Winter Portfolios. As shown, the Preferred Plan results in a higher levelized rate impact compared to the Reference Portfolio optimized only to the Company's summer SPP peak capacity obligation (blue line). Considering the Preferred Plan relative to the Reference-Winter Portfolio, however, SWEPCO customers are shown to realize approximately $5/month lower levelized rate impact. SPP has indicated its intention to establish a binding winter reserve margin obligation by the 2026/27 planning year to which, the Preferred Plan would result in lower costs for SWEPCO customers.

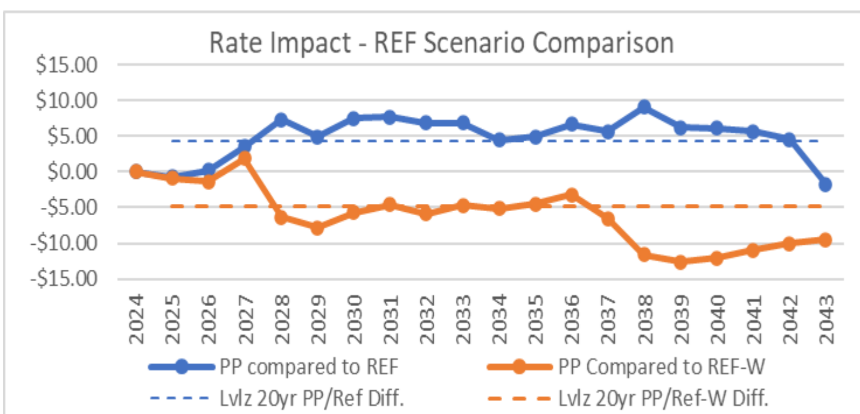


Figure 88 Preferred Plan Residential Customer Rate Impact

9. Conclusion

SWEPCO's Preferred Plan was informed by the different least-cost Portfolios modeled and includes a diverse set of dispatchable and renewable generation resources that bring a broad set of benefits to customers. Collectively, they support numerous objectives identified in the IRP Scorecard in a holistic manner including maintaining a diverse portfolio of resources that supports an expected seasonal capacity obligation construct within SPP while mitigating potential cost risks to ratepayers in the event future market conditions change.

Five-Year Action Plan (2024 to 2028)

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

- Issue an All-Source RFP in Q12024 to identify resources in support of the Company's capacity needs.
- Seek Commission approval for 2024 RFP resources to meet company obligations to reliably serve load
- Monitor and evaluate the changes to SPP Resource Adequacy requirements as more information becomes available and issue subsequent RFPs as needed to meet final requirements
- Given the timeframe to add new generation in SPP and considering the transmission interconnection queue process, SWEPCO will continue to evaluate and implement steps as necessary to ensure a sufficient pipeline of resources consistent with the Preferred Plan that are needed beyond the five-year period.
- Remain committed to closely following developments related to environmental regulations and update our analysis of compliance options and timeliness when sufficient information becomes available.

10. Appendix

Exhibit A: Load Forecast

Exhibit A-1

Southwestern Electric Power Company
Actual and Forecast Internal Energy Requirements (GWh)***
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other** Energy Requirements	Growth Rate	Internal Energy Requirements	Growth Rate
Actual										
2013	6,431	---	6,011	---	5,612	---	7,430	---	25,484	---
2014	6,311	-1.9	5,996	-0.2	5,901	5.1	7,308	-1.6	25,516	0.1
2015	6,336	0.4	6,076	1.3	5,370	-9.0	7,333	0.3	25,115	-1.6
2016	6,148	-3.0	6,064	-0.2	5,074	-5.5	7,074	-3.5	24,360	-3.0
2017	5,903	-4.0	5,824	-4.0	5,339	5.2	6,817	-3.6	23,884	-2.0
2018	6,564	11.2	5,910	1.5	5,391	1.0	6,429	-5.7	24,294	1.7
2019	6,303	-4.0	5,776	-2.3	5,338	-1.0	6,373	-0.9	23,790	-2.1
2020	5,988	-5.0	5,296	-8.3	4,891	-8.4	5,617	-11.9	21,792	-8.4
2021	6,205	3.6	5,489	3.6	4,682	-4.3	5,673	1.0	22,049	1.2
2022	6,538	5.4	5,732	4.4	5,174	10.5	5,990	5.6	23,434	6.3
Forecast										
2023*	5,988	-8.4	5,488	-4.3	5,261	1.7	5,755	-3.9	22,491	-4.0
2024	6,191	3.4	5,518	0.6	5,353	1.7	5,860	1.8	22,921	1.9
2025	6,181	-0.2	5,518	0.0	5,371	0.3	5,900	0.7	22,971	0.2
2026	6,192	0.2	5,518	0.0	5,420	0.9	5,947	0.8	23,078	0.5
2027	6,204	0.2	5,519	0.0	5,478	1.1	5,959	0.2	23,161	0.4
2028	6,210	0.1	5,511	-0.1	5,537	1.1	6,012	0.9	23,270	0.5
2029	6,228	0.3	5,517	0.1	5,604	1.2	6,027	0.3	23,376	0.5
2030	6,225	-0.1	5,506	-0.2	5,656	0.9	6,059	0.5	23,446	0.3
2031	6,238	0.2	5,496	-0.2	5,701	0.8	6,088	0.5	23,524	0.3
2032	6,256	0.3	5,489	-0.1	5,739	0.7	6,122	0.6	23,606	0.3
2033	6,266	0.1	5,485	-0.1	5,782	0.7	6,147	0.4	23,680	0.3
2034	6,275	0.1	5,476	-0.2	5,820	0.7	6,183	0.6	23,754	0.3
2035	6,298	0.4	5,476	0.0	5,859	0.7	6,203	0.3	23,835	0.3
2036	6,320	0.4	5,475	0.0	5,895	0.6	6,225	0.4	23,914	0.3
2037	6,352	0.5	5,479	0.1	5,931	0.6	6,246	0.3	24,008	0.4
2038	6,377	0.4	5,482	0.1	5,968	0.6	6,273	0.4	24,101	0.4
2039	6,400	0.4	5,485	0.0	6,006	0.6	6,306	0.5	24,196	0.4
2040	6,413	0.2	5,484	0.0	6,042	0.6	6,337	0.5	24,276	0.3
2041	6,438	0.4	5,493	0.2	6,084	0.7	6,339	0.0	24,354	0.3
2042	6,456	0.3	5,493	0.0	6,120	0.6	6,364	0.4	24,433	0.3
2043	6,478	0.3	5,494	0.0	6,158	0.6	6,387	0.4	24,517	0.3

Note: *2023 data are six months acutal and six months forecast.
**Other energy requirements include other retail sales, wholesale sales and losses.
***Historical data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

Compound Annual Growth Rate 2013-2022

Residential	Commercial	Industrial	Other** Energy Requirements	Internal Energy Requirements
0.2	-0.5	-0.9	-2.4	-0.9

Compound Annual Growth Rate 2024-43

Residential	Commercial	Industrial	Other** Energy Requirements	Internal Energy Requirements
0.2	0.0	0.7	0.5	0.4

Exhibit A-2.1

Southwestern Electric Power Company-Arkansas
Actual and Forecast Retail Sales (GWh)**
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2013	1,135	---	1,332	---	1,540	---	12	---	4,018	---
2014	1,121	-1.2	1,343	0.8	1,543	0.2	12	-0.5	4,019	0.0
2015	1,111	-0.9	1,353	0.8	1,442	-6.6	12	-0.2	3,917	-2.5
2016	1,121	0.9	1,332	-1.6	1,426	-1.1	12	0.7	3,890	-0.7
2017	1,087	-3.1	1,309	-1.7	1,367	-4.1	12	0.6	3,775	-3.0
2018	1,207	11.1	1,332	1.8	1,340	-2.0	11	-2.3	3,891	3.1
2019	1,175	-2.6	1,311	-1.6	1,257	-6.2	12	1.5	3,754	-3.5
2020	1,114	-5.2	1,202	-8.3	1,116	-11.2	11	-4.3	3,443	-8.3
2021	1,163	4.4	1,269	5.6	1,081	-3.2	10	-7.8	3,523	2.3
2022	1,216	4.6	1,314	3.5	1,141	5.6	10	-6.7	3,680	4.5
Forecast										
2023*	1,138	-6.5	1,272	-3.2	1,167	2.3	9	-8.0	3,586	-2.6
2024	1,173	3.1	1,277	0.4	1,167	-0.1	9	1.5	3,626	1.1
2025	1,166	-0.6	1,277	0.0	1,166	-0.1	9	-0.1	3,618	-0.2
2026	1,171	0.4	1,281	0.3	1,172	0.6	9	0.0	3,634	0.4
2027	1,178	0.6	1,285	0.3	1,186	1.1	9	0.1	3,658	0.7
2028	1,184	0.5	1,287	0.2	1,199	1.1	9	-0.2	3,680	0.6
2029	1,192	0.7	1,294	0.5	1,215	1.3	9	0.2	3,710	0.8
2030	1,197	0.4	1,296	0.2	1,227	0.9	9	0.0	3,729	0.5
2031	1,205	0.6	1,298	0.1	1,235	0.7	9	0.0	3,747	0.5
2032	1,211	0.5	1,300	0.1	1,241	0.5	9	-0.1	3,761	0.4
2033	1,216	0.4	1,303	0.3	1,247	0.5	9	0.0	3,775	0.4
2034	1,220	0.4	1,306	0.2	1,251	0.3	9	-0.1	3,786	0.3
2035	1,227	0.6	1,310	0.3	1,255	0.3	9	0.1	3,801	0.4
2036	1,234	0.5	1,314	0.3	1,258	0.3	9	0.0	3,815	0.4
2037	1,242	0.6	1,320	0.4	1,262	0.3	9	0.0	3,833	0.5
2038	1,248	0.5	1,326	0.4	1,266	0.3	9	0.0	3,849	0.4
2039	1,255	0.5	1,331	0.4	1,271	0.3	9	-0.1	3,865	0.4
2040	1,260	0.4	1,336	0.4	1,275	0.3	9	-0.1	3,880	0.4
2041	1,267	0.6	1,344	0.6	1,281	0.5	9	0.2	3,900	0.5
2042	1,273	0.4	1,349	0.4	1,285	0.3	9	-0.1	3,915	0.4
2043	1,278	0.5	1,354	0.4	1,290	0.4	9	0.0	3,931	0.4

Note: *2023 data are six months acutal and six months forecast.
**Historical data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

Compound Annual Growth Rate 2013-2022

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.8	-0.2	-3.3	-2.2	-1.0

Compound Annual Growth Rate 2024-2043

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.5	0.3	0.5	0.0	0.4

Exhibit A-2.2

Southwestern Electric Power Company-Louisiana
Actual and Forecast Retail Sales (GWh)**
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2013	3,041	---	2,428	---	1,020	---	40	---	6,528	---
2014	2,991	-1.6	2,406	-0.9	1,034	1.4	40	0.3	6,472	-0.9
2015	3,032	1.4	2,454	2.0	1,039	0.5	40	0.8	6,565	1.4
2016	2,919	-3.7	2,489	1.4	1,026	-1.2	40	0.6	6,475	-1.4
2017	2,793	-4.3	2,344	-5.8	1,160	13.0	41	1.0	6,337	-2.1
2018	3,081	10.3	2,376	1.4	1,179	1.7	40	-0.9	6,676	5.4
2019	2,945	-4.4	2,310	-2.8	1,213	2.9	41	1.3	6,509	-2.5
2020	2,800	-4.9	2,118	-8.3	1,116	-8.0	41	0.0	6,075	-6.7
2021	2,887	3.1	2,186	3.2	1,051	-5.9	40	-2.5	6,163	1.4
2022	3,029	4.9	2,279	4.2	1,191	13.3	38	-4.3	6,537	6.1
Forecast										
2023*	2,770	-8.6	2,170	-4.8	1,184	-0.6	37	-3.2	6,160	-5.8
2024	2,876	3.8	2,198	1.3	1,241	4.8	37	0.9	6,352	3.1
2025	2,868	-0.3	2,197	-0.1	1,257	1.3	37	-0.1	6,359	0.1
2026	2,868	0.0	2,196	0.0	1,260	0.3	37	0.0	6,361	0.0
2027	2,866	-0.1	2,195	0.0	1,268	0.6	37	0.0	6,366	0.1
2028	2,860	-0.2	2,190	-0.2	1,276	0.6	37	-0.1	6,362	0.0
2029	2,858	0.0	2,190	0.0	1,285	0.7	37	0.1	6,371	0.1
2030	2,846	-0.4	2,185	-0.2	1,291	0.4	37	0.0	6,359	-0.2
2031	2,840	-0.2	2,180	-0.2	1,294	0.3	37	0.0	6,351	-0.1
2032	2,839	0.0	2,177	-0.2	1,295	0.1	37	0.0	6,348	-0.1
2033	2,834	-0.1	2,174	-0.1	1,297	0.1	37	0.0	6,343	-0.1
2034	2,831	-0.1	2,170	-0.2	1,298	0.1	37	0.0	6,336	-0.1
2035	2,834	0.1	2,168	-0.1	1,299	0.1	37	0.0	6,339	0.0
2036	2,837	0.1	2,167	-0.1	1,300	0.1	37	0.0	6,341	0.0
2037	2,846	0.3	2,166	0.0	1,302	0.1	37	0.0	6,351	0.2
2038	2,851	0.2	2,165	-0.1	1,303	0.1	37	0.0	6,356	0.1
2039	2,855	0.1	2,164	-0.1	1,305	0.1	37	0.0	6,360	0.1
2040	2,855	0.0	2,161	-0.1	1,306	0.1	37	0.0	6,359	0.0
2041	2,858	0.1	2,162	0.0	1,309	0.2	37	0.1	6,366	0.1
2042	2,860	0.1	2,160	-0.1	1,311	0.1	37	0.0	6,368	0.0
2043	2,864	0.1	2,158	-0.1	1,312	0.1	37	0.0	6,372	0.1

Note: *2023 data are six months acutal and six months forecast.
**Historical data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

Compound Annual Growth Rate 2013-2022

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.0	-0.7	1.7	-0.4	0.0

Compound Annual Growth Rate 2024-2043

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.0	-0.1	0.3	0.0	0.0

Exhibit A-2.3

Southwestern Electric Power Company-Texas
Actual and Forecast Retail Sales (GWh)**
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2013	2,256	---	2,251	---	3,053	---	29	---	7,588	---
2014	2,198	-2.5	2,247	-0.2	3,324	8.9	29	-0.6	7,798	2.8
2015	2,193	-0.2	2,270	1.0	2,889	-13.1	29	-1.0	7,381	-5.4
2016	2,108	-3.9	2,244	-1.1	2,622	-9.2	28	-0.8	7,002	-5.1
2017	2,023	-4.0	2,172	-3.2	2,812	7.2	28	-0.7	7,035	0.5
2018	2,276	12.5	2,203	1.4	2,872	2.1	27	-3.3	7,378	4.9
2019	2,182	-4.1	2,156	-2.1	2,868	-0.2	27	-0.1	7,233	-2.0
2020	2,074	-5.0	1,977	-8.3	2,658	-7.3	27	-1.2	6,735	-6.9
2021	2,155	3.9	2,034	2.9	2,551	-4.0	27	-0.5	6,767	0.5
2022	2,293	6.4	2,140	5.2	2,842	11.4	27	0.2	7,302	7.9
Forecast										
2023*	2,080	-9.3	2,046	-4.4	2,910	2.4	26	-1.9	7,062	-3.3
2024	2,142	3.0	2,043	-0.1	2,945	1.2	26	0.3	7,157	1.3
2025	2,147	0.2	2,044	0.1	2,948	0.1	26	0.0	7,166	0.1
2026	2,153	0.3	2,041	-0.2	2,987	1.3	26	-0.1	7,208	0.6
2027	2,160	0.3	2,040	-0.1	3,025	1.3	26	0.0	7,251	0.6
2028	2,166	0.3	2,034	-0.3	3,062	1.2	26	-0.1	7,288	0.5
2029	2,178	0.5	2,033	0.0	3,103	1.4	26	0.1	7,341	0.7
2030	2,181	0.2	2,025	-0.4	3,138	1.1	26	0.0	7,371	0.4
2031	2,194	0.6	2,018	-0.4	3,172	1.1	26	0.0	7,410	0.5
2032	2,207	0.6	2,012	-0.3	3,203	1.0	26	0.0	7,448	0.5
2033	2,215	0.4	2,007	-0.2	3,239	1.1	26	0.0	7,488	0.5
2034	2,223	0.4	2,000	-0.4	3,271	1.0	26	-0.1	7,521	0.4
2035	2,236	0.6	1,997	-0.1	3,305	1.0	26	0.0	7,564	0.6
2036	2,248	0.5	1,994	-0.2	3,336	1.0	26	0.0	7,605	0.5
2037	2,264	0.7	1,993	-0.1	3,367	0.9	26	0.0	7,651	0.6
2038	2,277	0.6	1,992	-0.1	3,399	0.9	26	0.0	7,694	0.6
2039	2,290	0.5	1,990	-0.1	3,430	0.9	26	0.0	7,737	0.5
2040	2,299	0.4	1,986	-0.2	3,462	0.9	26	-0.1	7,774	0.5
2041	2,313	0.6	1,987	0.0	3,495	1.0	26	0.1	7,821	0.6
2042	2,323	0.5	1,984	-0.2	3,525	0.9	26	0.0	7,858	0.5
2043	2,336	0.5	1,981	-0.1	3,556	0.9	26	0.0	7,899	0.5

Note: *2023 data are six months acutal and six months forecast.
**Historical data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

	Residential	Commercial	Industrial	Other Retail	Retail Sales
Compound Annual Growth Rate 2013-2022					
	0.2	-0.6	-0.8	-0.9	-0.4
Compound Annual Growth Rate 2024-2043					
	0.5	-0.2	1.0	0.0	0.5

Exhibit A-3

Southwestern Electric Power Company
Winter, Summer and Annual Peak Demand (MW)
Internal Energy Requirements (GWh) and Load Factor (%)

Year	Summer Peak Demand	Preceding Winter Peak Demand	Annual Peak Demand	Internal Energy Requirements	Load Factor
Actual					
2013	5,048	4,178	5,048	25,484	57.6
2014	4,836	4,919	4,919	25,516	59.2
2015	5,149	4,708	5,149	25,115	55.7
2016	4,921	4,051	4,921	24,360	56.4
2017	4,769	4,419	4,769	23,884	57.2
2018	4,834	4,792	4,834	24,294	57.4
2019	4,727	4,148	4,727	23,790	57.4
2020	4,351	3,900	4,351	21,792	57.0
2021	4,444	4,563	4,563	22,049	55.2
2022	4,838	3,896	4,918	23,434	54.4
Forecast					
2023*	4,690	4,918	4,690	22,491	54.7
2024	4,687	4,369	4,687	22,921	55.7
2025	4,690	4,383	4,690	22,971	55.9
2026	4,711	4,403	4,711	23,078	55.9
2027	4,724	4,418	4,724	23,161	56.0
2028	4,749	4,437	4,749	23,270	55.8
2029	4,748	4,452	4,748	23,376	56.2
2030	4,761	4,462	4,761	23,446	56.2
2031	4,778	4,476	4,778	23,524	56.2
2032	4,801	4,490	4,801	23,606	56.0
2033	4,812	4,503	4,812	23,680	56.2
2034	4,810	4,513	4,810	23,754	56.4
2035	4,829	4,528	4,829	23,835	56.3
2036	4,849	4,540	4,849	23,914	56.1
2037	4,869	4,559	4,869	24,008	56.3
2038	4,889	4,575	4,889	24,101	56.3
2039	4,910	4,591	4,910	24,196	56.3
2040	4,914	4,602	4,914	24,276	56.2
2041	4,927	4,615	4,927	24,354	56.4
2042	4,946	4,628	4,946	24,433	56.4
2043	4,965	4,643	4,965	24,517	56.4

Note: *2023 data are six months acutal and six months forecast.

Compound Annual Growth Rate 2013-2022

	-0.5	-0.8	-0.3	-0.9	-0.6

Compound Annual Growth Rate 2024-2043

	0.3	0.3	0.3	0.4	0.1

Exhibit A-4.1

Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2013	1	630.1	442.5	409.2	646.6	2,128.4
2013	2	390.8	393.1	398.2	625.7	1,807.7
2013	3	472.8	443.7	451.3	526.9	1,894.7
2013	4	390.3	453.6	465.4	479.5	1,788.9
2013	5	429.8	519.0	501.3	561.6	2,011.6
2013	6	626.6	582.6	498.6	657.2	2,365.0
2013	7	695.3	548.7	467.2	757.5	2,468.6
2013	8	750.2	635.5	513.5	736.1	2,635.3
2013	9	635.5	561.1	461.9	655.7	2,314.3
2013	10	414.8	482.6	456.0	519.8	1,873.2
2013	11	357.0	478.0	525.1	565.2	1,925.3
2013	12	638.2	470.3	464.5	697.9	2,270.8
2014	1	711.6	488.7	454.8	723.5	2,378.6
2014	2	550.0	434.6	437.0	610.9	2,032.5
2014	3	485.4	470.0	485.6	622.3	2,063.3
2014	4	312.2	407.0	563.0	517.2	1,799.5
2014	5	389.6	470.6	502.9	602.7	1,965.7
2014	6	576.0	567.8	498.7	618.5	2,261.0
2014	7	640.8	556.2	477.3	722.4	2,396.7
2014	8	750.8	690.1	590.8	505.5	2,537.2
2014	9	557.6	498.4	442.6	705.1	2,203.8
2014	10	408.3	497.7	487.3	504.6	1,897.9
2014	11	387.2	470.8	505.7	564.2	1,928.0
2014	12	541.6	444.4	455.0	610.7	2,051.8
2015	1	674.7	491.3	433.6	696.3	2,295.8
2015	2	495.4	425.4	403.4	714.5	2,038.7
2015	3	536.1	448.9	408.5	533.5	1,927.1
2015	4	316.0	456.1	455.0	476.2	1,703.3
2015	5	428.9	528.0	491.2	477.0	1,925.2
2015	6	597.1	573.0	468.4	669.8	2,308.3
2015	7	778.8	621.6	483.4	785.9	2,669.6
2015	8	750.9	606.4	442.0	758.9	2,558.2
2015	9	557.1	554.0	493.8	646.4	2,251.3
2015	10	406.6	475.7	442.8	498.7	1,823.8
2015	11	344.8	469.6	448.9	447.3	1,710.7
2015	12	449.4	426.4	399.0	628.4	1,903.1

Exhibit A-4.2

Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2016	1	605.3	492.7	444.0	621.7	2,163.7
2016	2	440.3	385.4	399.7	574.9	1,800.3
2016	3	349.1	423.1	404.3	529.9	1,706.5
2016	4	378.9	483.5	443.7	364.4	1,670.5
2016	5	409.2	501.1	433.3	526.4	1,870.0
2016	6	590.9	573.4	451.6	689.8	2,305.6
2016	7	796.5	611.8	402.9	791.2	2,602.4
2016	8	714.6	605.6	433.5	699.2	2,452.9
2016	9	593.9	575.8	417.5	614.4	2,201.5
2016	10	424.7	483.0	423.7	563.9	1,895.2
2016	11	342.9	466.8	400.0	479.8	1,689.6
2016	12	502.0	462.2	419.5	618.3	2,002.1
2017	1	557.7	449.4	397.5	558.6	1,963.2
2017	2	319.4	345.0	366.3	584.0	1,614.8
2017	3	432.6	495.1	474.0	368.1	1,769.8
2017	4	357.5	431.7	416.7	509.3	1,715.1
2017	5	434.1	502.2	464.2	493.1	1,893.7
2017	6	558.7	533.3	469.9	633.0	2,194.9
2017	7	721.8	587.3	463.6	737.9	2,510.7
2017	8	649.6	545.3	437.7	703.6	2,336.2
2017	9	515.5	525.8	456.6	599.8	2,097.7
2017	10	456.1	482.4	485.4	525.5	1,949.4
2017	11	388.8	464.9	451.8	436.5	1,742.0
2017	12	511.2	461.8	455.5	668.0	2,096.5
2018	1	737.4	454.5	389.6	685.9	2,267.5
2018	2	474.2	399.5	385.4	483.9	1,743.0
2018	3	346.7	412.6	445.5	478.7	1,683.5
2018	4	340.5	418.5	444.0	412.2	1,615.2
2018	5	555.2	619.8	551.6	361.1	2,087.8
2018	6	710.0	568.1	450.8	617.9	2,346.8
2018	7	740.1	580.6	453.5	694.5	2,468.7
2018	8	702.6	592.4	475.7	655.7	2,426.4
2018	9	549.4	501.8	436.3	570.5	2,058.0
2018	10	444.7	496.0	471.2	399.2	1,811.0
2018	11	388.6	448.7	469.2	520.7	1,827.2
2018	12	574.6	417.9	418.3	548.5	1,959.3
2019	1	580.5	454.8	428.5	636.8	2,100.7
2019	2	466.0	384.8	387.2	524.2	1,762.2
2019	3	481.2	433.5	434.7	459.8	1,809.2
2019	4	316.7	405.9	439.7	449.8	1,612.2
2019	5	414.6	504.8	479.8	502.4	1,901.6
2019	6	566.2	500.6	436.5	553.9	2,057.2
2019	7	709.1	594.1	492.7	534.0	2,329.8
2019	8	716.1	591.5	483.3	693.0	2,484.0
2019	9	645.4	560.0	437.6	639.0	2,282.0
2019	10	431.8	432.9	432.6	494.9	1,792.1
2019	11	452.0	496.6	495.2	321.9	1,765.8
2019	12	523.1	416.2	389.9	563.7	1,892.9

Exhibit A-4.3

Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2020	1	534.2	432.7	410.8	496.0	1,873.6
2020	2	471.3	399.8	401.3	496.3	1,768.7
2020	3	400.6	395.3	430.3	390.7	1,616.9
2020	4	328.8	346.2	408.3	385.2	1,468.5
2020	5	427.0	393.8	374.1	443.1	1,638.0
2020	6	590.1	496.7	404.5	529.0	2,020.3
2020	7	738.4	554.0	401.1	588.7	2,282.2
2020	8	684.4	534.8	403.9	583.8	2,206.8
2020	9	527.2	462.9	380.0	461.8	1,831.9
2020	10	392.4	463.5	488.3	340.9	1,685.1
2020	11	356.1	386.9	388.2	406.0	1,537.2
2020	12	537.3	429.4	400.5	495.7	1,863.0
2021	1	664.1	427.3	319.5	501.8	1,912.7
2021	2	615.3	444.2	339.8	522.9	1,922.2
2021	3	420.4	337.2	312.0	513.5	1,583.1
2021	4	306.0	411.1	420.3	370.9	1,508.3
2021	5	412.6	460.2	436.0	351.2	1,660.0
2021	6	555.7	524.6	437.5	531.3	2,049.1
2021	7	704.5	537.9	402.6	588.6	2,233.5
2021	8	739.6	600.3	434.9	526.8	2,301.7
2021	9	554.8	478.5	365.4	541.5	1,940.2
2021	10	439.5	479.3	441.7	360.5	1,721.0
2021	11	356.9	403.3	387.2	422.5	1,570.0
2021	12	435.3	384.9	385.3	441.8	1,647.2
2022	1	612.6	480.7	402.8	506.8	2,002.9
2022	2	535.2	357.5	326.5	586.7	1,805.9
2022	3	488.2	428.2	385.4	395.6	1,697.3
2022	4	322.0	398.9	421.9	407.5	1,550.4
2022	5	519.6	544.8	476.9	422.0	1,963.2
2022	6	660.6	543.6	495.5	559.9	2,259.7
2022	7	804.8	580.9	468.4	705.7	2,559.9
2022	8	707.8	554.4	449.8	613.9	2,325.9
2022	9	506.2	495.5	448.3	510.4	1,960.4
2022	10	405.5	448.4	428.0	351.6	1,633.5
2022	11	386.4	443.3	456.0	423.3	1,709.0
2022	12	589.3	455.6	414.6	506.1	1,965.6
2023	1	542.5	391.2	365.7	536.2	1,835.6
2023	2	447.3	366.7	379.0	469.5	1,662.5
2023	3	361.3	409.5	458.5	415.8	1,645.1
2023	4	332.5	375.9	453.2	398.5	1,560.1
2023	5	464.7	525.6	481.2	342.6	1,814.1
2023	6	573.4	511.6	425.7	531.0	2,041.7

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

Exhibit A-5.1

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2023	7	703.6	538.9	443.1	618.7	2,304.3
2023	8	731.3	583.3	478.8	628.5	2,421.9
2023	9	502.9	462.5	418.6	516.3	1,900.4
2023	10	410.4	462.9	461.5	336.4	1,671.1
2023	11	353.6	416.3	453.4	429.8	1,653.1
2023	12	564.1	443.2	442.5	532.0	1,981.8
2024	1	646.2	439.3	421.5	567.1	2,074.1
2024	2	497.7	374.9	397.5	532.8	1,802.9
2024	3	409.6	381.7	425.7	452.0	1,669.0
2024	4	314.4	390.4	448.6	413.5	1,566.9
2024	5	454.4	500.5	498.7	362.1	1,815.7
2024	6	590.9	515.6	465.5	490.0	2,062.0
2024	7	700.8	540.5	441.7	621.8	2,304.8
2024	8	723.4	580.0	475.4	630.4	2,409.2
2024	9	502.8	459.2	415.5	518.5	1,895.9
2024	10	417.1	466.2	461.9	329.1	1,674.2
2024	11	366.4	424.7	457.6	407.0	1,655.7
2024	12	567.1	445.1	443.2	535.4	1,990.8
2025	1	650.2	442.8	420.9	573.5	2,087.3
2025	2	473.0	356.6	381.5	542.2	1,753.4
2025	3	415.3	385.4	422.2	455.5	1,678.3
2025	4	320.0	394.3	445.4	417.0	1,576.8
2025	5	461.4	508.2	497.8	353.2	1,820.6
2025	6	579.8	506.5	454.5	533.9	2,074.7
2025	7	695.9	540.6	451.0	625.2	2,312.7
2025	8	718.0	578.5	483.0	633.3	2,412.8
2025	9	502.4	458.9	423.4	521.9	1,906.7
2025	10	423.3	471.1	472.2	314.7	1,681.2
2025	11	372.9	429.9	468.2	391.3	1,662.2
2025	12	568.9	445.6	450.9	538.9	2,004.3
2026	1	633.3	427.1	416.3	616.8	2,093.5
2026	2	479.4	359.8	387.7	535.0	1,761.9
2026	3	418.3	385.4	426.3	458.8	1,688.7
2026	4	322.6	393.4	448.5	420.2	1,584.6
2026	5	467.3	513.3	505.2	338.9	1,824.7
2026	6	588.6	515.1	463.8	520.4	2,087.9
2026	7	697.0	541.8	455.3	628.4	2,322.4
2026	8	718.9	580.2	487.7	636.6	2,423.4
2026	9	503.2	459.8	427.8	525.0	1,915.9
2026	10	424.0	471.8	477.1	312.0	1,684.9
2026	11	369.0	424.6	469.1	413.2	1,675.8
2026	12	570.7	445.7	455.4	542.1	2,014.0

Exhibit A-5.2

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2027	1	648.1	437.3	426.6	585.9	2,097.9
2027	2	480.1	359.2	391.4	537.9	1,768.7
2027	3	422.7	389.0	432.9	462.7	1,707.1
2027	4	320.4	393.5	453.6	423.0	1,590.7
2027	5	457.7	502.5	502.5	369.3	1,831.9
2027	6	586.4	512.3	466.9	528.8	2,094.3
2027	7	695.1	540.1	459.5	631.0	2,325.7
2027	8	720.1	581.1	493.5	639.8	2,434.5
2027	9	502.8	458.9	432.6	527.9	1,922.2
2027	10	426.0	472.7	482.7	305.5	1,686.9
2027	11	372.4	427.0	475.6	401.9	1,676.9
2027	12	572.7	445.8	460.5	545.3	2,024.2
2028	1	645.3	433.3	429.2	597.4	2,105.2
2028	2	484.5	361.3	397.5	591.7	1,834.9
2028	3	421.0	386.5	436.3	465.1	1,708.9
2028	4	318.0	389.6	455.9	425.2	1,588.7
2028	5	464.9	509.1	512.1	358.8	1,844.9
2028	6	586.6	511.3	471.7	529.1	2,098.6
2028	7	692.8	537.2	463.4	633.4	2,326.8
2028	8	720.8	580.9	499.0	642.8	2,443.5
2028	9	499.8	455.4	436.4	530.2	1,921.8
2028	10	434.5	479.0	491.5	291.0	1,696.0
2028	11	374.1	427.8	481.4	400.2	1,683.4
2028	12	567.7	440.1	462.3	547.1	2,017.2
2029	1	649.8	436.2	436.5	602.9	2,125.4
2029	2	482.3	358.9	401.1	544.0	1,786.2
2029	3	421.1	385.6	440.8	468.0	1,715.5
2029	4	321.4	391.6	462.2	428.7	1,603.9
2029	5	467.8	511.7	519.1	359.3	1,857.8
2029	6	589.2	512.9	478.1	527.4	2,107.7
2029	7	698.0	540.1	470.3	637.2	2,345.7
2029	8	724.9	582.8	505.5	646.4	2,459.6
2029	9	500.7	455.1	441.7	533.2	1,930.7
2029	10	428.2	473.2	493.8	318.9	1,714.1
2029	11	373.7	426.9	485.8	410.8	1,697.2
2029	12	571.1	442.1	468.6	550.5	2,032.4
2030	1	649.1	435.0	440.8	606.6	2,131.5
2030	2	481.5	358.0	405.3	546.7	1,791.4
2030	3	418.9	383.8	444.5	470.4	1,717.5
2030	4	321.8	392.1	467.3	431.7	1,612.9
2030	5	466.9	510.6	523.2	361.9	1,862.7
2030	6	588.5	511.4	482.2	527.5	2,109.6
2030	7	699.9	540.3	475.5	640.2	2,355.9
2030	8	723.3	580.1	509.3	648.7	2,461.4
2030	9	502.3	455.2	446.7	536.1	1,940.4
2030	10	426.0	470.7	497.2	326.5	1,720.3
2030	11	374.0	426.9	490.3	409.5	1,700.8
2030	12	572.2	442.4	473.5	553.4	2,041.4

Exhibit A-5.3

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2031	1	646.6	431.7	443.3	616.6	2,138.2
2031	2	482.3	357.1	409.0	549.3	1,797.6
2031	3	419.0	382.4	447.8	472.9	1,722.2
2031	4	322.6	391.2	470.9	434.2	1,618.9
2031	5	470.1	512.4	528.7	353.6	1,864.7
2031	6	589.7	510.1	486.0	534.5	2,120.3
2031	7	702.1	539.2	479.5	642.9	2,363.6
2031	8	723.5	577.4	512.5	651.0	2,464.5
2031	9	505.6	455.4	451.1	539.0	1,951.2
2031	10	426.9	469.9	500.8	328.7	1,726.3
2031	11	375.1	426.6	493.9	409.3	1,704.8
2031	12	574.9	442.9	477.7	556.2	2,051.6
2032	1	647.5	429.8	445.9	611.6	2,134.7
2032	2	488.8	360.6	414.5	595.3	1,859.1
2032	3	423.2	385.1	453.1	476.1	1,737.5
2032	4	320.6	389.6	473.7	436.4	1,620.3
2032	5	466.0	506.5	528.2	362.3	1,863.0
2032	6	591.7	509.6	489.4	536.5	2,127.3
2032	7	700.7	535.3	481.0	644.8	2,361.8
2032	8	725.5	576.4	515.7	653.6	2,471.2
2032	9	505.8	452.8	453.4	541.2	1,953.3
2032	10	435.4	475.4	507.2	299.5	1,717.5
2032	11	375.9	426.1	496.9	406.0	1,704.9
2032	12	575.2	441.5	480.2	558.5	2,055.4
2033	1	648.4	430.0	449.5	620.2	2,148.1
2033	2	483.9	356.4	415.3	554.3	1,810.0
2033	3	425.2	385.9	456.9	478.9	1,746.9
2033	4	321.5	389.3	476.8	438.9	1,626.5
2033	5	469.4	509.2	533.6	365.6	1,877.8
2033	6	592.5	509.2	493.0	543.8	2,138.5
2033	7	702.5	535.4	485.0	647.5	2,370.4
2033	8	731.0	579.3	521.3	656.9	2,488.5
2033	9	508.2	453.5	457.8	544.0	1,963.6
2033	10	429.3	469.2	507.9	322.0	1,728.3
2033	11	376.8	425.9	500.6	414.0	1,717.3
2033	12	576.9	441.7	484.3	561.2	2,064.0
2034	1	648.3	428.1	452.3	630.4	2,159.1
2034	2	484.9	355.9	418.6	556.7	1,816.1
2034	3	425.3	384.8	459.7	481.1	1,750.9
2034	4	321.0	387.3	479.0	441.0	1,628.3
2034	5	473.2	511.8	538.9	364.1	1,888.0
2034	6	593.9	508.7	496.4	544.5	2,143.5
2034	7	704.2	534.9	488.4	649.9	2,377.4
2034	8	733.1	579.3	525.0	659.4	2,496.7
2034	9	507.6	451.4	460.3	546.0	1,965.4
2034	10	430.5	469.1	511.2	329.5	1,740.3
2034	11	377.7	425.9	503.8	417.4	1,724.8
2034	12	575.2	439.1	486.1	563.0	2,063.4

Exhibit A-5.4

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2035	1	652.3	429.7	456.5	628.2	2,166.7
2035	2	486.4	355.6	421.5	559.1	1,822.5
2035	3	423.8	382.1	461.2	482.9	1,750.0
2035	4	323.8	388.0	482.5	443.5	1,637.9
2035	5	476.4	513.5	543.2	361.7	1,894.8
2035	6	595.9	508.7	499.7	542.4	2,146.7
2035	7	708.3	536.2	492.4	652.6	2,389.5
2035	8	735.3	579.2	528.3	661.8	2,504.6
2035	9	507.6	449.7	462.7	548.0	1,968.0
2035	10	431.3	468.4	514.2	337.6	1,751.4
2035	11	379.3	426.0	507.0	419.6	1,731.9
2035	12	577.1	438.9	489.3	565.3	2,070.5
2036	1	654.0	429.2	459.5	624.1	2,166.8
2036	2	491.8	358.2	426.1	608.4	1,884.5
2036	3	422.6	380.0	463.1	484.7	1,750.3
2036	4	324.8	387.7	485.4	445.7	1,643.7
2036	5	477.9	513.3	546.0	354.8	1,891.9
2036	6	597.9	508.5	502.6	540.1	2,149.1
2036	7	710.0	535.7	495.1	654.8	2,395.6
2036	8	731.1	574.1	528.7	663.0	2,496.9
2036	9	510.7	450.4	466.1	550.5	1,977.6
2036	10	438.7	473.2	519.7	320.5	1,752.0
2036	11	381.1	426.3	510.0	410.4	1,727.8
2036	12	579.0	438.9	492.2	567.5	2,077.7
2037	1	655.8	428.3	461.9	631.9	2,177.9
2037	2	490.2	355.3	427.1	563.6	1,836.1
2037	3	426.1	380.8	466.2	487.1	1,760.2
2037	4	328.7	389.1	488.9	448.3	1,655.0
2037	5	481.5	514.9	549.7	353.9	1,900.0
2037	6	600.5	508.6	505.5	552.8	2,167.4
2037	7	715.7	538.2	499.3	657.6	2,410.7
2037	8	737.2	577.1	533.1	665.9	2,513.3
2037	9	515.3	452.5	470.0	553.2	1,991.1
2037	10	433.5	467.3	519.5	338.8	1,759.1
2037	11	383.2	426.4	513.0	422.6	1,745.2
2037	12	584.1	441.1	496.7	570.3	2,092.3
2038	1	655.4	426.0	463.5	637.1	2,182.0
2038	2	491.9	355.3	429.9	565.7	1,842.9
2038	3	432.3	384.6	471.5	490.2	1,778.5
2038	4	329.4	389.1	492.1	450.4	1,660.9
2038	5	480.7	512.2	550.8	364.2	1,908.0
2038	6	603.0	509.1	508.7	555.0	2,175.8
2038	7	717.0	537.7	501.8	659.7	2,416.2
2038	8	741.9	579.5	537.4	668.6	2,527.4
2038	9	517.4	452.8	473.2	555.4	1,998.8
2038	10	434.9	467.2	522.6	336.4	1,761.1
2038	11	385.2	426.8	516.3	418.1	1,746.4
2038	12	587.4	442.2	500.5	572.7	2,102.8

Exhibit A-5.4 (continued)

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2039	1	655.7	424.5	465.7	648.0	2,193.8
2039	2	493.7	355.3	432.9	567.9	1,849.9
2039	3	433.3	384.1	474.2	492.2	1,783.8
2039	4	329.7	387.6	494.1	452.2	1,663.6
2039	5	485.4	515.5	555.9	363.0	1,919.9
2039	6	605.6	509.7	512.1	556.9	2,184.3
2039	7	718.3	537.2	504.5	661.7	2,421.7
2039	8	746.7	582.1	541.7	671.3	2,541.7
2039	9	519.4	453.1	476.3	557.6	2,006.4
2039	10	436.3	467.1	525.7	339.7	1,768.8
2039	11	387.2	427.3	519.6	420.7	1,754.9
2039	12	588.1	441.1	502.9	574.6	2,106.7
2040	1	657.8	425.3	469.4	646.1	2,198.5
2040	2	497.3	357.4	437.1	624.4	1,916.2
2040	3	428.9	379.8	474.7	493.2	1,776.5
2040	4	330.1	386.4	496.1	453.2	1,665.8
2040	5	491.0	520.1	562.1	353.7	1,926.8
2040	6	607.7	510.3	515.5	548.1	2,181.6
2040	7	719.9	537.1	507.6	663.7	2,428.3
2040	8	746.6	580.7	544.3	673.0	2,544.6
2040	9	515.4	448.4	477.1	558.5	1,999.4
2040	10	445.3	473.7	532.3	329.3	1,780.6
2040	11	388.9	427.8	523.0	418.1	1,757.9
2040	12	584.6	436.7	503.3	575.6	2,100.1
2041	1	663.2	428.9	474.9	645.5	2,212.4
2041	2	495.9	355.6	439.1	571.9	1,862.5
2041	3	430.4	380.1	477.8	495.2	1,783.4
2041	4	333.9	388.9	500.6	456.4	1,679.8
2041	5	492.1	520.1	564.9	360.3	1,937.4
2041	6	609.4	510.6	518.7	551.0	2,189.7
2041	7	726.0	540.8	512.6	666.5	2,446.0
2041	8	749.2	581.7	547.8	675.1	2,553.8
2041	9	520.3	451.6	481.8	561.2	2,014.9
2041	10	437.8	466.5	531.6	355.9	1,791.7
2041	11	390.3	428.2	526.2	421.6	1,766.2
2041	12	589.6	439.9	508.4	578.2	2,116.1
2042	1	660.6	425.3	475.7	657.1	2,218.8
2042	2	497.2	355.6	441.9	573.8	1,868.5
2042	3	430.9	379.5	480.3	496.9	1,787.6
2042	4	335.5	389.0	503.6	457.7	1,685.8
2042	5	495.0	521.6	568.9	354.1	1,939.6
2042	6	611.2	510.6	521.7	557.5	2,201.0
2042	7	728.5	541.3	515.9	668.5	2,454.2
2042	8	749.5	580.6	550.4	676.8	2,557.3
2042	9	523.9	453.2	485.6	563.4	2,026.0
2042	10	438.9	466.3	534.6	357.9	1,797.7
2042	11	392.0	428.6	529.4	420.5	1,770.4
2042	12	592.6	441.0	512.3	580.3	2,126.3
2043	1	660.7	423.8	477.8	659.7	2,222.1
2043	2	498.7	355.7	444.9	575.6	1,874.9
2043	3	433.1	380.1	483.7	498.8	1,795.7
2043	4	336.6	388.7	506.4	460.1	1,691.7
2043	5	497.3	522.4	572.3	349.9	1,941.9
2043	6	613.3	510.7	524.8	564.6	2,213.3
2043	7	731.1	541.8	519.2	670.4	2,462.4
2043	8	752.4	581.4	554.0	678.8	2,566.5
2043	9	526.1	453.6	489.0	565.2	2,033.9
2043	10	440.3	466.1	537.7	355.3	1,799.4
2043	11	393.7	428.7	532.6	427.0	1,782.0
2043	12	594.7	441.1	515.5	582.2	2,133.4

Exhibit A-6

Southwestern Electric Power Company
Actual and Weather Normal Energy Sales (GWh)
And Peak Demand (MW) vs. 2019 IRP Forecast

	2019 IRP Forecast				Actual				Difference				% Difference			
	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022
Residential	6,126	6,243	6,231	6,247	6,303	5,988	6,205	6,538	-177	255	26	-291	-2.8%	4.3%	0.4%	-4.5%
Commercial	5,751	5,855	5,845	5,843	5,776	5,296	5,489	5,732	-25	559	356	111	-0.4%	10.6%	6.5%	1.9%
Industrial	5,356	5,473	5,517	5,560	5,338	4,891	4,682	5,174	18	582	835	385	0.3%	11.9%	17.8%	7.4%
Other Retail	79	80	80	80	80	79	77	75	-1	1	3	5	-0.9%	0.8%	3.4%	6.7%
Wholesale	5,171	4,610	4,648	4,708	5,255	4,433	4,523	4,824	-84	177	126	-116	-1.6%	4.0%	2.8%	-2.4%
Total Sales	22,483	22,261	22,321	22,437	22,751	20,687	20,975	22,343	-268	1,574	1,346	94	-1.2%	7.6%	6.4%	0.4%

	2019 IRP Forecast				Normal				Difference				% Difference			
	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022
Residential	6,126	6,243	6,231	6,247	6,263	6,310	6,176	6,185	-137	-67	55	62	-2.2%	-1.1%	0.9%	1.0%
Commercial	5,751	5,855	5,845	5,843	5,756	5,394	5,445	5,576	-5	461	399	267	-0.1%	8.5%	7.3%	4.8%
Industrial	5,356	5,473	5,517	5,560	5,338	4,891	4,682	5,174	18	582	835	385	0.3%	11.9%	17.8%	7.4%
Other Retail	79	80	80	80	80	79	77	75	-1	1	3	5	-0.9%	0.8%	3.4%	6.7%
Wholesale	5,171	4,610	4,648	4,708	5,248	4,473	4,522	4,800	-77	137	127	-92	-1.5%	3.1%	2.8%	-1.9%
Total Sales	22,483	22,261	22,321	22,437	22,685	21,148	20,902	21,809	-201	1,113	1,419	627	-0.9%	5.3%	6.8%	2.9%

	2019 IRP Forecast				Actual				Difference				% Difference			
	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022
Winter Peak	4,148	4,170	4,200	4,222	4,148	3,900	4,563	3,896	0	271	-363	326	0.0%	6.9%	-8.0%	8.4%
Summer Peak	4,784	4,673	4,696	4,720	4,727	4,351	4,444	4,838	57	322	252	-118	1.2%	7.4%	5.7%	-2.4%

	2019 IRP Forecast				Normal				Difference				% Difference			
	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022	2019	2020	2021	2022
Winter Peak	4,148	4,170	4,200	4,222	4,322	4,272	4,159	4,197	-174	-101	41	24	-4.0%	-2.4%	1.0%	0.6%
Summer Peak	4,784	4,673	4,696	4,720	4,869	4,640	4,595	4,607	-85	34	101	114	-1.7%	0.7%	2.2%	2.5%

Exhibit A-7

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in 2019 IRP Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	SWEPCO DSM/EE			SWEPCO - Arkansas DSM/EE			SWEPCO - Louisana DSM/EE			SWEPCO - Texas DSM/EE		
Year	**Energy**	**Summer* Demand**	**Winter* Demand**	**Energy**	**Summer* Demand**	**Winter* Demand**	**Energy**	**Summer* Demand**	**Winter* Demand**	**Energy**	**Summer* Demand**	**Winter* Demand**
2019	22.2	3.9	4.4	14.5	2.5	2.6	7.6	1.3	1.7	0.1	0.0	0.0
2020	37.5	6.4	7.1	27.2	4.7	4.9	9.6	1.6	2.1	0.7	0.0	0.1
2021	46.8	7.8	8.5	38.3	6.7	6.9	6.6	1.0	1.4	1.9	0.1	0.2
2022	53.0	8.8	9.4	46.6	8.3	8.4	3.5	0.3	0.6	2.9	0.1	0.3
2023	50.6	7.2	8.4	44.4	6.9	7.7	2.2	0.1	0.3	3.9	0.2	0.5
2024	43.2	4.3	6.1	35.8	3.9	5.3	2.4	0.1	0.3	5.0	0.2	0.6
2025	35.5	2.4	4.5	28.3	2.1	3.7	2.3	0.1	0.3	4.8	0.2	0.6
2026	20.2	1.0	2.4	15.3	0.7	1.8	1.6	0.1	0.2	3.4	0.2	0.4
2027	9.4	0.5	1.1	6.5	0.3	0.8	1.0	0.0	0.1	2.0	0.1	0.2
2028	1.1	0.1	0.1	0.0	0.0	0.0	0.4	0.0	0.0	0.7	0.0	0.1
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	4.6	1.5	1.2	1.9	0.6	0.6	1.1	0.4	0.2	1.6	0.5	0.4
2031	11.2	3.7	2.8	4.8	1.5	1.5	2.6	1.0	0.5	3.8	1.3	0.9
2032	12.1	4.0	3.0	4.9	1.5	1.5	2.9	1.1	0.5	4.3	1.4	1.0
2033	9.5	3.2	2.3	3.3	1.0	1.0	2.5	0.9	0.5	3.7	1.2	0.8
2034	7.1	2.4	1.7	1.9	0.6	0.6	2.1	0.8	0.4	3.1	1.1	0.7
2035	4.9	1.7	1.1	0.6	0.2	0.2	1.7	0.6	0.3	2.6	0.9	0.6
2036	3.3	1.2	0.7	0.0	0.0	0.0	1.3	0.5	0.3	2.0	0.7	0.5
2037	2.4	0.8	0.5	0.0	0.0	0.0	0.9	0.3	0.2	1.4	0.5	0.3
2038	1.4	0.5	0.3	0.0	0.0	0.0	0.5	0.2	0.1	0.9	0.3	0.2
2039	0.6	0.2	0.1	0.0	0.0	0.0	0.2	0.1	0.0	0.4	0.1	0.1

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

Exhibit A-8

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Residential Customer and Energy Usage Models

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Arkansas Housing Stock	SWEPCO Louisiana Population	SWEPCO Louisiana Real Personal Income	SWEPCO Louisiana Housing Stock	SWEPCO Texas Population	SWEPCO Texas Real Personal Income
1995	566.0	15,338.1	238.5	572.4	15,263.4	245.9	784.8	20,349.1
1996	582.1	16,066.6	245.8	573.6	15,472.1	247.2	796.2	21,264.9
1997	593.8	16,807.2	252.3	574.1	15,797.7	248.5	804.8	22,484.2
1998	602.5	17,932.1	257.7	573.0	16,262.9	249.3	813.4	23,521.2
1999	613.6	18,751.1	262.8	575.5	16,591.8	250.2	819.5	24,072.8
2000	627.3	19,560.6	268.4	577.2	17,098.1	251.6	825.4	25,190.3
2001	636.3	20,081.4	273.6	576.6	18,221.0	253.9	830.1	26,148.8
2002	647.0	20,463.3	279.3	576.7	18,446.5	256.2	837.4	26,394.2
2003	659.7	21,339.3	285.4	575.9	18,685.5	258.5	845.2	26,950.2
2004	672.9	23,135.9	292.5	579.9	19,045.1	262.6	853.1	27,500.9
2005	690.0	24,316.6	300.9	583.4	20,197.6	261.6	861.1	28,808.7
2006	708.5	25,729.7	311.5	589.7	20,831.3	249.0	873.9	30,204.0
2007	722.3	27,045.2	319.0	589.7	20,887.1	258.4	882.2	30,968.6
2008	733.4	28,050.4	324.0	590.3	23,110.2	263.8	890.2	34,350.4
2009	743.7	26,610.8	327.5	596.1	22,262.4	266.9	900.5	32,539.5
2010	755.6	27,551.6	330.8	603.4	23,557.8	268.7	907.8	34,373.0
2011	767.2	29,996.4	333.0	606.9	23,678.8	270.7	912.4	36,460.3
2012	776.3	33,249.3	335.0	611.8	23,794.0	272.9	915.6	36,619.4
2013	784.3	32,741.8	337.5	608.3	23,712.4	275.2	916.9	36,562.9
2014	792.2	36,047.1	340.3	605.8	24,569.1	277.5	921.0	37,657.7
2015	803.3	38,130.4	343.7	603.5	24,102.1	279.9	924.9	36,479.6
2016	814.3	39,574.2	347.8	600.9	23,233.9	282.2	929.4	35,350.7
2017	826.4	40,162.7	352.8	596.6	23,081.1	284.9	933.7	36,816.1
2018	834.9	41,844.2	357.9	591.0	23,675.6	287.1	939.6	37,844.3
2019	844.2	41,929.5	363.4	586.6	23,860.3	289.1	945.0	38,598.2
2020	854.1	43,447.0	369.5	584.9	25,254.7	291.1	948.8	39,494.9
2021	862.2	44,893.9	376.2	584.0	25,669.5	293.1	951.9	40,786.8
2022	871.4	43,427.9	383.1	583.6	23,635.3	295.2	957.0	39,422.4
2023	880.6	44,361.8	390.3	583.2	24,144.2	297.2	962.7	40,952.6
2024	890.0	45,376.8	396.9	583.0	24,482.1	299.6	967.3	41,951.5
2025	899.0	46,569.1	403.7	582.5	24,717.4	302.1	971.4	42,797.7
2026	908.0	48,053.7	410.4	581.6	25,059.0	304.7	975.1	43,913.2
2027	916.8	49,424.5	417.1	580.5	25,359.0	307.4	978.9	44,999.5
2028	925.4	50,655.2	423.8	579.0	25,632.0	310.0	983.0	46,026.1
2029	933.9	51,854.7	430.2	577.3	25,882.9	312.6	987.3	47,035.9
2030	942.3	52,915.4	436.4	575.6	26,086.2	315.2	991.7	47,992.7
2031	950.8	53,881.8	442.4	573.8	26,260.7	317.6	996.2	49,000.0
2032	959.2	54,825.9	448.1	571.9	26,413.2	320.0	1,000.6	50,032.4
2033	967.5	55,899.2	453.4	570.0	26,553.0	322.3	1,004.8	50,962.5
2034	975.8	56,961.0	458.5	568.0	26,682.1	324.5	1,008.7	51,887.4
2035	984.0	58,004.7	463.1	566.1	26,791.6	326.6	1,012.5	52,781.5
2036	992.1	59,047.5	467.6	564.2	26,885.0	328.5	1,015.9	53,657.4
2037	1,000.2	60,069.2	471.8	562.3	26,965.6	330.4	1,019.2	54,517.3
2038	1,008.1	61,071.2	475.7	560.3	27,026.9	332.2	1,022.3	55,344.4
2039	1,015.9	62,042.1	479.4	558.3	27,067.5	333.9	1,025.2	56,152.0
2040	1,023.5	63,003.8	482.9	556.3	27,103.7	335.5	1,028.0	56,957.0
2041	1,030.9	64,014.8	486.2	554.3	27,158.0	337.0	1,030.6	57,800.0
2042	1,038.1	65,062.6	489.2	552.2	27,216.8	338.5	1,033.0	58,656.4
2043	1,045.0	66,128.7	492.2	550.1	27,274.6	339.9	1,035.3	59,512.0
Units	**Thousands**	**Millions (2012 $)**	**Thousands**	**Thousands**	**Millions (2012 $)**	**Thousands**	**Thousands**	**Millions (2012 $)**

Exhibit A-9

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Commercial Energy Sales Models

Year	SWEPCO Arkansas Commercial Employment	SWEPCO Louisiana Commercial Gross Regional Product	SWEPCO Louisiana Commercial Employment	SWEPCO Texas Commercial Employment
1995	142.2	13,589.0	115.7	160.2
1996	146.8	14,305.7	118.2	164.8
1997	150.9	14,696.5	120.9	172.5
1998	155.8	14,739.0	124.8	176.0
1999	162.0	15,159.1	128.0	178.4
2000	166.4	15,587.8	130.8	181.3
2001	173.4	15,334.6	130.7	184.4
2002	179.3	15,518.6	129.7	186.7
2003	182.4	15,542.7	130.2	189.6
2004	187.2	16,268.5	134.3	196.8
2005	194.7	17,345.1	140.9	200.4
2006	201.0	18,410.2	143.9	204.6
2007	205.7	17,274.8	144.9	211.0
2008	206.5	18,306.8	145.5	215.0
2009	200.2	18,573.2	141.3	212.1
2010	202.1	19,211.9	141.0	213.4
2011	207.8	19,451.8	144.0	216.8
2012	213.7	19,337.0	144.9	222.3
2013	217.9	18,984.8	145.3	227.1
2014	226.2	18,965.6	147.9	228.1
2015	237.6	18,817.6	148.8	231.4
2016	247.2	18,792.3	149.0	231.2
2017	251.7	18,657.7	147.4	232.7
2018	255.8	18,866.7	148.7	235.1
2019	259.9	18,610.6	148.1	237.6
2020	252.9	18,207.0	137.7	228.9
2021	263.3	18,660.5	140.4	236.9
2022	276.0	18,996.6	145.5	247.5
2023	281.6	19,140.8	149.2	250.3
2024	284.7	19,394.8	150.9	252.4
2025	288.4	19,767.5	152.1	254.9
2026	290.8	20,112.4	151.9	256.5
2027	293.1	20,412.4	151.6	258.3
2028	295.3	20,702.9	151.2	260.4
2029	297.6	20,964.4	150.9	262.6
2030	299.7	21,183.4	150.5	264.8
2031	301.6	21,392.8	150.0	266.8
2032	303.2	21,631.0	149.5	268.6
2033	305.0	21,897.9	149.1	270.6
2034	306.6	22,176.3	148.7	272.4
2035	308.2	22,458.4	148.3	274.2
2036	309.6	22,749.4	147.9	275.8
2037	311.0	23,035.0	147.5	277.3
2038	312.3	23,332.1	147.1	278.8
2039	313.7	23,634.6	146.7	280.3
2040	315.1	23,940.6	146.4	281.9
2041	316.7	24,252.8	146.2	283.6
2042	318.3	24,575.4	146.0	285.4
2043	319.7	24,912.0	145.8	287.2
Units	**Thousands**	**Millions (2012 $)**	**Thousands**	**Thousands**

Exhibit A-10

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Manufacturing Energy Sales Models

Year	SWEPCO Arkansas Gross Regional Product - Manufacturing	SWEPCO Louisana Gross Regional Product - Manufacturing	SWEPCO Texas Manufacturing Employment	FRB Industrial Producion Index - Manufacturing
1995	5,112.2	3,775.3	28.0	70.0
1996	4,916.4	3,315.3	27.2	73.7
1997	4,942.0	3,645.9	25.5	79.9
1998	4,880.2	3,729.8	25.2	85.2
1999	5,478.0	4,077.2	25.1	89.6
2000	5,518.5	3,170.8	25.0	93.5
2001	5,497.2	2,805.5	23.3	90.2
2002	5,944.0	3,301.2	21.2	90.8
2003	6,428.2	4,988.6	21.0	92.2
2004	6,950.3	5,913.0	21.3	95.2
2005	7,033.0	7,267.7	21.6	99.3
2006	7,113.5	6,140.4	21.3	102.1
2007	5,991.9	5,029.5	21.1	105.4
2008	5,328.0	4,507.1	18.6	100.5
2009	4,833.1	4,107.1	16.6	86.8
2010	5,305.9	4,970.3	16.6	92.5
2011	5,076.6	4,329.8	16.6	95.5
2012	4,599.7	4,111.9	16.3	98.2
2013	4,953.1	3,674.6	15.9	99.3
2014	5,125.8	3,996.2	16.2	100.5
2015	4,991.5	3,826.9	15.9	100.1
2016	4,982.5	3,637.1	15.3	99.3
2017	5,058.9	3,861.3	15.2	100.0
2018	5,276.2	3,950.6	15.6	101.5
2019	5,545.4	3,891.0	16.0	99.5
2020	5,560.7	3,586.4	14.9	93.2
2021	5,767.4	3,652.9	14.4	99.2
2022	5,933.3	3,812.0	14.8	103.6
2023	6,082.4	3,912.3	14.9	105.7
2024	6,238.0	3,990.9	14.9	107.7
2025	6,375.0	4,021.8	14.9	109.3
2026	6,487.2	4,008.8	14.7	110.5
2027	6,588.3	3,988.5	14.5	111.9
2028	6,696.3	3,987.9	14.3	113.5
2029	6,810.1	4,005.7	14.2	115.2
2030	6,925.2	4,037.0	14.0	117.1
2031	7,052.9	4,078.8	13.9	119.1
2032	7,188.2	4,125.8	13.7	121.3
2033	7,328.9	4,179.9	13.6	123.5
2034	7,470.9	4,239.4	13.5	125.8
2035	7,615.9	4,303.7	13.3	128.1
2036	7,761.5	4,370.6	13.2	130.3
2037	7,904.6	4,433.8	13.1	132.5
2038	8,046.7	4,499.0	12.9	134.7
2039	8,191.5	4,566.2	12.8	136.9
2040	8,334.8	4,634.6	12.7	139.2
2041	8,478.0	4,703.9	12.6	141.3
2042	8,620.2	4,773.8	12.5	143.4
Units	**Millions (2012 $)**	**Millions (2012 $)**	**Thousands**	**Index (2015=100)**

Exhibit A-11

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Other Retail and Wholesale Energy Sales Models

Year	SWEPCO Arkansas Gross Regional Product	SWEPCO Arkansas Employment	SWEPCO Arkansas Regulated Employment	SWEPCO Louisana Employment	SWEPCO Louisana Households	SWEPCO Texas Population
1995	18,863.0	273.2	16.0	572.4	211.6	784.8
1996	19,579.4	278.5	16.1	573.6	212.9	796.2
1997	20,019.0	283.1	15.8	574.1	214.2	804.8
1998	20,428.9	288.1	15.7	573.0	215.6	813.4
1999	22,092.0	296.6	16.4	575.5	218.6	819.5
2000	22,642.7	303.8	16.3	577.2	219.7	825.4
2001	23,381.7	309.4	18.8	576.6	220.0	830.1
2002	24,916.9	313.1	22.1	576.7	220.4	837.4
2003	26,724.0	315.3	22.1	575.9	220.8	845.2
2004	28,502.3	321.5	21.7	579.9	221.5	853.1
2005	30,116.8	332.3	22.2	583.4	225.2	861.1
2006	30,832.4	340.7	22.5	589.7	229.4	873.9
2007	29,943.8	342.5	22.5	589.7	231.9	882.2
2008	29,226.8	340.8	21.0	590.3	232.6	890.2
2009	27,967.2	326.9	18.6	596.1	234.6	900.5
2010	29,109.0	327.3	19.3	603.4	236.5	907.8
2011	29,303.1	329.3	19.4	606.9	238.7	912.4
2012	29,761.5	334.5	19.5	611.8	241.1	915.6
2013	30,865.5	337.1	19.2	608.3	241.1	916.9
2014	31,618.4	347.6	19.8	605.8	241.2	921.0
2015	32,506.6	360.4	20.9	603.5	241.0	924.9
2016	33,128.2	371.9	21.4	600.9	240.9	929.4
2017	34,018.9	378.9	21.2	596.6	239.6	933.7
2018	34,950.9	385.1	22.0	591.0	238.8	939.6
2019	35,825.1	390.7	22.9	586.6	237.7	945.0
2020	36,284.7	382.6	22.4	584.9	236.7	948.8
2021	38,638.6	395.3	22.7	584.0	237.8	951.9
2022	40,135.9	412.2	24.0	583.6	238.6	957.0
2023	40,466.2	418.4	24.1	583.2	239.0	962.7
2024	41,660.3	422.1	24.5	583.0	239.4	967.3
2025	43,228.4	426.0	24.9	582.5	239.9	971.4
2026	44,977.4	428.3	25.1	581.6	240.3	975.1
2027	46,650.7	430.4	25.2	580.5	240.6	978.9
2028	48,215.8	432.4	25.4	579.0	240.6	983.0
2029	49,710.0	434.5	25.5	577.3	240.7	987.3
2030	51,084.6	436.1	25.7	575.6	240.7	991.7
2031	52,395.3	437.4	25.8	573.8	240.7	996.2
2032	53,728.7	438.4	25.9	571.9	240.7	1,000.6
2033	55,104.7	439.6	26.0	570.0	240.6	1,004.8
2034	56,492.9	440.6	26.1	568.0	240.4	1,008.7
2035	57,885.3	441.5	26.2	566.1	240.2	1,012.5
2036	59,317.4	442.4	26.2	564.2	240.0	1,015.9
2037	60,766.2	443.1	26.3	562.3	239.7	1,019.2
2038	62,213.4	443.9	26.4	560.3	239.3	1,022.3
2039	63,712.1	444.7	26.4	558.3	238.9	1,025.2
2040	65,214.5	445.6	26.5	556.3	238.5	1,028.0
2041	66,754.4	446.7	26.6	554.3	238.1	1,030.6
2042	68,320.2	447.7	26.7	552.2	237.6	1,033.0
Units	**Millions (2012 $)**	**Thousands**	**Thousands**	**Thousands**	**Thousands**	**Thousands**

Exhibit A-12

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	SWEPCO DSM/EE			SWEPCO - Arkansas DSM/EE			SWEPCO - Louisana DSM/EE			SWEPCO - Texas DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2023	14.6	2.9	2.7	5.6	1.0	1.3	9.0	1.8	1.4	0.0	0.0	0.0
2024	22.6	5.7	4.4	11.0	2.0	2.7	11.6	2.8	1.7	0.0	0.9	0.0
2025	25.5	8.4	5.2	16.6	3.1	4.1	8.9	2.9	1.1	0.0	2.4	0.0
2026	21.7	9.2	4.3	14.4	3.1	3.7	7.3	3.0	0.7	0.0	3.2	0.0
2027	18.8	10.7	3.0	11.9	3.7	2.5	6.8	3.0	0.4	0.0	3.9	0.1
2028	16.3	10.2	2.2	9.5	3.2	1.6	6.8	3.1	0.5	0.0	3.9	0.2
2029	11.6	7.7	1.3	6.5	2.3	1.0	5.1	2.4	0.3	0.0	3.0	0.0
2030	7.1	5.2	0.5	3.6	1.4	0.4	3.5	1.7	0.1	0.0	2.1	0.0
2031	3.2	2.9	0.0	1.1	0.6	0.0	2.1	1.1	0.0	0.0	1.2	0.0
2032	0.7	0.6	0.0	0.0	0.0	0.0	0.7	0.4	0.0	0.0	0.3	0.0
2033	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2041	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2043	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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

Exhibit A-13

Southwestern Electric Power Company
Actual and Forecast Losses (GWh)

Year	Losses
2013	1,049.7
2014	1,009.5
2015	1,004.0
2016	911.6
2017	905.7
2018	1,072.4
2019	1,038.6
2020	1,105.2
2021	1,073.7
2022	1,091.0
2023	1,181.1
2024	1,086.9
2025	1,093.8
2026	1,108.7
2027	1,103.7
2028	1,126.8
2029	1,111.9
2030	1,115.6
2031	1,117.8
2032	1,125.1
2033	1,124.6
2034	1,136.2
2035	1,132.6
2036	1,132.2
2037	1,131.9
2038	1,138.3
2039	1,150.1
2040	1,161.7
2041	1,144.9
2042	1,152.7
2043	1,159.1

Note: *2023 data are six months actual
six months forecast

Exhibit A-14

Southwestern Electric Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results

Class	Arkansas	Louisiana	Texas
Residential	Long-Term	Long-Term	Long-Term
Commercial	Long-Term	Long-Term	Long-Term
Industrial	Long-Term	Long-Term	Long-Term
Other Retail	Long-Term	Long-Term	Long-Term

Exhibit A-15

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-16

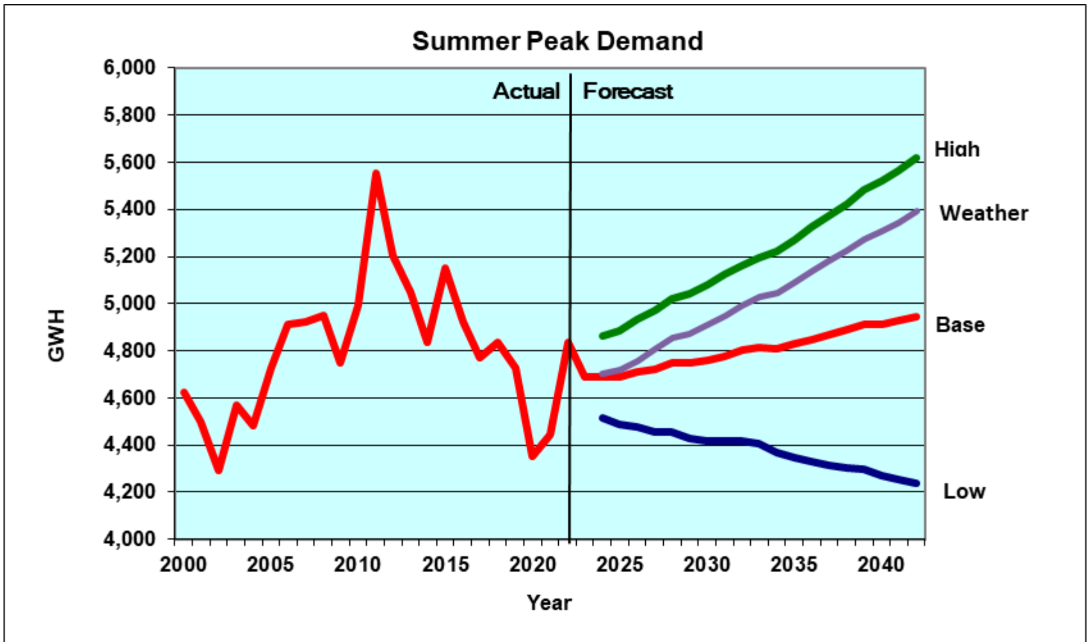
Southwestern Electric Power Company
Seasonal Peak Demand (MW), Energy Sales (GWh) and High/Low Scenarios

	Winter Peak Demand			Summer Peak Demand			Energy Sales		
Year	Low Scenario	Base Forecast	High Scenario	Low Scenario	Base Forecast	High Scenario	Low Scenario	Base Forecast	High Scenario
2024	4,207	4,369	4,533	4,514	4,687	4,863	22,073	22,921	23,783
2025	4,193	4,383	4,566	4,487	4,690	4,886	21,978	22,971	23,934
2026	4,184	4,403	4,611	4,477	4,711	4,933	21,932	23,078	24,169
2027	4,169	4,418	4,652	4,458	4,724	4,974	21,855	23,161	24,387
2028	4,162	4,437	4,692	4,454	4,749	5,022	21,828	23,270	24,611
2029	4,154	4,452	4,729	4,430	4,748	5,044	21,810	23,376	24,831
2030	4,142	4,462	4,762	4,419	4,761	5,080	21,764	23,446	25,018
2031	4,136	4,476	4,798	4,416	4,778	5,122	21,738	23,524	25,214
2032	4,133	4,490	4,830	4,419	4,801	5,164	21,731	23,606	25,392
2033	4,123	4,503	4,864	4,406	4,812	5,197	21,680	23,680	25,575
2034	4,099	4,513	4,897	4,369	4,810	5,219	21,573	23,754	25,774
2035	4,078	4,528	4,941	4,349	4,829	5,269	21,465	23,835	26,009
2036	4,055	4,540	4,983	4,330	4,849	5,323	21,355	23,914	26,248
2037	4,039	4,559	5,030	4,314	4,869	5,372	21,273	24,008	26,492
2038	4,028	4,575	5,077	4,304	4,889	5,425	21,217	24,101	26,748
2039	4,017	4,591	5,126	4,296	4,910	5,482	21,171	24,196	27,015
2040	3,999	4,602	5,168	4,271	4,914	5,518	21,099	24,276	27,261
2041	3,982	4,615	5,212	4,252	4,927	5,565	21,014	24,354	27,508
2042	3,966	4,628	5,257	4,239	4,946	5,618	20,939	24,433	27,753
2043	3,951	4,643	5,304	4,226	4,965	5,672	20,866	24,517	28,006

Exhibit A-17

Southwestern Electric Power Company

Range of Forecasts and Weather Scenario



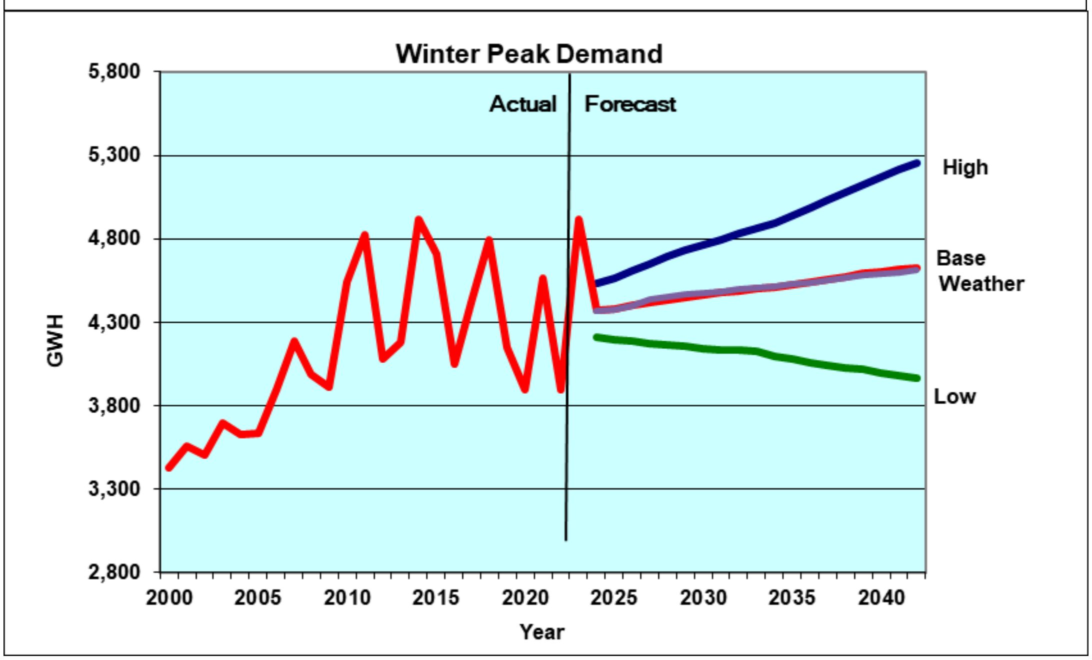


Exhibit A-18

SWEPCO Electric Vehicle Adoption Scenarios by State Jurisdiction

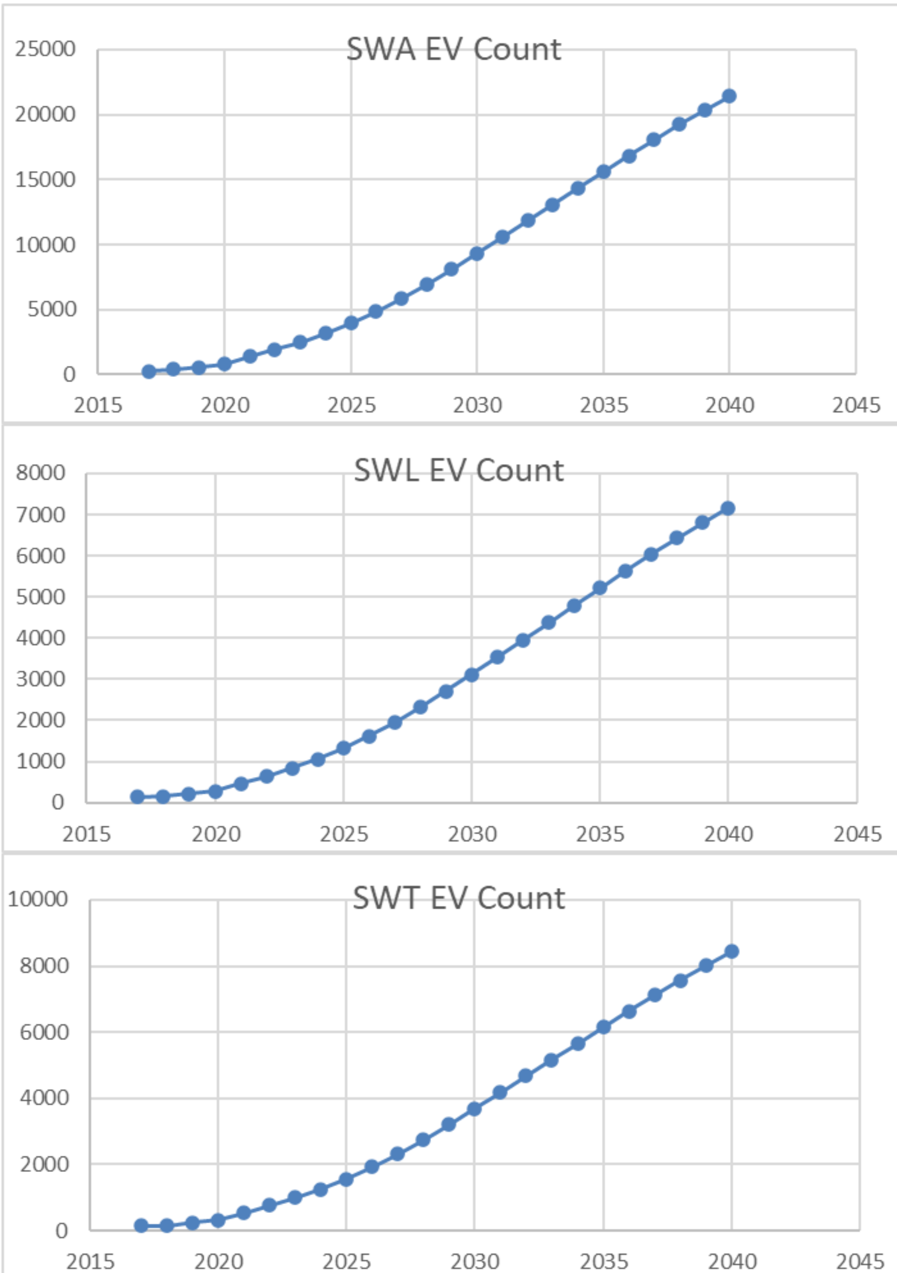


Exhibit A-19

SWEPCO Distributed Generation

	Distributed Energy Resources			In Service Capacity (kW)		
Year	Arkansas	Louisiana	Texas	Arkansas	Louisiana	Texas
2010	8	195	15	38	770	167
2011	15	305	27	70	1,345	344
2012	18	472	39	81	2,789	489
2013	20	763	55	104	4,172	1,385
2014	28	1,120	56	536	7,150	1,387
2015	33	1,518	60	649	9,215	1,396
2016	44	1,603	62	6,303	9,696	1,429
2017	84	1,668	64	8,457	10,110	1,445
2018	138	1,710	85	8,902	10,401	1,606
2019	237	1,735	131	9,773	10,624	1,965
2020	397	1,752	181	13,700	10,790	2,433
2021	635	1,815	280	15,180	11,366	3,239
2022	711	2,032	313	16,992	12,723	3,626
2023	788	2,253	347	18,839	14,106	4,020
2024	855	2,446	377	20,454	15,315	4,364
2025	910	2,601	401	21,758	16,291	4,643
2026	969	2,770	427	23,169	17,348	4,944
2027	1,024	2,928	452	24,490	18,337	5,226
2028	1,073	3,068	473	25,661	19,213	5,475
2029	1,129	3,229	498	27,008	20,222	5,763
2030	1,176	3,361	519	28,113	21,049	5,999
2031	1,233	3,526	544	29,491	22,081	6,293
2032	1,284	3,671	566	30,700	22,986	6,550
2033	1,347	3,850	594	32,204	24,113	6,871
2034	1,410	4,030	622	33,708	25,239	7,192
2035	1,460	4,175	644	34,915	26,143	7,450
2036	1,529	4,371	674	36,553	27,369	7,800
2037	1,599	4,573	706	38,248	28,638	8,161
2038	1,668	4,771	736	39,900	29,875	8,514
2039	1,755	5,017	774	41,957	31,415	8,953
2040	1,840	5,262	812	44,010	32,953	9,391
2041	1,922	5,494	848	45,953	34,407	9,805
2042	2,013	5,757	888	48,146	36,050	10,273

Exhibit B: Detailed Generation Technology Modeling Parameters

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

Type	First Available Year	Capacity (MW) Summer	Overnight Cost (b)(c) ($/kW)	Full Load Heat Rate HHV,Btu/kWh	Fuel Cost (d) (nom$/MMBtu)	Variable O&M (c) (nom$/MWh)	Fixed O&M (c) (nom$/kW-yr)	SO2 (Lb/mmBtu)	NOx (Lb/mmBtu)	CO2 (Lb/mmBtu)	Levelized Capacity Factor (%)	LCOE (e) ($/MWh)
Base Load												
SMALL MODULAR REACTOR	2034	600	7,600	10,443	1.05	4.29	135.72	0.00	0.00	0.00	88%	126
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE	2031	377	2,700	6,696	4.13	7.02	32.19	0.00000	0.01460	11.70	74%	76
COMBUSTION TURBINE H CLASS, COMBINED CYCLE MULTI SHAFT	2031	1,100	1,100	6,370	4.13	2.37	15.23	0.00752	0.00056	122.00	77%	67
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT	2031	418	1,300	6,431	4.13	3.24	17.60	0.00752	0.00056	122.00	72%	73
Peaking												
COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE	2031	240	800	9,905	4.13	6.09	9.04	0.00752	0.00056	122.00	15%	162
COMBUSTION TURBINES AERODERIVATIVE	2031	105	1,400	9,124	4.13	6.36	21.06	0.00752	0.00056	122.00	21%	165
INTERNAL COMBUSTION ENGINES	2031	21	2,200	8,295	4.13	7.70	45.41	0.00752	0.00056	122.00	26%	201
20-HOUR DURATION PUMPED THERMAL ENERGY STORAGE	2033	25	3,400	65% (f)	N/A	N/A	58.19	0.00	0.00	0.00	1%	N/A
20-HOUR DURATION VANADIUM FLOW BATTERY STORAGE	2033	25	2,900	70% (f)	N/A	N/A	9.40	0.00	0.00	0.00	2%	N/A
20-HOUR DURATION COMPRESSED AIR ENERGY STORAGE	2033	25	3,400	52% (f)	N/A	N/A	23.87	0.00	0.00	0.00	1%	N/A
Intermittent												
4-HOUR DURATION LITHIUM-ION BATTERY	2028	50	1,000	85% (f)	N/A	N/A	39.26	0.00	0.00	0.00	3%	N/A
6-HOUR DURATION LITHIUM-ION BATTERY	2028	50	1,300	85% (f)	N/A	N/A	54.64	0.00	0.00	0.00	4%	N/A
8-HOUR DURATION LITHIUM-ION BATTERY	2028	50	1,700	85% (f)	N/A	N/A	70.03	0.00	0.00	0.00	4%	N/A
UTILITY-SCALE ONSHORE WIND TIER 1	2028	100	2,000	N/A	N/A	N/A (i)	40.39	0.00	0.00	0.00	44%	55
UTILITY-SCALE ONSHORE WIND TIER 2	2028	100	2,200	N/A	N/A	N/A (i)	40.39	0.00	0.00	0.00	44%	60
UTILITY-SCALE SOLAR PHOTOVOLTAIC TIER 1	2028	50	1,800	N/A	N/A	N/A (i)	25.85	0.00	0.00	0.00	25%	66
UTILITY-SCALE SOLAR PHOTOVOLTAIC TIER 2	2028	50	2,000	N/A	N/A	N/A (i)	25.85	0.00	0.00	0.00	25%	74
UTILITY-SCALE SOLAR + STORAGE (3:1)	2028	150	2,700	N/A	N/A	N/A	36.43	0.00	0.00	0.00	11%	179

Notes:
(a) Intsalled cost, capability and heat rate have been rounded
(b) Total Plant overnight cost including interconnection cost estimate
(c) Costs provided in nominal terms in the first available year
(d) Average fuel price across study horizon
(e) First year levelized cost of energy based on capacity factors shown in table. Not shown for storage as LCOE is dependent on charging. Not shown for low dispatch.
(f) Denotes efficiency, (w/ power electronics)
(i) Denotes VOM before PTC

Exhibit C: Capability, Demand and Reserve (CDR) – "Going-In"

CAPABILITY

	Plant Capabilities	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	ARSENAL HILL 5	111	111	111	111	111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	J.L. STALL CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
	FLINT CREEK 1	259	259	259	259	259	259	259	259	259	259	259	258	258	258	259	0	0	0	0	0
	TURK	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
	KNOX LEE 5	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339	0	0	0	0
	LIEBERMAN 3	111	111	111	111	111															
	LIEBERMAN 4	108	108	108	108	108															
	MATTISON 1	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
	MATTISON 2	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	MATTISON 3	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	MATTISON 4	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	WELSH 1	525	525	525	525	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WELSH 3	528	528	528	528	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 1	162	162	162	162	162	162	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 2	352	352	352	352	352	352	352	352	352	352	352	352	0	0	0	0	0	0	0	0
	WILKES 3	350	350	350	350	350	350	350	350	350	350	350	350	350	0	0	0	0	0	0	0
	SUNDANCE	17	17	16	16	16	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	MAVERICK	25	24	23	23	23	22	22	22	22	22	22	22	22	22	22	22	21	21	21	21
	TRAVERSE	85	83	81	80	79	78	77	77	76	76	76	76	75	75	75	75	74	74	74	74
	Diversion		31	30	30	29	29	28	28	28	28	28	28	28	28	28	28	27	27	27	27
	Wagon Wheel		0	89	88	87	86	84	84	83	83	83	83	82	82	82	82	81	81	81	81
	Mooringsport			142	140	138	133	128	118	109	97	88	80	74	71	68	65	58	55	52	49
1 (Summer)	**Total**	**4,243**	**4,271**	**4,498**	**4,493**	**3,435**	**3,097**	**2,926**	**2,916**	**2,905**	**2,892**	**2,884**	**2,874**	**2,513**	**2,160**	**2,158**	**1,896**	**1,548**	**1,544**	**1,541**	**1,538**
	Adjustments to Plant Capability	0	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	0	0
2	**TOTAL**	**0**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**0**	**0**
3 (Summer)	**Net Plant Capability (1 + 2)**	**4,243**	**4,226**	**4,453**	**4,448**	**3,390**	**3,052**	**2,881**	**2,871**	**2,860**	**2,847**	**2,839**	**2,829**	**2,468**	**2,115**	**2,113**	**1,851**	**1,503**	**1,499**	**1,541**	**1,538**
	Sales Without Reserves																				
4	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases Without Reserves																				
	NTEC - HCPP	341.0	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341
	NTEC GENERATION - PIRKEY/DOLET HILLS/TL	54.3	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
	NTEC - ENTERGY ISES	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC - SPA NARROWS	25.5	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	TEX-LA - HCPP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ETEC - HCPP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CUSTOMER GENERATION - MINDEN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EXELON GREEN COUNTRY (2)																				
	MAJESTIC WIND PROJECT	12.4	12	12	12	12					0	0	0	0	0	0	0	0	0	0	0
	HIGH MAJESTIC WIND PROJECT	12.5	12	12	12	12	11	11	11	11	0	0	0	0	0	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	17.0	17	16	16	16	16	15	15	15	0	0	0	0	0	0	0	0	0	0	0
	CANADIAN HILLS WIND PROJECT	31.4	31	30	30	29	29	28	28	28	0	0	0	0	0	0	0	0	0	0	0
	ROCKING R		53	52	51	50	49	47	43	40	35	32	29	27	26	25	24	21	20	19	18
	SHORT TERM CAPACITY PURCHASE	482	485	278	78																
5 (Summer)	**TOTAL**	**976**	**1,030**	**821**	**619**	**539**	**525**	**523**	**519**	**515**	**456**	**453**	**450**	**448**	**447**	**446**	**445**	**442**	**441**	**440**	**439**
6 (Summer)	**Total Capability (3 - 4 + 5)**	**5,220**	**5,256**	**5,273**	**5,067**	**3,929**	**3,577**	**3,404**	**3,390**	**3,375**	**3,304**	**3,292**	**3,280**	**2,916**	**2,562**	**2,559**	**2,296**	**1,945**	**1,941**	**1,981**	**1,977**

DEMAND			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
A	Peak Demand Before Passive DSM		4,693	4,698	4,720	4,735	4,759	4,756	4,766	4,781	4,801	4,812	4,810	4,829	4,849	4,869	4,889	4,910	4,914	4,927	4,946	4,965
A	Peak Demand Before Passive DSM Adjusted		4,693	4,698	4,720	4,735	4,759	4,756	4,766	4,781	4,801	4,812	4,810	4,829	4,849	4,869	4,889	4,910	4,914	4,927	4,946	4,965
B	Passive DSM																					
		TOTAL	6	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C	Peak Demand (A - B)		4,687	4,693	4,719	4,735	4,759	4,756	4,766	4,781	4,801	4,812	4,810	4,829	4,849	4,869	4,889	4,910	4,914	4,927	4,946	4,965
D	Active DSM																					
		TOTAL	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
E	Firm Demand (C - D)		4,651	4,657	4,682	4,698	4,722	4,719	4,730	4,745	4,765	4,776	4,774	4,792	4,813	4,832	4,852	4,874	4,878	4,891	4,910	4,928
F	Other Demand Adjustments																					
		TOTAL	25	25	26	27	27	25	25	26	26	26	24	25	25	27	27	28	26	26	26	26
7	Native Load Responsibility (E - F)		4,625	4,631	4,656	4,671	4,696	4,694	4,704	4,719	4,739	4,749	4,750	4,767	4,788	4,805	4,825	4,846	4,852	4,865	4,883	4,902
	Sales With Reserves																					
8		TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Purchases With Reserves																					
9		TOTAL	172	172	172	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122
10	Load Responsibility (7 + 8 - 9)		4,453	4,459	4,484	4,549	4,573	4,572	4,582	4,596	4,616	4,627	4,627	4,645	4,665	4,683	4,702	4,723	4,730	4,743	4,761	4,780

RESERVES		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
11 (Summer)	Reserve Capacity (6 - 10)	753	722	712	440	-644	-995	-1,178	-1,206	-1,241	-1,323	-1,335	-1,365	-1,749	-2,121	-2,143	-2,428	-2,785	-2,802	-2,779	-2,802
12 (Summer)	% Reserve Margin ((11/10) * 100)	17	16	16	10	-14	-22	-26	-26	-27	-29	-29	-29	-37	-45	-46	-51	-59	-59	-58	-59
13 (Summer)	% Capacity Margin (11/(6) * 100)	14	14	14	9	-16	-28	-35	-36	-37	-40	-41	-42	-60	-83	-84	-106	-143	-144	-140	-142
14 (Summer)	Reserves Above Minimum 15% Reserve Margin (MW)	162	134	(5)	(504)	(1,588)	(1,604)	(1,790)	(1,821)	(1,852)	(1,965)	(1,975)	(2,003)	(2,383)	(2,758)	(2,786)	(3,070)	(3,411)	(3,435)	(3,609)	(3,636)
14 (Summer)	Reserves Above Minimum 22% Reserve Margin (MW)	(93)	(259)	(275)	(561)	(1,650)	(2,000)	(2,186)	(2,217)	(2,257)	(2,341)	(2,353)	(2,387)	(2,775)	(3,151)	(3,178)	(3,467)	(3,825)	(3,846)	(3,827)	(3,854)

Exhibit D: Modeled Scenarios

Long-Term Commodity Price Forecast

SUMMARY OF LONG-TERM COMMODITY PRICE FORECASTS

Annual Average (Nominal Dollars)

	Natural Gas (Henry Hub) $/mmbtu			CO2 $/ton			Coal (FOB) $/ton	
	Base	High	Low	Base	High	No Price	PRB 8800	CAPP
2024	4.25	6.01	3.61	0.00	0.00	0.00	15.7	106.4
2025	3.72	5.83	3.11	0.00	0.00	0.00	15.0	84.7
2026	3.33	5.55	2.86	0.00	0.00	0.00	15.2	111.6
2027	3.16	5.40	2.76	0.00	0.00	0.00	15.5	101.9
2028	3.16	5.52	2.75	0.00	0.00	0.00	15.8	89.7
2029	3.24	5.71	2.85	0.00	40.00	0.00	15.5	91.5
2030	3.40	5.86	3.02	13.61	42.00	0.00	15.6	91.3
2031	3.62	6.21	3.23	14.08	44.10	0.00	15.1	93.1
2032	3.89	6.66	3.45	14.58	46.31	0.00	15.8	139.0
2033	4.22	7.07	3.67	15.09	48.62	0.00	16.5	129.2
2034	4.49	7.42	3.70	15.62	51.05	0.00	17.3	98.8
2035	4.72	7.71	3.77	16.16	53.60	0.00	18.0	100.8
2036	4.82	7.97	3.80	16.73	56.28	0.00	18.7	102.8
2037	4.97	8.18	3.86	17.31	59.10	0.00	19.4	104.9
2038	5.24	8.42	3.97	17.92	62.05	0.00	20.2	107.0
2039	5.24	8.63	4.03	18.55	65.16	0.00	20.9	182.4
2040	5.55	8.89	4.16	19.20	68.41	0.00	21.6	189.7
2041	5.78	9.05	4.27	19.87	71.83	0.00	22.3	98.7
2042	5.88	9.19	4.30	20.56	75.43	0.00	23.1	100.7
2043	5.90	9.24	4.33	21.28	79.20	0.00	23.8	158.5

	Power On-Peak (SPP) $/MWh					Power Off-Peak (SPP) $/MWh				
	REF	NCR	FOR	CETA	ECR	REF	NCR	FOR	CETA	ECR
2024	43.59	43.59	43.59	43.69	43.39	30.16	30.17	30.16	30.24	30.02
2025	46.70	43.36	47.74	52.51	58.89	33.13	30.26	33.32	34.73	41.29
2026	43.43	41.00	43.32	43.69	54.93	31.05	28.63	31.02	31.28	39.67
2027	41.71	39.78	41.54	41.54	51.94	29.46	27.51	29.46	29.54	37.99
2028	40.01	37.99	39.94	40.03	50.01	28.66	26.53	28.78	28.94	37.74
2029	38.94	36.84	38.89	38.92	76.74	27.90	25.71	28.03	28.19	63.00
2030	47.71	35.87	47.70	47.37	74.17	35.47	25.51	35.82	35.72	61.77
2031	46.90	35.34	46.81	45.89	72.85	37.14	26.54	37.13	36.69	62.90
2032	46.60	35.46	47.68	45.92	73.78	38.29	27.95	39.27	38.18	65.18
2033	47.80	36.53	49.46	47.17	75.09	40.54	29.51	41.62	40.36	67.40
2034	48.64	37.08	50.82	47.93	75.35	42.52	30.68	43.97	42.30	68.85
2035	50.44	38.26	53.04	49.60	76.86	43.67	30.98	45.33	43.31	70.09
2036	51.36	38.94	54.05	50.24	78.09	44.51	31.45	46.37	44.04	71.20
2037	52.46	39.62	55.36	51.03	78.68	46.19	32.51	48.08	45.59	72.90
2038	54.77	40.88	57.47	52.95	80.43	48.05	33.33	49.78	47.17	74.29
2039	55.60	42.18	58.62	53.22	81.28	49.21	34.70	51.08	48.01	76.22
2040	58.71	43.27	61.35	56.08	82.69	52.56	36.47	54.06	51.32	77.88
2041	61.57	44.99	64.40	57.75	84.95	54.39	36.98	55.91	52.14	79.14
2042	61.96	45.16	64.92	57.76	84.19	55.23	37.43	57.08	52.99	79.11
2043	62.00	45.21	65.00	57.13	82.59	55.71	37.88	57.44	53.03	79.01

Scenario Capacity Mix

Reference Scenario Case (GW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	21	0	32	0	2	0	2	3	1	34	0	0
2025	21	0	32	0	2	0	2	3	1	35	0	0
2026	21	0	32	0	2	0	2	3	2	37	0	0
2027	20	0	31	0	2	0	2	3	3	38	1	0
2028	19	0	31	0	2	0	2	3	5	40	2	0
2029	19	0	32	0	2	0	2	3	7	41	3	0
2030	18	0	32	0	2	0	2	3	9	41	4	0
2031	13	0	31	0	2	0	2	3	11	42	6	0
2032	12	0	32	1	2	0	2	3	14	42	7	0
2033	10	0	32	1	2	0	2	3	16	42	9	0
2034	10	0	33	1	2	0	2	3	19	43	10	0
2035	10	0	33	1	2	0	2	3	21	43	11	0
2036	9	0	33	1	2	0	2	3	22	43	12	0
2037	8	0	33	1	2	0	2	3	23	43	13	0
2038	6	0	34	1	2	0	2	3	25	44	14	0
2039	4	0	34	1	2	0	2	3	26	44	15	0
2040	2	0	35	1	2	0	2	3	27	44	17	0
2041	1	0	35	1	2	0	2	3	28	44	18	0
2042	1	0	36	1	2	0	2	3	29	45	19	0
2043	1	0	36	1	2	1	2	3	31	45	20	0

FOR Scenario Case (GW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	21	0	32	0	2	0	2	3	1	34	0	0
2025	21	0	32	0	2	0	2	3	1	35	0	0
2026	21	0	32	0	2	0	2	3	2	37	0	0
2027	20	0	32	0	2	0	2	3	3	38	1	0
2028	19	0	32	0	2	0	2	3	5	39	2	0
2029	19	0	33	0	2	0	2	3	7	40	3	0
2030	18	0	34	0	2	0	2	3	9	41	4	0
2031	13	0	34	0	2	0	2	3	11	41	6	0
2032	12	0	35	0	2	0	2	3	13	42	7	0
2033	10	0	34	0	2	0	2	3	14	42	8	0
2034	10	0	36	0	2	0	2	3	15	42	9	0
2035	10	0	36	0	2	0	2	3	16	42	9	0
2036	9	0	37	0	2	0	2	3	17	42	10	0
2037	9	0	37	0	2	0	2	3	18	42	10	0
2038	9	0	38	0	2	0	2	3	19	43	10	0
2039	6	0	39	0	2	0	2	3	20	43	10	0
2040	5	0	39	0	2	0	2	3	21	43	11	0
2041	3	0	39	0	2	0	2	3	22	43	11	0
2042	3	0	39	0	2	0	2	3	23	43	11	0
2043	3	0	40	0	2	0	2	3	24	43	11	0

NCR Scenario Case (GW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	21	0	32	0	2	0	2	3	1	34	0	0
2025	21	0	32	0	2	0	2	3	1	35	0	0
2026	21	0	32	0	2	0	2	3	2	37	0	0
2027	20	0	31	0	2	0	2	3	3	38	1	0
2028	19	0	32	0	2	0	2	3	5	39	2	0
2029	19	0	32	0	2	0	2	3	7	39	3	0
2030	18	0	34	0	2	0	2	3	9	40	4	0
2031	13	0	35	1	2	0	2	3	10	40	6	0
2032	13	0	36	1	2	0	2	3	12	40	7	0
2033	12	0	36	1	2	0	2	3	13	40	7	0
2034	11	0	37	1	2	0	2	3	14	40	8	0
2035	11	0	37	1	2	0	2	3	15	41	9	0
2036	9	0	38	1	2	0	2	3	15	41	9	0
2037	8	0	37	1	2	0	2	3	16	41	10	0
2038	7	0	38	1	2	0	2	3	16	41	10	0
2039	6	0	40	1	2	0	2	3	17	41	11	0
2040	5	0	41	1	2	0	2	3	17	41	11	0
2041	3	0	42	1	2	0	2	3	18	42	12	0
2042	3	0	42	1	2	0	2	3	18	42	12	0
2043	3	0	42	1	2	0	2	3	19	42	13	0

CETA Scenario Case (GW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	21	0	32	0	2	0	2	3	1	34	0	0
2025	21	0	32	0	2	0	2	3	1	35	0	0
2026	21	0	32	0	2	0	2	3	2	37	0	0
2027	20	0	33	0	2	0	2	3	4	38	1	0
2028	19	0	33	0	2	0	2	3	6	40	2	0
2029	19	0	33	0	2	0	2	3	8	41	3	0
2030	18	0	34	0	2	0	2	3	11	41	4	0
2031	13	0	34	1	2	0	2	3	14	42	6	0
2032	12	0	35	2	2	0	2	3	17	42	7	0
2033	10	0	36	2	2	0	2	3	20	43	9	0
2034	10	0	36	2	2	0	2	3	23	43	10	0
2035	10	0	37	2	2	0	2	3	26	44	11	0
2036	9	0	37	2	2	1	2	3	28	44	13	0
2037	8	0	37	2	2	1	2	3	31	45	15	0
2038	6	0	37	2	2	1	2	3	33	45	16	0
2039	4	0	38	2	2	1	2	3	36	46	17	0
2040	2	0	38	2	2	2	2	3	38	46	19	0
2041	1	0	38	2	2	2	2	3	41	47	20	0
2042	1	0	38	2	2	2	2	3	43	47	22	0
2043	1	0	38	2	2	2	2	3	46	48	24	0

ECR Scenario Case (GW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	21	0	32	0	2	0	2	3	1	34	0	0
2025	21	0	32	0	2	0	2	3	1	35	0	0
2026	21	0	32	0	2	0	2	3	2	37	0	0
2027	20	0	31	0	2	0	2	3	4	38	1	0
2028	19	0	31	0	2	0	2	3	6	40	2	0
2029	19	0	32	0	2	0	2	3	8	41	3	0
2030	18	0	32	1	2	0	2	3	11	41	5	0
2031	13	1	31	2	2	0	2	3	15	42	6	0
2032	12	1	32	3	2	0	2	3	18	43	8	0
2033	10	1	32	3	2	0	3	3	22	44	9	0
2034	10	1	32	3	2	0	3	3	26	44	10	0
2035	10	1	31	3	2	0	3	3	29	45	11	0
2036	9	1	31	3	2	1	3	3	32	45	12	0
2037	8	1	30	3	2	1	3	3	35	46	13	0
2038	6	1	30	3	2	1	3	3	37	46	14	0
2039	4	1	30	3	2	1	3	3	39	47	15	0
2040	2	1	30	3	2	1	3	3	41	47	16	0
2041	1	1	29	3	2	1	3	3	44	48	17	0
2042	1	1	29	3	2	2	3	3	46	48	18	0
2043	1	1	29	3	2	2	3	3	48	49	18	0

Scenario Resource Retirements

Reference Firm Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	494	0	0	0	0	0	0	0	0	0
2026	460	0	462	0	0	0	0	0	0	0	0	0
2027	0	0	190	0	0	0	0	0	0	0	0	0
2028	1056	0	112	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	244	0	0	0	0	0	0	0	0	0
2031	0	0	243	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	243	0	0	0	0	0	0	0	0	0
2035	0	0	172	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0
2037	1067	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	196	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	2583	0	2356	0	0	0	0	0	0	0	0	0

Reference Economic Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	186	0	27	0	0	0	0	0	0	0
2025	16	0	8	0	0	0	0	0	0	0	0	0
2026	0	0	235	0	0	0	0	0	0	0	0	0
2027	0	0	106	0	0	0	0	0	0	0	0	0
2028	518	0	0	0	0	0	0	0	0	0	0	0
2029	445	0	218	0	0	0	0	0	0	0	0	0
2030	4673	0	9	0	0	0	0	0	0	0	0	0
2031	1885	0	0	0	0	0	0	0	0	0	0	0
2032	1509	0	454	0	0	0	0	0	0	0	0	0
2033	0	0	182	0	0	0	0	0	0	0	0	0
2034	0	0	392	0	30	0	0	0	0	0	0	0
2035	1461	0	514	0	0	0	0	0	0	0	0	0
2036	339	0	513	0	5	0	0	0	0	0	0	0
2037	900	0	295	0	0	0	0	0	0	0	0	0
2038	1884	0	19	0	0	0	0	0	0	0	0	0
2039	2493	0	345	0	0	0	0	0	0	0	0	0
2040	677	0	1077	0	0	0	0	0	0	0	0	0
2041	249	0	238	0	5	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	17050	0	4791	0	67	0	0	0	0	0	0	0

FOR Firm Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	494	0	0	0	0	0	0	0	0	0
2026	460	0	462	0	0	0	0	0	0	0	0	0
2027	0	0	190	0	0	0	0	0	0	0	0	0
2028	1056	0	112	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	244	0	0	0	0	0	0	0	0	0
2031	0	0	243	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	243	0	0	0	0	0	0	0	0	0
2035	0	0	172	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0
2039	1067	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	196	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	2583	0	2356	0	0	0	0	0	0	0	0	0

FOR Economic Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	186	0	27	0	0	0	0	0	0	0
2025	16	0	8	0	0	0	0	0	0	0	0	0
2026	0	0	235	0	0	0	0	0	0	0	0	0
2027	0	0	106	0	0	0	0	0	0	0	0	0
2028	518	0	0	0	0	0	0	0	0	0	0	0
2029	445	0	233	0	0	0	0	0	0	0	0	0
2030	4673	0	1	0	0	0	0	0	0	0	0	0
2031	1885	0	15	0	0	0	0	0	0	0	0	0
2032	1228	0	470	0	0	0	0	0	0	0	0	0
2033	0	0	150	0	0	0	0	0	0	0	0	0
2034	0	0	393	0	30	0	0	0	0	0	0	0
2035	1009	0	512	0	0	0	0	0	0	0	0	0
2036	339	0	513	0	5	0	0	0	0	0	0	0
2037	0	0	295	0	0	0	0	0	0	0	0	0
2038	2617	0	19	0	0	0	0	0	0	0	0	0
2039	662	0	354	0	0	0	0	0	0	0	0	0
2040	1182	0	1068	0	0	0	0	0	0	0	0	0
2041	17	0	231	0	5	0	0	0	0	0	0	0
2042	0	0	53	0	0	0	0	0	0	0	0	0
2043	340	0	0	0	0	0	0	0	0	0	0	0
Total	14932	0	4844	0	67	0	0	0	0	0	0	0

NCR Firm Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	494	0	0	0	0	0	0	0	0	0
2026	460	0	462	0	0	0	0	0	0	0	0	0
2027	0	0	190	0	0	0	0	0	0	0	0	0
2028	1056	0	112	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	244	0	0	0	0	0	0	0	0	0
2031	0	0	243	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	243	0	0	0	0	0	0	0	0	0
2035	0	0	172	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0
2037	1067	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	2583	0	2160	0	0	0	0	0	0	0	0	0

NCR Economic Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	186	0	27	0	0	0	0	0	0	0
2025	16	0	8	0	0	0	0	0	0	0	0	0
2026	0	0	235	0	0	0	0	0	0	0	0	0
2027	0	0	106	0	0	0	0	0	0	0	0	0
2028	518	0	0	0	0	0	0	0	0	0	0	0
2029	445	0	218	0	0	0	0	0	0	0	0	0
2030	4673	0	9	0	0	0	0	0	0	0	0	0
2031	520	0	0	0	0	0	0	0	0	0	0	0
2032	736	0	813	0	0	0	0	0	0	0	0	0
2033	1365	0	182	0	0	0	0	0	0	0	0	0
2034	0	0	155	0	30	0	0	0	0	0	0	0
2035	1953	0	154	0	0	0	0	0	0	0	0	0
2036	339	0	513	0	5	0	0	0	0	0	0	0
2037	0	0	295	0	0	0	0	0	0	0	0	0
2038	1884	0	19	0	0	0	0	0	0	0	0	0
2039	1002	0	345	0	0	0	0	0	0	0	0	0
2040	1463	0	531	0	0	0	0	0	0	0	0	0
2041	17	0	27	0	5	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	14932	0	3796	0	67	0	0	0	0	0	0	0

CETA Firm Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	494	0	0	0	0	0	0	0	0	0
2026	460	0	462	0	0	0	0	0	0	0	0	0
2027	0	0	190	0	0	0	0	0	0	0	0	0
2028	1056	0	112	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	244	0	0	0	0	0	0	0	0	0
2031	0	0	243	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	243	0	0	0	0	0	0	0	0	0
2035	0	0	172	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0
2037	1067	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	2583	0	2160	0	0	0	0	0	0	0	0	0

CETA Economic Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	186	0	27	0	0	0	0	0	0	0
2025	16	0	8	0	0	0	0	0	0	0	0	0
2026	0	0	235	0	0	0	0	0	0	0	0	0
2027	0	0	106	0	0	0	0	0	0	0	0	0
2028	518	0	0	0	0	0	0	0	0	0	0	0
2029	445	0	218	0	0	0	0	0	0	0	0	0
2030	4673	0	9	0	0	0	0	0	0	0	0	0
2031	1885	0	0	0	0	0	0	0	0	0	0	0
2032	1509	0	454	0	0	0	0	0	0	0	0	0
2033	0	0	182	0	0	0	0	0	0	0	0	0
2034	0	0	155	0	30	0	0	0	0	0	0	0
2035	1461	0	514	0	0	0	0	0	0	0	0	0
2036	339	0	513	0	5	0	0	0	0	0	0	0
2037	900	0	295	0	0	0	0	0	0	0	0	0
2038	1884	0	19	0	0	0	0	0	0	0	0	0
2039	2493	0	345	0	0	0	0	0	0	0	0	0
2040	677	0	531	0	0	0	0	0	0	0	0	0
2041	249	0	27	0	5	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	17050	0	3796	0	67	0	0	0	0	0	0	0

ECR Firm Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	494	0	0	0	0	0	0	0	0	0
2026	460	0	462	0	0	0	0	0	0	0	0	0
2027	0	0	190	0	0	0	0	0	0	0	0	0
2028	1056	0	112	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	244	0	0	0	0	0	0	0	0	0
2031	0	0	243	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	243	0	0	0	0	0	0	0	0	0
2035	0	0	172	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0
2037	1067	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	196	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	2583	0	2356	0	0	0	0	0	0	0	0	0

ECR Economic Retirement
Capacity Mix (MW)

Year	Coal	Coal CCS	Gas	Gas CCS	Oil	Hydrogen	Nuclear	Hydro	Solar	Wind	Storage	Other
2024	0	0	186	0	27	0	0	0	0	0	0	0
2025	16	0	8	0	0	0	0	0	0	0	0	0
2026	0	0	235	0	0	0	0	0	0	0	0	0
2027	0	0	106	0	0	0	0	0	0	0	0	0
2028	518	0	0	0	0	0	0	0	0	0	0	0
2029	445	0	281	0	0	0	0	0	0	0	0	0
2030	4673	0	5	0	0	0	0	0	0	0	0	0
2031	1885	0	32	0	0	0	0	0	0	0	0	0
2032	1509	0	454	0	0	0	0	0	0	0	0	0
2033	0	0	150	0	0	0	0	0	0	0	0	0
2034	0	0	392	0	30	0	0	0	0	0	0	0
2035	1461	0	514	0	0	0	0	0	0	0	0	0
2036	339	0	513	0	5	0	0	0	0	0	0	0
2037	900	0	296	0	0	0	0	0	0	0	0	0
2038	1884	0	19	0	0	0	0	0	0	0	0	0
2039	2493	0	345	0	0	0	0	0	0	0	0	0
2040	677	0	1079	0	0	0	0	0	0	0	0	0
2041	249	0	228	0	5	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0
Total	17050	0	4842	0	67	0	0	0	0	0	0	0

Exhibit E: Cost of Capital

Cap Structure	SWE
Cost of Debt (%)	4.47%
Return on Equity (%)	9.52%
Equity % Rate Base	45.10%
State Income Tax Rate (if applicable)	3.3%
Property Tax Rate	0.8%
SWEPCO Discount Rate for Economic Analysis	6.35%
AFUDC %	6.11%

Exhibit F: Modeled Portfolio Results

Annual Portfolio Additions in nameplate MW (EE in cumulative MW per year) :

REF	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	600	350	200	250	500	600	300	0	0	0	0	0	0	0	0	3400
New Solar T2	0	0	0	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	0	0	0	0	0	200	400	400	0	0	0	0	0	0	0	0	1000
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	480	480	720	480	480	0	0	0	2640
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	0	0	0	105	105	420
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 4hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 6hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 8hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Hybrid (Solar+Storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	150	196	189	461	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	72	64	57	50	43	36	29	24	19	16	12	9	6	4	3	
Portfolio RM With New Resources	20%	23%	23%	23%	23%	23%	23%	23%	23%	24%	28%	28%	27%	28%	23%	25%	25%	23%	24%	24%	

REFW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	0	150	0	0	0	300	600	0	0	0	0	0	0	0	0	1650
New Solar T2	0	0	0	0	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	400	300	100	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T2	0	0	0	0	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	400
New Gas CT	0	0	0	0	0	0	0	240	0	240	0	0	480	720	720	480	480	0	0	0	3360
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105	0	0	0	0	105	210
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 4hr Storage	0	0	0	0	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	150
New 6hr Storage	0	0	0	0	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	300
New 8hr Storage	0	0	0	0	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	150
New Hybrid (Solar+Storage)	0	0	0	0	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	400
Optional MP	150	229	444	726	233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	480
Cumulative Annual EE	20	38	54	67	79	72	64	57	50	43	36	31	26	22	19	15	11	8	6	5	
Portfolio RM With New Resources	28%	31%	34%	34%	34%	35%	34%	37%	35%	36%	35%	34%	35%	41%	33%	35%	36%	35%	34%	34%	

NCR	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	600	350	150	200	250	100	500	600	50	0	0	0	0	0	0	3400
New Solar T2	0	0	0	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	240	480	240	240	0	0	0	1200
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0	0	550
New 4hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	0	50	50	50	0	250
New 6hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	50	100	0	100	0	350
New 8hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	0	0	50
New Hybrid (Solar+Storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	150	196	185	457	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	70	61	53	45	38	31	25	20	16	13	10	7	5	4	3	
Portfolio RM With New Resources	20%	23%	23%	23%	23%	23%	23%	23%	23%	23%	23%	28%	25%	23%	23%	22%	22%	22%	23%	22%	

NCRW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
New Solar T2	0	0	0	0	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	400
New Wind T2	0	0	0	0	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	400
New Gas CT	0	0	0	0	0	0	0	240	0	0	0	0	480	480	720	480	240	0	0	0	2640
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	42	0	0	0	0	42	84
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 4hr Storage	0	0	0	0	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	150
New 6hr Storage	0	0	0	0	100	100	100	50	0	50	100	100	100	100	100	100	100	50	0	0	1150
New 8hr Storage	0	0	0	0	50	50	50	0	0	0	0	50	50	50	50	50	50	50	0	0	500
New Hybrid (Solar+Storage)	0	0	0	0	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
Optional MP	150	232	442	724	229	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	480
Cumulative Annual EE	20	38	54	67	79	69	58	49	39	31	23	17	11	7	4	2	1	0	0	0	
Portfolio RM With New Resources	28%	31%	34%	34%	34%	36%	35%	39%	37%	35%	36%	38%	41%	45%	36%	39%	34%	34%	33%	33%	

FOR-SUMMER	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	600	350	150	200	350	50	600	500	0	0	0	0	0	0	0	3400
New Solar T2	0	0	0	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	0	0	0	0	0	0	300	0	0	0	0	0	0	0	0	0	300
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	240	240	720	240	480	0	0	0	1920
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105	0	105
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0	0	550
New 4hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 6hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	100	0	0	150
New 8hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Hybrid (Solar+Storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	150	196	189	461	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	70	61	53	45	38	31	25	20	16	13	10	7	5	4	3	
Portfolio RM With New Resources	20%	23%	23%	23%	23%	23%	23%	23%	23%	23%	23%	27%	28%	23%	24%	22%	24%	24%	24%	22%	

FOR-WINTER	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	0	150	0	0	0	0	600	50	0	0	0	0	0	0	0	1400
New Solar T2	0	0	0	0	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T2	0	0	0	0	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	400
New Gas CT	0	0	0	0	0	0	0	240	0	240	0	0	720	480	720	480	480	0	0	0	3360
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	21
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 4hr Storage	0	0	0	0	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	150
New 6hr Storage	0	0	0	0	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	300
New 8hr Storage	0	0	0	0	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	150
New Hybrid (Solar+Storage)	0	0	0	0	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	400
Optional MP	150	232	447	729	236	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	480
Cumulative Annual EE	20	38	54	67	79	72	64	57	50	43	36	29	24	19	16	12	9	6	4	3	
Portfolio RM With New Resources	28%	31%	34%	34%	34%	35%	34%	36%	34%	36%	35%	34%	41%	43%	32%	34%	34%	34%	33%	33%	

CETA	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	600	600	500	0	600	450	0	0	0	0	0	0	0	0	0	3350
New Solar T2	0	0	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	250
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	0	0	0	0	0	300	400	300	0	0	0	0	0	0	0	0	1000
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	720	480	720	480	240	0	240	0	2880
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0	0	550
New 4hr Storage	0	0	0	0	50	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	100
New 6hr Storage	0	0	0	0	0	0	0	0	0	0	0	100	0	0	0	0	100	100	0	0	300
New 8hr Storage	0	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	50	50	0	0	150
New Hybrid (Solar+Storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	150	304	334	650	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0	0	0	0	240
Cumulative Annual EE	20	38	54	67	79	70	61	53	45	38	31	25	20	16	13	10	7	5	4	3	
Portfolio RM With New Resources	19%	23%	23%	23%	23%	23%	26%	27%	23%	23%	23%	24%	26%	25%	23%	25%	23%	22%	25%	23%	

ECR	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**Total**
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	600	600	200	200	600	600	600	150	0	0	0	0	0	0	0	0	3550
New Solar T2	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	50
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	400	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	1200
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	480	480	720	480	240	0	240	0	2640
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	105	210	0	0	0	0	0	315
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 4hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	0	50
New 6hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New 8hr Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Hybrid (Solar+Storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	150	193	164	418	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	72	64	57	50	43	36	31	26	22	19	15	11	8	6	5	
Portfolio RM With New Resources	20%	23%	23%	23%	26%	23%	23%	24%	26%	27%	28%	24%	24%	27%	22%	26%	23%	22%	27%	26%	

PREFERRED	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273
New Solar T1	0	0	0	0	400	100	200	0	0	0	0	0	0	0	0	0	0	0	0	0	700
New Solar T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800
New Wind T1	0	0	0	0	400	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	600
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	480	0	240	0	0	480	240	720	480	240	0	0	0	2880
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas Rice	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0	0	550
New 4hr Storage	0	0	0	0	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
New 6hr Storage	0	0	0	0	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200
New 8hr Storage	0	0	0	0	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
New Hybrid (Solar+Storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	150	150	150	557	380	100	250	0	0	0	0	0	0	0	0	0	0	0	0	0	
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1053
Early Gas CT	0	0	0	0	0	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	480
Cumulative Annual EE	20	38	54	67	79	70	61	53	45	38	31	25	20	16	13	10	7	5	4	3	
Portfolio RM With New Resources (Summer)	20%	20%	22%	25%	31%	33%	35%	37%	35%	37%	36%	34%	35%	31%	31%	31%	28%	27%	26%	26%	
Portfolio RM With New Resources (Winter)	28%	29%	27%	30%	30%	30%	30%	34%	32%	34%	33%	32%	33%	29%	31%	34%	31%	30%	30%	29%	

Portfolio NPV Revenue Requirements:

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
Reference Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	175,772	343,344	86,604	1,182,814	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	157,870	350,968	120,239	1,210,549	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	188,789	236,624	112,642	1,234,610	20,715,144
2028	236,713	145,331	425,632	185,640	351,572	327	-114,583	170,382	169,430	135,756	1,367,340	20,867,232
2029	237,985	192,943	497,052	189,798	281,398	265	-188,826	135,158	148,497	159,509	1,356,785	20,946,024
2030	238,890	213,058	499,843	197,638	193,283	67,789	-226,825	207,687	119,745	162,018	1,433,637	21,008,472
2031	175,309	224,457	492,193	203,538	197,285	68,573	-263,964	212,565	120,243	160,530	1,350,243	21,078,528
2032	143,564	238,546	494,887	211,683	169,302	60,464	-289,100	219,370	106,880	161,990	1,303,826	21,155,856
2033	136,160	282,466	560,255	236,401	146,706	51,947	-353,703	224,864	95,747	183,112	1,372,461	21,253,152
2034	137,803	348,249	661,323	267,752	154,557	55,254	-442,847	179,519	171,096	216,109	1,406,624	21,306,528
2035	124,809	398,098	723,772	296,930	177,104	60,566	-551,203	139,701	249,668	236,823	1,356,933	21,385,464
2036	123,694	422,792	711,609	313,035	190,989	65,871	-407,908	133,069	254,488	234,154	1,532,817	21,466,560
2037	125,949	448,075	705,693	333,245	203,455	72,586	-401,802	137,710	265,944	232,605	1,591,571	21,562,488
2038	128,125	474,436	743,954	312,200	271,248	94,083	-343,893	120,772	346,187	244,599	1,699,338	21,649,272
2039	130,302	501,079	741,395	336,431	266,856	85,038	-288,802	146,125	340,700	243,506	1,821,229	21,750,336
2040	131,938	528,473	740,123	361,244	374,720	121,127	-235,215	118,448	482,948	242,568	1,900,479	21,828,912
2041	134,640	528,473	705,265	366,624	436,554	143,918	-203,083	114,249	572,512	230,704	1,884,832	21,907,896
2042	136,447	538,850	682,154	375,674	457,929	152,791	-194,861	117,024	600,041	222,705	1,888,671	21,977,136
2043	140,739	549,574	663,674	389,009	435,765	150,324	-105,246	124,412	565,208	215,586	1,998,627	22,071,048
Net Present Value 2024-2043	2,071,098	2,756,927	5,713,881	2,379,417	3,757,927	520,291	(2,189,313)	1,870,813	2,883,908	1,853,909	15,851,042	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
REF Winter Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)=(1)thru(8)-(9)+(10)	
	Existing Depreciation	New Depreciation	Capital Charge	Fixed O&M	Fuel Costs	Emission Costs	Other VOM Costs	Market Purchases Costs	*Less:* Market Sales Revenue	Taxes	GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	179,589	343,344	86,604	1,186,632	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	185,931	350,968	120,239	1,238,610	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	218,539	236,624	112,642	1,264,359	20,715,144
2028	236,713	287,817	671,459	250,845	351,572	327	-233,354	137,262	297,098	214,031	1,619,575	20,867,232
2029	237,985	339,629	670,616	257,203	304,094	265	-256,748	88,429	266,981	216,944	1,591,436	20,946,024
2030	238,890	393,364	682,440	278,440	214,814	73,702	-297,841	127,165	254,503	223,100	1,679,570	21,008,472
2031	175,309	401,228	643,292	283,393	223,580	75,813	-328,113	130,252	237,104	212,119	1,579,769	21,078,528
2032	143,564	412,525	614,947	294,463	204,620	70,168	-329,099	134,272	207,266	203,996	1,542,192	21,155,856
2033	136,160	432,754	600,934	306,676	171,949	58,884	-340,617	154,708	131,617	199,525	1,589,356	21,253,152
2034	137,803	441,137	578,222	311,589	183,392	63,225	-339,894	159,364	139,402	191,906	1,587,342	21,306,528
2035	124,809	473,605	623,321	331,703	203,741	67,950	-431,866	145,284	208,944	205,137	1,534,740	21,385,464
2036	123,694	498,299	618,724	348,652	230,944	77,060	-286,934	137,071	230,995	203,358	1,719,874	21,466,560
2037	125,949	536,222	632,307	378,349	253,852	86,885	-280,263	140,768	256,313	206,941	1,824,697	21,562,488
2038	128,125	527,044	664,398	353,927	331,979	111,611	-13,789	119,098	342,835	216,326	2,095,884	21,649,272
2039	130,302	524,574	662,713	378,441	330,487	103,783	33,777	142,375	337,101	215,219	2,184,569	21,750,336
2040	131,938	523,121	661,462	403,542	466,882	148,493	106,436	110,393	515,275	214,327	2,251,319	21,828,912
2041	134,640	523,121	626,236	409,210	548,184	177,731	117,539	108,622	639,322	202,433	2,208,395	21,907,896
2042	136,447	523,121	589,466	412,922	560,562	184,553	114,508	112,595	652,355	190,235	2,172,053	21,977,136
2043	140,739	508,457	558,486	420,733	518,526	176,511	112,709	122,361	587,586	179,291	2,150,228	22,071,048
Net Present Value 2024-2043	2,071,098	3,532,844	5,979,429	2,816,629	4,077,257	608,741	(1,573,001)	1,661,522	3,298,972	1,941,553	17,817,100	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
CETA Portfolio Under Reference Scenario

Utility Costs (Nominal$000)

	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	187,256	343,344	86,604	1,194,298	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	173,639	350,968	120,239	1,226,318	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	209,847	236,624	112,642	1,255,668	20,715,144
2028	236,713	166,829	464,352	194,285	351,572	327	-136,261	164,580	187,506	148,086	1,402,978	20,867,232
2029	237,985	201,573	503,215	193,094	292,746	265	-190,714	132,602	167,043	161,817	1,365,541	20,946,024
2030	238,890	236,056	537,552	207,413	204,048	70,746	-250,066	195,838	157,575	174,315	1,457,216	21,008,472
2031	175,309	264,551	563,987	220,958	207,420	71,367	-316,672	194,434	180,342	183,934	1,384,945	21,078,528
2032	143,564	264,551	528,740	222,552	179,041	63,141	-318,416	206,944	145,136	173,839	1,318,821	21,155,856
2033	136,160	322,084	620,128	254,007	153,505	53,815	-401,296	199,665	142,696	203,205	1,398,577	21,253,152
2034	137,803	379,636	698,736	281,523	161,056	57,048	-477,050	162,877	211,367	229,266	1,419,528	21,306,528
2035	124,809	435,037	725,430	309,407	182,910	62,175	-548,945	137,122	258,237	238,569	1,408,277	21,385,464
2036	123,694	472,078	730,269	334,695	207,862	70,593	-403,921	128,950	277,909	240,801	1,627,113	21,466,560
2037	125,949	497,360	723,203	355,083	221,246	77,629	-397,699	133,780	291,044	238,637	1,684,144	21,562,488
2038	128,125	527,821	787,051	343,359	400,717	130,078	-305,701	55,966	514,118	258,487	1,811,786	21,649,272
2039	130,302	554,464	782,312	367,930	399,815	122,699	-270,417	69,111	502,742	256,544	1,910,018	21,750,336
2040	131,938	594,939	776,439	391,953	490,265	154,273	-192,109	55,439	644,740	254,128	2,012,526	21,828,912
2041	134,640	622,241	752,790	406,216	555,096	178,600	-127,489	56,808	753,469	245,882	2,071,317	21,907,896
2042	136,447	636,787	727,819	420,016	591,997	193,022	-142,088	57,739	804,502	237,403	2,054,639	21,977,136
2043	140,739	636,787	688,903	427,910	553,835	186,462	-22,952	62,533	742,127	223,886	2,155,976	22,071,048
Net Present Value 2024-2043	2,071,098	3,082,258	5,984,686	2,525,793	4,066,180	606,860	(2,206,678)	1,719,765	3,423,093	1,944,002	16,370,871	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
ECR Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	175,419	343,344	86,604	1,182,462	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	155,157	350,968	120,239	1,207,836	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	184,072	236,624	112,642	1,229,892	20,715,144
2028	236,713	175,260	481,816	202,218	351,572	327	-147,956	149,604	194,968	153,650	1,408,238	20,867,232
2029	237,985	240,270	575,640	217,858	281,398	265	-237,090	96,828	182,913	185,045	1,415,285	20,946,024
2030	238,890	282,348	609,374	238,743	193,283	67,789	-293,916	120,607	166,406	197,950	1,488,662	21,008,472
2031	175,309	293,746	591,970	244,948	197,285	68,573	-342,867	124,342	168,668	193,999	1,378,638	21,078,528
2032	143,564	327,561	630,092	262,701	169,302	60,464	-399,254	118,831	181,436	207,169	1,338,995	21,155,856
2033	136,160	360,952	666,587	281,910	146,706	51,947	-454,153	127,222	161,121	219,723	1,375,935	21,253,152
2034	137,803	396,925	706,438	297,576	154,557	55,254	-511,189	124,938	227,337	233,365	1,368,330	21,306,528
2035	124,809	405,042	688,955	305,718	177,104	60,566	-571,791	124,409	266,611	228,111	1,276,313	21,385,464
2036	123,694	435,367	688,297	323,853	190,989	65,871	-428,579	117,277	271,871	228,048	1,472,946	21,466,560
2037	125,949	469,651	698,444	349,360	209,251	74,231	-421,322	120,165	291,498	230,906	1,565,137	21,562,488
2038	128,125	496,012	739,395	328,514	278,690	96,231	-291,776	105,053	377,747	243,258	1,745,757	21,649,272
2039	130,302	522,656	738,551	352,950	274,556	87,307	-178,494	127,895	370,953	242,332	1,927,100	21,750,336
2040	131,938	536,353	719,468	368,145	365,156	118,267	-65,506	102,015	490,744	235,668	2,020,760	21,828,912
2041	134,640	536,353	684,368	373,561	423,970	140,085	-34,520	98,465	577,763	223,694	2,002,853	21,907,896
2042	136,447	550,899	666,390	387,219	457,925	152,789	26,636	101,558	624,923	217,267	2,072,207	21,977,136
2043	140,739	550,899	633,581	394,976	423,845	146,583	84,415	108,604	569,110	205,628	2,120,159	22,071,048
Net Present Value 2024-2043	2,071,098	3,061,446	6,038,807	2,570,589	3,755,213	519,324	(2,217,451)	1,518,833	3,156,932	1,965,086	16,126,014	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
FOR Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)=(1)thru(8)-(9)+(10)	
	Existing Depreciation	New Depreciation	Capital Charge	Fixed O&M	Fuel Costs	Emission Costs	Other VOM Costs	Market Purchases Costs	*Less:* Market Sales Revenue	Taxes	GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	175,772	343,344	86,604	1,182,814	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	157,870	350,968	120,239	1,210,549	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	188,789	236,624	112,642	1,234,610	20,715,144
2028	236,713	145,331	425,632	185,640	351,572	327	-114,583	170,382	169,430	135,756	1,367,340	20,867,232
2029	237,985	192,943	497,052	189,798	281,398	265	-188,826	134,572	148,236	159,509	1,356,460	20,946,024
2030	238,890	213,058	499,843	197,638	193,283	67,789	-226,825	206,779	119,273	162,018	1,433,201	21,008,472
2031	175,309	221,607	485,928	202,245	197,285	68,573	-259,384	212,954	116,130	158,534	1,346,921	21,078,528
2032	143,564	232,878	483,081	209,123	169,302	60,464	-280,070	220,693	98,883	158,171	1,298,324	21,155,856
2033	136,160	252,357	500,983	221,476	146,706	51,947	-312,913	254,752	70,294	164,083	1,345,257	21,253,152
2034	137,803	279,744	526,259	234,694	154,557	55,254	-343,276	226,835	87,713	172,441	1,356,599	21,306,528
2035	124,809	312,212	574,198	253,805	177,104	60,566	-429,793	216,035	157,929	187,506	1,318,512	21,385,464
2036	123,694	351,177	617,074	272,747	183,820	63,866	-323,172	205,763	200,020	201,623	1,496,573	21,466,560
2037	125,949	363,818	599,517	283,097	185,661	67,542	-319,259	216,539	198,851	196,456	1,520,471	21,562,488
2038	128,125	399,597	671,011	270,469	353,336	116,404	-252,059	103,656	363,721	218,821	1,645,639	21,649,272
2039	130,302	420,974	660,597	287,108	335,374	103,717	-189,230	124,158	331,204	215,349	1,757,142	21,750,336
2040	131,938	448,368	662,398	311,135	425,755	135,104	-138,104	105,163	455,698	215,647	1,841,706	21,828,912
2041	134,640	465,107	641,040	321,036	475,576	154,506	-114,138	101,007	526,071	208,258	1,860,962	21,907,896
2042	136,447	475,483	620,702	329,286	496,855	163,581	-102,386	102,284	552,584	201,304	1,870,972	21,977,136
2043	140,739	475,483	591,554	336,101	468,628	159,494	-72,942	110,535	508,048	190,980	1,892,523	22,071,048
Net Present Value 2024-2043	2,071,098	2,442,171	5,296,198	2,194,982	3,857,831	547,522	(1,802,615)	1,980,729	2,670,721	1,713,181	15,630,377	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
NCR Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	175,772	343,344	86,604	1,182,814	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	157,435	350,968	120,239	1,210,113	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	188,345	236,624	112,642	1,234,166	20,715,144
2028	236,713	145,331	425,632	185,640	351,572	327	-114,583	170,382	169,430	135,756	1,367,340	20,867,232
2029	237,985	192,943	497,052	189,798	281,398	265	-188,826	134,572	148,236	159,509	1,356,460	20,946,024
2030	238,890	213,058	499,843	197,638	193,283	67,789	-226,825	206,779	119,273	162,018	1,433,201	21,008,472
2031	175,309	221,607	485,928	202,245	197,285	68,573	-259,384	212,954	116,130	158,534	1,346,921	21,078,528
2032	143,564	232,878	483,081	209,123	169,302	60,464	-280,070	220,693	98,883	158,171	1,298,324	21,155,856
2033	136,160	246,792	488,747	218,944	146,706	51,947	-303,874	258,622	63,884	160,185	1,340,345	21,253,152
2034	137,803	252,279	475,073	220,408	154,557	55,254	-311,370	265,625	73,501	156,026	1,332,154	21,306,528
2035	124,809	279,336	516,402	236,913	177,104	60,566	-383,864	254,994	131,296	168,556	1,303,520	21,385,464
2036	123,694	311,277	560,137	249,023	176,652	61,861	-285,419	244,433	172,044	182,678	1,452,291	21,466,560
2037	125,949	332,348	555,516	262,204	177,570	65,252	-284,109	255,440	174,565	181,501	1,497,107	21,562,488
2038	128,125	376,807	625,505	247,002	329,645	109,566	-218,278	133,108	305,235	203,412	1,629,656	21,649,272
2039	130,302	398,184	615,988	263,145	309,932	96,223	-151,363	156,988	272,344	200,296	1,747,352	21,750,336
2040	131,938	444,709	620,334	287,467	373,757	119,651	-104,242	137,918	353,128	201,553	1,859,957	21,828,912
2041	134,640	450,884	591,376	293,302	411,480	135,082	-82,282	133,514	399,277	191,948	1,860,668	21,907,896
2042	136,447	474,301	572,205	302,514	419,434	139,632	-68,732	137,085	406,638	185,444	1,891,691	21,977,136
2043	140,739	474,301	542,587	308,518	396,797	136,806	-50,339	148,275	373,599	175,037	1,899,120	22,071,048
Net Present Value 2024-2043	2,071,098	2,354,057	5,096,617	2,106,731	3,747,893	514,253	(1,660,803)	2,122,203	2,416,920	1,647,221	15,582,350	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
FOR Winter Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	179,589	343,344	86,604	1,186,632	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	185,931	350,968	120,239	1,238,610	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	218,539	236,624	112,642	1,264,359	20,715,144
2028	236,713	287,817	671,459	250,845	351,572	327	-233,354	137,262	297,098	214,031	1,619,575	20,867,232
2029	237,985	339,629	670,616	257,203	304,094	265	-256,748	88,429	266,981	216,944	1,591,436	20,946,024
2030	238,890	399,111	695,076	281,050	214,814	73,702	-306,341	125,907	263,660	227,126	1,685,674	21,008,472
2031	175,309	410,176	658,710	289,683	226,481	76,619	-336,741	128,975	249,995	217,126	1,596,344	21,078,528
2032	143,564	410,176	614,710	292,200	196,724	68,004	-339,529	132,997	203,510	204,162	1,519,498	21,155,856
2033	136,160	421,711	594,584	305,249	172,132	58,929	-340,305	151,947	127,033	197,702	1,571,077	21,253,152
2034	137,803	421,711	562,945	305,268	178,497	61,861	-340,678	157,564	128,043	187,159	1,544,087	21,306,528
2035	124,809	435,240	568,408	316,721	199,492	66,768	-398,230	153,727	171,312	187,670	1,483,293	21,385,464
2036	123,694	472,281	585,753	342,932	236,717	78,669	-251,797	144,258	206,500	192,357	1,718,362	21,466,560
2037	125,949	497,563	586,865	363,368	250,346	85,886	-246,923	149,276	218,365	191,798	1,785,763	21,562,488
2038	128,125	485,355	618,748	337,293	326,376	109,993	19,719	126,936	299,003	200,994	2,054,536	21,649,272
2039	130,302	482,885	620,662	361,681	325,289	102,253	69,738	156,454	299,556	200,923	2,150,631	21,750,336
2040	131,938	481,432	622,382	386,655	456,266	145,380	152,344	122,016	463,433	200,944	2,235,922	21,828,912
2041	134,640	481,432	589,506	392,194	537,604	174,561	162,918	118,865	583,633	189,841	2,197,929	21,907,896
2042	136,447	481,432	555,064	395,782	550,975	181,596	163,132	122,674	597,594	178,430	2,167,938	21,977,136
2043	140,739	481,432	525,636	403,472	506,322	172,710	148,986	133,801	532,154	168,004	2,148,948	22,071,048
Net Present Value 2024-2043	2,071,098	3,397,198	5,845,585	2,766,075	4,053,267	601,678	(1,460,597)	1,689,933	3,156,228	1,897,015	17,705,025	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
NCR Winter Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1) Existing Depreciation $000	(2) New Depreciation $000	(3) Capital Charge $000	(4) Fixed O&M $000	(5) Fuel Costs $000	(6) Emission Costs $000	(7) Other VOM Costs $000	(8) Market Purchases Costs $000	(9) *Less:* Market Sales Revenue $000	(10) Taxes $000	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs $000	Load Served MWh
2024	234,062	0	256,159	72,661	513,884	1,012	50,873	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	179,589	343,344	86,604	1,186,632	20,520,336
2026	232,257	79,352	379,756	111,819	530,181	1,027	-50,983	185,408	350,968	120,239	1,238,087	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	218,006	236,624	112,642	1,263,827	20,715,144
2028	236,713	287,817	671,459	250,845	351,572	327	-233,354	136,505	297,098	214,031	1,618,818	20,867,232
2029	237,985	330,893	658,705	250,893	304,094	265	-236,493	96,611	261,875	213,154	1,594,233	20,946,024
2030	238,890	359,740	619,698	259,986	214,814	73,702	-244,311	153,077	216,851	203,010	1,661,756	21,008,472
2031	175,309	370,806	591,216	268,574	226,481	76,619	-267,948	158,900	205,565	194,871	1,589,264	21,078,528
2032	143,564	370,806	552,759	270,934	196,724	68,004	-271,622	165,254	160,794	183,307	1,518,935	21,155,856
2033	136,160	400,133	539,466	285,665	165,128	57,006	-274,197	202,760	92,181	178,854	1,598,793	21,253,152
2034	137,803	429,859	527,446	295,977	171,958	60,056	-274,342	219,099	103,678	174,449	1,638,627	21,306,528
2035	124,809	460,049	519,449	311,554	193,686	65,160	-299,697	236,514	142,346	170,764	1,639,942	21,385,464
2036	123,694	515,391	537,520	339,001	219,973	73,984	-154,950	237,429	171,325	175,724	1,896,441	21,466,560
2037	125,949	568,002	548,462	364,724	227,498	79,406	-151,417	253,464	185,372	178,399	2,009,116	21,562,488
2038	128,125	546,554	562,527	332,705	287,073	98,645	114,989	240,023	246,618	182,151	2,246,176	21,649,272
2039	130,302	557,406	577,795	365,955	297,012	93,918	123,636	262,013	255,382	186,220	2,338,876	21,750,336
2040	131,938	542,256	557,568	380,453	400,659	128,848	138,645	214,874	355,740	179,285	2,318,786	21,828,912
2041	134,640	542,256	521,528	385,139	468,805	153,713	147,259	205,795	443,941	167,080	2,282,274	21,907,896
2042	136,447	552,471	497,535	392,771	487,660	161,997	150,447	207,092	465,273	158,774	2,279,922	21,977,136
2043	140,739	537,388	484,654	406,982	464,449	159,393	139,790	212,244	428,159	153,408	2,270,887	22,071,048
Net Present Value 2024-2043	2,071,098	3,504,258	5,489,148	2,699,310	3,925,965	563,844	(1,083,608)	2,127,418	2,803,214	1,776,861	18,271,080	

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
Proposed Portfolio Under Reference Scenario

	Utility Costs (Nominal$000)											
	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs	Load Served
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	MWh
2024	234,062	0	256,159	72,661	0	1,012	564,757	186,536	218,060	81,230	1,178,357	20,457,096
2025	232,253	16,372	274,250	82,204	593,467	1,157	64,080	162,502	343,344	86,604	1,169,545	20,520,336
2026	232,257	79,352	379,756	111,819	530,183	1,027	-50,983	161,421	350,971	120,239	1,214,100	20,630,784
2027	235,066	79,352	354,038	114,053	443,615	842	-57,164	253,273	236,624	112,642	1,299,093	20,715,144
2028	236,713	192,940	473,546	208,127	351,572	327	-130,614	206,030	187,718	150,981	1,501,904	20,867,232
2029	237,985	227,844	463,785	204,754	304,094	265	-139,906	154,174	155,049	149,247	1,447,193	20,946,024
2030	238,890	254,630	478,108	216,865	214,814	73,702	-182,287	246,914	123,474	154,934	1,573,095	21,008,472
2031	175,309	276,761	472,973	234,379	235,401	79,076	-198,590	202,355	138,142	153,872	1,493,395	21,078,528
2032	143,564	276,761	443,589	237,028	218,100	73,737	-201,618	212,587	116,646	144,833	1,431,935	21,155,856
2033	136,160	288,296	434,656	250,208	177,001	60,265	-205,618	265,930	46,704	141,626	1,501,821	21,253,152
2034	137,803	288,296	410,908	250,368	184,042	63,367	-206,703	280,538	52,023	133,687	1,490,284	21,306,528
2035	124,809	288,296	393,685	255,778	204,693	68,342	-225,848	294,747	81,334	127,162	1,450,329	21,385,464
2036	123,694	312,990	404,969	273,030	238,362	79,184	-79,918	279,907	102,717	129,966	1,659,466	21,466,560
2037	125,949	325,631	399,700	283,455	241,343	83,127	-78,071	291,951	100,480	127,514	1,700,118	21,562,488
2038	128,125	332,080	480,782	270,905	428,098	137,587	47,969	134,676	239,472	152,296	1,873,048	21,649,272
2039	130,302	329,610	491,287	294,624	439,671	134,944	57,675	165,305	257,900	155,124	1,940,642	21,750,336
2040	131,938	343,307	482,092	309,079	537,388	168,281	132,367	134,758	372,360	151,928	2,018,777	21,828,912
2041	134,640	343,307	456,525	313,741	612,846	196,110	141,842	131,370	478,640	143,352	1,995,094	21,907,896
2042	136,447	343,307	429,346	316,465	626,485	203,703	143,737	135,154	492,804	134,459	1,976,299	21,977,136
2043	140,739	343,307	407,162	323,282	586,013	196,629	130,081	147,955	437,409	126,548	1,964,306	22,071,048
Net Present Value 2024-2043	2,071,098	2,348,678	4,527,308	2,286,837	3,775,766	659,930	(224,056)	2,282,305	2,401,794	1,448,004	16,774,077	

Exhibit G: Stakeholder Comments

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
1.	Staff	SWEPCO's going-in position (page 12 of SWEPCO Assumptions), which begins with the year 2022, seems to include only about 150 MW of wind, while the North Central Wind project, which is nearing completion, is reported by AEP to total 1,484 MW. Further, SWEPCO notes on page 13 of SWEPCO Assumptions that its share of this project is 809 MW. The 809 MW might have been presented in de-rated (aka "firm"} terms by SWEPCO in its going in position so that the 809 MW nameplate capacity would be scaled back to a much lower number. Staff asks that this be clarified in SWEPCO Draft IRP, and that the role of existing power purchase agreements (for renewable or other generation) be made transparent and clearly accounted for (volume, time period of contract) in the going in position, as they do not seem to be included in the projection on page 12.	The 809 MW represents SWEPCO's share of the North Central Wind (NCW) wind farms. The information in the Going In position chart represents the accredited capacity of the 809 MW. Additionally, the Company will update the Going-In chart to differentiate the PPA resources more clearly from owned resources.
2.	Staff	Also on page 12 of SWEPCO Assumptions, the going in position includes an addition of what appears to be about 300 MW of coal capacity in 2038, though this may not have appeared in the version of the chart that SWEPCO presented on March 29, 2022; Staff asks that this be clearly identified in the Draft IRP, and if it is not an error, SWEPCO should explain why a capacity addition over 15 years into the future is included in its going in position.	The amount of Coal Resources was mis-represented in the presentation and was updated for the July Stakeholder meeting.
3.	Staff	Staff requests that SWEPCO provide, in the Draft IRP, an analysis of the historical and going forward costs for each of the existing supply side resources included in the going in position. This analysis should include transparent details of operating and maintenance costs, additional capital	The Company will prepare an indicative analysis.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		costs including the cost of new equipment needed to comply with Federal and state-level emissions requirements such as the requirements discussed by SWEPCO in its 2019 IRP Final Report, in Section 3.3, especially for meeting potential future requirements under EPA 's Coal Combustion Residuals ("CCR") Rule and Effluent limitations Guidelines (" ELG"). 1 SWEPCO should then convert the going-forward costs (including a transparent assumption for each resource's capacity factor) to a levelized cost of energy ("LCOE") for each resource; and then SWEPCO should compare each resource's LCOE to SWEPCO's forecast of energy prices in each of its Scenarios. The Draft IRP should then discuss SWEPCO's decisions whether to deactivate or retire each of its existing resources in the context of the going-forward LCOE and energy prices as well as reliability and resource adequacy in each of SWEPCO's future Scenarios.	
4.	Staff	Staff requests that SWEPCO include total historical peak load and total energy for SWEPCO and SWEPCO LA for the past IO years, and the growth rate of load for the past I0 years, in its Draft IRP. This should be broken out by end-use sector (i.e., residential, commercial, industrial).	The Company has included SWEPCO historical peak demand and energy requirements in Exhibit A-3. Exhibits A-1 and A-2, page 2 provide energy sales for the Company and Louisiana.
5.	Staff	In the future Scenarios the actual rate of growth assumed in the Base, High and Low growth should be defined in transparent and quantitative terms. The role of customer counts, usage per customer, the customer segment, and role of incremental energy efficiency in driving peak load and energy consumption should be described, and annual tables of numbers for these drivers should be provided.	The Company’s Base, High and Low load forecast scenarios are provided on Exhibit A-16. The Company expects that any alternative scenario that might be affected by customer usage variation would fall within the High and Low ranges and does not quantify the customer usage variations in the load forecasts.
6.	Staff	Staff asks that any and all assumptions (in addition to overnight capex, variable operating and maintenance ("VOM"), fixed operating and maintenance ("FOM"), and heat rate)	The Company will include a summary table in the IRP identifying the Supply-Side modeling parameters and assumptions.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		used by SWEPCO to characterize supply side resources for the purposes of modeling the resources, including capacity factors if these are used as inputs into any of the model, be provided transparently in the Draft IRP. SWEPCO did not provide a clear indication as to whether the cost of transmission interconnection was included in any of the supply resource costs for purposes of capacity expansion modeling, and Staff asks that these costs (if any are included in SWEPCO's modeling assumption) be made transparent in the Draft IRP.	Additionally, the Company intends to include a proxy for transmission interconnection costs and will provide this information in the Draft IRP.
7.	Staff	During the March 29, 2022 stakeholder meeting, SWEPCO's referred to its 2021 IRP for Arkansas, noting nameplate capacity for wind in SPP increases from about 20 gigawatts ("GW") in 2021 to about 35 GW (i.e., an additional 15 GW) in 2041 in SWEPCO's reference case, and about 40 GW (i.e., an additional 20 GW) in its Clean Energy Technology Acceleration ("CETA") scenario. SWEPCO's scenarios show about 15 GW of additional solar by 2041 in the reference case, and about 35 GW of additional solar in the CETA case. However, as of March I, 2022, there are already 29 GW of wind and 42 GW of solar capacity in the SPP interconnection queue. This increment is more than what is contemplated over 20 years in SWEPCO's scenarios. Staff recommends SWEPCO consider a scenario in which, at least, the capacity currently in the SPP queue is eventually developed, and it is assumed that the strong ongoing interest in solar and wind development does not come to an abrupt halt in 2023. This may have a large impact on projected SPP energy prices.	The Company included limits around the renewable resources available to the model informed by an assumption of an approximately 20% development of the SPP queue.
8.	Staff	SWEPCO does not consider any transmission options in its IRP process, which is not consistent with the IRP Rules.	SWEPCO is a member of SPP, and SPP has functional control of SWEPCO's transmission facilities. SPP works

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		Section 5 of the IRP Rules require that "[t]he IRP shall include the most recent long-term transmission plan and planning study prepared by the entity charged with performing transmission planning pursuant to the effective FERC jurisdictional open access transmission tariff. Unless this information is included in the transmission planning study provided, the utility shall identify and describe significant transmission constraints and limitations within its system and identify and describe any Reliability Must Run ("RMR") units that it operates. *Furthermore, the utility shall discuss any actions that could be taken to eliminate the constraints, limitations, and RMR units*" (emphasis added).	with its members to determine the transmission infrastructure needed in the near-term and long-term planning horizon to maintain electric reliability, meet public policy mandates and provide economic benefits. SWEPCO relies on the SPP Transmission Expansion Plan (STEP) which is a compilation of SPP-directed projects based on studies performed by SPP to determine upgrades needed to maintain reliability, provide transmission service, provide for generation interconnections, and provide economic benefit to its members into the future. Rather than looking at the needs of just one load serving entity (LSE), SPP assesses needs from a larger, regional perspective and determines necessary new transmission infrastructure that would provide the most net benefits to the region. SPP's Integrated Transmission Planning process assesses near and long term economic and reliability transmission needs. Their plan would attempt to mitigate these issues.
9.	Staff	The previous SWEPCO Final 2019 IRP in Docket No. 1-34715 provided a narrative of transmission issues and noted that SWEPCO's (or, rather, AEP-SPP's) existing transmission system is designed to be used in the manner now required by SPP. SWEPCO noted that this "can stress the system ... when generation is dispatched in a manner substantially different from the original design of utilizing local generation to serve local load." 5 However, SWPECO provided no analysis of transmission and no discussion of actions to be taken to eliminate constraints or reduce stress on the system.	Please see response to item 8 above. Transmission system planning is coordinated through the ITP process of SPP.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
10.	Staff	For the Draft IRP in the current docket, Staff wants SWEPCO to examine and transparently present the cost of transmission alternatives. This is needed to achieve a holistic view of future transmission and generation needs. SPP's process of approval for transmission lines includes an economic foundation as well as a reliability foundation; its economic foundation is based on congestion scores associated with a constraint. SPP South, the location of SWEPCO's service territory is a generally constrained area within SPP, with generally higher energy prices than SPP North. Most transmission projects in SPP are paid for by the highway/byway cost allocation methodology (based on the voltage level of the specific facility). This means that the cost of a high-voltage project that reduces congestion would not necessarily be allocated I 00% to the utilities in the zone where the project is located, and this cost allocation should be considered in SWEPCO's analyses where appropriate.	For this IRP, transmission considerations were evaluated through the analysis in all Portfolios. Specifically, the Company modeled portfolios to manage the net import and export of energy from the SWEPCO resources. Additionally, while the IRP serves to identify non-locational specific new resources to meet the Company's capacity and demand obligations, an estimate of costs for transmission upgrades and congestion costs in the SPP South zone were included in the modeling. While market capacity and energy resources are available for economic consideration, the Transmission network upgrades required to interconnect and ensure firm delivery of energy from new resources is comprehensively analyzed for each RFP resource in response to SWEPCOs RFP request. The regional transmission upgrade costs are coordinated through a detailed process by SPP (SPP ITP) where multiple complex factors such as expansion needs and cost allocation on a regional basis are evaluated.
11.	Staff	In addition, the SPP Market Monitoring Unit found that wind was the price-setting resource in over 20% of hours in 2020, with gas accounting for about 50% of hours, 6 and given that SPP has approved policies for expansion of SPP into the Western Energy Imbalance Service ("WEIS") market, SPP will likely have more access to renewable generation, namely wind, with this enlarged footprint. What would be the impact on energy prices in an expanded SPP in SWECPO's various scenarios if key SPP transmission projects went forward in the context of an expanded SPP? Staff would like to see this addressed in SWEPCO's Draft IRP.	The Company is unable to effectively analyze this request.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
12.	Staff	SWEPCO noted at the March 29,2022 stakeholder meeting that natural gas prices used in its modelling outlook are prices recorded at the TX/OK hub, not delivered prices at its generation plants. Therefore, these are strictly commodity prices, and do not include delivery charges (whether fixed or variable) to the power plant. Such charges are tracked separately as FOM costs to the plant However, at the stakeholder meeting it was not clear how this is modelled. Staff asks that SWEPCO provide transparency on this in its Draft IRP.	The TX/OK hub price is used in the scenario modeling as an input to determine regional pricing dynamics reflected in the LMP prices. In the portfolio modeling, where the Company assesses the need to meet the local capacity requirements, each of the existing resources are modeled with gas prices that include the commodity price and delivery charges as an input.
13.	Staff	SWEPCO explained at the March 29,2022 stakeholder meeting that its base outlook for natural gas prices is the Energy Information Administration's Annual Energy Outlook 2020 Reference case projection (page 22 of SWEPCO Assumptions). SWEPCO explained that its high and low natural gas prices outlooks were driven only by supply-side assumptions: In the Enhanced Carbon Regulation ("ECR") Scenario, regulatory pressure limits drilling and gas prices are higher, and in the No Carbon Regulation ("NCR") Scenario, regulators support exploration and production of new resources and gas prices are lower. Staff notes that North American natural gas prices have been much more volatile over the past 15-20 years than is captured by SWEPCO's scenarios, and that demand also plays a role in the formation of natural gas prices. The North American natural gas market is more exposed to international demand because of ever-increasing LNG export capacity, and the long-term trends in demand should be a consideration in SWEPCO's natural gas price outlook. Staff asks SWEPCO to include the role of demand for gas in its gas price forecasts and examine the potential for a wider range of outcomes for natural gas prices· in its scenarios.	SWEPCO evaluated a wide range of gas prices under the cost risk assessment described in Sections 7.5 and 8.4.1 of the Draft IRP.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
14.	Staff	As noted above, SWEPCO does not consider any transmission options in its IRP process. Staff has noted in a previous IRP filing that there are *"essentially two ways transmission may enter the !RP Process: 1) as an alternative to a generation project; or 2) through identified amounts of excess capacity available through the (RTO) network, which could be considered alternative resources. Both of these possibilities should be fully analyzed in the /RP Process and included in the Draft /RP Report*... "1 SWEPCO should examine and transparently present the cost of transmission alternatives, as noted above.	Please see responses to Staff comments 8 & 10.
15.	Sierra Club	Sierra Club urges SWEPCO to provide more detail about its plans for the Company's remaining solid-fuel units, including the Welsh and Flint Creek power plants. Ideally, SWEPCO would conduct a fleet optimization or retirement study, in which the Company allows its model to select the optimal retirement date for its existing, increasingly uncompetitive solid fuel units, including both Flint Creek and Welsh.	Many specific details are required to conduct a unit specific disposition study that is beyond the scope of the IRP.
16.	Sierra Club	Low gas prices observed in the wake of the fracking boom are not likely to continue into the future. This year, gas prices have reached highs not seen since 2008. Just this week, Henry Hub futures went above $6/MMBtu–approximately 50 percent higher than the highest levels in SWEPCO's current "high-case" gas price forecast.7 As Henry Hub prices are at their highest point since 2008, it appears likely that real-time gas prices for SWEPCO's region are also higher than any of their modeled IRP gas price scenarios. SWEPCO should be more transparent about how its gas price forecast was developed, including providing the baseline Henry Hub assumptions and the regional modifiers that were applied to it.	The Company is using the AEO2022 Henry Hub gas prices in this IRP.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
17.	Sierra Club	The current reality of high gas prices should be incorporated into SWEPCO's IRP. Given the volatility of gas prices, it is critical that SWEPCO understand the risks to ratepayers from continued reliance on gas resources. These risks take the form of high fuel costs for existing gas resources, and stranded asset risk for existing, and especially new gas resources, that will be uneconomic sooner than projected if gas prices continue to rise. By using such low gas prices, SWEPCO has not assessed how ratepayers will be impacted if gas prices are significantly higher than projected moving forward.	Please see response to Staff 13.
18.	Sierra Club	SWEPCO's current portfolios hard-wire gas additions into the model (meaning the model does not choose to build gas, it is told to build it) and also use gas plants as "placeholders" in the 2030s. Taking this approach to capacity expansion modeling, while neglecting to analyze the threat that high gas prices pose to gas-reliant portfolios, is a disservice to ratepayers, who will bear the cost of insufficient planning. SWEPCO should model the performance of each portfolio against a gas price forecast 25 percent higher than the current "high-case" forecast to fully assess the impact on ratepayers of SWEPCO's proposed portfolios if high gas prices persist. Because SWEPCO already locked in many of its gas additions, this sensitivity will provide clarity on (1) which scenarios are least impacted by high gas prices, and therefore protect customers most from potential future volatility; and (2) the magnitude of the potential risk.	In this IRP, the Company did not "hard-wire" any resources.
19.	Sierra Club	SWEPCO should issue an all-source RFP or RFI as part of its planning process, as soon as possible, to acquire current	Renewable technology resource costs were informed by the Company's 2022 RFP.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		market data and to help inform decision-making on low-cost, low-risk resources with high benefit to customers.	
20.	Sierra Club	SWEPCO likely overstates the cost of renewable energy and storage options. Given SWEPCO's pursuit of power purchase agreements (PPAs) in the past and likely future market procurement (which we address further in these comments), the IRP should have included these options. One of the primary goals of the IRP modeling is to optimize resources on a cost-basis; but to do so requires modeling the best information and ownership options available. To preclude the IRP modeling from accessing lower-cost resources means that, by definition, it will choose more expensive ones because the model cannot select resources that it does not know exist. PPAs could offer reduced prices and different financing structures that offer lower customer costs than self-build resources. For instance, PPA's allow the developer (and by extension the buyer) to benefit from the full Investment Tax Credit (ITC) for solar or solar-battery hybrids immediately, whereas regulated utilities must "normalize" the credit over the life of the project, as SWEPCO is assuming in this IRP. The Company must consider these potentially lower-cost ownership options in its model to ensure that it is truly developing a low-cost plan and that the plan comports more closely with reality.	The Company included two tiers of Solar and Wind resources, informed by its 2022 RFP, to test a range of assumed responses that would come from a specific RFP process. Furthermore, the Inflation Reduction Act (IRA) signed into law in August 2022, released the requirement for regulated utilities to "normalize" the associated tax credits. The IRP will include the new IRA tax benefits related to the clean energy resources modeled in this IRP.
21.	Sierra Club	To protect the communities SWEPCO serves, and also account for the environmental impacts of its fleet, it is increasingly important for SWEPCO to include quantified health impacts in its assessments of its portfolio options in this IRP process. SWEPCO should quantify and analyze the comparative public health impacts from air pollution, namely SO2, NOx, PM, and mercury emissions, of each of the portfolios it considers in its IRP and evaluate the public health	The Company will include a CO_2 emissions reductions metric as part of the Scorecard assessment of the different Portfolios modeled. Any further analysis to quantify public health impacts on non-location specific resource additions would be highly speculative.

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	Stake-holder	Comment	SWEPCO Response
		cost that various air pollutants have on public health, especially in environmental justice communities.	
22.	Sierra Club	SWEPCO should consider the environmental justice implications associated with its ultimate selection of its preferred portfolio because the communities that are harmed most by persisting reliance on fossil fuel burning power plants are the communities who should benefit the greatest from reduced emissions, coal retirements, and investments in renewable energy. EJSCREEN14 is EPA's environmental justice screening and mapping tool that combines environmental and demographic indicators based on nationally consistent data and allows utilities to do just that. When run for a particular power plant, EJScreen demonstrates the relative environmental justice concerns for designated areas by "EJ Indexes," making significant data explicit, especially when reviewing communities that surround facilities and their racial composition, per capita income, and other demographic indicators in relation to various pollutants. SWEPCO should take care to consider the distinct communities whose health is impacted by SWEPCO's continued reliance on fossil fuel generation.	The IRP serves to inform the Company of types and amounts of different resources to meet its obligation without specific locational assessments. The Company does not consider the EJ screen to be an appropriate tool for use in non-locational specific plans.
23.	Sierra Club	We recommend that SWEPCO hold two interim stakeholder meetings between now and the draft IRP filing with the understanding that the input from stakeholders will be considered throughout the modeling process leading up to the Draft IRP filing.	The Company held an additional Stakeholder meeting in July 2022 to engage stakeholders throughout the process. Another Stakeholder meeting will be offered in accordance with the LPSC IRP Process Schedule of Events.
24.	AEMA	In the IRP Scenario #2, the Clean Energy Technology Advancement, tax extensions for renewable energy and a new credit for storage were the only credits included. Based on the tax credits currently under consideration, it would be useful in at least one scenario additional tax incentives for	The Company will evaluate a Clean Energy Technology Advancement (CETA) Portfolio where higher levels of tax incentives under the Inflation Reduction Act (IRA) are assumed and where Technology costs decline more rapidly. This will be modeled under a high load condition.

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	Stake-holder	Comment	SWEPCO Response
		microgrids, interconnection, and bonus credits for deployment in low-income communities—all of which will materially lower the cost of DERs while increasing access to clean energy for many more residents and business in Louisiana.	
25.	AEMA	AEMA inquired during the stakeholder presentation if Order 2222 (“Order”) had been considered in the IRP development process.6 SWEPCO is part of Southwest Power Pool (“SPP”) which is under the jurisdiction of the Federal Energy Regulatory Commission (“FERC”) and as such is required to comply with Order 2222 which mandates that DERs be able to fully participate in all wholesale markets. We recommend that implementation of this Order be made clear in the scenarios for the IRP.	As it pertains to the Company’s Demand and Energy needs, while the net impact of DERs to the load forecast is not explicitly quantified, to the extent that it affects historical trends, it is implicitly captured in the load forecast.
26.	AEMA	SWEPCO reports that at the end of 2020, only 0.4% of all customers had Distributed Generation (“DG”) installed (fewer than 2,300 customers) and that by 2030, SWEPCO projects only 0.9% of customers will have installed DG at their premise.7 If Order 2222 is implemented as FERC intended in SPP and other organized markets, AEMA would predict the deployment of DERs, including DG, could be much greater than anticipated. In addition, given the rapid move toward electrification, AEMA would recommends that SWEPCO consider that customer DER deployment could increase faster than anticipated and that these trends be considered in the planning process.	Please see the Company’s response to question 25.
27.	AEMA	When discussing DER, SWEPCO explicitly only considers rooftop solar, not a more holistic list of community solar, distributed storage, microgrids, energy efficiency, and demand response. While electric vehicles are included in the analysis, other forms of electrification, such as electric heat pump and transitioning from natural gas to electric appliances, are not considered. It would be prudent for	Please see the Company’s response to question 25

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	Stake-holder	Comment	SWEPCO Response
		SWEPCO to include a wider variety of technologies in the planning process and modeling runs to ensure that a range of outcomes are considered more fully in developing a long range portfolio.	
28.	AEMA	Only utility-scale solar plus 4 -hour battery storage are considered in the capacity credit planning, yet with Order 2222 implementation, resources of all types on the customer side will be eligible to participate in wholesale markets and, as such, could be considered for capacity credits within SWEPCO's system.	Please see the Company's response to question 25.
29.	AEMA	AEMA's recommendations for more complete inclusion of DERs in the IRP modeling points to the need to determine the full value of these resources and account for that value in the planning process.	Please see the Company's response to question 25.
30.	AEMA	AEMA recommends DERs being taken into consideration for resilience purposes which, while not explicit in the IRP, will be crucial to include in long term planning given the increased frequency and severity of storms.	Please see the Company's response to question 25.
31.	SREA	Complete the 3,000 MW wind RFP	The Company has conducted and will continue to conduct RFPs for new resources.
32.	SREA	Announce plans to issue a 1,000 MW solar RFP in early 2023	The Company has conducted and will continue to conduct RFPs for new resources.
33.	SREA	Use the most up-to-date NREL ATB cost assumptions for renewable generation resources	Resource costs were informed from multiple resources including EIA, Charles River Associates and RFP data. NREL was used to identify the associated technology learning curves used for future resource cost assumptions.
34.	SREA	Provide an analysis showing the effect of modeling renewable generation resources as PPA's in the IRP model	The Company included two tiers of Solar and Wind resources to test a range of assumed responses that would come from a specific RFP process.

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	Stake-holder	Comment	SWEPCO Response
35.	SREA	Incorporate multiple battery storage configurations (1-hr, 2-hr, and 4-hr), and develop different dispatch strategies that may better highlight battery storage value	The Company considered multiple battery considerations in the portfolio selection process. The development of different dispatch strategies is outside of the IRP scope.
36.	SREA	Conduct a reliability study that evaluates the loss of load expectations (LOLE) and ELCC's for resources on SWEPCO's system and captures the interaction between all resources across the Company's entire portfolio	LOLE study is an RTO function to which, the Company is actively engaged with SPP. For this IRP, the Company modeled a dynamic ELCC for solar resources for each Portfolio.
37.	SREA	Conduct an ELCC analysis on its existing fossil generation fleet, as well as new fossil units	For traditional resources such as a thermal generator, ELCC is approximately equal to its unforced capacity (UCAP) value (which is determined based on the resource's forced outage rate). The Company continues to be engaged with SPP with respect to their Resource Adequacy assessments and the associated accredited capacities for each of its thermal resources.
38.	SREA	Provide an updated Action Plan with details on the costs of winterizing its fossil fleet, in alignment with SPP and LPSC recommendations	NERC updated their rules shortly after Winter Storm Uri to which, SWEPCO is in full compliance with at this time. SPP and LPS recommendations are in alignment with NERC standards. All SWEPCO plants also updated their winterization plans following winter storm Uri that were modified to include additional areas required by updated NERC rules.
39.	SREA	Allow renewable energy resources and energy storage options to be selected by the model within a reasonable amount of time (1-2 years)	The First-Year availability for resources identified for the modeling considered the timing needed to conduct an RFP process, evaluate responses, proposed any new resources to the commission for approval and for the final construction of new resources. The Company does not consider a 1-2 year time frame to be reasonable.
40.	SREA	Do not include annual limits on solar or wind resource additions	Modeling results did not reach annual limits for solar and wind resources suggesting the limits included were not a

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
			limiting factor. A sensitivity to remove any annual limits is not expected to provide any further insights.
41.	SREA	Include a much higher cost natural gas cost assumption to better capture a broader band of risk	The stochastics analysis considered a wide range of gas prices that reflect a broader band of risk as discussed in section 7.5.1 of the draft IRP.
42.	SREA	Continue monitoring federal policy changes (e.g., PTC/ITC extensions)	The Company acknowledges this feedback.
43.	SREA	Improve modeling of paired resources, solar-battery hybrids in particular by recognizing the economics of scale that exist when co-locating resources	For this IRP, the Company included a paired Solar + Storage resource for selection.
44.	SREA	Provide additional details regarding “green hydrogen” production or use cases	The Company will include additional discussion around “Green Hydrogen” production in the IRP.

Draft IRP Stakeholder Feedback

	Stake-holder	Comment	SWEPCO Response
1.	Sierra Club	SWEPCO should include modeling runs that allow for economic retirement of its existing fossil plants. In its Draft report, SWEPCO did not allow the AURORA model to make economic retirement decisions for its coal units or test alternative retirement dates. SWEPCO simply preselected retirement dates for its existing units without apparent consideration of economics or risks.	Please see the Company’s response to Staff Feedback items 35 and 36 below.
2.	Sierra Club	SWEPCO should explain its understanding of the environmental controls and costs that would be required at Flint Creek and Turk to comply with final and proposed regulations and include such costs in its modeling for this IRP.	Please see the Company’s response to Staff Feedback item 46 below.

		SWEPCO's Draft IRP was released before the U.S. Environmental Protection Agency ("EPA") proposed significant regulations that create risk for SWEPCO's coal units – one focused on carbon dioxide ("CO2") emissions from power and another related to water discharges from steam electric power plants (known as the Effluent Limitation Guidelines ("ELG") for coal-burning electric generating units). SWEPCO should study and incorporate compliance with these regulations into its analysis before issuing its final IRP. SWEPCO has not presented a full picture of the environmental regulation costs that will likely be imposed on its coal plants in the near term, including EPA's Good Neighbor Plan and the Regional Haze Rule, which the Draft IRP did not evaluate.	
3.	Sierra Club	SWEPCO should model additional tax credits available for renewables under the Inflation Reduction Act ("IRA") in its final IRP modeling runs. SWEPCO should include the 10% adders for "energy communities" and domestic content.	The Company has not modeled any type of location specific resource and the assumption that responses to an RFP would meet the additional ten percent tax credit available would be overly speculative. In the Company's experience based on a large sample of renewable RFP responses in SPP since the IRA was enacted, the vast majority of projects that could actually be available to SWEPCO in central SPP are either not located in energy communities, or the developers are not willing to make binding commitments to the level of domestic content needed to allow the project to receive that 10% adder, or both. As a proxy for the improved economics which could result from more tax credits, the Company prepared the CETA scenario, which assumes renewables are more economic than in other scenarios due to rapid declines in capital costs over time. To the extent project developers bid projects into future RFPs with binding commitments that the projects will qualify for these adders, the higher tax credits will be factored into the project economics.
4.	Sierra Club	SWEPCO should also re-evaluate its cost assumptions for new resources and benchmark its costs against the cost	The Company's costs for renewable resources are aligned to responses it received from its 2021 RFP.

		assumptions relied on by utilities in the region as well as the responses from recent RFPs.	SWEPCO's own transparent RFP's are the most reliable source of information for the costs of resources actually available to SWEPCO in SPP. The Company does not know the basis for the costs relied on by other utilities in the region.
5.	Sierra Club	SWEPCO should expand its modeling assumptions to include 6-hour and 8-hour batteries	The Company included 6- and 8-hour battery alternatives to the available resources for economic selection in the Final IRP optimization and analysis.
6.	Sierra Club	SWEPCO should apply for the U.S. Department of Energy loan financing to lower the cost of replacing coal units and expanding transmission capacity.	This question is outside the scope of this IRP.
7.	Sierra Club	SWEPCO should consider public health impacts as one metric in its resource planning.	The purported impacts are a matter of public policy and effectively would be accounted for in any federal and state policies the Company will continue to remain in compliance with.
8.	Southern Renewable Energy Association (SREA)	On August 29, 2023, a stakeholder meeting was held regarding the Draft IRP. SREA appreciates the opportunity to provide the following comments. Overall, SREA is pleased with the work conducted by SWEPCO and their consultants. SWEPCO reasonably anticipates potential changes in market and legal requirements and has created multiple scenarios to evaluate those potential futures and thus, potential outcomes. SWEPCO evaluated solar, wind, short term batteries, longer term storage, several natural gas generation options, plus advanced technologies such as small modular reactors, carbon capture sequestration (both retrofits and new build), and hydrogen-fired generation. SWEPCO discussed both summer and winter capacity assessments and current reforms ongoing at the Southwest Power Pool (SPP). SWEPCO also conducted Effective Load Carrying Capacity (ELCC) analysis based on multiple market scenarios for some resources. The Company also provided some details regarding transmission plans. For our comments regarding the data inputs submitted in	

		May 2022, we submitted a short list of recommendations. SWEPCO largely accepted our recommendations and provided a sufficient amount of information to stakeholders. SREA appreciates SWEPCO's efforts. Our following comments mirror our previous requests, along with commentary.	
9.	Southern Renewable Energy Association (SREA)	Complete the 3,000 MW wind RFP SWEPCO responded to our request stating, "The Company has conducted and will continue to conduct RFPs for new resources." SREA appreciates SWEPCO's competitive solicitation opportunities and the Company's efforts to implement its plans.	
10.	Southern Renewable Energy Association (SREA)	Announce plans to issue a 1,000 MW solar RFP in early 2024 SWEPCO uses the IRP to guide its resource procurement and acquisition process and is frequently cited in certification for new energy and capacity purchase. 1 This is a straightforward and reasonable use for IRPs and provides clear market signals for potential bidders. SWEPCO's analysis supports an even larger RFP than we previously requested. SWEPCO is forecasting a nearly 2 GW shortfall in capacity by 2028. SWEPCO's draft Reference Portfolio shows adding approximately 1,000 MW of solar by 2028, in addition to nearly 200 MW of energy storage. By 2030, that total reaches over 2,000 MW plus an additional roughly 400-500 MW of wind energy resources. The NCR Portfolio adds a similar amount of solar in the same timeframe. The CETA Portfolio adds roughly 2,000 MW of solar between 2026-2030, 1,000 MW of wind energy, and somewhere between 500-800 MW of battery storage. Meanwhile, the ECR Portfolio adds the least amount of solar at roughly 1,000 MW, and 1,000 MW wind energy, with roughly 500 MW of battery storage between now and 2030. The FOR-Winter portfolio adds no stand-alone solar, but adds about 2,000 MW of solar+storage, with close to 4,000 MW of wind energy by 2030.	The Company released an All-source RFP where approximately 2,000MW of accredited capacity from a diverse mix of resources is requested with no specific minimum or maximum amounts of any particular resource type.

		All the portfolios (besides the FOR-Winter portfolio) are estimated to have 30-Year Levelized Rates against the Reference Scenario within 10% of each other. Even with the diversity of SWEPCO's portfolios, the portfolios still result in similar end costs and rate forecasts. Issuing RFPs for at least 1-2 GW of solar, and 1-2 GW of wind energy, and potentially 1 GW of battery storage appear to be "no regrets" options. Based on SWEPCO's results, and upcoming capacity needs, SREA recommends SWEPCO issue a 5 GW clean energy all-source RFP that allows for multiple clean energy technologies (including solar, wind, energy storage, hydrogen and hybrid projects) to bid into the process.	
11.	Southern Renewable Energy Association (SREA)	Use the most up-to-date NREL ATB cost assumptions for renewable generation resources SWEPCO is using the DOE EIA Outlook data for its energy price assumptions. The NREL ATB data were published in June 2023, two months after the Draft IRP was published. SREA would appreciate an analysis of SWEPCO's previous data assumptions compared to the updated NREL 2023 ATB data, both for capital expenditures but also on a levelized cost of energy (LCOE) basis, or an update to use the latest NREL data. As noted at the stakeholder meeting, SWEPCO is updating their market fundamental data and will re-run model scenarios with updated data. SREA supports this decision to update its fundamental data and to provide the most up-to-date analysis.	The Final IRP includes updated technology cost assumptions from AEO2023 and NREL ATB for those resources not informed through the Company's RFP responses. The updated cost assumptions will be included in the final IRP.
12.	Southern Renewable Energy Association (SREA)	Provide an analysis showing the effect of modeling renewable generation resources as PPA's in the IRP model SWEPCO currently holds several power purchase agreement (PPA) contracts for renewable energy projects. In response to our request to model PPAs, SWEPCO explained that, "The Company included two tiers of Solar and Wind resources to test a range of assumed responses that would come from a specific RFP process." However, because PPAs are effectively pay-as-you-go contractual	Although PPA resources provide a "pay as you go" alternative to an owned resource for the energy produced, they do not provide the associated tax credits to ratepayers that owned resources are eligible for. The purpose of the Company's approach in IRP modeling is to test whether the model will select resources at more than one level of cost. Based on the Company's transparent RFP process and associated confidential responses, the Company has evidence that, on average, owned and

		instruments, model selection methodology (especially through the AURORA planning software) is likely not adequately reflecting PPA payment structures by creating a "two tier" cost system. SREA requests that SWEPCO further discuss how the model evaluates the "two tier" options versus a PPA option.	PPA resources are very similar in cost when measured over common useful lives. With this insight, the Company does not model a specific PPA resource in the IRP.
13.	Southern Renewable Energy Association (SREA)	Incorporate multiple battery storage configurations (1-hr, 2-hr, and 4-hr), and develop different dispatch strategies that may better highlight battery storage value SWEPCO incorporated some discussion around longer range energy storage. For example, SWEPCO states that "For the purposes of this IRP, long-duration storage refers to storage that can provide 20 hours' worth of energy." SREA would appreciate some additional analysis about the value stack of energy storage (from SWEPCO's perspective), and potentially some sort of "break even" analysis highlighting when energy storage becomes a valuable generation resource.	The Company has included 6- and 8-hour battery alternatives to the available resources for economic selection in the Final IRP optimization and analysis.
14.	Southern Renewable Energy Association (SREA)	Conduct a reliability study that evaluates the loss of load expectations (LOLE) and ELCC's for resources on SWEPCO's system and captures the interaction between all resources across the Company's entire portfolio SWEPCO noted that "The capacity credit for wind is evaluated based on its Effective Load Carrying Capability (ELCC), consistent with SPP's methodology used for accrediting the capacity credit for wind resources. Based on SWEPCO's analysis of wind ELCC, wind resources are credited with 15.4% capacity value in the IRP analyses." Further, SWEPCO created different capacity values based on different scenarios of generation growth, specifically, "Solar capacity credit for summer is estimated at a percentage of ICAP. This capacity credit is discussed further in section 7.3.3. The percentage credit is modeled at 60% in 2026 and then declines to 15% by 2042, depending on the scenario (see Section 7.4.2)." SWEPCO also provided an assessment of the projected SPP reserve margin requirements of 15%. By evaluating SPP's current accreditation methodology, but then also anticipating potential	The Company appreciates the feedback.

		changes over time, SWEPCO's modeling framework is a reasonable effort that is an industry leader in Louisiana.	
15.	Southern Renewable Energy Association (SREA)	Conduct an ELCC analysis on its existing fossil generation fleet, as well as new fossil units While SWEPCO's efforts regarding its ELCC efforts are praiseworthy regarding renewable energy resources, it appears that there may be a gap in such a robust analysis with regards to existing and potential new fossil generation units. After Winter Storm Uri in February 2021, SPP noted that most of the natural gas and coal generation failures occurred in the southern parts of its system. SREA encourages SWEPCO to conduct a forecasted ELCC methodology for its existing generation fleet and incorporate those operational characteristics in its modeling.	For this IRP, the Company included an assumption for a Performance Based Accreditation (PBA) impact to its conventional resources. Although a specific impact to each resource has not been fully defined, the Company assumed a 45MW reduction in capacity from its existing conventional resources towards the current SPP PRM to account for some potential change expected by SPP. SPP's Resource Adequacy Working Group (SAWG) is targeting the implementation of the PBA for the 2026/27 planning year.
16.	Southern Renewable Energy Association (SREA)	Provide an updated Action Plan with details on the costs of winterizing its fossil fleet, in alignment with SPP and LPSC recommendations SWEPCO noted that the company is in compliance with the updated NERC rules, SPP rules, and the LPSC recommendations. SREA recommend SWEPCO provide more details regarding these winterization plans, and also include a discussion and costs regarding "firm" natural gas contract pricing during wintertime for specific existing facilities and assumptions for new facilities.	As stated in its draft IRP, SWEPCO is in compliance with NERC, SPP, and LPSC requirements related to winterization of its generating units. Additional details regarding any NERC and SPP reports and findings related to Winter Storm Uri and winterization may be found on the respective websites. Following the storm, the LPSC also opened Docket No. R-34758 related to a staff investigation into the cost consequences of the 2021 winter storms and the decisions made by Louisiana utilities to identify lessons learned to prepare for future events. Additional details of each utility's winterization requirements and other one-time and annual reporting requirements may be found in Staff's report issued in the docket on April 18, 2022 and SWEPCO's subsequent reports filed in the same docket. Finally, Staff's report also required that All LPSC—jurisdictional electric utilities conduct an investigation into, and submit a report on the findings of, the potential costs and benefits of the procurement of: 1) longer-term gas contracts during winter months; 2) additional financial natural gas contracts as a stability mechanism for short—term price spikes; 3) additional natural gas storage resources/facilities in close proximity to each of their natural gas generating units, and establishing firm transportation between the two, as

			a means of ensuring fuel stock availability for their natural gas generators during prospective natural disasters. That report was submitted by SWEPCO on December 29, 2022. The LPSC also opened a rulemaking related to gas hedging in Docket No. R-32976. Finally, the Arkansas and Texas jurisdictions also opened dockets following the winter storm. Those dockets were related to investigations into natural gas pricing as well as winterization of generating units for the jurisdictional utilities. Additional details may be found in APSC Docket No. 21-036-U and PUCT Docket No. 52345 as well as ongoing reporting in Project No. 39339.
17.	Southern Renewable Energy Association (SREA)	Allow renewable energy resources and energy storage options to be selected by the model within a reasonable amount of time (1-2 years) As part of SWEPCO's response to our request that renewable energy options be modeled sooner rather than later, the company stated, "The Company does not consider a 1- 2 year time frame to be reasonable." SWEPCO appears to have modeled solar and wind additions beginning in 2026. By allowing the model to select resources sooner than 2026, SWEPCO could have discovered near-term opportunities for evaluation. For example, some renewable energy resources may already be operating and could be available for either purchase or contracting. Considering SWEPCO is anticipating a capacity shortfall in 2025, a sooner-rather-than-later analysis would be valuable.	It would be overly speculative to assume in the base IRP assumptions that existing renewable resources would be available to either purchase or contract with inside a 1-2 year time frame. To the extent any such assets do exist, under the applicable regulations in SWEPCO's states such resources would need to bid into SWEPCO's next resource solicitation, which will be in early 2024. Those resources would need to then be subject to the time it takes to complete the analysis of the bids in that RFP and receive regulatory approvals of a purchase or PPA which the Company assumed would require a 2-year window. Resources that might be available will have the opportunity to respond to the Company's All-Source RFP for consideration. For the Final IRP, the Company did model a sensitivity, however, to test the unlikely potential that a proxy capacity resource might be available beginning in 2026. The result of this capacity expansion analysis is discussed further in Section 8.3.1 of the IRP.
18.	Southern Renewable Energy Association (SREA)	Do not include annual limits on solar or wind resource additions SWEPCO included annual capacity caps of 400 MW of Tier 1 wind resources, 1,600 MW of Tier 2 wind resources, with a maximum of 4,400	The Company appreciates the additional feedback related to its discussion on model inputs and assumptions and will consider this in future IRPs.

		MW of wind resources. SWEPCO also included annual capacity caps for solar with 150 MW for Tier 1 sites and 450 MW for Tier 2 sites with a maximum is 4,500 MW. SWEPCO noted that "Modeling results did not reach annual limits for solar and wind resources suggesting the limits included were not a limiting factor. A sensitivity to remove any annual limits is not expected to provide any further insights." SREA believes that the modeling results indicate that SWEPCO selected reasonable annual capacity addition limitations. When SREA made our request in this early IRP process, it was not clear how SWEPCO planned to model any limitations during the "Data Input" portion of this process. We recommend that this assumption be included as a "standard" data input to be provided to stakeholders early in the process in the future.	
19.	Southern Renewable Energy Association (SREA)	Include a much higher cost natural gas cost assumption to better capture a broader band of risk SWEPCO noted that the company included a stochastic analysis regarding natural gas prices. Based on Figure 44, it appears that SWEPCO has done a reasonable job of capturing a higher cost natural gas scenario.	The Company appreciates the feedback.
20.	Southern Renewable Energy Association (SREA)	Continue monitoring federal policy changes (e.g., PTC/ITC extensions) SWEPCO included the Inflation Reduction Act (IRA) tax incentives for a variety of renewable energy technologies. "Pursuant to the Inflation Reduction Act (IRA) of 2022, projects whose construction begins by the end of 2032 are eligible for a Production Tax Credit ("PTC"), added to the project value at a rate of 100% of the PTC, or $25/MWh11, which is implemented in AURORA as a negative variable cost adder. After 2032, PTC tax credits were assumed to be reduced to 75%, 50% and 0% of their value in 2033, 2034, and 2035, respectively." SREA appreciates SWEPCO's inclusion of the IRA in all its scenarios.	The Company appreciates the feedback and will continue to monitor federal policy changes.
21.	Southern Renewable Energy	Improve modeling of paired resources, solar-battery hybrids in particular by recognizing the economics of scale that exist when co-locating resources	The Company continues to be open to hybrid resources however, provisions in the Inflation Reduction Act (IRA)

	Association (SREA)	Solar+storage (hybrid) resources only surface in the FOR-Winter scenario/portfolio. Further, the modeled version of the SPP market appears to include no solar+storage across any scenario between now and 2042. However, stand-alone battery storage appears to be readily selected across multiple portfolios and scenarios. Regarding battery storage dispatch strategies, SWEPCO noted that, "The development of different dispatch strategies is outside of the IRP scope." SREA disagrees. Creating different generation characteristics (such as higher inverter loading ratios for hybrid resources, multiple duration configurations, and different dispatch strategies) for clean energy and energy storage resources is no different from evaluating multiple configurations for natural gas units. Whereas natural gas unit characteristics are usually set due to the mechanics of those technologies (e.g., CC's, CT's, RICE, Aeroderivative, etc. have specific ramp rates, heat rates, capex and operational costs, etc.), clean energy resources are highly modular and electronic, which necessitates making conscious methodology assumptions to take advantage of the flexibility of those systems. The purpose of developing different dispatch strategies for modelling purposes is one way to identify a truly optimized portfolio. SREA has been impressed with SWEPCO's thorough analytical work over multiple IRPs, and in many areas, SWEPCO is clearly the analytical leader in Louisiana. However, battery storage and hybrid resources could benefit from additional thought leadership from SWEPCO.	have diminished some of the original incentives. Specifically, prior to the IRA, hybrid systems were eligible to receive tax credits if their storage component was charged from the associated renewable (solar) resource (closed-loop system). The IRA removed this requirement such that the storage charging is not limited to a closed-loop system only to be eligible for tax credits. Additionally, stand-alone storage are eligible for federal ITCs that were previously not available prior to the passage of the IRA. The Company considers hybrid systems based on their nameplate value of the associated renewable system with the intention to utilize the storage component of the hybrid system to extend the period of energy output during the time when the renewable resource "fuel" source declines during the day (ex. when the sun goes down). The hybrid systems do include a higher accredited capacity value than the associated individual renewable resource which is also taken into account by the modeling.
22.	Southern Renewable Energy Association (SREA)	Provide additional details regarding "green hydrogen" production or use cases SREA appreciates SWEPCO's inclusion of discussion regarding hydrogen technology. SWEPCO states that, "Projects whose construction begins by the end of 2032 are eligible for a Production Tax Credit ("PTC"). This is applied as a discount to the price of hydrogen fuel in AURORA at a rate of $3/kg." And "Hydrogen is made available in	The Company appreciates the feedback.

		AURORA starting in 2032, based on statements by various major power equipment providers committing to provide 100% H2 CTs by 2030 and a best estimate of when market supply of hydrogen could be reliably available." This is clearly an area where SWEPCO is providing thought leadership, and we appreciate their efforts.	
23.	Southern Renewable Energy Association (SREA)	SPP Market Build Appears Reasonable As described, SWEPCO creates a model of the SPP market to provide the model for energy purchases on an hourly basis. Key components of the market forecast are the generation type and quantities. Compared to SPP's own projections in their annual Integrated Transmission Planning (ITP) process, SWEPCO's forecasts are reasonably aligned with SPP's forecasts. However, it should be noted, that SPP's forecasts appear to be advancing a similar amount of renewable energy as forecasted by SWEPCO sooner rather than later.	The Company appreciates the feedback.
24.	Southern Renewable Energy Association (SREA)	Transmission Planning Improvements Needed - SWEPCO could extend its transmission analysis and develop in this IRP potential transmission improvements in that region, beyond what has already been identified in the current report. Throughout these comments, SREA has complemented SWEPCO for their earnest efforts to engage stakeholders, provide feedback, and conduct reasonable analyses. These are hallmarks of good integrated resource planning processes. Increasingly, regional transmission organizations are relying on utility IRPs for baseline data assumptions for transmission planning practices. MISO has incorporated utility IRPs for several years. SPP is just beginning to collect and include individual member company resource plans for reference. These regional efforts rely on realistic, reasonable resource planning efforts to optimize transmission topology. SPP recently noted that their regular ITP process often underestimates the growth of renewable energy resources; the market is moving faster than previously forecasted. Updating forecasts, collecting solid	The Company continues to be an active member of SPP and their transmission planning process.

		information, and acting on that information is vitally important for strong generation and transmission planning practices. In turn, utilities can then develop reasonable market fundamental forecasts for their own internal purposes. Transparency is one of the prerequisites for a free market, and conducting robust resource and transmission planning is one way to help provide that transparency.	
25.	Southern Renewable Energy Association (SREA)	Out of all of the Louisiana IRP processes, SWEPCO provided some of the deepest details regarding its own transmission plans, as well as transmission plans from a grid operator. SWEPCO notes that, "At the heart of SPP's STEP process is its ITP process, which represented approximately 71% of the total cost in the 2023 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 ITP 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." By incorporating utility IRPs in the ITP, SPP can help better plan for the market. By incorporating SPP's ITP in this IRP, SWEPCO can better plan its position. The IRP/ITP interactions are iterative and feed each other. To that end, SWEPCO could extend its transmission analysis in this IRP. For example, the company noted that because wind and solar resources "tend to be located electrically further from load centers, a congestion and loss cost adder were also included". It is unclear how much those costs are in this IRP. Another way to resolve some congestion metrics is by incorporating additional transmission build-out in the modeling. At this point, it is not clear that the AURORA software is capable of providing the granularity needed to model and incorporate new transmission projects. While this IRP process is being conducted in Louisiana, SWEPCO is a multi-state utility and often one concern in a neighboring state can impact another. For example,	The Company appreciates the feedback related to the interaction and influence of utility IRPs and the SPP ITP. The Company's IRP does already include an appropriate level of information about transmission planning, which is a very high-level and discrete snap-shot of the extensive and robust electric transmission planning conducted by SPP and by the Company as a member of the AEP system. It would not be an appropriate or useful focus for the IRP to attempt to replace the transmission planning and analysis that the Company and SPP already do for the purpose of maintaining the electric grid reliability and enable the delivery of power resources across the SPP footprint. Additionally, the IRP already considers the delivered cost of capacity and energy resources to serve SWEPCO's customers. The IRP appropriately already takes into consideration the deliverability of the resources modeled, all of which are accessible to SWEPCO through the transmission system of which it is part. As previously discussed, this transmission system is the subject of robust regional planning.

		SWEPCO is currently requesting at the Arkansas Public Service Commission requesting that 93 MW of the Turk coal-fired power plant capacity be allocated to Arkansas, which may impact Texas and/or Louisiana.4 Within the SPP stakeholder process, Northwest Arkansas has been a known load pocket problem for quite some time. SREA encourages SWEPCO to develop in this IRP potential transmission improvements in that region, beyond what has already been identified in the current report.	
26.	Advanced Energy Management Alliance (AEMA)	Account for the potential for more rapid deployment and expansion of DERs such as EVs, based on tax credits and state and federal grant programs;	The potential DER growth projected by AEMA is assumed in the Company's Load Forecast. The broader analysis of the IRP provides directional insight to the Company's needs in the mid to later years of the IRP and the opportunity for potential offsets that DERs might provide. With respect to EV growth in the jurisdiction, the Company's forecast suggests that this is not reaching a level in the near and mid-terms to be of significant impact to the company's load. The Company continues to monitor the growth of this load type.
27.	Advanced Energy Management Alliance (AEMA)	Include community solar, microgrids, and other demand side resources in addition to rooftop solar as part of the modeling for distributed generation resources	The Company continues to monitor DERs although they currently are implemented by end-use customers based on individual benefit drivers not necessarily being entirely cost focused. To the extent that other DERs continue to be implemented into SWEPCOs territory, their net benefits will be recognized in the ongoing load forecasts and associated peak reduction. The Company is currently working to complete its microgrid solar pilot project to which, it looks forward to learning more about the potential benefits this type of DER will bring.
28.	Advanced Energy Manage-	Consider developing flexible demand tariffs beyond current DSM programs	Currently, the LPSC has an open proceeding in Docket No. R-35136 related to demand response in the Louisiana retail jurisdiction. SWEPCO submitted draft tariffs in that proceeding in 2021 and is awaiting a Staff determination related to the submittal. SWEPCO is currently deploying

	ment Alliance (AEMA)		advanced meters in its Louisiana retail jurisdiction which will provide better ability to offer more programs such as residential time of use rates as well as electric vehicle charging programs. Furthermore, as part of SWEPCO's deployment of AMS, SWEPCO agreed to the following in its settlement agreement in Docket No. U-36169: Once SWEPCO's proposed demand response tariffs are approved in LPSC Docket No. R-31536, SWEPCO will thoroughly research customer participation in Demand Response and potential options available, with the intention of implementing programs that would benefit both SWEPCO and customers as a whole. Within 12 months following tariff approval and AMS implementation, SWEPCO shall file a DR study with the Commission, identifying its findings related to the programs implemented in its demand response tariffs.
29.	Staff	Staff appreciates SWEPCO's efforts and recognizes that SWEPCO has already complied with many of the requests made by Staff and stakeholders, and this is reflected in SWEPCO's Draft IRP. Overall, as discussed below in more detail, Staffs believes there are a number of topics and issues which require more transparency; and several which require further analysis to provide SWEPCO, stakeholders, and the Commission with insight to determine the reasonableness of SWEPCO's IRP and intended future investment plans.	See subsequent company comments.
30.	Staff	Does the adjustment for current EE and DSM happen after the forecast which is driven by the parameters of the econometric models? What is the size and annual impact of each adjustment, for each sector? When and by how much is the annual load forecast reduced by codes and standards? What exactly are the codes and standards?	The Company has expanded its discussion on EE and Demand-Side Management in Section 2.2.5 of the IRP.
31.	Staff	If SWEPCO's models are sectoral (residential, commercial, industrial) rather than specific to end-uses (such as heating, cooling, etc.), how does SWEPCO implement energy efficiency adjustments that reflect codes and standards for specific types of equipment and end-uses?	The Company has expanded its discussion on EE and Demand-Side Management in Section 2.2.5 of the IRP.

32.	Staff	Why does DSM/EE decline to zero by 2034?	In reference to exhibit A-12 in Appendix A, the DSM/EE resources in the load forecast represent approved programs by the different Commissions. While there is a continued gross savings, the Load Forecast information represents the relative net impact to the Company's load from approved EE programs as new codes and standards are implemented.
33.	Staff	There seems to be no discussion of SWEPCO's residential and commercial EE programs' historical rate of uptake. Staff would like to see this historical information. What is the implied uptake for the various cost bundles which are modelled in Aurora? How do these compare with historical rates of uptake?	The IRP includes approximately 19MW annually of gross EE resources through 2028. Comparatively, a review of historical gross EE capacity within SWEPCO jurisdictions has averaged approximately 14MW annually over the previous 5 years.
34.	Staff	Going forward, in a high energy-price scenario (such as SWEPCO's ECR scenario), customers would be motivated to adopt more EE. Why is this not evident in SWEPCO's scenarios? Why does cumulative annual EE peak in 2028 in every scenario?	New EE resources are selected as part of the economic set of resources in the portfolios to meet SWEPCOs capacity obligation. Although additional new EE resources are included in the economic selection after 2028, their net cumulative effect on the Company's load forecast after 2028 continues to decline as a result of trends in EE both in the historical data as well as the forecasted trends in appliance saturations discussed in Section 2.2.5 of the IRP.
35.	Staff	The cost of existing coal indicates earlier retirement may be economic, and SWEPCO should address this in its Final IRP.	The Company reviewed the analysis presented as part of Staff's feedback to its draft IRP and respectfully disagrees with Staff's interpretation of the analysis. The Staff's request to compare market energy prices that reflect only variable costs to an indicative LCOE that represents a plants total costs including fixed costs is an "apples to oranges" comparison and ultimately, inappropriate to base a suggestion that earlier retirement may be economic. The Company updated its analysis in Confidential Exhibit – J to discuss this further.
36.	Staff	SWEPCO should report economic retirements of existing resources that result from Aurora runs in SWEPCO's future scenarios (not just the going-in retirements that are assumed by SWEPCO as inputs to the Aurora process). This output is within the capability of Aurora. Hard-wiring	The Aurora analysis does not inform comprehensively, the unit retirement decisions as does a unit disposition analysis that supports the Company's review and decision process for evaluating unit retirement economics.

		uneconomic units into all SWEPCO's scenarios will not likely result in a least-cost portfolio.	The scenario analysis relies on publicly available information regarding existing and new resource costs and announcements to produce a range of plausible regional capacity expansion and associated regional market prices. Related to this discussion, please also refer to Company's response to item 35 and the associated Confidential Exhibit J. Appendix D provides the economic retirements by fuel produced by the scenario analysis for each of the 5 scenarios.
37.	Staff	Staff concludes that SWEPCO's solar PY capital cost assumptions may be too high, and SWEPCO should provide additional information to support these assumptions. Staff concludes that SWEPCO's ICE assumption may be too low, and SWEPCO should provide additional information to support this assumption. SWEPCO's assumptions for the other technologies in Figure 3 appear to be reasonable.	The Company relies on the market responses to its multiple RFPs conducted in SPP to inform the Solar costs. For this IRP, capital costs were informed from responses to the Company's 2021 RFP and are used as a proxy for potential costs of future resources. The Company reviewed Staffs assessment of the Internal Combustion Engine (ICE) resource with Exhibit B and respectfully suggests there was a misinterpretation of the table in the Draft Report. The ICE resource is sized at 20MW with an estimated cost of $2,600/kW. An Aeroderivative (AD) resource is sized at 105MW at an estimated cost of $1,600/kW.
38.	Staff	SWEPCO included assumptions for the capital cost of transmission network and interconnection upgrades. It assumed a cost of $20/kW for thermal resources, $90/kW for wind, and $115/kW for solar resources. It did not provide any detail of how these assumptions were developed. SWEPCO should provide this detail in the Final IRP.	The Company included additional references in Section 5.1 of the Final IRP to the updated cost basis for the estimated transmission network and interconnection upgrade costs assumed in the modeling.
39.	Staff	In its Final IRP SWEPCO should identify what and where the transmission limitations that are the result of AEP facilities, rather than those of neighboring systems.	Power transfers to AEP West load zone, location where AEP loads are settled by SPP, is exposed to transmission congestion when transferring power from resources outside the AEP West load zone to the AEP West load zone. Transmission facilities owned by SWEPCO are in AEP West load zone and AEP conventional resources are interconnected to the AEP transmission system.

			They do not affect adversely on congestion associated with resources outside the AEP West Load Zone.
40.	Staff	In the Final IRP, SWEPCO should explain how the "estimated costs of transmission upgrades and congestion" are modelled. SWEPCO should state clearly whether the three specific new projects it listed (Chisholm to Woodward/Border, Sooner to Wekiwa, and South Shreveport to Wallace Lake) address the limited capability of the neighboring systems.	Estimated congestion and hedging costs included in the modeling are identified in sections 5.4.1 and 5.4.2 of the Final IRP. Additionally, the Company includes additional discussion in section 4 of the IRP, noting that the reference projects are in fact, expected to support part of the limited capability of the neighboring systems.
41.	Staff	In its Final IRP, SWEPCO should identify (at a general level) opportunities for transmission projects that could reduce congestion, improve reliability, and better utilize SWEPCO's generation and transmission assets.	Section 4 of the IRP discusses the complex and coordinated SPP transmission planning process of which, SWEPCO is actively involved. Section 4.4.2 of the final IRP has been expanded to identify additional projects that may lead to reduced congestion and improved reliability in the region.
42.	Staff	In Staffs comments on SWEPCO's assumptions, Staff recommended that SWEPCO consider a scenario in which, at least, the capacity currently in the SPP queue is eventually developed, and it is assumed that the strong ongoing interest in solar and wind development does not come to an abrupt halt in 2023. However, in the Draft IRP, SWEPCO noted that it limited its modeling of additional renewables by assuming that only 20% of the renewables in the current SPP queue would be developed. It provided no support for this assumption. Staff expects S WEPCO to provide the rationale for this assumption in its Final IRP	The Company included a discussion in Section 5.1 of the Final IRP on the basis for identifying assumptions for resource capacity modeling limits included in the model.
43.	Staff	SWEPCO allowed Aurora to retire non-SWEPCO units based on economics. Staff does not take issue with this approach but notes that it is in contrast with SWEPCO's assumption that its own uneconomic plants would continue to run. Staff reiterates that SWEPCO should allow its own plants to be retired based on economics in its Aurora runs and develop alternatives to those plants as part of its Final IRP	The Company refers back to its response to Staff Feedback item 36 as it relates to retirement analysis based on Aurora simulations. The Company refers back to item 35 in response to the presumption that that its own plants are uneconomic. In keeping with the Louisiana IRP Rules, the resource plan is not intended to mandate specific outcomes or specific investment decisions as SWEPCO will bear responsibility for those proposals and decisions in other proceedings. SWEPCO's Final IRP appropriately reflects its

			unique circumstances and the judgement of its management and serves as a roadmap for the Company, the Commission and Stakeholders of how the Company may fulfill its resource commitments to meet customer load requirements under a number of different scenarios.
44.	Staff	In its Final IRP, SWEPCO should provide the annual capacity profile (total MW by fuel, with renewables adjusted for accreditation as appropriate) in SPP in each of different scenarios.	The Company included total annual MW capacities by fuel for each Scenario in the Appendix D.
45.	Staff	The minimum SPP Planning Reserve Margin (PRM") beginning on June 1, 2023, requires a reserve capacity of 15% above a utility's coincident summer peak load.21 Currently, SPP has planning reserves of over 20% (see Figure 4). Despite the 15% summer requirement, SWEPCO assumed an SPP PRM of22% above peak load by summer 2025. In its Final IRP, SWEPCO needs to provide the justification for assuming a PRM of 22%, which is far higher than the current summer requirement of 15%.	The Company identified several initiatives under review in SPP related to the current PRM in section 3.5 introducing risks to planning only to minimum SPPs minimum PRM. Furthermore, the Company also considered the pending additional requirement for LREs to meet a winter PRM that is yet to be conclusively identified but is expected to be the defining PRM.
46.	Staff	SWEPCO should explain its understanding of the environmental controls and costs that would be required at Flint Creek and Turk to comply with final and proposed regulations and include such costs in its modeling for this IRP	The Company has expanded its discussion of the proposed rules in section 3.4 of the IRP. In summary, the scope, timing, cost, and operational implications of the proposed EPA regulations cannot be known at this time. For this IRP, however, the Company included the Enhanced Carbon Regulation (ECR) Scenario to model a future where more stringent regulations are put in place. This scenario is intended to be a proxy for a broad range of regulations such as those that are currently proposed that might impact broader market prices.
47.	Staff	In its Final IRP Report S WEPCO should continue to report the results of its portfolios across all its scenarios, to provide insight into the risks as well as costs of the portfolios. It must provide a clear rationale for choosing its preferred portfolio.	The Company updated the Portfolio results across all scenarios in the final IRP. The Company also discusses its consideration of the portfolio analyses to identify the Preferred Plan (PP) in Section 8.5 of the IRP.
48.	Staff	The Final IRP should include SWEPCO's projections of rate impacts.	The Company included this analysis in section 8.5.1 of the Final IRP.

49.	Staff	The Final IRP should include an Action Plan which creates a link between the Company's preferred portfolio and the specific implementation actions that need to be performed during the first five years of the planning period. It should include a timetable indicating important activities, discuss permitting issues or other regulatory actions that are required for the resource action to take place, or account for environmental impacts or plans to meet environmental regulatory requirements at existing resources subject to such requirements. SWEPCO' Final IRP Report must contain a Five-Year Action Plan that complies with the requirements outlined in Section 7 of the IRP Rules.	The Company included a 5-Year action plan in the IRP.
50.	Staff	SWEPCO has stated it intends to achieve net-zero carbon dioxide emissions by 2050." Staff is pleased to note that, in its draft IRP, SWEPCO reported and the carbon footprint of each of its portfolios in 2042 (see Figure 8, which reproduces Table 26 in SWEPCO's Draft lRP) as well as its current carbon footprint of 16.5 million tons (mt") in 2022.' It was not clear whether each portfolio in SWEPCO's Table 26 was the optimal portfolio for the corresponding scenario or in the Reference Case, and SWEPCO should clarify this.	The corresponding table in the final IRP has been clarified to express the values are the reduction when modeled under the Reference Scenario conditions.
51.	Staff	Each portfolio represents a significant reduction in SWEPCO's carbon footprint in terms of total carbon emissions. It is not clear what the reduction is in terms of S/MWh, and SWEPCO should provide the demand outlook (consumption in MWh) for each year of each scenario, in order that such a calculation can be made	The Company added the demand for each year in each portfolio table included Appendix Exhibit F.

Confidential Exhibits

Volume 2

Exhibit H: Confidential – Existing Unit Fuel Forecast

Exhibit I: Confidential – Existing Unit Performance

Exhibit J: Confidential – Supplemental Analysis, Existing Units

Volume 3

Exhibit K: Confidential – SWEPCO Load Forecast Model Information