SOUTHWESTERN ELECTRIC POWER COMPANY

An AEP Company

2024 Integrated Resource Plan Report
to the
Arkansas Public Service Commission

February 14, 2025

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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 the load forecast and other modeling assumptions were developed. However, changes that affect this IRP can occur without notice and may not be reflected in this report due to the timing of the changes. Therefore, this IRP 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 fluid and subject to change as new information becomes available or as circumstances warrant.

To meet its customers' future capacity and 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 renewable resources and its gas-steam plants. In addition, SWEPCO's IRP considers the impacts of the evolving Southwest Power Pool (SPP) resource adequacy requirements and the emergence of new technologies and renewable energy resources, both large-scale and distributed.

Keeping all the multiple considerations discussed above in mind, SWEPCO has identified various future scenarios and modeled corresponding resource portfolios that are forecasted to provide adequate supply and demand resources to reliably and safely meet its SPP peak load and reserve capacity obligations, while giving consideration to reducing or minimizing the costs and risks to its customers, including both capacity and 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 local impacts and sustainability. The candidate resource portfolios are evaluated against these four objectives using the IRP Portfolio Performance Indicator Matrix to consider merits between each portfolio.

Arkansas IRP Stakeholder Process

As part of the IRP Process, the Company held the first stakeholder meeting on June 6, 2024. In this meeting the Company discussed the IRP process, the four objectives noted above, initial data inputs and assumptions along with the expected scenarios and portfolios to be modeled. A second stakeholder meeting was held on September 30, 2024, to provide an update of assumptions and inputs planned for the IRP along with modeling results for the base, high, and low scenario portfolios. Stakeholders provided feedback that the Company considered in this IRP. Additional written questions provided outside of the Stakeholder meetings were submitted to the Company and considered as part of this IRP.

SWEPCO held a final stakeholder meeting on December 13, 2024. In this meeting, the Company discussed all portfolios modeled, reviewed the Portfolio Performance Indicator Matrix, discussed the Preferred Plan, and noted the proposed action plan. Stakeholders were provided with pertinent work papers after the meeting and were requested to provide any additional questions by January 8, 2025. SWEPCO compiled and responded to questions noted during the December stakeholder meeting and the additional questions provided by Stakeholders on January 24, 2025. The Stakeholder Committee provided its report on February 7, 2025.

A record of stakeholder engagement is included in Appendix F of this report.

SWEPCO's Capacity and Energy Needs

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 going-in capacity position, prior to adding any new resources, that shows the forecasted load obligation and the current expectations about the level of SPP accredited capacity expected to be provided by existing and approved resources. Figure 1 and Figure 2 illustrate the starting summer and winter seasonal capacity needs of SWEPCO through 2044, respectively. Due to significant uncertainties in projecting capacity requirements, to ensure adequate supply, the Company also included an additional 6% layer of reserve capacity above the SPP Planning Reserve Margins (PRMs).

In this IRP, the Company co-optimized both the summer and winter PRMs and identified that for SWEPCO, the winter PRM constraint becomes a binding element in the modeling. Further details on the capacity needs assessment can be found in Section 3.5. The going-in capacity position shown in Figure 1 includes recently approved solar and wind resources.[1] With these assumptions, the Company identifies a capacity need beginning June 1, 2026. The need grows in the 2028/2029 summer planning season when SWEPCO's Welsh 1 & 3 units will cease burning coal and are removed from the going-in assumptions. It grows again for the 2029/2030 summer planning season when Arsenal Hill 5 and Lieberman units 3 and 4 are assumed to retire on May 31, 2029, and again in for the 2030/2031 summer planning season when Wilkes unit 1 is assumed to retire on May 31, 2030. The retirement assumptions are for planning purposes within this IRP.

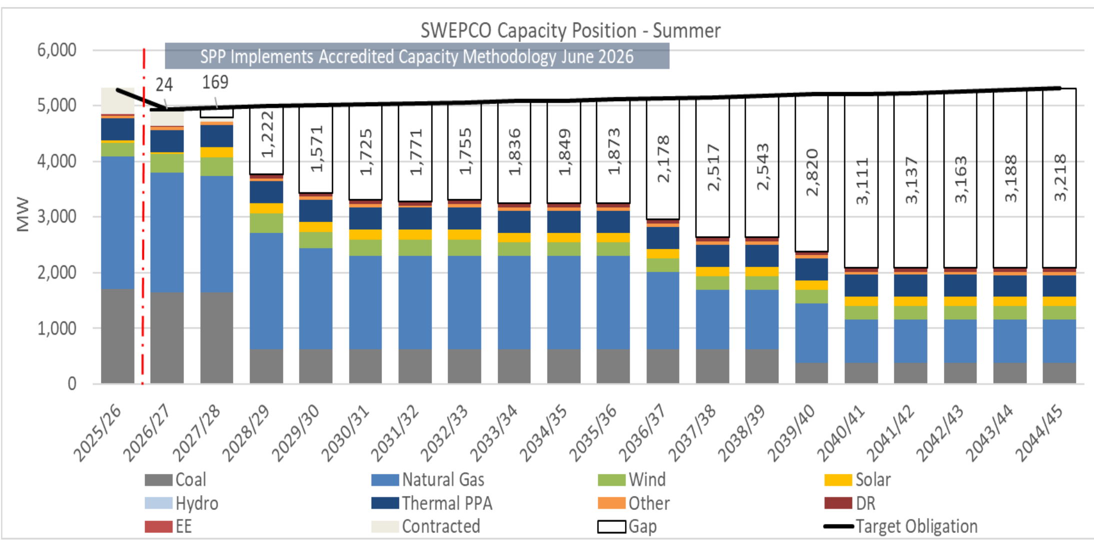

Figure 1: SWEPCO Summer Going-In Capacity Position

[1] The Mooringsport solar project, a 200MW facility located in Caddo Parish, Louisiana, was initially part of SWEPCO's renewable energy efforts. However, SWEPCO has decided not to proceed with this project. Note that 200MW of the capacity position is associated to this project.

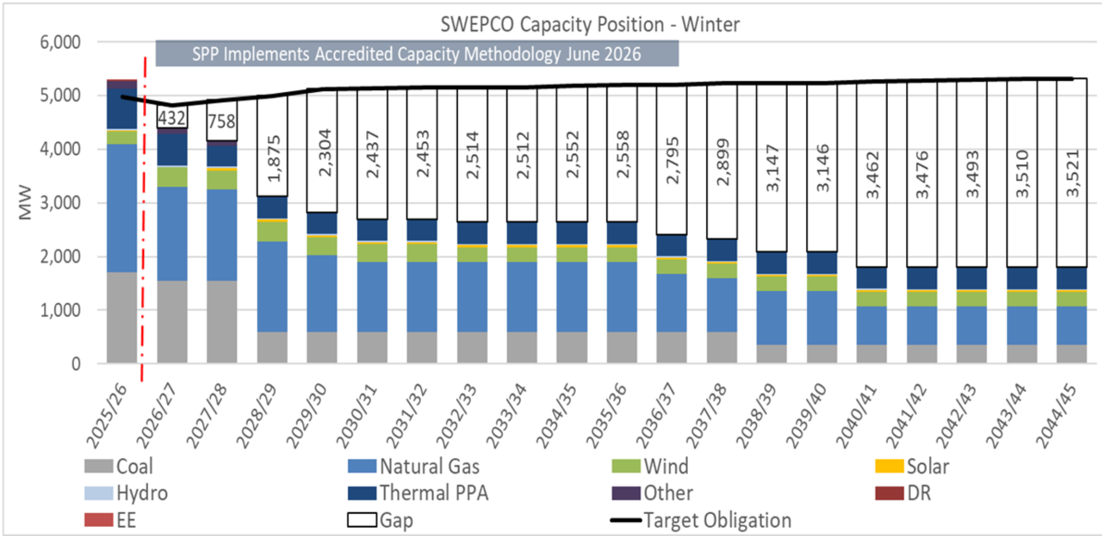

Figure 2: SWEPCO Winter Going-In Capacity Position

In addition, SWEPCO evaluated a going-in energy position, prior to adding any new resources, that shows the forecasted load and the current expectations about the level of energy expected to be provided by existing and approved resources. The going-in energy position can be noted in Figure 3. Further details on the energy needs assessment can be found in Section 3.6.

Risk associated with energy purchases was an important objective the Company identified for analysis in this IRP. Relying too heavily on energy market purchases could negatively impact SWEPCO's customers during times of elevated energy market prices. As such, the percentage of market purchases and sales was an element of the Portfolio Performance Indicator Matrix and an important consideration in comparing portfolios to identify the Preferred Plan. More details on the Energy Market Risk objective can be found in Section 8.3.2.

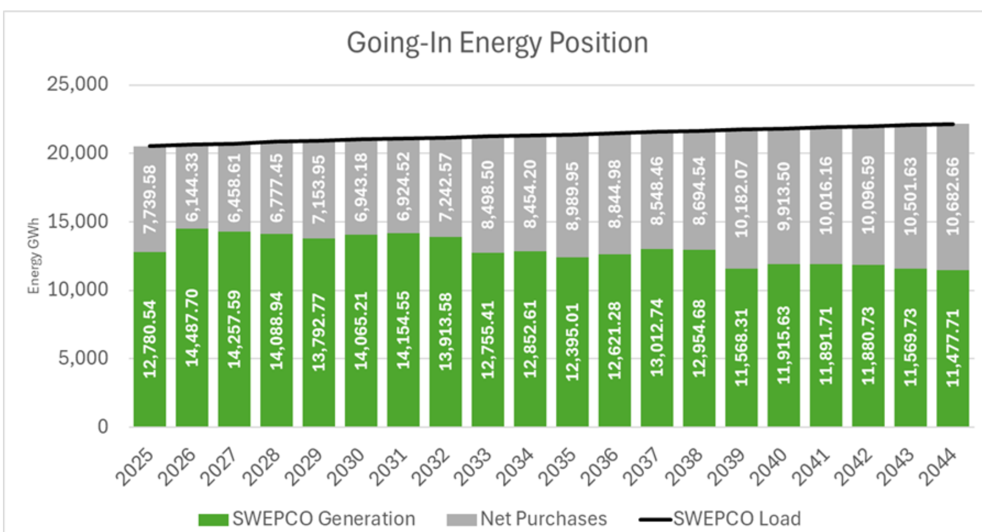

Figure 3: SWEPCO Going-In Energy Position

SWEPCO used the PLEXOS® 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 Portfolio Performance Indicators matrix. The list of candidate resources considered in this IRP also includes Energy Efficiency (EE) options that could be selected alongside, or as an alternative to, new utility-scale resources when meeting customer needs.

Responsive to Changing Customers' Needs

SWEPCO considered how customers' needs could change under four different market scenarios that consider different outcomes of fundamental factors that drive the demand for electricity as well as changes 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 scenario conditions, SWEPCO is projected to see customer count grow at a rate of 0.2% per year. Retail sales are also expected to grow at 0.4% per year with stronger growth expected from the residential class while the commercial class remains relatively flat and the industrial class experiences modest increases over the forecast horizon. SWEPCO's peak demand is also expected to increase at an average rate of 0.4% per year through 2044.

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 small modular nuclear reactors, in addition to 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 Demand-Side Management (DSM) and EE measures. Nonetheless, SWEPCO continues to explore the potential to further implement demand-side programs to the benefit of its customers as it deploys advanced metering systems across its service territory. This IRP considers EE measures that could be selected alongside new utility-scale resources to meet future capacity needs. These options empower customers with choices over how and when they interact with the energy system. Under the Preferred Plan, SWEPCO modeled the implementation of approximately 97MW of additional demand-side resources between 2027 and 2036.

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 method for evaluating cost risk includes a scenario analysis where SWEPCO tested candidate portfolios over a set of four 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, and resource costs.

This analysis measures the difference in portfolio costs between the most and least cost planning scenarios by evaluating the difference in Net Present Value Revenue Requirement (NPVRR). The NPVRR reflects the cost of all resource decisions, including unconstrained energy dispatch and additional capacity costs, over both a 30-year (2025-2054) and a 10-year (2028-2037) period.

In addition, the Company evaluated market risk by measuring the percentage of load that is served by the market energy purchases, as well as the amount of market sales that were made in these scenarios. This provides the Company with the metrics needed to evaluate market risk by scenario when developing a Preferred Plan.

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, renewable, and demand-side resources that bring a broad set of benefits to customers. Collectively, the resources support numerous objectives identified in the IRP Portfolio Performance Indicators matrix in a holistic manner including maintaining a diverse portfolio of resources that supports the new seasonal capacity obligation construct within SPP while helping to mitigate potential cost risks to customers in the event future market conditions change.

This plan includes two resources, the Hallsville gas combustion turbine project and the gas conversion of Welsh units 1 and 3, for which SWEPCO made filings in December of 2024 seeking regulatory approvals. Hallsville is represented by the New CT shown as being added in time for it to be counted in the 2029/2030 planning year.[2] Table 1 shows the Company's Preferred Plan Capacity Additions.

Table 1: Preferred Plan Capacity Additions

Preferred Plan Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	75	0	38
2026/27	0	0	0	0	0	0	0	50	0	30
2027/28	19	0	0	0	0	0	0	600	0	31
2028/29	36	0	0	0	0	0	1,053	500	0	32
2029/30	53	0	0	0	480	0	0	500	0	33
2030/31	73	300	0	0	0	0	0	500	0	29
2031/32	96	300	0	0	480	0	0	500	0	25
2032/33	97	0	0	0	0	1,100	0	500	6	14
2033/34	97	0	0	0	0	0	0	0	11	6
2034/35	97	0	0	0	0	0	0	0	11	6
2035/36	97	0	0	0	0	0	0	0	9	7
2036/37	97	0	0	0	240	0	0	0	9	7
2037/38	94	300	0	0	240	0	0	0	12	5
2038/39	91	0	0	0	240	0	0	0	13	4
2039/40	89	0	0	0	0	0	0	0	8	7
2040/41	86	0	0	0	480	0	0	0	10	5
2041/42	82	0	0	0	0	0	0	0	10	6
2042/43	65	0	0	0	480	0	0	0	10	6
2043/44	52	0	0	0	720	0	0	0	10	7
2044/45	37	0	0	0	0	0	0	0	10	5
Total		**900**	**0**	**0**	**3,360**	**1,100**	**1,053**			

[2] After the IRP in-service date assumptions were made, the planned in-service date for Hallsville was moved up to be included in SPP capacity planning for the 2028/2029 year.

Figure 4 and Figure 5 show how the capacity additions in the Preferred Plan meet SPP's summer and winter PRM requirement. SPP's key resource adequacy requirements, including several important recent changes, are discussed in Section 3.5 of this Report. For SWEPCO, the winter PRM requirement is a more significant driver, compared to the summer PRM requirement, of required capacity additions in the Preferred Plan. This can be seen in the figures below where SWEPCO's projected accredited capacity position in the winter season (Figure 5), including capacity additions in the Preferred Plan, closely aligns to the target obligation, whereas in the summer season (Figure 4), SWEPCO's projected accredited capacity position surpasses the target obligation.

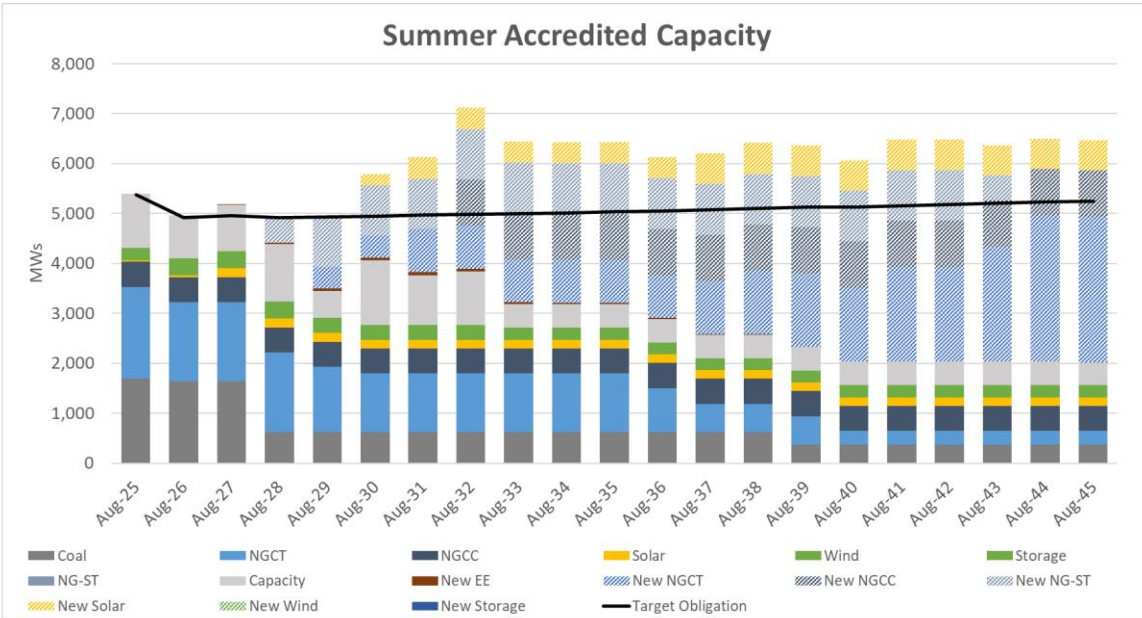

Figure 4: SWEPCO Summer Accredited Capacity Position – Preferred Plan

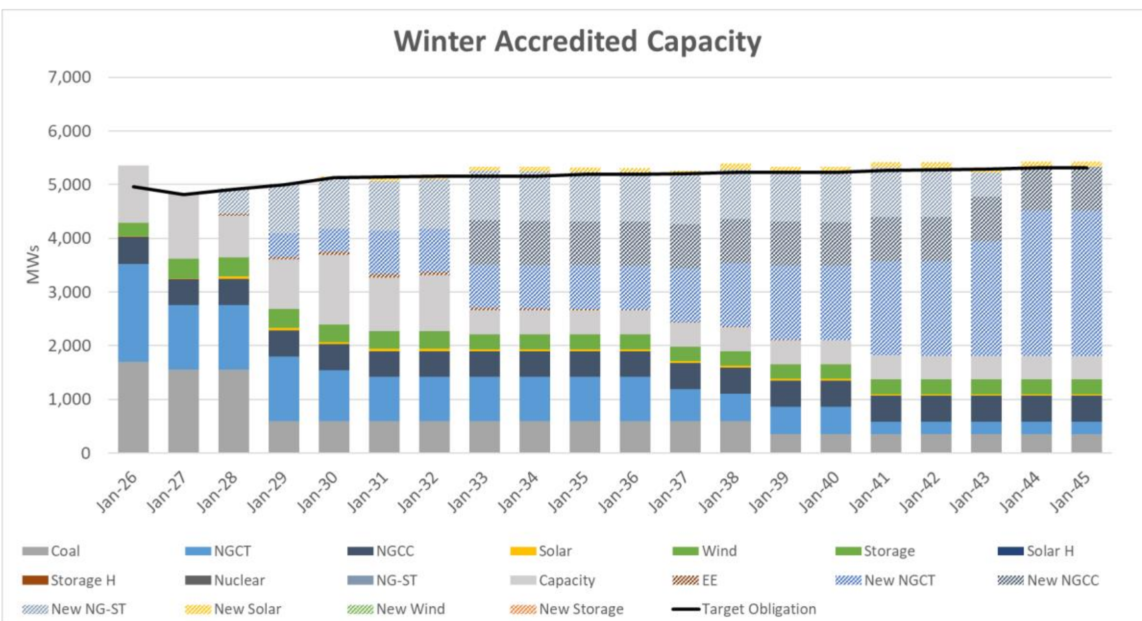

Figure 5: SWEPCO Winter Accredited Capacity Position – Preferred Plan

Powering the Future for SWEPCO's Customers

The Preferred Plan broadly supports SWEPCO's four objectives of customer affordability, rate stability, reliability, and local impacts and sustainability. Based on analysis of the portfolios considered in this IRP that is discussed in Section 8, the Company selected the Preferred Plan because it:

- Maintains affordable rates because it has a lower short-term growth rate, lower total long-term costs, lower fixed costs, and less reliance on market sales and production tax credit revenues to support affordability.

- Provides rate stability for customers because it has the lowest market energy risk and is resilient to changing commodity prices.

- Delivers reliability by meeting SPP's requirements with a diverse set of new resources including the highest dispatchable winter accredited capacity as a percentage of peak demand.

- Supports local impact and sustainability with all new resources able to be added within SWEPCO's service territory and additions of 900MW of solar resources; this is in addition to the 2,080MW of wind and 73MW of solar within SWEPCO's existing and approved resource fleet.

SWEPCO's Preferred Action Plan

Steps which have been or will be taken by SWEPCO in the near future as part of its Proposed Action Plan include:

- Seek regulatory approval for the Hallsville CT and the Welsh Gas Conversion in all of SWEPCO's three jurisdictions. SWEPCO filed for regulatory approval in Arkansas in December of 2024 under Docket No. 24-052-U.
- If the Hallsville CT is approved by regulators, evaluate adding a steam turbine to convert it to a combined cycle.
- Fill in the near-term capacity needs with short-term capacity contracts. SWEPCO filed for regulatory approval of a CPA in October of 2024 under Docket No. 24-044-U, which was approved on February 7, 2025.
- Evaluate costs and benefits of continuing to operate Arsenal Hill 5, Lieberman 3 and 4, and Wikes 1 beyond their current planning retirement dates.
- Continue to monitor environmental regulations and update the analysis of compliance options as needed consistent with those regulations.
- Remain engaged and responsive to changes in SPP resource adequacy requirements.
- Seek additional capacity as needed; timing and amount will be impacted by all the above. SWEPCO anticipates the need to issue Requests for Proposals in the near term.

1. Introduction

This Report presents the 2024 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 planned to ensure affordable and reliable energy to customers over the IRP planning period.

1.1 Integrated Resource Plan Objectives and Framework for Evaluation

The Company defined a set of performance objectives and metrics and arranged them into portfolio performance indicators 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 Energy Efficiency (EE).
- **Rate Stability** by considering a wide range of resources to reduce uncertainties around future fuel prices and market energy prices and ensuring an adequate energy supply to serve 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.
- **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 local economic impacts for new resources.

1.2 IRP Process

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. Moreover, this IRP includes assumptions related to the Company's load forecast, commodity forecast and technology costs at the time of modeling and not preparation.

The IRP process for SWEPCO includes the following components:

- Evaluate future customer needs and how those needs are likely to change over the IRP forecast period (Section 2).
- Assess the adequacy of the Company's existing resources including any committed additions and retirements, both demand- and supply-side, in meeting future customers' needs taking into account near term changes in the portfolio (Section 3).
- Evaluate the Company's current capacity position and create the framework for the resource planning process (Section 3.5).
- Evaluate transmission and distribution system integration opportunities in meeting future customer needs and the impact on potential future resource options (Section 4).
- Assess sources of future risks and uncertainties, and devise market scenarios to represent those risks as part of portfolio optimization (Section 5.3 and Section 8.2).
- Identify a list of resources that could be selected by the portfolio model to meet future customer needs. Candidate resources include both supply-side (Section 6) and demand-side options (Section 7).
- Define the objectives that the Preferred Plan should achieve and evaluate all resource options to identify the portfolio options (Section 1.1 and Section 8.3).
- Develop and evaluate the Preferred Plan and the associated proposed action plan based on all prior steps (Section 8.5 and Section 9).
- Engage with stakeholders and consider feedback received throughout the process (Exhibit F).

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 approximately 200,000 square miles in Arkansas, Louisiana, 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 (MW) 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 miles of transmission lines and more than 225,000 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 one 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 6). Currently, SWEPCO serves approximately 554,000 retail customers in those states: including approximately 127,000, 235,000 and 192,000 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 5,554MW, which occurred in August 2011; and the highest recorded winter peak was 4,919MW, which occurred in January 2014. The most recent 2024 actual SWEPCO summer peak demand was 4,593MW occurring on August 14th. SWEPCO's 2023/24 winter peak demand occurred on January 16, 2024, with a value of 4,845MW.

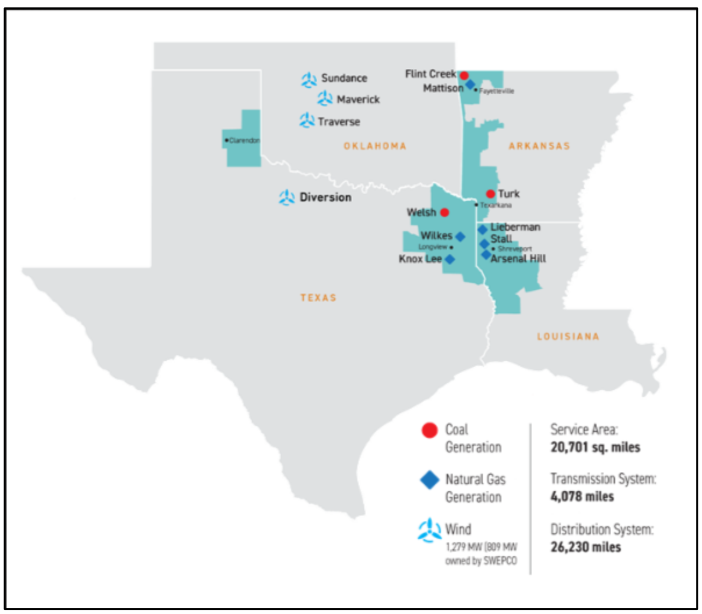

Figure 6: SWEPCO's Service Territory

2. Load Forecast and Forecasting Methodology

2.1 Overview

The SWEPCO load forecast utilized in this IRP was developed by AEP's Economic and Supply Forecasting organization and completed in April 2024.[3] 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 (2025-2044)[4], SWEPCO's service territory is expected to see population and non-farm employment experience similar growth of 0.4% and 0.2% 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 0.4% per year with stronger growth expected from the residential class (0.3% 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 to grow by 0.4% per year. Finally, SWEPCO's peak demand is also expected to increase at an average rate of 0.4% per year through 2044.

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 2023. Moody's Analytics projects moderate growth in the U.S. economy during the 2025-2044 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 2.1% 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 0.4% per year during the forecast period and real regional income per-capita annual growth of 1.6% for the SWEPCO service area.

2.2.2 Energy Price Assumptions

The Company utilizes an internally developed service area electricity price forecasted by AEP's Economic and Supply Forecasting organization. This forecast incorporates information from the Company's financial plan for the near term and the Company's fundamental forecast 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. 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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[3] 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.

[4] 20-year forecast periods begin with the first full forecast year, 2025.

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 gathered by 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 energy efficiency (EE) both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards including the (Energy Policy Act of 2005 [EPAct], and the Energy Independence and Security Act [EISA] of 2007, etc.) modeled by EIA. As highlighted in Sections 2.4.4 and 2.4.5, the Company uses Statistically Adjusted End-Use (SAE) models developed by Itron, a consulting firm with expertise in energy modeling, 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' 2024 scenario, which keeps EE standards and trends at 2024 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 was created to adjust the forecast for the impact of these programs. For this IRP, EE Resources through 2026 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.

2.3 Overview of Forecast Methodology

SWEPCO's load forecasts are based mostly on econometric, state-of-the-art statistically adjusted end-use data and the 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 40 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.

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 long-term forecasts are used at least on an annual basis for all classes. For the typically weather sensitive classes, i.e., residential and commercial, the short-term models are leveraged to develop a monthly pattern for the annual sales forecast developed in the long-term models. This process is used as the short-term models are perceived to provide additional insight into monthly sales patterns and their relationship with heating and cooling degree-days. 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 7.

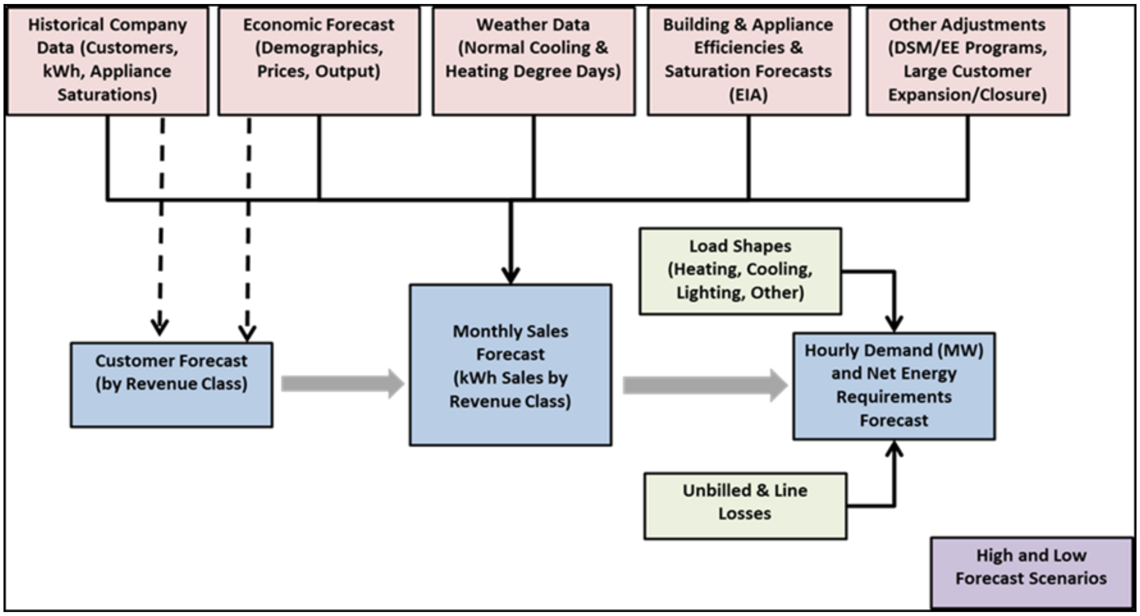

Figure 7: SWEPCO Internal Energy Requirements & Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast

This section provides a more detailed description of the short- 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- 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 utilizes long-term models to develop the final customer count forecast. The long-term residential customer forecasting models are monthly and extend for 40 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 long-term customer forecasts 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 and 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 Autoregressive Integrated Moving Average (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 2014 through December 2023.

There are models for residential, commercial, industrial, other retail, and wholesale sectors. 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.

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 40 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 1995-2023, 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.

2.4.4.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from an internally developed model of natural gas prices. They are first developed for Henry Hub and then developed for each state based on their historical relationship to Henry Hub. Further, they are also disaggregated in each state's primary consuming sectors: residential, commercial, and industrial. The natural gas price model is based upon 2000 through 2023 historical data.

2.4.4.2 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 an SAE, which was developed by Itron. 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 2000 through December 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 based on analysis by the EIA regarding appliance efficiency trends. The SAE models incorporate other government legislation affecting appliance, equipment and lighting efficiency standards through the Inflation Reduction Act (IRA) that was enacted in 2022.

The long-term residential energy sales forecast is derived by multiplying the 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.

2.4.4.3 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 2023 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, EIEA2008 and other legislation through IRA 2022 are captured in this model. Separate commercial SAE models are estimated for the Company's Arkansas, Louisiana, and Texas jurisdictions.

2.4.4.4 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 December 2023.

2.4.4.5 All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales are reflected as the most recent trend. 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.

2.4.4.6 Blending Short and Long-Term Sales

The annual energy forecasts are derived from the long-term model projections. For the typically weather sensitive classes, monthly patterns are developed using the X-11 procedure[5]. The monthly patterns for the other classes are derived from the respective forecast models. In this analysis, the weather sensitive classes were defined as residential and commercial.

2.4.4.7 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 typically 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.

2.4.4.8 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.

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[5] SAS Institute Inc. "The X11 Procedure." SAS/ETS® 13.2 User's Guide. Cary, NC: SAS Institute Inc., 2014. https://support.sas.com/documentation/onlinedoc/ets/132/x11.pdf.

This document provides detailed instructions on the X11 procedure for seasonal adjustment in time series analysis.

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’s 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, 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 2014-2023. 2024 data are six months actual, and six months forecast and on a forecast basis for the years 2025-2044. 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 Exhibit A-2.

Figure 8 provides a graphical depiction of weather normal and forecast Company residential, commercial, and industrial sales for 2002 through 2044. The data prior to the dotted line represents historical actuals while the data after the dotted line represents the forecast period of 2024 and beyond.

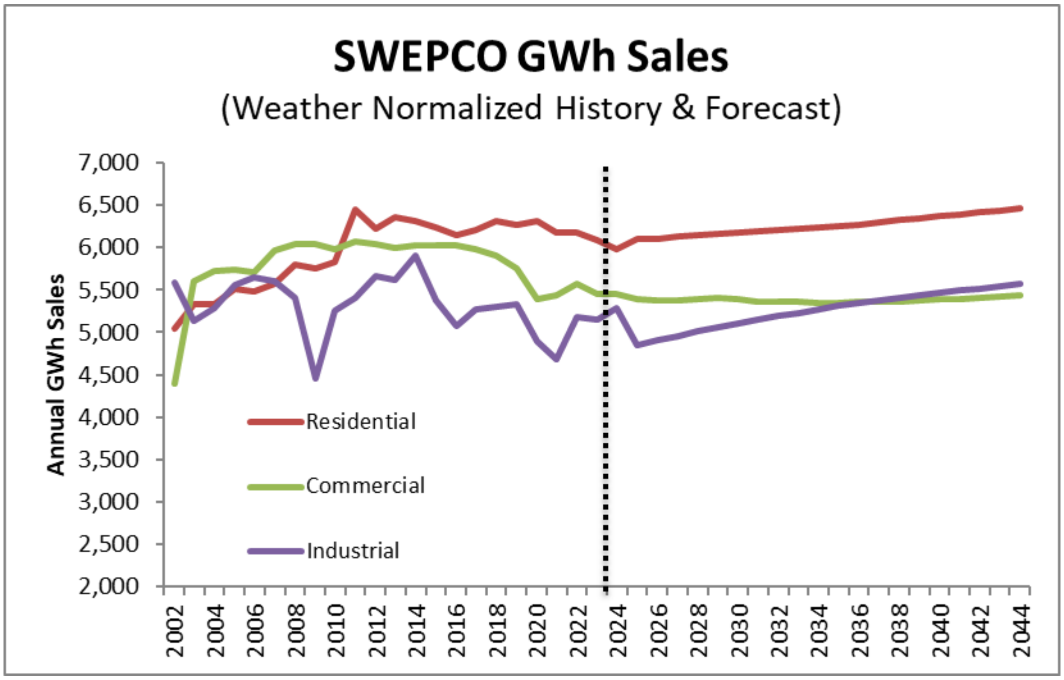

Figure 8: Weather Normalized History and Forecast of SWEPCO's Sales by Category

2.5.2 Peak Demand and Load Factor

Exhibit 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 2014-2023. 2024 data are six months actual, and six months forecast and on a forecast basis for the years 2025-2044. The table also shows annual growth rates for both the historical and forecast periods.

Figure 9 presents actual, normal and forecast SWEPCO peak demand for the period 2000 through 2044.

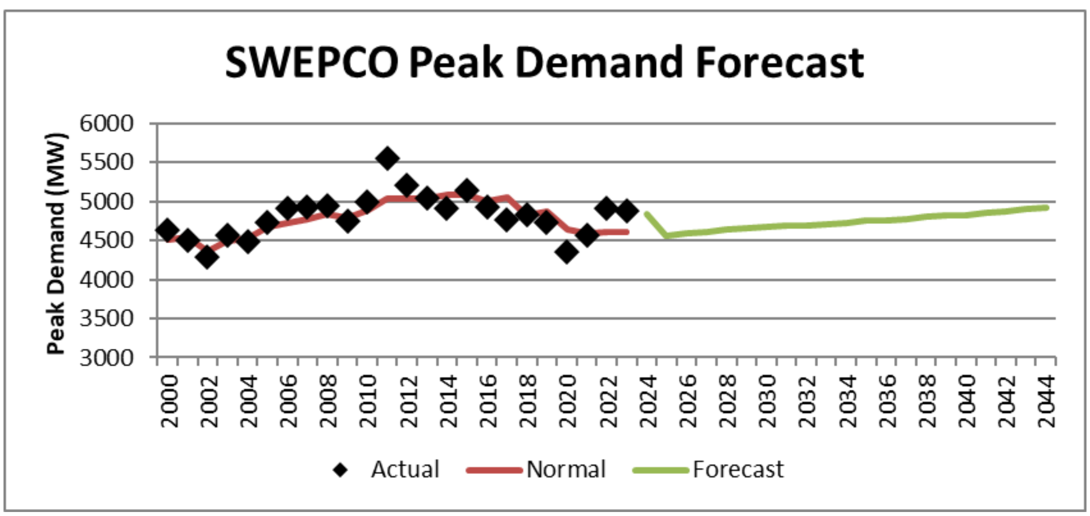

Figure 9: SWEPCO's Peak Demand Between 2000 and 2044

2.5.3 Monthly Data

Exhibit A-4 provides historical monthly sales data for SWEPCO by customer class (residential, commercial, industrial, other retail and wholesale) from January 2014 through June 2024. Exhibit A-5 provides forecast SWEPCO monthly sales data by customer class for July 2024 through December 2044.

2.5.4 Prior Load Forecast Evaluation

Exhibit A-6 presents a comparison of SWEPCO's energy sales and peak demand forecasts in the 2021 IRP with the actual and weather normal data for 2021, 2022 and 2023. The 2021 sales were over forecast by 1.5% in 2021, and this reflects the economy still being affected by the COVID-19 Pandemic. In part due to government transfer payments, the economy grew faster in 2022, and sales were under forecast by 2.2%. In 2023, the forecast sales were only 0.3% greater than actual. However, there is a constant monitoring of the modeling process to seek improvement in forecast accuracies. Exhibit A-7 provides the impact of demand-side management on the 2021 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

Exhibit A-8 provides significant economic and demographic variables incorporated in the various residential long-term energy sales models for the Company. Exhibit A-9 provides significant economic variables utilized in the various SWEPCO jurisdictional commercial energy sales models. Exhibit A-10 presents significant economic variables that the Company employed in its jurisdictional industrial models. Exhibit 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 10 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 (2025-2030), with normalized residential usage declining by 0.1% per year and normalized commercial usage declining by 0.3% per year as represented by the dotted lines in Figure 10.

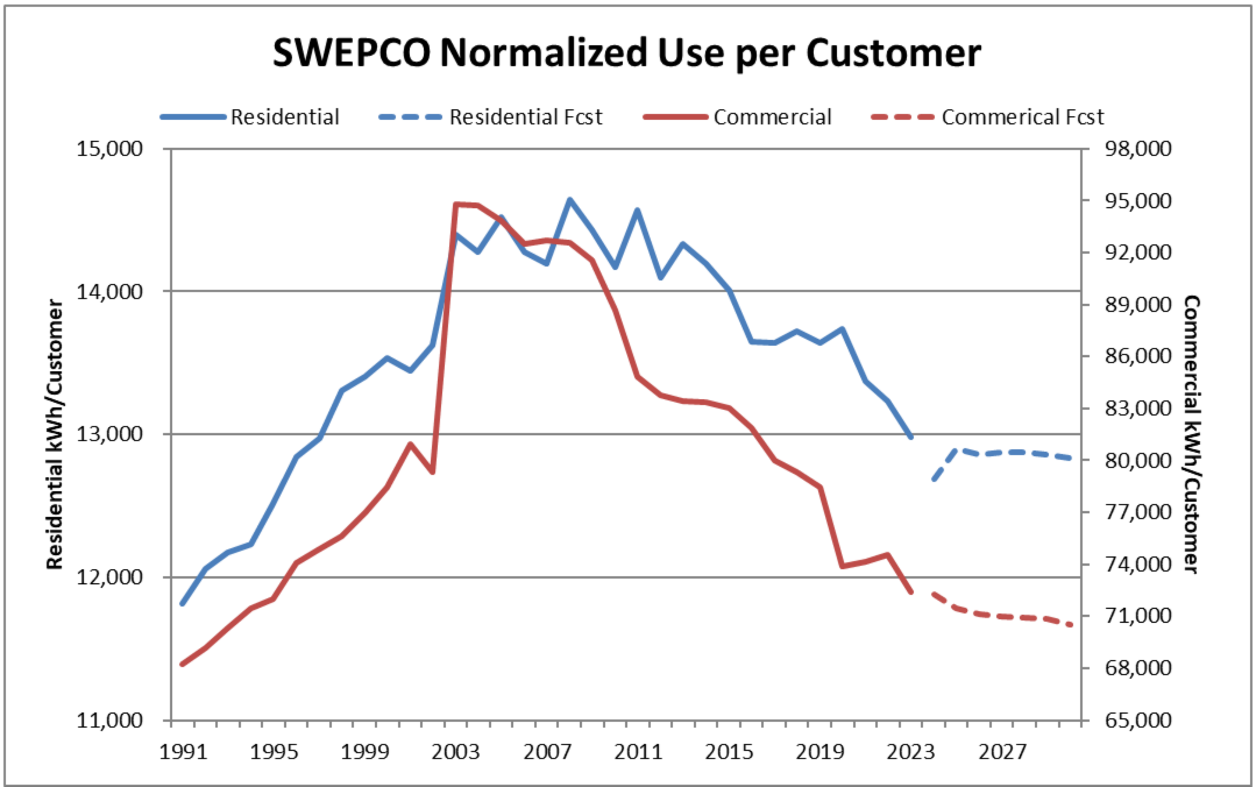

Figure 10: SWEPCO's Normalized Usage Per Customer-by-Customer Type

The SAE models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every three to four 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 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 11 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 15.57 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units. Figure 12 shows similar improvements in the efficiencies of lighting and refrigerators over the same period. However, there are few additional efficiency gains expected from lighting for residential customers, as consumers have already adopted the newer technologies and moved away from incandescent lighting.

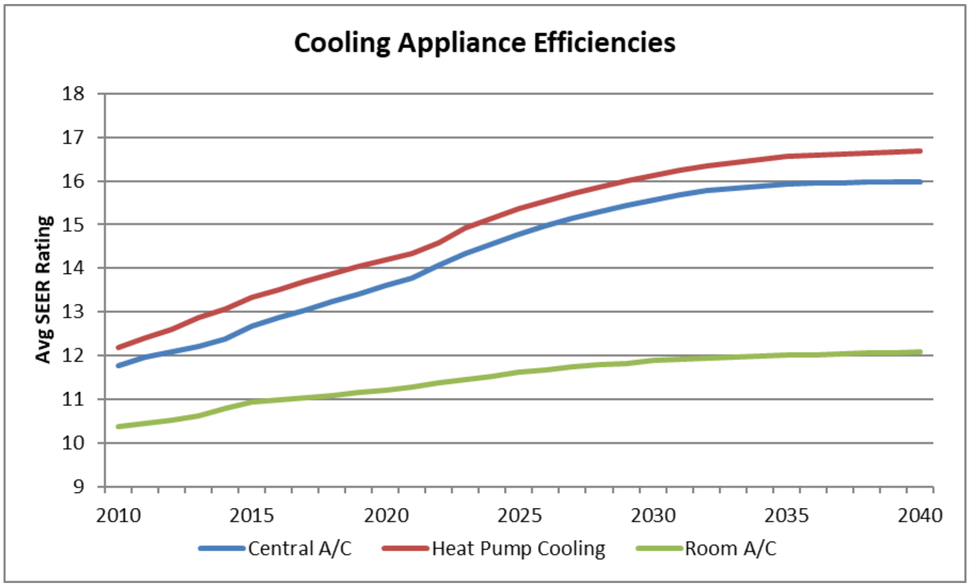

Figure 11: Projected Changes in Cooling Efficiencies, 2010 – 2040

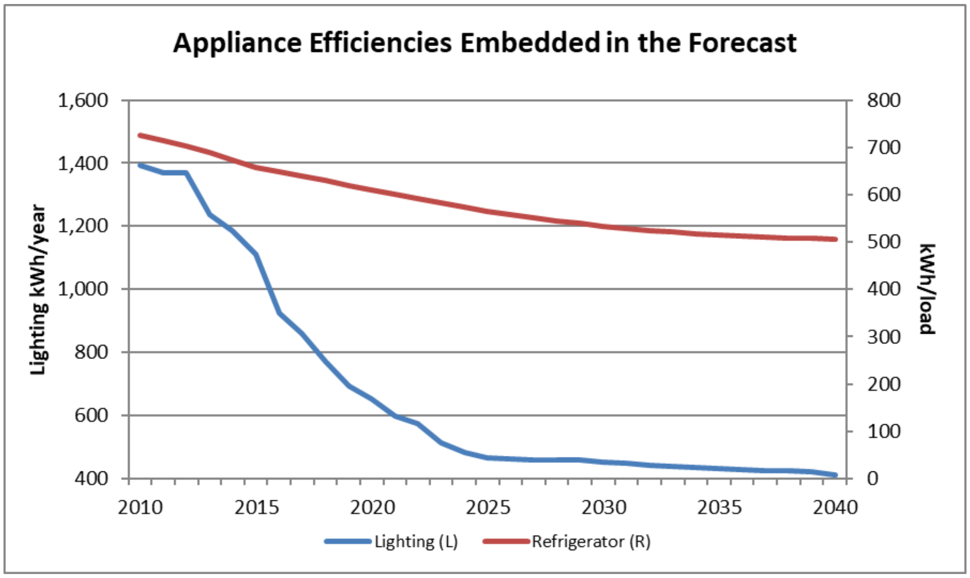

Figure 12: Projected Changes in Lighting & Refrigerator Efficiencies, 2010-2040

Figure 13 shows the impact of appliance, equipment, and lighting efficiencies on the Company's weather normalized 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, the historical and forecasted counts of SWEPCO residential customers are provided.

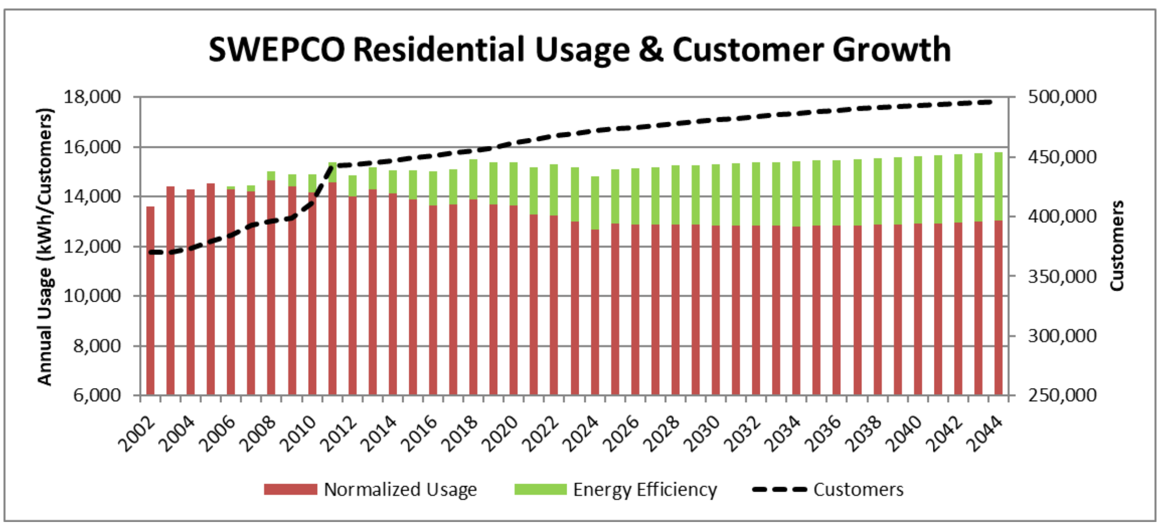

Figure 13: Residential Usage and Customer Growth, 2002 - 2044

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

Exhibit 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 Arkansas jurisdiction.

2.6.3 Losses and Unaccounted for Energy

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

2.6.4 Interruptible Load

The Company has 36 customers with interruptible provisions in their contracts. The aggregate on-peak capacity available for interruptions is 51MW. 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[6]. 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

In the typical non-weather sensitive classes, the long-term forecast is used for the entire forecast horizon. However, in order to capture the strengths of each modeling process as discussed above, elements of both the short- and long-term forecasts are used and blended together for the typical weather sensitive classes. This is accomplished by using the X-11 procedure which breaks down each forecast into trend and seasonal components.

For the weather sensitive classes, the trend component from the long-term forecast is always used to ensure structural economic changes are captured. Since the short-term forecast better captures the monthly usage patterns, a relative ratio of the seasonal components is developed and applied to the long-term seasonal component for each month. This adjusted, long-term seasonal component is then added to the long-term trend component to arrive at a final forecast. Although a small rounding error can occur, the final forecast for the weather sensitive classes will match the original long-term forecast on an annual basis. By limiting the change to the seasonal component on a relative basis, only the monthly usage pattern is altered, with some months adjusted higher and others lowered by an equal amount of energy.

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.

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[6] National Weather Service. "Winter Storm Summary: February 2021." https://www.weather.gov/lzk/win0221byr.htm#:~:text=Snow%20was%20heaviest%20from%20southwest,near%20Vilonia%20(Faulkner%20County).

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 scenario load forecast is the expected path for load growth that the Company uses for planning. There are several known and unknown potentials that could drive load growth to be 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.[7] 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, 2044, represent deviations of respectively, 14.9% below and 14.5% above the base-case forecast as shown below in Figure 14.

[7] U.S. Energy Information Administration. "Annual Energy Outlook." U.S. Energy Information Administration. https://www.eia.gov/outlooks/aeo/

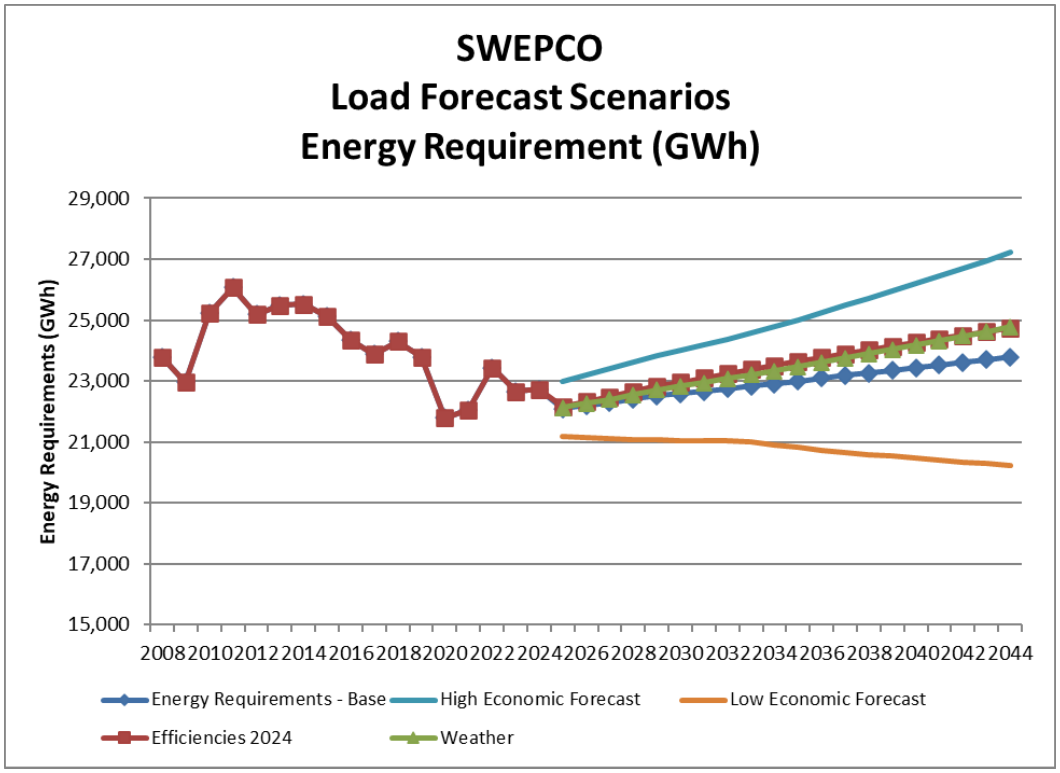

Figure 14: SWEPCO's Load Forecast Scenarios

The energy efficiencies 2024 scenario keeps energy efficiencies at 2024 levels for the residential and commercial equipment. This scenario results in a load forecast greater than the base forecast.

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 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 (EVs) 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 and especially in 2025 for entities that met the deadline prior to the changes in the net-metering rules in Arkansas, which closed the window for legacy 1:1 net metering on September 30, 2024. For EV growth, the Company has developed high, low, and base scenarios on adoption in the service area through 2044. These scenarios are presented graphically in Figure 15 and in Exhibit A-18 for SWEPCO's three state jurisdictions. Figure 16 illustrates the Company's projections for distributed generation (DG) growth for the Company's three state jurisdictions, which is also shown in Exhibit A-19.

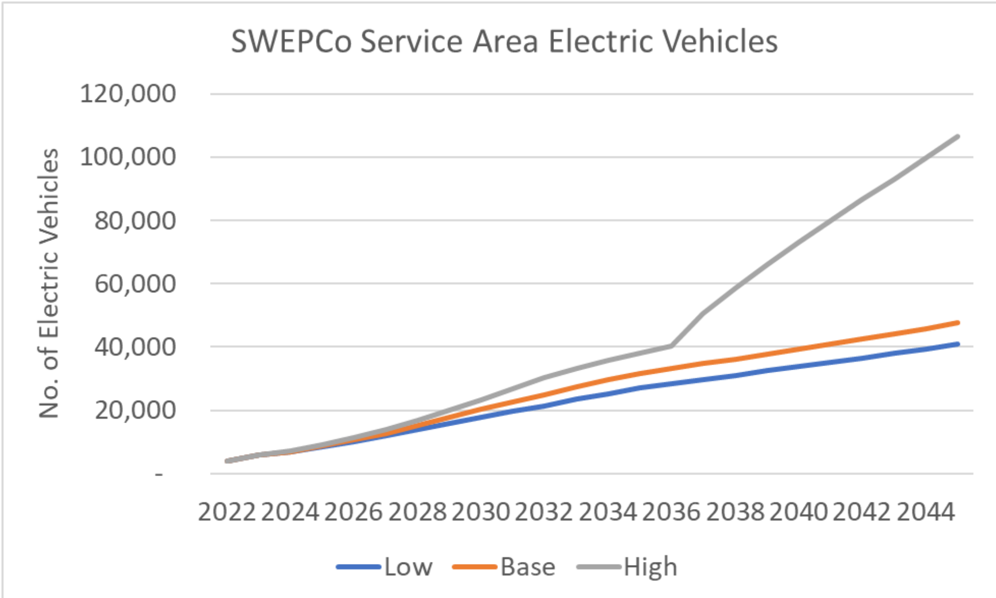

Figure 15: Electric Vehicle Growth Projections

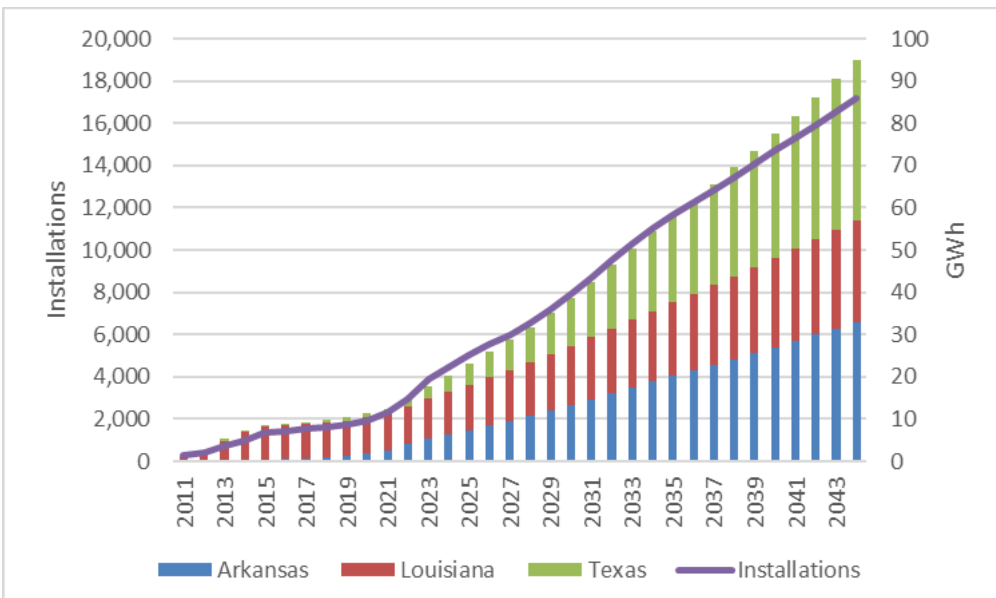

Figure 16: Distributed Generation Projections

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 one 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 one 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 0.15. For comparison, the estimated long-term elasticity for gasoline is 0.6 while the elasticity for restaurant meals is 2.3.[8]

[8] 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 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 along with the committed retirement dates. These resources are included in SWEPCO's Going-In Capacity position, which is further described in Section 3.5.

Table 2: SWEPCO's Generation Assets as of May 2024

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 (4)
Welsh 3	Coal	1982	528	TX	3/1/2028 (4)
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 (5)	OK	2051
Maverick	Wind	2021	156 (5)	OK	2051
Traverse	Wind	2022	544 (5)	OK	2051
Diversion	Wind	2024	201	TX	2054
Wagon Wheel	Wind	2025	598	OK	2055
Mooringsport	Solar	2026 (6)	200	LA	2060

(1) Commercial Operation Date.

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

(3) SWEPCO's share.

(4) Welsh units will cease burning coal by this date.

(5) Installed capacity; Represents SWEPCO's 54.5% ownership stake.

(6) SWEPCO has since cancelled the Mooringsport project and will not be moving forward with it, effective October 31,2024.

Table 3: SWEPCO's Contracted Generation Assets

Contracted Resource	Primary Fuel	Contract Expiration (SPP Planning Year)	Rating (MW)
Majestic	Wind	2029	80
High Majestic	Wind	2032	80
Canadian Hills	Wind	2032	201
Flat Ridge	Wind	2032	109
Rocking R	Solar	2045	73

In addition to these long-term resources, SWEPCO currently has Commission-approved and pending approval short-term contracts to provide capacity during the period between June 1, 2023, and May 31, 2028. The amounts currently under contract are 482MW for Planning Year (PY) 2024/2025, 635MW for PY 2025/2026, 428MW for PY 2026/2027 and 378MW for PY 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.

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.

3.2.1.1 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 considering 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 and 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.

3.2.1.2 Procurement Process – Natural Gas

SWEPCO forecasts weather-normalized customer load by month, over a rolling 36-month period, and compares available fixed cost resources in each month, to that load. At predetermined milestones of 36 months, 18 months, and 2 months before flow, SWEPCO increases the level of fixed-cost physical hedges to cover “target hedge percentages” of the weather normalized customer load. These percentages increase over time, to result in an increasing portion of the cost of customer load becoming fixed. In support of this program, SWEPCO issues request for proposals (RFPs) seeking offers of fixed price, forward month natural gas supply. SWEPCO utilizes spot market natural gas purchases (or sales) to balance daily positions. In 2023, SWEPCO incorporated natural gas storage into its portfolio, to further protect against natural gas price volatility and disruption of supply. SWEPCO continues to utilize both firm and interruptible transportation contracts, to move natural gas supply from designated receipt points to its plants.

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 robust EE programs in place in its Arkansas, Louisiana, and Texas service territories and DR programs in place in its Arkansas and Texas service territories.[9] SWEPCO forecasts EE measures and DR programs will reduce peak demand in 2024 by 47.8MW and reduce 2024 energy consumption by approximately 84GWh.

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

[9] SWEPCO has submitted demand response tariffs to the LPSC in Docket No. R-35136, some of which have recently been approved by the Commission Staff.

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.

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 February 2024, the EPA finalized revisions which strengthen the primary (health based) annual $PM_{2.5}$ standard.

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 (NOX), 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 Electric Generating Units (EGU) greater than 250MW and built between 1962 and 1977. If SIPs are not adequate or are not developed on schedule, regional haze requirements will be implemented through Federal Implementation Plans (FIP).

3.4.4 Arkansas Regional Haze

Arkansas has an approved SIP for implementation of the Regional Haze Rule’s Planning Period I. On August 2, 2022, Arkansas Department of Environmental Quality 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.

3.4.5 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 also do not impose any requirements on SWEPCO facilities. Those rules have not been approved by the Federal EPA.

3.4.6 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. 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’ more recent Regional Haze rulemakings. The Company cannot predict the outcome of that litigation Meanwhile, the Federal EPA disapproved portions of the Texas regional haze SIP and finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_X regional haze obligations for electric generating units in Texas.

Additionally, the Federal EPA finalized an intrastate SO2 emissions trading program based on CSAPR allowance allocations. Environmental groups filed challenges to these various rulemakings in district courts in the Fifth Circuit and the District of Columbia Circuit. In July 2024, the U.S. District Court for the District of Columbia Circuit entered a consent decree setting deadlines for the Federal EPA to rule on Regional Haze SIPs for 33 states, including Texas. In September 2024, the Federal EPA signed a proposed rule to partially approve and partially disapprove the Texas SIP revision. The proposed rule was published in the Federal Register in October 2024, initiating a public comment period ending November 14, 2024. The deadline for the Federal EPA to take final action on the Texas SIP is May 30, 2025.

SWEPCO is currently complying with the SO_2 intrastate trading program.

On June 30, 2021, Texas Commission on Environmental Quality (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.

3.4.7 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. The Company 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, for the 2015 Ozone NAAQS for those states where SIPs were denied. The Good Neighbor Plan is designed to increasingly reduce the cap on NO_X emission allowances annually from 2023 through 2029. The Good Neighbor Plan redefines states participating in the Group 2 and Group 3 NO_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 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. Additional appeals to the United States Supreme Court have resulted in a stay of the applicability of the Plan in additional states, and prompted EPA, on October 29, 2024, to issue a final rule to administratively stay the effectiveness of the Good Neighbor Plan's requirements for all sources covered by that rule as promulgated where an administrative stay was not already in place. The administrative stay of the Good Neighbor Plan's effectiveness for power plants and other industrial facilities in each of the 23 states will remain in place until the Supreme Court lifts its order staying enforcement of the Good Neighbor Plan, other courts lift any judicial orders staying the SIP disapproval action as to the state, and EPA takes subsequent rulemaking action consistent with any judicial rulings on the merits. SWEPCO will continue to monitor the outcome of this litigation and the development of SIPs for any potential impact to operations.

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, if the rule remains in place following conclusion of the various legal challenges.

3.4.8 Clean Air Act Section 111 Greenhouse Gas Emission Standards

On May 9, 2024, EPA finalized greenhouse gas (GHG) emissions standards that are applicable to existing coal and natural gas steam units, as well as new gas combustion turbine units. States will have until May 2026 to submit a state implementation plan (SIP) to EPA that details how the state will achieve the emission standards for applicable facilities. EPA will then have one year to approve the SIP (approximately May 2027). Effective dates for achieving the emission standards vary depending on the compliance option selected.

For coal units, four compliance options were finalized. The first establishes a carbon dioxide (CO_2) emission standard based on the use of a 90% carbon capture and storage (CCS) control systems. Facilities utilizing this option must have the CCS system in service by January 1, 2032. The CCS option does not have future requirement to retire coal unit operations by a specific date.

The second compliance option for existing coal units is to achieve a CO_2 emission standard that is based on the use of 40% natural gas co-firing. Facilities utilizing this option must have gas co-firing in service by January 1, 2030, and must retire coal unit operations by January 1, 2039. The third compliance option is 100% natural gas conversion. Facilities utilizing this option must have the natural gas conversion in service by January 1, 2030. Finally, the fourth compliance option is to retire the coal unit by January 1, 2032.

Regarding gas units, EPA finalized CO_2 emissions standards for existing gas steam units and new gas combustion turbine units. Emission standards for existing gas combustion turbine units will be developed by EPA in a separate rulemaking. The emissions standard for existing gas steam units are based on the capacity factor of the unit and efficient combustion operations. The standard does not include a specific retirement date for these existing units.

For new gas combustion turbine units, EPA established three emission standards, depending on the unit's capacity factor. The low load (<20% capacity factor) and intermediate load unit (20-40% capacity factor) standards are based on high efficiency operations. The low load and intermediate load unit standards are based on the use of low emitting fuel and high efficiency operations, respectively. The emission standards for baseload (>40% capacity factor) operations are high efficiency standards and the use of CCS technology achieving a 90% CO_2 reduction.

SWEPCO is evaluating and identifying the best strategy for complying with this and other new rules, discussed herein, while ensuring the adequacy of resources to meet customer needs. The rule has been challenged by 27 states, including Arkansas, Louisiana, and Texas, numerous companies, trade associations and others, including SWEPCO and other utilities. All the appeals have been consolidated. Numerous parties, including SWEPCO asked the court to stay the rule during the litigation, but in July 2024, the D.C. Circuit Court of appeals denied those motions to stay. Several parties, including SWEPCO and other utilities, filed applications with the United States Supreme Court seeking an emergency stay but in October 2024, the Supreme Court denied those applications. SWEPCO is continuing to evaluate its options for compliance should the rule stand.

Aside from GHG rulemaking activities, the Company has taken action to reduce CO_2 emissions from its generating fleet. The Company 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.

3.4.9 Mercury and Air Toxics Standards (MATS) Rule

In April 2024, the Federal EPA issued a revised MATS rule for power plants. The rule includes a more stringent standard for emissions of filterable PM for coal-fired electric generating units, as well as a new mercury standard for lignite-fired electric generating units. The rule also requires the installation and operation of continuous emissions monitors for PM. Several states and other parties have challenged the rule in the United States Court of Appeals for the District of Columbia Circuit, but SWEPCO cannot predict the outcome of the litigation. SWEPCO is evaluating the impacts of the rule yet does not anticipate any significant challenges complying with the rule.

3.4.10 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 and Environmental 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 April 2024, the EPA finalized 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"). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. SWEPCO is evaluating the applicability of the rule to current and former plant sites and has developed preliminary estimates of compliance costs, which are expected to be material, including costs to upgrade or close and replace legacy CCR surface impoundments and to conduct any required remedial actions including removal of coal ash. Additionally, several states, utilities and trade associations, including SWEPCO and one of its trade associations, have filed petitions for review of the rule with the U.S. Court of Appeals for the D.C. Circuit. One of the parties also filed a motion to stay the rule pending the outcome of the litigation. On November 1, 2024, the court denied the stay motion. SWEPCO cannot predict the outcome of the litigation.

3.4.11 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.

In April 2024, the EPA finalized further revisions to the ELG rule that establish a zero liquid discharge standard for FGD wastewater, bottom ash transport water, and managed combustion residual leachate, as well as more stringent discharge limits for unmanaged combustion residual leachate. The revised rule provides a new compliance alternative that would avoid the need to install zero liquid discharge systems for facilities that comply with the 2020 rule's control technology requirements and commit to retire by 2034. SWEPCO is evaluating the compliance alternatives in the rule, taking into consideration the requirements of the other new rules and their combined impacts to operations. Several appeals have been filed with various federal courts challenging the 2024 ELG rule. SWEPCO has also challenged the rule. The various appeals have been consolidated before the United States Court of Appeals for the Eighth Circuit. SWEPCO cannot predict the outcome of the litigation. 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 ELG Rule's 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.

3.5 Capacity Needs Assessment

As a member of SPP, SWEPCO 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 deficiency penalties. 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.

On August 6, 2024, SPP's Regional State Committee (RSC) and Board of Directors (SPP Board) approved increases to the Planning Reserve Margin (PRM) that member utilities are required to maintain to support regional grid reliability[10]. The RSC and SPP Board approved minimum requirements of a 36% winter-season Installed Capacity (ICAP) PRM and a 16% summer-season ICAP PRM, effective beginning summer 2026 and winter 2026/27. These actions were taken primarily based on SPP's analysis of the 2023 SPP Loss of Load Expectation Report.[11] At the time of preparation for this IPR, SPP Staff had indicated that it intended to recommend further increases to the PRMs by 2029/30 and in AEP's assessment this is the most likely outcome.[12] Based on this assessment, for AEP's system planning purposes the winter ICAP PRM was set at 36% for 2026/27 and was increased by 2% annually for each of the following three winter seasons reaching 42% for winter 2029/30 and was held constant at 42% thereafter. The incremental percentage increase in the winter ICAP PRM was an assumption by the Company for this IRP. AEP is highly engaged in the SPP stakeholder process and will continuously monitor this process.

Furthermore, SPP is modifying the basis for each load responsible entity (LRE) to meet the new PRMs by implementing an Accredited Capacity (ACAP) methodology.[13] The ACAP methodology will include an adjustment to convert the 16% summer and 36% winter ICAP PRMs to ACAP PRMs as well as implementing a resource performance-based adjustment (PBA) for existing thermal resources and an effective load carrying capability (ELCC) accreditation methodology for wind, solar, and storage resources. The PBA will be derived from each thermal unit's past performance and result in a reduction from the installed capacity to a lower accredited capacity for meeting the Company's minimum summer ACAP PRM obligations. Additionally, the winter ACAP for the company's thermal resources will be further adjusted to account for historical performance and fuel availability during critical systems periods.

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[10] Southwest Power Pool, "SPP Board Approves New Planning Reserve Margins to Protect Against High Winter, Summer Use", https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/#:~:text=SPP%27s%20Regional%20State%20Committee%20and,2026%20and%20winter%202026%2F27

[11] Southwest Power Pool, "2023 SPP Loss Of Load Expectation Study Report", https://www.spp.org/documents/71904/2023%20spp%20lole%20study%20report.pdf

This report analyzes the reliability of the SPP Balancing Authority Area's power generation to meet forecasted peak demand and determines the necessary Planning Reserve Margin.

[12] On February 4, 2025, the SPP RSC and Board voted to increase the Base PRM effective on June 1, 2029, to 17% for the 2029 summer planning year, and to 38% for the 2029/2030 winter planning year.

[13] Southwest Power Pool, "MOPC Educational FA and ACAP PRM Overview", https://spp.org/documents/71947/mopc%20educational%20fa%20and%20acap%20prm%20overview.pdf

This document provides an overview of the Fuel Assurance and Accredited Capacity Planning Reserve Margin (ACAP PRM) methodologies used by SPP.

For this IRP, the Company assumed a minimum SPP summer and winter ACAP PRM estimated by SPP of 5% and 11.9% respectively in 2026, where these correspond to the ICAP RPM's discussed in the previous paragraph.[14] For AEP's system planning purposes the winter ACAP PRM was increased by 2% annually for each of the following three winter seasons after 2026/27 reaching 17.9% for winter 2029/30 and was held constant at 17.9% thereafter. The Company also included an additional 6% capacity contingency to the ACAP PRM (7% capacity contingency to the ICAP PRM in 2025) to mitigate risks related to complying with the fast-changing SPP reserve margin requirements and other sources of forecast uncertainties and potential unit unplanned outages. Additional details on the capacity contingency can be found in Section 3.5.1.

SWEPCO also notes that it has historically had surplus capacity that exceeds the Company's current planned surplus, or capacity contingency of 6% ACAP, which equates to approximately 300MW. For example, for the 8-year period from 2015 through 2022, SWEPCO's average capacity surplus above SPP's requirement was approximately 630MWs. This was considered prudent considering it could be used as a contingency against a unit outage.

SWEPCO notes that the 6% ACAP capacity contingency of approximately 300MWs 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 300MWs could still result in SWEPCO being short on its commitment, and potentially facing deficiency penalties from the SPP.

Figure 17 and Figure 18 illustrate the resulting summer and winter capacity needs of SWEPCO through 2044, respectively. 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 need grows in the 2028/2029 summer planning season when SWEPCO's Welsh 1 & 3 units will cease burning coal and are removed from the going-in assumptions. It grows again for the 2029/2030 summer planning season when Arsenal Hill 5 and Lieberman units 3 and 4 are assumed to retire on May 31, 2029, and again in for the 2030/2031 summer planning season when Wilkes unit 1 is assumed to retire on May 31, 2030. The retirement assumptions are for planning purposes within this IRP.

[14] These ACAP PRMs were informed from a preliminary SPP report provided to the Company in April 2024, however, final ACAP PRMs have not yet been communicated to LREs.

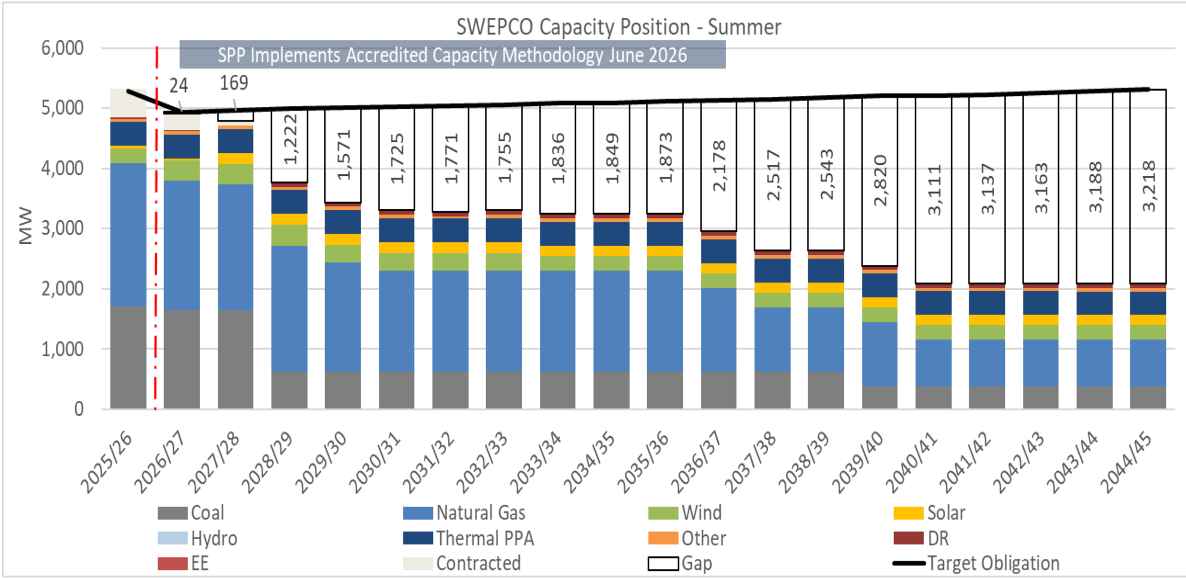


Figure 17: SWEPCO Going-In Summer Capacity Position and Obligation

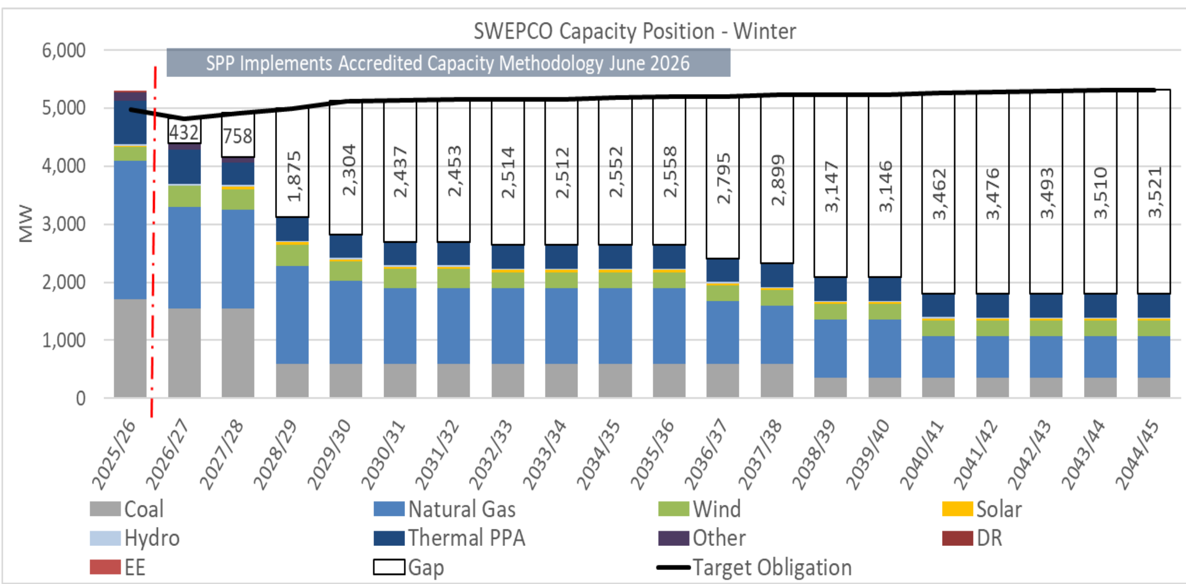


Figure 18: SWEPCO Going-In Winter Capacity Position and Obligation

3.5.1 Capacity Contingency

The capacity contingency target applied by SWEPCO represents an additional planning target above the minimum PRM set by SPP. This additional target is included to mitigate risks related to complying with the fast-changing SPP reserve margin requirements. SWEPCO believes it is not prudent to only plan to the minimum reserve margin obligation, particularly in this period of change across the SPP region and in which SWEPCO will need to add generation resources to meet the reliability needs of its customers.

There are many factors that lead to uncertainty in the peak load forecast and the amount of generating capacity that SWEPCO will have accredited in any future planning year. Those factors include load obligation variability, future ACAP methodology accreditation for dispatchable resources, ELCC accreditation for renewable resources, and credit risk associated with the counterparties for resources SWEPCO has under PPA contracts. Together, there is significant risk that SWEPCO's accredited capacity will not meet the load obligation if the Company does not aim to exceed it by planning to a target that includes the additional amount. The analysis on historical values showed that a capacity contingency of between 6.09% and 7.01% could give SWEPCO 95% confidence that the identified risks have been accounted for with the contingency.

The example graph below is the output of a study of a peak load roughly the size of SWEPCO's winter net coincident peak load. Figure 19 illustrates a general example of the distribution of the capacity surplus or deficit compared to the reserve margin obligation for a planning year, if the median accredited capacity equals the reserve margin obligation based on the current load forecast.

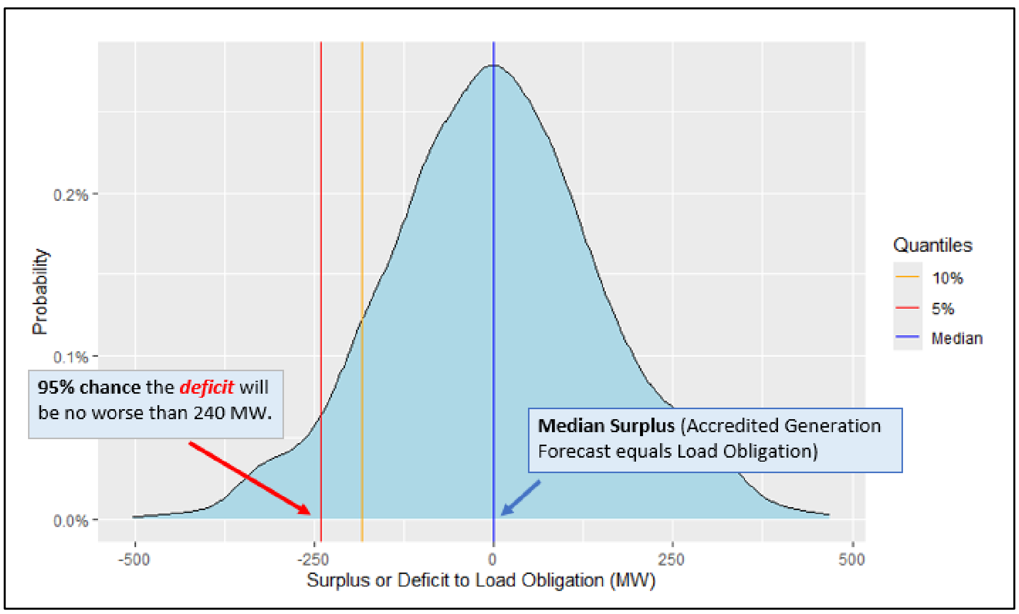


Figure 19: Capacity Contingency Probabilistic Distribution Example

If SWEPCO targets a surplus equal to zero, then the Company only has 50% confidence (one out of every two years) that it will have sufficient capacity to meet SPP's minimum requirement and, as such, would be subject to significant deficiency penalties by SPP. This risk is considered unacceptable by the Company and, in contrast, SWEPCO aims for 90% to 95% confidence that it will meet SPP's minimum requirements. In this illustration, the Company would need to target another 200MW of capacity to achieve 90% confidence and 240MW to achieve 95% confidence.

3.6 Energy Needs Assessment

Figure 20 illustrates the projected going-in energy position of the Company. This graphic quantifies the amount of the Company's load that will be served by Company resources, and the net purchases from the SPP energy market. These projections include existing resources, new resource additions, and existing resource retirements or contract expirations.

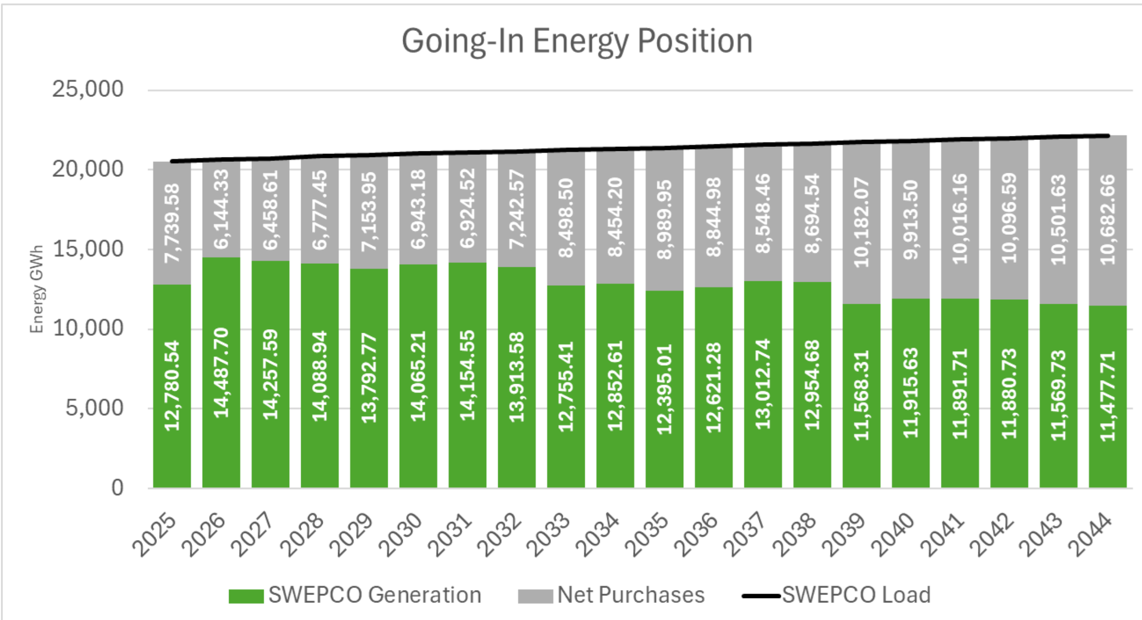


Figure 20: SWEPCO Going-In Energy Position

Over the planning horizon, the gap between SWEPCO generated energy and SWEPCO load increases. This is due to the steady increase in SWEPCO load over the planning horizon in addition to resource retirement or contract expirations. In 2033, the resource contract expirations result in an energy reduction of 1,360GWh. Later in the planning horizon, Flint Creek retires in year 2038, as part of the planning assumptions. This results in a reduction of 1,130GWh of energy. The combination of load growth, resource retirement, and resource contract expirations results in an increase of roughly 3,000GWh of energy required to be purchased from the market when comparing year 2025 to 2044.

In addition to optimizing the model with a capacity constraint, as described in Section 3.50, the Company modeled an energy constraint, focusing on the percentage of energy imports and exports compared to SWEPCO load. At the beginning of the planning horizon, the company allowed higher energy market imports and exports as resources did not become available for selection in the model until 2029 as noted in Section 6.5. After 2029, the Company reduced the energy market import and export limits, constraining the model to select resources to support the energy need instead of purchasing from the SPP energy market.

Risk associated with energy purchases was an important objective the Company wanted to analyze in this IRP. Relying too heavily on energy market purchases could negatively impact SWEPCO's customers during times of elevated energy market prices. As such, the percentage of market purchases and sales was an element of the Portfolio Performance Indicator Matrix and an important consideration in comparing portfolios to identify the Preferred Plan. More details on the Energy Market Risk objective can be found in Section 8.3.2.

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

Since becoming an RTO in 2004, many bulk transmission upgrades within the SPP have greatly increased SPP's ability to dispatch generation in a more economic and flexible manner while maintaining reliability, and more such upgrades continue each year. This was the objective of two important FERC orders. First, FERC Order 888 promoted wholesale competition through open access non-discriminatory transmission services by public utilities. Secondly, FERC Order 2000 was issued to encourage all transmission owners to voluntarily join RTOs. The RTO continues to work toward this end. Additional interconnection capacity between SPP and neighboring systems, as well as additional changes to the electrical topology of the SPP footprint transmission system, will continue to greatly increase the ability to deliver affiliate and 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. Additional seams agreements between SPP and its neighbors will also accelerate new interconnections. The additional interconnection capacity and seams agreements will alleviate stress on the system and continue to reduce congestion. In addition, factors such as outages, extreme weather, and power transfers can also stress the system.

SPP and MISO, under the terms of their Joint Operating Agreement,[15] engage in a coordinated study process to identify transmission improvement projects which are mutually beneficial. SPP and MISO have also worked to develop and implement a Joint Targeted Interconnection Queue (JTIQ) study to address the affected system impacts of new generator interconnections near the SPP & MISO seam. Both SPP and MISO have received approval from FERC of the necessary tariff provisions to facilitate cost recovery of the projects identified in this JTIQ study and issued Notices to Construct directing Transmission Owners to begin construction of these needed transmission facilities.

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/

[15] Southwest Power Pool, "SPP-MISO Joint Operating Agreement," https://www.spp.org/documents/72719/20241114_spp-miso%20joa.pdf

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[16] 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 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.

[16] Southwest Power Pool, "2024 SPP Transmission Expansion Plan Report," https://www.spp.org/documents/56611/2024%20spp%20transmission%20expansion%20plan%20report.pdf

- **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.

- **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.

- **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.

- **Muskogee - Tahlequah 161 kV rebuild, Muskogee - Fort Smith 345 kV Conversion/New Line:** This project includes a new 80-milee 345 kV line from Muskogee to Fort Smith as well as a new 500/345 kV transformer at Fort Smith. Transformation at Fort Smith has been restricting west to east flow across the system, this project will address 115 kV congestion between Muskogee and Fort Smith.

- **Siloam Springs (GRDA) – Siloam Springs (SWEPCO) 161kV Reconductor**: 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.

- **Winter Weather Projects**: The 2024 ITP SPP process included a special study for severe winter weather. Several of these projects will increase the west to east transfer capability in the SPP system and improve winter weather resiliency. The most impactful Winter Weather projects connect the west side of Wichita, KS to Branson Missouri. These three projects are a new 154.6-mile 345 kV line from Buffalo Flats to Delaware 345 kV, a new 114.5-mile 345 kV line From Delaware to Monett, and a new 47.2-mile line 345 kV line from Monett to North Branson[17].

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.

[17] The 2024 ITP portfolio is a document established by SPP to focus on reliability, winter weather, economic, short circuit and operational projects that will mitigate 1,062 system issues and over 100 transmission projects to address reliability, economic, policy and operational needs.

4.5 SWEPCO Distribution System Overview

SWEPCO serves approximately 554,000 customers across 20,701 square miles of Arkansas, Louisiana, and Texas. This includes approximately 471,000 residential, 75,000 commercial, 6,600 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 22,131 overhead circuit miles and approximately 3,810 underground circuit miles. SWEPCO's distribution system includes approximately 20,511 primary miles and 5,430 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, the Company proposed capital investments to its distribution grid of approximately $430.39M. 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
Reliability Enhancements	70.20
Asset Renewal	267.40
Total	430.39

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 has been commissioned for non-outage scenarios, but additional work is being done to allow the full use of the system as a microgrid, allowing the subdivision to disconnect from the main system and continue to maintain power during outages. That part of the project is expected to be completed and operational in early 2025. The Company looks forward to the addition and the opportunity to learn how the operation will impact the Company's peak load.

5. Modeling Parameters

5.1 Modeling and Planning Process – An Overview

The objective of a resource planning effort is to recommend a system resource expansion plan (Preferred Plan) that balances objectives as defined by the Company while also complying with RTO criteria. For this IRP, SWEPCO identified customer affordability, rate stability, maintaining reliability, and local impacts and sustainability as their four objectives. In addition, given the unique impact of fossil-fired generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the EPA-driven environmental compliance planning process.

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

Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the SWEPCO IRP process. Therefore, the objective function of the modeling application utilized in this process is to optimize the resource selection to develop the least-cost plan, with cost being more accurately described as net present value of revenue requirement.

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

This overall process reflects consideration of the objectives for customer affordability, rate stability, maintaining reliability, and local impacts and sustainability.

5.2 Methodology

The IRP process aims to address the gap between resource needs and its existing resources including any committed additions and retirements. Given the various assets and resources that can satisfy this expected gap, a tool is needed to sort through the myriads of potential combinations and return an optimum solution. PLEXOS® long-term optimization model (LT Plan) is the modeling application used by SWEPCO for identifying and ranking portfolios that address the gap between needs and current available resources. Given the cost and performance parameters around sets of potentially available proxy resources–both supply and demand side–and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs as well as projections of energy usage and peak demand, PLEXOS® will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the Net Present Value Revenue Requirement (NPVRR), of the resulting stream of revenue requirements. The least cost option is considered the optimum portfolio for that unique input parameter scenario.

5.3 The Fundamentals Forecast

AEP's Fundamental Forecast was developed by AEP's Economic and Supply Forecasting organization. The forecast is a long-term commodity market forecast completed July 2023. It covers the electricity market within the Eastern Interconnect. It is provided to AEPSC and all AEP operating companies for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, and other applications. The forecast includes (in both nominal and real dollars): 1) hourly, monthly and annual regional power prices; 2) prices for various types of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) emission prices; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors; Table 5 below describes the source of the Fundamental Forecast components.

Table 5: Fundamentals Forecast Components

Category	Forecast Component	Source
FUEL	Natural gas forecast; Henry Hub	AEP Fundamentals
FUEL	Natural gas locational values	AEP Fundamentals
FUEL	Oil price, WTI	AEP Fundamentals regression model
FUEL	Uranium prices	AEP Fundamentals regression model
FUEL	Coal	Wood MacKenzie Coal Forecast
LOAD	Load Forecast and hourly shapes	AEP Economic and Load Forecasting
GENERATION	New unit costs/Technology Learning Curves	EIA AEO Build Costs/NREL
GENERATION	New, low or zero carbon dispatchable technology	AEP Engineering
GENERATION	Solar/Wind production shapes by area	NREL
GENERATION	Generating Reserve Margins	RTO Requirements
GENERATION	Announced new generation units	Velocity Suite
GENERATION	Existing generation units	Velocity Suite (EIA 860 and 923 data)
POLICY	State-mandated Renewable Portfolio Standards	AEP Fundamentals; AEP Environmental
CREDITS	REC's	Evolution Markets and Wood MacKenzie
CREDITS	PTC's, ITC's	Inflation Reduction Act
ECONOMIC	Inflation/GDP deflators/PPI	Moody's Analytics
EMISSIONS	Annual SO_2, Seasonal/Annual NO_x	AEP Commercial Operations
EMISSIONS	CO_2-RGGI forecast	AEP Commercial Operations and Wood MacKenzie
EMISSIONS	Unit-level emission rates; CO_2, SO_2, NO_x	Velocity Suite (US EPA CEMS data)

Energy Exemplar's Aurora energy market simulation model is the primary tool used to make the Fundamental Forecast. 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 22,000 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.

5.3.1 Market Scenario Drivers and Assumptions

Four scenarios, shown in Table 6, were developed to create and test SWEPCO's Preferred Plan under various long-term pricing scenarios.

The Base scenario represents an expected view of how load growth, commodity prices, and technology development will evolve over time and contribute to the market conditions under which SWEPCO will operate. The High scenario assumes higher load growth and higher natural gas prices than Base scenario. The Low scenario assumes lower load growth and lower natural gas prices than Base scenario. The Enhanced Environmental Regulation scenario is similar to Base scenario but assumes that adoption of the Environmental Protection Agency's proposed rule changes to CAA Section 111(d). The proposed rule was published May 11, 2023.

Table 6: 2024 IRP Scenario Assumption Matrix

Portfolio	SWEPCO Load	Commodity Prices	Environmental Regulations	Technology Cost
Base Case	Base	Base	Base	Base
High Case	High	High	Base	Base
Low Case	Low	Low	Base	Base
Enhanced Environmental Regulations (EER)	Base	EER	111(b)(d) Informed	Base

5.3.1.1 Fuel Scenarios

Natural Gas Prices

Figure 21 illustrates the monthly Panhandle Eastern TX-OK natural gas price forecasts that are used for the SPP market modeling in the Base scenario. This pricing point was selected for the report because it is representative of gas prices in the region.

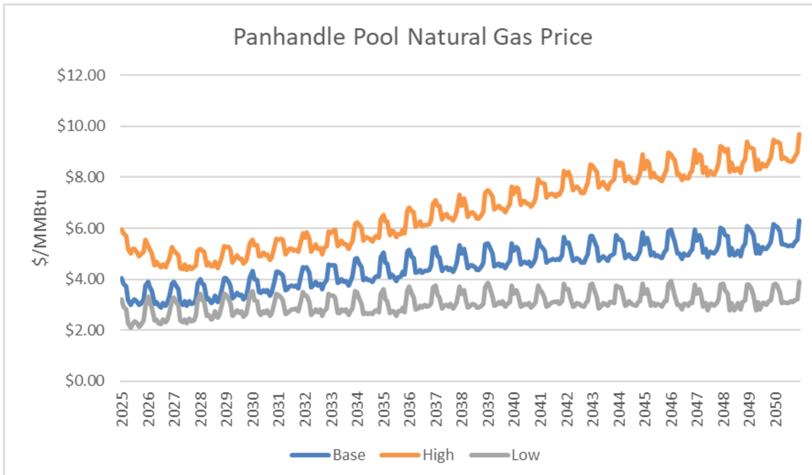


Figure 21: Panhandle Eastern TX-OK Nominal Natural Gas Prices ($ / MMBtu)

Coal Prices

SWEPCO uses Wood MacKenzie's coal price forecast in the 2024 IRP. Figure 22 illustrates the yearly forecast of Powder River Basin (PRB) coal prices at the point of purchase (i.e., exclusive of transportation costs) used in the Base 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 coal facilities.

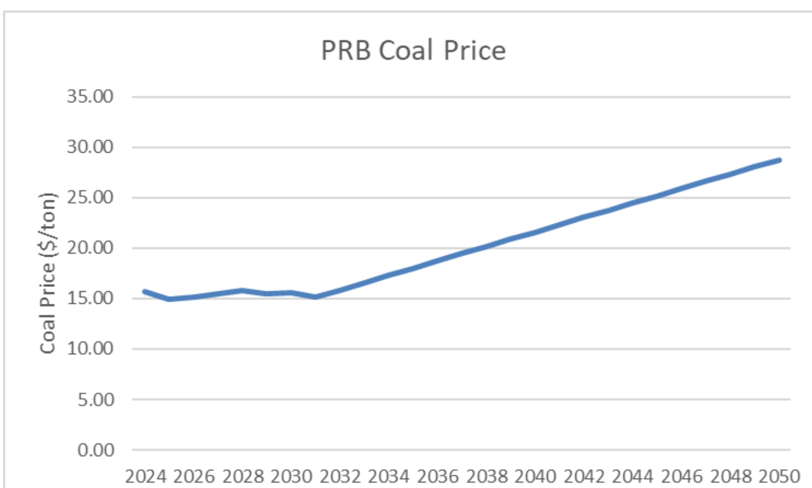


Figure 22: PRB Coal Prices (nominal $ / ton, FOB origin)

5.3.1.2 Capacity Expansion Results

SWEPCO used the AURORA long-term capacity expansion 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 might perform under certain conditions. Figure 23 and Figure 24 below illustrate the 2044 forecasted SPP capacity and generation mix (respectively) across all five market scenarios compared with the SPP resource mix in 2025.

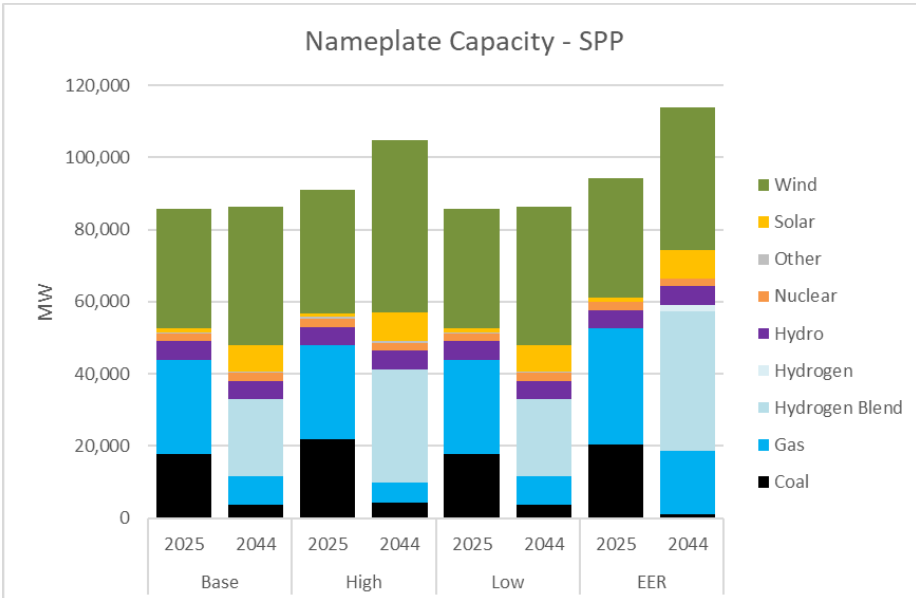


Figure 23: Comparison of 2044 Nameplate Capacity by Technology in SPP w/ 2025 Resource Mix

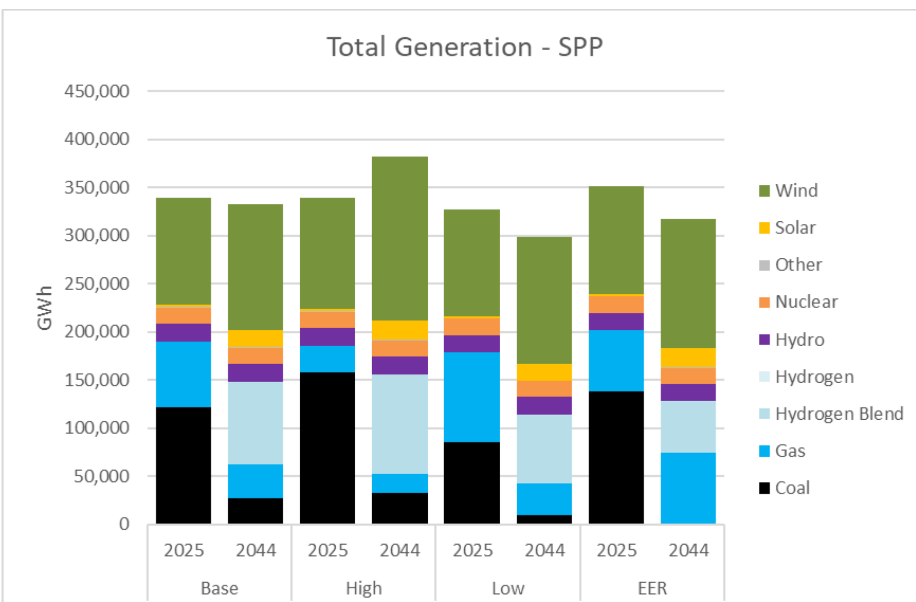


Figure 24: Comparison of 2044 Generation by Technology in SPP w/ 2025 Resource Mix

5.3.1.3 Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Figure 25 and Figure 26. Shown are all four market scenarios modeled in the 2024 IRP. These figures illustrate the wide but plausible range of energy prices that emerge from the scenario modeling step that were used to develop and select the Preferred Plan.

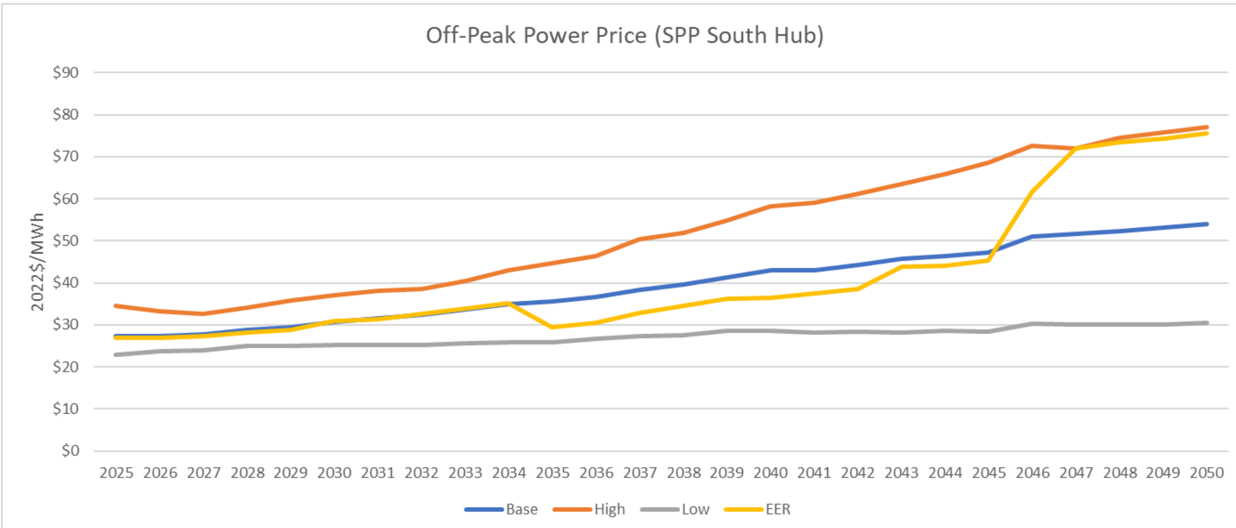


Figure 25: Annual On-Peak SPP South Hub Nominal Electricity Price ($ / MWh)

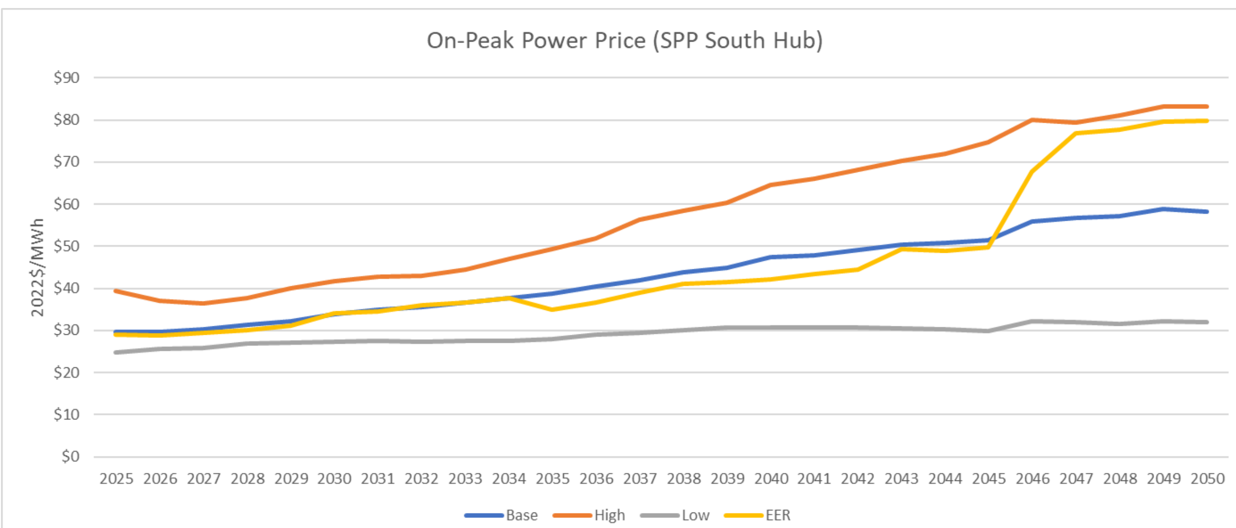


Figure 26: Annual Off-Peak SPP South Hub Nominal Electricity Price ($ / MWh)

6. Supply-Side Resource Options

6.1 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 obsolescent leading to a risk of premature retirements. The evolving electricity generation mix may also require a more diverse set of resources that can provide different system needs at different times to maintain system reliability particularly under extreme weather conditions.

The supply-side resource options considered by SWEPCO in this IRP fall into six categories: base / intermediate alternatives, peaking alternatives, renewable alternatives, advanced generation alternatives, 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. 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.

Changes to real dollars technology costs over time shown in Figure 27 are based on the moderate case of the 2023 National Renewable Energy Laboratory's (NREL) annual technology baseline (NREL ATB 2023) report[18]. For modeling, the Company also applied a producer price index (PPI) inflation cost to represent forward looking costs in nominal dollars shown in the subsequent sections.

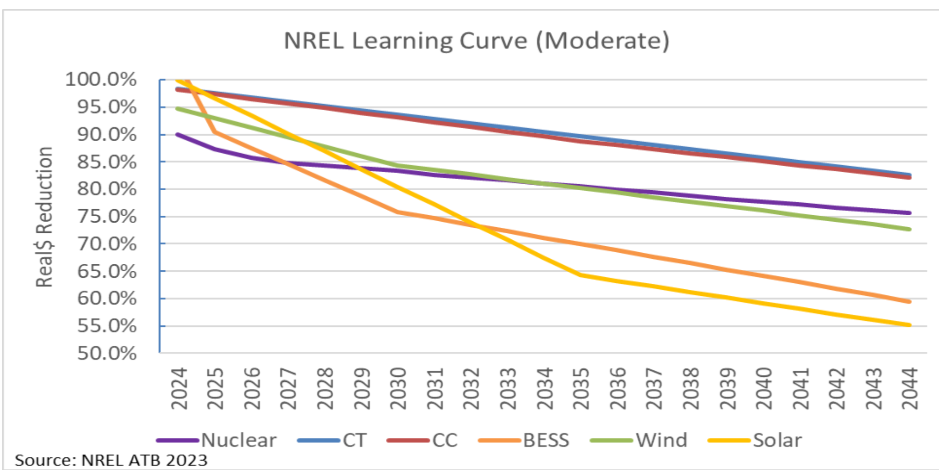


Figure 27: Technology Cost Learning Curves

[18] National Renewable Energy Laboratory, "Electricity Annual Technology Baseline (ATB) 2023," https://atb.nrel.gov/electricity/2023/data

The report provides data and analysis offering insights into the cost and performance of electricity generation technologies.

The Company included annual and cumulative capacity modeling limits for different resources informed through its analysis of the SPP queue and market intelligence gained from past Company Request For Proposals (RFPs). To establish the modeling limits, the Company first reviewed the potential MWs of resources that might be available through the analysis of the resources submitted in the SPP Queue. The Company then considered the responses to recent RFPs to substantiate the estimate of potential resources that might be available to the Company 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[19]. Wind resources included a capital cost of $113/kW and solar resources included a capital cost of $157/kW, informed from responses to Company RFPs and are used as a proxy for potential costs of future resources. Likewise, fixed costs for all new gas resources included an additional firm gas reservation fee of $0.2441/MMBtu based on a gas distribution company published transmission rate. This cost is applied as a proxy for ensuring the availability of an adequate and reliable fuel supply.

Wind and solar resources also included a proxy cost for congestion and losses, as noted in Figure 28. To calculate this proxy cost, the Company began with the 2023 Integrated Transmission Planning (ITP) PROMOD models supplied by SPP[20]. From there, the Company calculated the generation-weighted congestion and loss component differential between the AEP West[21] load hub and each generator (both wind and solar) in the study area. The average generation-weighted congestion and loss cost differentials by fuel type are displayed in Figure 28. For this analysis, the Company utilized forward-looking models for year 5 (2027) and year 10 (2032), and linear extrapolation was used to interpolate values for the years 2028 through 2031. The 2032 values were carried forward flat through 2040, based on the assumption that SPP will authorize economic projects through its forward-looking planning assessments to prevent further escalation of congestion and loss costs.

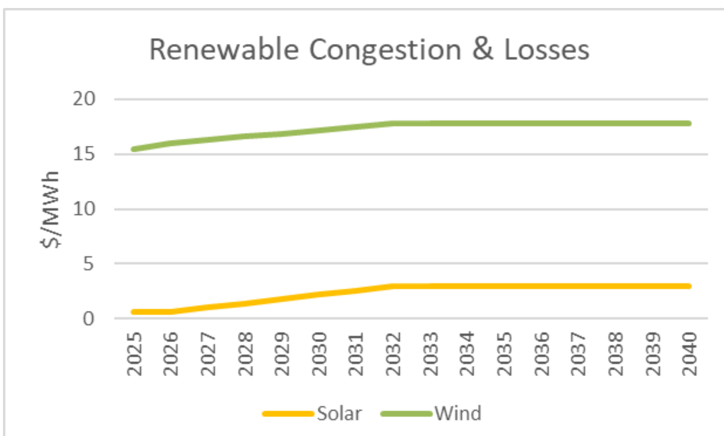


Figure 28: Renewable Congestion & Losses

[19] Joachim Seel et al., "Generator Interconnection Cost Analysis in the Southwest Power Pool (SPP) Territory," https://emp.lbl.gov/publications/generator-interconnection-cost-0

[20] Southwest Power Pool, “2023 Integrated Transmission Planning Report,” https://spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf

[21] “AEP West” refers to the AEP operating companies of AEP Texas, Public Service Company of Oklahoma, and SWEPCO.

6.1.1 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 continuous running. However, the electricity supply mix is changing with increased intermittent renewable generation. Furthermore, regulations and changing customers' needs have made new coal plants economically infeasible with significant risk. As such, new coal generation with and without carbon capture and storage are not part of supply-side resource options in this IRP.

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

6.1.1.1 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 PLEXOS® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. Three NGCC configurations in the model are available for selection, including the H-class turbine single shaft configuration with 418MW capacity, the H-class turbine multi-shaft configuration with 1,100MW capacity, and the F-class turbine multi-shaft configuration with 760MW capacity. These resources are made available in the model with a first operating year of 2032, 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 in Figure 29. The first operating year variable operations and maintenance cost (VOM), the fixed operations and maintenance cost (FOM), and heat rate assumptions are shown in Table 7.

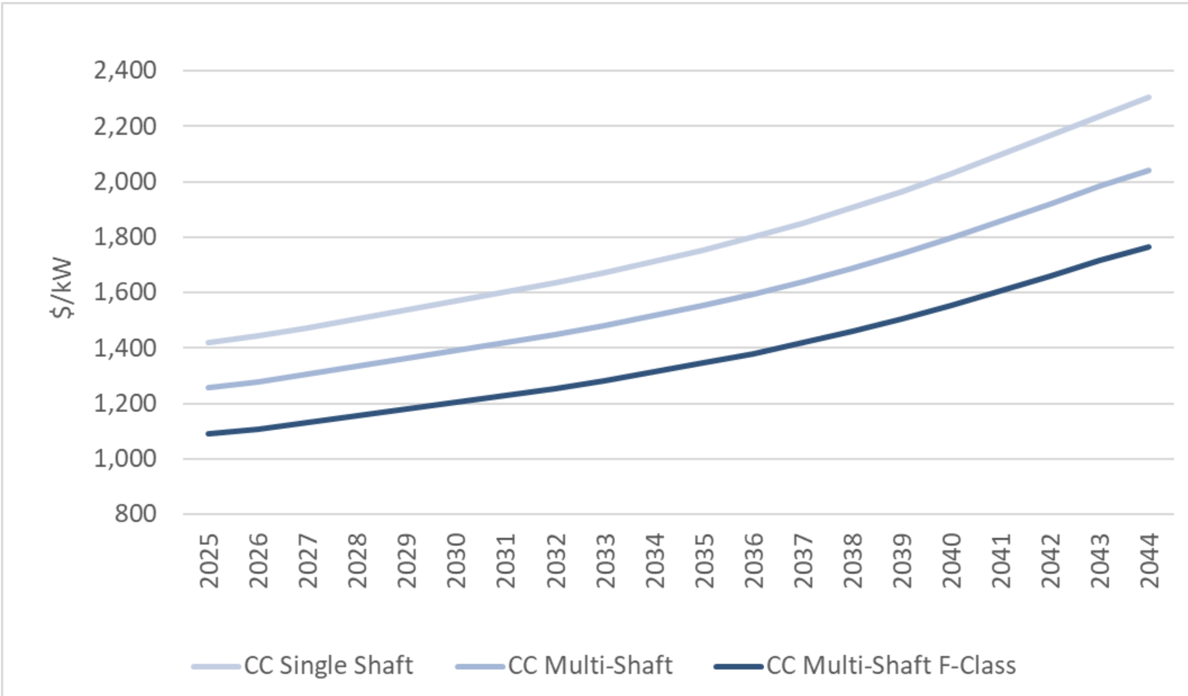


Figure 29: Capital Cost Assumptions for NGCC

Table 7: Operating and Heat Rate Assumptions for NGCC

		H-Class Multi-Shaft (1,100MW)	**H-Class Single Shaft (418MW)**	**F-Class Multi-Shaft (760MW)**
VOM	$ / MWh	2.57	3.51	2.76
FOM	$ / kW-yr	16.81	19.43	23.89
Heat Rate	Btu / kWh	6,370	6,431	6,601

6.1.1.2 Welsh Units 1 and 3

The Company's existing Welsh 1 and 3 coal units were included as separate resources available in 2028 a gas-fired resources, contingent upon certain environmental submissions and approvals. The continued operation of these units as gas-fired resources 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. For this modeling, it was assumed that the boiler will be able to produce a maximum of 1,053MW of power. The first operating year variable operations and maintenance cost (VOM), the fixed operations and maintenance cost (FOM), and heat rate assumptions are shown in Table 8.

Table 8: Operating and Heat Rate Assumptions for Welsh 1 and 3 Gas-Fired

		Welsh 1 (525MW)	Welsh 3 (528MW)
VOM	$ / MWh	1.8	1.8
FOM	$ / kW-yr	28.77	28.77
Heat Rate	Btu / kWh	10,875	10,875

6.1.2 Peaking Alternatives

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

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

6.1.2.1 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 thermal energy is released into the atmosphere via the exhaust gases instead of being recovered. NGCTs are usually expected to start up once a day and operate at full capacity during peak demand hours in the day, making them well suited for a power system with predictable peak patterns.

NGCTs are modeled in PLEXOS® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One NGCT configuration is available for PLEXOS® to select, the 240MW 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 720MW.

The NGCT overnight capital cost assumptions are shown in Figure 30. The first operating year FOM, VOM, and heat rate assumptions are shown in Table 9.

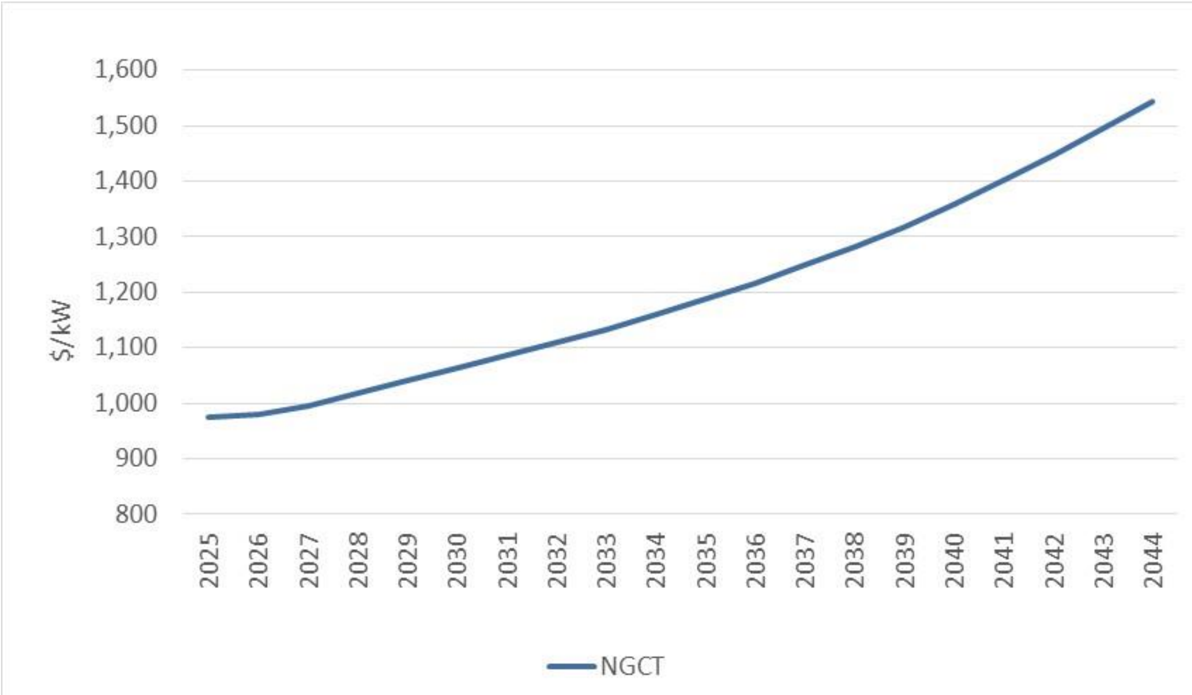


Figure 30: Capital Cost Assumptions for NGCT

Table 9: Operating and Heat Rate Assumptions for NGCT

		F-Class CT (240MW)
VOM	$ / MWh	6.09
FOM	$ / kW-yr	9.48
Heat Rate	Btu / kWh	9,905

Two early NGCT options up to 240MW (nameplate) each were made available to the model in 2029. These early NGCT options assume the re-use of the interconnection rights at the former Pirkey plant site. Please note that SWEPCO has filed for regulatory approval of these early NGCT options in Docket No. 24-052-U, and this resource (two 240MW units) is now named the Hallsville NGCT. FOM, VOM, and heat rate assumptions for the Hallsville NGCT are shown in Table 10.

Table 10: Operating and Heat Rate Assumptions for Hallsville NGCT

		CT (240MW)
VOM	$2024 / MWh	7.43
FOM	$2024 / kW-yr	9.48
Heat Rate	Btu / kWh	10,111

6.1.2.2 Aeroderivative (AD) Turbines

Aeroderivative turbine units are based off aircraft jet engines designs and are modified for the use in power generation. Their operating characteristics make them well suited with 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 100MW. However, AD units are relatively more expensive than NGCTs.

AD units are modeled in PLEXOS® in 105MW 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, with a maximum annual capacity addition of 210MW.

The AD overnight capital cost assumptions are shown in Figure 31. The first operating year FOM, VOM, and heat rate assumptions are shown in Table 11.

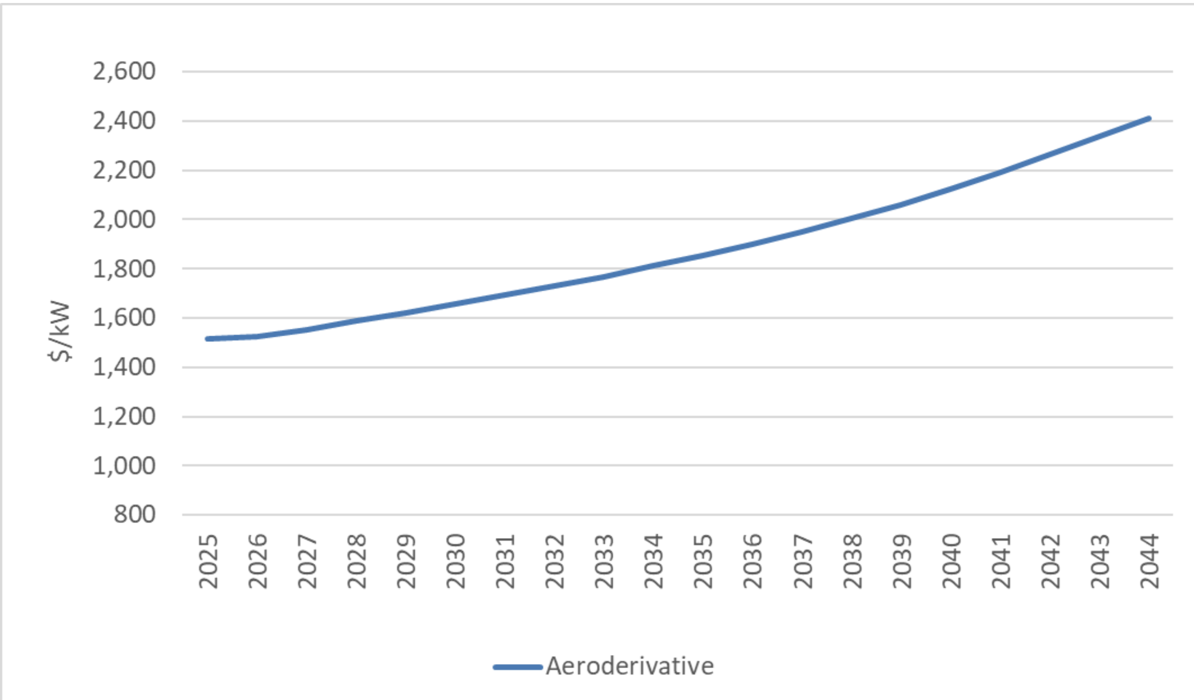


Figure 31: Capital Cost Assumptions for AD

Table 11: Operating and Heat Rate Assumptions for AD

		AD (100MW)
VOM	$ / MWh	6.36
FOM	$ / kW-yr	22.07
Heat Rate	Btu / kWh	9,124

6.1.2.3 Reciprocating Internal Combustion Engine (RICE)

Like NGCTs, Reciprocating Internal Combustion Engines (RICEs) rely on the combustion of air mixed with fuel to generate hot pressurized gases. Unlike NGCTs, the expansion of these gases creates pressure within piston chambers which is used to drive a rotating motion to generate electricity. Multiple RICE units are usually incorporated into a larger generating set for main grid applications.

RICE 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. RICE generating sets can also run more efficiently at partial load as individual RICE units within the generating set can be shut down to reduce output while allowing remaining units to run a full load. Unlike NGCTs or ADs, RICE units can be started multiple times in a day without incurring additional maintenance costs. These characteristics make RICE units well suited for power systems that require frequent but short-duration dispatches.

RICE units are modeled in PLEXOS® in 20MW 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, with a maximum annual capacity addition of 100MW.

The RICE overnight capital cost assumptions are shown in Figure 32. The first operating year FOM, VOM, and heat rate assumptions are shown in Table 12.

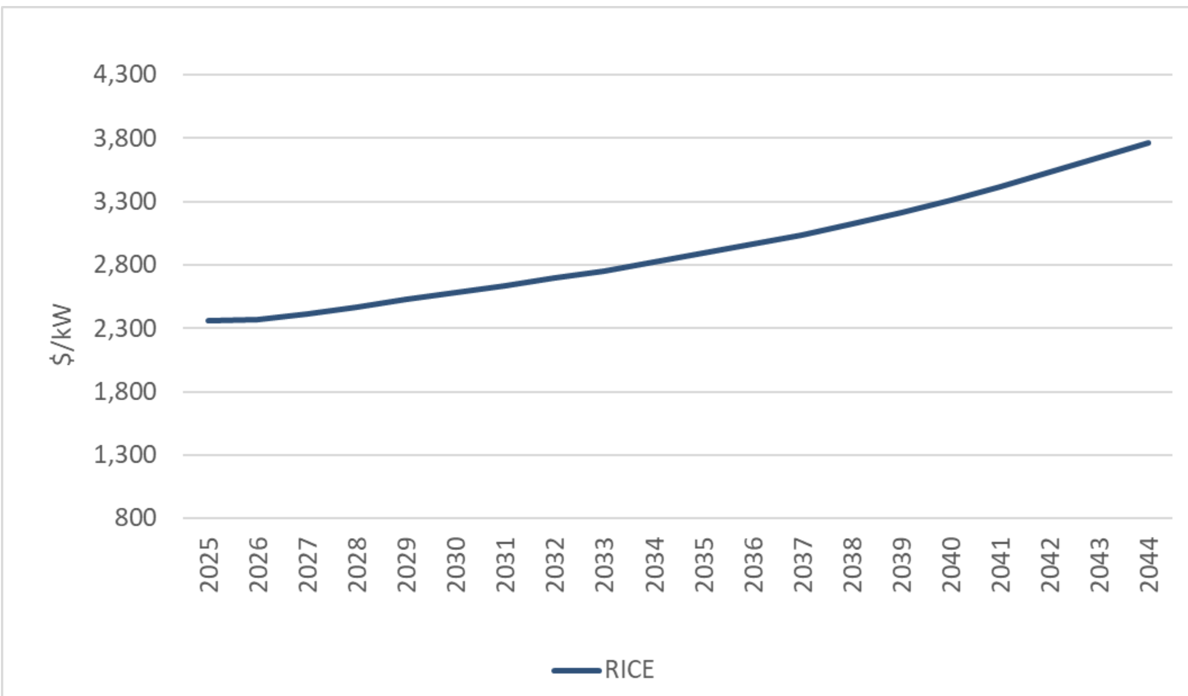


Figure 32: Capital Cost Assumptions for RE

Table 12: Operating and Heat Rate Assumptions for RE

		RE (20MW)
VOM	$ / MWh	7.70
FOM	$ / kW-yr	47.59
Heat Rate	Btu / kWh	8,295

6.1.3 Battery Energy Storage System (BESS) Alternatives

6.1.3.1 Lithium-Ion Battery (Li-ion) and Iron-Air Battery

Li-ion batteries store and discharge energy through the movement of lithium ions between a negative and positive electrode, separated by an electrolyte, while iron-air batteries use reversible rusting, where oxygen converts iron metal to rust during the discharge state, and then rust is converted back to iron during the charging state. 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 and iron-air batteries in the system can smooth out energy price volatility.

BESS alternatives 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, low self-discharge and fast response capabilities. The BESS alternatives can also respond to dispatch signals within a second, making them well suited for primary frequency regulations, such as 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, where battery augmentation is required during the project lifetime to maintain performance. Conversely, iron-air batteries will not require routine augmentation, but they are expected to degrade faster than Li-ion batteries, requiring a full repower in the middle of their useful life.

For this IRP, the modeling of BESS alternatives include an additional potential value stream available to these resources of $40/MWh. This is a proxy for value associated with sub-hourly and hourly energy arbitrage and ancillary services. The Company continues to explore methods to recognize additional value streams from fast responding resources like BESS. Additionally, BESS alternatives are made available in PLEXOS® and are modeled as an energy storage option with a duration of four, six, eight, ten and 100 hours. PLEXOS® optimizes charging and discharging of the resource against projected SPP hourly day-ahead electricity prices, taking into account a round-trip efficiency of 83%.

Li-ion batteries are made available in a configuration of 50MW, and the iron-air battery is made available in a configuration of 20MW. For annual limits, the 4-hr and 10-hr alternatives are limited to 50MW/yr, 6-hr and 8-hr alternatives are limited to 100MW/yr, and the 100-hr alterative is limited to 20MW/yr. The assumed cumulative maximum capacity addition for 4-hr and 6-hr alternatives is 400MW, while for 8-hr and 10-hr alternatives the maximum annual capacity is 200MW, and then the maximum annual capacity is 200MW for the 100-hr alternative. The cumulative maximum for all battery energy storage resources is 1,400MW.

The first operating year overnight capital cost assumptions for both Li-ion and iron-air alternatives are shown in Figure 33. These costs are further influenced by the availability of Federal Investment Tax Credits (ITCs) discussed in Section 6.4. Table 13 shows the assumed first year FO&M costs for BESS alternatives.

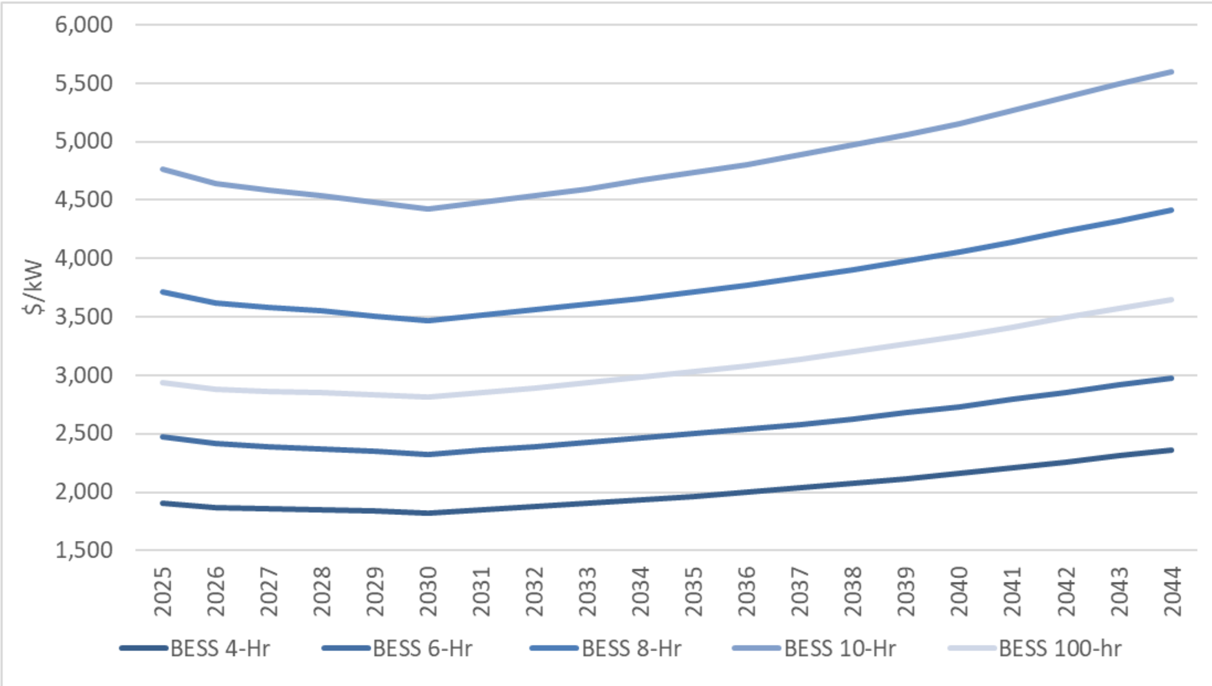


Figure 33: Capital Cost Assumptions for BESS

Table 13: First Year FO&M Assumptions for BESS

		BESS 4-Hr (50MW)	BESS 6-Hr (50MW)	BESS 8-Hr (50MW)	BESS 10-Hr (50MW)	BESS 100-hr (20MW)
FOM	$ / kW-yr	53.11	79.66	106.21	132.76	18.00

6.1.4 Renewable Alternatives

Renewable generation alternatives provide an opportunity to deliver affordable clean energy to address future electricity needs when cost effective. These technologies can provide a hedge against future uncertainties in fuel prices, carbon policies, and technology risks as they have zero carbon emissions and zero marginal costs. While these resources provide a reasonable hedge against several uncertainties, their intermittent nature for energy generation adds other uncertainties and variables to recognize in resource planning.

In this IRP, three renewable alternatives considered are onshore wind, utility-scale solar photovoltaic and hybrid solar. These technologies are made available as resource options in PLEXOS®. For hybrid solar, PLEXOS® can choose to pair utility-scale photovoltaic with lithium-ion battery where a paired solution is economic. Additionally, wind and solar resources are further influenced in the modeling by their eligibility for Federal Production Tax Credits (PTCs) discussed in Section 6.4.

6.1.4.1 Onshore Wind

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

Wind is first made available as a resource option in PLEXOS® in 2032. It is modeled with a generic production profile representative of the region with an average capacity factor of 47%.

Wind resources are made available in a unit size of 200MW. Because wind generation resources tend to be located electrically further from load centers, a congestion and loss cost adder of approximately $17/MWh was assumed as found in Figure 28. The maximum annual capacity addition is 400MW and was informed through analysis of the SPP queue. The assumed cumulative maximum available additions of wind resources over the planning horizon are 3,000MW.

Capital costs were informed from responses to recent RFPs conducted in the SPP region by the Company and are used as a proxy for potential costs of future resources. The Wind overnight capital cost assumptions are shown in Figure 34. The first operating year FOM assumption is show in Table 14.

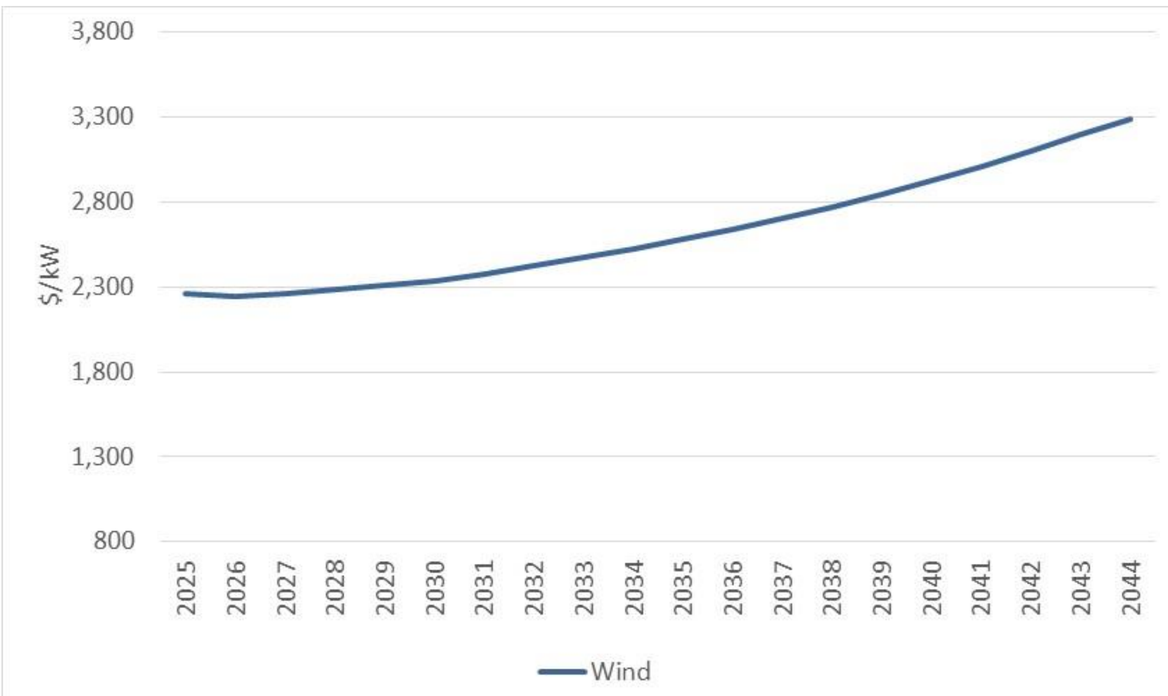


Figure 34: Capital Cost Assumptions for Onshore Wind

Table 14: First Year FO&M Assumptions for Onshore Wind

		Wind (200MW)
FOM	$ / kW-yr	37.08

6.1.1.2 Solar

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

Utility-scale solar PV is first made available as a resource option in PLEXOS® in 2029. It is modeled with a generic production profile representative of the region with an average capacity factor of 28% assuming a single-axis tracking configuration.

Solar resources are made available in a unit size of 150MW. The maximum annual capacity addition is 600MW and was informed through analysis of the SPP queue. A congestion and loss adder of approximately $1.80/MWh was assumed in 2025, rising to approximately $3/MWh by 2033. The cumulative maximum available additions over the planning horizon are 4,500MW. In addition, a co-located solar-battery option is available in 200MW blocks (150MW solar plus 50MW of 4-hour duration storage), with an annual limit of 400MW.

The overnight capital cost assumptions for solar PV are shown in Figure 35. Table 15 shows the first operating year FOM cost assumptions for solar and co-located solar-battery options.

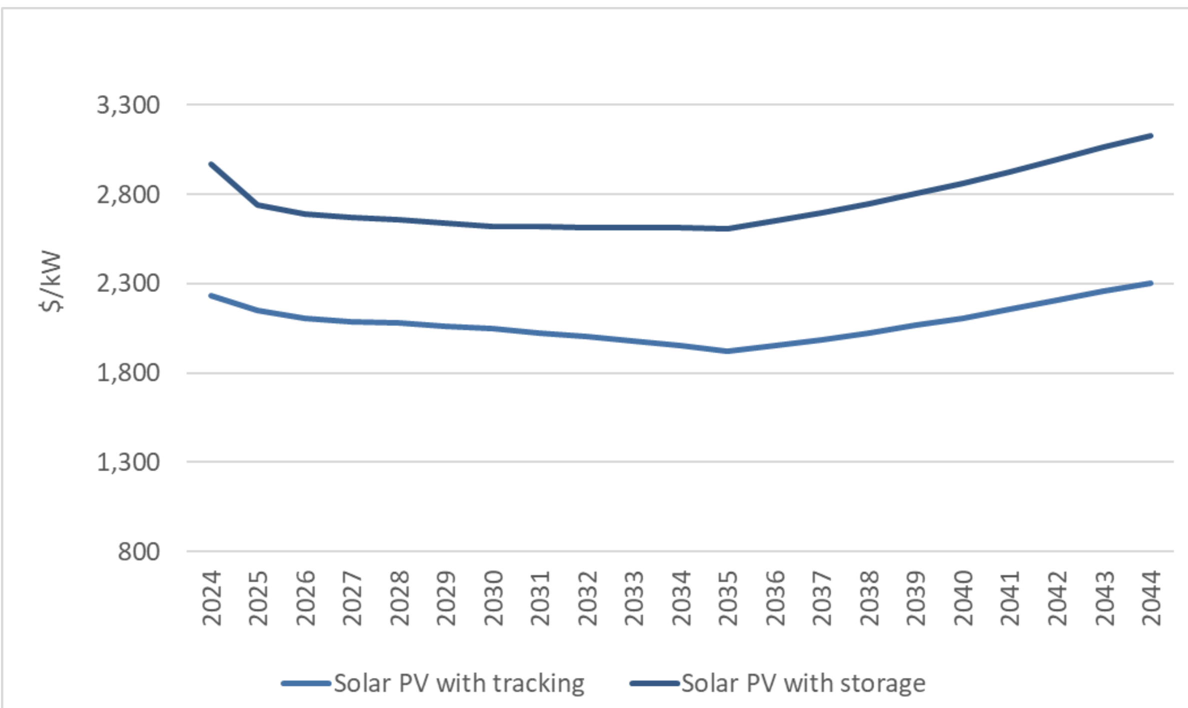


Figure 35: Capital Cost Assumptions for Utility-Scale Solar PV

Table 15: First Year FO&M Assumptions for Utility-Scale Solar PV

		Solar with Tracking (150MW)	Solar with Storage (150MW)
FOM	$ / kW-yr	15.86	39.54

6.1.5 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 become the new standards of generation to complement or replace traditional resources. Including advanced generation technologies in this IRP allows SWEPCO to consider the impact of future technology uncertainties on the Company's generation portfolio.

Two advanced generating technologies are potentially available within the planning horizon of this IRP, namely small modular reactor (SMR) and carbon capture and storage (CCS).

6.1.5.1 Small Modular Reactor (SMR)

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

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

SMR is 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.

SMR is still in the early stages of development and there remain uncertainties over the cost, performance, and availability of the technology. It is assumed that SMR will not be available for commercial deployment until 2036. SMR is available in the model in a block size of 600MW and a maximum annual capacity addition of 600MW.

Figure 36 below shows the assumed overnight capital cost of SMR cost over time. The first operating year FOM, VOM assumptions are shown in Table 16 below.

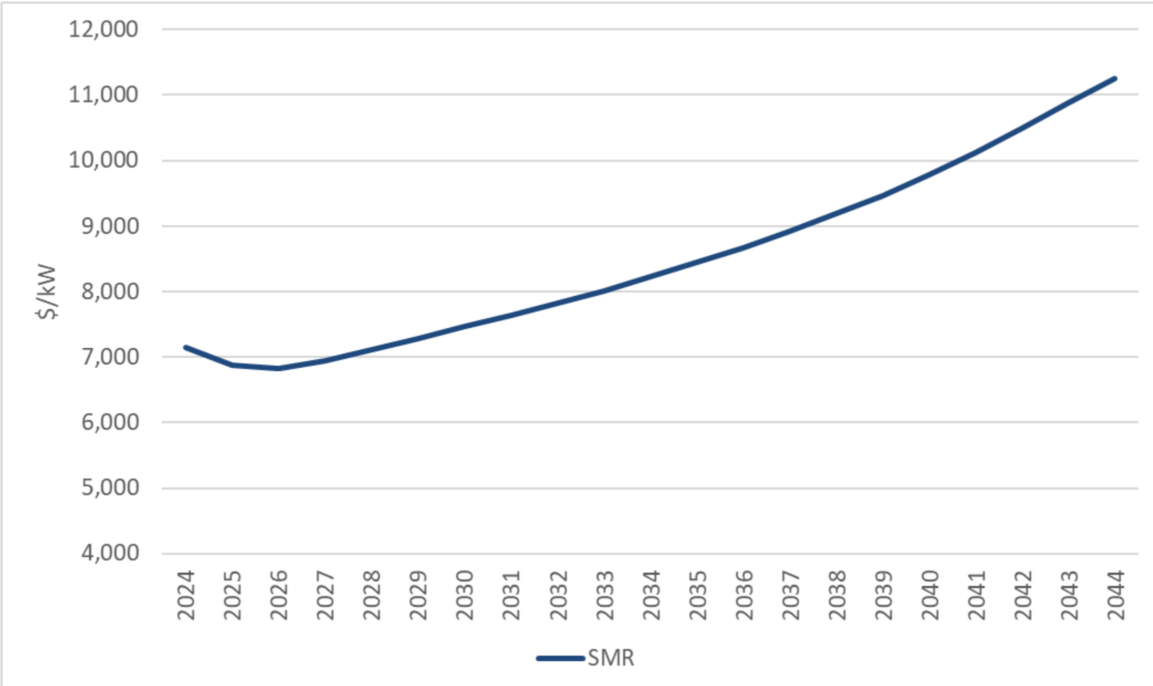


Figure 36: Capital Cost Assumptions for SMR

Table 16: Operating and Heat Rate Assumptions for SMR

		SMR (600MW)
VOM	$ / MWh	4.46
FOM	$ / kW-yr	141.00
Heat Rate	Btu / kWh	10,447

6.1.5.2 Carbon Capture and Storage Technologies (CCS)

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

In PLEXOS®, CCS is modeled as new build options. CCS plants are treated as standard dispatch resources in PLEXOS®, which are assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These costs are further influenced by the availability of Federal Tax Credits for CO_2 sequestration (CCS) discussed in Section 6.4.

One new build CCS configuration is available for selection in PLEXOS®, as a 390MW H-class single shaft, combined-cycle natural gas turbine with 90% carbon capture. The assumption on overnight capital costs for the new build CCS is shown in Figure 37. The first operating year FOM, VOM, and heat rate assumptions are shown in Table 17 below.

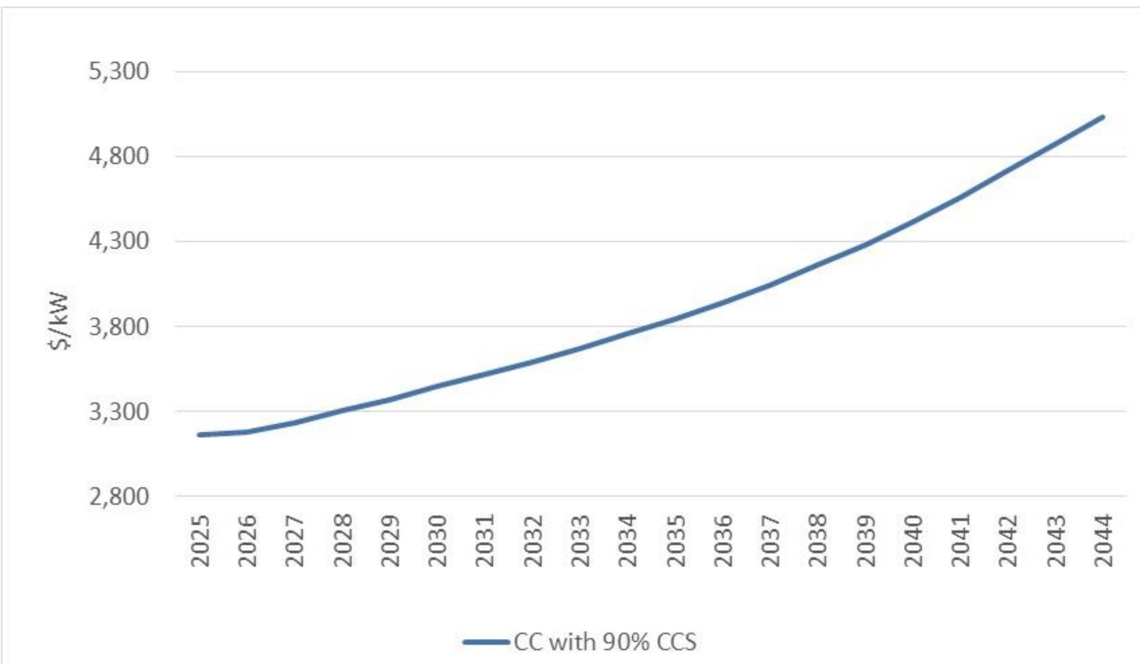


Figure 37: Capital Cost Assumptions for New Build CCS

Table 17: Operating and Heat Rate Assumptions for New Build CCS

		NG CCS (390MW)
VOM	$ / MWh	8.04
FOM	$ / kW-yr	38.03
Heat Rate	Btu / kWh	7,124

6.2 Resource Accredited Capacities

As discussed in Section 3.5, SPP is implementing a new Accredited Capacity (ACAP) methodology[22]. Under the new approach, SPP will continue to use an effective load carrying capability (ELCC) accreditation methodology for wind, solar, and storage resources. This ELCC method is used to reduce the accredited capacity value for these resources compared to their installed capacity amounts. Therefore, the capacity values for different hour ranges of BESS resources are recognized to reflect their ability to serve peak loads. Furthermore, under the ACAP methodology, the summer and winter ELCC adjustments will be different for each season.

Regarding thermal resources, SPP has historically accredited thermal resources at their installed capacity value. However, SPP's ACAP methodology will also include a new performance-based adjustment (PBA) for existing thermal resources. The PBA will be derived from each thermal unit's past performance and result in a reduction from the installed capacity for the summer and winter seasons. Additionally, the winter ACAP for thermal resources will be further adjusted to account for historical performance and fuel availability during critical system periods.

[22] Southwest Power Pool, "MOPC Educational FA and ACAP PRM Overview", https://spp.org/documents/71947/mopc%20educational%20fa%20and%20acap%20prm%20overview.pdf

This document provides an overview of the Fuel Assurance and Accredited Capacity Planning Reserve Margin (ACAP PRM) methodologies used by SPP.

Summer and winter ELCC values for wind, solar, and battery resources are illustrated in Figure 38 and Figure 39.

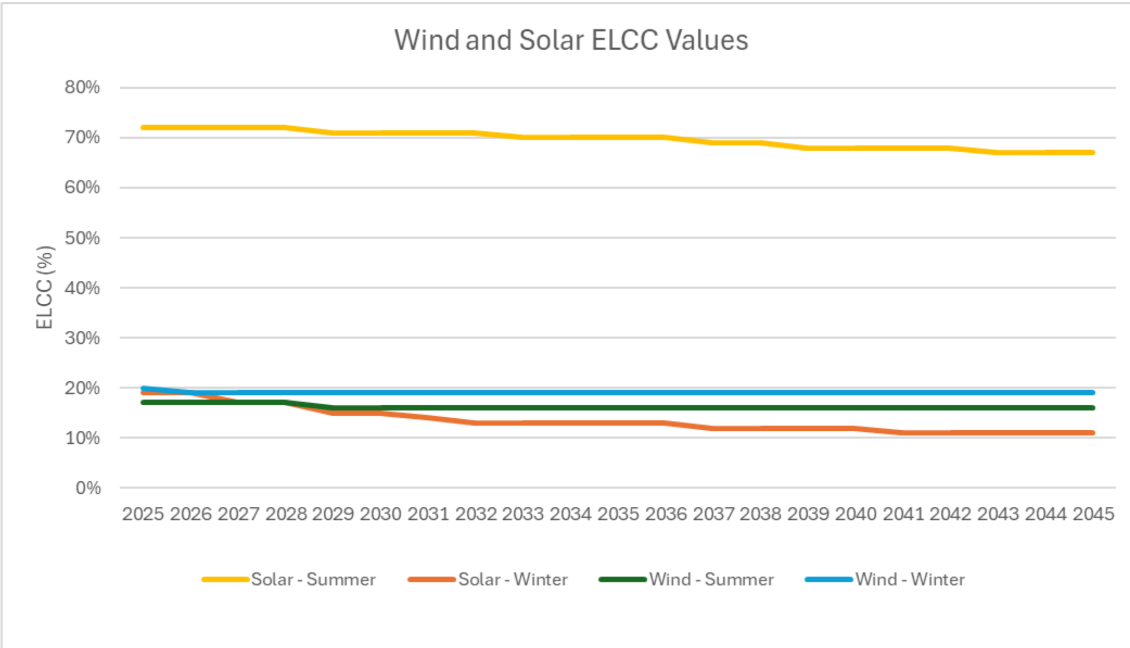


Figure 38: Renewable Resource ELCC Values

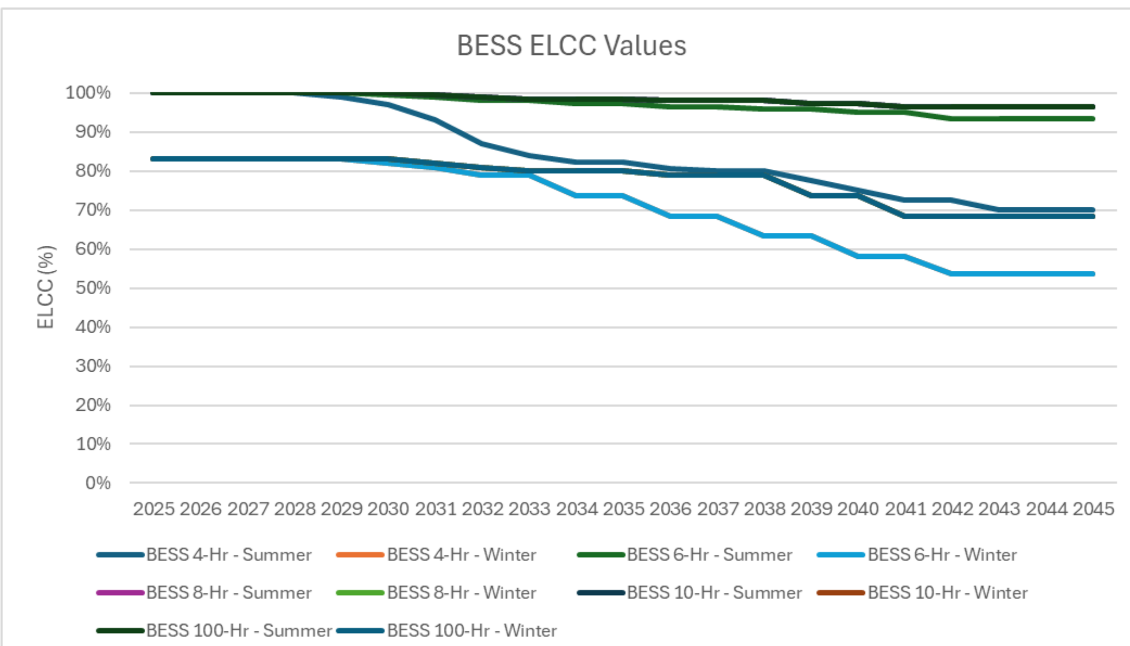


Figure 39: BESS ELCC Values

SPP's preliminary guidance regarding thermal resource capacity accreditation reductions are shown in Table 18. Although SPP is conducting further analysis, the Company used their preliminary guidance for class average ACAP ratings for new thermal resources modeled in this IRP[23].

Table 18: SPP Preliminary Guidance Thermal Resource ACAP Reductions

Fuel Type	Season	Summer Reduction (Weighted EFORd)	Winter Reduction
Natural Gas and Other Gases	Summer	8.04%	
	Winter	14.26%	22.99%
Nuclear	Summer	1.98%	
	Winter	0.64%	1.05%

6.3 Short-Term Capacity

Short-Term (S-T) Capacity purchase 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. For this IRP, up to 800MW of S-T Capacity resources was made available between 2025-2027. In the High Case portfolio and the High Commodity, Base Load sensitivity portfolio, discussed in Section 8, up to 800MW was made available 2029-2031 and 500MW in 2028 and 2032. In the remaining portfolios, 500MW was made available 2028-2032.

6.4 Inflation Reduction Act (IRA)

In August 2022, the Inflation Reduction Act was enacted which, among many things, introduced additional benefits for clean energy resources. Specifically, the IRA allows for the inclusion of Production Tax Credits (PTCs) or Investment Tax Credits (ITCs) for solar and wind resources as well as for new nuclear facilities, such as SMRs. Additionally, the IRA introduced incentives for storage resources in the form of ITCs and expanded benefits for carbon sequestration solutions.

A summary of IRA benefit assumptions to specific resources included in this plan is the following:

- 10 years of 100% PTCs or ITCs for "Technology Neutral" Clean Electricity resources including solar, wind and advanced nuclear resources for projects whose construction begins by the end of 2033. After 2033, ITC tax credits reduce to 75% and 50% of their value in 2038 and 2039, respectively. In this IRP, the Company also assumed a four-year safe harbor assumption that extends the eligibility of tax credits.
- ITC benefits for storage resources for projects whose construction begins by the end of 2033. After 2033, ITC tax credits reduce to 75% and 50% of their value in 2038 and 2039, respectively.

[23] Southwest Power Pool, "EFORd and EFOF Class Averages," in *SAWG Meeting Materials*, June 18-19, 2024, https://www.spp.org/Documents/71781/SAWG%20Meeting%20Materials%2020240618-19.zip

In this IRP, the Company also assumed a four-year safe harbor assumption that extends the eligibility of tax credits.

- The passage of Section 45Q legislation provides a tax credit of $85/ton of CO_2 sequestered for twelve years.
- The law also provides an opportunity for the PTCs and ITCs to extend beyond these dates although for this IRP, no further extensions were assumed beyond 2039.

Additionally, the IRA also includes opportunities for additional bonus tax credits for projects that qualify for specific siting requirements. The IRP does not include these as part of its analysis as the modeling does not include any location-specific assumptions. The analysis of any projects qualifying for bonus credits beyond what is included in the IRP analysis will be included during an RFP process for projects from developers that include the associated binding commitments.

6.5 Modeling Parameters and Resource Limits

The major system parameters that were modeled for each resource described in Section 6.1 are shown in Table 19. PLEXOS® models these parameters in tandem with the objective function to yield the least-cost resource plan for each scenario modeled.

Table 19: New Resource Assumptions

Technology	First Year	Life	Block Size (MW)	Annual Limit (MW)	Total Cumulative Limit (MW)
Base Load					
SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW	2036	40	600	600	1,800
COMBUSTION TURBINE F CLASS, COMBINED-CYCLE, F- Class	2032	30	760	1,520	4,560
COMBUSTION TURBINE H CLASS, 1100-MW COMBINED CYCLE (RFP)	2032	30	1,100	1,100	4,400
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW (RFP)	2032	30	418	836	4,598
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW (RFP)	2032	40	390	780	4,290
Peaking					
COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE (RFP)	2031	30	240	720	4,560
COMBUSTION TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE (RFP)	2031	30	105	210	945
INTERNAL COMBUSTION ENGINES, 20 MW (RFP)	2031	20	20	100	400
Intermittent					
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH, 4hr (RFP)	2029	20	50	50	400
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 300 MWH, 6hr (RFP)	2029	20	50	100	400
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 400 MWH, 8hr (RFP)	2029	20	50	100	200
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 500 MWH, 10hr (RFP)	2029	20	50	50	200
BATTERY ENERGY STORAGE SYSTEM, FORM, 20 MW / MWH, 100hr	2029	20	20	20	200
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW	2032	30	200	400	3,000
SOLAR PHOTOVOLTAIC, 150 MWAC	2029	35	150	600	4,500
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MWx200 MWh	2029	35	200	400	2,000
SHORT-TERM CAPACITY PRUCHASES	2025	1	25	800	800
EARLY 2029 NGCT	2028	30	240	480	480
WELSH UNIT 1 AND 3 CONVERSIONS	2028	15	525/528	1,053	1,053

The Company considered a variety of different constraints when establishing the annual and cumulative limits shown in the table. These included 1) the Company capacity obligations and needs over the planning horizon, 2) the Company's objective to ensure reliability through a diverse mix of new resources, 3) an assessment of the resources in the SPP queue and 4) practical limits of resources informed in part, by past responses to RFPs.

While the limits are imposed in the model to provide enough capacity and energy resources to meet the necessary SPP and SWEPCO obligations and objectives, these do not specifically suggest that these resources and amounts are in fact available and would respond to future RFPs.

7. Demand-side Resource Options

7.1 Energy Efficiency Measures

This IRP considers incremental Energy Efficiency (EE) programs as resource options to meet future capacity needs. These incremental EE programs, starting in 2030, are in addition to the existing demand-side programs discussed in Section 3.3.

7.1.1 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[24]. 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 costs, energy savings, market acceptance ratios and program implementation factors. Table 20 provides a list of current and anticipated EE measures for both the residential and commercial sector.

Table 20: Energy Efficiency Measure Categories by Sector

Residential Measures	Ceiling Insulation	Wall Insulation	Windows
	Dish Washer	Refrigerator	Freezer
	Television	Heat Pump	Lighting
	Central AC	Clothes Washer	Clothes Dryer
	HP Water Heater	Behavioral	Smart Thermostats
	HVAC Tune-Ups		
Commercial Measures	Heating Measures	Cooling Measures	Chiller Space Cooling
	Water Heating	Commercial Ventilation	Refrigeration
	Behavioral		Compressed Air
	Personal Computers	Servers	Indoor Lighting*
	Outdoor Lighting*	Smart Thermostats	VFDs
	HVAC Tune-Ups		

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. The Utility Cost Test (UCT) measures the benefits of EE measures with respect to the cost of achieving the potential benefits. Achievable potential is a subset of economic potential accounting for market acceptance and implementation barriers.

The achievable potential can be further broken into the amount that would be accomplished if implemented through utility-sponsored programs, and the total amount that would fall under codes and

24 EPRI, "U.S. Energy Efficiency Potential Through 2040: Update on Potential for Energy Savings Through Utility Programs Across the Nation," https://www.epri.com/research/products/000000003002010564

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.

7.1.2 Modeling EE Measures

SWEPCO developed proxy EE bundles for residential and commercial & industrial customer classes to be modeled within PLEXOS®. These bundles are based on measure characteristics identified within the EPRI report and SWEPCO customer usage.

Table 21 and Table 22 list the energy and cost profiles of EE resource bundles for the residential and commercial sectors, respectively. In order to reflect the potential EE savings available in the industrial sector, each of the lighting bundles shown in Table 22 includes potential savings for both commercial and industrial customers. Each EE bundle is a stand-alone resource within the model with its own unique cost and potential energy and demand savings.

Table 21: Residential Energy Efficiency Bundles

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041	Yearly Potential Savings (MWh) 2042-2046	Bundle Life
Thermal Shell - AP	$0.26	3,782	2,072	2,561	2,655	10
Thermal Shell - HAP	$0.39	11,674	1,064	701	0	10
Heating/Cooling - AP	$0.42	41,262	10,416	1,127	1,047	18
Heating/Cooling - HAP	$0.66	5,765	0	0	0	18
Water Heating - AP	$0.48	12,059	5,084	5,955	3,392	14
Water Heating - HAP	$0.68	28,639	4,458	5,664	0	14
Appliances - AP	$0.24	15,917	849	635	0	13
Appliances - HAP	$0.34	3,681	0	0	0	13
Lighting - AP	$0.16	1,869	0	0	0	30
Lighting - HAP	$0.24	1,236	0	0	0	30
Behavioral Programs	$0.05	13,173	0	0	0	2

Table 22: Commercial & Industrial (C&I) Energy Efficiency Bundles

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041	Yearly Potential Savings (MWh) 2042-2046	Bundle Life
Heat Pump - AP	$9.62	44,292	6,479	6,936	6,947	19
Heat Pump - HAP	$14.57	24,938	0	0	0	19
HVAC Equipment - AP	$0.09	5,064	814	771	0	15
HVAC Equipment - HAP	$0.17	3,597	0	0	0	15
Indoor Screw-In Lighting - AP	$0.01	4,069	0	0	0	6
Indoor Screw-In Lighting - HAP	$0.02	1,727	0	0	0	6
Indoor HID/Fluor. Lighting - AP	$0.11	28,023	5,025	0	0	14
Indoor HID/Fluor. Lighting - HAP	$0.16	3,114	0	0	0	14
Outdoor Lighting - AP	$0.15	5,569	1,132	0	0	15
Outdoor Lighting - HAP	$0.23	6,188	0	0	0	15

8. Portfolio Analysis

8.1 Introduction

Portfolio analysis is conducted through the use of PLEXOS® long-term optimization model (LT Plan) from which the SWEPCO-specific capacity and energy requirement evaluations were examined. The LT Plan model finds the optimal portfolio of future capacity and energy resources, including DSM additions, which minimizes the Net Present Value Revenue Requirement (NPVRR) of a planning entity's generation-related variable and fixed costs (Power Supply Costs) over a long-term planning horizon. By minimizing NPVRR, the model will provide optimized portfolios with the lowest and most stable customer rates, while adhering to the Company's constraints.

Optimized portfolios are identified subject to a series of modeling parameters and constraints, to identify a mix of resources that seeks to minimize the aggregate of the following components of Power Supply Costs of the portfolio of resources:

- Fixed costs of capacity additions, i.e., carrying charges on incremental capacity additions (based on an SWEPCO-specific, weighted average cost of capital), and fixed O&M,
- fixed costs of any capacity purchases,
- program costs of (incremental) DSM alternatives,
- variable costs associated with SWEPCO generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances, and variable O&M costs, and
- a 'netting' of the production revenue earned in the SPP power market from SWEPCO's generation resource sales and the cost of energy necessary to meet SWEPCO's load obligation.

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

- Minimum capacity reserve margins,
- limited energy market purchases and sales,
- resource additions (i.e., maximum units built),
- age and lifetime of power generation facilities,
- operation constraints, such as ramp rates, minimum up/down times, capacity, heat rates, etc.
- fuel burn minimum and maximums, and
- energy contract parameters such as energy and capacity.

8.2 Portfolios Considered

For this IRP, SWEPCO modeled a series of Candidate Portfolio Cases and Sensitivities to identify an optimal portfolio of resources to meet expected future customer needs under the different SPP market scenarios. These SPP market scenarios were discussed in Section 5.30 and the associated SWEPCO load was discussed in Section 2.7. Table 23 shows the different Candidate Portfolio Cases modeled and their respective key inputs.

Table 23: SWEPCO Candidate Portfolio Cases

Portfolio	SWEPCO Load	Commodity Prices	Environmental Regulations	Technology Cost
Base Case	Base	Base	Base	Base
High Case	High	High	Base	Base
Low Case	Low	Low	Base	Base
Enhanced Environmental Regulations (EER)	Base	EER	111(b)(d) Informed	Base

The Base, High and Low Candidate Portfolio Cases serve to inform the Company of an optimal portfolio of resources without implementation of the recent EPA GHG 111(d) 2024 Final Rule and the EPA ELG 2024 rule update, as well as the implications to SWEPCO's coal and gas fleet. These Portfolios serve to provide an important baseline for the Company to evaluate impacts for future changes to rules.

The Enhanced Environmental Regulations (EER) case is included understand the impact of resource selection under the recent EPA GHG 111(d) 2024 Final Rule and the EPA ELG 2024 rule update, discussed in Section 3.4. The Company imposed capacity factor constraints to its existing gas CC and CT resources, to serve as proxy guideline per EPA's pending new proposal on existing natural gas units. For the EER case, the following constraints on gas resources not equipped with CCS technology are applied:

- New gas CT resources: operate at less than 20% annual capacity factor beginning upon selection of the resource.
- New gas CC resources: operate at less than 40% annual capacity factor beginning upon selection of the resource.
- Existing gas CT and CC resources: operate at less than 50% annual capacity factor beginning 1/1/2030.

The rule imposes requirements for the Company's existing coal fired units including Flint Creek and Turk. Specifically, under the new rule, coal fired units must comply through one of the following alternatives:

- Install 90% Carbon Capture and Sequestration (CCS) technology by January 1, 2032. The Company is not pursuing CCS as a compliance option, however, because in the Company's view 90% CCS is not a proven technology that can be deployed at utility scale by 2032;[25]
- Convert the unit to co-fire with natural gas by January 1, 2030, and continue operations until January 1, 2039;
- Convert the unit to operate as a 100% natural gas fired boiler unit by January 1, 2030; or,
- Retire the unit by January 1, 2032.

Specific to the Flint Creek plant, additional considerations are required with respect to the service it provides to the Northwest Arkansas load pocket (NWALP). The unit serves as one of three primary sources of energy into this area along with two transmission lines. The area would become vulnerable to overload conditions such that a third source of energy would need to be provided without the Flint Creek generation. The Company assumed the addition of a new transmission line to serve the energy needs of the NWALP when the Flint Creek plant was retired from the portfolio under each of the compliance alternatives in the EER Case. The timing of the transmission line cost was important in the model's optimal selection of one of the compliant alternatives for the Flint Creek plant. The cost of this new transmission line is in addition to the cost of the new generation that SWEPCO would be required to replace the capacity lost by the retirement of Flint Creek. This generation capacity would be needed to comply with SPP's capacity margin requirements.

To determine the cost estimate of the transmission alternative, the Company considered the Rebuttal Testimony of Jeffrey L. Ellis filed January 13, 2022, on behalf of SWEPCO in Arkansas Public Service Commission (APSC) Docket No. 21-070-U addressing concerns raised by Staff witness John Athas about transmission that may be needed upon Flint Creek's retirement.[26] The estimated cost for this proxy transmission solution identified in the Ellis testimony was estimated to be approximately $205 million. For the Company's IRP modeling analysis, the cost was adjusted to $250 million to account for inflation and the likely inclusion of reactive compensation.

[25] *See* the Declaration of Christian Beam (Executive Vice President, Energy Delivery, American Electric Power Company, Inc.), filed on May 24, 2024 in support of Petitioner's Motion for Stay Pending Judicial Review before the United States Court of Appeals for the District of Columbia, *Electric Generators for a Sensible Transition v. United States Environmental Protection Agency,* Case No. 24-1128, Dkt. No. 2056364, p. 68:

> AEP cannot in good faith pursue CCS as a compliance option because 90% CCS is not a proven technology that can be deployed at utility scale by 2032… A comprehensive review of those challenges, coupled with experiences of private and public entities developing the technologies, reveals that CCS has yet to be demonstrated as the BSER…CCS development challenges include technical, financial, regulatory, legal and practical concerns related to each of the capture, transport, and storage aspects of the process. Even though much investment has gone into advancement of CCS technologies, these technologies have not yet been demonstrated to be viable for reducing CO_2 emissions at fossil fueled power plants. Simply put, there exists not a single coal or gas power plant in operation today in the US with integrated CCS capturing and permanently sequestering 90% of the CO_2 produced by that plant. Not one! At the current pace of development, CCS is not likely to be adequately demonstrated as a viable control option, if at all, for many years.

[26] APSC Docket No. 21-070-U, Doc. 183, Rebuttal Testimony of Jeffrey L. Ellis, beginning p, 25, https://apps.apsc.arkansas.gov/pdf/21/21-070-U_183_1.pdf.

The Company will use the EER Case to understand directionally, the estimated impacts the rule will have on the Company's fleet of resources and indicative costs to its ratepayers as well as the potential impact on the Company's ability to maintain a fleet of resources with the ability to serve customers reliably.

SWEPCO modeled various sensitivities to Candidate Portfolios to understand how resource selections might be affected by changing combinations of commodity prices and technology costs. These sensitivities are shown in Table 24.

Table 24: Candidate Portfolio Sensitivities

Portfolio Sensitivities	SWEPCO Load	Commodity Prices	Environmental Regulations	Technology Cost
High Commodity, Base Load	Base	High	Base	Base
Low Commodity, Base Load	Base	Low	Base	Base
High Technology Costs	Base	Base	Base	Base + 25%
Low Technology Costs	Base	Base	Base	Base - 25%

The High and Low Commodity, Base Load sensitivities evaluate an optimized portfolio of resources under a condition where commodity prices such as gas and energy are high or low while serving SWEPCO's base load forecast. The High and Low Technology Cost sensitivities evaluate an optimized portfolio of resources under a condition where the installed resource costs were increased and decreased by 25%, respectively.

8.2.1 Base Case Portfolio

The Base Case was optimized under scenario conditions that represent an expected view of how load growth, commodity prices, and technology development are projected to evolve over time and contribute to the market conditions under which SWEPCO will operate. Resource additions in the Base Case Portfolio are shown in Table 25 and illustrated in Figure 40.

Table 25: Base Case Annual Resource Additions

Base Case Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	75	0	38
2026/27	0	0	0	0	0	0	0	50	0	30
2027/28	19	0	0	0	0	0	0	600	0	31
2028/29	36	0	0	0	0	0	1,053	500	0	32
2029/30	53	0	0	0	480	0	0	500	0	33
2030/31	73	300	0	0	0	0	0	500	0	29
2031/32	96	300	0	0	480	0	0	500	0	25
2032/33	97	0	0	0	0	1,100	0	500	6	14
2033/34	97	0	0	0	0	0	0	0	11	6
2034/35	97	0	0	0	0	0	0	0	11	6
2035/36	97	0	0	0	0	0	0	0	9	7
2036/37	97	0	0	0	240	0	0	0	9	7
2037/38	94	300	0	0	240	0	0	0	12	5
2038/39	91	0	0	0	240	0	0	0	13	4
2039/40	89	0	0	0	0	0	0	0	8	7
2040/41	86	0	0	0	480	0	0	0	10	5
2041/42	82	0	0	0	0	0	0	0	10	6
2042/43	65	0	0	0	480	0	0	0	10	6
2043/44	52	0	0	0	720	0	0	0	10	7
2044/45	37	0	0	0	0	0	0	0	10	5
Total		**900**	**0**	**0**	**3,360**	**1,100**	**1,053**			

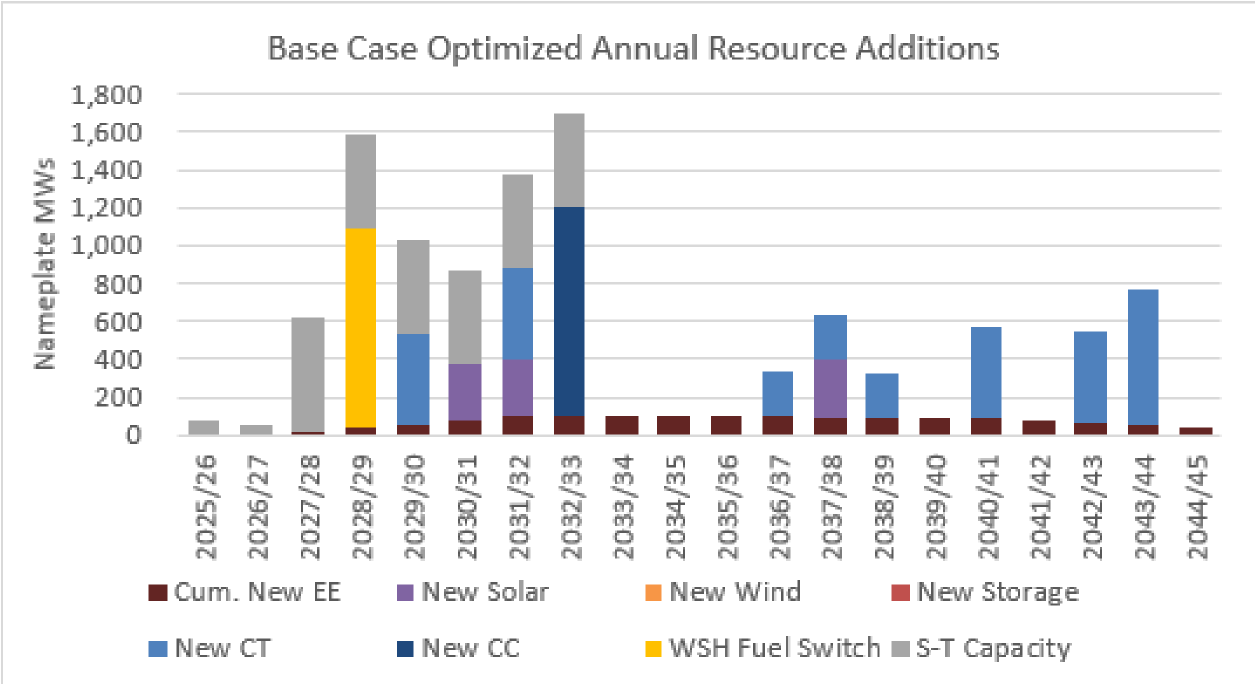


Figure 40: Base Case Annual Resource Additions

For the Base Case portfolio, approximately 0.9GW of new solar, 1.1GW of new natural gas combined cycles (NGCC), and 3.4GW of new natural gas combustion turbines (NGCT) are added by 2044. The portfolio was optimized considering seasonal capacity requirements and market energy risk mitigation, resulting in the selection of market capacity (S-T purchases) and early options through 2029, including the Welsh gas conversions (WSH Fuel Switch) in 2028 and the Hallsville NGCT in 2029. Starting in 2030, solar additions enhance the energy position and provide additional capacity benefits. In 2032, a 1,100MW NGCC addresses significant capacity needs and reduces reliance on market energy. Market energy purchases decline with resource additions from 2030 onwards. After 2032, 2.4GW of NGCTs and 0.3GW of solar are added to further support the capacity and energy needs.

8.2.2 High Case Portfolio

The High Case portfolio was optimized under scenario conditions that represent a view that assumes higher load growth and higher commodity prices than Base Case. In this case the load is assumed to grow to roughly 14.5% above the base load forecast over the forecast horizon. This case would be representative of the capacity and energy that would be needed in a future which includes new load from large customers such as data centers. Resource additions in the High Case portfolio are shown in Table 26 and illustrated in Figure 41.

Table 26: High Case Annual Resource Additions

High Case Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	300	0	21
2026/27	0	0	0	0	0	0	0	275	1	13
2027/28	20	0	0	0	0	0	0	425	1	13
2028/29	36	0	0	0	0	0	1,053	475	1	23
2029/30	52	0	0	0	480	0	0	775	0	30
2030/31	70	0	0	0	0	0	0	800	0	30
2031/32	85	0	0	0	720	0	0	800	0	32
2032/33	86	0	400	0	720	0	0	500	0	25
2033/34	87	0	400	0	240	0	0	0	0	25
2034/35	87	0	400	0	0	0	0	0	1	18
2035/36	87	150	400	0	0	0	0	0	3	13
2036/37	87	0	400	0	240	0	0	0	6	10
2037/38	85	300	400	0	240	0	0	0	12	6
2038/39	83	0	400	0	240	0	0	0	15	5
2039/40	81	0	200	0	0	0	0	0	14	7
2040/41	78	0	0	0	480	0	0	0	15	5
2041/42	74	150	0	0	0	0	0	0	15	6
2042/43	56	0	0	0	720	0	0	0	14	6
2043/44	43	0	0	0	480	0	0	0	14	6
2044/45	29	0	0	0	240	0	0	0	13	6
Total		**600**	**3,000**	**0**	**4,800**	**0**	**1,053**			

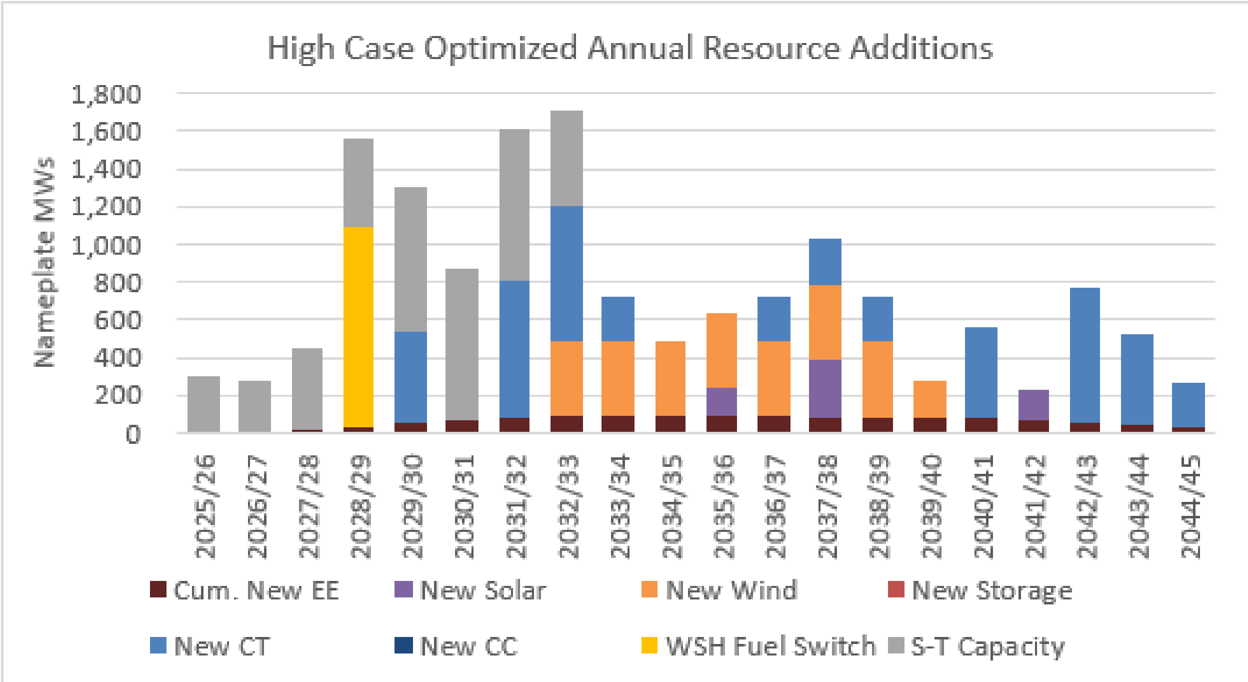


Figure 41: High Case Annual Resource Additions

For the High Case portfolio, approximately 0.6GW of new solar, 3.0GW of new wind, and 4.8GW of new NGCTs are added by 2044. The portfolio optimization selected the Welsh gas conversion (WSH Fuel Switch) in 2028 and the Hallsville NGCT in 2029. Additional NGCTs are added by 2032 to support the larger capacity needs due to the increased load forecast. Market energy purchases increase until wind is selected in 2032. Starting in 2032, 3GW of wind additions contribute to the energy position and provide some capacity benefits. After 2032, 2.4GW of NGCTs and 0.3GW of solar are added to further support the capacity and energy needs.

8.2.3 Low Case Portfolio

The Low Case portfolio was optimized under scenario conditions that represent a view that assumes lower load growth and lower commodity prices than Base Case. In this case the load is assumed to be 14.9% below the base load forecast over the forecast horizon. Resource additions in the Low Case portfolio are shown in Table 27 and illustrated in Figure 42.

Table 27: Low Case Annual Resource Additions

Low Case Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	0	0	52
2026/27	0	0	0	0	0	0	0	0	0	41
2027/28	31	0	0	0	0	0	0	175	0	40
2028/29	52	0	0	0	0	0	1,053	375	0	38
2029/30	87	0	0	0	480	0	0	475	0	39
2030/31	126	0	0	0	0	0	0	500	0	39
2031/32	178	0	0	0	0	0	0	500	0	40
2032/33	178	0	0	0	0	1,100	0	500	3	32
2033/34	178	0	0	0	0	0	0	0	5	10
2034/35	178	0	0	0	0	0	0	0	5	11
2035/36	178	0	0	0	0	0	0	0	5	12
2036/37	178	0	0	0	240	0	0	0	4	12
2037/38	171	0	0	0	0	0	0	0	5	12
2038/39	168	0	0	0	240	0	0	0	5	12
2039/40	160	0	0	0	0	0	0	0	5	13
2040/41	154	0	0	0	480	0	0	0	5	11
2041/42	142	0	0	0	0	0	0	0	5	12
2042/43	122	0	0	0	480	0	0	0	6	12
2043/44	100	0	0	0	480	0	0	0	5	14
2044/45	73	0	0	0	0	0	0	0	5	12
Total		**0**	**0**	**0**	**2,400**	**1,100**	**1,053**			

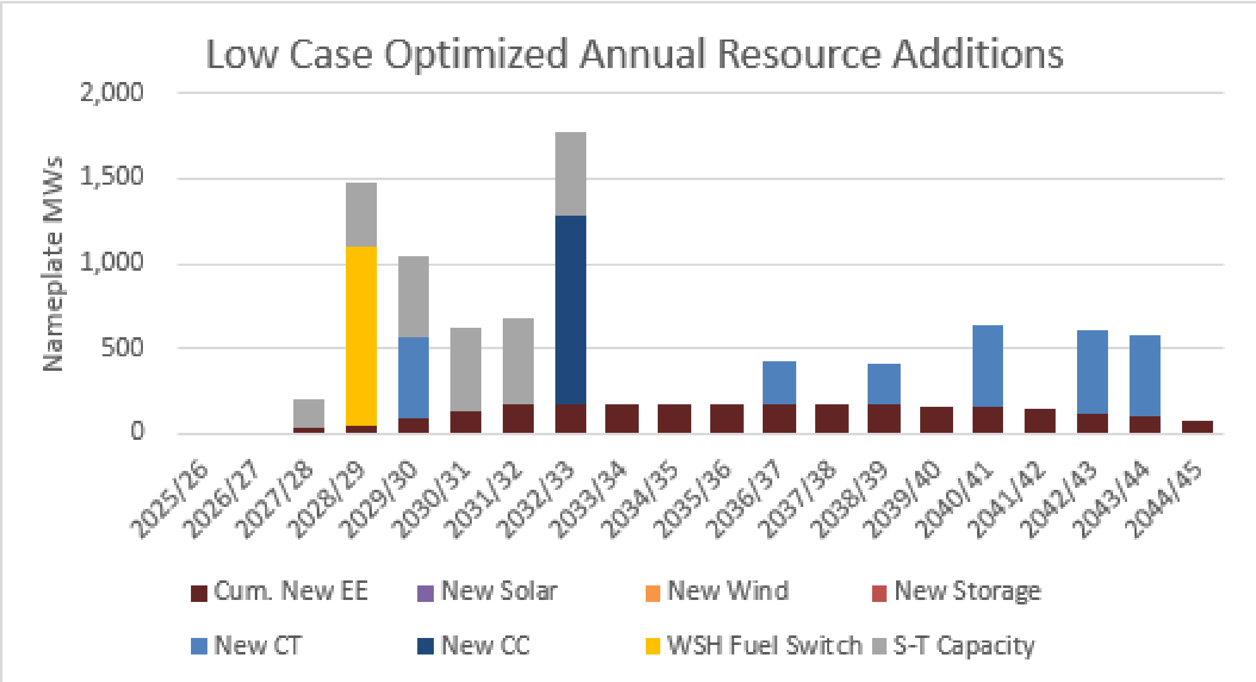


Figure 42: Low Case Annual Resource Additions

For the Low Case portfolio, approximately 1.1GW of new NGCC and 2.4GW of new NGCTs are added by 2044. The portfolio optimization selected the Welsh gas conversion (WSH Fuel Switch) in 2028 and the Hallsville NGCT in 2029. Market energy purchases increase until a NGCC is added in 2032 to support the capacity needs and mitigate market energy reliance. After 2032, 1.9GW of NGCTs are added to further support the capacity and energy needs.

8.2.4 Enhanced Environmental Regulations (EER) Case Portfolio

The EER Case portfolio was optimized under scenario conditions that represent a view that assumes that adoption of the Environmental Protection Agency's rule changes to CAA Section 111(d). As noted earlier in this section, capacity factor constraints were applied to natural gas resources and three compliant alternative options for existing coal facilities were offered to the model for selection. Resource additions in the EER Case Portfolio are shown in Table 28 and illustrated in Figure 43.

Table 28: EER Case Annual Resource Additions

EER Case Capacity Additions by Planning Year (Nameplate MW)												
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	FC Fuel Switch	Turk Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	0	0	75	0	39
2026/27	0	0	0	0	0	0	0	0	0	50	0	33
2027/28	17	0	0	0	0	0	0	0	0	575	0	37
2028/29	31	0	0	0	0	0	1,053	0	0	500	0	36
2029/30	49	150	0	0	480	0	0	0	0	500	0	33
2030/31	68	600	0	0	0	0	0	259	389	500	0	40
2031/32	92	0	0	0	480	0	0	0	0	500	0	40
2032/33	94	0	400	0	0	760	0	0	0	500	1	30
2033/34	95	0	200	0	0	0	0	0	0	0	1	27
2034/35	98	0	0	0	0	0	0	0	0	0	1	24
2035/36	100	0	0	0	0	0	0	0	0	0	0	33
2036/37	100	0	400	0	240	0	0	0	0	0	1	26
2037/38	99	150	400	0	0	0	0	0	0	0	3	17
2038/39	98	0	200	0	0	0	0	0	0	0	7	11
2039/40	96	0	0	0	0	0	0	0	0	0	5	10
2040/41	93	0	0	0	480	0	0	0	0	0	6	10
2041/42	89	0	0	0	0	0	0	0	0	0	7	10
2042/43	73	0	0	0	0	760	0	0	0	0	9	10
2043/44	60	0	0	0	480	760	0	0	0	0	20	7
2044/45	45	0	0	0	240	0	0	0	0	0	20	7
Total		**900**	**1,600**	**0**	**2,400**	**2,280**	**1,053**	**259**	**389**			

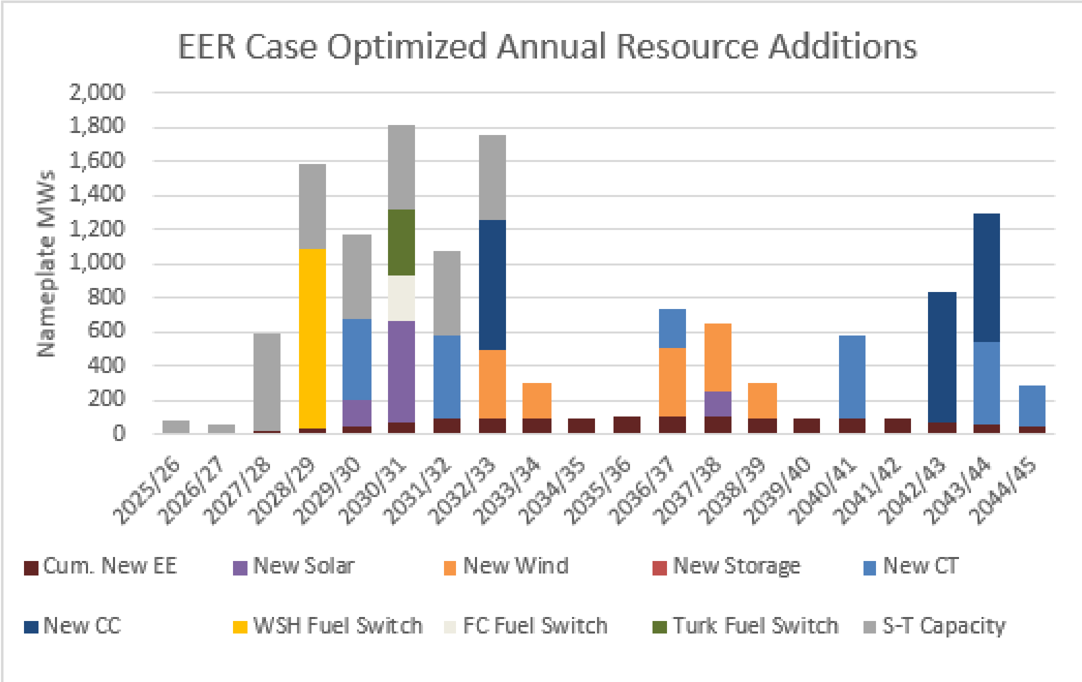


Figure 43: EER Case Annual Resource Additions

For the EER Case portfolio, approximately 0.9GW of new solar, 1.6GW of new wind, 2.3GW of new NGCC and 2.4GW of new NGCTs are added by 2044. The portfolio optimization selected the Welsh gas conversion (WSH Fuel Switch) in 2028 and the Hallsville NGCT in 2029. Solar resources are added starting in 2029, with wind resources following in 2032.The gas conversion (Fuel Switch) of Flint Creek and Turk were selected in 2030. By 2032, new NGCT and NGCC are added to address significant capacity and energy needs while balancing reliance on market energy purchases. After 2032, 1.2GW of wind, 1.4GW of NGCTs and 1.5GW of NGCC are added to further support the capacity and energy needs.

8.2.5 High Commodity, Base Load Sensitivity

The High Commodity, Base Load sensitivity was optimized to select resources to serve the Company's base load but with assumed higher commodity prices. Resource additions in the High Commodity, Base Load sensitivity are shown in Table 29 and illustrated in Figure 44.

Table 29: High Commodity, Base Load Sensitivity Case Annual Resource Additions

High Commodity, Base Load Sensitivity Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	75	0	17
2026/27	0	0	0	0	0	0	0	50	3	10
2027/28	16	0	0	0	0	0	0	575	3	10
2028/29	31	0	0	0	0	0	1,053	500	1	19
2029/30	48	0	0	0	480	0	0	450	0	26
2030/31	69	0	0	0	0	0	0	500	0	26
2031/32	94	150	0	0	720	0	0	500	0	25
2032/33	96	0	400	0	240	0	0	500	0	18
2033/34	96	300	400	0	240	0	0	0	0	15
2034/35	96	0	200	0	0	0	0	0	1	11
2035/36	96	0	0	0	0	0	0	0	1	12
2036/37	96	0	400	0	240	0	0	0	5	7
2037/38	96	300	400	0	0	0	0	0	13	4
2038/39	94	0	400	0	240	0	0	0	15	3
2039/40	92	0	0	0	0	0	0	0	13	6
2040/41	90	0	0	0	480	0	0	0	13	4
2041/42	85	0	0	0	0	0	0	0	14	5
2042/43	70	0	0	0	500	0	0	0	14	5
2043/44	57	0	0	0	720	0	0	0	13	5
2044/45	42	0	0	0	0	0	0	0	13	5
Total		**750**	**2,200**	**0**	**3,860**	**0**	**1,053**			

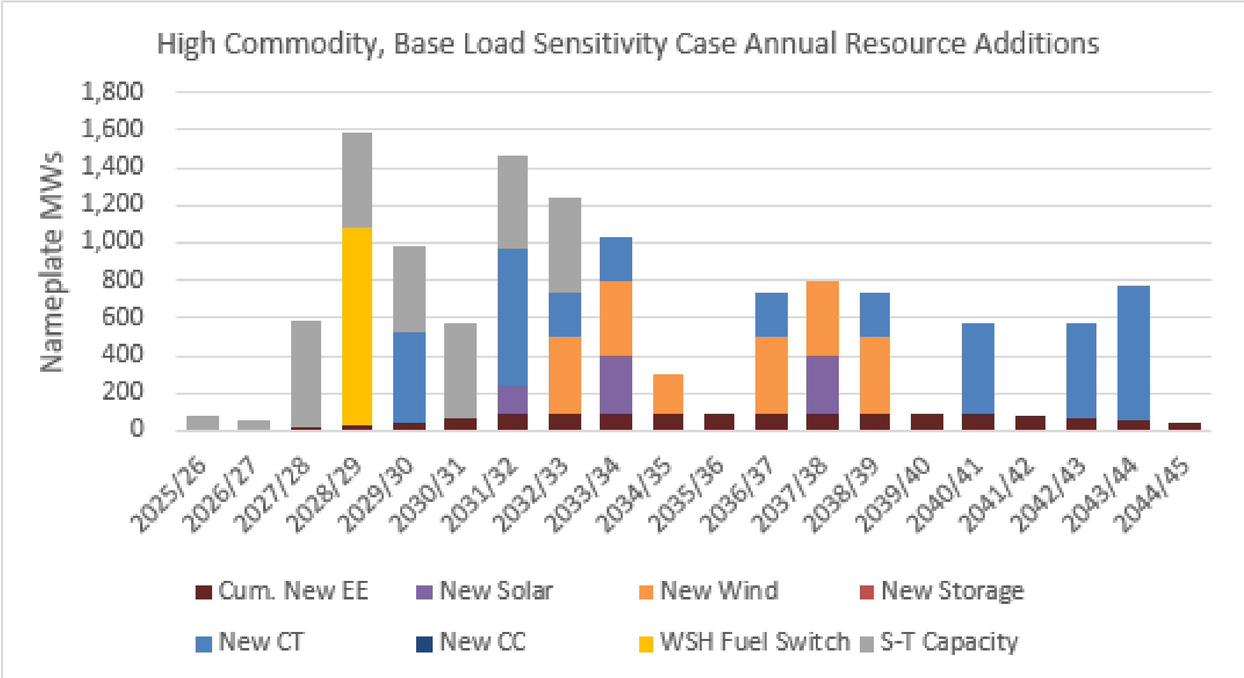


Figure 44: High Commodity, Base Load Sensitivity Case Annual Resource Additions

For the High Commodity, Base Load sensitivity, approximately 0.8GW of new solar, 2.2GW of new wind, and 3.9GW of new NGCTs are added by 2044. The High Commodity, Base Load sensitivity analysis selected the Welsh gas conversion (WSH Fuel Switch) in 2028 and the Hallsville NGCT in 2029. The sensitivity analysis selected a higher level of wind resources over NGCC resources compared to the Base Case portfolio due to higher market and fuel prices, making renewable energy more economically attractive.

8.2.6 Low Commodity, Base Load Sensitivity

The Low Commodity, Base Load sensitivity was optimized to select resources to serve the Company's Base load but with assumed lower commodity prices. Resource additions in the Low Commodity, Base Load sensitivity is shown in Table 30 and illustrated in Figure 45.

Table 30: Low Commodity, Base Load Sensitivity Case Annual Resource Additions

Low Commodity, Base Load Sensitivity Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	75	0	54
2026/27	0	0	0	0	0	0	0	50	0	44
2027/28	19	0	0	0	0	0	0	600	0	43
2028/29	37	0	0	0	0	0	1,053	500	0	42
2029/30	57	0	0	0	480	0	0	500	0	43
2030/31	91	0	0	0	0	0	0	500	0	43
2031/32	112	0	0	0	480	0	0	500	0	45
2032/33	112	0	0	0	0	1,100	0	0	4	11
2033/34	112	0	0	0	0	0	0	0	2	15
2034/35	112	0	0	0	0	0	0	0	1	16
2035/36	112	0	0	0	0	0	0	0	1	18
2036/37	112	0	0	0	480	0	0	0	1	18
2037/38	111	0	0	0	0	0	0	0	1	18
2038/39	110	0	0	0	480	0	0	0	1	18
2039/40	106	0	0	0	0	0	0	0	1	20
2040/41	100	0	0	0	240	0	0	0	1	19
2041/42	97	0	0	0	0	0	0	0	1	20
2042/43	79	0	0	0	0	760	0	0	6	19
2043/44	62	0	0	0	480	0	0	0	12	10
2044/45	47	0	0	0	0	0	0	0	13	10
Total		**0**	**0**	**0**	**2,640**	**1,860**	**1,053**			

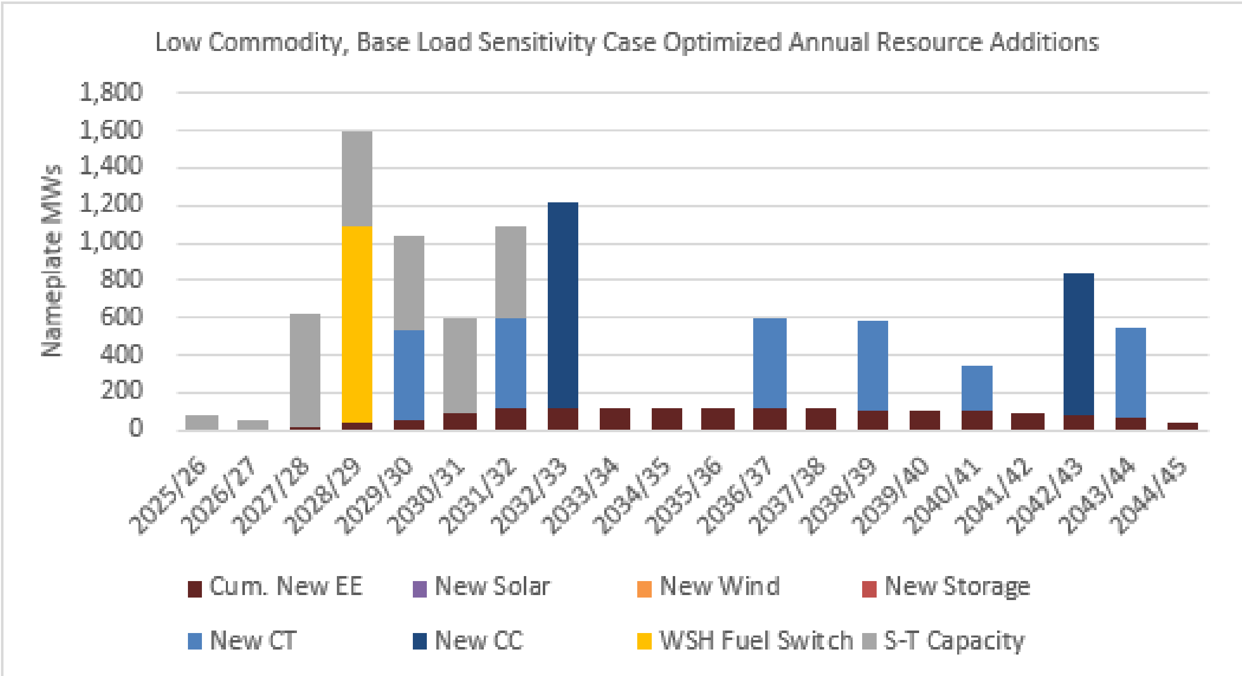


Figure 45: Low Commodity, Base Load Sensitivity Case Annual Resource Additions

For the Low Commodity, Base Load sensitivity, approximately 1.9GW of new NGCCs, and 2.6GW of new NGCTs are added by 2044. The Low Commodity, Base Load sensitivity analysis selected the Welsh gas conversion (WSH Fuel Switch) in 2028 and the Hallsville NGCT in 2029. The sensitivity analysis achieved the largest dispatchable capacity among all scenarios, primarily due to the selection of natural gas resources, which were more economically favorable under low commodity price assumptions.

8.2.7 High Technology Cost Sensitivity

The High Technology Cost sensitivity was optimized to select resources to serve the Company's base load but with assumed higher technology cost. Resource additions in the High Technology Cost sensitivity are shown in Table 31 and illustrated in Figure 46.

Table 31: High Technology Cost Sensitivity Case Annual Resource Additions

High Technology Costs Sensitivity Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	75	0	38
2026/27	0	0	0	0	0	0	0	50	0	30
2027/28	29	0	0	0	0	0	0	500	0	31
2028/29	63	0	0	0	0	0	1,053	500	0	32
2029/30	109	0	0	0	480	0	0	500	0	33
2030/31	162	150	0	0	0	0	0	500	0	30
2031/32	254	300	0	0	240	0	0	500	0	25
2032/33	254	0	0	0	0	1,100	0	0	15	4
2033/34	255	0	0	0	0	0	0	0	10	6
2034/35	257	0	0	0	240	0	0	0	10	6
2035/36	257	0	0	0	0	0	0	0	9	8
2036/37	257	0	0	0	240	0	0	0	8	7
2037/38	250	0	0	0	240	0	0	0	9	7
2038/39	241	0	0	0	240	0	0	0	9	6
2039/40	229	0	0	0	0	0	0	0	5	9
2040/41	212	0	0	0	480	0	0	0	7	6
2041/42	186	0	0	0	0	0	0	0	7	8
2042/43	164	0	0	0	720	0	0	0	7	8
2043/44	139	0	0	0	480	0	0	0	8	8
2044/45	105	0	0	0	0	0	0	0	7	6
Total		**450**	**0**	**0**	**3,360**	**1,100**	**1,053**			

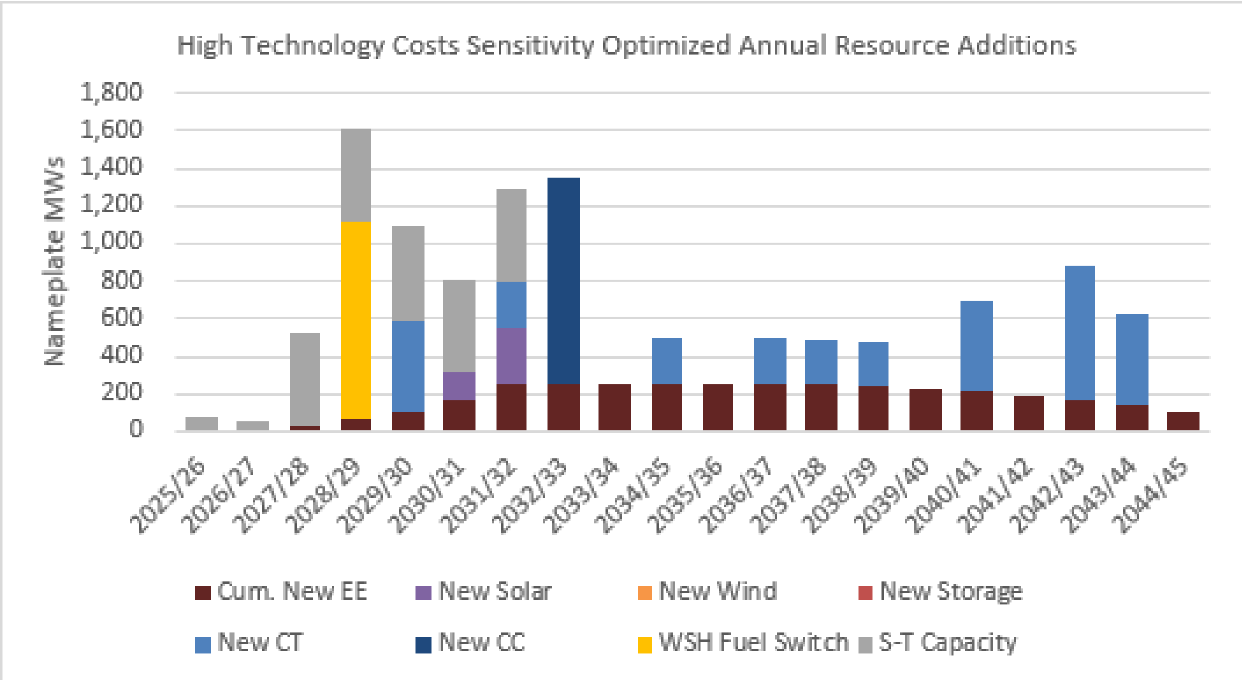


Figure 46: High Technology Costs Sensitivity Optimized Annual Resource Additions

For the High Technology Cost sensitivity, approximately 0.5GW of new solar, 1.1GW of new NGCC, and 3.4GW of new NGCTs are added by 2044. The High Technology Cost sensitivity analysis selected the Welsh gas conversion (WSH Fuel Switch) in 2028 the Hallsville NGCT in 2029. The sensitivity analysis resulted in a build plan similar to the Base Case portfolio with the main difference being higher values of EE resources selected. This resource selection is due to the capital cost rise of supply-side resources while the demand-side resource cost was not adjusted.

8.2.8 Low Technology Cost Sensitivity

The Low Technology Cost sensitivity was optimized to select resources to serve the Company's base load but with assumed lower technology cost. Resource additions in the Low Technology Cost sensitivity are shown in Table 32 and illustrated in Figure 47.

Table 32: Low Technology Cost Sensitivity Case Annual Resource Additions

Low Technology Costs Sensitivity Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	75	0	38
2026/27	0	0	0	0	0	0	0	50	0	30
2027/28	15	0	0	0	0	0	0	575	0	31
2028/29	30	0	0	0	0	0	1,053	500	0	32
2029/30	47	300	0	0	480	0	0	375	0	30
2030/31	65	0	0	0	0	0	0	500	0	29
2031/32	81	300	0	0	720	0	0	375	0	25
2032/33	81	0	400	0	240	0	0	250	0	19
2033/34	81	300	400	0	240	0	0	0	1	15
2034/35	81	0	200	0	0	0	0	0	2	12
2035/36	81	0	0	0	0	0	0	0	2	14
2036/37	81	0	400	0	0	0	0	0	4	8
2037/38	80	450	400	0	240	0	0	0	14	4
2038/39	79	0	200	0	240	0	0	0	15	3
2039/40	77	0	0	0	0	0	0	0	12	5
2040/41	74	0	0	0	480	0	0	0	15	3
2041/42	70	0	0	0	0	0	0	0	14	4
2042/43	56	0	0	0	480	0	0	0	14	4
2043/44	42	0	0	0	720	0	0	0	14	4
2044/45	28	0	0	0	0	0	0	0	15	3
Total		**1,350**	**2,000**	**0**	**3,840**	**0**	**1,053**			

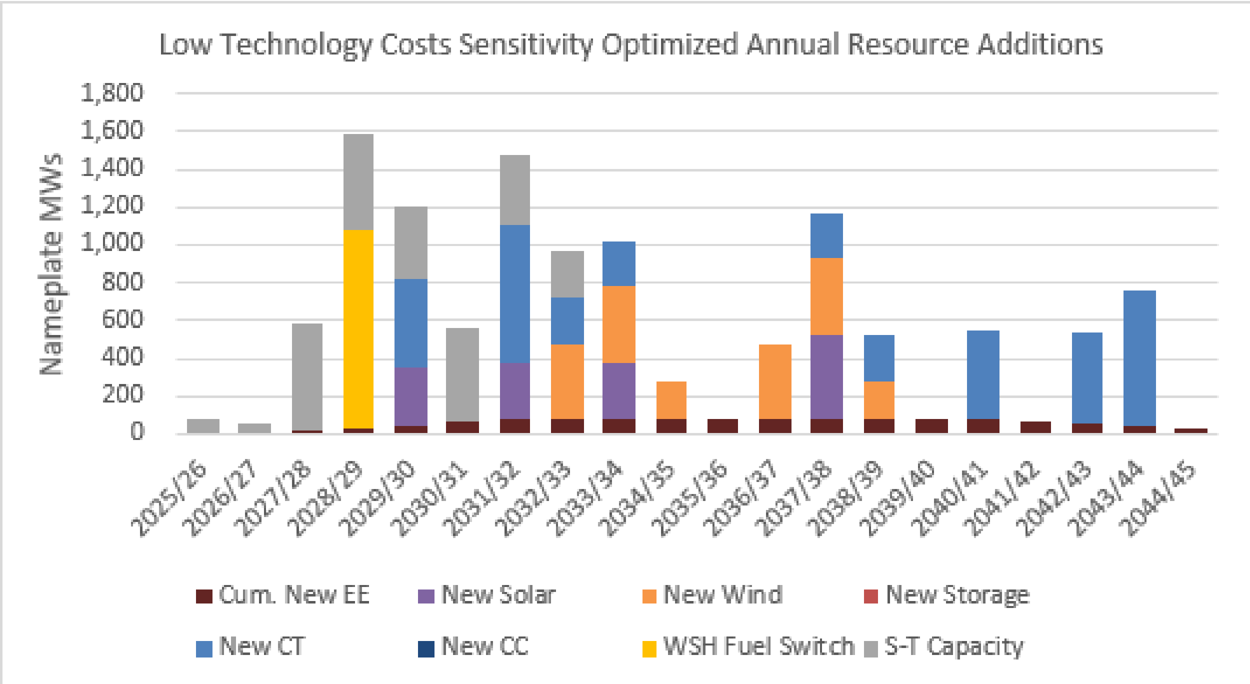


Figure 47: Low Technology Costs Sensitivity Optimized Annual Resource Additions

For the Low Technology Cost sensitivity, approximately 1.4GW of new solar, 2.0GW of new wind, and 3.8GW of new NGCTs are added by 2044. The Low Technology Cost sensitivity analysis selected the Welsh gas conversion in 2028 and the Hallsville NGCT in 2029. The sensitivity analysis resulted in a decrease in demand-side compared to the Base Case. This is due to the lower cost of supply-side resources compared to the demand-side resource cost which was not adjusted.

8.3 Portfolio Performance Indicators

The Portfolio Performance Indicator Matrix (PIM) can be an effective tool in decision-making when comparing different portfolios. The PIM for resource planning purposes refers to a matrix that illustrates the performance of alternative resource plans across a set of company-defined objectives, performance indicators, and metrics. The matrix enables the Company to consider the tradeoffs between portfolios for the purposes of making decisions based on how different plans perform across the metrics and how they support the Company and its customers. The matrix provides a simple and structured means of explaining how some objectives align, while other objectives can conflict and are traded off as part of reaching a reasonable decision that is in the best interest of customers.

The PIM has three primary elements, illustrated in Table 33.

- **Objectives** are overarching goals that align to SWEPCO or stakeholder priorities. The four objectives of the 2024 SWEPCO IRP are:
    - Customer Affordability,
    - Rate Stability,
    - 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 that 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.

Table 33: Elements of the 2024 SWEPCO IRP Performance Indicator Matrix

Objective	Performance Indicator	Metric
Customer Affordability	NPVRR	Portfolio 30yr NPVRR
		Portfolio 30yr Levelized Rate (MPVRR/Levelized Energy)
	Near-Term Rate Impact	7-year CAGR of Rate Impact
Rate Stability	Portfolio Resilience	Range of Portfolio NPVRR across Scenarios
	Energy Market Exposure – Purchases	Average Cost and volume exposure of market purchases (MWhs % of Internal Load) 2028-2034
	Energy Market Exposure – Sales	Average Revenue and volume exposure of market sales (MWhs % of Internal Load), 2028-2034
Reliability	Reserve Margin	Portfolio Total Reserve Margin
	Fleet Resiliency	Dispatchable Winter Accredited MW % of Company Peak Load
	Resource Diversity	Diversity Index inclusive of Capacity and Energy Diversity
Local Impacts & Sustainability	Local Impacts	New Nameplate MW Installed inside of SWEPCO as a % of Total New Nameplate MW
	Portfolio Emissions	CO_2, SO_2, NOx emissions change from 2005 Baseline

The objectives, performance indicators and metrics are further described in the following sections. The PIM is shown below in Figure 48.

Objective	**Customer Affordability**			**Rate Stability**			**Reliability**			**Local Impacts & Sustainability**					
Performance Indicators and Metrics	***Short Term***	***Long Term***		***Portfolio Resilience***	***Energy Market Risk***		***Planning Reserves***	***Fleet Resiliency***	***Resource Diversity***	***Local Impacts***	***Emission Reductions***				
	7-yr Rate (RR) CAGR	*Portfolio NPVRR*	*Portfolio NPVRR Levelized Rate*	*High Minus Low Scenario Range, Portfolio NPVRR*	*Average Cost of Market Purchases*	*Average Revenue of Market Sales*	*% Reserve Margin (ACAP)*	Dispatchable Winter Accredited MW	*Shannon-Weiner Diversity Index*	*New Nameplate MW Installed Inside SWEPCO as % of Total New Nameplate MW*	*% Change from 2005 Baseline*				
					AVG MWh % of AVG SWEPCO Demand	AVG MWh % of AVG SWEPCO Demand		% of Company Peak Demand			*CO_2*			*NOx*	*SO_2*
Years Referenced	2025-2032	2025-2054	2025-2054	2025-2054 | 2028-2037	2028-2034	2028-2034	2034 | 2035	2034	2034	2025-2034	2030	2034	2044	2034	2034
Units of Measure	%	$MM	$/MWh	$MM	$K	$K	Summer % | Winter %	MW	Accredited Capacity+ Energy Diversity	%	% Reduction				

Figure 48: 2024 IRP Performance Indicator Matrix

8.3.1 Objective 1: Customer Affordability

Customer affordability is a primary objective for SWEPCO. For the SWEPCO 2024 IRP, minimizing the expected cost to customers, to the extent reasonable when evaluated against other objectives, was a clear and obvious objective to measure.

There are two performance indicators that track customer affordability across the short- and long-term. It should be noted that these affordability metrics are for the generation component Power Supply Costs only and do not represent final costs which will apply to customers. Power Supply Costs represents the annualized capital associated with the resources selected, O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on capital.

8.3.1.1 Short Term: 7-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 affordability. Portfolios with similar net present values over the longer term can have significantly different short-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 rates over seven years as the metric for the short-term customer affordability performance indicator. The short-term affordability metric is measured using a 7-year Compound Annual Growth Rate (CAGR) of Power Supply Costs for the years 2025-2032.

8.3.1.2 Long Term: Portfolio net present value of revenue requirement

Portfolios that perform well in the short-term may be expensive over the longer term. Further, portfolios that perform similarly in the short-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.

Net present value revenue requirement (NPVRR) was selected as the metric for this performance indicator. NPVRR is a representation of the total long-term Power Supply Costs. The portfolio NPVRR allows for all the resource decisions made in the optimized run to be fully reflected. NPVRR will be measured over the long-term using a 30-year period (2025-2054) and is expressed both in terms of total and levelized rate. The levelized rate is the fixed charge per MWh needed to recover the 30-year NPVRR.

8.3.2 Objective 2: Rate Stability

Rate stability is a primary objective for SWEPCO. 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.

The performance indicators of rate stability test how robust the expected costs of each portfolio are by subjecting them to different market scenario conditions. This assessment evaluates how portfolios perform under a 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 two performance indicators for rate stability are described below and include an assessment of the potential change in rates across a range of scenarios and track the amount of reliance on the SPP energy market under each candidate plan.

8.3.2.1 Portfolio Resilience: Range of Portfolio NPVRRs

This performance indicator describes the range of Power Supply Costs for a given portfolio of resources when modeled across all market scenarios commodity conditions and the associated SWEPCO load. This allows the Company to compare the overall variability or consistency of costs and risks for each candidate portfolio case under the full range of market conditions considered in the IRP.

The metric for this performance indicator measures the range in portfolio costs between its best and worst performing planning scenario. It is calculated by subtracting the portfolio NPVRR for a single resource plan in the (1) the market scenario under which Power Supply Costs for the resource plan were the lowest from (2) the market scenario under which the Power Supply Costs to the resource plan were the highest. This metric was calculated using a 30-year period (2025-2054) and using a shorter 10-year period (2028-2037).

The portfolio NPVRR allows for all the resource decisions made in the optimized run to be fully reflected. Furthermore, the NPVRRs include the value of any unconstrained energy dispatch of the firm resources in the portfolio along with the ability to include additional capacity costs to meet the respective loads of each market scenario if needed.

8.3.2.2 Energy Market Risk:

As a member of SPP, the Company can leverage low-cost market energy for the benefits of its customers. Under normal conditions, this is of high value to ensure access to reliable and low-cost energy. Energy markets, however, include risks both in a reliance on this resource for purchases and sales during periods of high volatility. Measuring the total portion of customer energy served by the market, or conversely, the reliance on market energy sales in periods of excess generation will provide insight to potential market risks of each portfolio.

8.3.2.3 Energy Market Purchases:

The metric for this performance indicator measures the portfolio costs of energy market purchases and the percent of purchases to the Company’s internal peak load. The portfolio cost metrics are calculated as the average market energy costs and percentage of internal peak load from 2028 through 2034. The Company analyzed this same metric over a 20-year (2025-2044) and 30-year period (2025-2054) to gain additional insights on longer-term impacts to Energy Market Risk.

8.3.2.4 Energy Market Sales:

The metric for this performance indicator measures the portfolio revenues of energy market sales and the percent of sales to the Company’s internal peak load. The portfolio revenue metrics are calculated as the average market energy revenues and percentage of internal peak load from 2028 through 2034. The Company analyzed this same metric over a 20-year (2025-2044) and 30-year period (2025-2054) to gain additional insights on longer-term impacts to Energy Market Risk.

8.3.3 Objective 3: Maintaining Reliability

Understanding the role that SPP plays in maintaining broader system reliability, SWEPCO has identified maintaining reliability as an important, fundamental objective. Three performance indicators were selected to measure progress towards maintaining reliability. These cover the total capacity reserves maintained by SWEPCO under each plan, the amount of dispatchable capacity included in each plan, and a measure of the resource diversity in the portfolios reflecting both capacity and energy contributions.

8.3.3.1 Planning Reserves:

As a Load Responsible Entity (LRE), SWEPCO must maintain a minimum amount of accredited capacity above its coincident peak load with SPP as described in Section 3.5. This performance indicator measures SWEPCO's amount of firm capacity in each candidate portfolio in 2034 for summer and 2035 for winter relative to its coincident peak load. The metric allows SWEPCO to evaluate the exposure of different candidate resource plans towards meeting planning reserve margin requirements.

The metric for this performance indicator will be SWEPCO's reserve margin measured as the ratio of ACAP supply to forecasted company peak demand. This metric is calculated by dividing the (seasonal) ACAP of the resource plan by SWEPCO's (seasonal) peak requirement of the resource plan in 2034 for summer and 2035 for winter.

8.3.3.2 Fleet Resiliency:

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.

This performance indicator allows the Company to evaluate the amount of ramping capacity or potential for continuous energy output on its system. The metric is measured as the cumulative amount of dispatchable accredited winter capacity selected by the candidate portfolio in 2034 including all thermal and storage resources.

8.3.3.3 Resource Diversity:

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 innovative technologies can play to help customers reach their goals. This performance indicator will allow the Company to assess the overall diversity of its long-term resource plan.

This measure will evaluate the diversity of different resource contributions to their respective total summer accredited capacity and energy as part of the total portfolio of resource types. Diversity will be calculated based on the Shannon-Weiner Diversity Index[27] that considers the number of different types of resources and their respective contributions to the portfolio total with respect to capacity and energy. Capacity diversity will be evaluated based on summer accredited MWs while energy diversity will be based on modeled annual MWhs. The Portfolio Diversity index will be the sum of the Capacity Diversity Index and the Energy Diversity Index.

[27] Zach Bobbitt, "Shannon Diversity Index: Definition & Example," Statology, https://www.statology.org/shannon-diversity-index/

8.3.4 Objective 4: Local Impacts and Sustainability

This objective allows SWEPCO to evaluate the benefits to the local economy each portfolio provides in addition to the relative exposure of each portfolio under outcomes where significant reductions in Greenhouse Gas (GHG) emissions are required in the power sector.

8.3.4.1 Local Impacts

SWEPCO is interested in understanding how each portfolio's resource selections will impact their local economy. This metric quantifies the nameplate capacity installed within SWEPCO's footprint as a percentage of the total nameplate capacity selected for the entire portfolio. The Company included solar, storage, NGCT, NGCT, and any existing facilities that were selected for gas conversions as resources included in this metric.

8.3.4.2 Emissions Reduction

SWEPCO is interested in understanding how each portfolio's resource selections will impact sustainability and emissions reduction. This metric quantifies the percentage change from the 2005 baseline levels of CO_2, NOx, and SO_2. Additional analysis was completed for CO_2 to understand the change in emissions reduction over different time periods.

8.4 Portfolio Analysis

8.4.1 Customer Affordability

SWEPCO's portfolio metrics of short- and long-term customer affordability can be noted in Table 34. As discussed in Section 8.3, the indicators for this objective include the seven-year compound annual growth rate and the net present value revenue requirement (NPVRR) over the 30-year period (2025-2054) expressed on both an NPVRR basis and a levelized rate basis.

Table 34: Customer Affordability Metrics

Objective	Customer Affordability		
Performance Indicators and Metrics	***Short Term***	***Long Term***	
	7-yr Rate (RR) CAGR	*Portfolio NPVRR*	*Portfolio NPVRR Levelized Rate*
Years Referenced	2025-2032	2025-2054	2025-2054
Units of Measure	%	$MM	$/MWh
Base Case Portfolio	6.62%	$17,077	$49.46
High Case Portfolio	5.82%	$22,314	$57.73
Low Case Portfolio	4.78%	$11,670	$38.20
EER Case Portfolio	7.23%	$17,167	$49.72
High Commodity, Base Load Sensitivity	4.76%	$18,360	$53.18
Low Commodity, Base Load Sensitivity	7.11%	$14,307	$41.44
High Technology Costs Sensitivity	7.25%	$18,482	$53.53
Low Technology Costs Sensitivity	4.23%	$14,810	$42.90

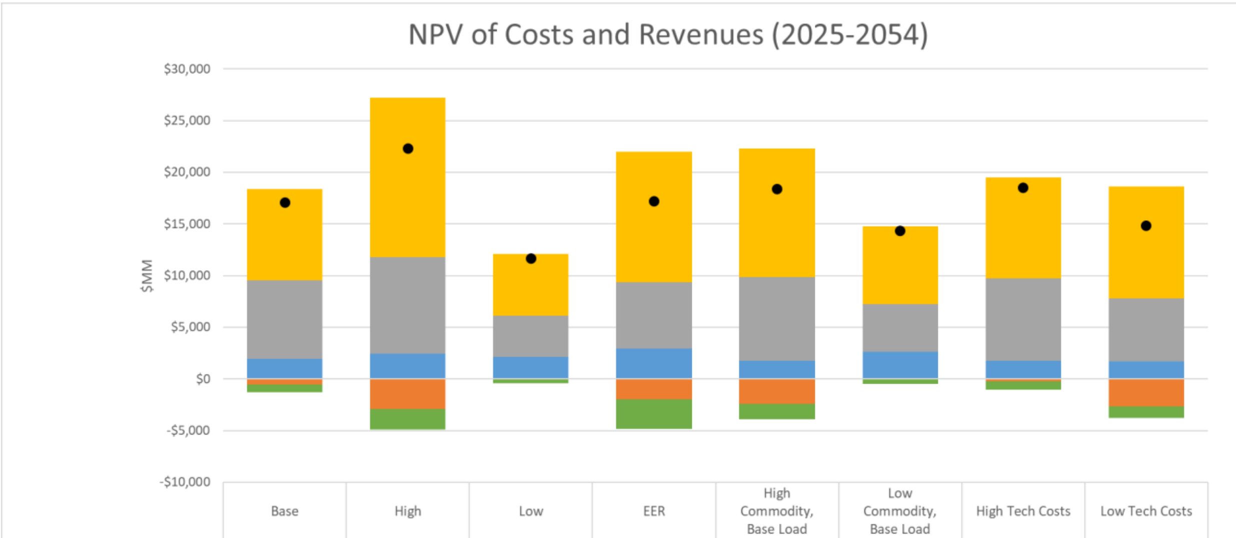
8.4.1.1 Short-Term

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. As expected, the Low Case portfolio and the Low Technology Cost sensitivity show the lowest CAGR values at 4.78% and 4.23%, respectively. A notable relationship is shown with the High Case portfolio and High Commodity, Base Load sensitivity having lower CAGR values compared to the Base Case portfolio. However, the High Case portfolio and the High Commodity, Base Load sensitivity both have a higher NPVRR compared to the Base Case portfolio. This relationship indicates that both the High Case portfolio and the High Commodity, Base Load sensitivity result in slower growth in the near term but overall higher Power Supply Costs in the long term. The Base Case portfolio has a lower growth rate of 6.62% compared to the EER Case portfolio which has a growth rate of 7.23%.

8.4.1.2 Long-term

The Low Case portfolio, Low Commodity, Base Load sensitivity, and the Low Technology Costs sensitivity have the lowest NPVRR values, ranging from $11.67B to $14.31B. This is expected as each of these portfolios have either low economic growth, low technology costs, or low commodity pricing. The Base Case and the EER Case portfolios have similar NPVRR values. The Company further investigated the NPVRR values of the Base Case and EER Case portfolios to understand the drivers behind the metric results for these two portfolios. The remainder of the cases have NPVRR values between $18.36B and $22.31B.

The Company further analyzed the component costs and revenues that make up the NPVRR to understand key differences between the long-term affordability metric for the portfolios, particularly to identify important differences between the cost of the Base Case and EER Case portfolios. This can be noted visually in Figure 49.



	Base	High	Low	EER	High Commodity, Base Load	Low Commodity, Base Load	High Tech Costs	Low Tech Costs
PV of Fixed Costs	$8,854	$15,437	$5,993	$12,638	$12,438	$7,526	$9,775	$10,817
PV of Production Cost	$7,579	$9,369	$3,938	$6,432	$8,068	$4,618	$7,988	$6,130
PV of Market Purchase Cost	$1,934	$2,423	$2,153	$2,921	$1,786	$2,621	$1,753	$1,670
PV of Market Sales Revenue	-$767	-$2,012	-$414	-$2,845	-$1,528	-$457	-$774	-$1,155
PV of PTC Revenue	-$523	-$2,903	$0	-$1,978	-$2,404	$0	-$259	-$2,653
Total NPVRR	$17,077	$22,314	$11,670	$17,167	$18,360	$14,307	$18,482	$14,810

Figure 49: NPV of Costs and Revenues (2025-2054)

The upper portion of the figure represents the costs associated with each portfolio while the lower portion of the figure represents the revenues associated with each portfolio. The Base Case portfolio's fixed costs are $3.78B less compared to the EER Case portfolio. In addition, the EER Case portfolio has $1B higher energy market purchase cost compared to the Base Case portfolio. Additional details on energy market risk will be covered in Section 8.4.2. Comparing revenues, the EER Case portfolio is more reliant on revenues from energy market sales and production tax credits (PTCs) compared to the Base Case portfolio. The EER Case portfolio has $4.82B in revenues compared to the Base Case portfolio which has $1.29B in revenues.

The additional long-term affordability analysis helped SWEPCO further understand key differences between these two portfolios. While the Base Case and EER Case portfolios have NPVRR values that are similar, the Base Case portfolio represents less risk from the energy market and PTC revenues compared to EER Case portfolio. Additionally, the Base Case portfolio represents lower fixed costs compared to the EER Case portfolio.

8.4.2 Rate Stability

SWEPCO's portfolio metrics associated with the Rate Stability objective can be noted in Table 35. As discussed in Section 8.3, the indicators for this objective include Portfolio Resilience and Energy Market Risk.

Table 35: Rate Stability Metrics

Objective	**Rate Stability**		
Performance Indicators and Metrics	***Portfolio Resilience***	***Energy Market Risk***	
	High Minus Low Scenario Range, Portfolio NPVRR	*Average Cost of Market Purchases* *AVG MWh % of AVG SWEPCO Demand*	*Average Revenue of Market Sales* AVG MWh % of AVG SWEPCO Demand
Years Referenced	2025-2054 | 2028-2037	2028-2034	2028-2034
Units of Measure	$MM	$K	$K
Base Case Portfolio	$9,786 | $1,986	$139,430 20.5%	$30,018 4.0%
High Case Portfolio	$10,978 | $2,294	$248,433 26.0%	$1,718 0.2%
Low Case Portfolio	$5,615 | $1,699	$158,537 29.8%	$8,853 1.8%
EER Case Portfolio	$7,727 | $2,030	$228,563 33.0%	$2,992 0.4%
High Commodity, Base Load Sensitivity	Not Evaluated	$178,177 19.91%	$3,923 0.5%
Low Commodity, Base Load Sensitivity	Not Evaluated	$175,467 30.61%	$5,204 1.0%
High Technology Costs Sensitivity	Not Evaluated	$130,795 19.21%	$38,021 5.1%
Low Technology Costs Sensitivity	Not Evaluated	$158,654 22.98%	$4,431 0.6%

8.4.2.1 Portfolio Resilience

Table 36 shows the 30-year NPVRRs across the four market scenarios and the difference between the highest and lowest NPVRRs of each of the four portfolios considered. The difference between the highest and lowest value is used to populate the Portfolio Resilience indicator on Table 35. A lower number is generally favorable, indicating a tighter grouping of expected customer costs across a wide range of long-term market conditions. However, it is important to understand how each portfolio performs under the different Market Scenarios to identify portfolios with lower costs.

Table 36: Portfolio Resilience 30-Year

Market Scenarios (2025-2054) $MM

Portfolios	Base	High	Low	EER	High/Low Difference
Base Case	16,630	12,953	22,739	18,010	9,786
High Case	15,724	11,234	22,212	17,295	10,978
Low Case	18,277	16,244	21,859	17,880	5,615
EER Case	17,313	14,945	22,672	17,167	7,727

Over the 30-year NPVRR it can be noted that the Low Case portfolio has the lowest cost range followed by the EER Case portfolio. While the Low Case and EER Case portfolios have the lowest cost range, the relatively higher costs under the High Market Scenario for these portfolios drive the lower cost range values reported for this metric. The Base Case portfolio has a lower value compared to the EER Case portfolio under the High Market Scenario, indicating that it is more resilient than the EER Case portfolio under higher commodity prices.

SWEPCO reviewed the same Portfolio Resilience metric over a 10-year period and the results can be noted in Table 37.

Table 37: Portfolio Resilience 10-Year

Market Scenarios (2028-2037) $MM

Portfolios	Base	High	Low	EER	High/Low Difference
Base Case	4,486	3,585	5,571	4,715	1,986
High Case	4,448	3,395	5,689	4,678	2,294
Low Case	4,495	3,666	5,365	4,722	1,699
EER Case	4,614	3,755	5,784	4,587	2,030

Over the 10-year period the Low Case and the Base Case portfolios have the lowest cost ranges. The Base Case portfolio performs well under the High Market Scenario, with the second lowest cost over the 10-year time horizon. This indicates that the Base Case portfolio is more resilient than the Low Case and EER Case portfolios under higher commodity prices. The Base Case portfolio has a lower value compared to the EER Case portfolio under the Low Market Scenario, indicating that it is more resilient than the EER Case portfolio under lower commodity prices. The results indicate that over the short-term period, the Low Case and the Base Case portfolios are more resilient to varying market conditions.

8.4.2.2 Energy Market Risk

Table 35 shows the average costs and revenues of market purchases along with the average energy sales and purchases as a percentage of SWEPCO's demand over a six-year period (2028-2034). The Energy Market Risk financial figures in Table 35 are in nominal dollars. The Base Case portfolio has the lowest amount of market purchases compared to the other cases, reliant on the energy market for roughly 20% of SWEPCO's energy compared to the Company's load. Comparatively, the EER Case portfolio has the highest amount of market purchases, reliant on the energy market for 33% of SWEPCO's energy compared to the Company load with average costs of $229M per year. Alternatively, the Base Case portfolio has the highest amount of sales compared to the other cases with an average revenue of $30M.

As shown in Table 38 below, the Company further analyzed the Energy Market Risk of the Base Case, High Case, Low Case, and EER Case portfolios over varying time periods. Table 38 shows the Energy Market risk over the six-year, 20-year, and 30-year period. The 30-year period reflects the market risk that is embedded in the NPVRR within the affordability metrics in Section 8.4.1. The Energy Market Risk financial figures in Table 38 are in nominal dollars.

Table 38: Energy Market Risk

	Energy Market Risk		***Energy Market Risk***		***Energy Market Risk***	
	Purchases	*Sales*	*Purchases*	*Sales*	*Purchases*	*Sales*
	2028-2034	2028-2034	2025-2044	2025-2044	2025-2054	2025-2054
	Average Cost of Market Purchases ($000) AVG MWh % of AVG SWEPCO Demand	Average Revenue of Market Sales ($000) AVG MWh % of AVG SWEPCO Demand	Average Cost of Market Purchases ($000) AVG MWh % of AVG SWEPCO Demand	Average Revenue of Market Sales ($000) AVG MWh % of AVG SWEPCO Demand	Average Cost of Market Purchases ($000) AVG MWh % of AVG SWEPCO Demand	Average Revenue of Market Sales ($000) AVG MWh % of AVG SWEPCO Demand
Base Case Portfolio	$139,430 20.5%	$30,018 4.0%	$105,828 14.8%	$61,849 6.6%	$112,272 13.0%	$73,648 6.7%
High Case Portfolio	$248,433 26.0%	$1,718 0.2%	$161,739 14.6%	$87,423 6.6%	$175,886 12.3%	$136,797 8.1%
Low Case Portfolio	$158,537 29.8%	$8,853 1.8%	$123,156 23.3%	$16,236 3.1%	$126,352 23.4%	$20,761 3.7%
EER Case Portfolio	$228,563 33.0%	$2,992 0.4%	$165,980 23.8%	$45,019 4.2%	$142,691 17.62%	$261,851 15.4%

For the 20-year period, compared to the six-year period, there is a reduction in reliance on energy market purchases and an increase in reliance on energy market sales for all portfolios. In the 30-year period, there is a further reduction in energy market purchases for the Base Case portfolio with the average purchases compared to SWEPCO's load decreasing from 20% in the six-year period to 13% in the 30-year period. Notably, there is a significant increase in reliance on energy market sales for the EER Case portfolio shifting from almost no reliance on sales in the six-year period to 15.4% of sales compared to SWEPCO's load resulting in an average yearly revenue of $260M. Based on this analysis, the Company concluded that the Base Case portfolio has the lowest energy market risk over the varying time periods; in contrast, the EER Case portfolio has the most energy market risk over the varying time periods. These key difference between the Base Case portfolio and the EER Case portfolio can also be seen in the Affordability analysis discussed in Section 8.4.1.

8.4.3 Maintaining Reliability

SWEPCO's portfolio metrics associated with the Reliability objective can be noted in Table 39. As discussed in Section 8.3, the indicators for this objective include Planning Reserves, Fleet Resiliency, and Resource Diversity.

Table 39: Reliability Metrics

Objective	Reliability		
Performance Indicators and Metrics	***Planning Reserves***	***Fleet Resiliency***	***Resource Diversity***
	% Reserve Margin (ACAP)	Dispatchable Winter Accredited MW % of Company Peak Demand	*Shannon-Weiner Diversity Index*
Years Referenced	2034 | 2035	2034	2034
Units of Measure	Summer % | Winter %	MW	Accredited Capacity+ Energy Diversity
Base Case Portfolio	42.4% | 26.9%	4,455 107.1%	1.8+1.3 = 3.1
High Case Portfolio	28.9% | 24.7%	4,577 102.1%	1.6+1.3 = 2.9
Low Case Portfolio	36.9% | 27.9%	4,077 106.8%	1.8+1.1 = 2.8
EER Case Portfolio	40.6% | 24.3%	4,207 100.3%	1.6+1.3 = 2.9
High Commodity, Base Load Sensitivity	36.9% | 24.9%	4,199 100.9%	1.7+1.4 = 3.1
Low Commodity, Base Load Sensitivity	33.2% | 25.1%	4,455 107.1%	1.7+1.1 = 2.8
High Technology Costs Sensitivity	36.5% | 27.3%	4,266 102.6%	1.8+1.3 = 3.1
Low Technology Costs Sensitivity	43.7% | 26.1%	4,199 100.9%	1.7+1.4 = 3.1

8.4.3.1 Planning Reserves

Table 39 shows the summer and winter planning reserves in 2034 and 2035. As discussed in Section 3.5, the target ACAP summer and winter planning reserves modeled in year 2034 and 2035 are 11% and 24%, respectively. Each of the portfolios was constrained by the winter planning reserve requirement compared to the summer. This can be noted by the much higher summer reserve values compared to the target planning reserve constraint of 11% in year 2034. Additionally, there is a wider range of summer planning reserve margins, ranging from 28.9% to 43.7% compared to the winter planning reserve margin which ranges from 24.3% to 27.9%.

The EER Case and High Case portfolios have the lowest winter reserve margin while the Low Case portfolio has the highest winter reserve margin. The Base Case portfolio is the second-highest of the range of winter reserve margin values, with 26.9% winter reserve margin in 2035. The additional reserve margin offers SWEPCO's customers reliability benefits when comparing to the High Case and EER case portfolios.

8.4.3.2 Fleet Resiliency

Table 39 shows the winter accredited capacity of dispatchable units in 2034 along with the percentage of the winter accredited capacity compared to SWEPCO's peak demand. The Company considers dispatchable resources as all thermal and storage resources.

The Base Case portfolio, Low Case portfolio, and Low Commodity, Base Load sensitivity have the highest fleet resiliency values at around 107%. This is due to the addition of greater amounts of dispatchable thermal resources selected in these plans compared to the other portfolios. The EER Case portfolio has the lowest value due to the lower amount of dispatchable capacity selected by the model in the first 10 years of the planning horizon. The Base Case portfolio selects 2,060MW of installed thermal dispatchable capacity in the first 10 years compared to the EER Case which selects 1,720MW of installed thermal dispatchable capacity in the same period. Additionally, the 100% natural gas conversions of Flint Creek and Turk in the EER Case portfolio marginally decrease their collective winter accredited capacity by 36MW, further reducing the Fleet Resiliency metric for the EER Case portfolio.

8.4.3.3 Resource Diversity

Table 39 shows the Shannon-Weiner Diversity Index for both the summer accredited capacity and the energy in 2034. A larger value for this metric indicates a more diverse portfolio. The Base Case portfolio, Low Case portfolio, and the High Technology Cost sensitivity have the highest summer accredited capacity diversity index values at 1.8 while the High Case and EER Case portfolios have the lowest value at 1.6. The High Commodity, Base load and the Low Technology Cost sensitivities have the highest energy diversity index values at 1.4, closely followed by the Base Case and the EER Case portfolios at 1.3. The Base Case portfolio has one of the highest combined diversity indices, indicating the selected resource mix of the Base Case will provide additional reliability benefits.

8.4.4 Local Impacts & Sustainability

SWEPCO's portfolio metrics associated with the Local Impacts and Sustainability objective can be noted in Table 40. As discussed in Section 8.3, the indicators for this objective include Local Impacts and Emission Reductions.

Table 40: Local Impacts & Sustainability Metrics

Objective	Local Impacts & Sustainability					
Performance Indicators and Metrics	***Local Impacts***	***Emission Reductions***				
	New Nameplate MW Installed Inside SWEPCO as % of Total New Nameplate MW	*% Change from 2005 Baseline*				
		CO_2			*NOx*	*SO_2*
Years Referenced	2025-2034	2030	2034	2044	2034	2034
Units of Measure	%	% Reduction				
Base Case Portfolio	100%	81.1%	66.6%	69.2%	91.6%	98.7%
High Case Portfolio	73%	73.1%	73.1%	80.1%	88.9%	98.0%
Low Case Portfolio	100%	93.1%	80.0%	81.0%	98.5%	100.0%
EER Case Portfolio	87%	94.6%	90.1%	78.9%	97.8%	100.0%
High Commodity, Base Load Sensitivity	76%	73.1%	73.1%	80.4%	88.9%	98.0%
Low Commodity, Base Load Sensitivity	100%	93.1%	80.0%	71.6%	98.5%	100.0%
High Technology Costs Sensitivity	100%	81.1%	66.6%	69.2%	91.6%	98.7%
Low Technology Costs Sensitivity	78%	81.1%	80.0%	82.5%	92.4%	98.7%

8.4.4.1 Local Impacts

Table 40 compares the total installed nameplate capacity inside SWEPCO service territory to the total installed nameplate capacity of the portfolio between 2025 and 2034. As noted in Section 8.3.4, this includes an assumption of particular resources being located within SWEPCO's territory. The Company will continue to explore opportunities to locate resources within and outside of SWEPCO's territory if they are beneficial to SWEPCO customers.

The Base Case and Low Case portfolios provide the highest values for this metric, with 100% of resources selected being within SWEPCO's service territory. The High Case and the EER Case portfolios provide lower values for this metric, with 73% and 87%, respectively.

8.4.4.2 Emissions Reduction

Table 40 shows the reduction in CO_2, NOx, and SO_2 compared to the 2005 baseline. The emissions reduction for CO_2 was analyzed further to understand the reduction values in 2030, 2034, and 2044.

In 2030, each case shows a reduction in CO_2 emissions. All portfolios except the High Commodity, Base Load Sensitivity result in CO_2 reductions of greater than 80% by 2030. In 2034, CO_2 emission reduction performance declines as all portfolios add natural gas resources to meet SWEPCO's capacity and energy needs. In 2044, many of the cases have flat or improved CO_2 emission reduction values, except for the EER Case portfolio. This is due to the selection of 2,960MW of natural gas resources in the last 10 years of the planning horizon.

It can be noted that all portfolios perform well when reviewing the NOx and SO_2 reductions. The NOx reduction values range from 88.9% to 98.5% while the SO_2 reduction values range from 98% to 100% by 2034.

8.4.5 Highlighted Portfolio Performance Indicators and Modeling Results

The fully populated Portfolio Performance Indicator Matrix is shown in Figure 50. The highlighted results are summarized below:

- The Base Case and EER Case portfolios have comparable net present value costs (revenue requirement) that are significantly less than the High Case portfolio.
- The Base Case portfolio has a lower near-term cost growth rate than the EER portfolio.
- The Base Case portfolio requires approximately $3.7B less in cost recovery of fixed capital investments than the EER portfolio over the 30-year period.
- The High Case and EER Case portfolios include a high reliance on production tax credits and market sales revenues to offset capital investment costs.
- All portfolios continue to rely on the SPP market energy, but the Base Case portfolio has significantly lower market purchases, and thus, lower potential risks than the other portfolios.
- The Base Case portfolio provides the most dispatchable resources as a percent of peak demand to reliably serve customers in a predictable manner.
- All portfolios and sensitivities modeled selected the Welsh gas conversions in 2028 and the Hallsville NGCT in 2029.

Objective	Customer Affordability			Rate Stability			Reliability			Local Impacts & Sustainability					
Performance Indicators and Metrics	***Short Term***	***Long Term***		***Portfolio Resilience***	***Energy Market Risk***		***Planning Reserves***	***Fleet Resiliency***	***Resource Diversity***	***Local Impacts***	***Emission Reductions***				
	7-yr Rate (RR) CAGR	*Portfolio NPVRR*	*Portfolio NPVRR Levelized Rate*	*High Minus Low Scenario Range, Portfolio NPVRR*	*Average Cost of Market Purchases* *AVG MWh % of AVG SWEPCO Demand*	*Average Revenue of Market Sales* AVG MWh % of AVG SWEPCO Demand	*% Reserve Margin (ACAP)*	Dispatchable Winter Accredited MW % of Company Peak Demand	*Shannon-Weiner Diversity Index*	*New Nameplate MW Installed Inside SWEPCO as % of Total New Nameplate MW*	*% Change from 2005 Baseline*				
											CO_2			*NOx*	*SO_2*
Years Referenced	2025-2032	2025-2054	2025-2054	2025-2054 | 2028-2037	2028-2034	2028-2034	2034 | 2035	2034	2034	2025-2034	2030	2034	2044	2034	2034
Units of Measure	%	$MM	$/MWh	$MM	$K	$K	Summer % | Winter %	MW	Accredited Capacity+ Energy Diversity	%	% Reduction				
Base Case Portfolio	6.62%	$17,077	$49.46	$9,786 | $1,986	$139,430 20.5%	$30,018 4.0%	42.4% | 26.9%	4,455 107.1%	1.8+1.3 = 3.1	100%	81.1%	66.6%	69.2%	91.6%	98.7%
High Case Portfolio	5.82%	$22,314	$57.73	$10,978 | $2,294	$248,433 26.0%	$1,718 0.2%	28.9% | 24.7%	4,577 102.1%	1.6+1.3 = 2.9	73%	73.1%	73.1%	80.1%	88.9%	98.0%
Low Case Portfolio	4.78%	$11,670	$38.20	$5,615 | $1,699	$158,537 29.8%	$8,853 1.8%	36.9% | 27.9%	4,077 106.8%	1.8+1.1 = 2.8	100%	93.1%	80.0%	81.0%	98.5%	100.0%
EER Case Portfolio	7.23%	$17,167	$49.72	$7,727 | $2,030	$228,563 33.0%	$2,992 0.4%	40.6% | 24.3%	4,207 100.3%	1.6+1.3 = 2.9	87%	94.6%	90.1%	78.9%	97.8%	100.0%
High Commodity, Base Load Sensitivity	4.76%	$18,360	$53.18	Not Evaluated	$178,177 19.91%	$3,923 0.5%	36.9% | 24.9%	4,199 100.9%	1.7+1.4 = 3.1	76%	73.1%	73.1%	80.4%	88.9%	98.0%
Low Commodity, Base Load Sensitivity	7.11%	$14,307	$41.44	Not Evaluated	$175,467 30.61%	$5,204 1.0%	33.2% | 25.1%	4,455 107.1%	1.7+1.1 = 2.8	100%	93.1%	80.0%	71.6%	98.5%	100.0%
High Technology Costs Sensitivity	7.25%	$18,482	$53.53	Not Evaluated	$130,795 19.21%	$38,021 5.1%	36.5% | 27.3%	4,266 102.6%	1.8+1.3 = 3.1	100%	81.1%	66.6%	69.2%	91.6%	98.7%
Low Technology Costs Sensitivity	4.23%	$14,810	$42.90	Not Evaluated	$158,654 22.98%	$4,431 0.6%	43.7% | 26.1%	4,199 100.9%	1.7+1.4 = 3.1	78%	81.1%	80.0%	82.5%	92.4%	98.7%

Figure 50: Portfolio Performance Indicator Matrix

8.5 Preferred Plan

The Company identified the Preferred Plan based on insights from the different portfolio analyses discussed in Section 8.4. The Company selected the Base Case portfolio as the Preferred Plan because it supports SWEPCO's four IRP objectives of Customer Affordability, Rate Stability, Reliability, and Local Impacts and Sustainability. The Preferred Plan maintains affordable and stable rates for SWEPCO customers and mitigates market energy risks. It includes significant dispatchable resources that supports fleet resiliency and provides reliability for SWEPCO customers. Finally, it provides portfolio diversity by adding additional natural gas and solar resources to SWEPCO's existing fleet that already includes substantial wind capacity.

Resource additions in the Preferred Plan are shown in Table 41 and Figure 51.

Table 41: Preferred Plan New Resource Additions

Preferred Plan Capacity Additions by Planning Year (Nameplate MW)										
SPP Planning Year	Cum. New EE	New Solar	New Wind	New Storage	New CT	New CC	WSH Fuel Switch	S-T Capacity	Energy Exports (%)	Energy Imports (%)
2025/26	0	0	0	0	0	0	0	75	0	38
2026/27	0	0	0	0	0	0	0	50	0	30
2027/28	19	0	0	0	0	0	0	600	0	31
2028/29	36	0	0	0	0	0	1,053	500	0	32
2029/30	53	0	0	0	480	0	0	500	0	33
2030/31	73	300	0	0	0	0	0	500	0	29
2031/32	96	300	0	0	480	0	0	500	0	25
2032/33	97	0	0	0	0	1,100	0	500	6	14
2033/34	97	0	0	0	0	0	0	0	11	6
2034/35	97	0	0	0	0	0	0	0	11	6
2035/36	97	0	0	0	0	0	0	0	9	7
2036/37	97	0	0	0	240	0	0	0	9	7
2037/38	94	300	0	0	240	0	0	0	12	5
2038/39	91	0	0	0	240	0	0	0	13	4
2039/40	89	0	0	0	0	0	0	0	8	7
2040/41	86	0	0	0	480	0	0	0	10	5
2041/42	82	0	0	0	0	0	0	0	10	6
2042/43	65	0	0	0	480	0	0	0	10	6
2043/44	52	0	0	0	720	0	0	0	10	7
2044/45	37	0	0	0	0	0	0	0	10	5
Total		**900**	**0**	**0**	**3,360**	**1,100**	**1,053**			

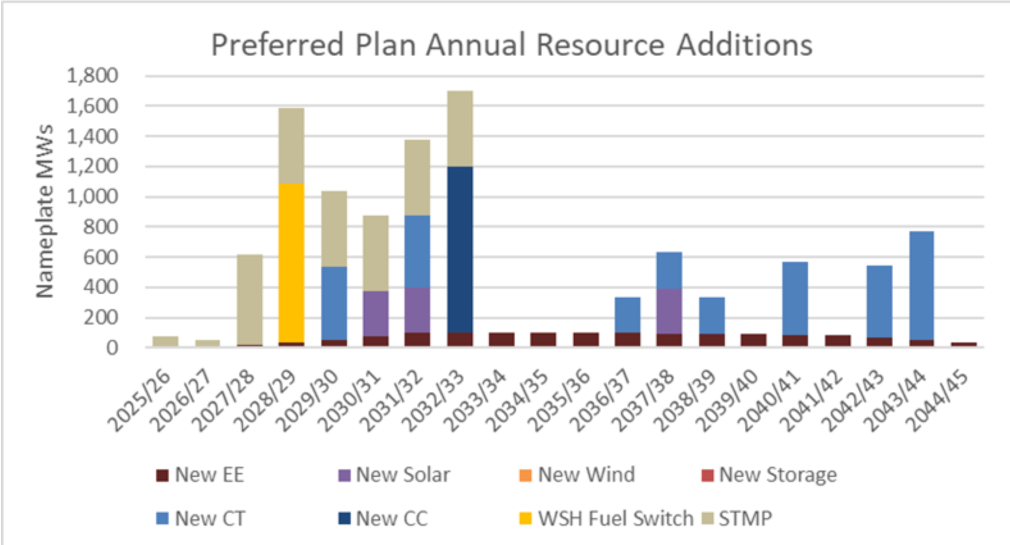


Figure 51: Preferred Plan New Resource Additions

In the Company's Preferred Plan, approximately 0.9GW of new solar, 1.1GW of new natural gas combined cycles (NGCC), and 3.4GW of new natural gas combustion turbines (NGCT) are added by 2044. The portfolio was optimized considering seasonal capacity requirements and market energy risk mitigation, resulting in the selection of market capacity (S-T purchases) and early options through 2029, including the Welsh gas conversions (WSH Fuel Switch) in 2028 and the Hallsville NGCT in 2029. Starting in 2030, solar additions enhance the energy position and provide additional capacity benefits. In 2032, a 1,100MW NGCC addresses significant capacity needs and reduces reliance on market energy. Market energy purchases decline with resource additions from 2030 onwards. After 2032, 2.4GW of NGCTs and 0.3GW of solar are added to further support the capacity and energy needs.

8.5.1 Affordability

The Preferred Plan has one of the lowest short-term growth rates and NPVRR compared to all other portfolios. This can be noted in Table 34 and is discussed in Section 8.4.1. In addition, the Preferred Plan provides lower fixed costs compared to the EER Case and High Case portfolio and is less reliant upon market sales and production tax credit revenues to support the affordability of the portfolio as noted in Figure 49.

8.5.2 Rate Stability

The Preferred Plan has the lowest market energy risk compared to the other portfolios analyzed. This was discussed in Section 8.4.2 and can be noted in Table 38. In the near time, over a six-year period, it is less reliant upon market purchases compared to all other portfolios. In the long term, over a 30-year period, it has the lowest average cost of market purchases and the second lowest average revenue of market sales. The Preferred Plan performs better than the EER Case portfolio under the High Market Scenario in the short- and long-term, indicating it is more resilient to higher commodity prices.

8.5.3 Maintaining Reliability

Given the uncertainty in SPP regarding the final planning reserve margin requirements, the Preferred Plan includes resources that support both seasonal optimization selections and balances customer rate stability risks when considering the associated metrics for this objective. As shown in Table 39, the Preferred Plan includes resources to support both the summer and winter planning reserve margin. 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 26.9% winter reserve margin in 2035 offers SWEPCO's customers reliability benefits when comparing to the High Case and EER case portfolios.

Figure 52 and Figure 53 illustrate how the Preferred Plan meet the summer and winter planning reserve margin, respectively.

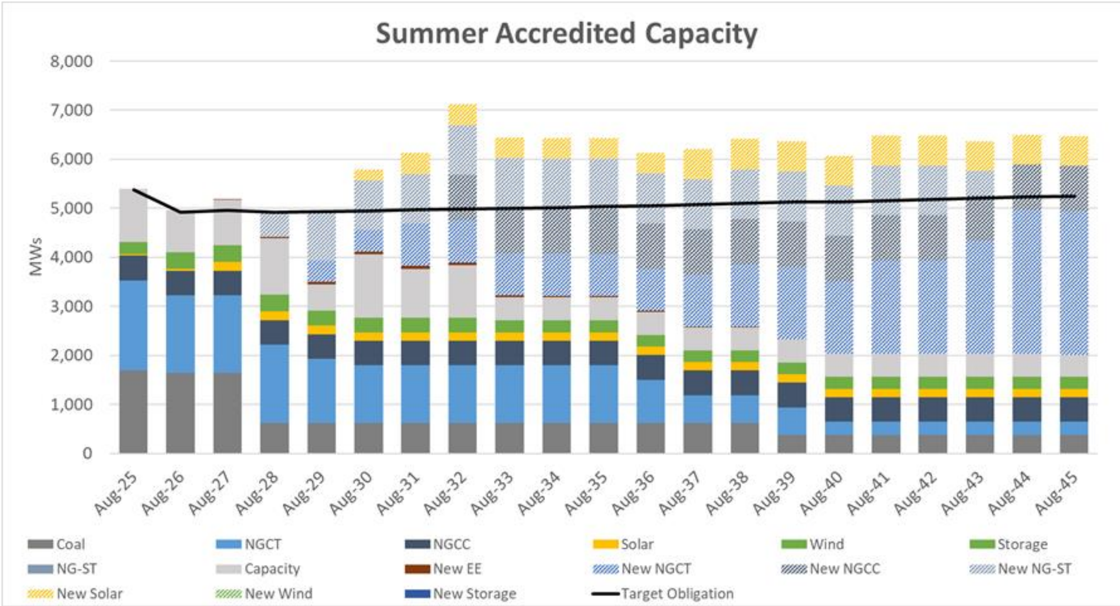


Figure 52: Preferred Plan Summer Accredited Capacity

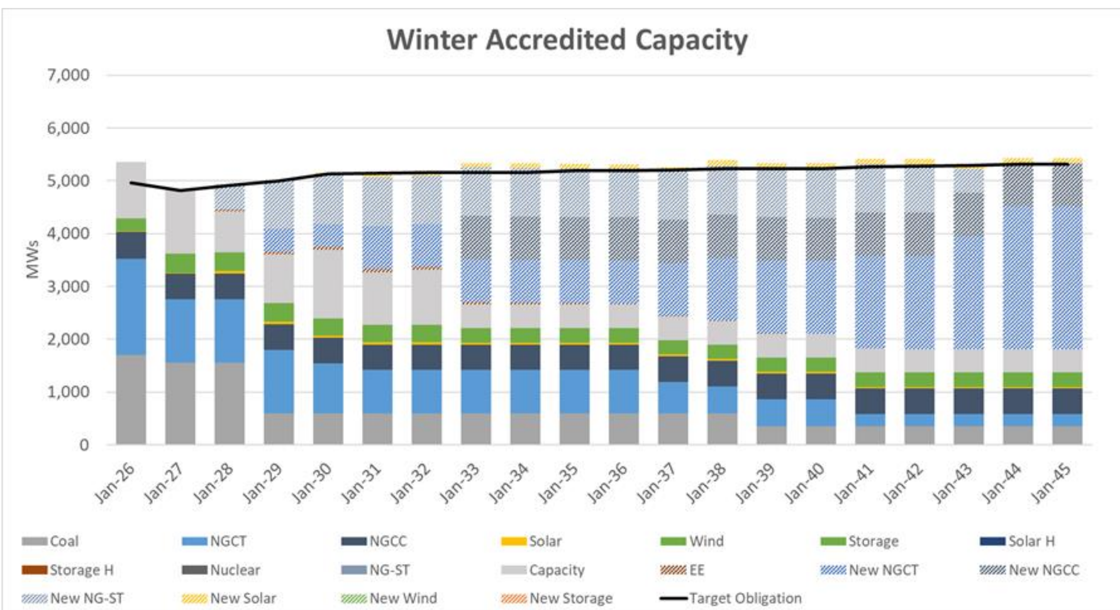


Figure 53: Preferred Plan Winter Accredited Capacity

The Preferred Plan includes dispatchable resources that support the fleet resiliency metric, resulting in the Preferred Plan having the highest dispatchable winter accredited capacity as a percentage of company peak demand in year 2034. The Preferred Plan includes a mix of dispatchable resources capable of providing energy to meet SWEPCOs peak demand in the 10-year forecast.

Lastly, the Preferred Plan includes a mix of diverse resources including new solar resources. The Preferred Plan has one of the highest diversity index values compared to the other portfolios analyzed.

8.5.4 Local Impacts & Sustainability

The Preferred Plan has one of the largest amounts of new resource capacity assumed to be installed within SWEPCO jurisdictions compared to the total resource capacity additions. The Preferred Plan also estimates 81.1% reduction in CO_2 emissions by 2030 compared to the Company's 2005 baseline from energy generated to serve its customers.

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 Portfolio Performance Indicators matrix 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.

9.1 SWEPCO's Preferred Action Plan

Steps which have been or will be taken by SWEPCO in the near future as part of its Proposed Action Plan include:

- Seek regulatory approval for the Hallsville CT and the Welsh Gas Conversion. SWEPCO filed for regulatory approval in December of 2024 under Docket No. 24-052-U.
- If the Hallsville CT is approved by regulators, evaluate adding a steam turbine to convert it to a combined cycle.
- Fill in the near-term capacity needs with short-term capacity contracts. SWEPCO filed for regulatory approval in October of 2024 under Docket No. 24-044-U.
- Evaluate costs and benefits of continuing to operate Arsenal Hill 5, Lieberman 3 and 4, and Wikes 1 beyond their current planning retirement dates.
- Continue to monitor environmental regulations and update the analysis of compliance options as needed consistent with those regulations.
- Remain engaged and responsive to changes in SPP resource adequacy requirements.
- Seek additional capacity as needed; timing and amount will be impacted by all the above. SWEPCO anticipates the need to issue Requests for Proposals in the near term.

10. Appendix

Exhibit A: Load Forecast

Exhibit B: Detailed Generation Technology Modeling Parameters

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

Exhibit D: Annual Overnight Capital Expenditure by Technology Type & Capacity Prices

Exhibit F: Stakeholder Engagement, Comments and Report

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										
2014	6,311	---	5,996	---	5,901	---	7,308	---	25,516	---
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
2023	6,138	-6.1	5,538	-3.4	5,147	-0.5	5,838	-2.5	22,662	-3.3
Forecast										
2024*	6,130	-0.1	5,546	0.1	5,283	2.6	5,776	-1.1	22,735	0.3
2025	6,108	-0.4	5,387	-2.9	4,850	-8.2	5,744	-0.6	22,089	-2.8
2026	6,109	0.0	5,374	-0.2	4,908	1.2	5,799	1.0	22,189	0.5
2027	6,134	0.4	5,378	0.1	4,957	1.0	5,815	0.3	22,284	0.4
2028	6,154	0.3	5,388	0.2	5,011	1.1	5,848	0.6	22,401	0.5
2029	6,167	0.2	5,400	0.2	5,059	1.0	5,890	0.7	22,516	0.5
2030	6,173	0.1	5,385	-0.3	5,106	0.9	5,921	0.5	22,585	0.3
2031	6,188	0.2	5,367	-0.3	5,149	0.9	5,953	0.5	22,657	0.3
2032	6,205	0.3	5,363	-0.1	5,190	0.8	5,987	0.6	22,746	0.4
2033	6,222	0.3	5,359	-0.1	5,233	0.8	6,019	0.5	22,832	0.4
2034	6,235	0.2	5,354	-0.1	5,273	0.8	6,051	0.5	22,913	0.4
2035	6,254	0.3	5,354	0.0	5,312	0.7	6,082	0.5	23,002	0.4
2036	6,275	0.3	5,358	0.1	5,348	0.7	6,115	0.5	23,096	0.4
2037	6,299	0.4	5,362	0.1	5,379	0.6	6,140	0.4	23,180	0.4
2038	6,321	0.4	5,368	0.1	5,408	0.5	6,164	0.4	23,263	0.4
2039	6,346	0.4	5,376	0.2	5,438	0.6	6,190	0.4	23,350	0.4
2040	6,367	0.3	5,385	0.2	5,466	0.5	6,217	0.4	23,436	0.4
2041	6,390	0.4	5,397	0.2	5,491	0.5	6,243	0.4	23,522	0.4
2042	6,415	0.4	5,409	0.2	5,517	0.5	6,268	0.4	23,609	0.4
2043	6,440	0.4	5,421	0.2	5,543	0.5	6,292	0.4	23,696	0.4
2044	6,469	0.5	5,438	0.3	5,569	0.5	6,316	0.4	23,792	0.4

Note: *2024 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 2014-2023

	Residential	Commercial	Industrial	Other** Energy Requirements	Internal Energy Requirements
	-0.3	-0.9	-1.5	-2.5	-1.3

Compound Annual Growth Rate 2025-44

	Residential	Commercial	Industrial	Other** Energy Requirements	Internal Energy Requirements
	0.3	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										
2014	1,121	---	1,343	---	1,543	---	12	---	4,019	---
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
2023	1,132	-6.9	1,262	-3.9	1,146	0.4	8	-12.2	3,548	-3.6
Forecast										
2024*	1,143	1.0	1,271	0.7	1,126	-1.7	8	-3.1	3,548	0.0
2025	1,152	0.7	1,246	-2.0	1,137	1.0	8	1.7	3,543	-0.2
2026	1,154	0.2	1,246	0.0	1,143	0.6	8	-0.4	3,552	0.3
2027	1,162	0.7	1,250	0.3	1,147	0.4	8	0.2	3,567	0.4
2028	1,168	0.5	1,259	0.7	1,153	0.5	8	0.0	3,589	0.6
2029	1,174	0.5	1,273	1.1	1,160	0.5	8	-0.1	3,614	0.7
2030	1,178	0.4	1,273	0.0	1,165	0.4	8	0.0	3,624	0.3
2031	1,184	0.5	1,272	0.0	1,169	0.4	8	0.0	3,634	0.3
2032	1,189	0.4	1,275	0.2	1,174	0.4	8	0.0	3,646	0.3
2033	1,194	0.4	1,277	0.2	1,179	0.4	8	0.0	3,658	0.3
2034	1,198	0.4	1,279	0.2	1,184	0.4	8	0.0	3,669	0.3
2035	1,202	0.4	1,282	0.2	1,189	0.4	8	0.0	3,681	0.3
2036	1,206	0.3	1,286	0.3	1,193	0.4	8	0.0	3,694	0.4
2037	1,210	0.3	1,290	0.3	1,198	0.4	8	0.0	3,706	0.3
2038	1,214	0.3	1,294	0.3	1,202	0.3	8	0.0	3,718	0.3
2039	1,218	0.3	1,299	0.4	1,205	0.3	8	0.0	3,730	0.3
2040	1,221	0.3	1,304	0.4	1,209	0.3	8	0.0	3,742	0.3
2041	1,225	0.3	1,309	0.4	1,213	0.3	8	0.0	3,755	0.3
2042	1,228	0.3	1,315	0.5	1,217	0.3	8	0.0	3,769	0.4
2043	1,231	0.3	1,321	0.4	1,221	0.4	8	0.0	3,782	0.4
2044	1,235	0.3	1,328	0.5	1,226	0.4	8	0.0	3,797	0.4

Note: *2024 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 2014-2023

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.1	-0.7	-3.3	-3.5	-1.4

Compound Annual Growth Rate 2025-2044

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.4	0.3	0.4	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										
2014	2,991	---	2,406	---	1,034	---	40	---	6,472	---
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
2023	2,876	-5.1	2,195	-3.7	1,158	-2.8	36	-4.3	6,265	-4.2
Forecast										
2024*	2,838	-1.3	2,185	-0.4	1,201	3.7	37	0.1	6,260	-0.1
2025	2,799	-1.4	2,113	-3.3	1,198	-0.3	37	0.3	6,145	-1.8
2026	2,789	-0.3	2,093	-0.9	1,198	0.0	37	-0.2	6,117	-0.5
2027	2,792	0.1	2,082	-0.5	1,204	0.5	37	0.1	6,115	0.0
2028	2,794	0.0	2,072	-0.5	1,212	0.7	37	0.0	6,115	0.0
2029	2,792	0.0	2,064	-0.4	1,217	0.4	37	0.0	6,110	-0.1
2030	2,788	-0.1	2,049	-0.7	1,222	0.4	37	0.0	6,096	-0.2
2031	2,784	-0.2	2,033	-0.8	1,226	0.3	37	0.0	6,079	-0.3
2032	2,783	0.0	2,024	-0.5	1,230	0.3	37	0.0	6,073	-0.1
2033	2,782	0.0	2,015	-0.5	1,234	0.3	37	0.0	6,067	-0.1
2034	2,780	-0.1	2,006	-0.4	1,239	0.4	37	0.0	6,061	-0.1
2035	2,781	0.0	2,000	-0.3	1,243	0.4	37	0.0	6,060	0.0
2036	2,784	0.1	1,995	-0.2	1,247	0.3	37	0.0	6,063	0.0
2037	2,787	0.1	1,991	-0.2	1,251	0.3	37	0.0	6,066	0.1
2038	2,791	0.1	1,989	-0.1	1,255	0.3	37	0.0	6,071	0.1
2039	2,794	0.1	1,987	-0.1	1,258	0.3	37	0.0	6,076	0.1
2040	2,797	0.1	1,985	-0.1	1,262	0.3	37	0.0	6,080	0.1
2041	2,800	0.1	1,985	0.0	1,265	0.2	37	0.0	6,086	0.1
2042	2,803	0.1	1,985	0.0	1,268	0.2	37	0.0	6,092	0.1
2043	2,807	0.1	1,984	0.0	1,271	0.2	37	0.0	6,099	0.1
2044	2,812	0.2	1,986	0.1	1,274	0.2	37	0.0	6,109	0.2

Note: *2024 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 2014-2023	-0.4	-1.0	1.3	-1.0	-0.4
Compound Annual Growth Rate 2025-2044	0.0	-0.3	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										
2014	2,198	---	2,247	---	3,324	---	29	---	7,798	---
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
2023	2,130	-7.1	2,082	-2.7	2,844	0.0	26	-2.9	7,081	-3.0
Forecast										
2024*	2,149	0.9	2,090	0.4	2,956	3.9	26	-1.0	7,220	2.0
2025	2,158	0.4	2,028	-3.0	2,516	-14.9	26	1.3	6,728	-6.8
2026	2,165	0.3	2,035	0.4	2,567	2.0	26	0.0	6,793	1.0
2027	2,179	0.7	2,046	0.5	2,606	1.5	26	0.1	6,857	0.9
2028	2,192	0.6	2,057	0.5	2,645	1.5	26	0.0	6,920	0.9
2029	2,201	0.4	2,064	0.4	2,682	1.4	26	-0.1	6,973	0.8
2030	2,207	0.3	2,063	0.0	2,719	1.4	26	0.0	7,015	0.6
2031	2,220	0.6	2,062	-0.1	2,754	1.3	26	0.0	7,062	0.7
2032	2,234	0.6	2,065	0.2	2,787	1.2	26	0.0	7,112	0.7
2033	2,246	0.6	2,067	0.1	2,820	1.2	26	0.0	7,160	0.7
2034	2,257	0.5	2,069	0.1	2,851	1.1	26	0.0	7,203	0.6
2035	2,271	0.6	2,072	0.2	2,880	1.0	26	0.0	7,249	0.6
2036	2,285	0.6	2,077	0.2	2,907	0.9	26	0.0	7,295	0.6
2037	2,301	0.7	2,081	0.2	2,930	0.8	26	0.0	7,338	0.6
2038	2,317	0.7	2,086	0.2	2,952	0.7	26	0.0	7,381	0.6
2039	2,333	0.7	2,091	0.3	2,975	0.8	26	0.0	7,425	0.6
2040	2,349	0.7	2,097	0.3	2,996	0.7	26	0.0	7,467	0.6
2041	2,366	0.7	2,103	0.3	3,014	0.6	26	0.0	7,509	0.6
2042	2,383	0.7	2,110	0.3	3,033	0.6	26	0.0	7,551	0.6
2043	2,401	0.8	2,116	0.3	3,051	0.6	26	0.0	7,594	0.6
2044	2,422	0.9	2,124	0.4	3,069	0.6	26	0.0	7,641	0.6

Note: *2024 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 2014-2023	-0.3	-0.8	-1.7	-1.2	-1.1
Compound Annual Growth Rate 2025-2044	0.6	0.2	1.1	0.0	0.7

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					
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	56.5
2017	4,769	4,419	4,769	23,884	57.0
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	57.2
2021	4,444	4,563	4,563	22,049	55.0
2022	4,838	3,896	4,918	23,434	54.4
2023	4,886	4,918	4,886	22,662	53.0
Forecast					
2024*	4,627	4,845	4,845	22,735	53.6
2025	4,563	4,293	4,563	22,089	55.1
2026	4,584	4,309	4,584	22,189	55.3
2027	4,606	4,324	4,606	22,284	55.2
2028	4,635	4,340	4,635	22,401	55.2
2029	4,653	4,371	4,653	22,516	55.1
2030	4,669	4,381	4,669	22,585	55.2
2031	4,687	4,392	4,687	22,657	55.2
2032	4,695	4,401	4,695	22,746	55.3
2033	4,714	4,418	4,714	22,832	55.1
2034	4,727	4,439	4,727	22,913	55.3
2035	4,748	4,452	4,748	23,002	55.3
2036	4,760	4,468	4,760	23,096	55.4
2037	4,780	4,477	4,780	23,180	55.2
2038	4,803	4,487	4,803	23,263	55.3
2039	4,827	4,500	4,827	23,350	55.2
2040	4,829	4,518	4,829	23,436	55.4
2041	4,852	4,534	4,852	23,522	55.2
2042	4,875	4,547	4,875	23,609	55.3
2043	4,896	4,561	4,896	23,696	55.3
2044	4,923	4,571	4,923	23,792	55.2

Note: *2024 data are six months acutal and six months forecast.

	Summer Peak Demand	Preceding Winter Peak Demand	Annual Peak Demand	Internal Energy Requirements	Load Factor
Compound Annual Growth Rate 2014-2023					
	0.1	0.0	-0.1	-1.3	-1.2
Compound Annual Growth Rate 2025-2044					
	0.4	0.3	0.4	0.4	0.0

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
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
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

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
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
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

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
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	342.7	1,814.2
2023	6	573.4	511.6	425.7	531.0	2,041.7
2023	7	754.8	570.6	439.9	604.4	2,369.7
2023	8	859.9	647.0	462.3	628.0	2,597.2
2023	9	565.7	470.9	410.6	574.4	2,021.5
2023	10	389.7	447.1	427.4	407.7	1,672.0
2023	11	346.6	411.5	432.0	433.9	1,623.9
2023	12	499.5	410.6	412.1	496.6	1,818.7
2024	1	736.0	473.4	407.3	587.0	2,203.7
2024	2	422.1	352.5	351.9	475.6	1,602.1
2024	3	351.0	413.7	468.0	369.1	1,601.8
2024	4	350.3	416.7	456.0	415.8	1,638.8
2024	5	409.1	451.2	545.3	476.2	1,881.8
2024	6	631.5	562.0	412.7	516.6	2,122.8

*Other energy requirements include other retail sales, wholesale sales and losse:

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
2024	7	700.4	541.7	438.0	596.4	2,276.5
2024	8	747.4	598.4	474.1	522.6	2,342.5
2024	9	523.9	473.6	415.6	508.0	1,921.1
2024	10	369.6	438.0	444.6	400.6	1,652.8
2024	11	340.0	404.0	446.3	431.7	1,621.9
2024	12	548.5	420.7	423.0	476.8	1,869.0
2025	1	650.7	427.7	371.6	538.0	1,988.0
2025	2	504.4	368.5	346.6	514.0	1,733.5
2025	3	421.3	386.9	385.9	439.4	1,633.5
2025	4	317.6	382.8	405.2	401.3	1,506.9
2025	5	427.3	474.0	451.3	375.6	1,728.2
2025	6	544.7	484.7	412.8	543.8	1,986.0
2025	7	699.6	540.5	412.1	591.6	2,243.7
2025	8	735.8	585.0	441.6	545.4	2,307.9
2025	9	529.5	468.9	388.4	508.7	1,895.4
2025	10	374.1	435.6	415.9	395.2	1,620.8
2025	11	344.1	403.6	417.7	431.2	1,596.6
2025	12	559.3	428.4	400.9	459.4	1,848.1
2026	1	645.9	422.2	375.7	549.0	1,992.8
2026	2	504.0	367.4	352.2	517.1	1,740.7
2026	3	422.7	385.5	391.2	442.6	1,642.0
2026	4	317.9	381.2	409.9	404.4	1,513.4
2026	5	424.2	468.9	453.4	384.6	1,731.1
2026	6	547.7	485.0	418.4	547.2	1,998.4
2026	7	706.2	544.6	419.2	583.5	2,253.5
2026	8	757.7	602.1	455.2	503.5	2,318.5
2026	9	528.9	470.4	394.3	511.8	1,905.4
2026	10	357.9	423.2	415.0	429.1	1,625.3
2026	11	344.1	403.1	422.7	441.2	1,611.1
2026	12	551.4	420.0	400.5	484.8	1,856.7
2027	1	651.0	423.9	380.4	542.0	1,997.4
2027	2	505.6	366.5	355.2	520.0	1,747.2
2027	3	431.6	391.0	398.1	446.8	1,667.5
2027	4	317.8	380.3	413.4	407.0	1,518.6
2027	5	424.5	467.8	456.5	389.5	1,738.3
2027	6	549.4	485.5	422.0	550.1	2,007.0
2027	7	706.8	544.6	422.5	585.6	2,259.5
2027	8	747.6	594.2	454.9	536.1	2,332.8
2027	9	530.5	470.4	398.5	514.6	1,914.0
2027	10	367.1	429.1	422.4	410.3	1,629.0
2027	11	343.9	400.5	425.6	434.9	1,604.9
2027	12	557.9	423.7	407.8	478.2	1,867.6

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
2028	1	649.4	421.6	383.0	548.6	2,002.5
2028	2	537.0	389.8	372.5	528.3	1,827.6
2028	3	427.7	389.0	401.2	449.1	1,667.1
2028	4	312.2	378.6	417.0	409.2	1,517.1
2028	5	411.4	453.9	451.2	435.2	1,751.7
2028	6	549.4	484.6	425.5	552.8	2,012.3
2028	7	710.8	547.4	427.9	574.6	2,260.8
2028	8	750.0	595.8	459.6	535.9	2,341.3
2028	9	527.4	467.9	401.1	516.9	1,913.3
2028	10	370.9	431.9	427.9	404.9	1,635.6
2028	11	345.3	401.1	430.0	435.2	1,611.7
2028	12	562.5	426.7	413.8	456.8	1,859.8
2029	1	654.5	424.6	388.1	558.4	2,025.5
2029	2	509.0	368.3	363.0	526.0	1,766.3
2029	3	429.4	389.0	404.0	452.0	1,674.4
2029	4	318.8	380.9	420.9	412.8	1,533.3
2029	5	429.9	473.3	467.5	394.8	1,765.6
2029	6	551.3	486.6	430.3	556.1	2,024.2
2029	7	711.8	548.2	432.0	591.2	2,283.2
2029	8	756.0	600.5	465.7	538.1	2,360.2
2029	9	529.5	469.9	405.6	520.2	1,925.1
2029	10	368.4	430.3	430.8	425.3	1,654.8
2029	11	345.2	401.4	433.6	448.3	1,628.5
2029	12	563.2	427.5	417.6	466.9	1,875.2
2030	1	655.0	423.6	392.0	561.3	2,032.0
2030	2	508.9	367.1	366.4	528.8	1,771.2
2030	3	427.1	385.8	406.3	454.4	1,673.6
2030	4	320.1	380.4	424.9	415.8	1,541.3
2030	5	433.9	476.2	474.0	385.8	1,769.9
2030	6	550.7	484.1	433.7	556.8	2,025.3
2030	7	712.8	546.6	436.1	598.5	2,294.0
2030	8	754.6	596.8	468.8	543.1	2,363.3
2030	9	531.8	469.2	410.1	523.4	1,934.5
2030	10	369.1	429.2	434.8	428.0	1,661.2
2030	11	346.1	400.9	437.8	449.8	1,634.6
2030	12	563.2	425.3	420.9	475.1	1,884.5
2031	1	655.7	421.8	395.6	564.1	2,037.2
2031	2	509.8	365.3	369.5	531.6	1,776.2
2031	3	427.7	384.1	409.5	454.6	1,675.8
2031	4	320.5	378.5	428.1	418.6	1,545.7
2031	5	436.3	476.7	478.8	378.7	1,770.5
2031	6	552.6	483.0	437.9	561.8	2,035.3
2031	7	713.4	543.5	439.3	605.7	2,301.9
2031	8	757.2	595.4	472.9	541.8	2,367.3
2031	9	535.3	468.8	414.5	526.5	1,945.2
2031	10	367.6	425.6	437.4	436.8	1,667.4
2031	11	346.9	399.8	441.2	452.2	1,640.1
2031	12	565.0	424.5	424.6	480.8	1,894.9

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
2032	1	653.6	417.7	396.8	563.6	2,031.7
2032	2	540.9	387.5	385.9	539.7	1,854.1
2032	3	432.6	388.6	416.3	460.9	1,698.4
2032	4	315.7	378.3	432.9	421.0	1,547.9
2032	5	414.2	452.5	466.4	436.1	1,769.2
2032	6	553.7	482.4	441.3	564.5	2,041.9
2032	7	715.7	543.6	443.0	596.4	2,298.7
2032	8	759.6	595.5	476.6	540.1	2,371.9
2032	9	534.1	466.1	416.7	528.8	1,945.7
2032	10	371.4	427.7	442.1	416.9	1,658.0
2032	11	347.6	399.6	444.6	439.3	1,631.0
2032	12	566.1	423.9	427.8	479.9	1,897.8
2033	1	658.3	419.5	401.5	569.6	2,049.0
2033	2	512.8	364.4	375.8	537.3	1,790.3
2033	3	436.4	388.6	419.3	464.1	1,708.4
2033	4	320.0	376.5	434.4	423.9	1,554.8
2033	5	436.4	474.1	484.6	389.8	1,784.9
2033	6	557.3	484.1	446.2	567.9	2,055.5
2033	7	715.4	541.0	445.5	608.4	2,310.4
2033	8	760.9	594.5	480.1	556.9	2,392.5
2033	9	538.2	467.5	421.4	532.3	1,959.4
2033	10	370.3	425.5	444.9	430.4	1,671.1
2033	11	348.4	399.4	448.2	450.9	1,646.9
2033	12	567.3	423.6	431.3	486.9	1,909.1
2034	1	661.2	420.3	405.7	572.9	2,060.1
2034	2	513.4	363.6	378.8	540.1	1,795.9
2034	3	435.6	386.9	421.9	466.6	1,711.0
2034	4	319.2	374.7	436.8	426.4	1,557.1
2034	5	438.7	475.5	489.1	391.7	1,795.0
2034	6	558.7	483.8	449.7	570.8	2,063.0
2034	7	716.7	540.2	448.7	613.9	2,319.5
2034	8	762.8	594.2	483.6	561.5	2,402.1
2034	9	538.2	465.8	424.1	534.8	1,962.9
2034	10	372.2	426.0	448.6	435.5	1,682.3
2034	11	349.2	399.2	451.5	456.8	1,656.7
2034	12	569.1	423.7	434.7	479.7	1,907.2
2035	1	662.9	419.9	408.6	575.6	2,067.1
2035	2	514.6	363.1	381.5	542.8	1,802.0
2035	3	433.6	383.9	423.2	468.7	1,709.4
2035	4	321.4	375.1	440.1	429.3	1,565.9
2035	5	442.8	478.7	494.5	386.0	1,802.0
2035	6	558.9	482.4	452.3	573.3	2,066.9
2035	7	720.0	541.4	452.7	619.4	2,333.5
2035	8	765.3	594.5	487.2	565.3	2,412.3
2035	9	538.9	464.8	426.9	537.4	1,968.1
2035	10	374.3	426.6	452.2	441.6	1,694.7
2035	11	350.4	399.5	454.7	461.0	1,665.6
2035	12	570.9	423.9	437.9	481.9	1,914.6

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
2036	1	662.3	418.1	410.3	577.9	2,068.6
2036	2	539.0	380.6	394.5	549.6	1,863.7
2036	3	430.3	381.7	425.0	470.8	1,707.7
2036	4	320.7	376.6	444.6	432.1	1,574.1
2036	5	431.3	465.8	488.8	415.4	1,801.4
2036	6	559.1	481.3	454.5	575.7	2,070.6
2036	7	723.8	543.1	456.5	618.0	2,341.4
2036	8	768.1	595.3	490.5	552.9	2,406.8
2036	9	541.3	465.4	430.1	540.1	1,976.8
2036	10	374.9	426.4	454.9	439.1	1,695.3
2036	11	351.7	399.9	457.7	455.9	1,665.2
2036	12	572.6	424.0	440.5	487.0	1,924.1
2037	1	665.4	418.8	413.3	580.6	2,078.1
2037	2	518.1	363.3	386.7	548.0	1,816.0
2037	3	438.7	386.0	429.6	461.9	1,716.2
2037	4	325.1	376.9	446.6	434.7	1,583.3
2037	5	445.3	479.2	500.1	383.0	1,807.7
2037	6	564.6	485.0	459.1	578.8	2,087.5
2037	7	722.7	540.2	457.1	635.9	2,355.9
2037	8	771.0	596.0	493.2	562.2	2,422.4
2037	9	546.2	467.9	433.7	542.9	1,990.7
2037	10	373.8	424.4	456.3	448.1	1,702.6
2037	11	352.9	399.9	460.0	469.5	1,682.3
2037	12	574.9	424.4	443.1	494.6	1,937.1
2038	1	665.7	417.6	414.8	582.4	2,080.5
2038	2	519.4	363.0	388.6	550.0	1,821.0
2038	3	442.8	388.2	433.1	476.8	1,740.9
2038	4	325.7	376.7	448.7	436.6	1,587.7
2038	5	447.5	480.6	503.2	382.7	1,814.1
2038	6	566.8	485.8	461.7	581.0	2,095.3
2038	7	725.2	540.9	459.6	634.9	2,360.7
2038	8	773.5	596.8	495.8	570.2	2,436.3
2038	9	548.6	468.8	436.2	545.1	1,998.8
2038	10	375.1	424.8	458.8	446.2	1,704.9
2038	11	354.4	400.6	462.6	458.1	1,675.8
2038	12	576.6	424.5	445.2	500.2	1,946.5
2039	1	669.5	418.9	417.8	584.9	2,091.1
2039	2	520.9	362.9	390.6	552.1	1,826.5
2039	3	443.5	387.8	435.0	477.4	1,743.6
2039	4	325.2	375.1	449.9	438.4	1,588.6
2039	5	451.2	483.6	507.3	382.8	1,824.9
2039	6	569.1	486.9	464.4	583.4	2,103.8
2039	7	727.8	541.9	462.1	634.6	2,366.5
2039	8	776.1	597.9	498.4	578.5	2,450.9
2039	9	551.0	469.8	438.8	547.5	2,007.1
2039	10	376.5	425.3	461.2	449.5	1,712.5
2039	11	355.8	401.2	465.1	462.8	1,684.9
2039	12	579.0	425.2	447.8	497.7	1,949.6

Exhibit A-5.5

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

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2040	1	670.2	418.4	419.3	585.8	2,093.7
2040	2	553.6	387.1	406.6	559.9	1,907.2
2040	3	436.5	383.4	434.8	479.8	1,734.5
2040	4	322.2	375.9	453.3	440.4	1,591.8
2040	5	435.8	467.0	498.2	431.5	1,832.4
2040	6	567.8	484.7	465.1	585.0	2,102.7
2040	7	733.4	545.7	466.2	628.0	2,373.3
2040	8	778.8	599.0	500.9	573.8	2,452.4
2040	9	547.0	465.4	438.5	548.7	1,999.5
2040	10	383.5	430.6	465.9	440.5	1,720.5
2040	11	357.1	402.0	467.4	461.2	1,687.8
2040	12	581.3	426.1	450.1	482.4	1,939.9
2041	1	676.3	421.7	423.0	589.8	2,110.8
2041	2	524.9	364.1	394.7	556.6	1,840.3
2041	3	444.6	387.6	438.5	469.9	1,740.5
2041	4	329.0	378.3	455.6	443.2	1,606.1
2041	5	452.1	483.3	510.7	397.7	1,843.8
2041	6	570.5	486.3	467.7	587.4	2,112.0
2041	7	735.1	546.0	467.8	644.8	2,393.8
2041	8	781.9	600.5	503.3	579.6	2,465.3
2041	9	553.2	469.8	442.2	551.7	2,016.9
2041	10	380.9	428.4	466.3	457.9	1,733.5
2041	11	358.5	403.4	469.6	468.6	1,700.1
2041	12	583.4	427.5	452.2	495.4	1,958.5
2042	1	677.9	422.3	424.6	592.0	2,116.8
2042	2	526.3	364.7	396.3	558.7	1,846.1
2042	3	448.1	390.1	441.4	463.6	1,743.1
2042	4	329.9	378.9	457.5	445.3	1,611.7
2042	5	454.0	484.9	513.2	393.5	1,845.6
2042	6	574.2	488.8	470.7	590.0	2,123.8
2042	7	736.0	545.2	469.0	653.2	2,403.4
2042	8	784.9	601.7	505.6	578.8	2,471.1
2042	9	557.6	472.3	445.2	554.3	2,029.4
2042	10	380.2	427.5	467.5	465.3	1,740.4
2042	11	359.9	404.4	471.8	471.9	1,708.0
2042	12	585.6	428.5	454.3	501.7	1,970.1
2043	1	678.7	421.8	425.7	593.9	2,120.2
2043	2	528.0	365.2	398.0	560.8	1,852.0
2043	3	452.5	392.9	444.5	459.9	1,749.8
2043	4	330.7	379.3	459.3	447.3	1,616.7
2043	5	456.2	486.6	516.0	388.8	1,847.6
2043	6	578.1	491.4	473.9	592.6	2,136.0
2043	7	737.7	545.0	470.5	659.2	2,412.4
2043	8	787.0	602.0	507.6	584.4	2,481.0
2043	9	560.6	473.7	447.7	556.6	2,038.6
2043	10	381.2	427.9	469.5	464.9	1,743.4
2043	11	361.2	405.2	473.8	480.3	1,720.5
2043	12	588.1	429.9	456.5	503.2	1,977.7
2044	1	681.3	422.5	427.5	584.3	2,115.7
2044	2	561.6	390.0	413.9	568.6	1,934.0
2044	3	446.9	389.8	444.6	489.1	1,770.4
2044	4	326.3	379.0	461.5	448.9	1,615.6
2044	5	441.0	470.2	506.4	438.3	1,855.9
2044	6	578.8	491.3	475.2	594.4	2,139.7
2044	7	742.1	547.8	473.5	642.8	2,406.2
2044	8	790.8	604.2	510.1	586.0	2,491.1
2044	9	559.9	472.5	448.4	558.2	2,039.0
2044	10	386.6	432.3	473.3	446.6	1,738.8
2044	11	363.0	406.9	476.2	462.4	1,708.5
2044	12	590.7	431.3	458.5	496.9	1,977.4

Exhibit A-6

Southwestern Electric Power Company
Actual and Weather Normal Energy Sales (GWh)
And Peak Demand (MW) vs. 2021 IRP Forecast

	2021 IRP Forecast			Actual			Difference			% Difference		
	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
Residential	6,347	6,357	6,360	6,205	6,538	6,138	142	-181	222	2.3%	-2.8%	3.6%
Commercial	5,494	5,468	5,472	5,489	5,732	5,538	5	-263	-66	0.1%	-4.6%	-1.2%
Industrial	4,690	4,729	4,755	4,682	5,174	5,147	8	-445	-392	0.2%	-8.6%	-7.6%
Other Retail	79	79	79	77	75	71	2	4	8	2.3%	5.7%	11.2%
Wholesale	4,615	4,688	4,737	4,523	4,824	4,598	92	-136	139	2.0%	-2.8%	3.0%
Total Sales	21,224	21,322	21,403	20,975	22,343	21,493	249	-1,021	-89	1.2%	-4.6%	-0.4%

	2021 IRP Forecast			Normal			Difference			% Difference		
	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
Residential	6,347	6,357	6,360	6,176	6,185	6,094	170	173	266	2.8%	2.8%	4.4%
Commercial	5,494	5,468	5,472	5,445	5,576	5,451	49	-107	21	0.9%	-1.9%	0.4%
Industrial	4,690	4,729	4,755	4,682	5,174	5,147	8	-445	-392	0.2%	-8.6%	-7.6%
Other Retail	79	79	79	77	75	71	2	4	8	2.3%	5.7%	11.2%
Wholesale	4,615	4,688	4,737	4,522	4,800	4,584	93	-113	153	2.1%	-2.3%	3.3%
Total Sales	21,224	21,322	21,403	20,902	21,809	21,348	322	-488	56	1.5%	-2.2%	0.3%

	2021 IRP Forecast			Actual			Difference			% Difference		
	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
Winter Peak	4,563	4,238	4,253	4,563	3,896	4,918	0	341	-665	0.0%	8.8%	-13.5%
Summer Peak	4,556	4,555	4,563	4,444	4,838	4,886	112	-283	-323	2.5%	-5.8%	-6.6%

	2021 IRP Forecast			Normal			Difference			% Difference		
	2021	2022	2023	2021	2022	2023	2021	2022	2023	2021	2022	2023
Winter Peak	4,563	4,238	4,253	4,159	4,197	4,323	404	40	-70	9.7%	1.0%	-1.6%
Summer Peak	4,556	4,555	4,563	4,595	4,607	4,610	-39	-52	-47	-0.8%	-1.1%	-1.0%

Exhibit A-7

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in 2021 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
2021	16.2	2.9	3.4	10.8	1.7	2.5	5.4	1.1	0.9	0.0	0.0	0.0
2022	25.4	4.8	5.5	19.1	3.4	4.5	6.3	1.4	1.0	0.1	0.0	0.0
2023	19.7	3.4	4.0	15.6	2.4	3.6	3.6	1.0	0.3	0.5	0.0	0.1
2024	17.3	2.1	1.7	13.8	1.4	1.5	2.6	0.7	0.2	0.9	0.0	0.1
2025	14.9	1.5	1.6	11.9	0.9	1.3	2.2	0.5	0.2	0.8	0.0	0.1
2026	5.6	0.5	0.6	4.2	0.2	0.5	1.3	0.3	0.1	0.2	0.0	0.0
2027	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	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

***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	16,437.3	238.5	572.4	16,353.2	245.9	784.8	21,804.1
1996	582.1	17,208.3	245.8	573.6	16,568.9	247.2	796.2	22,775.0
1997	593.8	18,016.5	252.3	574.1	16,900.8	248.5	804.8	24,095.2
1998	602.5	19,217.9	257.7	573.0	17,427.3	249.3	813.4	25,266.9
1999	613.6	20,058.8	262.8	575.5	17,766.8	250.2	819.5	25,804.8
2000	627.3	20,899.6	268.4	577.2	18,296.0	251.6	825.4	26,948.5
2001	636.3	21,501.9	273.6	576.6	19,510.2	253.9	830.1	27,984.9
2002	647.0	21,915.1	279.3	576.7	19,819.3	256.2	837.4	28,233.0
2003	659.7	22,843.4	285.4	575.9	20,071.8	258.5	845.2	28,832.8
2004	672.9	24,755.6	292.5	579.9	20,424.4	262.6	853.1	29,371.1
2005	690.0	25,838.1	300.9	583.4	21,595.6	261.6	861.1	30,764.9
2006	708.5	27,242.2	311.5	589.7	22,264.9	249.0	873.9	32,221.3
2007	722.3	28,582.6	319.0	589.7	22,330.6	258.4	882.2	33,018.3
2008	733.4	29,863.3	324.0	590.3	24,739.7	263.8	890.2	36,716.4
2009	743.7	28,477.0	327.5	596.1	23,860.9	266.9	900.5	34,828.9
2010	755.6	29,317.9	330.8	603.4	25,240.4	268.7	907.8	36,699.2
2011	766.0	32,085.2	333.0	604.6	25,411.8	270.7	912.6	38,941.3
2012	776.0	35,313.4	335.0	607.9	25,431.0	272.9	914.9	38,968.0
2013	786.0	34,597.3	337.5	603.3	25,009.4	275.2	916.9	38,823.8
2014	795.6	37,831.5	340.3	600.0	25,202.0	277.5	918.4	39,935.7
2015	807.5	39,910.1	343.7	596.6	24,940.9	279.9	918.7	38,600.4
2016	818.5	41,339.3	347.8	593.4	24,429.5	282.2	921.4	37,352.2
2017	829.9	42,510.6	352.8	590.8	24,492.1	284.9	925.2	39,088.6
2018	837.8	44,475.9	357.9	586.9	25,145.9	287.1	931.2	40,366.3
2019	845.9	43,062.7	363.4	583.3	25,159.7	289.1	934.7	41,002.9
2020	852.8	45,117.4	369.5	580.1	27,151.8	291.1	940.2	42,791.7
2021	864.4	48,873.2	376.2	575.5	27,416.0	293.1	949.0	45,269.2
2022	878.4	47,998.5	383.0	572.2	25,569.0	295.2	956.8	44,514.9
2023	887.9	49,290.2	390.1	571.7	25,643.7	296.9	963.3	44,781.6
2024	897.5	50,691.7	397.4	571.4	25,838.5	298.9	968.6	45,615.5
2025	907.2	52,169.5	404.1	570.7	26,138.3	301.1	973.4	46,698.4
2026	916.7	53,625.7	411.1	569.8	26,493.8	303.5	978.3	48,025.8
2027	925.9	55,182.6	418.3	568.6	26,865.5	306.0	983.2	49,517.9
2028	934.9	56,765.5	425.4	567.0	27,227.6	308.5	988.2	51,012.4
2029	943.8	58,295.9	432.0	565.3	27,541.6	310.9	993.4	52,422.9
2030	952.6	59,674.0	438.3	563.4	27,794.0	313.3	998.7	53,851.1
2031	961.4	61,079.4	444.2	561.5	28,037.6	315.5	1,004.1	55,376.9
2032	970.2	62,451.6	449.8	559.5	28,259.8	317.6	1,009.5	56,942.8
2033	978.9	63,886.5	455.0	557.4	28,490.1	319.5	1,014.7	58,429.7
2034	987.5	65,317.7	459.9	555.4	28,677.5	321.4	1,019.8	59,879.0
2035	996.0	66,747.2	464.4	553.3	28,845.7	323.2	1,024.7	61,326.8
2036	1,004.4	68,186.6	468.7	551.2	28,996.8	324.9	1,029.4	62,770.4
2037	1,012.7	69,617.3	472.8	549.2	29,134.8	326.5	1,033.8	64,204.6
2038	1,020.9	71,062.6	476.7	547.0	29,268.9	328.0	1,038.1	65,661.7
2039	1,028.8	72,509.5	480.3	544.9	29,389.4	329.5	1,042.3	67,127.1
2040	1,036.6	73,958.5	483.7	542.7	29,503.3	330.9	1,046.3	68,598.9
2041	1,044.0	75,425.0	487.0	540.4	29,623.6	332.2	1,050.3	70,106.6
2042	1,051.2	76,911.0	490.0	538.1	29,740.5	333.5	1,054.1	71,627.9
2043	1,058.2	78,398.0	492.9	535.8	29,848.4	334.7	1,057.9	73,152.5
2044	1,064.9	79,864.2	495.7	533.5	29,944.5	335.9	1,061.6	74,681.3
Units	**Thousands**	**Millions (2017 $)**	**Thousands**	**Thousands**	**Millions (2017 $)**	**Thousands**	**Thousands**	**Millions (2017 $)**

Exhibit A-9

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

Year	SWEPCO Arkansas Gross Regional Product	SWEPCO Louisiana Commercial Gross Regional Product	SWEPCO Texas Gross Regional Product
1995	20,078.2	15,181.5	27,472.0
1996	20,738.1	15,900.3	28,573.7
1997	21,170.9	16,258.6	30,672.8
1998	21,700.7	16,447.9	31,738.6
1999	23,530.8	16,807.4	32,566.3
2000	24,099.6	17,040.0	33,557.2
2001	24,971.9	16,669.4	33,698.2
2002	26,442.5	16,782.9	34,943.4
2003	28,383.1	16,985.3	35,515.1
2004	30,495.8	17,804.8	38,721.8
2005	31,994.4	19,065.2	38,429.1
2006	32,611.6	20,218.8	40,592.5
2007	31,998.5	18,947.9	42,579.3
2008	31,222.8	20,107.0	42,516.1
2009	29,795.2	20,443.5	41,079.6
2010	31,100.8	21,230.4	42,814.3
2011	31,544.3	21,392.3	43,937.7
2012	32,033.7	21,355.3	45,029.4
2013	33,410.0	20,968.1	46,522.9
2014	34,369.7	21,087.2	47,472.0
2015	35,230.6	21,005.5	47,770.1
2016	35,868.5	20,938.1	46,036.6
2017	36,984.3	20,861.6	46,726.8
2018	38,081.0	21,013.2	49,211.9
2019	38,754.9	20,841.5	49,595.6
2020	39,598.3	20,357.0	47,849.5
2021	42,327.4	20,853.5	49,635.6
2022	43,506.2	20,627.9	50,135.4
2023	44,881.9	20,937.4	52,263.4
2024	45,718.6	21,122.6	53,216.5
2025	46,706.8	21,285.5	54,386.7
2026	48,011.0	21,561.7	55,928.2
2027	49,405.5	21,827.4	57,624.3
2028	50,855.0	22,105.9	59,351.6
2029	52,278.0	22,371.6	61,029.1
2030	53,643.9	22,611.8	62,637.4
2031	54,973.3	22,843.8	64,185.7
2032	56,355.4	23,095.0	65,791.9
2033	57,809.4	23,375.2	67,457.6
2034	59,315.7	23,677.5	69,146.4
2035	60,834.7	23,982.8	70,833.0
2036	62,376.1	24,300.2	72,518.7
2037	63,921.1	24,620.9	74,166.9
2038	65,456.3	24,935.6	75,777.6
2039	67,012.1	25,254.7	77,403.0
2040	68,572.1	25,572.7	79,023.2
2041	70,127.7	25,891.1	80,632.0
2042	71,697.7	26,214.1	82,253.4
2043	73,284.4	26,543.0	83,893.4
2044	74,902.9	26,879.3	85,573.9
Units	**Millions (2017 $)**	**Millions (2017 $)**	**Millions (2017 $)**

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	5,906.6	3,563.3	48.4	69.7
1996	5,582.7	3,170.9	49.0	73.4
1997	5,591.4	3,371.3	49.8	79.5
1998	5,469.1	3,373.9	51.0	84.9
1999	6,189.0	3,689.1	51.1	89.3
2000	6,166.7	2,993.4	51.1	93.2
2001	6,093.4	2,609.9	49.5	90.0
2002	6,604.8	3,060.4	48.0	90.6
2003	7,165.1	4,342.3	47.7	92.0
2004	7,784.2	5,147.9	48.9	95.1
2005	7,835.6	6,198.2	49.7	99.2
2006	7,828.9	5,427.5	50.4	101.9
2007	6,522.7	4,665.8	50.7	105.2
2008	5,794.2	4,056.0	49.2	100.4
2009	5,268.5	3,770.6	42.0	86.7
2010	5,779.7	4,587.6	39.7	92.4
2011	5,536.1	4,194.6	39.4	95.4
2012	4,999.0	3,997.8	38.0	98.2
2013	5,371.0	3,534.8	37.9	99.3
2014	5,528.9	3,665.7	39.7	100.5
2015	5,396.6	3,450.4	39.9	100.1
2016	5,367.7	3,281.5	38.5	99.4
2017	5,447.2	3,348.7	38.5	100.0
2018	5,628.8	3,623.7	40.0	101.4
2019	5,606.3	3,745.6	40.7	99.5
2020	5,606.8	3,240.6	39.8	93.0
2021	6,019.1	3,261.0	39.8	97.7
2022	6,203.5	3,189.9	41.7	100.5
2023	6,376.4	3,279.8	43.1	100.0
2024	6,431.2	3,310.1	43.5	100.4
2025	6,500.2	3,360.5	43.7	101.9
2026	6,610.7	3,431.3	43.7	103.2
2027	6,760.0	3,503.0	43.6	105.3
2028	6,908.7	3,580.0	43.5	107.6
2029	7,048.9	3,655.0	43.3	109.9
2030	7,176.5	3,720.1	43.2	112.2
2031	7,295.7	3,778.5	43.0	114.4
2032	7,419.5	3,841.1	42.9	116.6
2033	7,547.7	3,907.8	42.7	118.8
2034	7,680.3	3,979.0	42.5	120.9
2035	7,813.1	4,049.7	42.3	122.9
2036	7,944.1	4,118.6	42.2	124.9
2037	8,071.3	4,183.9	41.9	126.8
2038	8,195.4	4,245.6	41.7	128.7
2039	8,321.0	4,307.0	41.5	130.6
2040	8,444.7	4,364.5	41.3	132.5
2041	8,563.1	4,418.0	41.1	134.2
2042	8,681.2	4,469.7	40.9	135.9
2043	8,800.3	4,519.8	40.7	137.6
2044	8,924.5	4,569.2	40.5	139.4
Units	**Millions (2017 $)**	**Millions (2017 $)**	**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 Households	SWEPCO Texas Employment
1995	20,078.2	273.2	16.1	211.6	287.5
1996	20,738.1	278.5	16.2	212.9	294.1
1997	21,170.9	283.1	15.9	214.2	305.4
1998	21,700.7	288.1	15.8	215.6	309.5
1999	23,530.8	296.6	16.5	218.6	312.7
2000	24,099.6	303.8	16.6	219.7	318.1
2001	24,971.9	309.4	19.1	220.0	320.9
2002	26,442.5	313.1	22.3	220.4	321.0
2003	28,383.1	315.3	22.2	220.8	323.6
2004	30,495.8	321.5	21.8	221.5	333.2
2005	31,994.4	332.3	22.2	225.2	340.1
2006	32,611.6	340.7	22.6	229.4	347.3
2007	31,998.5	342.5	22.5	231.9	357.9
2008	31,222.8	340.8	21.1	232.6	366.2
2009	29,795.2	326.9	18.7	234.6	352.4
2010	31,100.8	327.3	19.4	236.5	354.0
2011	31,544.3	329.3	19.5	237.8	356.5
2012	32,033.7	334.7	19.7	239.6	360.8
2013	33,410.0	337.8	19.3	239.1	367.2
2014	34,369.7	348.7	19.9	238.9	371.3
2015	35,230.6	361.9	21.1	238.4	372.0
2016	35,868.5	373.9	21.5	238.0	366.0
2017	36,984.3	381.2	21.4	237.4	367.2
2018	38,081.0	387.9	22.2	236.4	373.2
2019	38,754.9	394.0	23.2	236.5	376.9
2020	39,598.3	387.2	22.6	234.2	361.5
2021	42,327.4	401.8	22.1	234.4	369.5
2022	43,506.2	421.8	24.1	236.7	384.9
2023	44,881.9	435.6	25.1	236.9	393.6
2024	45,718.6	440.2	25.2	237.6	397.6
2025	46,706.8	442.5	25.5	238.3	400.3
2026	48,011.0	444.2	25.7	238.9	402.8
2027	49,405.5	445.4	25.9	239.2	404.9
2028	50,855.0	446.8	26.0	239.3	407.2
2029	52,278.0	448.1	26.2	239.5	409.7
2030	53,643.9	449.6	26.3	239.6	412.3
2031	54,973.3	450.9	26.5	239.7	414.9
2032	56,355.4	452.0	26.6	239.7	417.4
2033	57,809.4	453.3	26.7	239.7	420.0
2034	59,315.7	454.6	26.7	239.6	422.5
2035	60,834.7	455.7	26.8	239.4	424.9
2036	62,376.1	456.6	26.9	239.3	427.1
2037	63,921.1	457.2	27.0	239.0	428.8
2038	65,456.3	457.6	27.0	238.6	430.4
2039	67,012.1	458.0	27.1	238.3	432.1
2040	68,572.1	458.5	27.1	237.9	433.8
2041	70,127.7	459.0	27.2	237.5	435.5
2042	71,697.7	459.4	27.3	237.0	437.3
2043	73,284.4	459.7	27.3	236.4	438.9
2044	74,902.9	459.8	27.4	235.9	440.4
Units	**Millions (2017 $)**	**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
2024	8.8	1.6	1.3	4.3	0.8	0.6	4.4	0.8	0.6	0.0	0.0	0.0
2025	15.1	2.6	2.1	8.1	1.4	1.1	7.0	1.3	1.0	0.0	0.0	0.0
2026	20.2	3.4	2.7	11.4	1.8	1.4	8.8	1.6	1.3	0.0	0.0	0.0
2027	24.9	4.7	3.5	14.2	2.5	1.7	10.7	1.9	1.6	0.0	0.3	0.2
2028	19.6	3.6	2.8	11.4	2.0	1.4	8.2	1.5	1.3	0.0	0.2	0.1
2029	3.7	0.7	0.6	0.0	0.0	0.0	3.7	0.7	0.6	0.0	0.0	0.0
2030	0.6	0.1	0.1	0.0	0.0	0.0	0.6	0.1	0.1	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	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
2044	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
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	1,169.6
2024	1,083.9
2025	1,071.9
2026	1,095.9
2027	1,083.0
2028	1,085.8
2029	1,097.8
2030	1,097.5
2031	1,099.5
2032	1,104.5
2033	1,105.1
2034	1,107.7
2035	1,111.1
2036	1,116.4
2037	1,118.8
2038	1,121.8
2039	1,124.7
2040	1,130.0
2041	1,133.7
2042	1,137.5
2043	1,140.4
2044	1,144.7

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

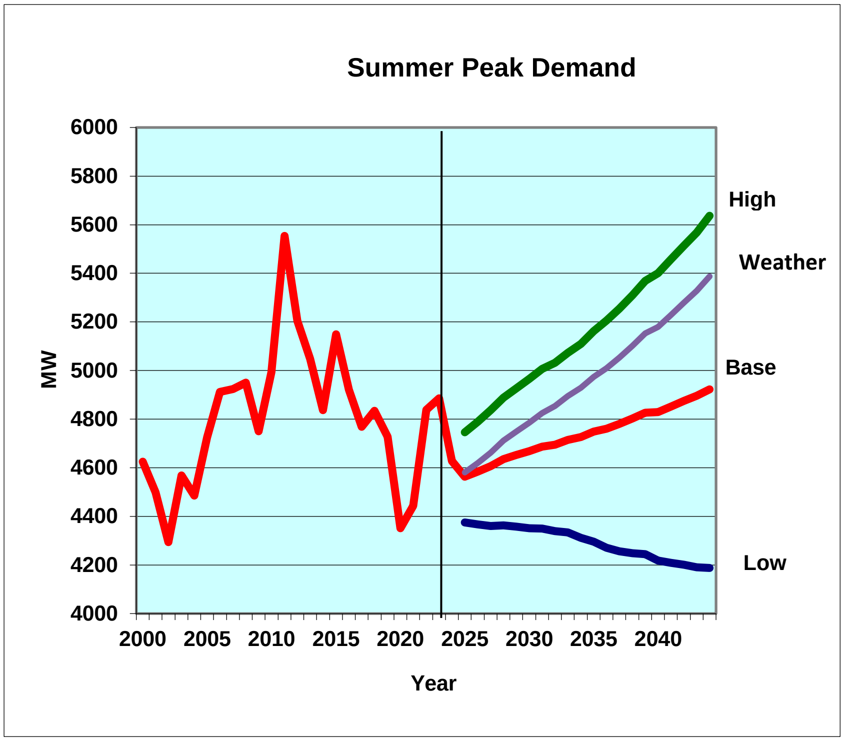
Southwestern Electric Power Company
Seasonal Peak Demand (MW), Energy Sales (GWh) and High/Low Scenarios

	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
2025	4,116	4,293	4,465	4,375	4,563	4,746	21,177	22,089	22,973
2026	4,106	4,309	4,503	4,367	4,584	4,789	21,142	22,189	23,185
2027	4,093	4,324	4,541	4,360	4,606	4,837	21,092	22,284	23,401
2028	4,085	4,340	4,576	4,363	4,635	4,888	21,085	22,401	23,622
2029	4,093	4,371	4,628	4,357	4,653	4,927	21,087	22,516	23,842
2030	4,083	4,381	4,659	4,351	4,669	4,965	21,048	22,585	24,019
2031	4,075	4,392	4,691	4,349	4,687	5,007	21,023	22,657	24,200
2032	4,068	4,401	4,718	4,340	4,695	5,032	21,026	22,746	24,382
2033	4,062	4,418	4,754	4,335	4,714	5,073	20,993	22,832	24,571
2034	4,049	4,439	4,799	4,312	4,727	5,110	20,902	22,913	24,771
2035	4,027	4,452	4,840	4,296	4,748	5,162	20,811	23,002	25,008
2036	4,009	4,468	4,886	4,271	4,760	5,205	20,722	23,096	25,255
2037	3,986	4,477	4,922	4,256	4,780	5,255	20,639	23,180	25,482
2038	3,970	4,487	4,961	4,249	4,803	5,310	20,580	23,263	25,720
2039	3,957	4,500	5,005	4,245	4,827	5,369	20,533	23,350	25,970
2040	3,946	4,518	5,053	4,218	4,829	5,401	20,473	23,436	26,213
2041	3,933	4,534	5,100	4,209	4,852	5,458	20,404	23,522	26,459
2042	3,918	4,547	5,143	4,201	4,875	5,514	20,345	23,609	26,705
2043	3,904	4,561	5,187	4,191	4,896	5,568	20,282	23,696	26,950
2044	3,888	4,571	5,234	4,188	4,923	5,637	20,240	23,792	27,243

Exhibit A-17

Southwestern Electric Power Company

Range of Forecasts and Weather Scenario



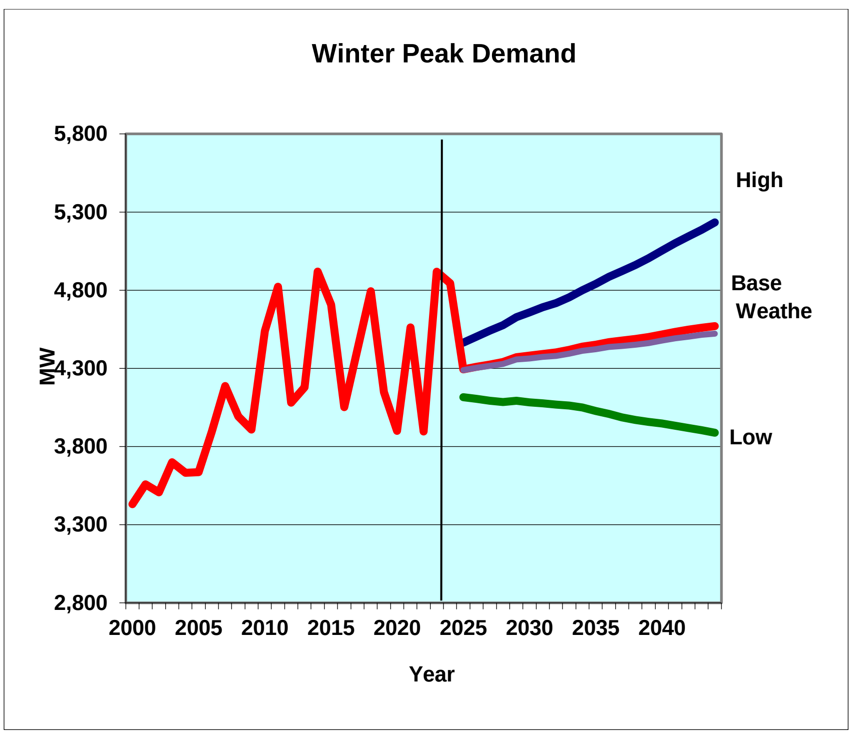
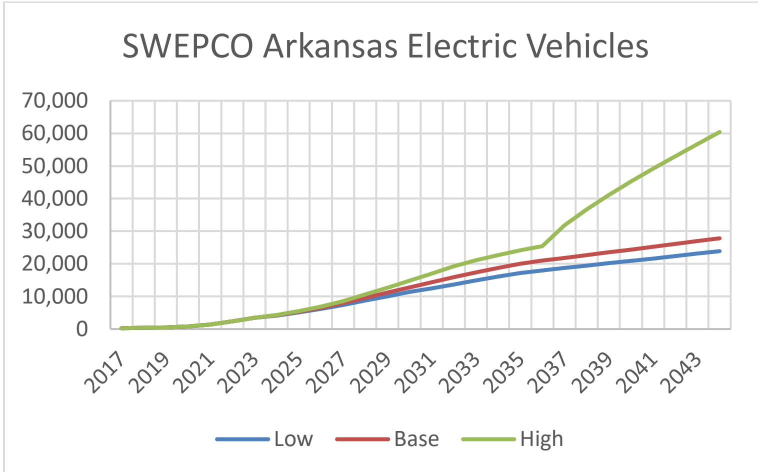
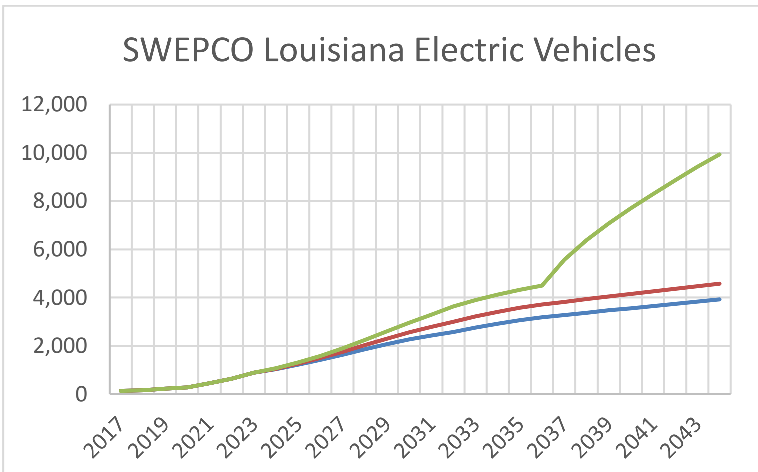


Exhibit A-18

SWEPCO Electric Vehicle Adoption Scenarios by State Jurisdiction





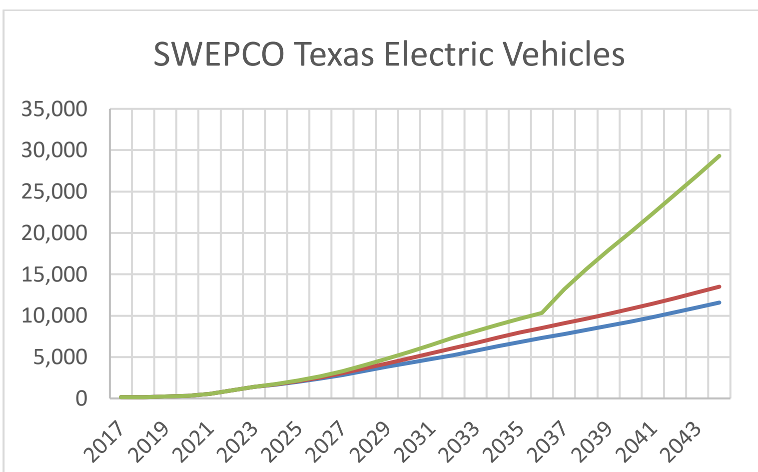


Exhibit A-19

SWEPCO Distributed Generation

	Distributed Energy Resources			In Service Generation (kWh)		
Year	Arkansas	Louisiana	Texas	Arkansas	Louisiana	Texas
2011	9	257	14	114,003	902,724	217,469
2012	11	405	23	119,271	1,382,879	286,324
2013	13	659	31	214,834	4,715,664	352,545
2014	20	962	31	323,569	6,687,658	352,545
2015	26	1,305	34	474,816	7,681,480	360,447
2016	34	1,375	36	541,037	7,911,021	365,716
2017	68	1,419	38	766,042	8,162,368	370,984
2018	110	1,447	58	1,012,120	8,281,272	513,963
2019	191	1,472	97	1,315,785	8,347,127	706,991
2020	313	1,486	141	1,953,188	8,429,153	913,190
2021	527	1,526	236	2,697,495	8,579,668	1,208,586
2022	1,005	1,576	382	4,092,080	8,982,263	1,728,620
2023	1,432	1,713	754	5,487,764	9,433,442	2,708,539
2024	1,633	1,747	1,113	6,423,571	9,974,486	3,879,956
2025	1,825	1,796	1,421	7,425,513	10,645,704	5,051,691
2026	2,017	1,852	1,666	8,473,836	11,333,682	6,105,303
2027	2,223	1,899	1,896	9,603,565	11,999,980	7,160,930
2028	2,448	1,942	2,188	10,782,330	12,654,071	8,382,462
2029	2,685	1,982	2,534	11,994,718	13,301,421	9,789,077
2030	2,944	2,023	2,957	13,308,127	13,952,779	11,401,644
2031	3,213	2,069	3,434	14,694,536	14,614,158	13,199,294
2032	3,486	2,118	3,933	16,089,351	15,286,650	15,101,935
2033	3,741	2,170	4,410	17,484,313	16,009,293	16,989,428
2034	3,983	2,221	4,866	18,890,630	16,730,842	18,867,493
2035	4,172	2,263	5,223	20,200,425	17,427,614	20,530,179
2036	4,358	2,303	5,584	21,503,214	18,120,923	22,204,307
2037	4,542	2,342	5,957	22,845,380	18,811,318	23,954,821
2038	4,725	2,381	6,342	24,229,723	19,500,255	25,781,721
2039	4,904	2,420	6,741	25,649,238	20,236,245	27,690,729
2040	5,080	2,460	7,151	27,060,347	20,973,146	29,628,340
2041	5,250	2,500	7,562	28,502,426	21,708,954	31,613,733
2042	5,417	2,539	7,979	29,979,678	22,444,397	33,658,350
2043	5,580	2,578	8,400	31,493,503	23,179,111	35,762,190
2044	5,739	2,616	8,827	32,996,120	23,912,915	37,925,254

Exhibit B: Detailed Generation Technology Modeling Parameters

Technology	First Year	Capacity (MW)	Installed Cost ($/kW)	Full Load Heat Rate (btu/kWh)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE ($/MWh)
Base Load								
SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW	2036	600	9,300	10,440	4.46	141.00	90	109
COMBUSTION TURBINE F CLASS, COMBINED-CYCLE, F- Class	2032	760	1,130	6,600	2.76	23.89	60	76
COMBUSTION TURBINE H CLASS, 1100-MW COMBINED CYCLE (RFP)	2032	1,030	1,490	6,370	2.57	16.81	60	76
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW (RFP)	2032	420	1,680	6,430	3.51	19.43	60	82
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW (RFP)	2032	380	3750	7,120	8.04	38.03	60	110
Peaking								
COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE (RFP)	2031	230	1,140	9,910	6.09	9.48	15	175
COMBUSTION TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE (RFP)	2031	110	1,780	9,120	6.36	22.07	15	227
INTERNAL COMBUSTION ENGINES, 20 MW (RFP)	2031	20	2,800	8,300	7.70	47.59	15	308
Intermittent								
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH, 4hr (RFP)	2029	50	1,850		0	53.11	16	184
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 300 MWH, 6hr (RFP)	2029	50	2,370		0	79.66	25	165
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 400 MWH, 8hr (RFP)	2029	50	3,550		0	106.21	33	176
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 500 MWH, 10hr (RFP)	2029	50	4,540		0	132.76	41	179
BATTERY ENERGY STORAGE SYSTEM, FORM, 20 MW / MWH, 100hr	2029	20	2,850		0	18.00	5	600
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW	2032	200	2,380		0	37.08	47	51
SOLAR PHOTOVOLTAIC, 150 MWAC	2029	150	2,080		0	15.86	28	55
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MWx200 MWh	2029	150	2,660		0	39.54	25	100

*A 2029 gas-fired CT alternative for up to 480MW was offered assuming the re-use an existing company interconnection.
** Levelized cost of energy (LCOE) values are indicative based on capacity factors shown in table.

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

Southwestern Electric Power Company
Capability, Demand, and Reserve Forecast
2025 – 2044

CAPABILITY - Summer

	Plant Capabilities	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	ARSENAL HILL 5	111	96	96	96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	J.L. STALL CC	511	501	501	501	501	501	501	501	501	501	501	501	501	501	501	501	501	501	501	501
	DOLET HILLS 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	FLINT CREEK 1	259	248	248	248	248	248	248	248	248	248	248	248	248	248	0	0	0	0	0	0
	TURK	387	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380
	KNOX LEE 2																				
	KNOX LEE 3																				
	KNOX LEE 4																				
	KNOX LEE 5	335	291	291	291	291	291	291	291	291	291	291	291	291	291	291	0	0	0	0	0
	LIEBERMAN 2																				
	LIEBERMAN 3	111	102	102	102	0	0	0	0	0	0	0	0	0	0	0					
	LIEBERMAN 4	108	86	86	86	0	0	0	0	0	0	0	0	0	0	0					
	LONE STAR 1																				
	PIRKEY 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	MATTISON 1	74	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
	MATTISON 2	74	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
	MATTISON 3	74	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	MATTISON 4	74	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
	WELSH 1	525	515	515		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WELSH 3	528	497	497		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 1	162	135	135	135	135	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 2	352	292	292	292	292	292	292	292	292	292	292	0	0	0	0	0	0	0	0	0
	WILKES 3	350	315	315	315	315	315	315	315	315	315	315	315	0	0	0	0	0	0	0	0
	SUNDANCE	22	22	22	22	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	MAVERICK	22	22	22	22	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	TRAVERSE	78	78	78	78	74	74	74	74	74	74	74	74	74	74	73.5	73.5	73.5	74	74	74
	Diversion	34	34	34	34	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
	Wagon Wheel		102	102	102	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
	Mooringsport			144	144	142	142	142	142	140	140	140	140	138	138	136	136	136	136	134	134
1 (Summer)	**Total**	**4,190**	**3,987**	**4,131**	**3,119**	**2,817**	**2,681**	**2,681**	**2,681**	**2,679**	**2,679**	**2,679**	**2,388**	**2,070**	**2,070**	**1,820**	**1,529**	**1,529**	**1,529**	**1,527**	**1,527**
	Adjustments to Plant Capability	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	LOUISIANA GENERATION (FORMERLY CAJUN)	57.5	57.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
	PBA Capacity Deduction - Coal		-20	-20	-10	-12	-12	-12	-12	-12	-12	-12	-14				0	0	0	0	0
	PBA Capacity Deduction - NG		-25	-25	-35	-33	-33	-33	-33	-33	-33	-33	-31					0	0	0	0
2	**TOTAL**	**81**	**36**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**
3 (Summer)	**Net Plant Capability (1 + 2)**	**4,271**	**4,023**	**4,110**	**3,097**	**2,795**	**2,660**	**2,660**	**2,660**	**2,658**	**2,658**	**2,658**	**2,366**	**2,094**	**2,094**	**1,844**	**1,553**	**1,553**	**1,553**	**1,551**	**1,551**
	Sales Without Reserves	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	Backup contracts (Eastman & Domtar)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Transfer to PSO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	**TOTAL**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**
	Purchases Without Reserves	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	NTEC - HCPP	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342
	NTEC GENERATION - TURK	54	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
	NTEC - SPA NARROWS	26	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	25	25	25	25	25	25	0	25	25	25	25	25	25	25	25	25	25	25	25	25
	MAJESTIC WIND PROJECT	28	28	28	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	HIGH MAJESTIC WIND PROJECT	24	24	24	24	23	23	23	23	0	0	0	0	0	0	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	16	16	16	16	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0
	CANADIAN HILLS WIND PROJECT	20	20	20	20	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0
	ROCKING R	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	Upstream	26																			
	Thunderhead	31																			
	Jpower	350	200																		
	TransAlta (Horizon, White Rock East & West)	78	78	78																	
5 (Summer)	**TOTAL**	**1,052**	**845**	**645**	**567**	**536**	**536**	**511**	**536**	**479**	**479**	**479**	**479**	**479**	**479**	**479**	**479**	**479**	**479**	**479**	**479**
6 (Summer)	**Total Capability (3 - 4 + 5)**	**5,309**	**4,854**	**4,740**	**3,650**	**3,317**	**3,181**	**3,156**	**3,181**	**3,122**	**3,122**	**3,122**	**2,831**	**2,558**	**2,558**	**2,308**	**2,017**	**2,017**	**2,017**	**2,015**	**2,015**

DEMAND SUMMER		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	Original Forecast	3,579	3,592	3,612	3,635	3,640	3,649	3,660	3,665	3,677	3,681	3,696	3,705	3,719	3,737	3,756	3,756	3,772	3,791	3,807	3,830
	Bentonville, City of	167	170	173	175	179	181	184	185	188	191	194	196	198	200	203	205	207	209	211	213
	Hope, City of	48	48	48	48	48	48	49	48	49	49	49	49	49	49	49	49	49	49	49	49
	Minden, City of	35	35	35	36	36	36	36	36	36	36	36	35	35	35	35	35	35	35	35	35
	North Texas EC	722	726	729	732	738	743	747	747	753	758	762	763	766	769	772	771	776	779	782	783
	Prescott, City of	12	12	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13	13	13	13
A	Peak Demand Before Passive DSM	4,566	4,587	4,611	4,639	4,654	4,669	4,687	4,695	4,714	4,727	4,748	4,760	4,780	4,803	4,827	4,829	4,852	4,875	4,896	4,923
B	Passive DSM																				
	Approved Passive DSM	3	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	3	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C	Peak Demand (A - B)	4,563	4,584	4,610	4,639	4,654	4,669	4,687	4,695	4,714	4,727	4,748	4,760	4,780	4,803	4,827	4,829	4,852	4,875	4,896	4,923
D	Active DSM																				
	Interruptible	7	4	4	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
	DLC/ELM	7	3	3	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	TOTAL	14	7	7	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
E	Firm Demand (C - D)	4,550	4,577	4,603	4,568	4,583	4,599	4,617	4,624	4,644	4,656	4,678	4,690	4,709	4,732	4,756	4,758	4,781	4,805	4,825	4,852
F	Other Demand Adjustments																				
	DIVERSITY	42	41	39	38	38	38	37	36	36	36	36	36	36	36	36	37	37	37	37	37
	TOTAL	42	41	39	38	38	38	37	36	36	36	36	36	36	36	36	37	37	37	37	37
7	Native Load Responsibility (E - F)	4,508	4,536	4,564	4,530	4,545	4,561	4,580	4,588	4,608	4,620	4,641	4,653	4,673	4,696	4,721	4,721	4,744	4,768	4,788	4,816
	Sales With Reserves																				
	TEX-LA ERCOT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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																				
	NTEC SPA HYDRO PEAKING	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
9	TOTAL	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
10	Load Responsibility (7 + 8 - 9)	4,406	4,434	4,462	4,428	4,443	4,459	4,478	4,486	4,506	4,518	4,539	4,551	4,571	4,594	4,619	4,619	4,642	4,666	4,686	4,714

RESERVES - Summer		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
11 (Summer)	Reserve Capacity (6 - 10)	903	420	278	-778	-1,126	-1,278	-1,322	-1,305	-1,384	-1,395	-1,417	-1,721	-2,013	-2,036	-2,311	-2,602	-2,625	-2,648	-2,671	-2,698
12 (Summer)	% Reserve Margin ((11/10) * *100*)	20.5	9.5	6.2	-17.6	-25.3	-28.7	-29.5	-29.1	-30.7	-30.9	-31.2	-37.8	-44.0	-44.3	-50.0	-56.3	-56.5	-56.8	-57.0	-57.2
13 (Summer)	% Capacity Margin (11/(6) * *100*)	17.0	8.6	5.9	-21.3	-34.0	-40.2	-41.9	-41.0	-44.3	-44.7	-45.4	-60.8	-78.7	-79.6	-100.1	-129.0	-130.1	-131.3	-132.5	-133.9
14 (Summer)	Reserves Above Minimum Reserve Margin (MW)	242.5	196.7	54.0	(1,000.9)	(1,349.5)	(1,502.1)	(1,547.1)	(1,530.6)	(1,610.3)	(1,622.5)	(1,645.1)	(1,949.5)	(2,242.7)	(2,266.9)	(2,543.0)	(2,834.2)	(2,858.3)	(2,883.2)	(2,906.8)	(2,935.5)

CAPABILITY - Winter

	Plant Capabilities	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	ARSENAL HILL 5	111	93	93	93	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	J.L. STALL CC	511	483	483	483	483	483	483	483	483	483	483	483	483	483	483	483	483	483	483	483
	FLINT CREEK 1	259	239	239	239	239	239	239	239	239	239	239	239	239	0	0	0	0	0	0	0
	TURK	387	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
	KNOX LEE 5	335	286	286	286	286	286	286	286	286	286	286	286	286	286	286	0	0	0	0	0
	LIEBERMAN 3	111	78	78	78	0	0	0	0	0	0	0	0	0	0	0					
	LIEBERMAN 4	108	90	90	90	0	0	0	0	0	0	0	0	0	0	0					
	MATTISON 1	74	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
	MATTISON 2	74	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	MATTISON 3	74	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
	MATTISON 4	74	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WELSH 1	525	515	515	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WELSH 3	528	446	446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 1	162	124	124	124	124	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 2	352	227	227	227	227	227	227	227	227	227	227	0	0	0	0	0	0	0	0	0
	WILKES 3	350	84	84	84	84	84	84	84	84	84	84	84	0	0	0	0	0	0	0	0
	SUNDANCE	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	MAVERICK	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TRAVERSE	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
	Diversion	40	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
	Wagon Wheel		114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
	Mooringsport			34	34	30	30	28	26	26	26	26	26	24	24	24	24	22	22	22	22
1 (Winter)	**Total**	**4,196**	**3,518**	**3,552**	**2,592**	**2,328**	**2,204**	**2,202**	**2,200**	**2,200**	**2,200**	**2,200**	**1,973**	**1,886**	**1,648**	**1,648**	**1,362**	**1,360**	**1,360**	**1,360**	**1,360**
	Adjustments to Plant Capability	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	LOUISIANA GENERATION (FORMERLY CAJUN)	57.5	57.5	0																	
	SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
	PBA Capacity Deduction - Coal		-20	-20	-10	-12	-12	-12	-12	-12	-12	-12	-14				0	0	0	0	0
	PBA Capacity Deduction - NG		-25	-25	-35	-33	-33	-33	-33	-33	-33	-33	-31					0	0	0	0
2	**TOTAL**	**81**	**36**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**-22**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**
3 (Winter)	**Net Plant Capability (1 + 2)**	**4,277**	**3,554**	**3,531**	**2,570**	**2,306**	**2,182**	**2,180**	**2,178**	**2,178**	**2,178**	**2,178**	**1,951**	**1,910**	**1,671**	**1,671**	**1,386**	**1,384**	**1,384**	**1,384**	**1,384**
	Sales Without Reserves	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	Backup contracts (Eastman & Domtar)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
4	**TOTAL**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**
	Purchases Without Reserves	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	NTEC - HCPP	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342
	NTEC GENERATION - PIRKEY/DOLET HILLS/TURK	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
	NTEC - SPA NARROWS	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	MAJESTIC WIND PROJECT	26	26	26	26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	HIGH MAJESTIC WIND PROJECT	22	22	22	22	22	22	22			0	0	0	0	0	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	15	15	15	15	15	15	15			0	0	0	0	0	0	0	0	0	0	0
	CANADIAN HILLS WIND PROJECT	19	19	19	19	19	19	19			0	0	0	0	0	0	0	0	0	0	0
	ROCKING R	14	14	12	12	11	11	10	9	9	9	9	9	9	9	9	9	8	8	8	8
	Upstream	26																			
	Thunderhead	31																			
	Jpower	350	200																		
	TransAlta	78	78	78																	
5 (Winter)	**TOTAL**	**1,002**	**795**	**594**	**516**	**488**	**488**	**488**	**431**	**431**	**431**	**431**	**431**	**430**	**430**	**430**	**430**	**429**	**429**	**429**	**429**
6 (Winter)	**Total Capability (3 - 4 + 5)**	**5,265**	**4,335**	**4,110**	**3,072**	**2,780**	**2,656**	**2,653**	**2,594**	**2,594**	**2,594**	**2,594**	**2,368**	**2,326**	**2,087**	**2,087**	**1,801**	**1,798**	**1,798**	**1,798**	**1,798**

DEMAND WINTER		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	Original Forecast	3,133	3,142	3,153	3,163	3,183	3,185	3,189	3,192	3,200	3,214	3,220	3,228	3,234	3,239	3,246	3,260	3,269	3,278	3,286	3,293
	Bentonville, City of	133	135	137	140	142	144	146	148	150	152	154	156	158	160	161	163	165	167	168	170
	Hope, City of	39	39	39	39	39	39	39	39	39	39	40	40	40	40	40	40	40	40	40	40
	Minden, City of	23	24	24	24	24	24	24	24	24	24	24	24	24	23	23	23	23	23	23	23
	North Texas EC	955	960	964	968	974	979	984	988	995	1,000	1,005	1,011	1,013	1,016	1,019	1,022	1,026	1,030	1,033	1,035
	Prescott, City of	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
A	**Peak Demand Before Passive DSM**	**4,295**	**4,312**	**4,328**	**4,343**	**4,371**	**4,381**	**4,392**	**4,401**	**4,418**	**4,439**	**4,452**	**4,468**	**4,477**	**4,487**	**4,500**	**4,518**	**4,534**	**4,547**	**4,561**	**4,571**
A	**Peak Demand Before Passive DSM Adjusted (Winter)**	**4,295**	**4,312**	**4,328**	**4,343**	**4,371**	**4,381**	**4,392**	**4,401**	**4,418**	**4,439**	**4,452**	**4,468**	**4,477**	**4,487**	**4,500**	**4,518**	**4,534**	**4,547**	**4,561**	**4,571**
B	**Passive DSM Winter**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	Approved Passive DSM	2	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	**2**	**3**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
C	**Peak Demand (A - B)**	**4,293**	**4,309**	**4,327**	**4,343**	**4,371**	**4,381**	**4,392**	**4,401**	**4,418**	**4,439**	**4,452**	**4,468**	**4,477**	**4,487**	**4,500**	**4,518**	**4,534**	**4,547**	**4,561**	**4,571**
D	**Active DSM Winter**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	Interruptible	7	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	DLC/ELM	7	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	**14**	**7**	**7**	**7**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
E	**Firm Demand Winter (C - D)**	**4,279**	**4,303**	**4,320**	**4,336**	**4,371**	**4,381**	**4,392**	**4,401**	**4,418**	**4,439**	**4,452**	**4,468**	**4,477**	**4,487**	**4,500**	**4,518**	**4,534**	**4,547**	**4,561**	**4,571**
F	**Other Demand Adjustments Winter**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
	DIVERSITY	110	118	120	137	129	131	132	139	156	145	154	161	157	160	173	167	174	173	173	174
	TOTAL	**110**	**118**	**120**	**137**	**129**	**131**	**132**	**139**	**156**	**145**	**154**	**161**	**157**	**160**	**173**	**167**	**174**	**173**	**173**	**174**
7W	**Native Load Responsibility** Winter **(E - F)**	**4,169**	**4,184**	**4,201**	**4,199**	**4,243**	**4,250**	**4,261**	**4,262**	**4,261**	**4,293**	**4,298**	**4,306**	**4,320**	**4,327**	**4,327**	**4,351**	**4,360**	**4,374**	**4,387**	**4,396**
	Sales With Reserves Winter																				
	TEX-LA ERCOT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8W	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases With Reserves																				
	NTEC SPA HYDRO PEAKING	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
9W	**TOTAL**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**	**102**
10W	**Load Responsibility Winter (7+ 8 - 9)**	**4,067**	**4,082**	**4,099**	**4,097**	**4,141**	**4,148**	**4,159**	**4,160**	**4,159**	**4,191**	**4,196**	**4,204**	**4,218**	**4,225**	**4,225**	**4,249**	**4,258**	**4,272**	**4,285**	**4,294**
RESERVES - Winter		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
11 (Winter)	**Reserve Capacity (6 - 10)**	**1,198**	**253**	**12**	**-1,025**	**-1,361**	**-1,492**	**-1,506**	**-1,566**	**-1,565**	**-1,597**	**-1,602**	**-1,837**	**-1,893**	**-2,139**	**-2,138**	**-2,448**	**-2,460**	**-2,474**	**-2,487**	**-2,496**
12 (Winter)	**% Reserve Margin ((11/10) * *100*)**	**29.5**	**6.2**	**0.3**	**-25.0**	**-32.9**	**-36.0**	**-36.2**	**-37.6**	**-37.6**	**-38.1**	**-38.2**	**-43.7**	**-44.9**	**-50.6**	**-50.6**	**-57.6**	**-57.8**	**-57.9**	**-58.0**	**-58.1**
13 (Winter)	**% Capacity Margin (11/(6) * *100*)**	**22.8**	**5.8**	**0.3**	**-33.4**	**-49.0**	**-56.2**	**-56.7**	**-60.4**	**-60.3**	**-61.6**	**-61.7**	**-77.6**	**-81.4**	**-102.5**	**-102.5**	**-135.9**	**-136.8**	**-137.5**	**-138.3**	**-138.8**
14 (Winter)	**Reserves Above Planning Reserve Margin (MW)**	**588.5**	**(231.6)**	**(556.6)**	**(1,674.7)**	**(2,100.5)**	**(2,233.2)**	**(2,248.3)**	**(2,309.1)**	**(2,307.8)**	**(2,345.8)**	**(2,351.0)**	**(2,587.7)**	**(2,646.2)**	**(2,893.3)**	**(2,892.7)**	**(3,206.6)**	**(3,220.2)**	**(3,236.9)**	**(3,252.5)**	**(3,262.9)**

Exhibit D: Annual Overnight Capital Expenditure by Technology Type & Capacity Prices

Technology	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Base Load																				
SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW	$ 6,871.68	$ 6,832.23	$ 6,946.04	$ 7,115.00	$ 7,289.43	$ 7,474.12	$ 7,641.21	$ 7,819.05	$ 8,014.06	$ 8,229.01	$ 8,450.04	$ 8,672.48	$ 8,920.33	$ 9,190.62	$ 9,468.88	$ 9,778.24	$ 10,127.59	$ 10,492.42	$ 10,874.67	$ 11,249.93
COMBUSTION TURBINE F CLASS, COMBINED-CYCLE, F- Class	$ 836.31	$ 839.48	$ 853.90	$ 871.92	$ 889.95	$ 908.96	$ 927.19	$ 946.14	$ 965.78	$ 987.82	$ 1,010.28	$ 1,035.04	$ 1,062.72	$ 1,092.14	$ 1,123.72	$ 1,157.54	$ 1,195.09	$ 1,235.43	$ 1,276.68	$ 1,317.46
COMBUSTION TURBINE H CLASS, 1100-MW COMBINED CYCLE (RFP)	$ 1,252.38	$ 1,257.18	$ 1,279.06	$ 1,306.40	$ 1,333.77	$ 1,362.61	$ 1,390.26	$ 1,419.02	$ 1,448.82	$ 1,482.26	$ 1,516.34	$ 1,553.91	$ 1,595.90	$ 1,640.55	$ 1,688.46	$ 1,739.77	$ 1,796.75	$ 1,857.96	$ 1,920.54	$ 1,982.41
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW (RFP)	$ 1,412.19	$ 1,417.62	$ 1,442.37	$ 1,473.29	$ 1,504.23	$ 1,536.85	$ 1,568.13	$ 1,600.65	$ 1,634.35	$ 1,672.18	$ 1,710.72	$ 1,753.20	$ 1,800.70	$ 1,851.19	$ 1,905.38	$ 1,963.41	$ 2,027.85	$ 2,097.07	$ 2,167.85	$ 2,237.83
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW (RFP)	$ 3,164.94	$ 3,177.26	$ 3,233.43	$ 3,303.61	$ 3,373.86	$ 3,447.90	$ 3,518.89	$ 3,592.72	$ 3,669.22	$ 3,755.07	$ 3,842.56	$ 3,939.00	$ 4,046.81	$ 4,161.43	$ 4,284.42	$ 4,416.15	$ 4,562.42	$ 4,719.55	$ 4,880.23	$ 5,039.06
Peaking																				
COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE (RFP)	$ 974.23	$ 978.75	$ 996.30	$ 1,018.22	$ 1,040.30	$ 1,063.49	$ 1,085.90	$ 1,109.01	$ 1,133.10	$ 1,160.20	$ 1,187.74	$ 1,216.26	$ 1,248.17	$ 1,282.23	$ 1,318.63	$ 1,357.60	$ 1,400.91	$ 1,447.58	$ 1,495.09	$ 1,542.12
COMBUSTION TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE (RFP)	$ 1,517.16	$ 1,524.28	$ 1,551.95	$ 1,586.50	$ 1,621.31	$ 1,657.85	$ 1,693.18	$ 1,729.61	$ 1,767.58	$ 1,810.29	$ 1,853.70	$ 1,898.65	$ 1,948.95	$ 2,002.63	$ 2,060.01	$ 2,121.44	$ 2,189.71	$ 2,263.26	$ 2,338.14	$ 2,412.27
INTERNAL COMBUSTION ENGINES, 20 MW (RFP)	$ 2,361.66	$ 2,372.83	$ 2,416.24	$ 2,470.43	$ 2,525.03	$ 2,582.35	$ 2,637.77	$ 2,694.91	$ 2,754.48	$ 2,821.47	$ 2,889.58	$ 2,960.07	$ 3,038.98	$ 3,123.19	$ 3,213.20	$ 3,309.55	$ 3,416.64	$ 3,532.02	$ 3,649.48	$ 3,765.76
Intermittent																				
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH, 4hr (RFP)	$ 1,904.50	$ 1,867.42	$ 1,853.97	$ 1,845.80	$ 1,834.88	$ 1,822.71	$ 1,848.69	$ 1,875.28	$ 1,902.53	$ 1,933.98	$ 1,965.22	$ 1,997.29	$ 2,033.70	$ 2,072.42	$ 2,113.68	$ 2,157.93	$ 2,207.36	$ 2,260.41	$ 2,312.98	$ 2,362.93
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 300 MWH, 6hr (RFP)	$ 2,469.36	$ 2,414.81	$ 2,390.62	$ 2,372.80	$ 2,350.89	$ 2,326.79	$ 2,358.27	$ 2,390.44	$ 2,423.34	$ 2,461.51	$ 2,499.28	$ 2,537.98	$ 2,582.07	$ 2,628.96	$ 2,678.91	$ 2,732.48	$ 2,792.42	$ 2,856.75	$ 2,920.23	$ 2,980.16
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 400 MWH, 8hr (RFP)	$ 3,711.17	$ 3,623.55	$ 3,581.42	$ 3,548.50	$ 3,508.96	$ 3,465.66	$ 3,511.23	$ 3,557.73	$ 3,605.25	$ 3,660.52	$ 3,715.12	$ 3,770.98	$ 3,834.76	$ 3,902.59	$ 3,974.83	$ 4,052.32	$ 4,139.12	$ 4,232.26	$ 4,323.93	$ 4,410.11
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 500 MWH, 10hr (RFP)	$ 4,762.67	$ 4,645.69	$ 4,586.92	$ 4,539.65	$ 4,483.54	$ 4,422.19	$ 4,479.18	$ 4,537.29	$ 4,596.63	$ 4,665.80	$ 4,734.01	$ 4,803.75	$ 4,883.49	$ 4,968.29	$ 5,058.60	$ 5,155.46	$ 5,264.06	$ 5,380.56	$ 5,495.04	$ 5,602.35
BATTERY ENERGY STORAGE SYSTEM, FORM, 20 MW / MWH, 100hr	$ 2,940.12	$ 2,882.54	$ 2,861.65	$ 2,848.97	$ 2,832.00	$ 2,813.10	$ 2,853.45	$ 2,894.75	$ 2,937.07	$ 2,985.91	$ 3,034.44	$ 3,084.24	$ 3,140.78	$ 3,200.93	$ 3,265.01	$ 3,333.73	$ 3,410.49	$ 3,492.89	$ 3,574.53	$ 3,652.11
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW	$ 2,259.38	$ 2,246.64	$ 2,262.60	$ 2,286.68	$ 2,309.60	$ 2,333.31	$ 2,378.28	$ 2,424.79	$ 2,472.95	$ 2,527.32	$ 2,582.42	$ 2,639.60	$ 2,703.49	$ 2,771.64	$ 2,844.45	$ 2,922.68	$ 3,009.39	$ 3,102.78	$ 3,197.48	$ 3,290.70
SOLAR PHOTOVOLTAIC, 150 MWAC	$ 2,147.25	$ 2,105.44	$ 2,088.62	$ 2,077.26	$ 2,062.80	$ 2,046.87	$ 2,025.85	$ 2,002.49	$ 1,976.65	$ 1,951.44	$ 1,922.32	$ 1,953.23	$ 1,988.21	$ 2,025.45	$ 2,065.14	$ 2,107.72	$ 2,155.21	$ 2,206.22	$ 2,256.97	$ 2,305.52
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MWx200 MWh	$ 2,742.99	$ 2,689.97	$ 2,669.48	$ 2,656.17	$ 2,638.93	$ 2,619.85	$ 2,618.90	$ 2,616.53	$ 2,612.65	$ 2,611.68	$ 2,607.62	$ 2,649.50	$ 2,696.97	$ 2,747.48	$ 2,801.31	$ 2,859.05	$ 2,923.49	$ 2,992.68	$ 3,061.40	$ 3,126.95
Capacity Prices ($/MW-day)																				
SPP_Central/KSMO Cap.	$ 244.69	$ 249.26	$ 253.74	$ 258.39	$ 263.19	$ 267.93	$ 272.77	$ 277.64	$ 282.65	$ 287.87	$ 293.36	$ 299.07	$ 304.98	$ 311.10	$ 317.44	$ 323.95	$ 330.51	$ 337.23	$ 344.13	$ 351.26

Exhibit F: Stakeholder Engagement, Comments and Report

1. Stakeholder Engagement

SWEPCO established a stakeholder engagement process, pursuant to Arkansas Public Service Commission (APSC) rules providing for broad participation in the planning or review process before the plan is submitted to the APSC. SWEPCO's three objectives for the stakeholder engagement process are:

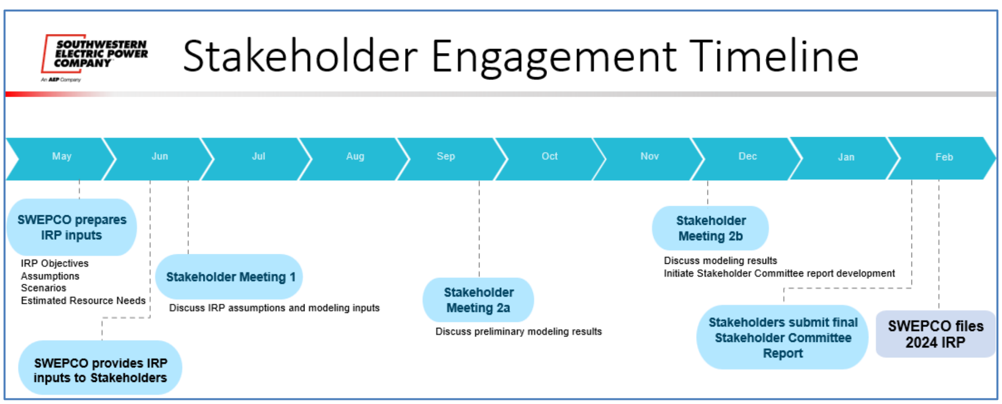
- **Listen:** Understand resource planning concerns and objectives of stakeholders.
- **Inform:** Increase stakeholder understanding of the IRP process, key assumptions and the challenges facing SWEPCO and the electric utility industry.
- **Consider:** Provide a forum for productive stakeholder feedback at key points in the IRP process to inform SWEPCO's resource planning decision making.

The Stakeholder Committee have produced a report, dated February 7, 2025, summarizing the discussions, decisions, and actions taken during these engagements, highlighting the collaborative efforts to ensure all stakeholder concerns were adequately addressed.

2. Stakeholder Engagement Summary

In its 2024 Arkansas IRP development, SWEPCO actively engaged a Stakeholder Committee, comprising of key stakeholders, to convene three times to discuss and address various questions and comments related to the development of the IRP. A timeline of the engagement is found below in Exhibit F-1.

Exhibit F-1



Stakeholder meetings were virtually held on June 6, September 30, and December 13 of 2024. Summaries of the agenda and discussion topics are found below. During these meetings, Stakeholders' questions and comments were addressed either during the meetings or through communications both before and after the meetings. The Company's responses to the Stakeholder Committee questions and comments can be found on SWEPCO's IRP website:

- https://www.swepco.com/community/projects/arkansasirp/.

3. Stakeholder Meeting Details

Stakeholder 1 Meeting Agenda, held on June 6, 2024:

- IRP Process
- 2024 IRP Objectives & Metrics
- IRP Inputs
- Proposed Scenarios and Portfolios
- Proposed Portfolio Performance Metrics
- Discussion & Feedback

Stakeholder 2A Meeting Agenda, September 30, 2024:

- IRP Planning and Assumptions Review
- IRP Inputs
- Portfolio Results
- Remaining Analysis Review
- Discussion & Feedback

Stakeholder 2B Meeting Agenda, held on December 13, 2024:

- IRP Planning and Assumptions Review
- IRP Inputs Review
- Portfolios Results
- Performance Indicators, Supplemental Analysis & Preferred Plan
- Discussion & Feedback

4. Stakeholder Committee Report

As part of the established a stakeholder engagement process, the Stakeholder Committee produced a findings report, dated February 7, 2025. The report is found below in Exhibit F-2.

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE FILING OF	**)**	
SOUTHWESTERN ELECTRIC POWER	**)**	
COMPANY'S CURRENTLY	**)**	
EFFECTIVE RESOURCE PLAN	**)**	**Docket No. 07-011-U**
PURSUANT TO THE COMMISSION'S	**)**	
RESOURCE PLANNING GUIDELINES	**)**	

REPORT OF THE STAKEHOLDER COMMITTEE ON SOUTHWESTERN ELECTRIC POWER COMPANY'S ARKANSAS 2024 INTEGRATED RESOURCE PLAN PROCESS

The Arkansas Advanced Energy Association, City of Fayetteville, National Audubon Society, Sierra Club, and Southern Renewable Energy Association the (collectively, "the Stakeholders") appreciate the opportunity to provide this Report of the Stakeholder Committee for filing with the 2024 Southwestern Electric Power Company ("SWEPCO" or "Company") Integrated Resource Plan ("IRP") pursuant to Section 4.8 of the Arkansas Public Service Commission ("Commission") Resource Planning Guidelines for Electric Utilities ("RPGs"). We have attended stakeholder meetings, including the presentations held by SWEPCO on June 6, September 30, and December 13 of 2024. We thank SWEPCO for providing timely responses to our Stakeholder questions, facilitating remote participation in meetings, and posting information publicly on its IRP website.[1] The following Stakeholder Committee Report provides our recommendations for how SWEPCO may improve this IRP, consistent with the objectives set forth in Section 4.1 of the Commission's Resource Planning Guidelines.[2]

[1] *See* SWEPCO, 2024 Arkansas Integrated Resource Plan (IRP). Available at https://www.swepco.com/community/projects/arkansasirp/.

[2] Arkansas Public Service Commission, Resource Planning Guidelines, Section 4.1 ("The objectives of the Resource Plan include, but are not limited to, low cost, adequate and reliable mew services; economic efficiency; financial integrity of the utility; comparable consideration of demand and supply resources; mitigation of risks, consideration of demand impacts; and consistency with governmental regulations and policies.").

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I. SWEPCO should select the Enhanced Environmental Regulation portfolio as its preferred portfolio and should adjust its short-term action plan to focus on no-regrets renewable procurement.

Table 1 shows SWEPCO's scenario framework for its IRP modeling. SWEPCO modeled a base case that represents business as usual and an Enhanced Environmental Regulation ("EER") case that examines the impacts of the 111 Rules. In addition, it modeled six scenarios that examine the impacts of high and low commodity prices and technology costs.

Table 2 shows resource builds over the next decade for the eight scenarios that SWEPCO modeled. All portfolios add between 2.6 and 3.4 GW of gas capacity over the next decade. This includes the conversion of Welsh to gas (1.1 GW), which the model selected in all scenarios. The remaining gas capacity additions are a mix of new combined cycle units ("CC"), new combustion turbines ("CT"), and coal-to-gas conversions. In the base portfolio, the model adds 1.1 GW of new CCs and 960 MW of new CTs between 2025 and 2034. In the EER portfolio, the model converts Flint Creek and Turk to gas (in addition to Welsh) and builds a correspondingly smaller quantity of new CCs (760 MW). The base and EER scenarios have the same quantity of CTs.

Renewable additions over the next decade vary widely among the scenarios. In the base case, the model adds 600 MW of solar and no wind by 2034, while in the EER case the model adds 750 MW of solar and 600 MW of wind. None of the portfolios include any battery storage.

Table 1. SWEPCO scenario structure[3]

Portfolio	SWEPCO Load	Commodity Prices	Environmental Regulations	Technology Cost
Base Case	Base	Base	Base	Base
Enhanced Environmental Regulations (EER)	Base	EER	Informed by 111 Rules	Base
High Case	High	High	Base	Base
Low Case	Low	Low	Base	Base
High Commodity Sensitivity	Base	High	Base	Base
Low Commodity Sensitivity	Base	Low	Base	Base
High Technology Cost Sensitivity	Base	Base	Base	Base + 25%
Low Technology Cost Sensitivity	Base	Base	Base	Base – 25%

Table 2. Cumulative capacity additions 2025–2034 in the eight portfolios SWEPCO modeled[4]

Resource Type	Base Case	EER Case	High Case	Low Case	High Commodity	Low Commodity	High Tech	Low Tech
Gas capacity	**3,113**	**3,421**	**3,213**	**2,633**	**2,733**	**3,113**	**3,113**	**2,733**
Coal to gas conversions	1,053	1,701	1,053	1,053	1,053	1,053	1,053	1,053
New CC	1,100	760	-	1,100	-	1,100	1,100	-
New CT	960	960	2,160	480	1,680	960	960	1,680
Renewables	**600**	**1,350**	**1,200**	**-**	**1,450**	**-**	**450**	**1,900**
Solar	600	750	-	-	450	-	450	900
Wind	-	600	1,200	-	1,000	-	-	1,000
Energy Efficiency	**97**	**98**	**87**	**178**	**96**	**112**	**257**	**81**

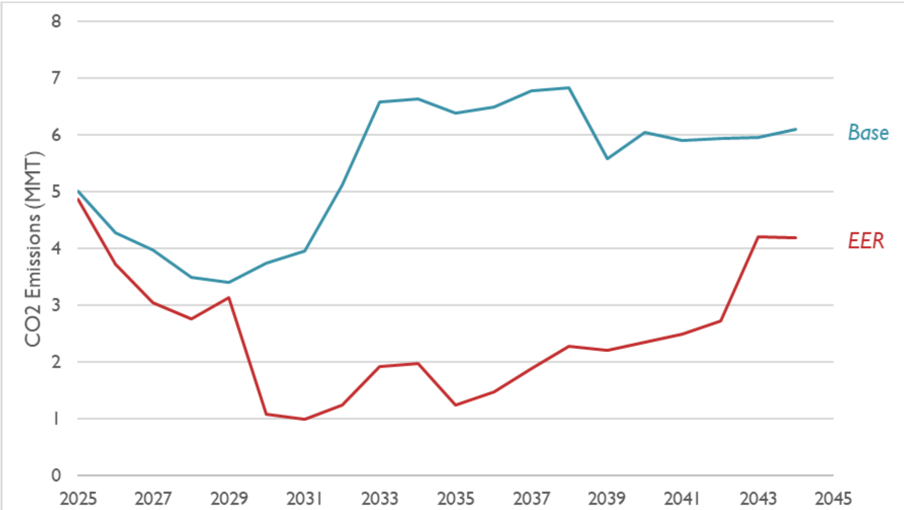
[3] SWEPCO December 13, 2024 stakeholder meeting slide deck at 14 and 16. Available at https://www.swepco.com/lib/docs/community/projects/SWEPCO_2024_IRP_Stakeholder%20Meeting_2B_Dec13_2024-R2.pdf.
[4] SWEPCO IRP Workpapers: *"2024 SWEPCO IRP Capacity Additions Summary Stakeholder Work Paper.xlsx."*

SWEPCO selected the base portfolio as its preferred portfolio, citing its low energy market risk, higher quantity of dispatchable resources, and portfolio diversity benefits.[5] However, the base and EER portfolios have very similar net present value rate of returns ("NPVRRs"): $17.1 billion for the base portfolio compared to $17.2 billion for the EER portfolio,[6] suggesting that SWEPCO should pursue whichever strategy will best shield ratepayers from risk going forward.

SWEPCO's selection of the base portfolio ignores regulatory risk. SWEPCO will likely face at least some level of climate regulation over the next two decades. The EER portfolio more accurately reflects the likely future regulatory environment than the base portfolio. Figure 1 shows carbon dioxide ("CO_2") emissions in the base and EER portfolios. In the base case, emissions fall in the near-term but then rise rapidly after 2029 due to the large number of gas CC additions. By 2033, emissions are 31 percent higher than today's levels, and they remain elevated through the end of the study period. The base portfolio would therefore expose ratepayers to a high level of risk associated with future climate regulations – SWEPCO could incur large costs to retrofit its gas CC and other fossil fuel units to comply with greenhouse gas regulations, potentially increasing the NPVRR of this portfolio substantially above what SWEPCO modeled in its IRP.

[5] SWEPCO December 13, 2024 stakeholder meeting slide deck at 37.
[6] *Id.* at 35.

Figure 1. Carbon dioxide emissions in the base and EER portfolios[7]



In the EER portfolio, emissions fall through 2031 as the Company's coal units retire, reaching a low of 1.0 million metric tons ("MMT") CO_2 in 2031 (79 percent lower than today's emissions). Emissions then begin to increase as CC buildouts replace purchased energy in SWEPCO's energy mix. While the EER portfolio will not completely shield ratepayers from regulatory risk, it represents a significant improvement over the base case, especially in the near term.

The CC builds in the base case will lock SWEPCO into paying for costly assets that are not resilient to future climate regulation or to increases in fuel prices. SWEPCO's modeling shows that in scenarios with high commodity prices, new CCs are not economic – the model selected no CCs between 2025 and 2034 in the High Case and High Commodity Sensitivity (Table 2). This underscores the risks associated with relying on new CCs as energy resources. If gas prices rise, ratepayers will be locked into paying off the large capital investment in the CCs as well as paying high fuel costs for generation from the units. Coal-to-gas conversions generally

[7] SWEPCO Response to Stakeholder Question 1B (January 2025), "SWEPCO_2024_AR_IRP_StakeholderMtg2B_Responses_Attachment 1-1 Stakeholder Question 1B.xlsx."

involve smaller capital investments than construction of new CCs, but SWEPCO should be similarly cautious about investing in gas pipeline to serve converted coal units, as these investments in gas infrastructure pose similar risks to building new gas plants.

In contrast, the near-term solar and wind builds in the EER portfolio are no-regrets resource additions that will provide low-cost energy to ratepayers, regardless of the level of future climate regulation or increase in fuel prices. SWEPCO should therefore adjust its short-term action plan to focus on testing the market and procuring renewables, rather than locking itself into risky new gas assets. This approach will preserve SWEPCO's flexibility to respond to future regulatory and market developments. Critically, SWEPCO should not limit its procurement of renewables based on the limits it imposed in the model, but rather should attempt to procure as much as the market can economically supply.

II. The Northwest Arkansas load pocket remains a key stakeholder concern that SWEPCO should address in its IRP.

Sierra Club's September 2024 comment letter raised concerns about SWEPCO's continued delay in addressing the Northwest Arkansas load pocket. The load pocket currently presents a barrier to retiring the Flint Creek coal plant. The area inside the load pocket has limited transmission interconnection with the surrounding power system and depends on three critical facilities (two 345 kV transmission lines and Flint Creek) to maintain reliability.[8] Past Company analysis has found that when Flint Creek retires, SWEPCO will need to construct an additional transmission line to maintain reliability in the area during high load periods, or else replace it with generation located within the load pocket.[9] This transmission solution will be needed regardless of whether Flint Creek retires now or in the future.

[8] Order No. 14, Arkansas Public Service Commission, Docket No. 12-008-U at 27 (July 10, 2013). Available at https://apps.apsc.arkansas.gov/pdf/12/12-008-u_227_1.pdf.
[9] *Id*.

Flint Creek began operating in 1978, and given the plant's age, the question is not so much *whether* a new transmission line will be necessary as *when* it will be necessary. The Company currently plans to wait until 2028 to begin planning for transmission solutions related to Flint Creek's retirement. This timeline is based on SPP's long-term planning process – which looks out ten years – and Flint Creek's scheduled retirement date of 2038.[10] In our September 2024 letter, Sierra Club recommended that SWEPCO begin analyzing solutions to address the Northwest Arkansas load pocket now, including studying whether earlier construction of the transmission line would be economically beneficial to ratepayers. While the driver of the transmission line is the retirement of Flint Creek, the line could also provide value to the system by enabling access to lower-cost renewable energy development outside of the load pocket.

In its response to Sierra Club's September comment letter, the Company failed to engage with the substance of this recommendation, instead writing that, "SWEPCO disagrees with the assumption that the Northwest Arkansas Load Pocket presents a reliability issue. Currently, the Northwest Arkansas Load Pocket is reliably served, including by the operation of Flint Creek."[11] During the December stakeholder meeting, SWEPCO appeared similarly dismissive of stakeholder concerns about the load pocket, explaining that areas where load exceeds generation are common on the power system. Our concern is not with the presence of a load pocket, but rather SWEPCO's refusal to address it. Transmission into the area is limited, creating a barrier to retiring generation inside the load pocket – including coal units like Flint Creek that are otherwise facing significant economic pressure to retire.

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[10] SWEPCO responses to initial stakeholder questions at 5. Available at https://www.swepco.com/lib/docs/community/projects/SWEPCO_2024_IRP_Stakeholder_Committee_Initial_Questions_and_Requests_8-16-24.pdf.
[11] SWEPCO response to Sierra Club pre-meeting suggestions at 3. Available at https://www.swepco.com/lib/docs/community/projects/SWEPCO_2024_AR_IRP-SWPECO_Responses_to_Sierra_Club_Pre-Meeting_Suggestions.pdf.

SWEPCO's lack of serious engagement on this issue is particularly concerning given that the Arkansas Public Service Commission directed the Company to address the load pocket more than ten years ago. The Commission's decision to approve flue gas desulfurization ("FGD") scrubbers at Flint Creek in 2013 was contingent on SWEPCO and Arkansas Electric Cooperative Corporation ("AECC") continuing "to work with SPP to conduct an appropriate solutions study to timely address reliability issues in the Northwest Arkansas load pocket."[12] At the time, the Commission estimated that it could take SWEPCO seven years to implement a transmission solution to the load pocket,[13] but over a decade later, SWEPCO still has not done so. Despite more recent stakeholder efforts to draw attention to the issue, including a June 2024 working group meeting convened by Commission Staff to discuss the load pocket, SWEPCO continues to delay addressing this problem.

III. When the availability of transmission impacts resource planning decisions, as it does in the Northwest Arkansas Load Pocket, SWEPCO should integrate transmission solutions and planning into its IRP.

In its current IRP materials, the Company again notes that additional transmission may be necessary once Flint Creek retires but says that it will not model any transmission solutions as part of its IRP.[14] SWEPCO's position is that transmission planning is outside the scope of its IRP and should take place exclusively through SPP's regional planning processes.[15] SWEPCO reiterated this position in response to Sierra Club's September comments, pointing to the Arkansas Resource Planning Guidelines,[16] which state that:

> The transmission plan necessarily results from a separate planning process and is a separate plan; however, it should be integrated into the overall resource planning

[12] Order No. 14, Arkansas Public Service Commission, Docket No. 12-008-U at 39 (July 10, 2013).
[13] *Id.* at 37.
[14] SWEPCO responses to initial stakeholder questions at 4–5.
[15] SWEPCO responses to initial stakeholder questions at 4–5 and 7.
[16] SWEPCO responses to Sierra Club Pre-Meeting Suggestions at 2–3.

> process, such that the analysis of generation options and demand response options can be synthesized and optimized. Transmission planning will be done by an independent entity and is regional in scope.[17]

It is true that SPP rather than SWEPCO is responsible for regional transmission planning, as the Resource Planning Guideline describes. However, SPP's planning focuses on reliability and other regional factors and would not necessarily identify if additional transmission would benefit SWEPCO ratepayers in the context of a least-cost resource planning portfolio. Specifically, SPP's 2024 Integrated Transmission Planning ("ITP") Assessment Report says the following about the projects it identified:

> The 2024 ITP portfolio is comprised of reliability, winter weather, economic, short circuit and operational projects that will mitigate 1,062 system issues. Reliability projects allow the region to meet compliance requirements and keep the lights on by providing loading relief, voltage support, and system protection. Winter weather projects address voltage and thermal overload violations that SPP observed during winter storm Elliott and a generically modeled winter storm based on aggregation of common stressors from multiple previous storms. Economic projects allow the region to lower energy costs through mitigation of transmission congestion.[18]

As resource economics issue, the load pocket does not fall into any of the areas of focus listed in the ITP. The Northwest Arkansas load pocket is internal to SWEPCO's service area and presents a long-term resource planning and resource economics issue. In cases such as this, where transmission constraints prevent the utility from effectively evaluating a least-cost a portfolio, transmission solutions should be considered as part of the planning exercise. Specifically, SWEPCO should analyze transmission solutions to the load pocket as part of its IRP, and it should consider all the value streams provided by new transmission – including enabling access

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[17] Arkansas Public Service Commission. Resource Planning Guidelines for Electric Utilities. Available at: https://www.sos.arkansas.gov/uploads/rulesRegs/Arkansas%20Register/2007/jun_2007/126.03.07-003.pdf.
[18] 2024 SPP Transmission Planning Assessment Report, January 24, 2025. Available at https://www.spp.org/documents/73086/2024%20itp%20assessment%20report%20v1.0.pdf.

to lower-cost renewables – to determine whether transmission buildout prior to 2038 would be the lowest cost option for ratepayers.

IV. Modeling economic retirement of Flint Creek is within the scope of the IRP, and SWEPCO should model early retirement and replacement of Flint Creek in multiple portfolios to determine if this option can save ratepayers money.

SWEPCO hard-coded Flint Creek's retirement date at the end of 2038 into all scenarios except the EER case. EER is the only scenario that includes the 111 rules.[19] In the EER case, SWEPCO modeled three options for Flint Creek: full conversion to gas by January 1, 2030; 40 percent gas co-firing by January 1, 2030; or retirement by January 1, 2032.[20] Continued operation on coal was not an option in this scenario. The model opted to convert Flint Creek fully to gas,[21] but it is unclear what assumptions and costs the company included for gas pipeline infrastructure.

SWEPCO did not allow endogenous retirement of existing resources in any scenarios, and it did not test early retirement of Flint Creek in any context except compliance with the 111 Rules.[22] SWEPCO argued that analyzing retirement of Flint Creek would be outside the scope of the IRP, because the "IRP process evaluates incremental variable production costs and fixed costs rather than a comprehensive assessment of all considerations of a retirement decision."[23] Notably, capital expenditures and new resource costs are exactly what the Company should be taking into account when deciding to retire a unit. If the forward-going, avoidable costs of an existing generating unit are greater than the all-in cost of replacement resources, the existing unit

[19] SWEPCO responses to initial stakeholder questions at 6.
[20] SWEPCO December 13, 2024 stakeholder meeting slide deck at 15.
[21] SWEPCO December 13, 2024 stakeholder meeting slide deck at 15 and 24.
[22] SWEPCO responses to Sierra Club Pre-Meeting Suggestions at 1.
[23] *Id.* at 1.

should be retired. This decision can and should be informed by the modeling that SWEPCO is completing for its IRP. An IRP is a resource planning, not a resource operations, exercise.

Similarly, it is unclear why SWEPCO argues that considerations such as "the cost of replacement resources," "potential reliability impact of the retirement," and the Company's "capacity and energy" needs, are "not within the scope of the IRP" [24] – these are the key considerations that a resource plan is designed to examine.

Modeling economic retirement of Flint Creek is clearly within the scope of SWEPCO's IRP. In fact, SWEPCO has completed this type of analysis in prior IRPs. For example, in its 2015 Arkansas IRP, SWEPCO modeled two "sensitivity" portfolios that considered power plant retirements, namely 1) an accelerated gas-steam unit retirement scenario, and 2) an early solid-fuel unit retirement scenario.[25] The Company modeled retiring "all gas-steam units five years earlier than initially planned" in the former scenario, and modeled retiring Pirkey unit 1 "[nineteen] years earlier than planned" in the latter scenario.[26] As part of its current IRP, SWEPCO should similarly model several portfolios with early retirement of Flint Creek, to test if this option would be economically beneficial to ratepayers. In addition, it is best practice in integrated resource planning to evaluate the economics of existing resources by modeling all avoidable forward-going resource costs and allowing the model to endogenously retire resources based on their economics.[27] SWEPCO should allow the model to endogenously retire coal units based on their economics in all scenarios.

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[24] *Id.*
[25] SWEPCO, 2015 Integrated Resource Planning Report at 108-109.
[26] *Id.*
[27] Synapse Energy Economics and Lawrence Berkley National Lab. 2024. *Best Practices in Integrated Resource Planning*, available at: https://eta-publications.lbl.gov/sites/default/files/2024-12/irp_best_practices_2024_synapse_lbnl_24-061_0.pdf.

V. SWEPCO has not adequately addressed stakeholder concerns that its assumptions about solar, wind, and battery storage costs and availability bias its model towards building conventional fossil resources.

In the September 2024 comment letter, Sierra Club presented concerns that SWEPCO's methodology for modeling new resources, which we believe biases the model towards building gas over renewables. SWEPCO has not adequately addressed these concerns, and as a result, its modeling continues to build more gas and fewer renewables than is likely to be economic for ratepayers in reality.

SWEPCO's capital cost assumptions for renewable resources are substantially higher than other industry sources. Figure 2, Figure 3, and Figure 4 compare SWEPCO's long-term estimates (now through 2044) for the overnight capital costs of wind, solar, and 4-hour battery storage to other industry forecasts. SWEPCO's forecasts for solar PV and wind are the highest, or among the highest, for all utilities we reviewed. Its 4-hour battery costs start in the middle of the range of the projections we reviewed, but decline less rapidly than the other projections.

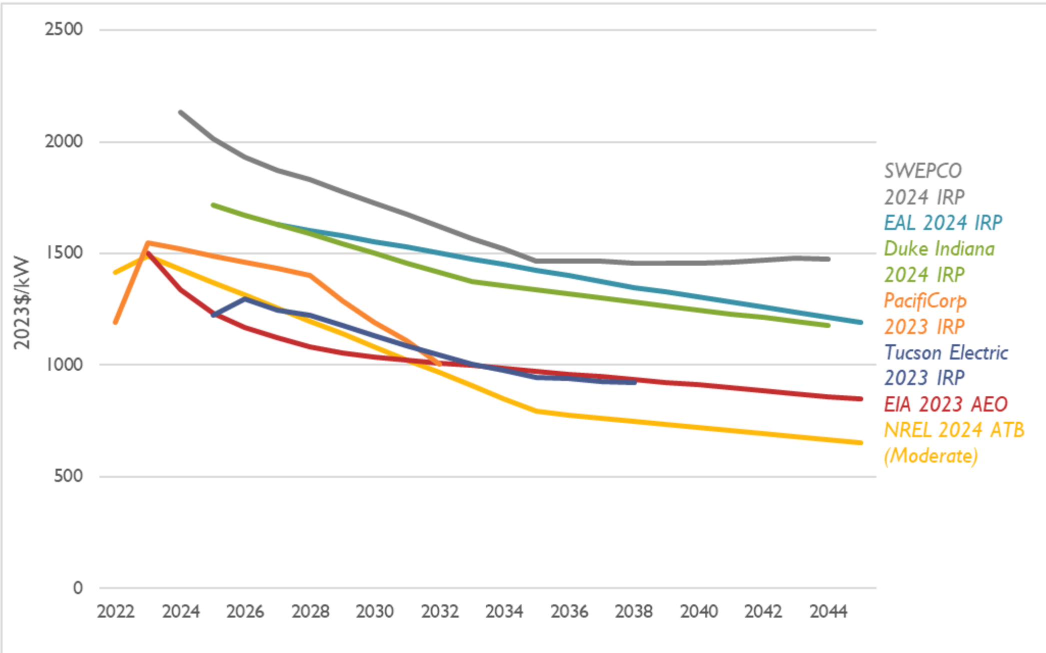
SWEPCO bases its current resource costs on request for proposal ("RFP") responses.[28] While these initial costs likely represent the actual market conditions for resources currently available to SWEPCO (or available at the time it received the bids), the Company's reliance on conservative learning curve assumptions (discussed below) cause the Company's costs to remain substantially higher than industry standard projections and other utility projections for the entire study period.

As justification for its high resource costs, SWEPCO again stated that it based its estimates on "market intelligence received by the Company from proposals received in its RFP processes."[29] As we explained in our first comment letter, it is reasonable to use starting costs

[28] SWEPCO responses to initial stakeholder questions at 16.
[29] SWEPCO responses to Sierra Club Pre-Meeting Suggestions at 3.

that reflect the results of recent RFPs. However, SWEPCO's response does not address the reason that the Company's cost projections *remain* so far above industry projections, which is that SWEPCO is using very conservative learning rate assumptions, as we discuss next.

Figure 2. Solar cost trajectories for SWEPCO compared to other utilities and industry sources[30]



[30] SWEPCO 024 IRP Stakeholder Meeting #1, June 6, 2024 at 33; NREL ATB 2024; EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Generating Power Technologies, January 2024; Lazard LCOE 2024; Entergy Response to Stakeholder Question 4, Set 5; TEP 2023 IRP; PacifiCorp's 2023 IRP; Duke Energy Indiana IRP Stakeholder Meeting 2, April 29, 2024.

Figure 3. Wind cost trajectories for SWEPCO compared to other utilities and industry sources[31]

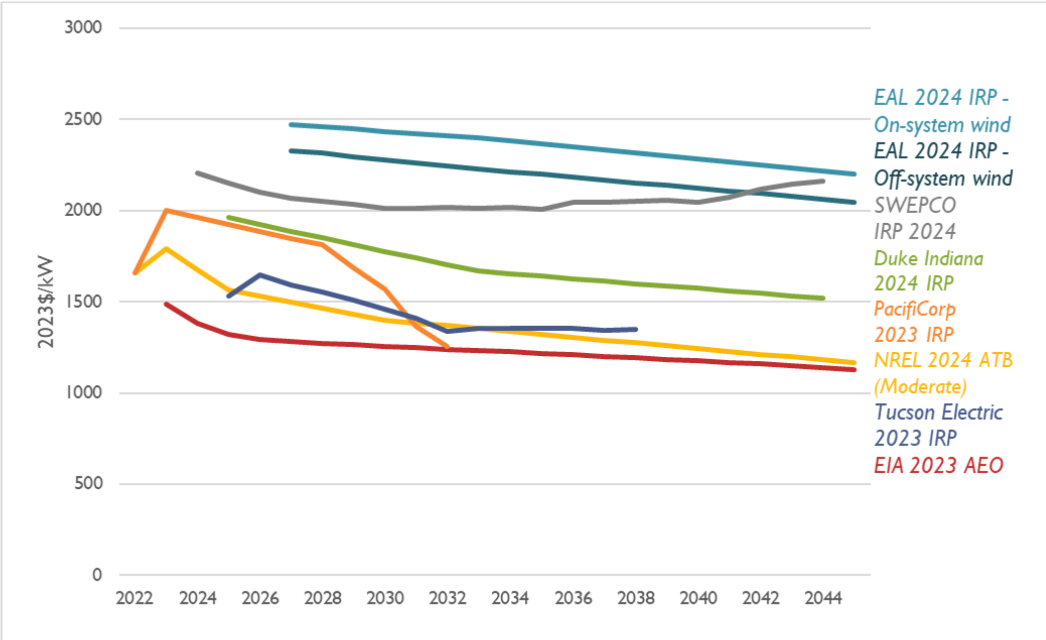
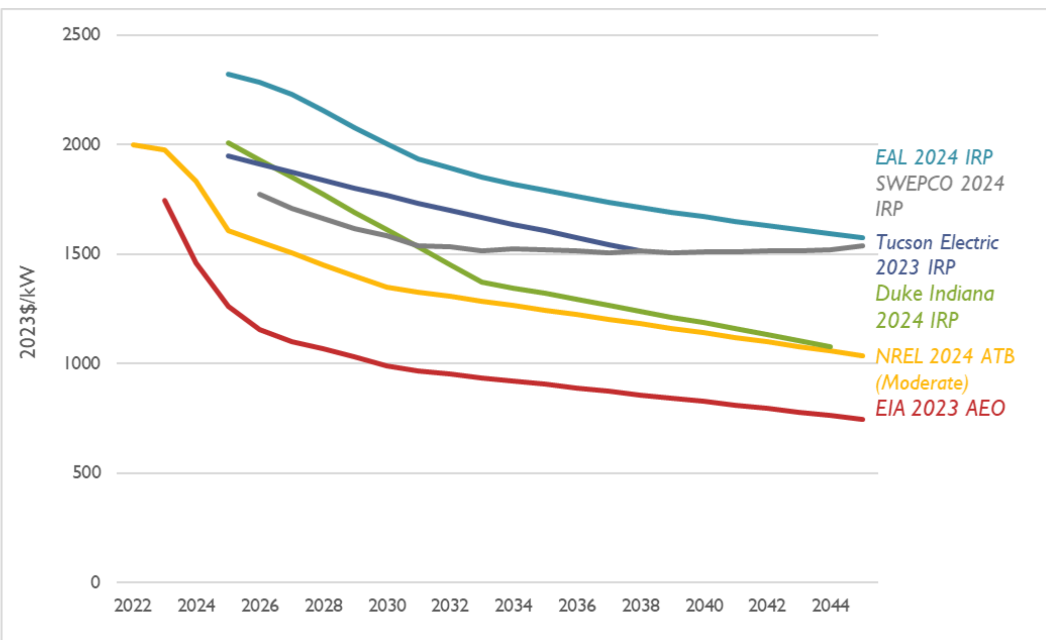


Figure 4. Four-hour battery cost trajectories for SWEPCO compared to other utilities and industry sources[32]



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[31] SWEPCO 2024 IRP Stakeholder Meeting #1, June 6, 2024 at 33; NREL ATB 2024; EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Generating Power Technologies, January 2024; Lazard LCOE 2024; Entergy Response to Stakeholder Question 4, Set 5; TEP 2023 IRP; PacifiCorp's 2023 IRP; Duke Energy Indiana IRP Stakeholder Meeting 2, April 29, 2024.

[32] SWEPCO 2024 IRP Stakeholder Meeting #1, June 6, 2024 at 33; NREL ATB 2024; EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Generating Power Technologies, January 2024; Lazard LCOE

SWEPCO models near-term cost declines, but then assumes solar and storage costs flatten out in the early- to mid-2030s, while wind costs actually rise around the same time (Figure 5). By 2044, wind costs are the same (in real dollars) as today – in other words, SWEPCO assumes that there will be *zero* decrease in wind costs over the next two decades. This does not match widespread industry expectations, and the source of SWEPCO's assumption is unclear. The Company includes a slide on NREL ATB cost decline trajectories in its stakeholder meeting materials,[33] but those do not match what it displays in its technology cost projections.[34] SWEPCO did not provide any additional explanation of these learning rates in its response to our letter.[35]

SWEPCO's conservative learning rates will bias the modeling results towards gas resources. Gas resources are generally considered mature technologies with limited room for technological or process improvement that will drive down costs. Solar and wind, on the other hand, are still developing as an industry and have substantial room for efficiency improvements on both hard costs (technology) and soft costs (procurement, permitting, etc.).

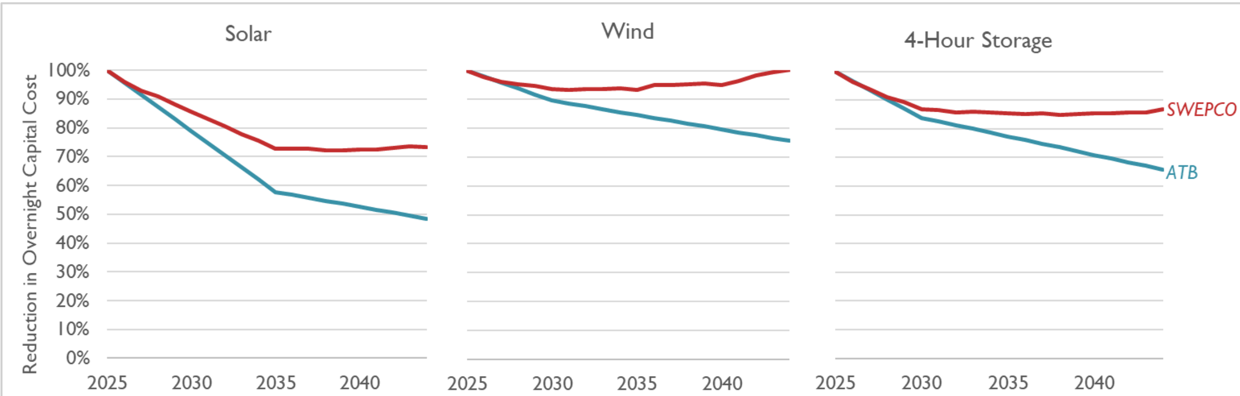
2024; Entergy Response to Stakeholder Question 4, Set 5; TEP 2023 IRP; PacifiCorp's 2023 IRP; Duke Energy Indiana IRP Stakeholder Meeting 2, April 29, 2024.

[33] 2024 IRP Stakeholder Meeting #1, June 6, 2024 at 32.

[34] *Id.* at 33.

[35] SWEPCO responded to our analysis by objecting to our conversion of its results from nominal to real dollars, saying this "do[es] not accurately represent SWPECO's 2024 IRP resource cost trajectories." This objection is confusing, given that we merely converted SWEPCO's results to a different a unit. In this letter, we continue to present the cost trajectories in real dollars to isolate the effects of learning curve assumptions from the effect of inflation.

Figure 5. Comparison of SWEPCO renewable learning curve assumptions (red) to the ATB moderate case (blue)[36] ($2023)



In addition to using artificially high resource cost estimates, SWEPCO includes annual and cumulative build limits in its modeling as shown in Figure 6. While annual build limits may be justified in the near-term based on actual market constraints, it is not reasonable to assume that this will continue indefinitely into the future. The limits on battery storage in particular are low at only 50 MW/year of 4-hour storage and 20–100 MW per year of the longer durations. Even more concerning is the cumulative build limits on BESS, which range between 200 MW and 500 MW over the entire study period. This is in contrast with new CTs, which have a cumulative limit that is an order of magnitude higher at 4,560 MW While the build limits are not binding in SWEPCO's current modeling results – meaning the model never reaches the build limit for any of its resources – they have the potential to become binding if SWEPCO adjusts its resource costs as we described above and adopts more defensible technology cost decline trajectories.

[36] NREL ATB 2024; SWEPCO 2024 IRP Stakeholder Meeting #1, June 6, 2024 at 33.

Figure 6. SWEPCO annual build limit assumptions[37]

Technology	First Year Available	Block Size (MW)	Annual Limit (MW)	Cumulative Technology Total [MW]
NGCC H-Class Single-Shaft	2032	418	836	4598
NGCC H-Class Multi-Shaft	2032	1100	1100	4400
NGCC F-Class Multi-Shaft	2032	760	760	4560
NGCC H-Class Single-shaft with 90% Carbon Capture	2032	390	780	4290
NGCT F-Class 240 MW	2031	240	720	4560
100 MW Aeroderivative	2031	105	210	945
20 MW Reciprocating Engines	2031	21	105	900
4-Hour Duration Lithium-Ion Battery	2029	50	50	250
6-Hour Duration Lithium-Ion Battery	2029	50	100	500
8-Hour Duration Lithium-Ion Battery	2029	50	100	500
10-Hour Duration Lithium-Ion Battery	2029	50	50	250
100-Hour Duration Storage	2029	20	20	200
Utility-scale Onshore Wind Tier 1	2029	75	300	3000
Utility-scale Onshore Wind Tier 2	2029	75	300	
Utility-scale Solar Photovoltaic Tier 1	2029	50	600	4500
Utility-scale Solar Photovoltaic Tier 2	2029	50	600	
Utility-scale Solar + Storage (3:1)	2029	150	300	1500
Small Modular Reactor	2036	300	600	4,500
Short Term Market Purchases	2024	1	200	400

VI. SWEPCO should include a metric measuring exposure to fuel price volatility on its scorecard and assess resource diversity using a more transparent methodology.

SWEPCO's scorecard emphasizes certain aspects of risk over others, again biasing the Company's results towards fossil resources and against renewables. The Company currently includes energy market exposure on its portfolio scorecard,[38] and it qualitatively considers the risk associated with portfolios that "include a high reliance on production tax credits and market sales revenues to offset capital investment costs" such as the EER portfolio.[39] But SWEPCO totally ignores fossil fuel price volatility and the risk to ratepayers posed by portfolios with high reliance on fossil resources. Portfolios with higher levels of fossil generation leave ratepayers exposed to volatile fuel prices, negatively impacting rate stability. To account for this risk, SWEPCO should include a metric for fuel price exposure on its scorecard.

[37] SWEPCO 2024 IRP Stakeholder Meeting #1, June 6, 2024 at 35.
[38] SWEPCO December 13, 2024 stakeholder meeting slide deck at 32.
[39] *Id.* at 36.

Relatedly, SWEPCO measures resource diversity using the Shannon-Weiner Diversity Index,[40] which is most commonly used in academic settings. For transparency and ease of stakeholder interpretation, we recommend that SWEPCO present data on resource diversity using a methodology that is simpler and more transparent, for example by showing the percentage of capacity and generation from each resource type, or else that it provide additional context for the index values, including a justification for how a higher Shannon-Weiner Index translates into tangible advantages from a utility resource planning perspective.

VII. SWEPCO's action plan should include a description of and timeline associated with its competitive bidding process, including a new all-source request for proposals

Section 4.6 of the Commission's Resource Planning Guidelines states that "[t]he action plan shall include a description of and timeline associated with the utility's competitive bidding process." However, the "Overview of Proposed Action Plan" provided on slide 38 of SWEPCO's December 2024 presentation does not include any description or timeline associated with SWEPCO's competitive bidding process. [41] Instead, it simply says "[s]eek additional capacity as needed; timing and amount will be impacted by all of the above." This language is very vague and therefore does not comply with the Commission's Resource Planning Guidelines. Additionally, slide 7 notes that SWEPCO conducted RFPs in 2024, but does not have an additional RFP planned. To address this ambiguity, the action plan in SWEPCO's filed IRP should provide more details about its procurement plans, even though they may be impacted by other aspects of the action plan.

[40] *Id.* at 9.
[41] 2025 Arkansas IRP Stakeholder Meeting: IRP Modeling Analysis & Results, December 13, 2024, https://www.swepco.com/lib/docs/community/projects/SWEPCO_2024_IRP_Stakeholder%20Meeting_2B_Dec13_2024.pdf.

In particular, SWEPCO's action plan should provide details regarding procurement process and timing for the near-term "Preferred Plan Capacity Additions" outlined on slide 37 from the December presentation. This slide indicates that SWEPCO will add a 480 MW new CT in 2029/30 and 2031/32, as well as 300 MWs of new solar in 2030/31 and 2031/32 respectively. SWEPCO's 2024 RFPs for solar include a commercial operations date of no later than 2028,[42] so the Stakeholders expect that SWEPCO would need to issue a new RFP for these resources. In response to Stakeholder questions regarding SWEPCO's procurement plans for these resources, SWEPCO stated the following:

> SWEPCO will follow the same process required by the [Louisiana Public Service Commission] that it has used for other recent RFPs including the 2024 RFP which ultimately led to the resources selected and presented to the APSC in Docket Nos. 24-044-U and 24-052-U. As to additional resources, SWEPCO is contemplating both the need for and timing of any actions at this point in time.

The Stakeholders recommend that SWEPCO include a new all-source RFP procurement process as part of its action plan, specify the timeframe when it plans to issue any new RFPs, and include a description of the RFP process that it will follow (pursuant to the Louisiana Commission's rules). The Stakeholders likewise recommend that SWEPCO plan to issue a new all-source RFP that is appropriately tailored to meet its projected capacity needs following the conclusion of the IRP process and prior to moving forward with the development of any particular generation resource or contract execution (with the exception of resources that were that were selected as part of previously issued RFPs, including its 2024 RFPs).[43] Having a procurement plan is required by the RPGs,[44] and issuing an all-source RFP before acquiring new

[42] SWEPCO, 2024 Wind, Solar, Storage & Natural Gas Energy Resource RFPS. Available at https://www.swepco.com/business/b2b/energy-rfps/2024-Energy-RFP.
[43] John Wilson, Mike O'Boyle, Ron Lehr, Mark Detsky, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (April 2020) at 1, available at https://energyinnovation.org/wp-content/uploads/2020/04/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices.pdf.
[44] Section 4.6 of the RPGs states that "The action plan shall include a description of and timeline associated with the utilities competitive bidding process."

generation resources is consistent with best resource planning practices.[45] At the conclusion of an IRP process, it has become industry standard to issue an RFP for renewable energy resources. Obtaining real market data directly from project developers via RFPs is the most accurate way to develop present-day cost expectations for most resources, particularly since the costs to procure new resources change constantly.[46] RFPs allow utilities to test the market against IRP assumptions and use competition to act in ratepayers' best interests. RFPs should be flexible, enabling renewable energy developers to bid in many different project sizes, locations, technologies, and contractual types.[47] Issuing RFPs is a zero-risk action item that should be included with every IRP, including this one.

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The Stakeholders appreciate the opportunity to participate in SWEPCO's IRP process pursuant to Section 4.8 of the Commission's Resource Planning Guidelines. The Stakeholders respectfully request that SWEPCO incorporate the recommendations provided in this Report into its 2024 IRP. The Stakeholders submit that their recommendations will be particularly helpful to aid SWEPCO in identifying a preferred Resource Plan pursuant to Section 4.5 of the Resource Planning Guidelines, as well as developing and finalizing an action plan pursuant to Section 4.6. The Stakeholders reserve their rights to file subsequent comments regarding the IRP process and results pursuant to Section 4.8 of the Commission's Resource Planning Guidelines.

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[45] *See* Synapse Energy Economics, *Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future,* November 2024 (Revised December 6, 2024) at 31, available at https://www.synapseenergy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf ("The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals.").
[46] *See id.* at 31.
[47] *See* Wilson et. al., *supra* note 43 at 31 (Model Process and For Bid Evaluation).

Respectfully Submitted,

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