SOUTHWESTERN ELECTRIC POWER COMPANY

An AEP Company

BOUNDLESS ENERGY

INTEGRATED RESOURCE PLANNING REPORT

TO THE

LOUISIANA PUBLIC SERVICE COMMISSION

August 29, 2019

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Cross Reference Table

REQUESTS OF THE LOUISIANA PUBLIC SERVICE COMMISSION STAFF	Location of SWEPCO's Response
The discussion of Existing Supply-Side Resources, and specifically the chart on page 23, did not include some of the information described in Section 5(b) of the IRP Rules, such as: 1) ownership information 2) condition of the resource; and 3) locations.	Refer to the updated Table 1 in Section 3.2
Staff requested that the Company's Final IRP Report include a detailed narrative discussion of the assumptions behind the Company's deactivations decisions, including any subjective decisions made in the assumptions. This discussion should also include any analysis which was performed with the result being a decision not to deactivate a unit.	See the updated Section 3.2
SWEPCO's Final IRP Report should include estimates of the rate impacts of the Company's portfolios.	See the updated Section 5.3.2
In order to comply with the IRP Order, the Company's Final IRP Report should include a discussion of existing fuel contracts.	See the updated Section 3.2.1
Staff requests that the Company's Final IRP Report contain a Five-Year Action Plan that complies with the IRP Rules.	See the Executive Summary and Section 6.1
Staff recommends that the Company include a chart responding to each of the stakeholders' comments on the Company's Draft IRP Report in the Company's Final IRP Report.	see Exhibit I

Executive Summary

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

An IRP explains how a utility company plans to meet the projected capacity (*i.e.*, peak demand) and energy requirements of its customers. SWEPCO is required to provide an IRP that encompasses a 20-year forecast planning period (in this filing, 2019-2038). This IRP has been developed using the Company's current long-term assumptions for:

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

To meet its customers' future energy requirements, SWEPCO will continue the operation of, and ongoing investment in, its existing fleet of generation resources including its efficient base-load coal plants, its newer combined cycle and combustion turbine plants, and certain older gas-steam plants. In addition, SWEPCO must consider the impact of the ongoing promulgation of environmental rules as well as the emergence of new technologies and renewable energy resources, both large-scale and distributed.

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

Environmental Compliance Issues

This 2019 IRP considers the impacts of final and proposed U.S. Environmental Protection Agency (EPA) regulations to SWEPCO generating facilities. Environmental compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. In addition, the IRP development process assumes potential future regulation of greenhouse gas (GHG)/carbon dioxide (CO_2). For that purpose, a reasonable proxy was utilized in the IRP that assumed that the resulting economic impact would be equivalent to a CO_2 "tax" applicable to each ton of carbon emitted from fossil-fired generation which would take effect beginning in 2028. Under the Company's Base commodity pricing scenario, the cost of such CO_2 emissions is equal to $15/metric ton commencing in 2028 and escalating at 5% per annum thereafter on a nominal dollar basis.

Louisiana IRP Stakeholder Process

In Louisiana, various stakeholders, including Louisiana Commission staff, were presented IRP assumptions in July 2018 and provided useful feedback which has been considered and incorporated in the analysis assumptions, where warranted.

Key dates related to the IRP process are shown below:

➢ SWEPCO submits request to initiate IRP Process	Dec. 2017
➢ SWEPCO holds first Stakeholder meeting	July 2018
➢ Stakeholders and Staff Comment on proposed plan	Sept. 2018
➢ Draft IRP is published	Jan. 2019
➢ SWEPCO holds second Stakeholder meeting	Feb. 2019
➢ Stakeholders file comments	April 2019
➢ Staff files comments	May 2019
➢ SWEPCO files Final IRP	Aug. 2019
➢ Staff submits recommendations to the Commission	Nov. 2019
➢ Commission Order acknowledging the IRP	Dec. 2019

Summary of SWEPCO Resource Plan

SWEPCO's retail sales are projected to grow at 0.2% per year with stronger growth expected from the residential class (+0.5% per year) while the commercial class experiences a modest decrease (-0.1% per year) and the industrial class experiences modest increases (0.2% per year) over the forecast horizon. The projected change in SWEPCO's internal energy over the next 20 years is for requirements to increase by 0.3% per year. Finally, SWEPCO's peak demand is also expected to increase at an average rate of 0.3% per year through 2039.

Figure ES- 1 below shows SWEPCO's "going-in" (i.e. before resource additions) capacity position over the planning period. In 2030, SWEPCO anticipates experiencing a 167MW capacity shortfall which then grows to approximately 1,600MW shortfall by 2038.

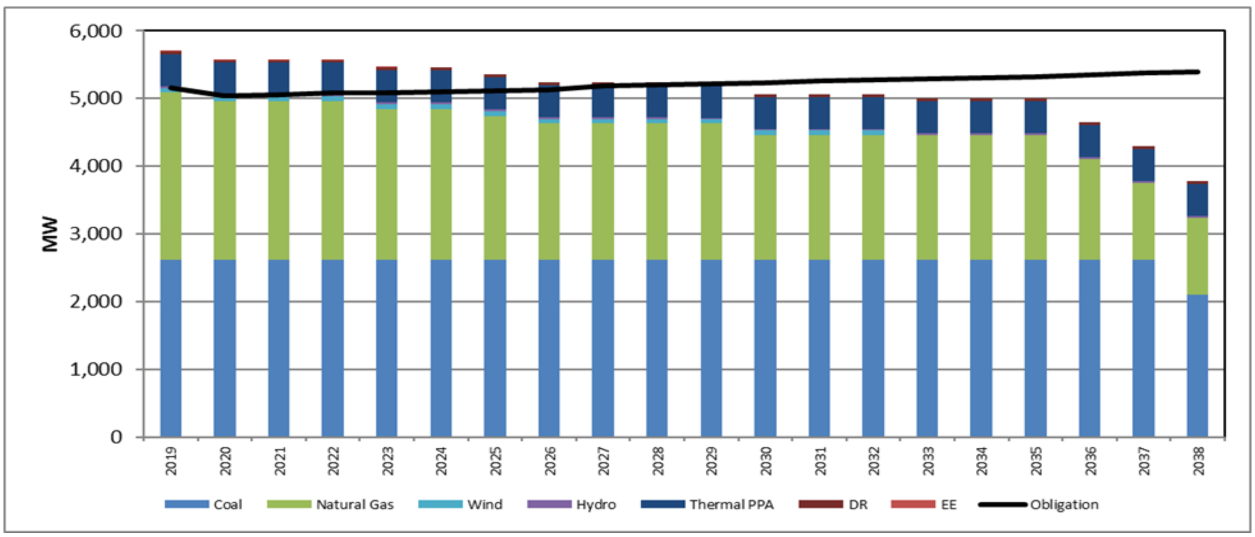

Figure ES- 1: SWEPCO "Going-In" SPP Capacity Position

To determine the appropriate level and mix of incremental supply and demand-side resources required to offset such going-in capacity deficiencies, SWEPCO utilized the *Plexos*® Linear Program (LP) optimization model to develop a "least-cost" resource plan. Although the IRP planning period is limited to 20 years (through 2038), the *Plexos*® modeling was performed through the year 2048 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

SWEPCO used the modeling results to develop a Preferred Plan or "Plan". To arrive at the Preferred Plan, using Plexos®, SWEPCO developed optimal portfolios based on five long-term commodity price forecasts and two load sensitivities. The Preferred Plan balances cost and other factors such as risk and environmental regulatory considerations, to cost effectively meet SWEPCO's demand and energy obligations. Given that the optimal portfolios under the five commodity pricing scenarios offer comparable resource additions, as discussed in Section 5, SWEPCO has elected to use the optimal plan developed under the Base commodity pricing scenario as its Preferred Plan.

Table ES- 1 provides a summary of the Preferred Plan, which was selected based on the results from optimization modeling under various load and commodity pricing scenarios:

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

Commodity Pricing Scenario		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base/ Preferred Plan	New Nat. Gas																				373
	New Solar (Nameplate)											150	300	600	800	950	1,100	1,250	1,400	1,400	1,400
	New Solar (Firm)											75	150	300	400	475	550	625	700	700	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	2,000	2,200	2,200	2,200
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	306	337	337	337
	New EE		5	8	10	10	11	12	11	10	8	7	6	6	5	5	3	3	2	2	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	34	34	47	47	47	47	58
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																				150
Capacity Reserves (MW) Above SPP Rqmts w/o new additions		547	540	510	480	373	357	237	119	50	47	15	(167)	(189)	(209)	(287)	(295)	(318)	(697)	(1,072)	(1,619)
Capacity Reserves (MW) Above SPP Rqmts with new additions		550	572	576	640	624	610	491	373	303	299	341	232	361	450	446	525	669	395	20	7

In summary, the Preferred Plan:

- Adds 200MW (nameplate) of wind resources in 2021, an additional 600MW (nameplate) in 2022 and 2023, 600MW (nameplate) in 2035 and 200MW (nameplate) in 2036 for a total of 2,200MW (nameplate) by the end of the planning period.
- Adds 150MW (nameplate) utility-scale solar resources beginning in 2029 increasing to 1,400MW (nameplate) of utility-scale solar by the end of the planning period.
- Implements customer and grid energy efficiency programs, including VVO, reducing energy requirements by 243GWh and capacity requirements by 59MW by 2038.
- Fills long-term needs through the addition of a total of 373MW of natural gas combined-cycle generation in 2038 to replace planned unit retirements.
- Recognizes additional distributed solar capacity will be added by SWEPCO's customers, beginning with 10MW (nameplate) in 2019 and growing to 24MW (nameplate) by 2038.

- In 2038, includes the addition of 150MW of Short-Term Market Purchases (STMP).

SWEPCO customers should recognize an increasing level of savings in their monthly bill over the planning period versus a plan with no renewables. The levelized monthly bill impact[1] analysis of the Preferred Plan relative to a plan where no renewables are selected indicates SWEPCO customer savings grow to over $15/month in their monthly bills.

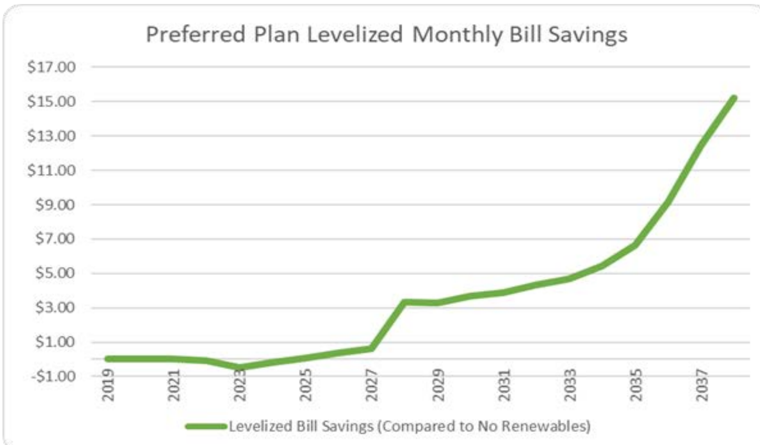

Figure ES- 2: SWEPCO Levelized Monthly Bill Savings

SWEPCO capacity changes over the 20-year planning period associated with the Preferred Plan are shown in Figure ES- 3 and Figure ES- 4. These figures show that the Preferred Plan would reduce SWEPCO's reliance on fossil fuel-based generation, and increase reliance on renewable resources. Specifically, over the 20-year planning horizon the Company's nameplate capacity mix attributable to renewable assets would increase from 8% to 46%, and fossil fuel-fired asset capacity declines from 91% to 52% due to the retirement of older gas steam units over the planning period and the retirement of a coal unit in 2037. Demand-side management (DSM), Demand Response (DR) and Distributed Generation resources increase from 1.2% to 2.0% of total nameplate capacity resources.

[1] The levelized monthly bill impact is an indicative estimate of the incremental cost (or savings) compared to a plan where no renewables were included. This indicative estimate is only capturing the costs and benefits related to the proposed resource additions included in this IRP. The estimate assumes the impact to an "Average Customer" that uses 12,000 kWh per year.

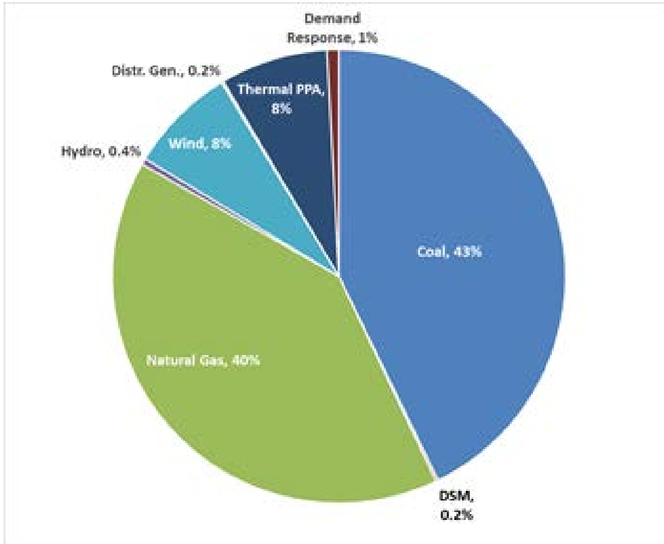

Figure ES- 3: 2019 SWEPCO Nameplate Capacity Mix

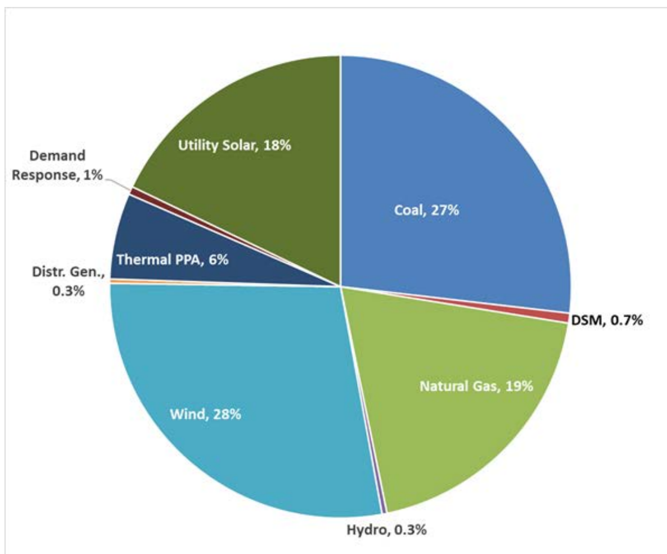

Figure ES- 4: 2038 SWEPCO Nameplate Capacity Mix

The relative impacts to SWEPCO's annual energy position are shown in Figure ES- 5 and Figure ES- 6. SWEPCO's energy output attributable to fossil fuel generation decreases from 88% to 48% over the planning period, while energy from renewable resources increases from 12% to 51%. Specifically, the Preferred Plan introduces solar resources, which contributes to 12% of total energy and energy from wind resources increases from 12% to 36% of SWEPCO's total energy mix.

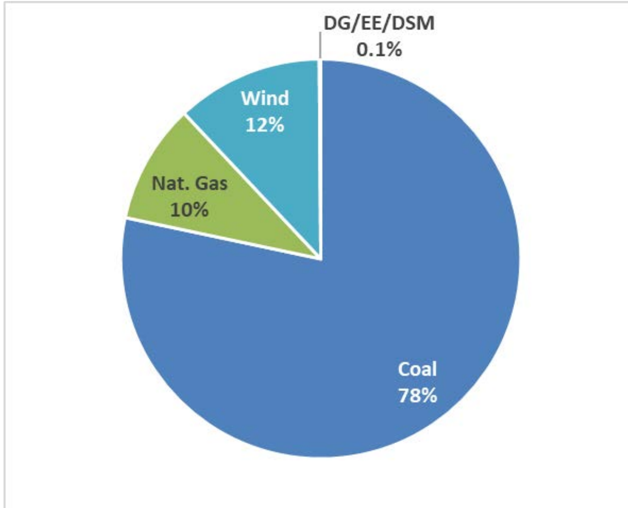

Figure ES- 5: 2019 SWEPCO Energy Mix

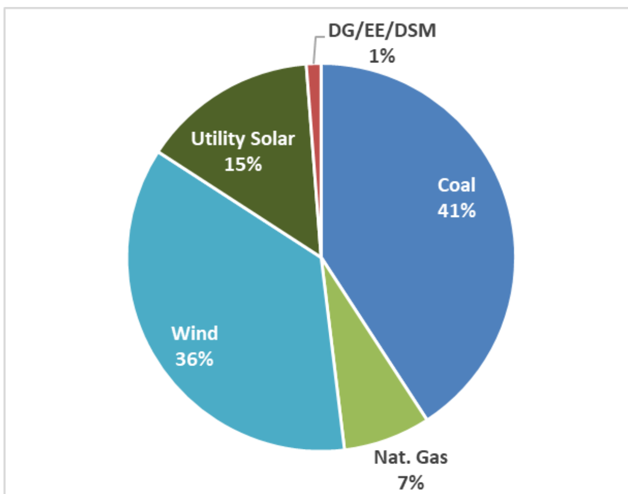

Figure ES- 6: 2038 SWEPCO Energy Mix

Figure ES- 7 and Figure ES- 8 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the treatment of capacity credit for intermittent resources within SPP; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they are a low cost energy resource. When comparing the capacity values in Figure ES- 7 with those in Figure ES- 3 and Figure ES- 4, it is important to note that Figure ES- 7 provides an analysis of SPP-recognized capacity, while Figure ES- 3 and Figure ES- 4 depict nameplate capacity.

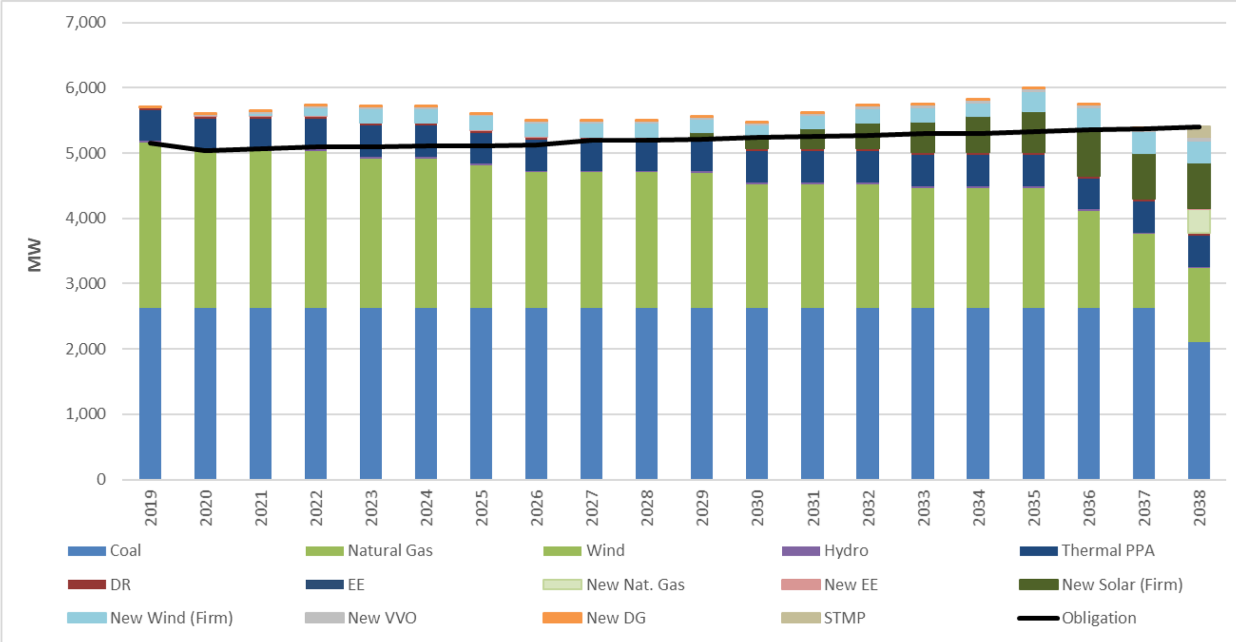

Figure ES- 7: SWEPCO Annual SPP Capacity Position (MW) per the Preferred Plan

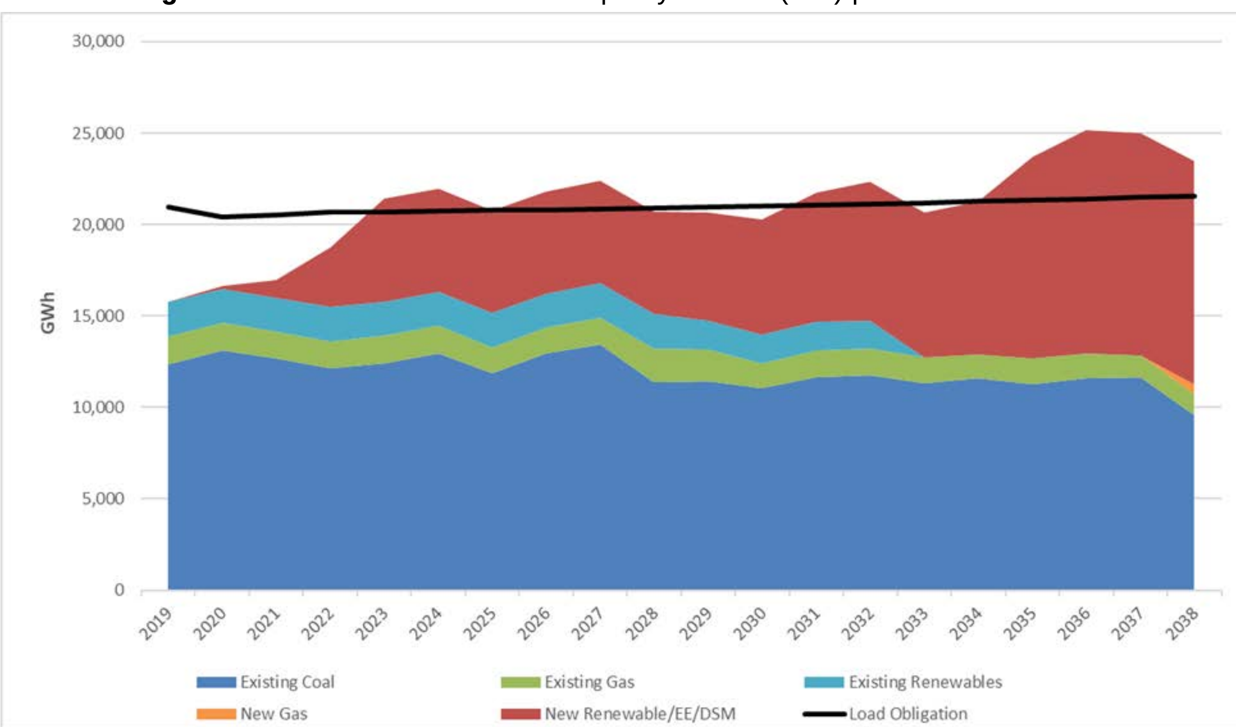

Figure ES- 8: SWEPCO Annual Energy Position (GWh) per the Preferred Plan

SWEPCO Five-Year Action Plan

In reference to the Preferred Plan and SWEPCO's ability to provide adequate capacity resources at a reasonable cost, the following actions over the next five (5) years are anticipated.

- Proceed with necessary regulatory filings consistent with commission rules around plant retirements including the Lone-Star 1, Lieberman 2 (12/31/2019) and Knox Lee Units 2 and 3 retirements (1/1/2020).
- Wind Resource Integration: Continue with the recently released Request for Proposal (RFP) to explore opportunities to add cost-effective wind generation in the near future to take advantage of the Federal Production Tax Credit.
- Solar Resource Integration: Continue efforts related to the notice filed with the commission to proceed with an RFP process in support of adding cost effective utility–scale solar resources.
- Environmental Impacts: Remain committed to closely following developments related to environmental regulations and update our analysis of compliance options and timeliness when sufficient information becomes available.
- Continue to work with the Commissioners related to the Quick Start Phase of energy efficiency programs scheduled to continue through December 31, 2019 and any potential extensions beyond 2019.
- Continue with the seasonal operation of Dolet Hills and continue to evaluate its viability.

Conclusion

SWEPCO's Preferred Plan provides the Company with an increasingly diversified portfolio of supply- and demand-side resources which provides flexibility to adapt to future changes to the power market, technology, and environmental regulations. The addition of renewables and demand-side management mitigates fuel price and environmental compliance risk. At the end of the planning period, efficient natural gas-fired generation will replace the capacity from a solid fuel unit that is expected to retire.

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

1.0 Introduction

1.1 Overview

This Report presents the 2019 Integrated Resource Plan (IRP, Plan, or Report) for Southwestern Electric Power Company (SWEPCO or Company) including descriptions of assumptions, study parameters, and methodologies. The results integrate supply- and demand-side resources.

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

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

1.2 Integrated Resource Plan (IRP) Process

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

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

1.3 Introduction to SWEPCO

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

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

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

SWEPCO's customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Arkansas, Louisiana and Texas (see Figure 1). Currently, SWEPCO serves approximately 539,000 retail customers in those states; including approximately 231,000 and 121,000 in the states of Louisiana and Arkansas, 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 (2018-19) actual SWEPCO summer and winter peak demands were 4,834MW and 4,090MW, occurring on July 19th and January 24th (2019), respectively.

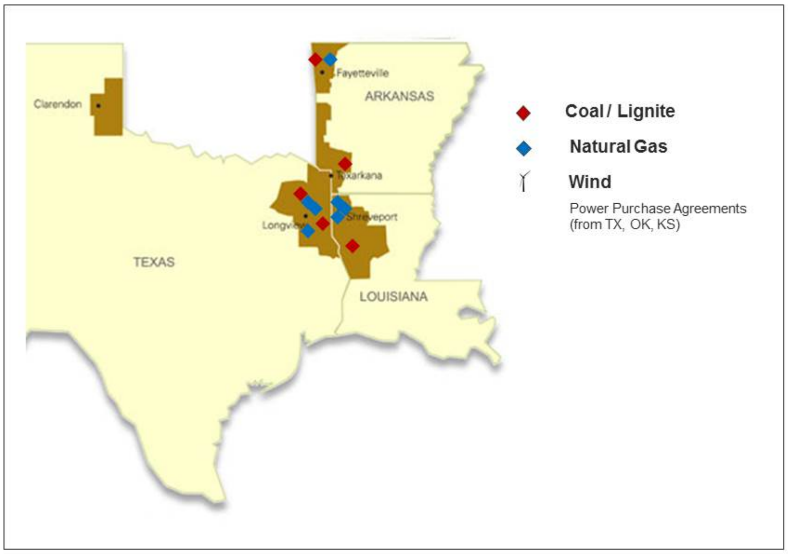

Figure 1. SWEPCO Service Territory

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

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

1.3.1 Annual Planning Process

SWEPCO and AEP are engaged in planning activities throughout the year which impact the IRP. Major activities include updating the load forecast, fundamental commodity pricing forecast, and new generation cost and performance characteristics. On an annual basis, the load forecasting group produces a peak demand and energy usage forecast for each operating company. This process typically begins as actual values are received, reviewed, and adjusted. The annual load forecast for this planning process was produced in June 2019.

The fundamental commodity forecast process is continually monitored relative to ongoing activities that could potentially affect the existing commodity forecast values. Typically, the fundamental commodity forecast is updated when material changes are observed or expected. The most recent commodity forecast was released in April of 2019.

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

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

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2.0 Load Forecast and Forecasting Methodology

2.1 Summary of SWEPCO Load Forecast

The SWEPCO load forecast was developed by AEP's Economic Forecasting organization and completed in June 2019.[2] The final load forecast is the culmination of a series of underlying forecasts that build on each other. In other words, the economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 20-year period (2020-2039)[3], SWEPCO's service territory is expected to see population and non-farm employment experience similar growth of 0.7% and 0.5% per year, respectively. Not surprisingly, SWEPCO is projected to see customer count growth at a rate of 0.3% per year. Over the same forecast period, SWEPCO's retail sales are projected to grow at 0.2% per year with stronger growth expected from the residential class (+0.5% per year) while the commercial class experiences a modest decrease (-0.1% per year) and the industrial class experiences modest increases (0.2% per year) over the forecast horizon. The projected change in SWEPCO's internal energy over the next 20 years is for requirements to increase by 0.3% per year. Finally, SWEPCO's peak demand is also expected to increase at an average rate of 0.3% per year through 2039.

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

[3] 20 year forecast periods begin with the first full forecast year, 2020

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 2018. Moody's Analytics projects moderate growth in the U.S. economy during the 2020-2039 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the implicit GDP price deflator expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's (FRBs) index of industrial production, is expected to grow at 1.5% per year during the same period. Moody's projected employment growth of 0.5% per year during the forecast period and real regional income per-capita annual growth of 2.4% for the SWEPCO service area.

2.2.2 Price Assumptions

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

2.2.3 Specific Large Customer Assumptions

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

2.2.4 Weather Assumptions

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

2.2.5 Energy Efficiency (EE) and Demand-Side Management (DSM) Assumptions

Inherent in the historical data used to specify the load forecast models are the impacts of past customer energy conservation and load management behaviors. Energy usage is being impacted by a combination of federal and/or state efficiency mandates in addition to company sponsored Energy Efficiency (EE) and DSM programs. The statistical adjusted end-use models incorporate changing saturations and efficiencies of the various end-use appliances, which results in a certain amount of EE to be "embedded" into the load forecast.

In addition to the "embedded" EE, the Company also accounts for Commission-approved DSM program impacts in the load forecasting process. For the IRP, the load forecast is used as described with a major assumption change to the state approved EE programs. At a given year, the state approved incremental EE assumption is assumed to stop, with some residual EE going forward due to lingering degradation impacts of prior years. Then, new annual EE assumptions are layered in to replace the state approved EE levels.

2.3 Overview of Forecast Methodology

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

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

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

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

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

A flow chart depicting the sequence of models used in projecting 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 2 below.

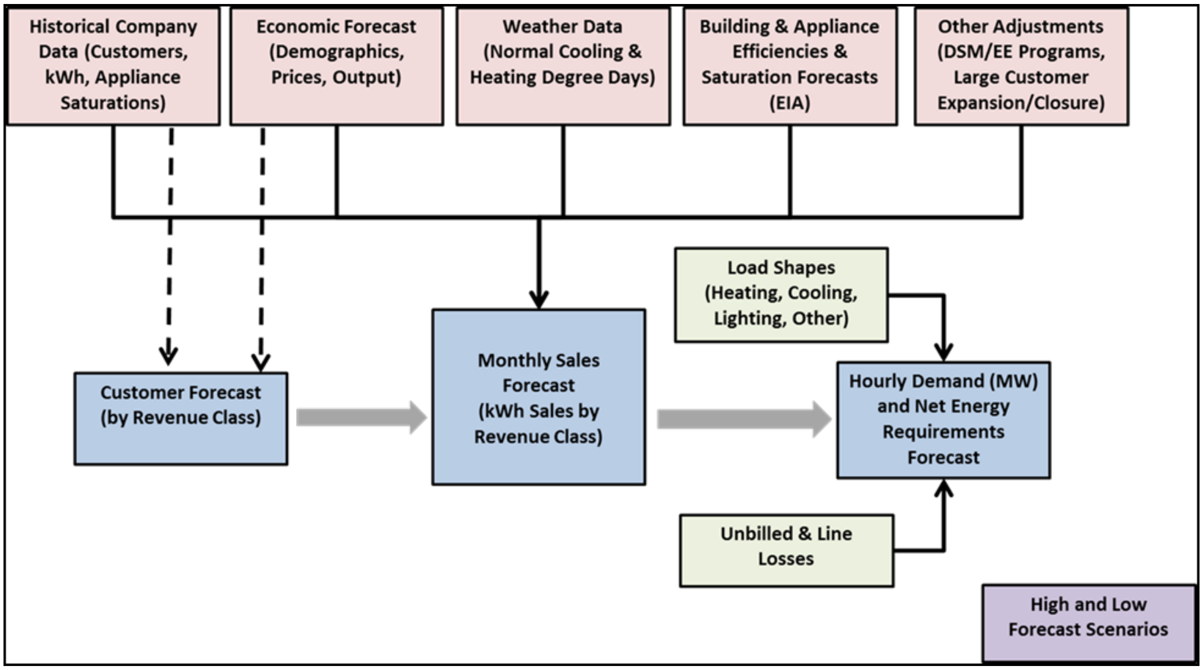

Figure 2. SWEPCO Internal Energy Requirements and Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast

2.4.1 General

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

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

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

2.4.2 Customer Forecast Models

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

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

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

2.4.3 Short-term Forecasting Models

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

There are separate models for the Arkansas, Louisiana and Texas Jurisdictions of the Company. The estimation period for the short-term models was January 2009 through January 2019.

2.4.3.1 Residential and Commercial Energy Sales

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

2.4.3.2 Industrial Energy Sales

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

2.4.3.3 All Other Energy Sales

The All Other Energy Sales category for SWEPCO includes public street and highway lighting (or other retail sales) and sales to municipals. Current SWEPCO wholesale requirements customers include the cities of Bentonville, Hope and Prescott in Arkansas, City of Minden in Louisiana, Northeast Texas Electric Cooperative, and Rayburn County Electric Coop. Figures from 2017 and prior years also include East Texas Electric Cooperative and Tex-La Electric Reliability Cooperative. Wholesale loads are generally longer term, full requirements, and cost-of-service based contracts.

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

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast, as they are not requirements load or part of the IRP process.

2.4.4 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by 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 1995-2018 The long-term energy sales forecast is developed by blending of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

2.4.4.1 Supporting Models

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.

2.4.4.1.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of state natural gas prices for four primary consuming sectors: residential, commercial, and industrial. In the state natural gas price models, sectoral prices are related to West South Central Census region's sectorial prices, with the forecast being obtained from EIA's "2019 Annual Energy Outlook." The natural gas price model is based upon 1980-2018 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 a Statistically Adjusted End-Use model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool and Xother variables.

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

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

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

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

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

The SAE residential models are estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2019. It is important to note, as will be discussed later in this document, that this modeling *has* incorporated the reductive effects of the Energy Policy Act of 2005 (EPAct), the Energy Independence and Security Act of 2007 (EISA), American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential (and commercial) energy usage.

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

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

2.4.4.3 Commercial Energy Sales

Long-term commercial energy sales are forecast 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 2018 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 2019. As with the residential SAE model, the effects of EPAct, EISA, ARRA and EIEA2008 are captured in this model. Separate commercial SAE models are estimated for the Company's Arkansas, Louisiana and Texas jurisdictions.

2.4.4.4 Industrial Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, service area manufacturing employment, FRB industrial production indexes, service area industrial electricity prices and state industrial natural gas price. In addition, binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers, there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Arkansas, Louisiana and Texas jurisdiction. The last actual data point for the industrial energy sales models is January 2019.

2.4.4.5 All Other Energy Sales

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

The municipal energy sales model is specified linear with the dependent and independent variables in linear form. Wholesale energy sales are modeled relating energy sales to economic variables such as service area gross regional product, 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. The long-term forecast reflects the effects of two wholesale contracts that expired December 31st, 2017 and one contract being terminated by 2020.

2.4.5 Final Monthly Internal Energy Forecast

2.4.5.1 Blending Short and Long-Term Sales

Forecast values for 2019 and 2020 are taken from the short-term process. Forecast values for 2021 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July of 2021, the entire forecast is from the long-term models. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. However, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon.

2.4.5.2 Large Customer Changes

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

2.4.5.3 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

2.4.6 Forecast Methodology for Seasonal Peak Internal Demand

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

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

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

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

2.5 Load Forecast Results and Issues

All tables referenced in this section of the report can be found in the appendix of this report in Exhibit A.

2.5.1 Load Forecast

Table 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 2009-2018. 2019 data are six months actual and six months forecast and on a forecast basis for the years 2020-2039. 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 are given in Table A-2.

Figure 3 below provides a graphical depiction of weather normal and forecast Company residential, commercial and industrial sales for 2002 through 2039.

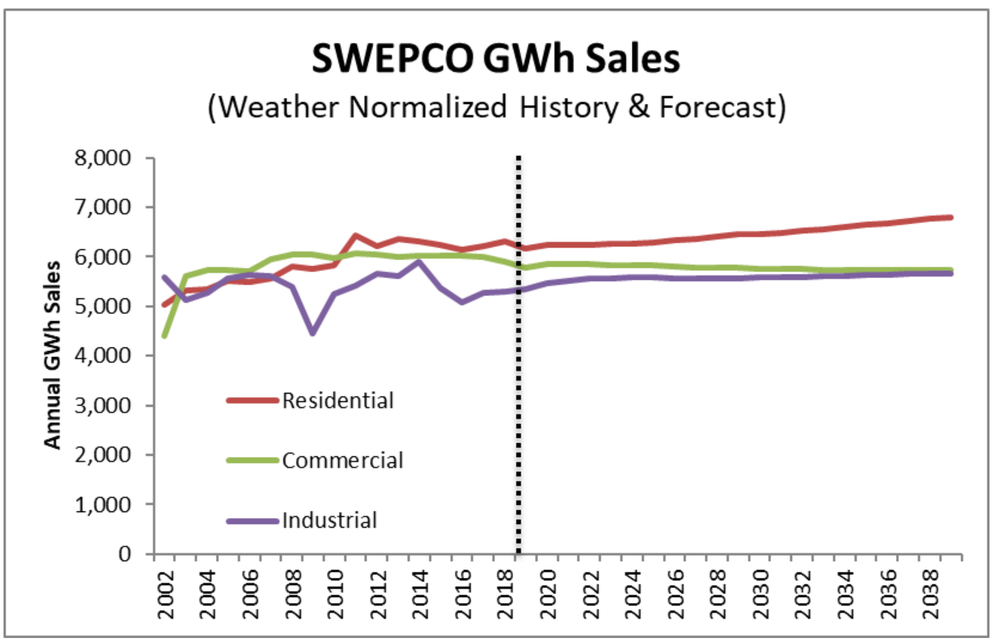

Figure 3. SWEPCO GWh Sales

2.5.2 Peak Demand and Load Factor

Table A-3 provides SWEPCO’s seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2009-2018. 2019 data are six months actual and six months forecast and on a forecast basis for the year 2020-2039. The table also shows annual growth rates for both the historical and forecast periods.

Figure 4 presents actual, weather normal and forecast PSO peak demand for the period 2000 through 2039.

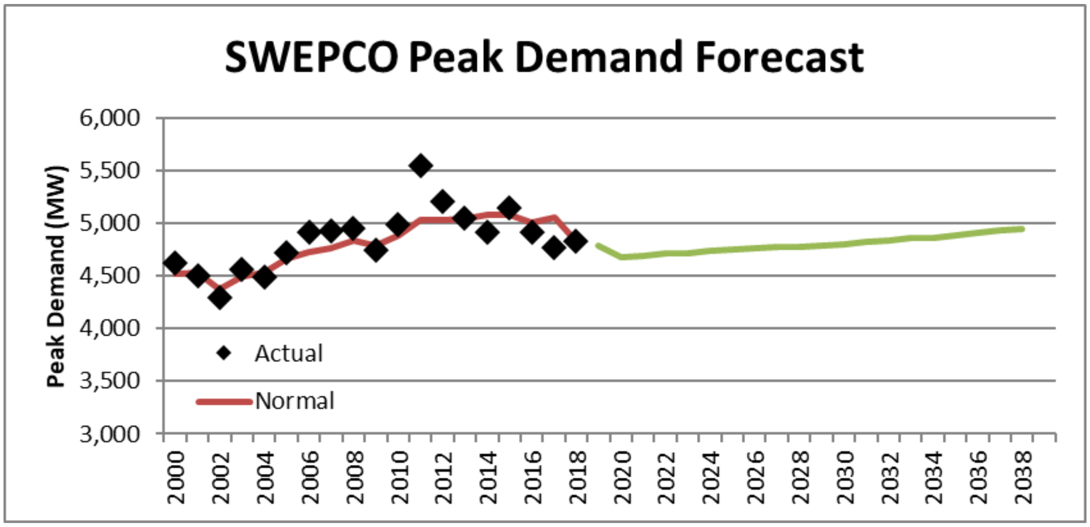

Figure 4: SWEPCO Peak Demand Forecast

2.5.3 Monthly Data

Table A-4 provides historical monthly sales data for SWEPCO by customer class (residential, commercial, industrial, other retail and wholesale) for the period January 2009 through June 2019. Table A-5 provides forecast SWEPCO monthly sales data by customer class for July 2019 through December 2039.

2.5.4 Prior Load Forecast Evaluation

Table A-6 presents a comparison of SWEPCO's energy sales and peak demand forecasts in the 2015 IRP with the actual and weather normal data for 2015, 2016, 2017 and 2018. The primary reason for the forecast differences is that the SWEPCO service area economy did not expand as quickly as was expected when the load forecast used in the previous (2015) IRP was developed. In fact, the SWEPCO service area experienced year-over-year contractions in real output from the third quarter in 2015 through the second quarter in 2016. On a regional level, real GDP was expected to grow at 3.3%, 3.5%, 2.6% and 2.0% in 2015, 2016, 2017 and 2018, respectively. Meanwhile, real GDP grew by 1.0% in 2015, declined by 0.4% in 2016, grew by

2.3% in 2017 and grew by 2.6% in 2018. The 2018 wholesale anticipated some departure of wholesale load that materialize to the level expected. As the sluggish economy was seen as the primary reason for the forecast differences, there were no significant changes to the forecast model structures. However, there is a constant monitoring of the modeling process to seek improvement in forecast accuracies. Table A-7 provides the impact of demand-side management on the 2015 IRP.

2.5.5 Weather Normalization

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

2.5.6 Significant Determinant Variables

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

2.6 Load Forecast Trends & Issues

2.6.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 5 presents SWEPCO's historical and forecasted residential and commercial usage per customer between 1991 and 2025. 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 last decade shown (2011-2020) Residential usage is projected to decline at a rate of 0.7% per year while the Commercial usage also falls by an average of 0.7% per year. This decline is expected to moderate for the last 5 years shown (2021-2025), with residential usage declining at a rate of 0.1% per year while commercial usage falls by 0.5%.

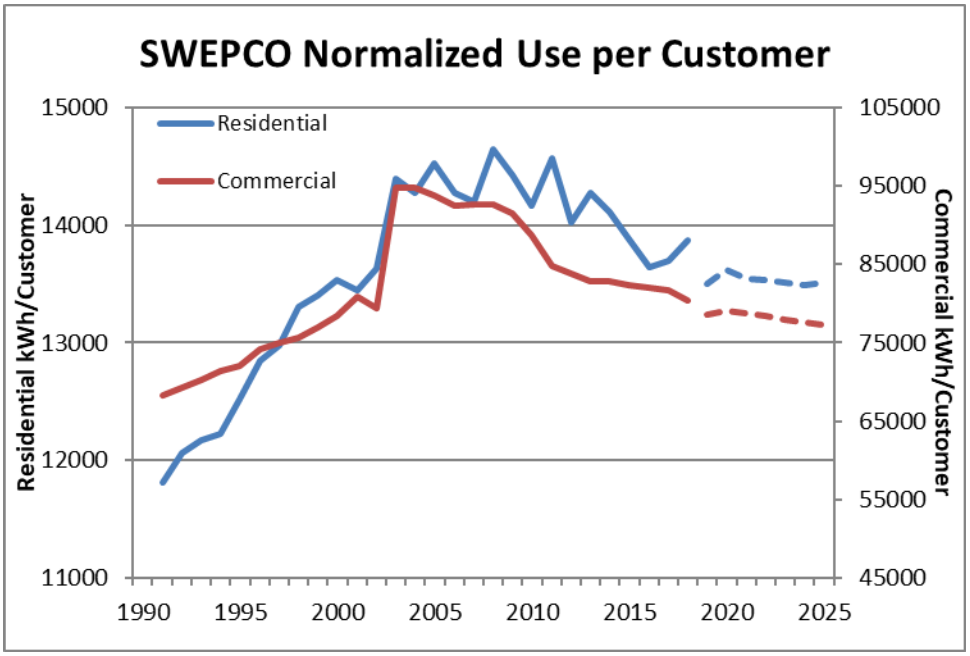

Figure 5. SWEPCO Normalized Use per Customer (kWh)

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

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected energy efficiency. For example, Figure 6 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 11.69 in 2010 to nearly 14.4 by 2035. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units as well.

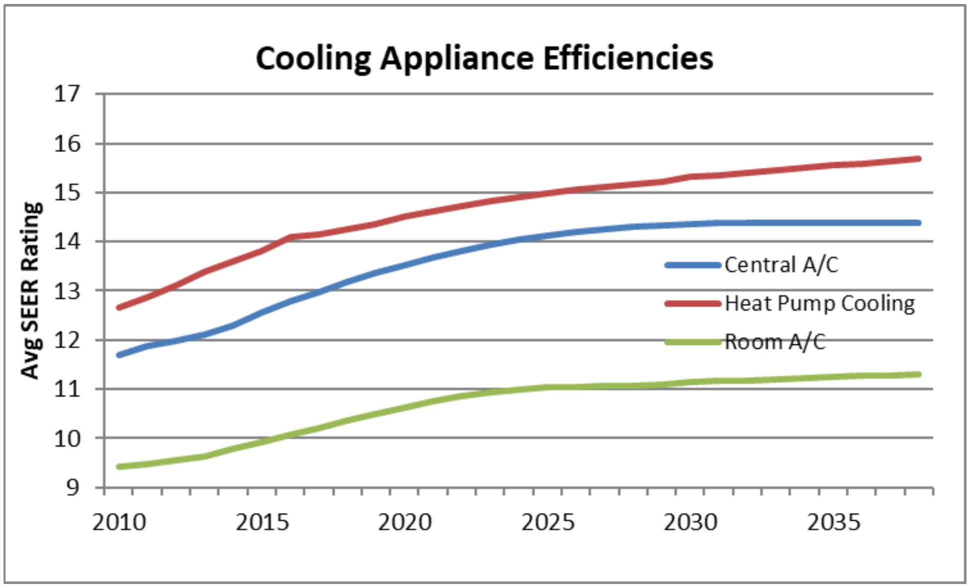

Figure 6. Projected Changes in Cooling Efficiencies, 2010-2038

Figure 7 below shows the impact of appliance, equipment and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast of SWEPCO residential customers are provided.

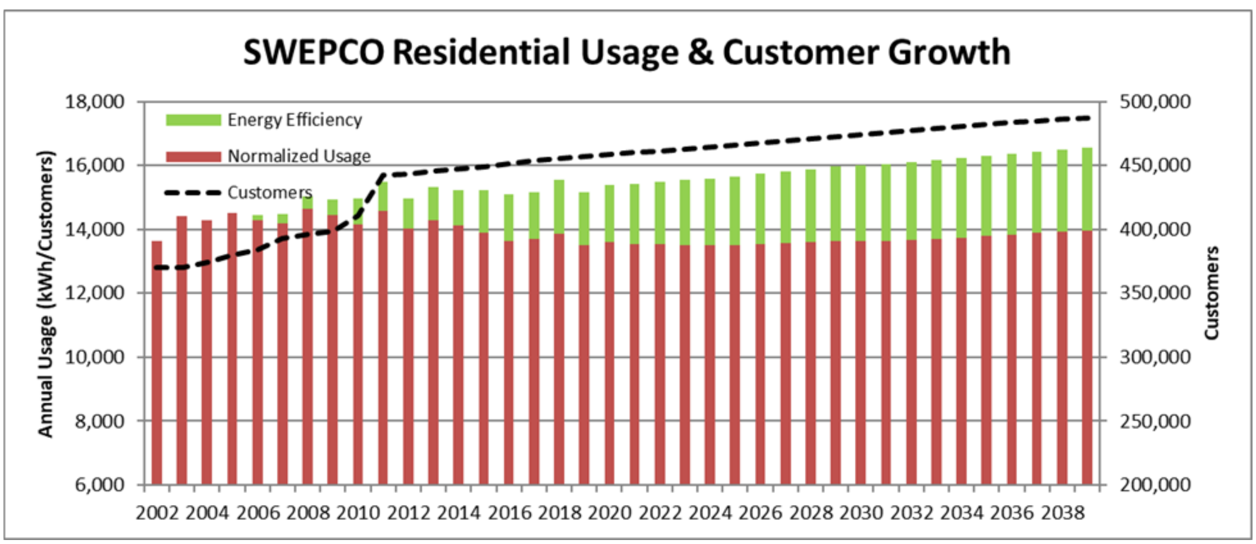

Figure 7. Residential Usage and Customer Growth, 2002-2038

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

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

2.6.3 Losses and Unaccounted for Energy

Actual and forecast losses and unaccounted for energy are provided in Table A-13. See Section 2.4.5.3 for a discussion of loss estimation. At this time, the Company does not have any planned loss reduction programs.

2.6.4 Interruptible Load

The Company has 25 customers with interruptible provisions in their contracts. The aggregate on-peak capacity available for interruptions is 35.6MW. 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. As such, estimates for "demand response" impacts are reflected by SWEPCO in determination of SPP-required resource adequacy (i.e., SWEPCO's projected capacity position).

2.6.5 Blended Load Forecast

As noted above, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon. Table A-14 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, seven of the nine wholesale forecasts utilize the long-term forecast model results and the other two uses the blended model results.

In general, forecast values for the year 2019 were typically taken from the short-term process. Forecast values for 2021 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2021 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results. Figure

8 illustrates a hypothetical example of the blending process (details of this illustration are shown in Table A-15). However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

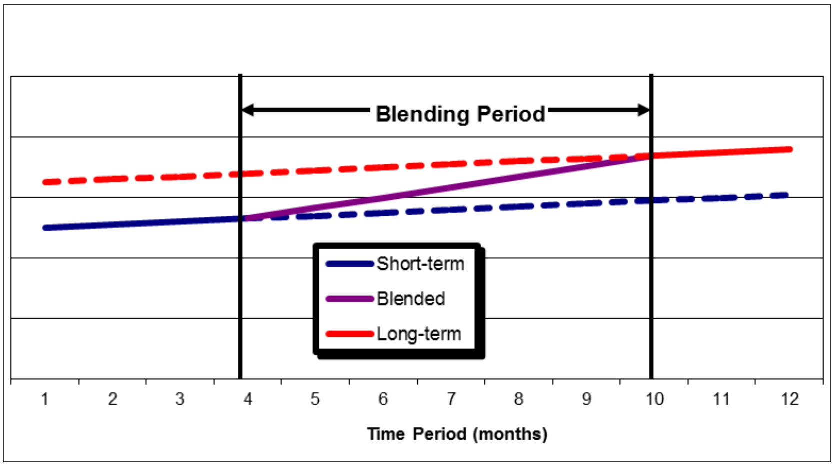

Figure 8. Load Forecast Blending Illustration

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 add factors may be used to reflect those large changes that are different from those 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. If a wholesale customer intends to seek bids for the supply of power, they typically would need to give the Company a five year notice of such intentions, although there may be stipulations within a contract that permits the customer to do so earlier. Within the context of these two items, the Company has one wholesale customer with a "full requirements" load contract that will expire by 2020. The load for this wholesale customer has been removed from the load forecast at the appropriate date. Concurrently, any self-generation provided by those wholesale customers that is appropriately "assumed" by SWEPCO for purposes of its long-term resource planning has been likewise removed.

2.7 Load Forecast Model Documentation

Full documentation of the short- and long-term load forecasts are provided in non-confidential and confidential accompanying CDs. Included in the CDs are model input data, model estimation and statistics and model output. In addition, descriptions of the SAE models are provided.

2.8 Load Forecast Scenarios

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

Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2019 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for 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, 2039, represent deviations of about 15.0% below and 14.9% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios. Figure 9 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

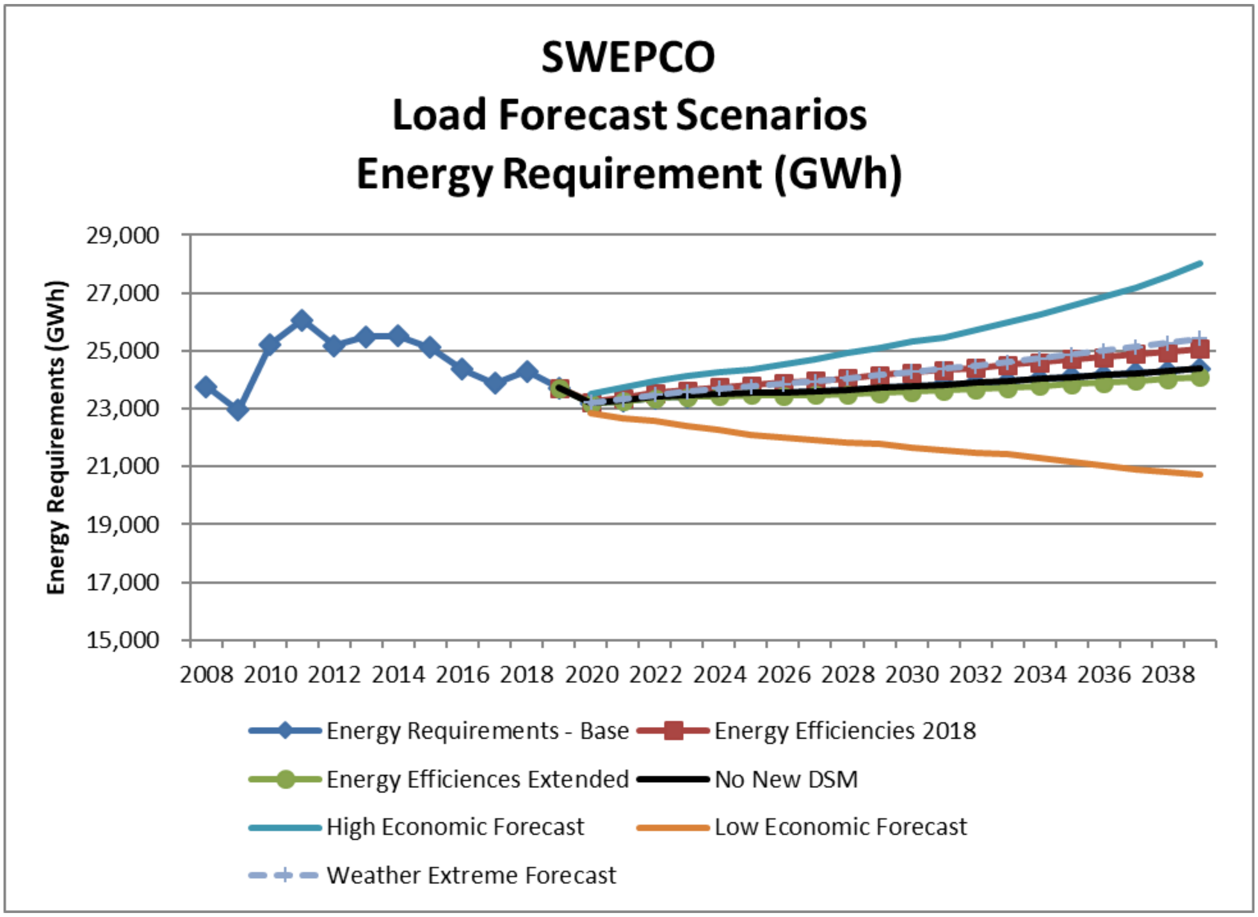

Figure 9. Load Forecast Scenarios

The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2019 scenario keeps energy efficiencies at 2019 levels for the residential and commercial equipment. Both of these scenarios result in a load forecast greater than the base forecast.

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

The weather extreme forecast assumes 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 requirements forecast. Exhibit A-17 provides graphical displays of the range of forecasts of summer and winter peak demand for SWEPCO along with the impacts of the weather scenario for each season.

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

3.0 Resource Evaluation

3.1 Current Resources

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

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

3.2 Existing SWEPCO Generating Resources

The underlying minimum reserve margin criterion to be utilized in SWEPCO's resource needs assessment is based on the current SPP minimum capacity margin of 10.7 percent.[4] As a function of peak demand this converts to an equivalent "reserve margin" of 12.0 percent.[5] The reserve margin is the result of SPP's own system reliability assessment. Table 1 displays key parameters for SWEPCO's current supply-side resources.

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

[5] 0.107 / (1 – 0.107) = 0.12.

Table 1. Current Supply-Side Resources, as of June 2019

Plant	Unit	Output Net MW Capability	In-Service Year	Expected Useful Life	Primary Fuel	State	Retirement Date (1)
Arsenal Hill	5	110	1960	65	Natural Gas	LA	2025
Dolet Hills (2)	1	650**	1986	60	Lignite	LA	2046
Flint Creek	1	528*	1978	60	Coal	AR	2038
Knox Lee	2	30	1950	69	Natural Gas	TX	2020
Knox Lee	3	31	1952	67	Natural Gas	TX	2020
Knox Lee	5	348	1974	65	Natural Gas	TX	2039
Lieberman	2	26	1949	70	Natural Gas	LA	2019
Lieberman	3	109	1957	65	Natural Gas	LA	2022
Lieberman	4	108	1959	65	Natural Gas	LA	2024
Lone Star	1	50	1954	65	Natural Gas	TX	2019
Mattison	1	76	2007	45	Natural Gas (CT)	AR	2052
Mattison	2	76	2007	45	Natural Gas (CT)	AR	2052
Mattison	3	76	2007	45	Natural Gas (CT)	AR	2052
Mattison	4	76	2007	45	Natural Gas (CT)	AR	2052
Pirkey	1	675***	1985	60	Lignite	TX	2045
Stall	6A, 6B, 6S	511	2010	40	Natural Gas (CC)	LA	2050
Turk	1	650	2012	55	Coal	AR	2067
Welsh	1	528	1977	60	Coal	TX	2037
Welsh	3	528	1982	60	Coal	TX	2042
Wilkes	1	177	1964	65	Natural Gas	TX	2029
Wilkes	2	362	1970	65	Natural Gas	TX	2035
Wilkes	3	362	1971	65	Natural Gas	TX	2036
Majestic	1	80 (A)	2009		Wind (PPA)	TX	2029
High Majestic	1	80 (A)	2012		Wind (PPA)	TX	2032
Flat Ridge	1,2	109 (A)	2013		Wind (PPA)	KS	2032
Canadian Hills	1,2,3	201 (A)	2012		Wind (PPA)	OK	2032

* SWEPCO's Share is 264 MW
** SWEPCO's Share is 262 MW
*** SWEPCO's Share is 580 MW
(1) Based on the latest Commission approved depreciation rates in the respective SWEPCO state jurisdictions.
(2) Dolet Hills has transitioned to seasonal operations and the Company is continuing to evaluate operations.

For purposes of establishing a modeling "baseline," it is necessary to establish assumptions pertaining to all of the capacity and energy resources available to SWEPCO. Figure 10 depicts SWEPCO's current generation resources along with their current age. For IRP purposes, each generating unit has an assumed planned retirement date based on the latest Commission approved depreciation rates in the respective SWEPCO state jurisdictions, which is shown in Table 1 and reflected in the Capacity, Demand, and Reserves summary (CDR) found in Exhibit F of the appendix. As depicted in the figure, the gas-steam units are the oldest units on the

SWEPCO system. These older units are of a less efficient design than newer Natural Gas Combined Cycle (NGCC) units and therefore are dispatched far less frequently in the SPP market, resulting in much lower expected capacity factors. As a result, while these units have relatively low fixed costs and provide capacity value, should either a catastrophic failure occur or a very expensive component fails that would require replacing, there is a higher degree of probability that such gas-steam units would not be economic to repair. In such a case, the unit would likely be retired.

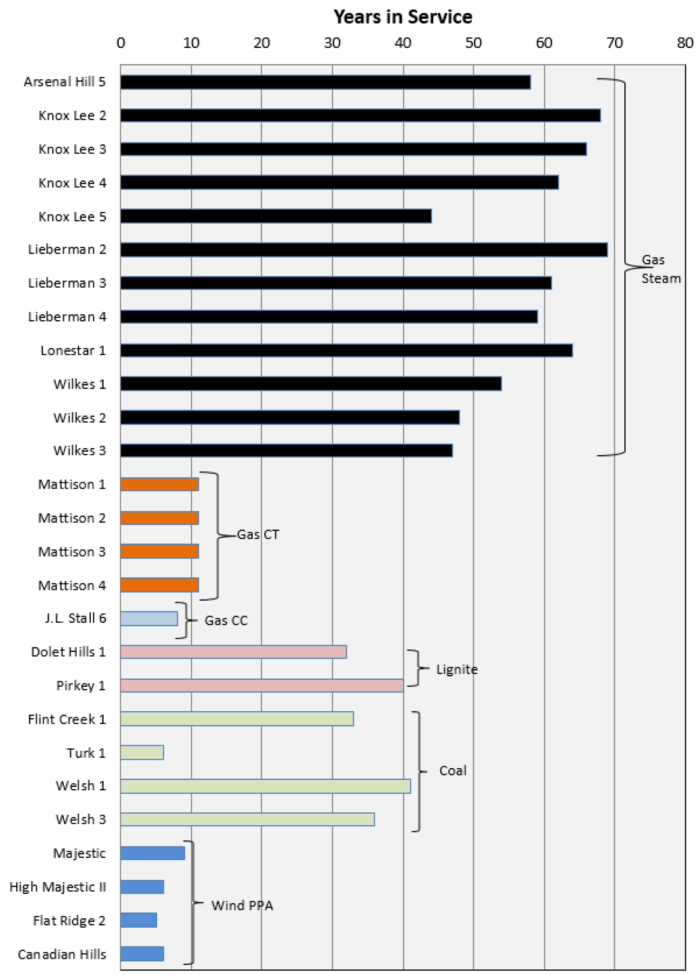

Figure 10. Current Resource Fleet (Owned and Contracted) with Years in Service, as of July 1, 2019

With the exception of Lieberman 2, Lone Star and Knox Lee Units 2 & 3, no firm commitment has been made to retire the balance of the gas-steam assets, however, given the age and the potential of such expensive component failures, this IRP assumes that some of these relative older, less efficient gas-steam units will be retired over the planning period. As well as, in 2037, the analysis includes the assumption that Welsh unit 1 is retired.

The IRP does not include analyses that support any decision to deactivate a generating unit although SWEPCO will weigh a variety of factors prior to making unit retirement decisions. These factors include such variables as:

1. the ongoing cost to operate and maintain the unit,
2. the cost of replacement capacity and energy,
3. the availability of replacement options, and
4. any reliability related issues or remedial actions necessary due to unit retirement. .

It is worth noting that the Dolet Hills Power Plant, which is co-owned by SWEPCO and Cleco Power, LLC (CLECO), has transitioned from year-round to seasonal operations (generally June through September), and the Company is continuing to evaluate operations. This change does not impact the Company's summer peak capacity position; however, it will impact the overall annual energy available from Dolet Hills.

Additionally, SWEPCO has a number of Renewable Energy Purchase Agreements (REPAs) referred to as Wind PPAs. With all of the wind PPAs, SWEPCO takes delivery of the output of the wind farms at the Point of Interconnection into the SPP grid. Additional detail related to the delivery of the wind farm output is provided in Exhibit I.

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 taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. SWEPCO's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases that are primarily made through a competitive Request for Proposal process. Long-term contracts (>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 demand. Occasionally, spot purchases may also be made to test-burn any promising and potential new sources of coal in order to determine its acceptability as a fuel source in a given power plant's generating units.

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. SWEPCO has two long-term coal supply agreements with one supplier. Additionally, several committed spot contracts 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 – Lignite

SWEPCO's two lignite-fueled generating stations, Dolet Hills and Pirkey, are located at mouth of mine. The Dolet Hills power station is served by the Dolet Hills mine which is owned and operated by Dolet Hills Lignite Company, LLC, a subsidiary of SWEPCO. The Pirkey power station is served by the Sabine Mine owned and operated by Sabine Mining Company, a subsidiary of North American Coal. The fuel inventory is managed to maintain a level of lignite usage that can be provided by the mine at a reasonable cost during the seasonal operation of Dolet Hills and year-round operations at Pirkey.

3.2.1.3 Procurement Process – Natural Gas

SWEPCO purchases the majority of its natural gas supply in the day ahead market. However, a small percentage of supply is purchased via a long-term, fixed price contract.

SWEPCO relies on both firm and interruptible transportation agreements to optimize the delivery of natural gas.

3.2.1.4 Forecasted Fuel Prices

SWEPCO specific forecasted annual fuel prices, by unit, for the period 2019 through 2048 are displayed in Exhibit J (Confidential) of the Appendix.

3.3 Environmental Issues and Implications

It should be noted that the following discussion of environmental regulations is based on the requirements currently in effect and those compliance option 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 eventually affect 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.

3.3.1 Clean Air Act (CAA) Requirements

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

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

3.3.2 National Ambient Air Quality Standards (NAAQS)

The Federal EPA issued new, more stringent NAAQS for PM in 2012 and ozone in 2015; the existing standards for NO_2 were retained after review by the Federal EPA in 2018 and 2019, respectively. Implementation of these standards is underway.

In 2016, the Federal EPA completed an integrated review plan for the 2012 particulate matter (PM) standard. Work is currently underway on scientific, risk and policy assessments necessary to develop a proposed rule, which is anticipated in 2021.

The Federal EPA finalized nonattainment designations for the 2015 ozone standard in 2018. The Federal EPA has also confirmed that the CSAPR program satisfies all interstate transport obligations associated with the 2008 ozone standard, as all areas of the country are expected to attain the 2008 ozone standard before 2023, but that finding has been challenged in the U.S. Court of Appeals for the D.C. Circuit. Challenges to the 2015 ozone standard and Federal EPA's 2018 rule governing implementation of the 2015 ozone standard also are pending in the U.S. Court of Appeals for the District of Columbia Circuit. SWEPCO cannot currently predict the nature, stringency or timing of additional requirements for SWEPCO's facilities based on the outcome of these activities.

3.3.3 Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule (CAIR), a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind nonattainment with the 1997 ozone and particulate matter

(PM) NAAQS. 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 sub-regional basis.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In 2016, the Federal EPA issued a final rule to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduced ozone season budgets in many states, including Arkansas and Texas, and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed.

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

3.3.4 Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of Hazardous Air Pollutants (HAPS) from coal and oil-fired electric generating units. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, filterable PM (as a surrogate for all regulated non-mercury metals) and hydrogen chloride (HCl) (as a surrogate for all acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance was required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

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

In 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the Mercy and Air Toxics Standards (MATS) rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPS from power plants. In 2016, the Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the Federal EPA proposed to retain the current MATS standards without change. A final rule has not yet been issued. The following is a list of retrofit technologies that have been added to the SWEPCO fleet, including technologies to meet the requirements of the MATS Rule.

- Flint Creek installed a dry FGD (NID™ technology), an ACI system, a baghouse to meet MATS and regional haze requirements, and LNB/OFA burners.
- Dolet Hills Unit 1 installed an activated coal injection (ACI) system, dry sorbent injection (DSI) technology, and a baghouse to mitigate mercury and PM emissions.
- Pirkey Unit 1 installed an ACI system.
- Welsh (Units 1 &3) installed an ACI system with a baghouse.
- Welsh Unit 2, per an unrelated settlement agreement, received an extension of the MATS requirements until the unit was retired on April 16, 2016.

All other SWEPCO generating units have been meeting the MATS requirements without additional control technologies.

3.3.5 Climate Change, CO_2 Regulations and Energy Policy

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

The final rules were challenged in the courts. In 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance, and the cases are still pending.

In 2019, the Federal EPA finalized the Affordable Clean Energy (ACE) rule replacing the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE establishes a framework for states to adopt standards of performance for utility boilers based on heat improvements for such boilers. In 2018, Federal EPA filed a proposal revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available through the U.S. and is not cost-effective. SWEPCO will work with respective state environmental regulators to develop and implement emission rate limits for affected sources under the ACE guidelines.

3.3.6 Regional Haze Rule (RHR)

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

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

3.3.7 Arkansas Regional Haze

The State of Arkansas and the Arkansas Department of Environmental Quality (ADEQ) submitted a regional haze SIP to the Federal EPA in 2008, including emission limits necessary to meet its BART obligations.

On November 16, 2011, the Federal EPA issued its proposed decision on Arkansas's regional haze SIP. The Federal EPA proposed to disapprove the regional haze SIP, in part, including the emission limitations based on ADEQ's BART analysis.

After the Federal EPA's proposed decision was issued, SWEPCO coordinated with ADEQ and Federal EPA to conduct a more detailed BART analysis for Flint Creek.

SWEPCO proposed to meet the RHR NO_X requirements at Flint Creek through participation in the CSAPR program. The Federal EPA had determined that, on a parameter-by-parameter basis, compliance with CSAPR is sufficient to meet the regional haze obligations for facilities covered by that program. SWEPCO proposed to meet the SO_2 Regional Haze requirements through the installation of a dry scrubber (NID^{TM} technology).

In 2015, the Federal EPA proposed a FIP that accepted the SO_2 controls presented in Flint Creek's BART analysis. However, the proposed Federal EPA FIP included the installation of Low NO_X Burner with Over-Fire-Air (LNB/OFA) and an emission limitation of 0.23 lb. NO_X/mmBtu. The Federal EPA did not address CSAPR at all in their FIP and SWEPCO submitted comments specifically seeking that CSAPR be approved as meeting the NO_X obligations at Flint Creek.

In a final rule that became effective on October 27, 2016, the Federal EPA established a final SO_2 emission limitation of 0.06 lb./mmBtu, and a final NO_X limitation of 0.23 lb./mmBtu for the Flint Creek Plant and accelerated the deadline for compliance. Both of these limitations were required to be met by April 27, 2018, and were consistent with the already-installed dry FGD system for SO_2 reductions and the planned installation of LNB/OFA for NO_X emission reduction. The final rule is being challenged in the U.S. Court of Appeals for the Eighth Circuit and the case is currently held in abeyance while the parties work on a settlement.

On February 12, 2018, the Federal EPA issued two final rules related to the Arkansas Regional Haze requirements and settlement that affect NO_x control for Flint Creek. The Federal EPA approved a SIP revision submitted by Arkansas on July 12, 2017 that proposed CSAPR participation as an alternative to BART for satisfying the Regional Haze NO_X requirements. The Federal EPA also withdrew the NO_X FIP requirements that would have required the installation of LNB/OFA and a NO_X limit of 0.23 lb/mmBtu by April 27, 2018. Installation of the LNB/OFA continued in order to enhance compliance with EPA's Mercury and Air Toxics Standards (MATS). On August 9, 2018, ADEQ finalized and submitted to EPA for approval a second SIP revision to address SO_2 requirements for BART sources. In this SIP revision, ADEQ determined that equipment already installed at Flint Creek Plant satisfies the requirements for the SO_2 Regional Haze requirements.

3.3.8 Louisiana Regional Haze

Louisiana submitted a regional haze SIP to the Federal EPA in June of 2008. All SWEPCO units were determined not to be "BART-eligible" and, therefore, no BART analysis or emission reductions were required for BART. The Federal EPA partially approved and partially disapproved Louisiana's SIP in July 2012. The Federal EPA approved the BART determinations but required additional evaluation to be done to meet the Reasonable Progress Goals and Long-Term Strategy to improve visibility in one Class I area in Louisiana. The impact evaluation did not include any of the SWEPCO units and no additional emission controls are expected for those facilities as a result of the RHR at this time. States are required to reevaluate their Reasonable Progress Goals and Long-Term Strategy every five years.

The Federal EPA issued a final rule approving the Louisiana SIP on December 21, 2017. No requirements were included that specifically impact SWEPCO facilities. Petitions for review of the final approved Louisiana SIP were filed in the U.S. Court of Appeals for the Fifth Circuit and remain pending.

3.3.9 Texas Regional Haze

Texas submitted its initial regional haze SIP to the Federal EPA in February 2009, and the 5-year update February 2014. Both submittals state that BART-eligible facilities in Texas do not impact Class I areas such that emissions controls are required. The Federal EPA reviewed the Texas SIP and issued a proposed FIP in November 2014. The Federal EPA took no action on the portions of the Texas SIP that relate to BART-eligible facilities, however, the Federal EPA determined that the Reasonable Progress Goals and Long Term Strategy did not adequately address visibility improvements needed in certain Class I areas. The Federal EPA conducted impact analyses to identify cost-effective controls to achieve those improvements. The proposed FIP required SO_2 reductions for 15 units in Texas resulting in scrubber retrofits for 7 units and scrubber upgrades for 7 other units. One unit is believed to be able to meet its new limit without adding additional controls. No SWEPCO unit was included in the group for which the Federal EPA proposed additional controls. On January 5, 2016, the Federal EPA issued a Final Rule partially approving and partially disapproving portions of the Texas SIP and finalizing the FIP. The Federal EPA took no action on the BART-eligible facilities since litigation with respect to the CSAPR budgets in Texas was still ongoing. No changes were included in the Final Rule that would impact any of the SWEPCO units. The FIP was challenged in the Fifth Circuit Court of Appeals, which issued a stay of the FIP. The parties engaged in unsuccessful settlement negotiations, and the Federal EPA later withdrew the FIP, and proposed to remove Texas from the CSAPR Rule.

On December 9, 2016, the Federal EPA proposed a clean air plan for the State of Texas to meet the regional haze BART and Interstate Visibility Transport requirements of the CAA. The proposed rule was published in the Federal Register on January 4, 2017. The proposal included SO_2 and NO_X emission reductions for 14 coal and natural gas-fired power plants in Texas. The proposed rule recommended an emission limit of 0.04 lb./MMBTU SO_2 for Welsh Unit 1 based on the retrofit of wet FGD technology. SWEPCO submitted comments on the proposal as did other companies and the State of Texas. On September 29, 2017 the Federal EPA finalized a rule 1) withdrawing Texas from participation in the Phase 2 CSAPR program and 2) determining that Texas has no further interstate transport obligations with respect to PM. The Federal EPA followed this rulemaking with the finalization of a BART alternative to source specific controls to address Texas Regional Haze requirements for SO_2 and NO_x in the federal register on October 17, 2017. Specifically, the Federal EPA issued a FIP that established a federal intrastate trading program to address SO_2 emissions and determined that Texas' participation in the CSAPR NO_x ozone season trading program satisfied Texas' Regional Haze NO_x requirements. The Federal EPA also determined that the BART alternatives satisfied many of Texas' interstate transport requirements. A petition for review of this final FIP was filed in the Fifth Circuit in December 2017. That challenge is currently stayed pending reconsideration of the FIP by the Federal EPA. On August 17, 2018, EPA issued a proposal to affirm the October 2017 Regional Haze Plan. In a related case, other parties challenged in the U.S. Court of Appeals for the District of Columbia Circuit a final rule withdrawing Texas from the CSAPR annual program and reaffirming that compliance with CSAPR remained better than compliance with BART. The U.S. Court of Appeals for the District of Columbia Circuit granted a motion in March 2018 to hold the case in abeyance until completion of the Federal EPA's review of pending petitions for reconsideration of the Texas RHR. SWEPCO is currently complying with the intrastate trading program.

3.3.10 Coal Combustion Residual (CCR) Rule

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and FGD gypsum generated at some coal-fired plants. The rule applies to new and existing CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period.

The final 2015 rule was challenged in the courts. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued its decision vacating and remanding certain provisions of the 2015 rule. Remaining issues were dismissed. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision. Further rulemaking is anticipated later in 2019.

Prior to the court's decision, the Federal EPA issued a final rule in July 2018 that modifies certain compliance deadlines and other requirements in the rule. In December 2018, challengers filed a motion for partial stay or vacate of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted Federal EPA's motion, and further rulemaking to address the court's decisions is expected to be completed near the end of 2019. SWEPCO supports the adoption of more flexible compliance alternatives subject to the Federal EPA or state oversight.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represents an "unpermitted discharge" under the Clean Water Act (CWA). Two cases have been accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. The Federal EPA has opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to ground water. On April 23, 2019, Federal EPA issued an "Interpretative Statement" considering comments received in the rulemaking docket and determined that "releases to groundwater are excluded from the scope of the NPDES program, even where pollutants are conveyed to jurisdictional surface waters via groundwater."

It should be noted that SWEPCO's solid-fuel plants are already equipped with dry fly ash handling systems and dry ash landfills to meet current permit requirements, and are well-positioned to meet future compliance with the CCR rulemaking. SWEPCO is closely following developments related to the final CCR Rule and determine its final compliance strategy when sufficient information becomes available.

3.3.11 Clean Water Act Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's National Pollutant Discharge Elimination System permit as those permits are renewed. SWEPCO's generating plants may be required to make investments to upgrade cooling water intake screen systems as a result of this rule, and any requirement for this relatively modest cost will be determined through each plant's NPDES permitting cycle. At this time, the 316(b) Rule is not expected to require major capital investment, such as the addition of cooling towers, at any SWEPCO plants.

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines (ELG) for electricity generating facilities. The rule established limits on flue gas desulfurization (FGD) wastewater, fly ash and bottom ash transport water (BATW) and flue gas mercury control wastewater as soon as possible after November 2018 and no later than December 2023. The rule was challenged in the U.S. Court of Appeals for the Fifth Circuit. In April 2019, the court vacated and remanded to the Federal EPA the portions of the rule dealing with legacy wastewater and leachate for reconsideration consistent with the decision. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017. The Federal EPA is reconsidering the final standards for FGD wastewater and bottom ash transport water, and a proposed rule could be issued later in 2019. SWEPCO continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting.

SWEPCO's solid-fueled generating plants are well positioned to comply with the ELG Rule because they utilize dry fly ash handling systems although The Dolet Hills, Flint Creek, and Pirkey Plants may require the addition of wastewater treatment facilities in future years. SWEPCO is closely following developments related to the final ELG Rule and determine its final compliance strategy when sufficient information becomes available.

In 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The final rule was challenged in several courts that have reached different conclusions about whether the 2015 rule should be implemented. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers released a proposed rule revising the definition, which would replace the definition in the 2015 rule and could significantly alter the scope of certain CWA programs. The comment period for this proposal ended in April 2019.

3.4 SWEPCO Current Demand-Side Programs

3.4.1 Background

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

Included in the load forecast discussed in Section 2.0 of this Report are the demand and energy impacts associated with SWEPCO's DSM programs that have been approved in Arkansas, Louisiana, and Texas prior to preparation of this IRP. As will be discussed later, within the IRP process, the potential for additional or "incremental" demand-side resources, including EE activity—over and above the levels embedded in the load forecast—as well as other grid related projects such as Volt VAR Optimization (VVO), are modeled on the same economic basis as supply-side resources. However, because customer-based EE programs are limited by factors such as customer acceptance and saturation, an estimate as to their costs, timing and maximum impacts must be formulated. For the year 2019, the Company anticipates 43MW of peak DSM reduction (total company basis); consisting of 3.9MW and 39MW of "passive" EE and "active" DR activity, respectively.[6]

3.4.2 Impacts of Existing and Future Codes and Standards

The EISA legislation requires, among other things, a phase-in of heightened lighting efficiency standards, appliance standards, and building codes and a back-stop provision effective in 2020 that prohibits the sale of light bulbs having an efficacy of less than 45 lumens per watt. Moreover, the cost of LED light bulbs has dropped dramatically as well. The impact of the phase-in requirements, back-stop provision, and market changes will have a pronounced effect on energy consumption as explained in Section 2.6. Many of the standards already in place impact lighting. For instance, since 2013, 2014, and 2015 common residential incandescent and compact fluorescent lighting alternatives have been phased out and less efficient commercial lighting fixtures requiring the use of magnetic and electronic ballasts have been replaced with highly efficient LED fixtures. Given that "lighting" measures have comprised a large portion of utility-sponsored EE programs prior to the phase-out, this pre-established transition is already incorporated into the SAE long-term load forecast modeling previously described in Section 2.4.4 and will likely greatly affect the market potential of utility EE programs in the near and intermediate term. Table 2 and Table 3 depict the current schedule for the implementation of new EISA codes and standards.

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

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

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Central AC	SEER 13										
Room AC	EER 11.0										
Electric Resistance	Space Heating										
Heat Pump	SEER 14.0/HSPF 8.0										
Water Heater (<=55 gallons)	EF 0.95										
Water Heater (>55 gallons)	Heat Pump Water Heater										
Screw-in/Pin Lamps	Advanced Incandescent (20 lumens/watt)					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
Refrigerator	25% more efficient										
Freezer	25% more efficient										
Clothes Washer	MEF 1.72 for top loader			MEF 2.0 for top loader							
Clothes Dryer	5% more efficient (EF 3.17)										
Furnace Fans	Conventional				40% more efficient						

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

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

The impact of energy efficiency, including codes and standards, is expected to reduce residential load, commercial load, and industrial lighting load in total by over 9%, as shown in Figure 11.

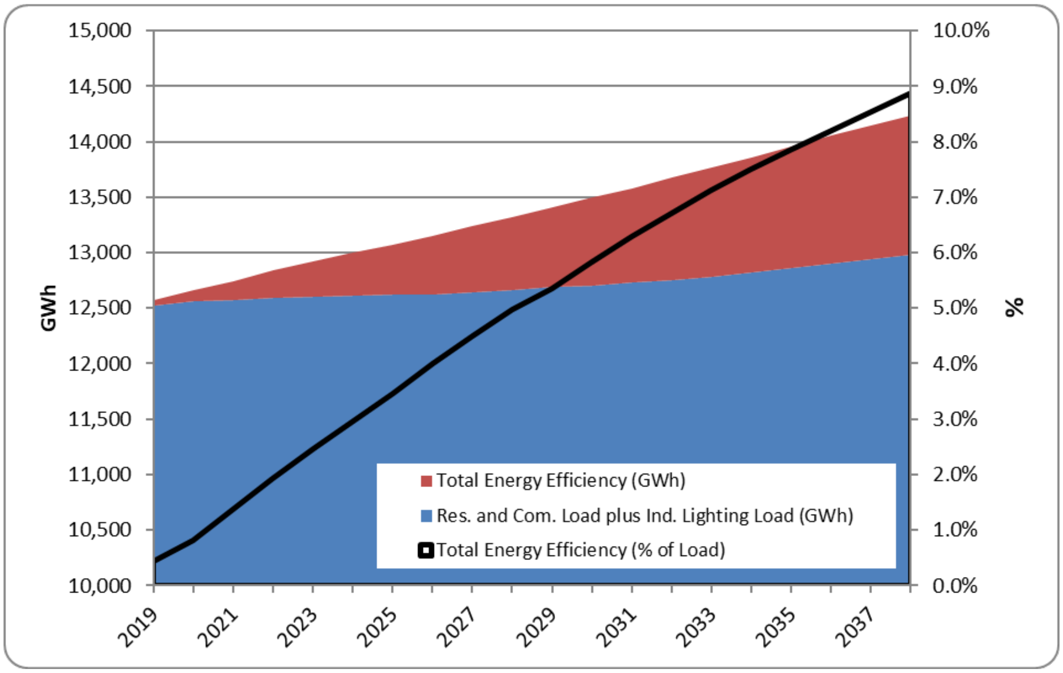

Figure 11. Total Energy Efficiency (GWh) Compared with Total Residential and Commercial Load (GWh)

3.4.3 Demand Response (DR)

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

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

- *Interruptible loads (Active DR).* This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.

- *Direct load control (Active DR).* Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Time-differentiated rates (Active DR).* This offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) to as often as 15-minute increments in what is known as "real-time pricing." Accomplishing real-time pricing requires digital (smart) metering.
- *EE measures (Passive DR).* If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less.
- *Voltage Regulation (Passive DR).* Certain technologies can be deployed that allow for improved monitoring of voltage throughout the distribution system. The ability to deliver electricity at design voltages improves the efficiency of many end use devices, resulting in less energy consumption.

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

3.4.3.1 Existing Levels of Active Demand Response (DR)

SWEPCO currently has active DR programs totaling 39MW of peak DR capability. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control.

3.4.4 Energy Efficiency (EE)

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

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

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

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

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

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP may begin adding new demand-side resources in 2020 that are incremental to programs that are currently approved or pending approval.

3.4.4.1 Existing Levels of Energy Efficiency (EE)

SWEPCO currently has EE programs in place in its Arkansas, Louisiana, and Texas service territories. SWEPCO forecasts EE measures will reduce peak demand in 2019 by 3.9MW and reduce 2019 energy consumption by approximately 22GWh.

3.4.5 Distributed Generation (DG)

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

The economics of DG, particularly solar, continue to improve. Figure 12 below charts the fairly rapid decline of expected installed solar costs, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) U.S. Renewable Energy Market Outlook forecast. The following installed cost forecast as well as the breakeven values calculated and shown in Figure 12 and Figure 13.

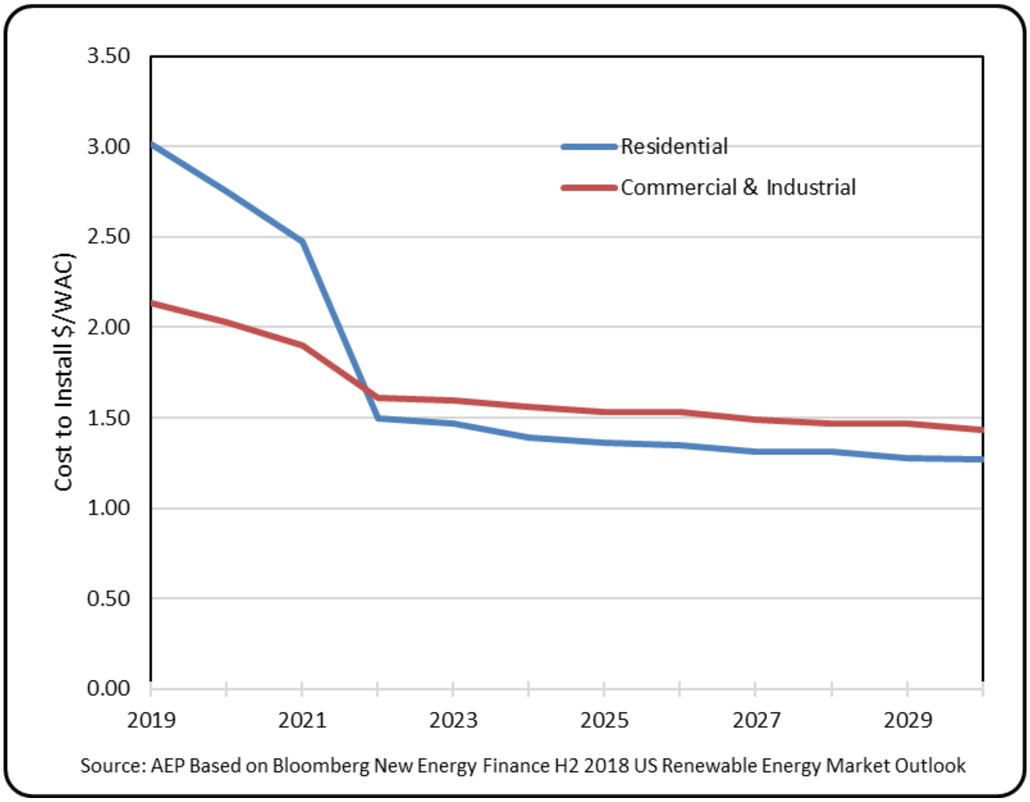

Figure 12. Residential and Commercial Forecasted Solar Installed Costs (Nominal $/W$_{AC}$) for SPP

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

While the cost to install residential solar continues to decline, the economics of such an investment are not favorable for the customer for a number of years. Figure 13 below illustrates, by SWEPCO state jurisdictional residential sector, the equivalent value a customer would need to achieve, on a dollar per watt-AC ($/WAC) basis, in order to breakeven on their investment, assuming a 25-year life of the installed solar panels based on the customer's avoided retail rate. Also included is the average cost of solar residential installations in SPP. Figure 13 below shows that the current cost of residential solar exceeds the cost which would allow a customer to breakeven on an investment over a 25-year period.

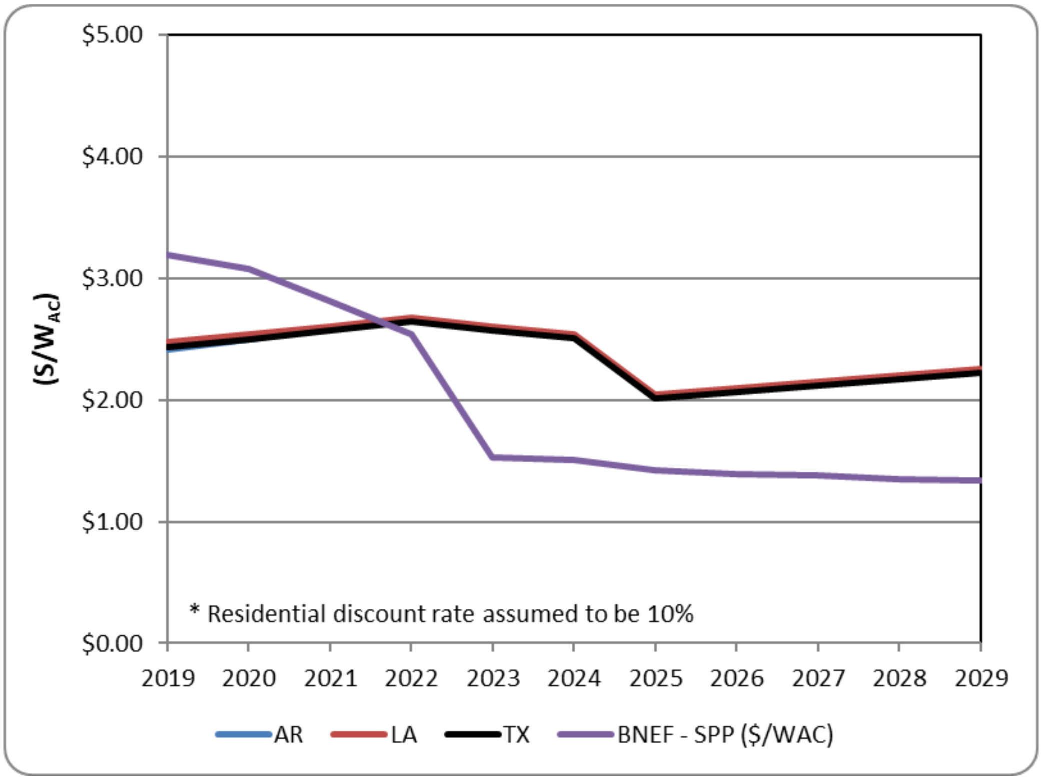

Figure 13. Distributed Solar Customer Breakeven Costs for Residential Customers ($/W$_{AC}$)

A challenge of determining the value of a residential solar system is assigning an appropriate cost of capital or discount rate. Discount rates for residential investments vary dramatically and are based on each individual's financial situation. Figure 14, below, shows how the value of a Louisiana residential customer's DG system can vary based on discount rate.

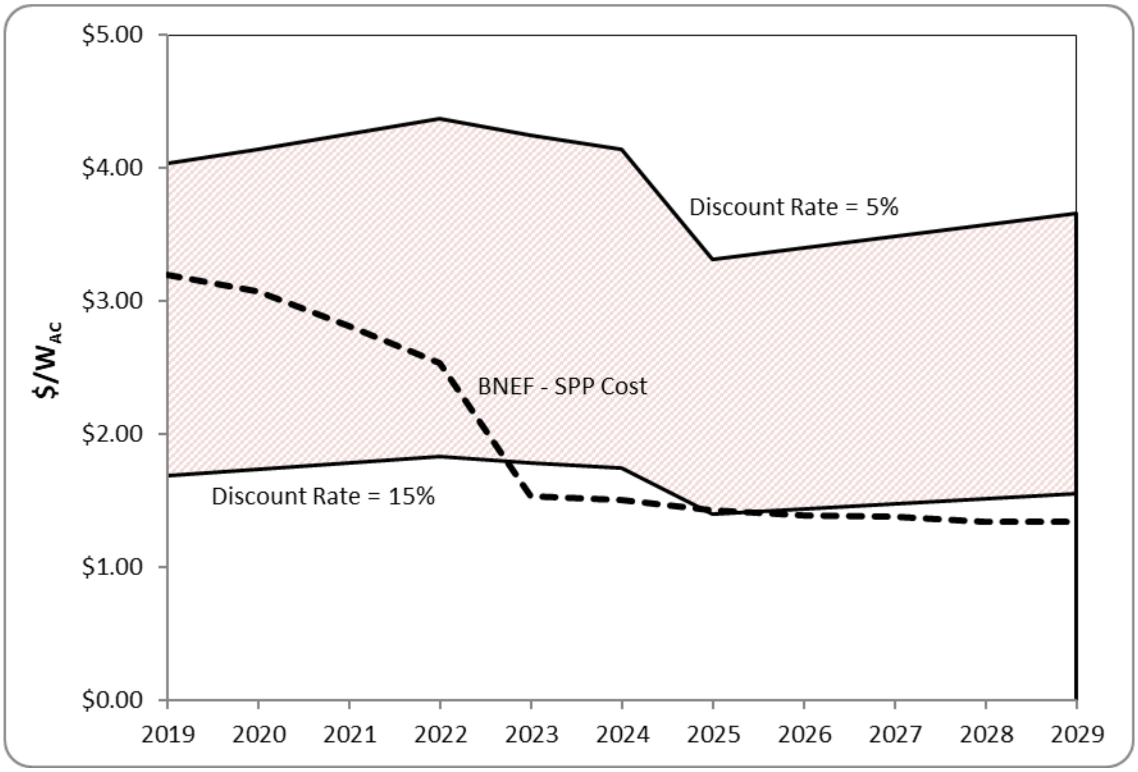

Figure 14. Range of Louisiana Residential Distributed Solar Breakeven Values Based on Discount Rate

3.4.5.1 Existing Levels of Distributed Generation (DG)

At the end of 2018 SWEPCO has a total of 11MW of customer-installed DG consisting of 2.1MW in Arkansas, 8.2MW in Louisiana, and 0.7MW in Texas. See Section 4.4.3.4 for additional details.

3.4.5.2 Impacts of Increased Levels of Distributed Generation (DG)

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

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

3.4.6 Volt VAR Optimization (VVO)

An emerging technology known as VVO represents a form of voltage control that allows the grid to operate more efficiently. Depicted at a high-level in Figure 15, with VVO sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor and voltage levels. Power factor is the ratio of real power to apparent power, and is a characteristic of electric power flow which is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. VVO enables Conservation Voltage Reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies. Early results from limited rollouts in AEP affiliate operating companies indicate a range of 0.7% to 1.2% of energy demand reduction for each 1% voltage reduction is possible. Furthermore, in 2018 an AEP affiliate operating company placed in service a VVO on 37 circuits in Oklahoma which has resulted in 6.2MW of demand reduction and 24GWh of energy reduction.

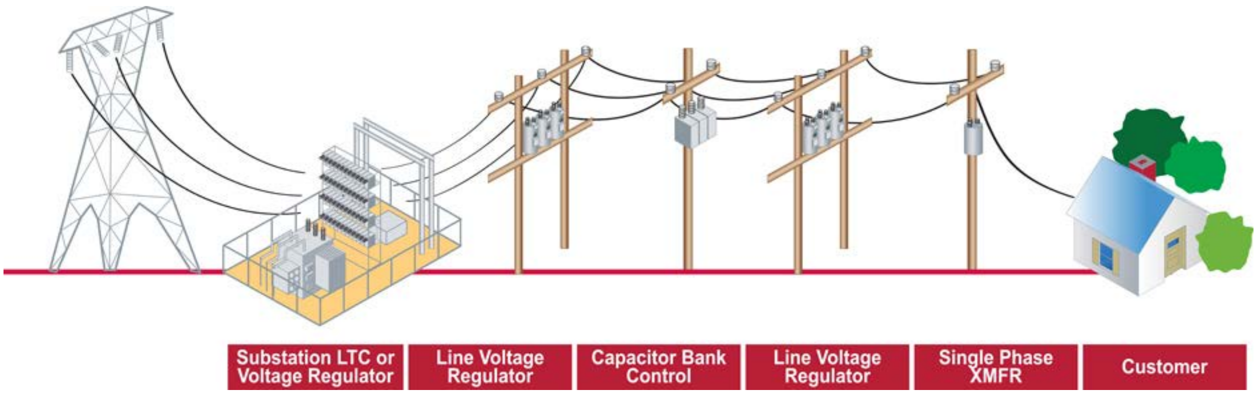

Figure 15. Volt VAR Optimization Schematic

While there is no "embedded" incremental VVO load reduction impacts implicit in the base load forecast case, VVO has been modeled as a unique EE resource.

3.5 AEP-SPP Transmission

3.5.1 Transmission System Overview

The portion of the AEP Transmission System operating in SPP (AEP-SPP zone) consists of approximately 1300 miles of 345 kV, approximately 3600 miles of 138 kV, approximately 2500 miles of 69 kV, and approximately 400 miles at other voltages above 100 kV. The AEP-SPP zone is also integrated with and directly connected to ten other companies at approximately 90 interconnection points, of which approximately 70 are at or above 69 kV and to Electric Reliability Council of Texas (ERCOT) via two High Voltage Direct Current (HVDC) ties. These interconnections provide an electric pathway to provide access to off-system resources, as well as a delivery mechanism to neighboring systems.

3.5.2 Current AEP-SPP Transmission System Issues

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

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

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

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

3.5.2.1 The SPP Transmission Planning Process

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

The 2019 STEP summarizes 2018 activities, including expansion planning and long-term SPP Open Access Transmission Tariff (OATT) studies (Tariff Studies) that impact future development of the SPP transmission grid. Key topics included in the STEP are:

1) Transmission Services,
2) Generator Interconnection,
3) Integrated Transmission Planning (ITP),

4) High Priority Studies,

5) Sponsored Upgrades,

6) Interregional Coordination, and

7) Project Tracking

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

STEP projects are categorized by the following designations:

- Generation Interconnect – Projects associated with a FERC-filed Interconnection Agreement;
- High Priority – Projects identified through the high priority studies process
- Interregional – Projects identified in SPP’s joint planning and coordination processes;
- ITP – Projects needed to meet regional reliability, economic, or policy needs in the ITP study process;
- Transmission service – Projects associated with a FERC-filed Service Agreement;
- Zonal Reliability – Projects identified to meet more stringent local Transmission Owner criteria; and
- Zonal-Sponsored – Projects sponsored by facility owner with no Project Sponsor Agreement

The 2019 STEP identified 568 transmission network upgrades with a total cost of approximately $5.2 billion. At the heart of SPP’s STEP process is its ITP process, which represented approximately 61% of the total cost in the 2019 STEP. The ITP process was designed to maintain reliability and provide economic benefits to the SPP region in both the near and long-term. In the ITP near-term assessment, the reliability of the SPP transmission system was studied, resulting in Notification to Construct (NTC) letters issued by SPP for upgrades that require a financial commitment within the next four years. The 2018 STEP is available at:

https://www.spp.org/Documents/56611/2019%20SPP%20Transmission%20Expansion%20Plan%20Report.pdf

3.5.2.2 SWEPCO-PSO Interchange Capability

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

As previously indicated, each company's generation capacity additions are planned so that each meets its own reserve requirement over the long-term. Any capacity transfers (i.e., "reserve sharing") should be considered for short time frames only. Specifically, the practice has been that, as the last step of the planning process, the respective SWEPCO and PSO expansion plans are adjusted to take advantage of any surplus of one company that might match a potential deficit of the other, and thereby delay some of the identified new capacity. Because of the sizes, demand growth rates, and peak coincidence of the two companies, it rarely appears that either company would ever have more than 200MW of surplus capacity in any year that could be transferred to the other company.

3.5.2.3 AEP-SPP Import Capability

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

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

3.5.2.4 SPP Studies that may Provide Import Capability

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

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

3.5.3 Recent AEP-SPP Bulk Transmission Improvements

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

- **Northwest Arkansas—**The AEP Transmission System serves approximately 1,300 MW of load in the Northwest Arkansas area, about 52% of which is Arkansas Electric Cooperative Commission (AECC) load. This load is supplied primarily by the SWEPCO and AECC jointly-owned Flint Creek generating plant, the SWEPCO Mattison generating plant, the Grand River Dam Authority – Tonnece – Flint Creek 345 kV line, and the Clarksville-Chamber Springs 345 kV line. Wal-Mart's international headquarters and its supplying businesses' offices and Tyson's headquarters are all located in this area. The Chamber Springs-

Farmington Rural Electric Cooperative 161 kV line has been upgraded to a larger conductor with improved thermal capacity. The Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line is also being upgraded to a larger conductor with improved thermal capacity.

- **McAlester, Oklahoma area –** The Lone Oak-Broken Bow (Southwestern Power Administration) 138 kV line rebuilt with new structures and upgraded to a larger conductor with improved thermal capacity.
- **Cornville/Rush Springs, Oklahoma area –** In addition to the previously completed 138 kV rebuild and conversion of the Cornville-Lindsay Water Flood radial line, approximately 33 miles, a 138 kV connection, approximately 10 miles, has been built from this line to an existing radial that serves Rush Springs Natural Gas from the existing Cornville-Duncan 138 kV line. This has created a 138 kV loop, improving reliability of the transmission system in this area.

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

3.5.4 Impacts of New Generation

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

- **Western Oklahoma/Texas Panhandle—**This area is one of the highest wind density areas within the SPP RTO footprint. The wind farm capacity for this area has exceeded 10,000 MW and has potential for substantial additional growth. Many wind farms are in operation, and several more are in the development stages. SPP is also studying the addition of multiple potential solar generating facilities. Generation additions in the SPP footprint in this region will likely require significant transmission enhancements, including EHV line and station construction, to address thermal, voltage, and stability constraints.
- **SPP Eastern Interface—** From the Gulf of Mexico (east of Houston) north to near Des Moines, Iowa there are only four east-west EHV transmission paths into the SPP region. This limitation constrains the amount of imports and exports along the eastern interface of SPP with neighboring regions. It also constrains the amount of transfers from the capacity-rich western SPP region to the market hubs east of the SPP RTO region. Significant generation additions near or along the SPP eastern interface would likely require significant transmission enhancements, including EHV line and station construction, to address thermal and stability

constraints should such generation additions adversely impact existing transactions along the interface.

Integration of generation resources at any location within the AEP-SPP zone will require significant analysis by SPP to identify potential thermal, short circuit, and stability constraints resulting from the addition of generation. Depending on the specific location, EHV line and station construction, in addition to connection facilities, could be necessary. Other station enhancements, including transformer additions and breaker replacements, may also be necessary. Some of the required transmission upgrades could be reduced or increased in scope if existing generating capacity is retired concurrent with the addition of new capacity. For example, if SWEPCO's Flint Creek Generating Plant were to have been retired, rather than retrofitted with environmental controls (for which SWEPCO received approval from the APSC in Docket No. 12-008-U), SWEPCO's transmission system would have required significant upgrades to support the delivery of power from remote generating plants, provide transfer capability, and supply reactive power for voltage support into that northwest Arkansas load pocket.

3.5.5 Summary of Transmission Overview

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

4.0 Modeling Parameters

4.1 Modeling and Planning Process – An Overview

The objective of a resource planning effort is to recommend a system resource expansion plan that balances “least-cost” objectives with planning flexibility, asset mix considerations, adaptability to risk, and conformance with applicable NERC and RTO criteria. In addition, the planning effort must ultimately be in concert with anticipated long-term requirements established by the EPA-driven environmental compliance planning process. Resources selected through the modeling process are not locational specific.

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

In general, assumptions and plans are continually reviewed and modified as new information becomes available to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are routinely reassessed to ensure optimal capacity resource planning.

Further impacting this process are a growing number of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the SWEPCO IRP process. Therefore, as a result, the “objective function” of the modeling applications utilized in this process is the establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. Other factors–some more difficult to monetize than others–were considered in the determination of the plan. Sensitivity analyses were performed to understand the impact of addressing factors which may increase costs.

4.2 Methodology

The IRP process aims to address the long-term “gap” between resource needs and current resources. Given the various assets and resources that can satisfy this expected long-term gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution–or portfolio–subject to constraints. *Plexos®* is the primary modeling application, used by SWEPCO and AEP for identifying and ranking portfolios that address the gap between needs and current available resources.[7] Given the cost and performance parameters around sets of potentially-available supply- and demand-side proxy resources and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, *Plexos®* will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the Cumulative Present Worth (CPW), of the resulting stream of revenue requirements. The least cost option is considered the “optimum” portfolio for that unique input parameter scenario.

4.3 The Fundamentals Forecast

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

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

locational natural gas prices, including the benchmark Henry Hub, 4) uranium fuel prices, 5) SO_2, NO_x and CO_2 values, 6) locational implied heat rates, 7) electric generation capacity values, 8) renewable energy subsidies and, 9) inflation factors, among others.

The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. It 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, among others. Ultimately, Aurora creates a weather-normalized, long-term forecast of the market in which a utility operates.

The Aurora energy market simulation model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility which are subsequently exported to the Aurora energy market simulation model.

The Fundamentals Forecast is a long-term, weather-normalized energy market forecast and there is the credible modeling expectation that each forecast-year experiences 30-year average heating and cooling degree-days. In fact, actual weather can deviate dramatically. The combination of both heating degree day departure from normal and above- or below-normal natural gas storage inventory levels are primary factors affecting any nearby deviation from weather-normalized values. Warmer-than-normal winters result in reduced natural gas demand and materially depressed natural gas prices. Understandably, the Polar Vortex winter of 2013-2014 had the opposite effects. When comparing actual results to a weather normalized forecast, it is imperative to account for these impacts.

AEPSC also has ample energy market research information available for its reference, which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. Although no exact forecast inputs from these sources of energy market research information are utilized, an in-depth assessment of this research information can yield, among other things, an indication of the supply, demand, and price relationship (price elasticity) over a period of time. This price elasticity, when applied to the Aurora-derived natural gas fuel consumption, yields a corresponding change in natural gas prices – which is recycled through the Aurora model iteratively until the change in natural gas fuel consumption for the electric generation sector is de minimis. Figure 16 illustrates that any changes in input assumptions must be iteratively processed through Aurora to determine a new merit order of dispatch. It is this new merit order of dispatch that takes into account the effect of operating conditions across North America and, in turn, ultimately determines zonal energy market prices.

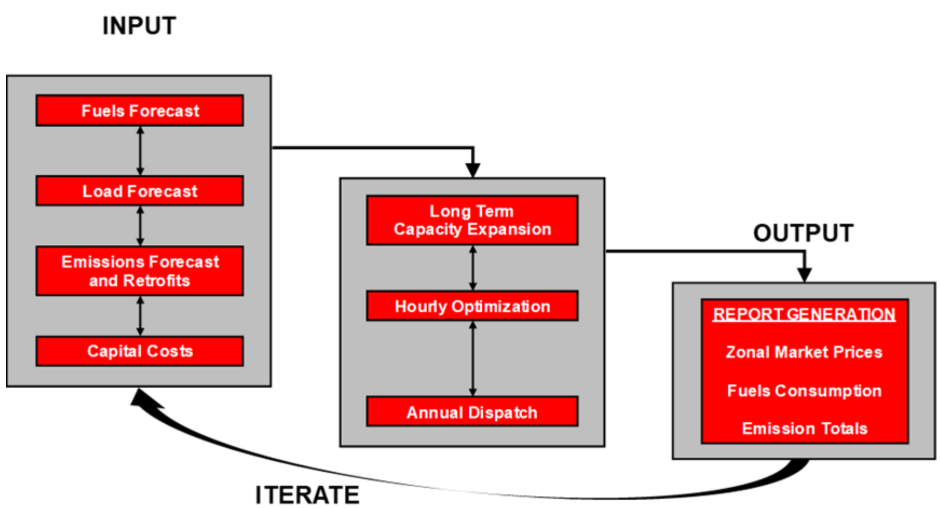

Figure 16. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Five commodity-pricing scenarios were developed to construct resource plans for SWEPCO under various long-term pricing conditions. In this Report, the five distinct long-term scenarios that were developed are the Base Case, Lower Band, Upper Band, Base, No Carbon and Low No Carbon scenarios. The overall fundamentals forecasting effort was most recently completed in April of 2019.

The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case Fundamentals Forecast. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices. Nominally, fossil fuel prices vary one standard deviation above and below Base Case values. Renewable Energy Credits (REC) are assumed to be zero over the long term in all of the Fundamental Commodity price forecasts.

The Fundamentals Forecast employs a CO_2 dispatch burden (adder) on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per metric ton commencing in 2028. This CO_2 dispatch burden is a proxy for the many pathways CO_2 may take (e.g. renewables subsidies/penetration, voluntary and mandatory portfolio standards, exceptionally low natural gas prices, considerable reduction in battery storage costs) in addition to any regulation to impose fees on the combustion of carbon-based fuels.

It is the assessment of Company experts that the likelihood of any federal climate legislation is very low over the next three years and still unlikely through the tenure of the 116th Congress. With 2021-2023 as the earliest reasonable date for a climate proposal to pass through committee, reach the floor and be approved by house for eventual passage, there will be an implementation period of approximately five years (as seen in previous climate proposals). Thus, 2028 is the earliest reasonable projection as to when such legislation could become effective.

The Fundamentals Forecast is not merely concerned with the current status of regulations and other current conditions that affect prices, but instead must also reflect reasonable expectations regarding future conditions that affect prices. As such, the carbon price proxy used for fundamentals forecasting is a reasonable assessment of future costs based on the current status for carbon regulations and potential changes thereto.

The Base No Carbon and Low No Carbon cases assume there will be no regulations limiting CO_2 emissions throughout the entire forecast period.

4.3.2 Forecasted Fundamental Parameters

Figure 17 through Figure 23 below illustrate the forecasted fundamental parameters (fuel, energy, capacity and CO_2 emission prices) used in the long-term optimization modeling for this IRP.

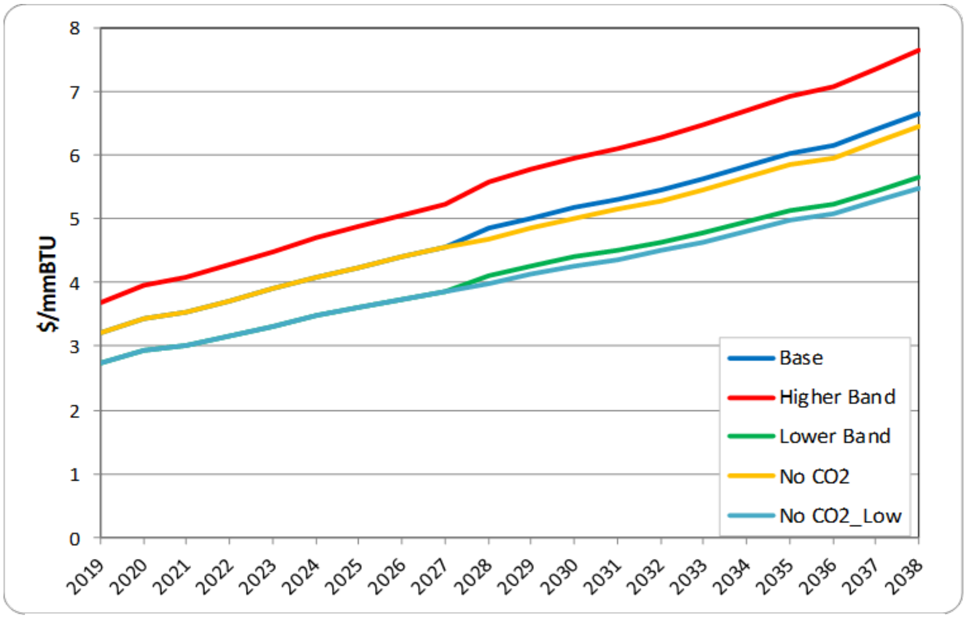

Figure 17. Henry Hub Natural Gas Prices (Nominal $/mmBTU)

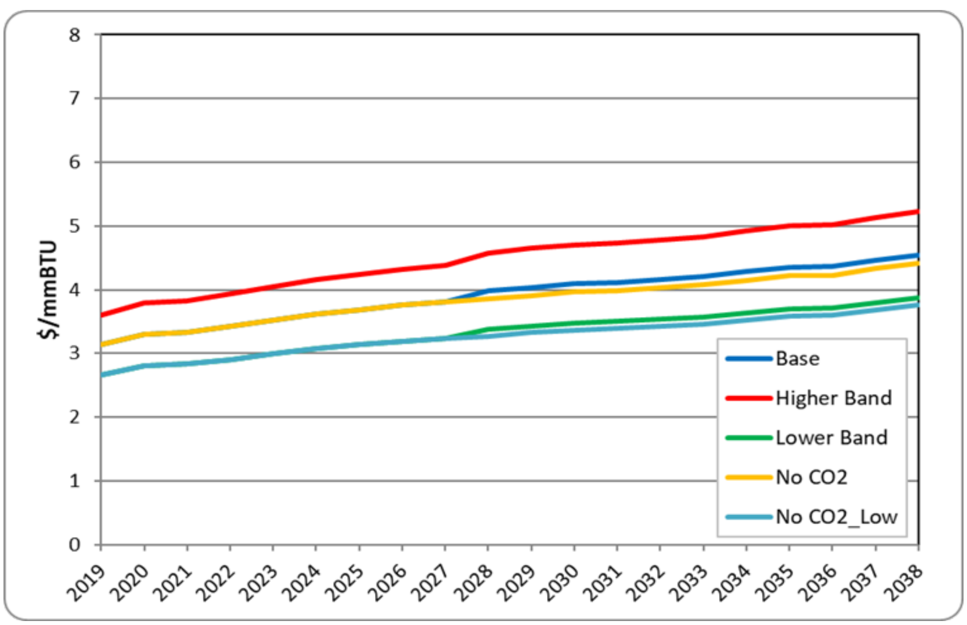

Figure 18. Henry Hub Natural Gas Prices (2018 Real $/mmBTU)

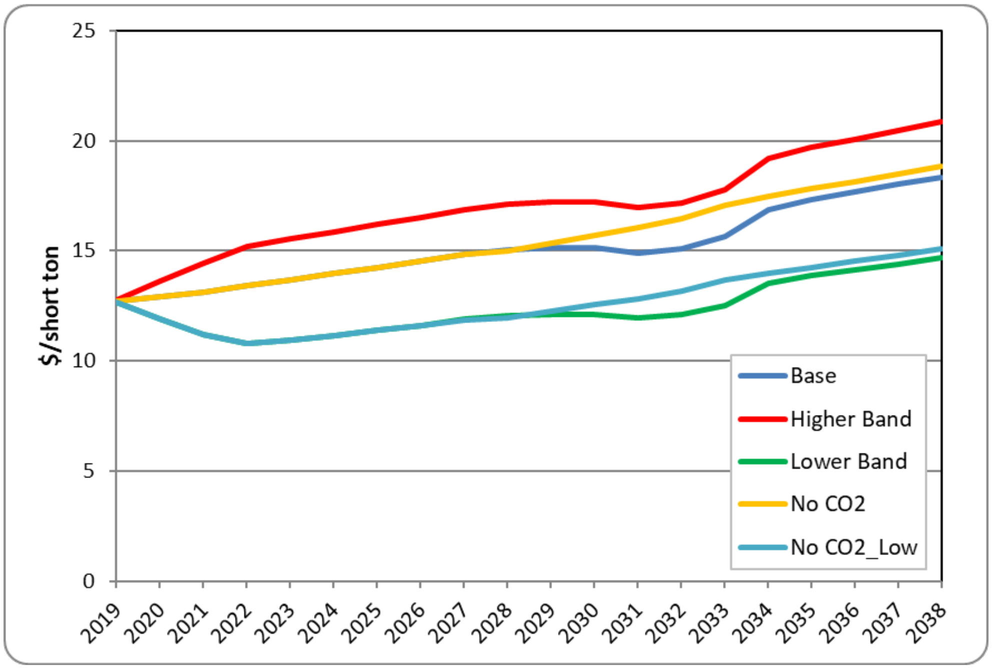

Figure 19. PRB 8800 Coal Prices (Nominal $/ton, FOB origin)

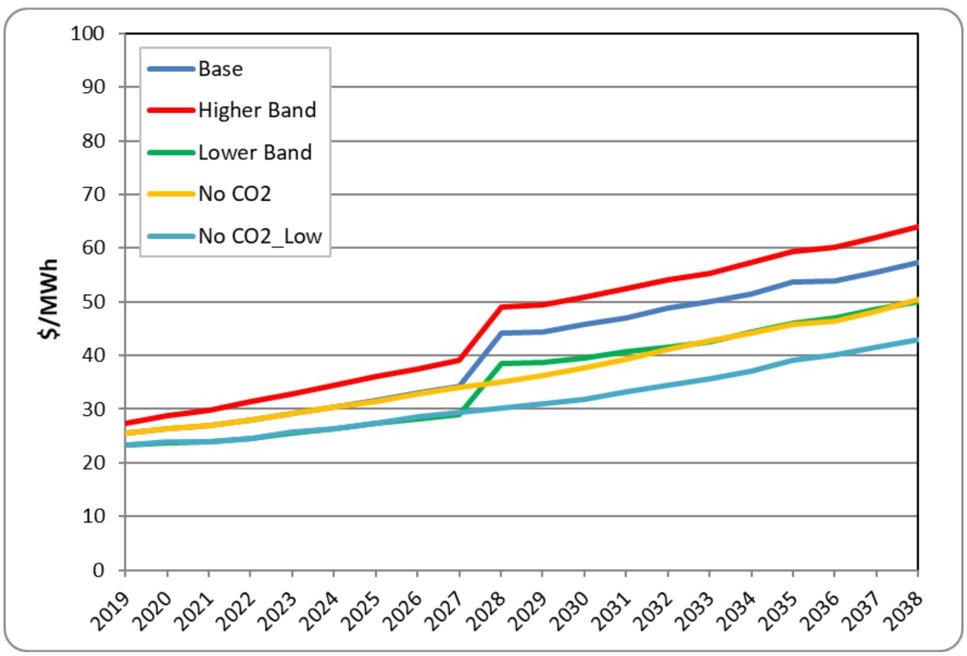

Figure 20. SPP Central On-Peak Energy Prices (Nominal $/MWh)

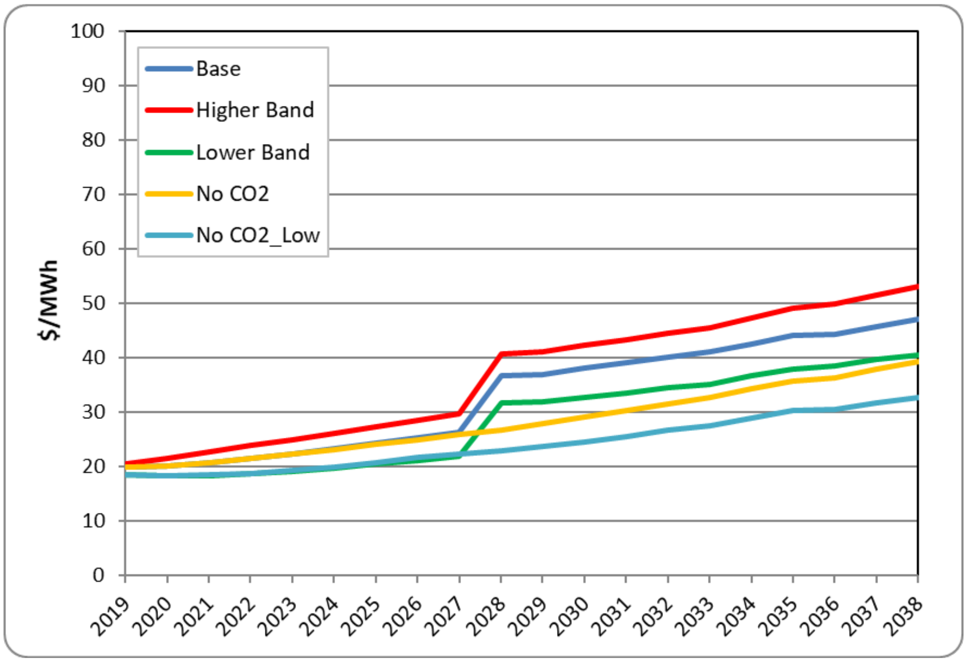

Figure 21. SPP Central Off-Peak Energy Prices (Nominal $/MWh)

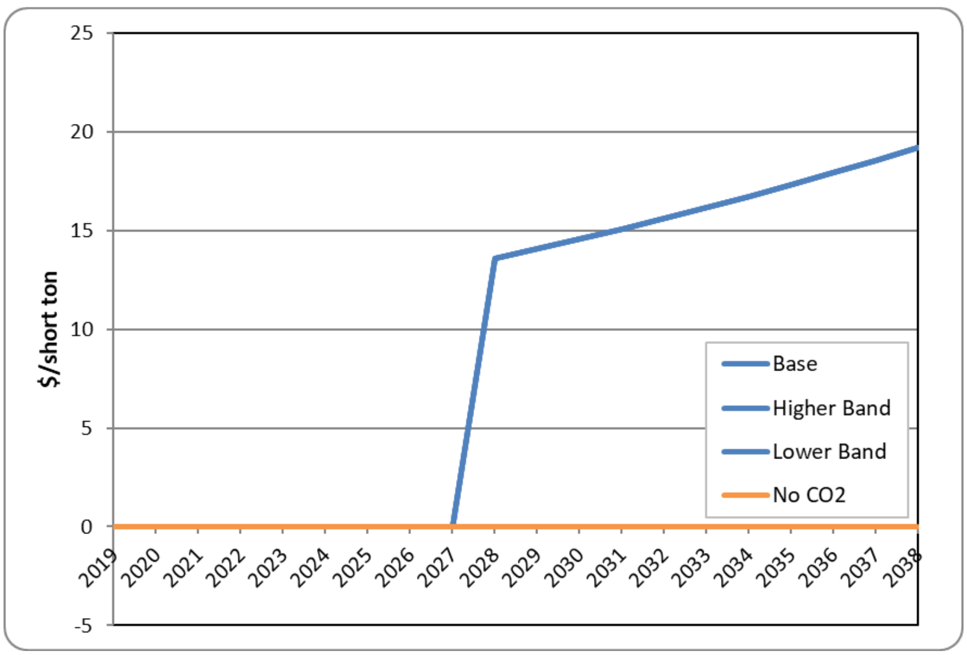

Figure 22. CO_2 Prices (Nominal $/short ton)

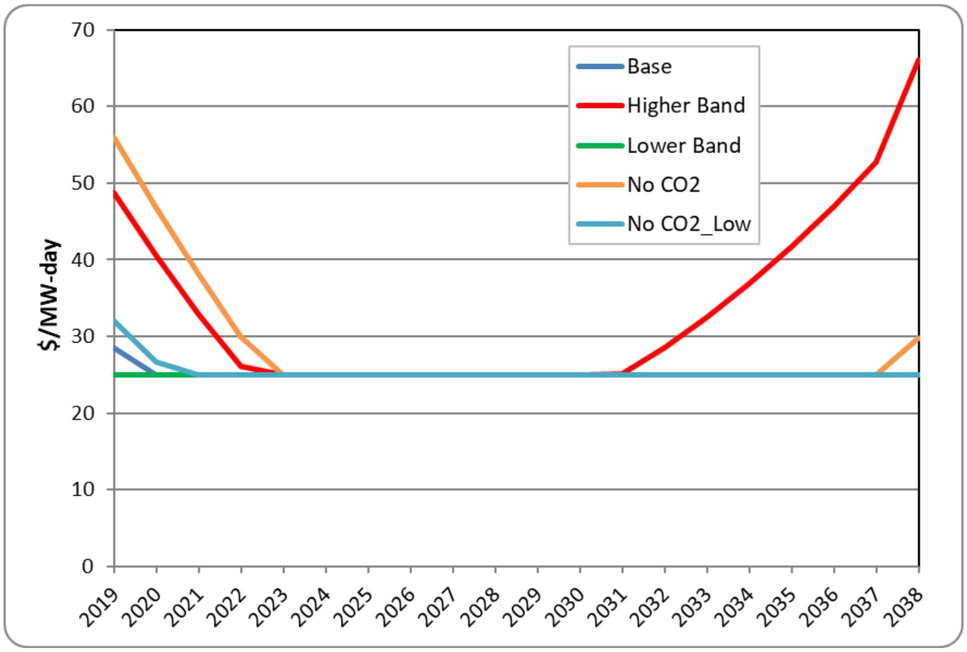

Figure 23. SPP Capacity Prices (Nominal $/MW-day)

The capacity prices in Figure 23 are a discrete output of the Aurora model used to project fundamental power prices. Capacity prices represent the non-energy revenue necessary for the least-dispatched units to remain economically viable and for the entire fleet to meet required reserve margins. The Capacity Values are bounded by an assumed minimum of $25 and the cost of new entry (CONE), currently defined as the cost of a new combustion turbine. It would be reasonable to infer that low capacity prices mean that the model is long in generation and that new generation is not required to maintain reserve margins. Similarly, an increase in capacity prices would indicate that new generation is required to meet reserve margins.

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

4.4.1 Overview

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

For SWEPCO, the potential incremental DSM programs were developed and ultimately modeled based on SWEPCO's DSM team input and the Electric Power Research Institute's (EPRI) "2014 U.S. Energy Efficiency Potential Through 2035" report. This report served as the basic underpinning for the establishment of potential EE "bundles", developed for residential and commercial customers that were then introduced as a resource option in the *Plexos*® optimization model. In order to reflect potential energy savings available in the industrial sector, the end-usage associated with lighting was combined for both the commercial and industrial sectors. The indoor and outdoor lighting bundles shown below in Table 7 reflect the potential energy savings for both sectors.

4.4.2 Achievable Potential (AP)

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

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

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

4.4.3 Evaluating Incremental Demand-Side Resources

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

4.4.3.1 Incremental Energy Efficiency (EE) Modeled

To determine the economic demand-side EE activity to be modeled that would be over-and-above existing EE program offerings in the load forecast, a determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs. It was assumed that the incremental programs modeled would be effective in 2020. Given that each of SWEPCO's jurisdictions have a subset of customers that are allowed to opt-out of participating in EE programs, these customers were removed from the available EE potential and thus not modeled. Figure 24 and Figure 25 show the "going-in" make-up of projected end-usage in 2020 for SWEPCO's residential and commercial sectors with lighting end-use also included for the industrial sector. Future incremental EE activity can further target these areas or address other end-uses.

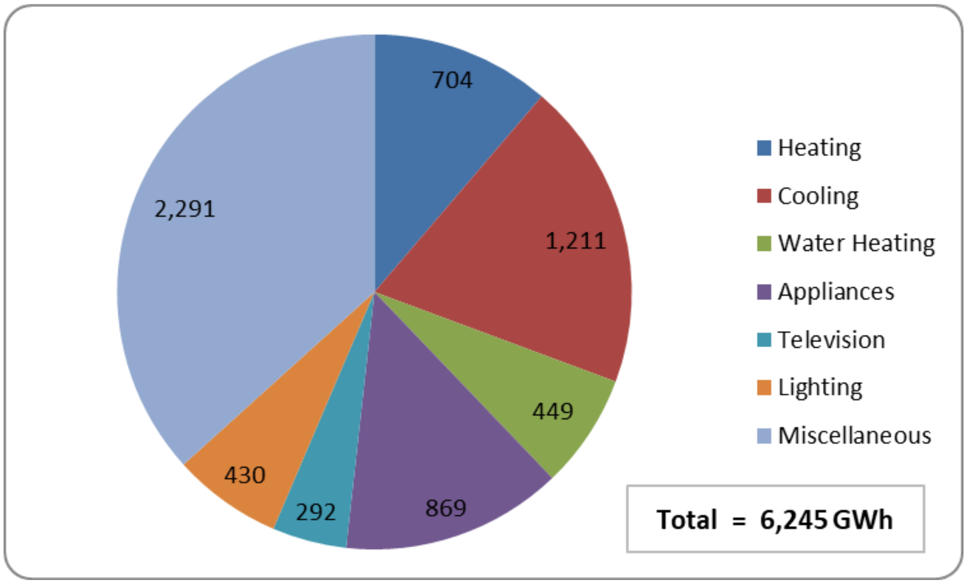

Figure 24. 2020 SWEPCO Residential End-Use (GWh)

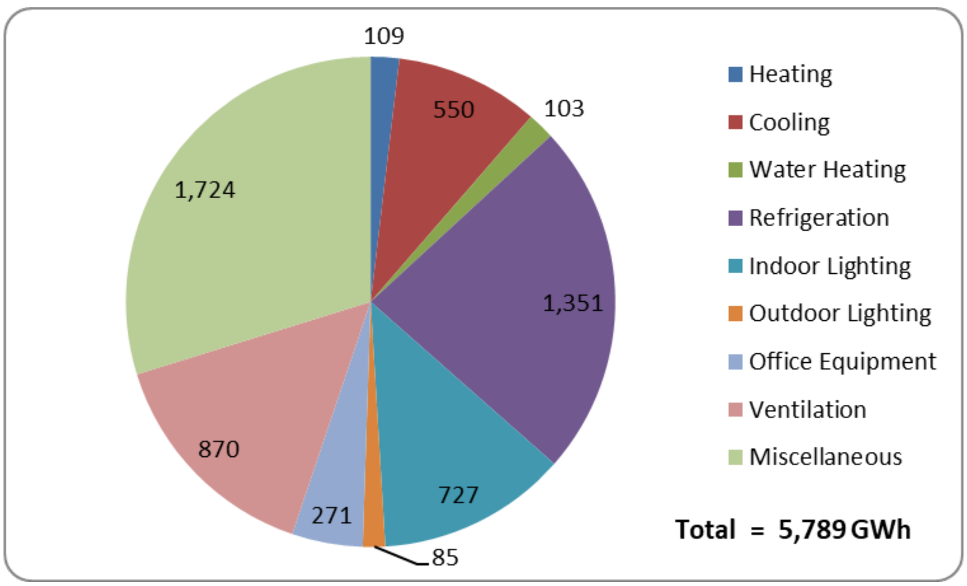

Figure 25. 2020 SWEPCO Commercial End-Use & Industrial Lighting End-Use (GWh)

To determine which end-uses are targeted, and in what amounts, SWEPCO looked at the previously-cited 2014 EPRI report and consulted its DSM team. The EPRI report and the SWEPCO DSM team provided information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. SWEPCO utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 4 and Table 5**,** from the EPRI report, list the individual measure categories considered for both the residential and commercial sectors.

Table 4. Residential Sector Energy Efficiency (EE) Measure Categories

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

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

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

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

Table 6 and Table 7 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 7 includes potential savings for both commercial and industrial customers.

Table 6. Incremental Residential Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Yearly Potential Savings (MWh) 2041-2048	Bundle Life
Thermal Shell - AP	$0.22	2,766	1,924	2,911	2,624	10
Thermal Shell - HAP	$0.32	11,948	13,488	7,197	8,682	10
Cooling - AP	$1.19	22,250	8,421	5,630	0	17
Cooling - HAP	$1.66	9,908	6,809	0	0	17
Water Heating - AP	$0.07	846	0	0	0	10
Water Heating - HAP	$0.11	3,655	3,409	1,295	1,500	10
Appliances - AP	$0.08	2,606	907	648	0	13
Appliances - HAP	$0.13	1,441	857	0	0	13
Lighting - AP	$0.03	8,142	0	0	0	30
Lighting - HAP	$0.05	7,105	1,273	0	0	30
Enhanced Customer Bill	$0.74	26,931	0	757	791	10
**HAP Potential is incremental to AP Potential*						

Table 7. Incremental Commercial and Industrial (Lighting) Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Yearly Potential Savings (MWh) 2041-2048	Bundle Life
Heat Pump - AP	$8.65	3,560	615	0	0	15
Heat Pump - HAP	$12.97	890	0	0	0	15
HVAC Equipment - AP	$0.19	1,359	0	0	0	16
HVAC Equipment - HAP	$0.30	2,154	0	0	0	17
Indoor Screw-In Lighting - AP	$0.01	3,021	0	0	0	6
Indoor Screw-In Lighting - HAP	$0.02	1,598	0	0	0	6
Indoor HID/Fluorescent Lighting - AP	$0.21	32,691	7,000	1,032	0	13
Indoor HID/Fluorescent Lighting - HAP	$0.32	8,173	2,045	0	0	13
Outdoor Lighting - AP	$0.15	5,045	1,186	0	0	15
Outdoor Lighting - HAP	$0.22	1,261	430	0	0	15
**HAP Potential is incremental to AP Potential*						

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

Residential Thermal Shell, Residential Water Heating and Commercial Cooling bundles—in both AP and HAP—include secondary measures. The MAR and PIF are utilized to develop the incremental AP program characteristics and the MAR only is used to develop the incremental HAP program characteristics.

Figure 26 shows the Levelized Cost of Electricity (LCOE) and potential energy savings in 2020 for each of the bundles offered into the model as a potential resource. To preserve a reasonable scale for illustrative purposes, the two bundles with the highest LCOE, Commercial Heat Pump AP and Commercial Heat Pump HAP, were omitted from Figure 26. The total potential energy savings for EE programs that begin in 2020 is 157GWh, 1.2% of SWEPCO's total residential, commercial & industrial lighting load. Figure 26 is offered as a rough comparison of EE bundle cost versus levelized market prices. However, it is not intended to illustrate which EE resources the model will select. Ultimately, the model will determine if an EE bundle is beneficial to an optimization scenario[8].

[8] For illustrative purposes, the Company has included in Figure 26 a proxy for the SPP Around-the-Clock LCOE, it should be noted within this calculation that, for comparison purposes only, these annual values are degraded over 15 years, which is similar to EE bundles with a 15-year life.

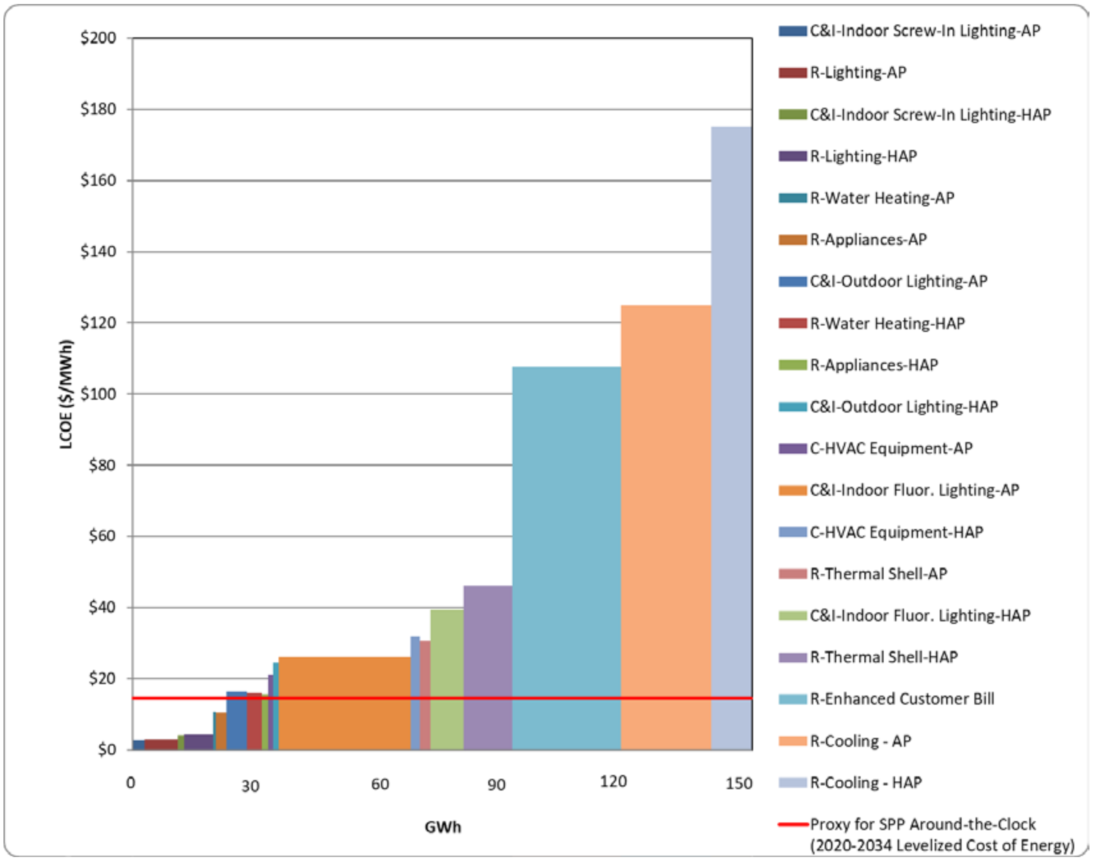

Figure 26. EE Bundle Levelized Cost vs. Potential Energy Savings for 2020

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

4.4.3.2 Volt VAR Optimization (VVO) Modeled

Potential future VVO circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 15 "tranches" based on the relative potential peak demand and energy reduction of each tranche of circuits. The *Plexos*® model was able to pick the most cost-effective tranches first and add subsequent tranches as merited. Each

VVO tranche is estimated to encompass approximately 41 circuits. Table 8 details all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in 2017 dollars.

Table 8. Volt VAR Optimization (VVO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	40	$13,360,000	$400,800	20,679	96,007
2	41	$13,694,000	$410,820	11,323	52,570
3	41	$13,694,000	$410,820	9,585	44,503
4	40	$13,360,000	$400,800	8,443	39,200
5	40	$13,360,000	$400,800	7,778	36,111
6	40	$13,360,000	$400,800	7,334	34,048
7	40	$13,360,000	$400,800	6,766	31,414
8	40	$13,360,000	$400,800	6,164	28,616
9	41	$13,694,000	$410,820	5,567	25,847
10	41	$13,694,000	$410,820	5,012	23,270
11	40	$13,360,000	$400,800	3,992	18,533
12	41	$13,694,000	$410,820	3,420	15,878
13	41	$13,694,000	$410,820	2,816	13,072
14	41	$13,694,000	$410,820	2,247	10,432
15	41	$13,694,000	$410,820	1,586	7,365

4.4.3.3 Demand Response (DR) Modeled

The current level of DR is maintained throughout the plan. SWEPCO has and will continue to provide demand response tariffs to meet customer needs. Company personnel work with customers to identify load suitable for interruption and will continue to do so. SWEPCO has offered demand response rates to other customer classes (including residential) and will continue to evaluate the value of these types of programs that will meet both customer and Company needs.

4.4.3.4 Distributed Generation (DG) Modeled

Distributed solar resources were evaluated assuming a residential rooftop solar resource, as this is the primary distributed resource. Solar has favorable characteristics in that it produces the majority of its energy at near-peak usage times. Distributed solar resources (i.e., rooftop Solar) are included in the model at an assumed growth rate based on the current level of federal incentives, future estimated costs of rooftop solar and historical rooftop solar additions.

The current distributed resources net metering cap for SWEPCO Louisiana is 7.8MW and SWEPCO Louisiana met this cap in 2016. The assumed annual growth rate for rooftop solar is 5% per year after SWEPCO Louisiana reached the cap. The assumed growth rate is an estimate and is based on both the declining cost for rooftop solar as well as the historical additions by SWEPCO state jurisdiction.

Figure 27 below demonstrates the historical installed rooftop solar capacity for SWEPCO by jurisdiction and projected rooftop solar capacity additions.

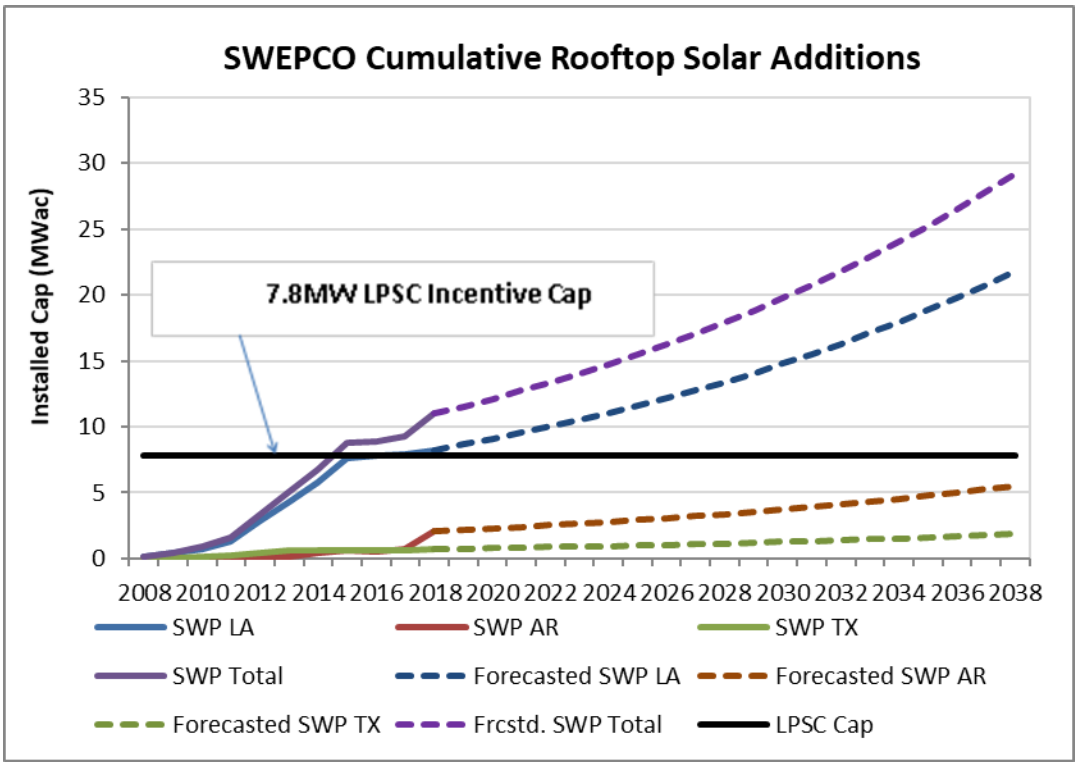

Figure 27. Distributed Generation (Rooftop Solar) Additions/Projections

4.4.3.5 Optimizing Incremental Demand-side Resources

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

4.4.3.6 Combined Heat and Power (CHP)

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

SWEPCO worked with AEP Generation Engineering to develop a generic CHP option. The CHP option developed is a 15MW facility utilizing a natural gas fired combustion turbine, Heat Recovery Steam Generator (HRSG) and SCR to control NO_x. A major assumption is that all of the steam is taken by the host and the efficiency of the modeled CHP resource is credited for the value of the steam provided to the host. The overnight installed cost is estimated to be $2,300/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%.

4.5 Identify and Screen Supply-side Resource Options

4.5.1 Capacity Resource Options

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

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

4.5.2 New Supply-Side Capacity Alternatives

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

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

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

AEP continually tracks and monitors changes in the estimated cost and performance parameters for a wide array of generation technologies. Access to industry collaborative organizations such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers, as well as its own experience and market intelligence, provides AEP with current estimates for the planning process. Table 9 below offers a summary (see Exhibit B for a more detailed description of the technologies and associated footnotes) of the most recent technology performance parameter data developed. Additional parameters such as the quantities and rates of solid waste production, hazardous material consumption, and water consumption are significant; however, the options which passed the screening phase and were included in *Plexos*® were natural gas facilities which generally have limited impacts on these areas of concern.

Table 9. New Generation Technology Options with Key Assumptions

Type	Capability (MW) (d) Std. ISO	Summer	Winter	Installed Cost (c,e) ($/kW)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load						
Nuclear	1,610	1,560	1,690	8,900	80	180.0
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,800	75	215.4
Combined Cycle (1X1 "J" Class)	610	800	820	900	75	58.0
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	75	53.8
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	740	75	54.6
Combined Heat and Power	15	15	16	2,500	90	89.5
Peaking						
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	25	148.3
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	800	25	115.9
Aero-Derivative (2 - Small Machines) (g,h)	120	120	120	1,400	25	145.2
Recip Engine Farm	220	220	230	1,300	25	124.8
Battery	10	10	10	1,900	25	156.3
Intermittent Resources						
Wind	200	30	30	1,200	44	15.6
Solar - Utility Scale	50	25	25	1,500	28	50.8

4.5.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by SWEPCO but were not included in the *Plexos*® resource optimization modeling analyses. The forecasted difference between SWEPCO's load forecast and existing resources is such that a large, central generating station would not be required. In addition, for coal generation resources, environmental regulation (see Section 3.3) makes the construction of new coal plants economically impractical. New nuclear construction is also economically impractical since it would potentially require an investment of $8,900/kW or more.

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

4.5.3.1 Natural Gas Combined Cycle (NGCC)

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

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-63% Lower Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain base-load needs. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration (Black Start) services. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

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

4.5.4 Peaking Alternatives

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

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

4.5.4.1 Simple Cycle Combustion Turbines (NGCT)

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

4.5.4.2 Aeroderivatives (AD)

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

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

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

4.5.4.3 Reciprocating Engines (RE)

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

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

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

4.5.4.4 Battery Storage

The modeling of Battery Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing platform for stationary storage applications. The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 40MWh, with a round trip efficiency of 87%. To develop this resource, AEP's Generation Engineering Services considered a wide range of sources including: the DOE/EPRI 2015 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI TAGWEB, BNEF and battery storage equipment suppliers. See Figure 28 below for an illustration of forecasted storage installed cost.

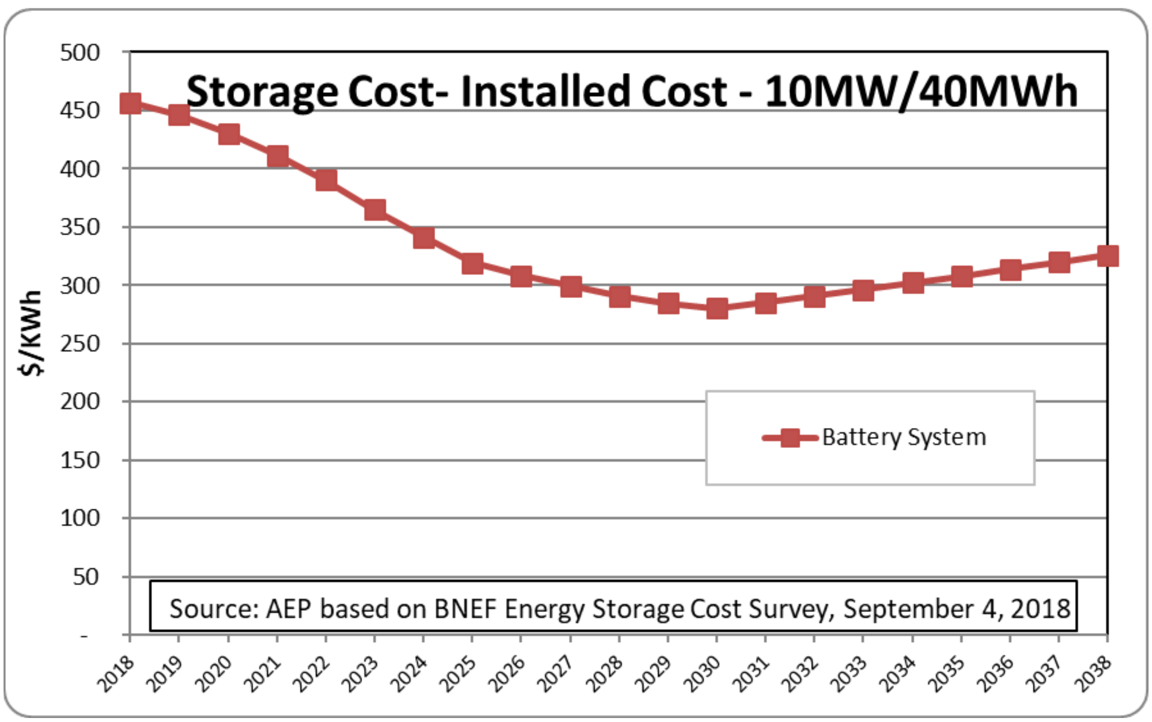

Figure 28. Forecasted Storage Installed Cost

4.5.5 Renewable Alternatives

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

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

4.5.5.1 Solar

4.5.5.1.1 Large-Scale Solar

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

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline (see Figure 29 below). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well, notwithstanding solar panel tariffs which from an IRP perspective are regarded as a short-term impact.

Large-scale solar plants require less lead time to build than fossil plants. There is no defined limit for how much utility solar can be built in a given time. However, in practice, solar facilities are not added in an unlimited fashion given siting and regulatory constraints.

Solar resources were made available in the *Plexos* model with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that large-scale solar resources were available in yearly quantities up to 300MWac[9] of nameplate capacity starting in 2023 (ie. Commercial operation date 12/31/22). A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources. Additionally, this 300MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted, constructed, and interconnected by SWEPCO in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be 7 acres, implying that 700 acres of land would be required to develop 100MW of solar annually. Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of SWEPCO's load obligation or 1,400MW. Certainly, as SWEPCO gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Solar resources were available in two tiers. Both tiers first year costs are informed by a recent SWEPCO Solar RFP and the overall pricing trend over the planning period is based on the BNEF utility scale solar pricing forecast. Tier 2 is indicative of an average price and tier 1 is indicative of a "Best-In-Class" solar resource. Both tiers of solar resources were available in blocks of 150MW, which is comprised of three 50MW installations and totals 300MW annually. Additionally, both tiers of solar resources were modeled with capacity factors of approximately 28%.

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

Figure 29 below illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs. The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has been commenced. The ITC benefit is included through 2030. After 2030, the 10% ITC benefit would become indiscernible from potential variations in forecasted prices. Solar resources are modeled with a 50% capacity credit. This is based on the expected long-term performance of the resource.

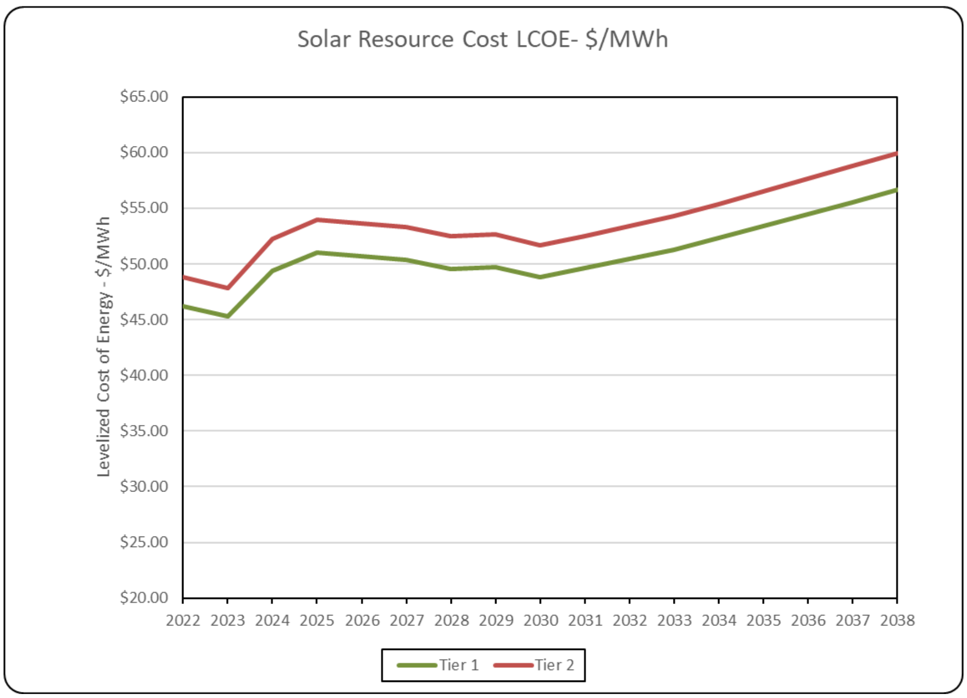

Figure 29. Large-Scale Solar Pricing Tiers

4.5.5.1.2 Trends in Solar Energy Pricing

As mentioned above, solar energy prices have declined significantly in recent years as shown below in Figure 30. From 2010 to 2018 installation costs have declined by more than 50% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale installations costing 50% and 30% less than residential and commercial installations, respectively, based on 2019 costs.

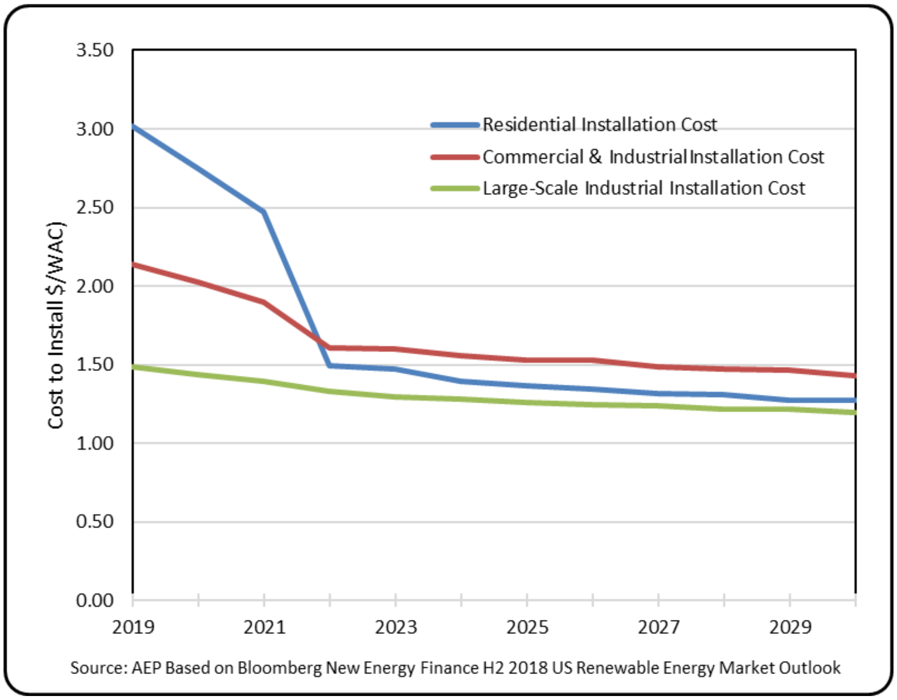

Figure 30. SPP Average Solar Photovoltaic (PV) Installation Cost (Nominal $/WAC) Trends, excluding Investment Tax Credit Benefits

4.5.5.2 Wind

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

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

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

Based on the Company's most recent wind RFP, for modeling purposes, wind resources are first made available to the model in 2021 (i.e., commercial operation date 12/31/20), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals. Figure 31 below shows the LCOE for the wind resource tranche assumed for the IRP. The tranche was modeled as a 44% capacity factor load shape and will be available in 200 MW blocks. Wind resources capacity credit for capacity planning purposes is assumed to be 15.3% of nameplate. The wind pricing reflects the value of Federal Production Tax Credits (PTCs). After 2020 tax credits reduce to 80%, 60% and 40% of their 2020 value in 2021, 2022, and 2023, respectively. These PTC values are based on developers taking advantage of the safe-harbor guidelines which provide up to a four-year delay in the effects of declining tax credits as long as adequate construction has commenced. Initial wind prices were informed by a recent SWEPCO Wind RFP and future prices are based on the Bloomberg New Energy Finance H2 2018 U.S. Renewable Energy Market Outlook and market knowledge.

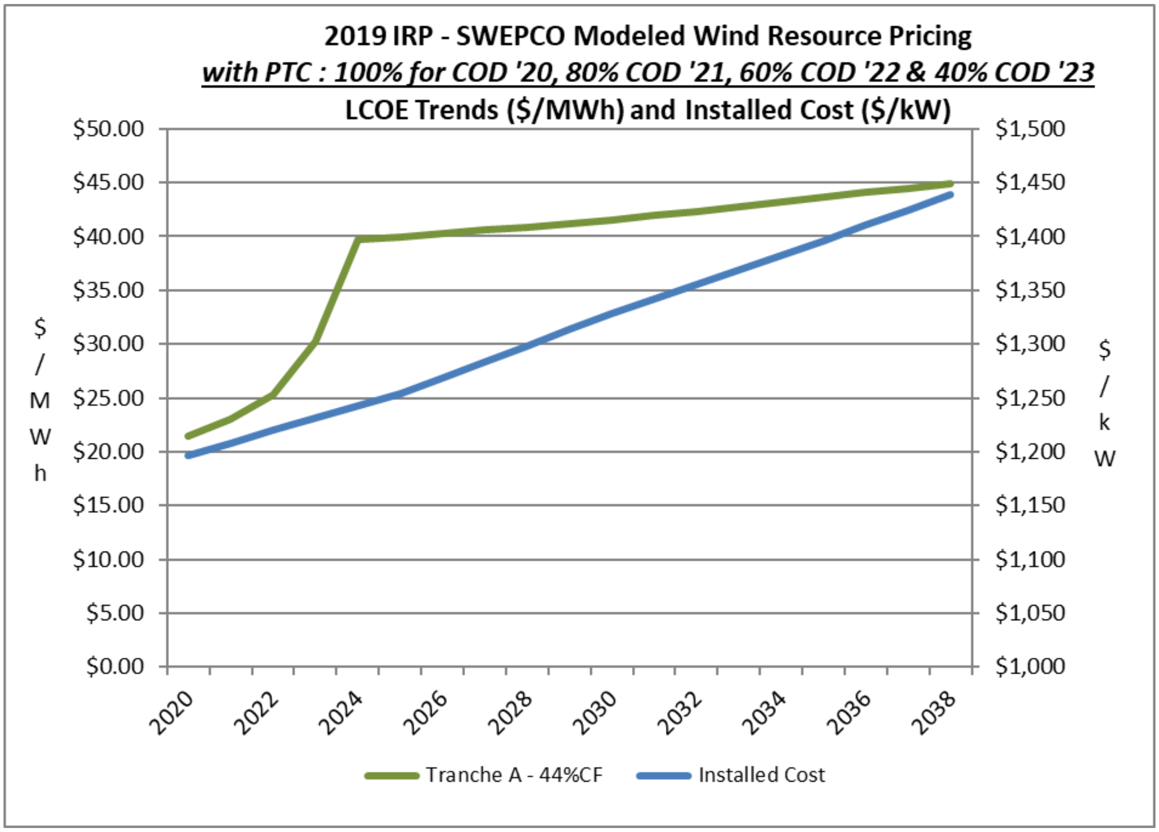

Figure 31.Levelized Cost of Electricity of Wind Resources (Nominal $/MWh)

The expected magnitude of wind resources available beginning in 2021 was limited to 200MW nameplate. The 2021 level is based on availability discovered through the RFP. For the remainder of the planning period, 600MW nameplate can be selected annually In total, wind resources were limited to 2,200MW nameplate over the planning period. The annual limit on wind additions is based on SWEPCO's ability to plan, manage and develop either the construction or the procurement of these resources. Similar to solar resource additions, as SWEPCO gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater later). This cap is based on the DOE's Wind Vision Report[10] which suggests from numerous transmission studies that transmission grids should be able to support

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

20% to 30% of intermittent resources in the 2020 to 2030 timeframe. The cap for SWEPCO allows the model to select up to 40% of generation energy resources as wind-powered by 2038.

Furthermore, based on recent experience and analysis the Company has included the cost of congestion and losses for incremental wind resource additions. Figure 32 below shows the annual value of congestion and losses included in the incremental wind dispatch cost.

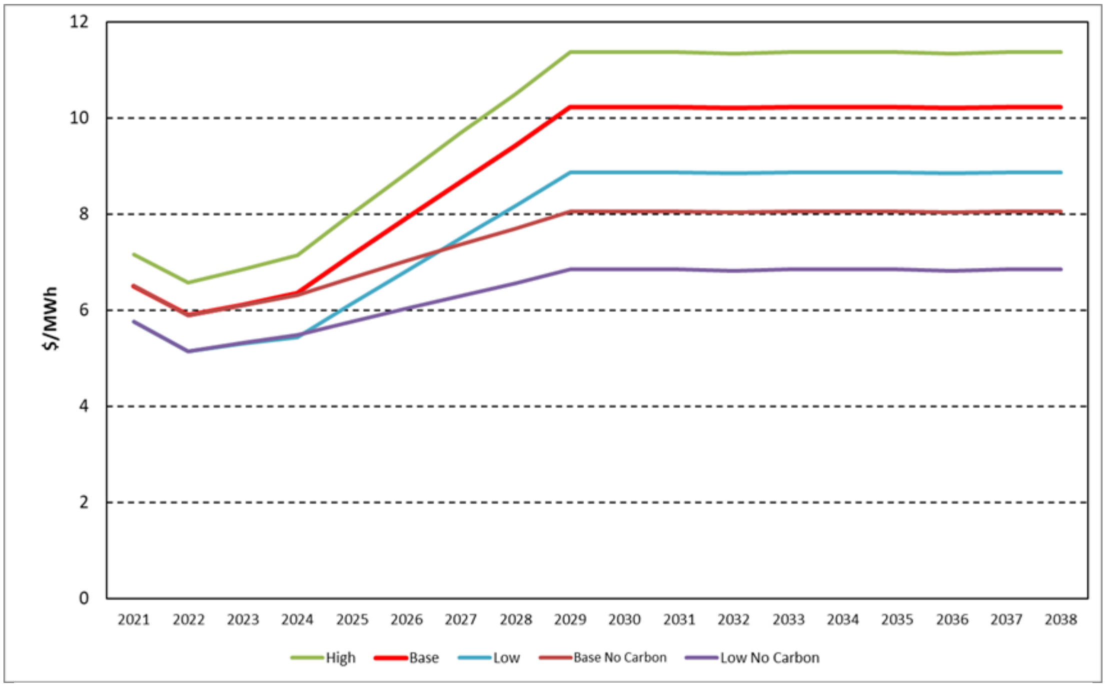

Figure 32. Modeled SPP Congestion & Losses for Wind Resources

4.5.5.3 Hydro

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

4.5.5.4 Biomass

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

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

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

4.6.1 Optimization of Expanded DSM Programs

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

4.6.2 Optimization of Other Demand-Side Resources

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

5.0 Resource Portfolio Modeling

5.1 The *Plexos*® Model - An Overview

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

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

- Fixed costs of capacity additions, *i.e.*, carrying charges on incremental capacity additions (based on an 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/or carbon 'tax,' and variable O&M costs;
- distributed, or customer-domiciled, resources which were effectively valued at the equivalent of a full-retail "net metering" credit to those customers; and
- a 'netting' of the production revenue earned in the SPP power market from SWEPCO's generation resource sales *and* the cost of energy – based on unique load shapes from SPP purchases necessary to meet SWEPCO's load obligation.

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

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

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

5.2 *Plexos*® Optimization

5.2.1 Key Input Parameters

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

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

5.2.2 Modeling Options and Constraints

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

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

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

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

- *Peaking* capacity was modeled, effective in 2022 due to the anticipated period required to approve, site, engineer and construct, from:

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

- *Intermediate-Baseload* capacity was modeled, effective in 2023 due to anticipated period required to approve, site, engineer and construct, from:
    - A 25% share of a NGCC (2x1 "J" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 1,604MW at summer conditions. The 25% interest assumes SWEPCO coordinates the addition of this resource with other parties.
- Wind resources were made available up to 200MW available in 2021 and 600MW annually beginning in 2022 (commercial operation date 12/31/21). The resource had a LCOE of $23.00/MWh in 2021 with an 80% PTC, without congestion and losses. The levelized congestion and losses for the 2021 wind resource is estimated to be approximately $8.72/MWh. Wind resources were assumed to have a SPP capacity value equal to 15.3% of nameplate rating.
- Large-scale solar resources were made available in two tiers, with up to 150MW of each tier available each year beginning in 2023, for a total of up to 300MW annually. Initial costs for Tier 1 were approximately $46/MWh in 2023 with the ITC. Tier 2 has an initial cost of approximately $49/MWh in 2023 with the ITC. Solar resources were assumed to have a SPP capacity value equal to 50% of nameplate rating.
- Short-Term Market Purchase alternative resources were made available to the model for selection during the development of the various optimal plans. These short-term capacity purchases were assumed to have no energy associated with them, a contract term of one year, and 250MW was allowed to be added annually. The pricing of these purchases was based on the SPP Capacity Prices

shown in Figure 23.

- DG, in the form of distributed solar resources, was embedded in amounts equal to a Compound Annual Growth Rate (CAGR) of 5% over the planning period.
- CHP resources were made available in 15MW (nameplate) blocks, with an overnight installed cost of $2,300/kW and assuming full host compensation for thermal energy for an effective full load heat rate of ~4,800 Btu/kWh.
- EE resources—incremental to those already incorporated into the Company's long-term load and peak demand forecast in up to 21 unique "bundles" of Residential, Commercial, and Industrial measures considering cost and performance parameters for both HAP and AP categories. Industrial measures were limited to lighting.
- VVO was available in 15 tranches of varying installed costs and number of circuits/sizes ranging from a low of 1.6MW up to 20.7MW of demand savings potential.

5.2.3 Traditional Optimized Portfolios

The key decision to be made by SWEPCO during the planning period is how to fill the resource need identified. Portfolios with various options addressing SWEPCO's capacity and energy resource needs over time were optimized under various conditions. Six traditional scenarios were initially analyzed for this IRP, resulting in six unique portfolios (see Table 10 below). The portfolios discussed below represent incremental resources which are in additional to those currently in-service.

Table 10. Traditional Scenarios/Portfolios

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

5.2.3.1 Commodity Pricing Portfolios

Figure 33 below show the capacity additions associated with the Base (Preferred Plan), Low Band, High Band, No Carbon and Low (Load) No Carbon commodity pricing scenarios. A table of the illustrated values can be found in Exhibit H. Recall from Section 4.3.1 that the modeling associated with the Base, Low Band, and High Band scenarios assumed a CO_2 dispatch burden, or allowance value, equal to $15/ton commencing in 2028 and escalating at 3.5% per annum thereafter on a nominal dollar basis. The No Carbon and Low No Carbon scenarios do not include a CO_2 dispatch burden.

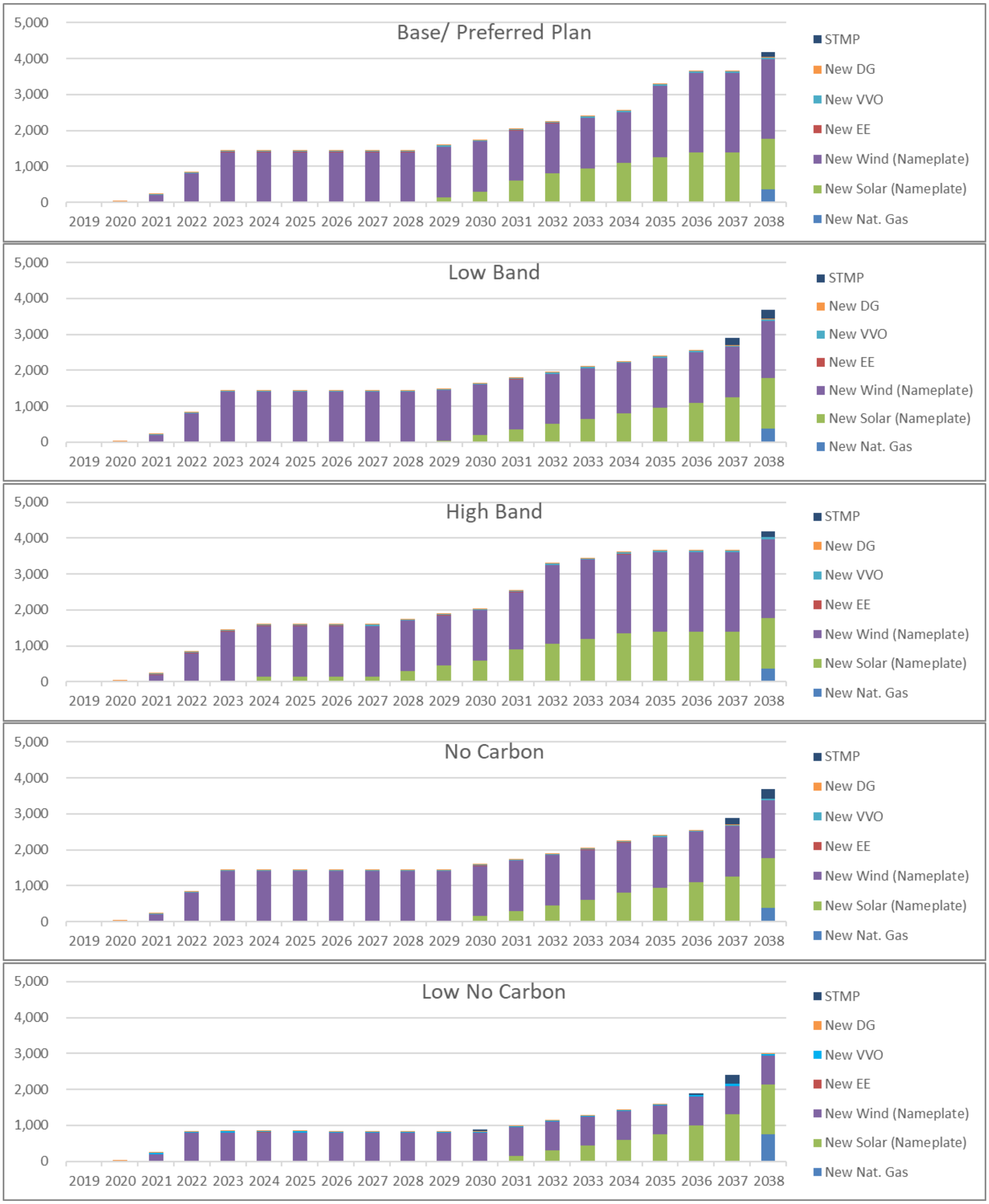

Figure 33. Cumulative SPP Capacity (Nameplate) Additions (MW) for Commodity Pricing Scenarios

All five portfolios include similar resource additions, such as:

- Wind resources of 200MW (nameplate) beginning in 2021 and 600 MW in 2022;
- Solar resources of 1,400 MW (nameplate) by 2038
- EE programs including VVO totaling 49MW or more by 2038.
- New natural gas resource delayed until 2038.

All five portfolios result in SWEPCO having a diverse group of new resource additions over the planning period, including, wind, solar, energy efficiency, VVO, natural gas combined cycle and Short-Term market purchases.

5.2.3.2 Load Sensitivity Scenario Portfolios

Figure 34 below shows the capacity additions associated with the Low Load and High Load sensitivity scenarios, using Base commodity prices. A table of the illustrated values can be found in Exhibit H.

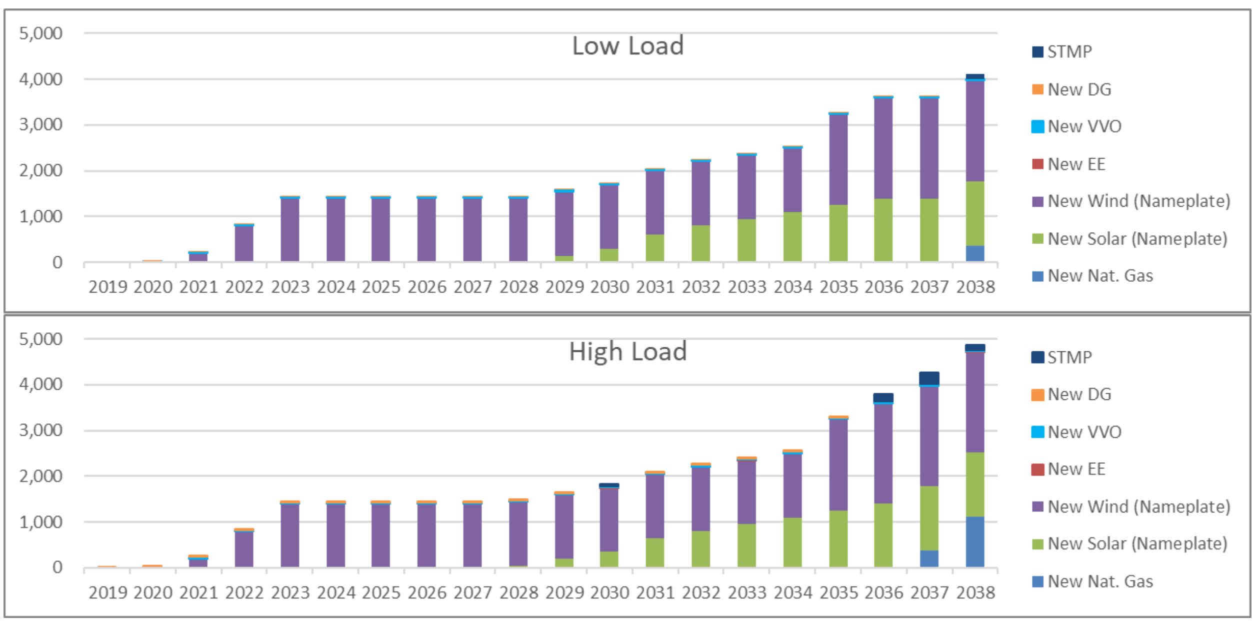

Figure 34. Cumulative SPP Capacity (Nameplate) Additions (MW) for Low Load and High Load Sensitivity Scenarios

As expected, the overall capacity additions in the High Load scenario are naturally greater than those in the Low Load scenario. The High Load scenario calls for a 1,119MW natural gas combined cycle (NGCC) resource for base/intermediate capacity by 2038 whereas the Low Load calls for only a 373MW NGCC by the end of the planning period.

5.3 Preferred Plan

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

This plan was developed based on the following considerations:

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

The cumulative capacity additions associated with the Preferred Plan are shown below in Table 11 and Figure 35.

Table 11. Cumulative SPP Capacity Additions (MW) for Preferred Plan

Commodity Pricing Scenario		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base/ Preferred Plan	New Nat. Gas																				373
	New Solar (Nameplate)											150	300	600	800	950	1,100	1,250	1,400	1,400	1,400
	New Solar (Firm)											75	150	300	400	475	550	625	700	700	700
	New Wind (Nameplate)			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	2,000	2,200	2,200	2,200
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	306	337	337	337
	New EE		5	8	10	10	11	12	11	10	8	7	6	6	5	5	3	3	2	2	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	34	34	47	47	47	47	58
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																				150
Capacity Reserves (MW) Above SPP Rqmts w/o new additions		547	540	510	480	373	357	237	119	50	47	15	(167)	(189)	(209)	(287)	(295)	(318)	(697)	(1,072)	(1,619)
Capacity Reserves (MW) Above SPP Rqmts with new additions		550	572	576	640	624	610	491	373	303	299	341	232	361	450	446	525	669	395	20	7

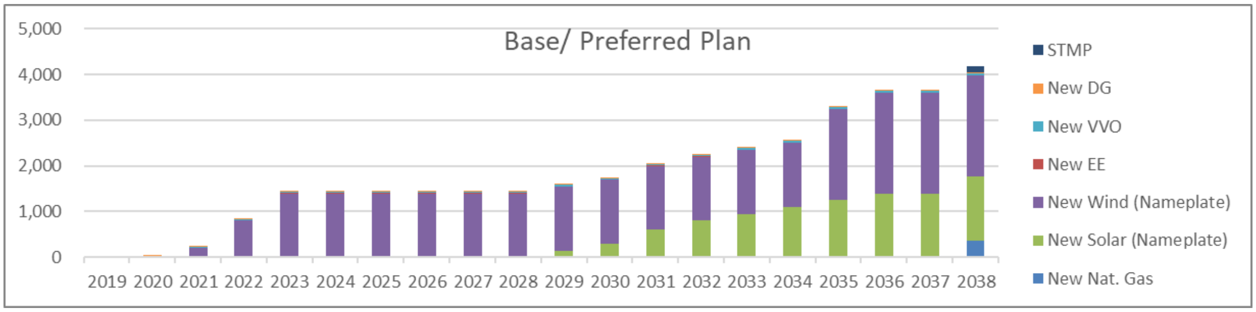

Figure 35. Cumulative SPP Nameplate Capacity Additions (MW) for Preferred Plan

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

5.3.1 Demand-Side Resources

In the Preferred Plan, incremental EE resources were selected beginning in 2020 and throughout the remainder of the planning period. Economic savings are attributable to both Commercial/Industrial and Residential programs, with the majority coming from Commercial/Industrial Lighting programs. By 2038, overall EE savings – consisting of Other Energy Efficiency, Existing DSM Programs, and Incremental DSM Programs – provide a decrease in residential and commercial energy usage of approximately 8.9% (see Figure 36 below).

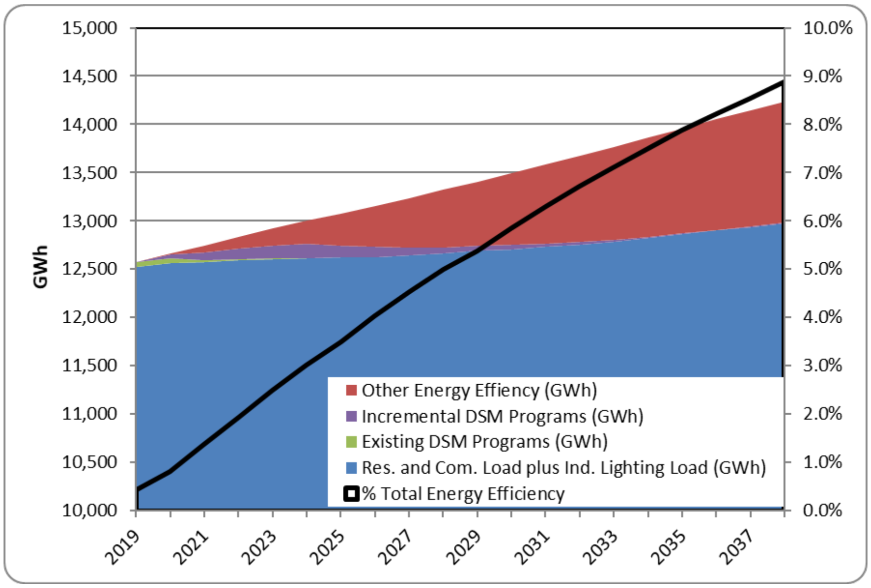

Figure 36. SWEPCO Energy Efficiency Savings According to Preferred Plan

As part of the Preferred Plan, four of the fifteen available VVO tranches are proposed additions, which results in a cumulative capacity reduction of 58MW by 2038. The four tranches of circuits are added from 2020 through 2037.

DG (i.e. rooftop solar) resources were not modeled during the planning period. DG resources were added incrementally at a 5% annual growth rate (based on nameplate capacity), resulting in a total of 8MW of SPP capacity credit (23MW nameplate) by 2038.

5.3.2 Preferred Plan Cost

As stated in section 5.2, the models were run to minimize the costs of the portfolio of resources. A summary of the Cumulative Present Worth (CPW) compared to a plan where no renewable resources are included in the plan is shown in Table 12. The net benefit to SWEPCO customers is approximately $2.27B.

Table 12 Preferred Plan Cumulative Present Worth Comparison

Cumulative Present Worth $000 (2019$)	Preferred Plan Net Utility Costs	No Renewables Net Utility Costs	Preferred Plan CPW Savings
Utility CPW 2019-2038 (20 yr)	$ 11,760,126	$ 12,274,377	($514,251)
Utility CPW 2019-2048 (30 Yr)	$ 15,151,679	$ 16,423,393	($1,271,713)
CPW of End Effects beyond 2048	$ 3,813,331	$ 4,811,386	($998,055)
TOTAL Utility Cost, Net CPW (2019$)	**$ 18,965,010**	**$ 21,234,779**	**($2,269,769)**

SWEPCO customers should recognize an increasing level of savings in their monthly bill over the planning period versus a plan with no renewables. The levelized monthly bill impact[1] analysis of the Preferred Plan relative to a plan where no renewables are selected indicates SWEPCO customers saving grow to over $15/month in their monthly bills.

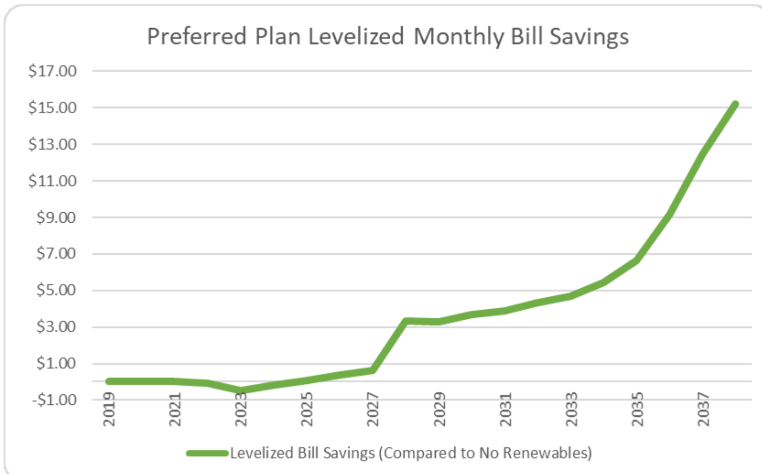

Figure 37: SWEPCO Levelized Monthly Bill Savings

5.4 Risk Analysis

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

This study included multiple risk iteration runs performed over the study period with three key price variables (risk factors) being subjected to this stochastic-based risk analysis. The results take the form of a distribution of possible revenue requirement outcomes for each plan. Table 13 below shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other.

Table 13. Risk Analysis Factors and Their Relationships

2019 - 2027	Natural GAS	CO_2	Electricity
Natural GAS	1.00	0.00	0.73
CO_2		0.00	0.00
Electricity			1.00
Avg Coeff of Variation	12.7%	0.0%	12.2%
2028 - 2038	**Natural GAS**	**CO_2**	**Electricity**
Natural GAS	1.00	0.90	0.60
CO_2		1.00	0.66
Electricity			1.00
Avg Coeff of Variation	13.3%	70.7%	21.3%

Comparing the Preferred Plan to an alternative portfolio which is significantly different provides a data point that may be used to evaluate the risk associated with the Preferred Plan. The Preferred Plan has a similar resource profile to other optimized plans, so there would be little difference in the risk profiles between such portfolios and the Preferred Plan, and therefore those portfolios were not included in the stochastic analysis. Instead, a portfolio that does not contain any renewable resources was used for comparison. This allows SWEPCO to determine if the renewable resources in the Preferred Plan introduce more risk than relying on no renewable additions. The range of values associated with the variable inputs is shown in Figure 38.

Figure 38. Range of Variable Inputs for Stochastic Analysis

5.4.1 Stochastic Modeling Process and Results

For each portfolio, the results of 100 random iterations are sorted from lowest cost to highest cost, with the differential between the median and higher percentile result from the multiple runs identified as Revenue Requirement at Risk (RRaR). For example, the 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, only five percent of the time. Thus, it is 95 percent likely that those higher-ends of revenue requirements would not be exceeded. The larger the RRaR, the greater the likelihood that customers could be subjected to higher costs relative to the portfolio's mean or expected cost. Conversely, there is equal likelihood that costs may be lower than the median value. These higher or lower costs are generally the result of the difference, or spread, between fuel prices and resultant SPP market energy prices. The greater that spread, the more "margin" is enjoyed by the Company and its customers. Figure 39 illustrates the RRaR (expressed in terms of incremental cost over the 50th percentile).

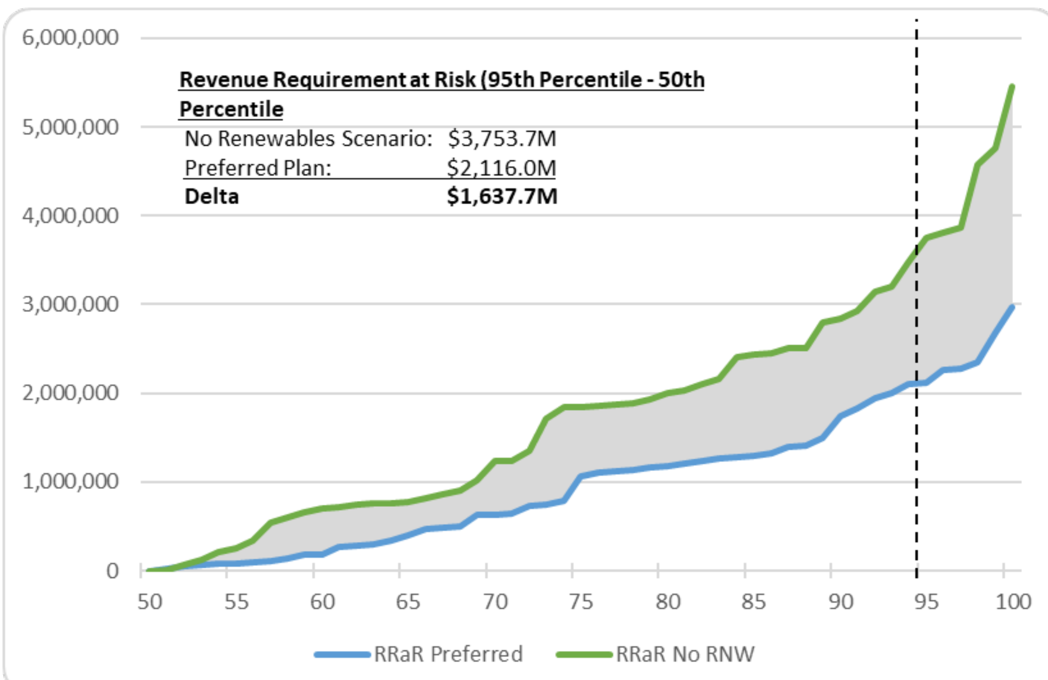

Figure 39. Revenue Requirement at Risk (RRaR) ($000) for Select Portfolios

The difference in RRaR between the two portfolios that were analyzed over the 100 simulations shows the Preferred Plan being less risky by about $1,637M, which indicates that the additional renewable generation in the Preferred Plan does not introduce significant additional risk.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of the Preferred Plan, which includes a higher level of renewable resources, is significantly less than a portfolio with no renewable resources. This suggests that the Preferred Plan represents a reasonable combination of expected costs and risk.

6.0 Conclusions and Five-Year Action Plan

SWEPCO used the modeling results to develop a Preferred Plan or “Plan”. To arrive at the Preferred Plan, using Plexos®, SWEPCO developed optimal portfolios based on five long-term commodity price forecasts and two load sensitivities. The Preferred Plan balances cost and other factors such as risk and environmental regulatory considerations, to cost effectively meet SWEPCO’s demand and energy obligations. Given that the optimal portfolios under the five commodity pricing scenarios offer comparable resource additions, SWEPCO has elected to use the Base commodity pricing scenario as its Preferred Plan.

Table 14 provides a summary of the Preferred Plan, which was selected based on the results from optimization modeling under various load and commodity pricing scenarios:

Table 14. Preferred Plan Cumulative Capacity Additions throughout Planning Period (2019-2038)

Commodity Pricing Scenario		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base/ Preferred Plan	New Nat. Gas																				373
	New Solar (Nameplate)											150	300	600	800	950	1,100	1,250	1,400	1,400	1,400
	New Solar (Firm)											75	150	300	400	475	550	625	700	700	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	2,000	2,200	2,200	2,200
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	306	337	337	337
	New EE		5	8	10	10	11	12	11	10	8	7	6	6	5	5	3	3	2	2	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	34	34	47	47	47	47	58
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																				150
Capacity Reserves (MW) Above SPP Rqmts w/o new additions		547	540	510	480	373	357	237	119	50	47	15	(167)	(189)	(209)	(287)	(295)	(318)	(697)	(1,072)	(1,619)
Capacity Reserves (MW) Above SPP Rqmts with new additions		550	572	576	640	624	610	491	373	303	299	341	232	361	450	446	525	669	395	20	7

In summary, the Preferred Plan:

- Adds 200MW (nameplate) of wind resources in 2021, an additional 600MW (nameplate) in 2022 and 2023, 600MW (nameplate) in 2035 and 200MW (nameplate) in 2036 for a total of 2,200MW (nameplate) by the end of the planning period.
- Adds 150MW (nameplate) utility-scale solar resources beginning in 2029 increasing to 1,400MW (nameplate) of utility-scale solar by the end of the planning period.
- Implements customer and grid energy efficiency programs, including VVO, reducing energy requirements by 243GWh and capacity requirements by 59MW by 2038.
- Fills long-term needs through the addition of a total of 373MW of natural gas combined-cycle

generation in 2038 to replace planned unit retirements.

- Recognizes additional distributed solar capacity will be added by SWEPCO's customers, beginning with 10MW (nameplate) in 2019 and growing to 24MW (nameplate) by 2038.
- In 2038, includes the addition of 150MW of Short-Term Market Purchases (STMP)

SWEPCO customers should recognize an increasing level of savings in their monthly bill over the planning period versus a plan with no renewables. The levelized monthly bill impact[1] analysis of the Preferred Plan relative to a plan where no renewables are selected indicates SWEPCO customer savings grow to over $15/month in their monthly bills.

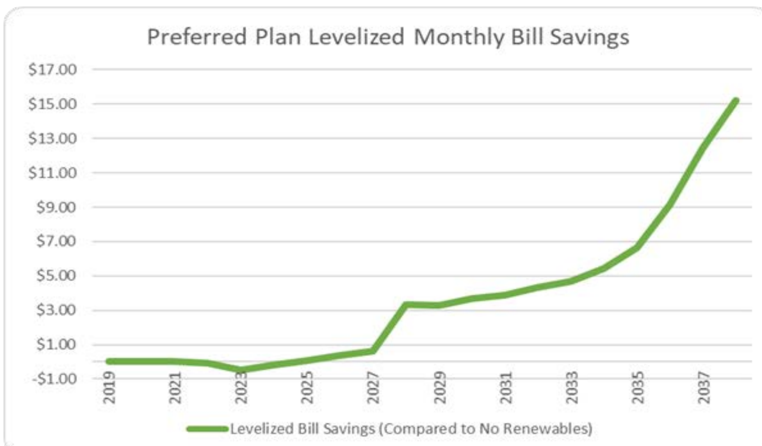

Figure ES- 9: SWEPCO Levelized Monthly Bill Savings

SWEPCO capacity changes over the 20-year planning period associated with the Preferred Plan are shown in Figure 40 and Figure 41. These figures show that the Preferred Plan would reduce SWEPCO's reliance on fossil fuel-based generation, and increase reliance on renewable resources. Specifically, over the 20-year planning horizon the Company's nameplate capacity mix attributable to fossil fuel-fired assets declines from 91% to 52% due to the retirement of older gas steam units over the planning period and the retirement of a coal unit in 2037. Demand-side management (DSM), Demand Response (DR) and Distributed Generation resources increase from 1.2% to 2.0% of total nameplate capacity resources.

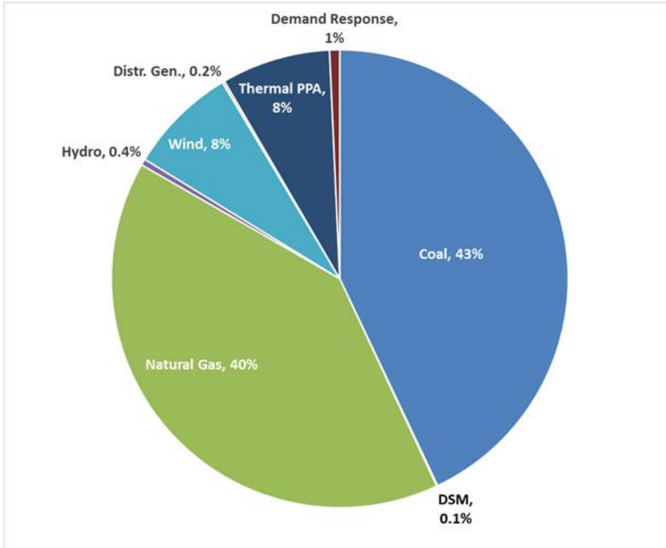

Figure 40. 2019 SWEPCO Nameplate Capacity Mix

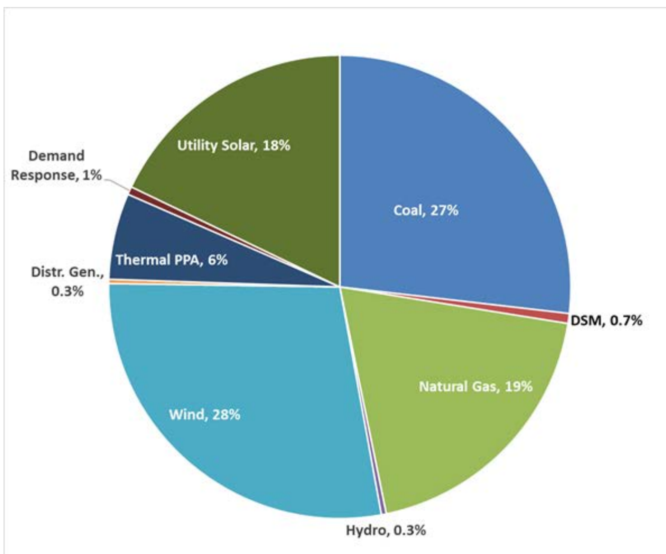

Figure 41. 2038 SWEPCO Nameplate Capacity Mix

The relative impacts to SWEPCO's annual energy position are shown in Figure 42 and Figure 43. SWEPCO's energy output attributable to fossil fuel generation decreases from 88% to 48% over the planning period, while energy from renewable resources increases from 12% to 51%. Specifically, the Preferred Plan introduces solar resources, which contributes to 12% of total energy and energy from wind resources increases from 12% to 36% of SWEPCO's total energy mix.

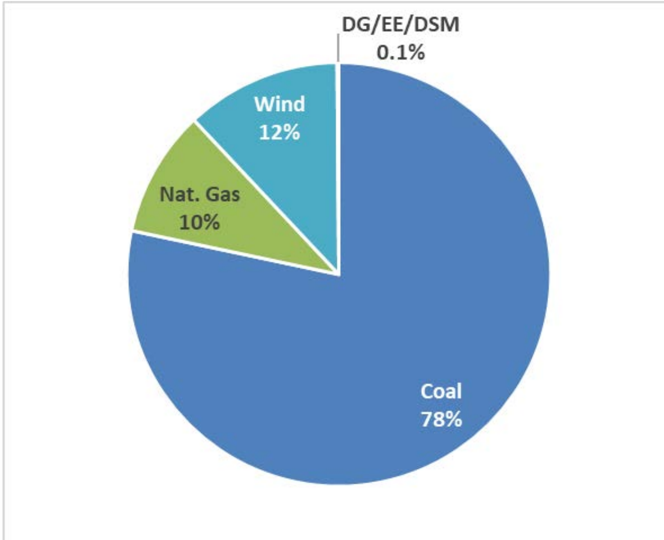

Figure 42. 2019 SWEPCO Energy Mix

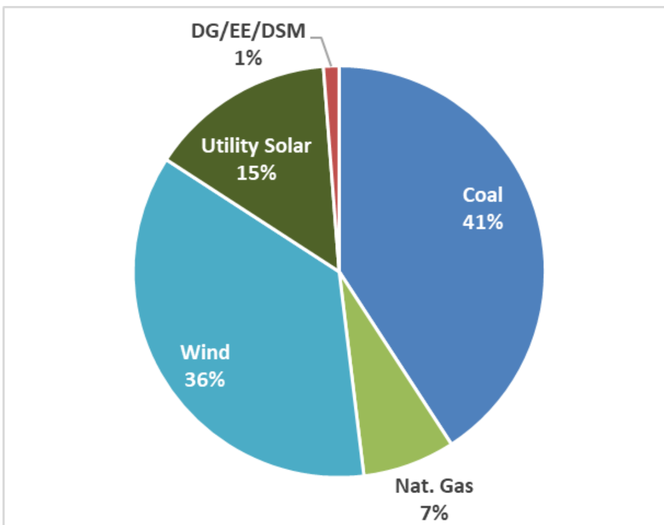

Figure 43. 2038 SWEPCO Energy Mix

Figure 44 and Figure 45 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is modest due to the treatment of capacity credit for intermittent resources within SPP; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they are a low cost energy resource. When comparing the capacity values in Figure 44 with those in Figure 40 and Figure 41, it is important to note that Figure 44 provides an analysis of SPP-recognized capacity, while Figure 40 and Figure 41 depict nameplate capacity.

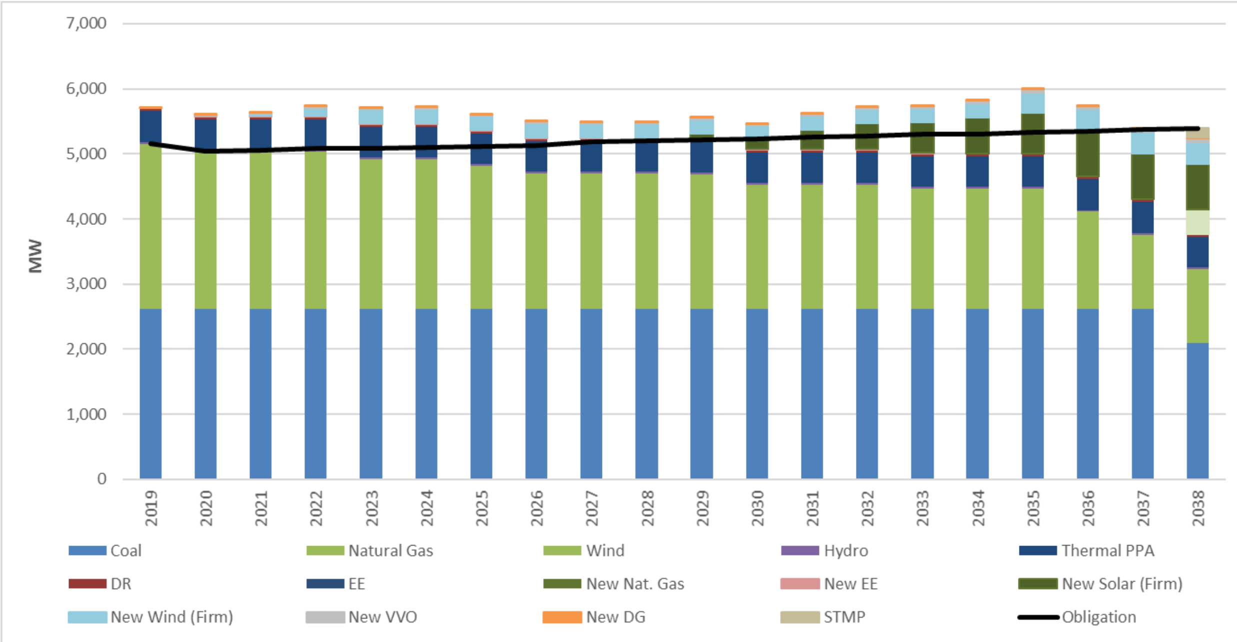

Figure 44. SWEPCO Annual SPP Capacity Position (MW) per the Preferred Plan

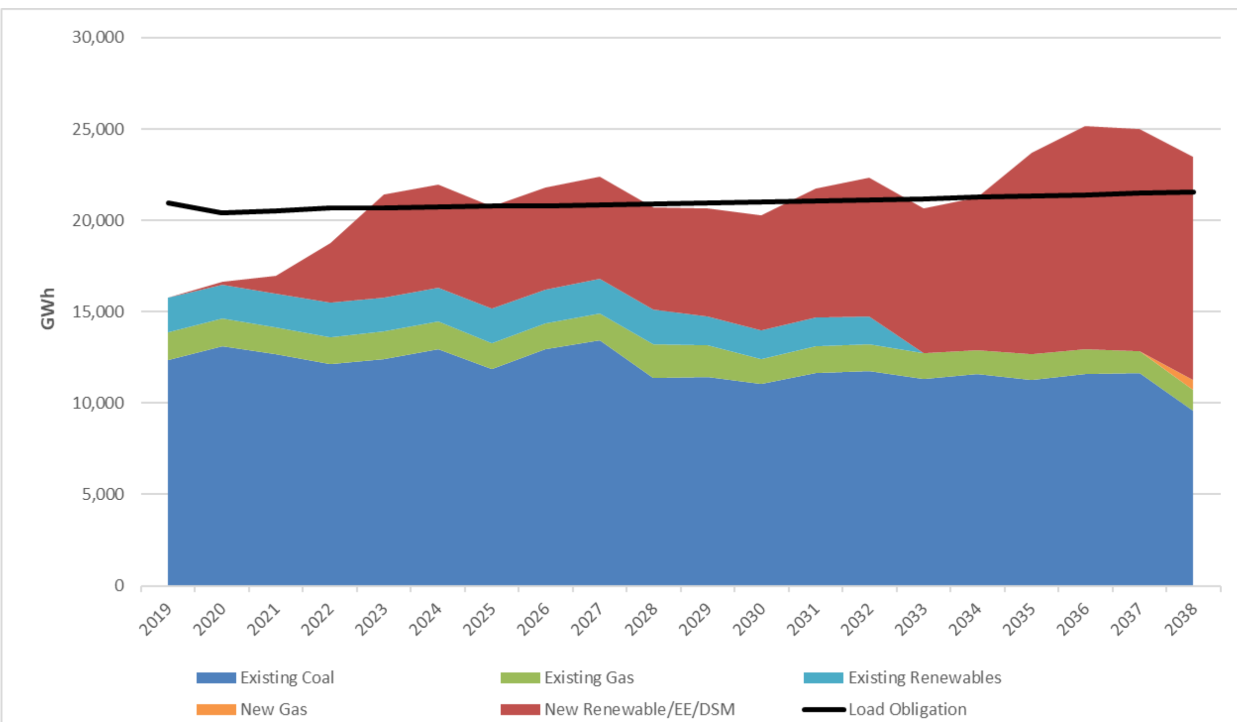

Figure 45. SWEPCO Annual Energy Position (GWh) per the Preferred Plan

6.1 SWEPCO Five-Year Action Plan

In reference to the Preferred Plan and SWEPCO's ability to provide adequate capacity resources at a reasonable cost, the following actions over the next five (5) years are anticipated.

- Proceed with necessary regulatory filings consistent with commission rules around plant retirements including the Lone-Star 1, Lieberman 2 (12/31/2019) and Knox Lee Units 2 and 3 retirements (1/1/2020).
- Wind Resource Integration: Continue with the recently released Request for Proposal (RFP) to explore opportunities to add cost-effective wind generation in the near future to take advantage of the Federal Production Tax Credit.
- Solar Resource Integration: Continue efforts related to the notice filed with the commission to proceed with an RFP process in support of adding cost effective utility–scale solar resources.
- Environmental Impacts: Remain committed to closely following developments related to environmental regulations and update our analysis of compliance options and timeliness when sufficient information becomes available.
- Continue to work with the Commissioners related to the Quick Start Phase of energy efficiency programs scheduled to continue through December 31, 2019 and any potential extensions beyond 2019.
- Proceed with the transition of Dolet Hills to seasonal operation and continue to evaluate its viability.

6.2 Plan Summary

SWEPCO's Preferred Plan provides the Company with an increasingly diversified portfolio of supply- and demand-side resources which provides flexibility to adapt to future changes to the power market, technology, and environmental regulations. The addition of renewables and demand-side management mitigates fuel price and environmental compliance risk. At the end of the planning period efficient natural gas-fired generation will replace the capacity from solid fuel units that are planned for retirement.

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

Appendix

Exhibit A Load Forecast Tables

Exhibit B New Generation Technologies

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

Type	Capability (MW) (d) Std. ISO	Capability (MW) (d) Summer	Capability (MW) (d) Winter	Installed Cost (c,e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load										
Nuclear	1,610	1,560	1,690	8,900	10,500	0.94	3.99	179.48	80	180.0
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,800	12,500	2.12	4.37	108.50	75	215.4
Combined Cycle (1X1 "J" Class)	610	800	820	900	6,200	3.00	1.77	12.86	75	58.0
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	6,200	3.00	1.55	10.65	75	53.8
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	6,300	3.00	1.51	11.07	75	54.6
Combined Heat and Power	15	15	16	2,500	4,800	3.00	-	162.83	90	89.5
Peaking										
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	11,700	3.00	4.05	30.83	25	148.3
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	800	10,000	3.00	6.27	24.79	25	115.9
Aero-Derivative (2 - Small Machines) (g,h)	120	120	120	1,400	9,900	3.00	2.51	33.65	25	145.2
Recip Engine Farm	220	220	230	1,300	8,300	3.00	5.36	14.47	25	124.8
Battery	10	10	10	1,900	83% (i)	0.00	0.00	38.99	25	156.3
Intermittent Resources										
Wind	200	30	30	1,200	NA	NA	NA	45.0	44	15.6
Solar - Utility Scale	50	25	25	1,500	NA	NA	NA	15.0	28	50.8

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2019 dollars, except as noted.
(c) $/kW costs are based on summer capability, except Intermittent Resources which are based on Std. ISO or Nameplate.
(d) All Capabilities are at 1,000 feet above sea level. For Intermittent Resources -Std. ISO = Nameplate, Summer = Capacity Planning value
(e) Total Plant Investment Cost w/AFUDC (7.1%,site rating $/kW)
(f) Levelized cost of energy based on capacity factors shown in table, Intermittent Resources include ITC/PTC.
(g) Includes Dual Fuel capability and SCR environmental installation
(h) Includes Black Start capability
(i) Denotes efficiency, (w/ power electronics)

Exhibit C Long-Term Commodity Price Forecast

SUMMARY OF LONG-TERM COMMODITY PRICE FORECASTS
Annual Average (Nominal Dollars)

	Natural Gas (Henry Hub) $/mmBTU				Coal (PRB 8800 0.8#) $/Ton FOB				CO_2 $/short ton			
	Base	Low Band	High Band	No Carbon	Base	Low Band	High Band	No Carbon	Base	Low Band	High Band	No Carbon
2019	3.14	2.66	3.61	3.14	12.43	12.35	12.46	12.43	0.00	0.00	0.00	0.00
2020	3.30	2.80	3.79	3.30	12.37	11.41	13.04	12.37	0.00	0.00	0.00	0.00
2021	3.33	2.83	3.83	3.33	12.34	10.54	13.57	12.34	0.00	0.00	0.00	0.00
2022	3.42	2.91	3.93	3.42	12.36	9.95	13.99	12.36	0.00	0.00	0.00	0.00
2023	3.52	2.99	4.05	3.52	12.36	9.89	14.05	12.36	0.00	0.00	0.00	0.00
2024	3.62	3.08	4.16	3.62	12.37	9.90	14.06	12.37	0.00	0.00	0.00	0.00
2025	3.69	3.13	4.24	3.69	12.38	9.91	14.07	12.38	0.00	0.00	0.00	0.00
2026	3.76	3.19	4.32	3.76	12.40	9.92	14.09	12.40	0.00	0.00	0.00	0.00
2027	3.81	3.24	4.38	3.81	12.44	9.95	14.14	12.42	0.00	0.00	0.00	0.00
2028	3.98	3.38	4.58	3.85	12.38	9.90	14.06	12.30	11.18	11.18	11.18	0.00
2029	4.04	3.43	4.65	3.91	12.21	9.77	13.88	12.37	11.36	11.36	11.36	0.00
2030	4.09	3.48	4.70	3.96	11.98	9.58	13.61	12.41	11.53	11.53	11.53	0.00
2031	4.12	3.50	4.74	3.99	11.58	9.26	13.16	12.46	11.72	11.72	11.72	0.00
2032	4.16	3.54	4.78	4.03	11.53	9.22	13.10	12.56	11.91	11.91	11.91	0.00
2033	4.21	3.58	4.84	4.08	11.73	9.38	13.33	12.79	12.10	12.10	12.10	0.00
2034	4.28	3.64	4.92	4.15	12.42	9.93	14.11	12.85	12.30	12.30	12.30	0.00
2035	4.35	3.70	5.00	4.22	12.53	10.02	14.23	12.87	12.51	12.51	12.51	0.00
2036	4.36	3.71	5.01	4.23	12.54	10.03	14.25	12.88	12.72	12.72	12.72	0.00
2037	4.46	3.79	5.13	4.33	12.56	10.05	14.27	12.90	12.94	12.94	12.94	0.00
2038	4.55	3.87	5.23	4.42	12.57	10.06	14.29	12.92	13.16	13.16	13.16	0.00

	Power On-Peak (SPP) $/MWh				Power Off-Peak (SPP) $/MWh			
	Base	Low Band	High Band	No Carbon	Base	Low Band	High Band	No Carbon
2019	24.99	22.69	26.68	24.98	19.33	18.15	20.10	19.34
2020	25.29	22.81	27.50	25.24	19.25	17.59	20.51	19.23
2021	25.33	22.53	27.99	25.39	19.45	17.27	21.28	19.46
2022	25.80	22.66	28.88	25.82	19.77	17.21	21.97	19.75
2023	26.38	23.02	29.63	26.38	20.09	17.32	22.47	20.10
2024	27.03	23.31	30.51	26.87	20.66	17.48	23.12	20.53
2025	27.55	23.80	31.35	27.33	21.09	17.88	23.79	20.94
2026	28.19	24.04	32.06	27.94	21.51	18.03	24.30	21.28
2027	28.72	24.35	32.78	28.47	21.95	18.26	24.88	21.71
2028	36.22	31.72	40.27	28.78	30.22	26.05	33.36	21.97
2029	35.84	31.27	39.88	29.32	29.79	25.67	33.05	22.47
2030	36.20	31.32	40.27	29.84	30.18	25.92	33.42	23.01
2031	36.55	31.60	40.78	30.58	30.31	26.02	33.64	23.48
2032	37.17	31.72	41.28	31.36	30.58	26.31	33.90	24.05
2033	37.46	31.90	41.47	31.99	30.72	26.33	34.07	24.53
2034	37.92	32.71	42.13	32.44	31.23	26.98	34.81	25.18
2035	38.79	33.28	42.86	33.15	31.81	27.32	35.40	25.80
2036	38.25	33.35	42.71	32.87	31.48	27.37	35.40	25.69
2037	38.70	33.86	43.20	33.60	31.89	27.61	35.84	26.45
2038	39.32	34.29	43.92	34.54	32.27	27.80	36.33	26.93

Exhibit D Cost of Capital

Southwestern Electric Power Company
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2018

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	6.98	6.98	6.98	6.98	6.98	6.98	6.98	6.98	6.98	6.98	6.98	6.98
Depreciation (2)	49.05	31.92	23.34	18.21	8.06	4.80	3.24	2.37	1.82	1.58	1.19	0.86
FIT (3) (4)	1.06	0.76	0.81	0.68	0.64	0.77	0.79	0.69	0.62	0.58	0.53	0.48
Property Taxes, General & Admin Expenses	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46
Carrying Cost Per Year	58.54	41.12	32.60	27.32	17.13	14.00	12.48	11.49	10.87	10.60	10.16	9.78

(1) Based on a 100% (as of 12/31/2018) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

Exhibit E Acronyms

ACRONYM	DEFINITION
A/C	Air Conditioning
AC	Alternating Current
ACI	Activated Carbon Injection
AD	Aeroderivative
ADEQ	Arkansas Department of Environmental Quality
AECC	Arkansas Electric Cooperative Corporation
AEP	American Electric Power
AMI	Advanced Metering Infrastructure
AP	Achievable Potential
APC&EC	Arkansas Pollution Control and Ecology Commission
APSC	Arkansas Public Service Commission
ARIMA	Autoregressive Integrated Moving Average
ARRA	American Recovery and Reinvestment Act
BART	Best Available Retrofit Technology
BNEF	Bloomberg New Energy Finance
BSER	Best System of Emission Reduction
BTU	British Thermal Unit
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CD	Compact Disc
CDR	Capacity Demand and Reserves
CERA	Cambridge Energy Research Associates
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COS	Cost of Service
CPP	Clean Power Plan
CPW	Cumulative Present Worth
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Reduction
DSI	Dry Sorbent Injection
DSM	Demand-side Management
EE	Energy Efficiency
EGU	Electric Generating Units
EHV	Extra High Voltage
EIA	Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA	Energy Independence and Security Act
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas

ESP	Electrostatic Precipitator
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FRB	Federal Reserve Board
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HAP	High Achievable Potential
HCl	Hydrochloric Acid
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Cooling
HVDC	High Voltage Direct Current
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
ITP	Integrated Transmission Planning
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
lb	Pound
LCOE	Levelized Cost of Energy
LHV	Lower Hating value
LNB	Low NO_x Burner
MAR	Market Acceptance Ratio
MATS	Mercury and Air Toxics Standard
mmBTU	Million BTU
MW	Megawatt
MWac	Alternating Current Megawatts
MWh	Megawatt-Hour
MWh-g	Megawatt-Hour, Gross
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combines Cycle
NGCT	Natural Gas Combustion Turbine
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OCC	Oklahoma Corporation Commission
OFA	Overfire Air
OG&E	Oklahoma Gas and Electric Energy Corporation
PCT	Participant Cost Test

PIF	Program Implementation Factor
PIRA	Petroleum Industry Research Associates
PM	Particulate Material
PPA	Power Purchase Agreement
PSIG	Pounds per Square Inch, Gage
PSO	Public Service Company of Oklahoma
PTC	Production Tax Credit
PV	Photovoltaic
PY	Program Year
RE	Reciprocating Engine
REPA	Renewable Energy Purchase Agreement
RFP	Request for Proposal
RHR	Regional Haze Rule
RIM	Ratepayer Impact Measure
RRaR	Revenue Requirement at Risk
RTO	Regional Transmission Organization
SAE	Statistically Adjust End-Use
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SEER	Seasonal Energy Efficiency Ratio
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
STEP	SPP Transmission Expansion Plan
SWEPCO	Southwestern Electric Power Company
TCEQ	Texas Commission on Environmental Quality
TRC	Total Resource Cost
UCT	Utility Cost Test
VVO	Volt VAR Optimization

Exhibit F Capability, Demand and Reserve (CDR) – "Going-In"[11]

SOUTHWESTERN ELECTRIC POWER COMPANY
CAPABILITY, DEMAND AND RESERVES FORECAST
2019 - 2051
(MW)

CAPABILITY

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
	Plant Capabilities																				
	ARSENAL HILL # 5	110	110	110	110	110	110	110													
	J.L. STALL CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
	DOLET HILLS #1	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	FLINT CREEK # 1	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258
	TURK	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
	KNOX LEE # 2, 3, 5	391	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338
	LIEBERMAN # 2, 3, 4	242	217	217	217	108	108														
	LONE STAR # 1	50																			
	PIRKEY #1	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
	MATTISON CTs	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284
	WELSH # 1, 3	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	528
	WILKES # 1, 2, 3	872	872	872	872	872	872	872	872	872	872	872	708	708	708	708	708	708	353		
1	TOTAL	5,085	4,957	4,957	4,957	4,848	4,848	4,740	4,630	4,630	4,630	4,630	4,466	4,466	4,466	4,466	4,466	4,466	4,111	3,758	3,233
	Adjustments to Plant Capability																				
2	TOTAL																				
3	**Net Plant Capability (1 + 2)**	5,085	4,957	4,957	4,957	4,848	4,848	4,740	4,630	4,630	4,630	4,630	4,466	4,466	4,466	4,466	4,466	4,466	4,111	3,758	3,233
	Sales Without Reserves																				
	Backup contracts (Eastman, Domtar, & Internat'l Paper)	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																				
	Purchase 1	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Purchase 2	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171
	Purchase 3	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
	MAJESTIC WIND PROJECT	12.2	12	12	12	12	12	12	12	12	12										
	HIGH MAJESTIC WIND PROJECT	12.2	12	12	12	12	12	12	12	12	12	12	12	12	12						
	FLAT RIDGE WIND PROJECT	16.6	17	17	17	17	17	17	17	17	17	17	17	17	17						
	CANADIAN HILLS WIND PROJECT	30.8	31	31	31	31	31	31	31	31	31	31	31	31	31						
5	TOTAL	570	570	570	570	570	570	570	570	570	570	558	558	558	558	498	498	498	498	498	498
6	**Total Capability (3 - 4 + 5)**	5,639	5,511	5,511	5,511	5,402	5,402	5,294	5,184	5,184	5,184	5,172	5,008	5,008	5,008	4,949	4,949	4,949	4,594	4,241	3,716

[11] Represents SWEPCO-owned installed capacity.

DEMAND	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Original Forecast	3,735	3,737	3,752	3,766	3,767	3,775	3,773	3,775	3,781	3,779	3,790	3,801	3,815	3,830	3,843	3,846	3,862	3,881	3,895	3,910
Customer 1	149	152	157	162	165	168	171	174	177	180	183	185	188	191	194	196	199	202	205	207
Customer 2	57	57	58	58	59	59	58	59	59	59	59	59	59	60	60	60	60	60	60	60
Customer 3	37	37	38	38	38	39	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Customer 4	677	678	682	690	684	686	696	698	700	701	705	707	709	710	712	713	714	715	718	720
Customer 5	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Customer 6	114																			
PSO	25	25	24	24	24	23	23	23	23	23	22	22	22	23	23	23	23	24	24	24
Less TEX-LA ERCOT Demand included above	-25	-25	-24	-24	-24	-23	-23	-23	-23	-23	-22	-22	-22	-23	-23	-23	-23	-24	-24	-24
A Peak Demand Before Passive DSM	4,788	4,680	4,703	4,729	4,727	4,741	4,751	4,758	4,770	4,772	4,789	4,806	4,825	4,844	4,862	4,868	4,889	4,911	4,931	4,950
B Passive DSM																				
Approved Passive DSM	4	3	1	0	0															
TOTAL	4	3	1	0	0															
C Peak Demand (A - B)	4,784	4,676	4,702	4,729	4,727	4,741	4,751	4,758	4,770	4,772	4,789	4,806	4,825	4,844	4,862	4,868	4,889	4,911	4,931	4,950
D Active DSM																				
Interruptible	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DLC/ELM	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
TOTAL	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
E Firm Demand (C - D)	4,745	4,637	4,663	4,690	4,688	4,702	4,712	4,719	4,731	4,733	4,750	4,767	4,786	4,805	4,823	4,829	4,850	4,872	4,892	4,911
F Other Demand Adjustments																				
DIVERSITY	25	25	24	24	24	23	23	23	23	23	22	22	22	23	23	23	23	24	24	24
TOTAL	25	25	24	24	24	23	23	23	23	23	22	22	22	23	23	23	23	24	24	24
7 Native Load Responsibility (E - F)	4,720	4,612	4,639	4,666	4,664	4,679	4,689	4,696	4,708	4,710	4,728	4,745	4,764	4,782	4,799	4,806	4,827	4,849	4,868	4,887
Sales With Reserves																				
8 TOTAL																				
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
LOUISIANA GENERATION (FORMERLY CAJUN)	50	50	50	50	50	50	50	50												
SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
9 TOTAL	174	174	174	174	174	174	174	174	124	124	124	124	124	124	124	124	124	124	124	124
10 Load Responsibility (7 + 8 - 9)	4,546	4,438	4,465	4,492	4,490	4,505	4,515	4,522	4,584	4,586	4,604	4,621	4,640	4,658	4,675	4,682	4,703	4,725	4,744	4,763

RESERVES	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
11 Reserve Capacity (6 - 10)	1,093	1,073	1,046	1,020	912	898	779	662	601	598	568	387	368	351	273	266	246	-131	-503	-1,048
12 % Reserve Margin ((11/10) * *100*)	24.0	24.2	23.4	22.7	20.3	19.9	17.3	14.6	13.1	13.0	12.3	8.4	7.9	7.5	5.8	5.7	5.2	-2.8	-10.6	-22.0
13 % Capacity Margin (11/(6) * *100*)	19.4	19.5	19.0	18.5	16.9	16.6	14.7	12.8	11.6	11.5	11.0	7.7	7.4	7.0	5.5	5.4	5.0	-2.8	-11.9	-28.2
14 Reserves Above Minimum 12.0% Reserve Margin	547	540	510	481	373	357	238	119	51	48	16	(167)	(189)	(208)	(288)	(296)	(319)	(698)	(1,073)	(1,619)

Exhibit G Capability, Demand and Reserve (CDR) – Preferred Plan[12]

[12] Represents SWEPCO-owned installed capacity.

SOUTHWESTERN ELECTRIC POWER COMPANY
CAPABILITY, DEMAND AND RESERVES FORECAST
2019 - 2051
(MW)

CAPABILITY

	Plant Capabilities	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
	ARSENAL HILL # 5	110	110	110	110	110	110	110													
	J.L. STALL CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
	DOLET HILLS #1	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	FLINT CREEK # 1	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258
	TURK	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
	KNOX LEE # 2, 3, 5	391	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338
	LIEBERMAN # 2, 3, 4	242	217	217	217	108	108														
	LONE STAR # 1	50																			
	PIRKEY #1	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
	MATTISON CTs	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284
	WELSH # 1, 3	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	528
	WILKES # 1, 2, 3	872	872	872	872	872	872	872	872	872	872	872	708	708	708	708	708	708	353		
1	TOTAL	**5,085**	**4,957**	**4,957**	**4,957**	**4,848**	**4,848**	**4,740**	**4,630**	**4,630**	**4,630**	**4,630**	**4,466**	**4,466**	**4,466**	**4,466**	**4,466**	**4,466**	**4,111**	**3,758**	**3,233**
	Adjustments to Plant Capability																				
	New CC1																				373
	VVO		24	24	24	24	24	24	24	24	24	24	24	24	34	34	47	47	47	47	58
	EE		5	8	10	10	11	12	11	10	8	7	6	6	5	5	3	3	2	2	1
	Distr Solar	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	IRP Wind			31	122	214	214	214	214	214	214	214	214	214	214	214	214	306	337	337	337
	IRP Solar											75	150	300	400	475	550	625	700	700	700
	STMP																				150
2	TOTAL	**3**	**32**	**66**	**160**	**252**	**253**	**254**	**254**	**252**	**251**	**325**	**400**	**550**	**659**	**733**	**820**	**987**	**1,092**	**1,092**	**1,626**
3	**Net Plant Capability (1 + 2)**	**5,088**	**4,989**	**5,022**	**5,117**	**5,099**	**5,101**	**4,994**	**4,883**	**4,882**	**4,881**	**4,955**	**4,865**	**5,015**	**5,125**	**5,199**	**5,286**	**5,452**	**5,203**	**4,850**	**4,859**
	Sales Without Reserves																				
	Backup contracts (Eastman, Domtar, & Internat'l Paper)	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																				
	Purchase 1	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	Purchase 2	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171
	Purchase 3	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
	MAJESTIC WIND PROJECT	12.2	12	12	12	12	12	12	12	12	12										
	HIGH MAJESTIC WIND PROJECT	12.2	12	12	12	12	12	12	12	12	12	12	12	12	12						
	FLAT RIDGE WIND PROJECT	16.6	17	17	17	17	17	17	17	17	17	17	17	17	17						
	CANADIAN HILLS WIND PROJECT	30.8	31	31	31	31	31	31	31	31	31	31	31	31	31						
5	TOTAL	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**558**	**558**	**558**	**558**	**498**	**498**	**498**	**498**	**498**	**498**
6	**Total Capability (3 - 4 + 5)**	**5,643**	**5,544**	**5,577**	**5,671**	**5,654**	**5,656**	**5,548**	**5,438**	**5,437**	**5,436**	**5,497**	**5,408**	**5,558**	**5,667**	**5,682**	**5,769**	**5,935**	**5,686**	**5,333**	**5,342**

DEMAND	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Original Forecast	3,735	3,737	3,752	3,766	3,767	3,775	3,773	3,775	3,781	3,779	3,790	3,801	3,815	3,830	3,843	3,846	3,862	3,881	3,895	3,910
Customer 1	149	152	157	162	165	168	171	174	177	180	183	185	188	191	194	196	199	202	205	207
Customer 2	57	57	58	58	59	59	58	59	59	59	59	59	59	60	60	60	60	60	60	60
Customer 3	37	37	38	38	38	39	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Customer 4	677	678	682	690	684	686	696	698	700	701	705	707	709	710	712	713	714	715	718	720
Customer 5	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Customer 6	114																			
PSO	25	25	24	24	24	23	23	23	23	23	22	22	22	23	23	23	23	24	24	24
Less TEX-LA ERCOT Demand included above	-25	-25	-24	-24	-24	-23	-23	-23	-23	-23	-22	-22	-22	-23	-23	-23	-23	-24	-24	-24
A Peak Demand Before Passive DSM	**4,788**	**4,680**	**4,703**	**4,729**	**4,727**	**4,741**	**4,751**	**4,758**	**4,770**	**4,772**	**4,789**	**4,806**	**4,825**	**4,844**	**4,862**	**4,868**	**4,889**	**4,911**	**4,931**	**4,950**
B Passive DSM																				
Approved Passive DSM	4	3	1	0	0															
TOTAL	**4**	**3**	**1**	**0**	**0**															
C Peak Demand (A - B)	**4,784**	**4,676**	**4,702**	**4,729**	**4,727**	**4,741**	**4,751**	**4,758**	**4,770**	**4,772**	**4,789**	**4,806**	**4,825**	**4,844**	**4,862**	**4,868**	**4,889**	**4,911**	**4,931**	**4,950**
D Active DSM																				
Interruptible	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DLC/ELM	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
TOTAL	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**
E Firm Demand (C - D)	**4,745**	**4,637**	**4,663**	**4,690**	**4,688**	**4,702**	**4,712**	**4,719**	**4,731**	**4,733**	**4,750**	**4,767**	**4,786**	**4,805**	**4,823**	**4,829**	**4,850**	**4,872**	**4,892**	**4,911**
F Other Demand Adjustments																				
DIVERSITY	25	25	24	24	24	23	23	23	23	23	22	22	22	23	23	23	23	24	24	24
TOTAL	**25**	**25**	**24**	**24**	**24**	**23**	**23**	**23**	**23**	**23**	**22**	**22**	**22**	**23**	**23**	**23**	**23**	**24**	**24**	**24**
7 Native Load Responsibility (E - F)	**4,720**	**4,612**	**4,639**	**4,666**	**4,664**	**4,679**	**4,689**	**4,696**	**4,708**	**4,710**	**4,728**	**4,745**	**4,764**	**4,782**	**4,799**	**4,806**	**4,827**	**4,849**	**4,868**	**4,887**
Sales With Reserves																				
8 TOTAL																				
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
LOUISIANA GENERATION (FORMERLY CAJUN)	50	50	50	50	50	50	50	50												
SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
9 TOTAL	**174**	**174**	**174**	**174**	**174**	**174**	**174**	**174**	**124**	**124**	**124**	**124**	**124**	**124**	**124**	**124**	**124**	**124**	**124**	**124**
10 Load Responsibility (7 + 8 - 9)	**4,546**	**4,438**	**4,465**	**4,492**	**4,490**	**4,505**	**4,515**	**4,522**	**4,584**	**4,586**	**4,604**	**4,621**	**4,640**	**4,658**	**4,675**	**4,682**	**4,703**	**4,725**	**4,744**	**4,763**

RESERVES	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
11 Reserve Capacity (6 - 10)	**1,096**	**1,105**	**1,112**	**1,180**	**1,164**	**1,151**	**1,033**	**916**	**853**	**849**	**893**	**787**	**918**	**1,010**	**1,006**	**1,086**	**1,233**	**961**	**589**	**578**
12 % Reserve Margin ((11/10) * 100)	**24.1**	**24.9**	**24.9**	**26.3**	**25.9**	**25.5**	**22.9**	**20.3**	**18.6**	**18.5**	**19.4**	**17.0**	**19.8**	**21.7**	**21.5**	**23.2**	**26.2**	**20.3**	**12.4**	**12.1**
13 % Capacity Margin (11/(6) * 100)	**19.4**	**19.9**	**19.9**	**20.8**	**20.6**	**20.3**	**18.6**	**16.8**	**15.7**	**15.6**	**16.2**	**14.6**	**16.5**	**17.8**	**17.7**	**18.8**	**20.8**	**16.9**	**11.0**	**10.8**
14 Reserves Above Minimum 12.0% Reserve Margin	**551**	**573**	**576**	**641**	**625**	**610**	**492**	**373**	**303**	**299**	**341**	**233**	**361**	**451**	**445**	**524**	**668**	**394**	**19**	**7**

Exhibit H Modeled Scenario Results

Cumulative SPP Capacity Additions (MW) for Commodity Pricing Scenarios

Commodity Pricing Scenario		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base/ Preferred Plan	New Nat. Gas																				373
	New Solar (Nameplate)											150	300	600	800	950	1,100	1,250	1,400	1,400	1,400
	New Solar (Firm)											75	150	300	400	475	550	625	700	700	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	2,000	2,200	2,200	2,200
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	306	337	337	337
	New EE		5	8	10	10	11	12	11	10	8	7	6	6	5	5	3	3	2	2	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	34	34	47	47	47	47	58
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																				150
Low Band	New Nat. Gas																				373
	New Solar (Nameplate)											50	200	350	500	650	800	950	1,100	1,250	1,400
	New Solar (Firm)											25	100	175	250	325	400	475	550	625	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,600
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	245
	New EE		3	5	7	8	9	9	8	6	5	4	4	4	4	3	2	2	2	1	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	35	35	35	35	35	35	48
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																			200	250
High Band	New Nat. Gas																				373
	New Solar (Nameplate)						150	150	150	150	300	450	600	900	1,050	1,200	1,350	1,400	1,400	1,400	1,400
	New Solar (Firm)						75	75	75	75	150	225	300	450	525	600	675	700	700	700	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,600	2,200	2,200	2,200	2,200	2,200	2,200	2,200
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	245	337	337	337	337	337	337	337
	New EE		6	11	13	12	14	14	13	12	10	8	7	7	6	5	3	3	2	2	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	34	34	47	47	58	58	58
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																				150
No Carbon	New Nat. Gas																				373
	New Solar (Nameplate)												150	300	450	600	800	950	1,100	1,250	1,400
	New Solar (Firm)												75	150	225	300	400	475	550	625	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,600
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	245
	New EE		5	8	10	10	11	11	10	8	6	5	5	5	4	3	2	2	2	1	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	35	35	35	35	35	35	48
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																			200	250
Low No Carbon	New Nat. Gas																				746
	New Solar (Nameplate)													150	300	450	600	750	1,000	1,300	1,400
	New Solar (Firm)													75	150	225	300	375	500	650	700
	New Wind (Nameplate			200	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
	New Wind (Firm)			31	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122
	New EE		3	5	7	8	9	8	7	5	4	3	3	3	2	2	2	1	1	1	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	37	48	48
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP												50						50	250	

Cumulative SPP Capacity Additions (MW) for Low Load and High Load Sensitivity Scenarios

Commodity Pricing Scenario		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Low Load	New Nat. Gas																				373
	New Solar (Nameplate)											150	300	600	800	950	1,100	1,250	1,400	1,400	1,400
	New Solar (Firm)											75	150	300	400	475	550	625	700	700	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	2,000	2,200	2,200	2,200
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	306	337	337	337
	New EE		5	8	10	10	11	12	11	10	8	7	6	6	5	5	3	3	2	2	2
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP																				100
High Load	New Nat. Gas																			373	1,119
	New Solar (Nameplate)										50	200	350	650	800	950	1,100	1,250	1,400	1,400	1,400
	New Solar (Firm)										25	100	175	325	400	475	550	625	700	700	700
	New Wind (Nameplate			200	800	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	2,000	2,200	2,200	2,200
	New Wind (Firm)			31	122	214	214	214	214	214	214	214	214	214	214	214	214	306	337	337	337
	New EE		5	8	10	10	11	12	11	10	8	7	6	6	5	5	4	3	3	2	1
	New VVO		24	24	24	24	24	24	24	24	24	24	24	24	37	37	37	37	37	37	37
	New DG	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	STMP												50						150	250	100

SOUTHWESTERN ELECTRIC POWER COMPANY
2019 INTEGRATED RESOURCE PLAN
Base' Commodity Pricing - Preferred Plan & Base Optimization

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	$489,097	$364,712	$6,796	$180,379	$25,360	$0	$25,763	$342,695	$749,411
2020	$487,832	$370,750	$7,277	$213,911	$27,714	$3,591	$25,245	$371,077	$765,244
2021	$502,373	$367,277	$7,530	$238,949	$27,741	$20,673	$24,208	$386,545	$802,205
2022	$524,871	$380,953	$8,016	$255,023	$27,369	$79,297	$23,174	$444,863	$853,841
2023	$546,939	$405,634	$8,496	$280,110	$29,008	$149,079	$21,968	$528,329	$912,906
2024	$574,690	$431,260	$9,122	$304,653	$30,585	$149,080	$20,313	$569,222	$950,482
2025	$598,337	$415,549	$19,129	$356,929	$29,276	$148,970	$18,865	$558,623	$1,028,433
2026	$623,392	$447,840	$20,656	$373,595	$32,226	$148,899	$17,287	$608,766	$1,055,129
2027	$649,291	$458,611	$21,782	$377,475	$34,125	$148,430	$15,503	$649,688	$1,055,528
2028	$866,058	$414,243	$197,740	$388,914	$32,234	$148,523	($2,997)	$796,162	$1,248,553
2029	$874,928	$459,205	$204,873	$425,090	$32,493	$165,946	($12,996)	$812,911	$1,336,629
2030	$905,150	$421,775	$201,434	$451,667	$30,821	$183,238	($15,487)	$825,247	$1,353,352
2031	$931,940	$451,443	$219,777	$474,306	$33,504	$218,453	($17,103)	$909,677	$1,402,643
2032	$966,922	$466,023	$228,882	$495,091	$35,505	$244,010	($18,607)	$976,070	$1,441,756
2033	$994,227	$457,165	$228,032	$516,523	$35,155	$261,246	$0	$992,044	$1,500,303
2034	$1,029,273	$481,318	$240,802	$538,205	$37,159	$281,797	$0	$1,053,445	$1,555,110
2035	$1,077,714	$487,379	$242,704	$557,235	$37,845	$402,064	$0	$1,223,802	$1,581,139
2036	$1,084,743	$504,121	$257,723	$572,259	$39,360	$454,331	$0	$1,292,932	$1,619,605
2037	$1,121,843	$509,656	$265,569	$583,773	$40,091	$454,368	$0	$1,325,254	$1,650,046
2038	$1,162,255	$455,849	$225,043	$559,682	$44,600	$511,262	$0	$1,285,861	$1,672,831
2039	$1,197,864	$469,884	$215,996	$539,893	$48,704	$566,113	$0	$1,307,684	$1,730,769
2040	$1,223,059	$490,480	$219,918	$528,798	$55,248	$622,040	$0	$1,358,562	$1,780,982
2041	$1,255,949	$507,691	$233,987	$526,739	$57,239	$622,040	$0	$1,393,620	$1,810,026
2042	$1,297,673	$514,290	$241,944	$520,934	$59,433	$622,040	$0	$1,426,369	$1,829,945
2043	$1,325,717	$450,382	$188,891	$466,218	$65,192	$682,668	$0	$1,350,900	$1,828,168
2044	$1,380,057	$500,149	$208,877	$454,707	$69,509	$743,059	$0	$1,457,702	$1,898,655
2045	$1,440,052	$518,700	$217,311	$440,394	$71,454	$743,603	$0	$1,525,512	$1,906,003
2046	$1,484,630	$392,591	$119,762	$417,098	$77,438	$807,156	$0	$1,330,223	$1,968,452
2047	$1,531,658	$386,816	$112,678	$400,905	$84,807	$868,972	$0	$1,380,660	$2,005,176
2048	$1,570,642	$398,952	$117,067	$388,097	$90,026	$868,972	$0	$1,418,931	$2,014,827
Cumulative Present Worth $000 (2019$)									
Utility CPW 2019-	$10,026,803	$5,337,996	$1,347,067	$4,683,081	$452,819	$2,948,919	$114,166	$9,759,172	$15,151,679
CPW of End Effects beyond 2045									$3,813,331
TOTAL Utility Cost, Net CPW (2018$)									$18,965,010

SOUTHWESTERN ELECTRIC POWER COMPANY
2019 INTEGRATED RESOURCE PLAN
Base' Commodity Pricing - Preferred Plan & Base Optimization

Resource (Capacity) Additions										Energy & Capacity Positions										Carbon Intensities	
(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(12)	(13)	(14)	(15)=(12)+(13)+(14)	(16)	(17)=(16)-(15)	(17)	(18)	(19)=(17)-(18)	(20)	(21)	(22)
Supply-Side (Thermal)		(Increm) Energy Efficiency + VVO		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation	(Current) Purchased Energy	(New) Wind, EE, Solar, IVV	= Market Sales	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2 Emissions
Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons
0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	13,899	1,874	19	15,793	20,971	(5,178)	5,642	5,092	550	24.1	13,978,224	13,978,224
0	0	29.0	29.0	0.0	3.30	0.0	0	0	0	14,618	1,880	150	16,648	20,438	(3,791)	5,543	4,971	572	24.9	14,728,233	14,728,233
0	0	2.6	31.5	0.3	3.63	30.6	31	0	0	14,133	1,874	945	16,953	20,534	(3,582)	5,577	5,001	576	24.9	14,292,332	14,292,332
0	0	2.4	34.0	0.0	3.63	91.8	122	0	0	13,626	1,874	3,277	18,778	20,664	(1,886)	5,671	5,031	640	26.3	13,752,611	13,752,611
0	0	(0.4)	33.6	0.3	3.96	91.8	214	0	0	13,915	1,874	5,606	21,396	20,706	689	5,654	5,029	624	25.9	14,025,255	14,025,255
0	0	1.4	35.0	0.0	3.96	0.0	214	0	0	14,452	1,880	5,630	21,961	20,756	1,205	5,655	5,045	610	25.5	14,564,900	14,564,900
0	0	0.4	35.4	0.3	4.29	0.0	214	0	0	13,302	1,874	5,611	20,787	20,787	0	5,548	5,057	491	22.9	13,413,377	13,413,377
0	0	(0.4)	35.0	0.3	4.62	0.0	214	0	0	14,338	1,874	5,605	21,817	20,804	1,013	5,438	5,065	373	20.2	14,486,868	14,486,868
0	0	(1.4)	33.6	0.0	4.62	0.0	214	0	0	14,923	1,874	5,592	22,390	20,836	1,554	5,436	5,134	303	18.6	15,056,088	15,056,088
0	0	(1.6)	32.0	0.3	4.95	0.0	214	0	0	13,242	1,880	5,595	20,717	20,888	(171)	5,435	5,137	299	18.5	13,134,531	13,134,531
0	0	(0.9)	31.1	0.0	4.95	0.0	214	75	75	13,141	1,591	5,936	20,669	20,962	(294)	5,497	5,157	341	19.4	13,153,947	13,153,947
0	0	(0.8)	30.2	0.3	5.28	0.0	214	75	150	12,404	1,569	6,300	20,274	21,016	(743)	5,408	5,175	232	17.0	12,486,396	12,486,396
0	0	(0.3)	29.9	0.3	5.61	0.0	214	150	300	13,119	1,569	7,029	21,718	21,073	645	5,558	5,197	361	19.8	13,187,461	13,187,461
0	0	9.0	39.0	0.3	5.94	0.0	214	100	400	13,225	1,528	7,570	22,323	21,126	1,197	5,667	5,217	450	21.7	13,285,788	13,285,788
0	0	(0.8)	38.1	0.0	5.94	0.0	214	75	475	12,725	0	7,916	20,641	21,193	(553)	5,682	5,236	446	21.5	12,808,501	12,808,501
0	0	11.4	49.5	0.3	6.27	0.0	214	75	550	12,916	0	8,335	21,250	21,265	(14)	5,769	5,244	525	23.2	13,080,079	13,080,079
0	0	(0.3)	49.2	0.3	6.60	91.8	306	75	625	12,692	0	11,012	23,704	21,339	2,365	5,936	5,267	669	26.2	12,747,475	12,747,475
0	0	(0.6)	48.6	0.3	6.93	30.6	337	75	700	12,971	0	12,173	25,143	21,403	3,740	5,686	5,291	395	20.4	13,098,611	13,098,611
0	0	(0.5)	48.1	0.3	7.26	0.0	337	0	700	12,859	0	12,149	25,007	21,477	3,531	5,333	5,313	20	12.4	13,051,884	13,051,884
373	373	10.6	58.7	0.3	7.59	0.0	337	0	700	10,732	0	12,195	22,927	21,543	1,384	5,342	5,335	7	12.1	10,638,496	10,846,057
373	746	(0.2)	58.5	0.3	7.92	0.0	337	0	700	9,846	0	12,196	22,041	21,621	420	5,357	5,357	0	12.0	9,627,452	10,049,479
373	1,119	(0.3)	58.2	0.3	8.25	0.0	337	0	700	9,542	0	12,219	21,761	21,687	74	5,392	5,366	26	12.5	9,300,019	9,901,407
0	1,119	(0.2)	57.9	0.3	8.58	0.0	337	0	700	9,765	0	12,197	21,962	21,752	211	5,392	5,388	4	12.1	9,601,977	10,187,295
0	1,119	(0.1)	57.8	0.3	8.91	0.0	337	0	700	9,748	0	12,198	21,946	21,821	125	5,442	5,414	28	12.6	9,632,893	10,185,216
373	1,492	1.4	59.2	0.3	9.24	0.0	337	0	700	7,556	0	12,204	19,760	21,887	(2,127)	5,439	5,435	4	12.1	7,127,126	7,841,088
373	1,865	(0.1)	59.1	0.3	9.57	0.0	337	0	700	7,970	0	12,229	20,199	21,955	(1,756)	5,562	5,458	104	14.1	7,533,051	8,388,364
0	1,865	(0.1)	59.0	0.3	9.90	0.0	337	0	700	7,978	0	12,207	20,186	22,031	(1,845)	5,483	5,466	18	12.4	7,547,819	8,438,731
373	2,238	(0.6)	58.4	0.7	10.56	0.0	337	0	700	4,077	0	12,209	16,286	22,101	(5,815)	5,489	5,489	0	12.0	3,546,074	4,522,041
373	2,611	(10.3)	48.1	0.3	10.89	0.0	337	0	700	3,608	0	12,169	15,777	22,165	(6,388)	5,545	5,511	33	12.7	2,942,345	4,131,793
0	2,611	0.0	48.1	0.3	11.22	0.0	337	0	700	3,600	0	12,195	15,794	22,214	(6,419)	5,545	5,531	14	12.3	2,947,588	4,153,096

SOUTHWESTERN ELECTRIC POWER COMPANY
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	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	$517,129	$377,801	$7,148	$152,104	$25,786	$0	$23,586	$370,868	$732,686
2020	$527,074	$391,630	$7,752	$180,379	$28,827	$4,028	$22,075	$417,765	$744,000
2021	$553,879	$398,355	$8,158	$213,911	$29,675	$21,362	$19,959	$454,189	$791,109
2022	$586,733	$418,207	$8,626	$238,949	$29,006	$79,297	$18,065	$522,520	$856,362
2023	$614,646	$441,412	$9,021	$255,023	$30,327	$149,285	$16,441	$615,451	$900,704
2024	$647,400	$471,465	$9,679	$280,110	$32,120	$165,738	$14,328	$678,161	$942,679
2025	$679,630	$457,651	$20,907	$304,653	$30,972	$165,366	$12,219	$676,102	$995,296
2026	$708,239	$490,586	$22,428	$356,929	$33,911	$165,295	$10,346	$733,770	$1,053,964
2027	$739,887	$504,656	$23,765	$373,595	$36,012	$165,305	$8,039	$786,858	$1,064,401
2028	$961,285	$457,264	$210,780	$377,475	$33,951	$182,827	($10,873)	$958,423	$1,254,286
2029	$974,200	$495,649	$219,174	$388,914	$34,349	$200,249	($19,892)	$983,266	$1,309,377
2030	$1,005,832	$451,591	$214,560	$425,090	$32,472	$217,541	($22,473)	$992,081	$1,332,533
2031	$1,038,933	$486,473	$235,035	$451,667	$35,474	$285,137	($24,428)	$1,132,602	$1,375,688
2032	$1,072,780	$499,253	$244,032	$474,306	$37,303	$402,697	($25,860)	$1,307,543	$1,396,966
2033	$1,101,543	$491,487	$242,856	$495,091	$37,010	$420,109	$0	$1,327,853	$1,460,244
2034	$1,144,757	$516,379	$256,587	$516,523	$39,044	$440,484	$0	$1,409,807	$1,503,967
2035	$1,192,714	$519,527	$257,579	$538,205	$39,461	$447,722	$0	$1,457,869	$1,537,338
2036	$1,214,892	$545,323	$276,138	$557,235	$42,276	$450,765	$0	$1,504,217	$1,582,411
2037	$1,256,361	$549,465	$284,464	$572,259	$42,991	$450,757	$0	$1,540,386	$1,615,911
2038	$1,301,820	$489,040	$239,292	$583,773	$48,558	$504,455	$0	$1,479,664	$1,687,275
2039	$1,340,434	$502,685	$227,949	$559,682	$51,114	$559,306	$0	$1,497,557	$1,743,613
2040	$1,366,429	$525,586	$231,675	$539,893	$57,786	$615,314	$0	$1,548,867	$1,787,817
2041	$1,410,796	$547,245	$247,500	$528,798	$60,286	$615,233	$0	$1,604,582	$1,805,276
2042	$1,469,126	$562,157	$258,100	$526,739	$64,864	$615,233	$0	$1,666,066	$1,830,154
2043	$1,502,681	$486,809	$197,940	$520,934	$76,218	$675,861	$0	$1,560,468	$1,899,974
2044	$1,562,761	$542,621	$218,546	$466,218	$70,852	$736,252	$0	$1,681,848	$1,915,402
2045	$1,625,146	$560,402	$226,487	$454,707	$72,682	$736,796	$0	$1,750,727	$1,925,493
2046	$1,653,835	$416,885	$124,671	$440,394	$90,201	$800,349	$0	$1,485,390	$2,040,944
2047	$1,673,933	$392,538	$110,626	$387,750	$92,786	$862,165	$0	$1,466,226	$2,053,572
2048	$1,715,968	$398,774	$114,170	$341,594	$97,226	$862,165	$0	$1,498,874	$2,031,024
Cumulative Present Worth $000 (2019$)									
Utility CPW 2019-	$11,169,102	$5,756,478	$1,430,694	$4,459,802	$479,949	$3,238,541	$65,525	$11,587,747	$15,012,344
CPW of End Effects beyond 2045									$3,843,986
TOTAL Utility Cost, Net CPW (2018$)									$18,856,330

SOUTHWESTERN ELECTRIC POWER COMPANY
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High' Commodity Pricing - Optimal Plan

	Resource (Capacity) Additions										Energy & Capacity Positions										Carbon Intensities	
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(12)	(13)	(14)	(15)=(12)+(13)+(14)	(16)	(17)=(16)-(15)	(17)	(18)	(19)=(17)-(18)	(20)	(21)	(22)
	Supply-Side (Thermal)		(Increm) Energy Efficiency + VVO		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation	(Current) Purchased Energy	(New) Wind, EE, Solar, IVV	= Market Sales	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2 Emissions
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	14,264	1,874	19	16,157	20,971	(4,814)	5,642	5,092	550	24.1	14,486,469	14,486,469
2020	0	0	30.0	**30.0**	0.0	3.30	0.0	0	0	0	15,359	1,880	154	17,392	20,438	(3,046)	5,544	4,971	573	24.9	15,555,180	15,555,180
2021	0	0	4.4	**34.5**	0.3	3.63	30.6	31	0	0	15,296	1,874	954	18,124	20,534	(2,410)	5,580	5,001	579	25.0	15,482,851	15,482,851
2022	0	0	2.3	**36.8**	0.0	3.63	91.8	122	0	0	14,568	1,874	3,285	19,728	20,664	(937)	5,674	5,031	643	26.3	14,708,842	14,708,842
2023	0	0	(1.1)	**35.7**	0.3	3.96	91.8	214	0	0	14,680	1,874	5,614	22,168	20,706	1,462	5,656	5,029	627	26.0	14,832,235	14,832,235
2024	0	0	2.0	**37.7**	0.0	3.96	0.0	214	75	75	15,310	1,880	6,007	23,196	20,756	2,440	5,733	5,045	688	27.3	15,439,095	15,439,095
2025	0	0	0.0	**37.7**	0.3	4.29	0.0	214	0	75	14,205	1,874	5,986	22,066	20,787	1,279	5,625	5,057	568	24.6	14,298,911	14,298,911
2026	0	0	(0.8)	**36.9**	0.3	4.62	0.0	214	0	75	15,216	1,874	5,978	23,068	20,804	2,264	5,515	5,065	450	21.9	15,342,113	15,342,113
2027	0	0	(0.9)	**36.0**	0.0	4.62	0.0	214	0	75	15,898	1,874	5,968	23,740	20,836	2,905	5,514	5,134	380	20.3	16,001,390	16,001,390
2028	0	0	(2.3)	**33.7**	0.3	4.95	0.0	214	75	150	14,091	1,880	6,338	22,309	20,888	1,420	5,587	5,137	450	21.8	13,975,362	13,975,362
2029	0	0	(1.4)	**32.3**	0.0	4.95	0.0	214	75	225	14,035	1,591	6,676	22,302	20,962	1,339	5,648	5,157	492	22.7	14,047,504	14,047,504
2030	0	0	(1.2)	**31.2**	0.3	5.28	0.0	214	75	300	13,193	1,569	7,038	21,801	21,016	785	5,559	5,175	383	20.3	13,276,585	13,276,585
2031	0	0	(0.6)	**30.5**	0.3	5.61	30.6	245	150	450	14,034	1,569	8,537	24,141	21,073	3,067	5,739	5,197	542	23.7	14,079,498	14,079,498
2032	0	0	8.8	**39.3**	0.3	5.94	91.8	337	75	525	14,091	1,528	11,274	26,892	21,126	5,766	5,915	5,217	698	27.0	14,140,411	14,140,411
2033	0	0	(0.7)	**38.6**	0.0	5.94	0.0	337	75	600	13,576	0	11,613	25,188	21,193	3,995	5,930	5,236	694	26.8	13,620,348	13,620,348
2034	0	0	11.2	**49.8**	0.3	6.27	0.0	337	75	675	13,781	0	12,031	25,812	21,265	4,547	6,017	5,244	772	28.5	13,914,498	13,914,498
2035	0	0	(0.4)	**49.4**	0.3	6.60	0.0	337	25	700	13,468	0	12,151	25,619	21,339	4,280	6,042	5,267	774	28.5	13,506,334	13,506,334
2036	0	0	10.5	**59.9**	0.3	6.93	0.0	337	0	700	13,939	0	12,219	26,158	21,403	4,755	5,697	5,291	406	20.6	14,014,287	14,014,287
2037	0	0	(0.6)	**59.3**	0.3	7.26	0.0	337	0	700	13,805	0	12,195	26,000	21,477	4,523	5,344	5,313	31	12.6	13,959,685	13,959,685
2038	373	373	(0.5)	**58.8**	0.3	7.59	0.0	337	0	700	11,437	0	12,195	23,632	21,543	2,089	5,342	5,335	7	12.1	11,305,083	11,516,152
2039	373	746	(0.3)	**58.5**	0.3	7.92	0.0	337	0	700	10,433	0	12,196	22,628	21,621	1,007	5,357	5,357	0	12.0	10,158,611	10,586,336
2040	373	1,119	(0.2)	**58.3**	0.3	8.25	0.0	337	0	700	10,105	0	12,220	22,325	21,687	638	5,392	5,366	26	12.5	9,813,271	10,409,871
2041	0	1,119	(0.3)	**58.0**	0.3	8.58	0.0	337	0	700	10,397	0	12,198	22,594	21,752	842	5,392	5,388	4	12.1	10,166,724	10,756,243
2042	0	1,119	(0.2)	**57.8**	0.3	8.91	0.0	337	0	700	10,471	0	12,199	22,670	21,821	849	5,442	5,414	28	12.6	10,265,245	10,847,738
2043	373	1,492	1.4	**59.2**	0.3	9.24	0.0	337	0	700	7,958	0	12,204	20,162	21,887	(1,725)	5,439	5,435	4	12.1	7,463,683	8,209,798
2044	373	1,865	(0.1)	**59.1**	0.3	9.57	0.0	337	0	700	8,391	0	12,229	20,620	21,955	(1,335)	5,562	5,458	104	14.1	7,881,814	8,769,708
2045	0	1,865	(0.1)	**59.0**	0.3	9.90	0.0	337	0	700	8,369	0	12,207	20,576	22,031	(1,455)	5,483	5,466	18	12.4	7,871,867	8,787,882
2046	373	2,238	(0.6)	**58.4**	0.7	10.56	0.0	337	0	700	4,299	0	12,209	16,508	22,101	(5,593)	5,489	5,489	0	12.0	3,756,891	4,695,099
2047	373	2,611	(10.3)	**48.1**	0.3	10.89	0.0	337	0	700	3,672	0	12,169	15,842	22,165	(6,324)	5,545	5,511	33	12.7	3,028,738	4,039,263
2048	0	2,611	0.0	**48.1**	0.3	11.22	0.0	337	0	700	3,614	0	12,195	15,809	22,214	(6,405)	5,545	5,531	14	12.3	3,015,901	4,032,537

SOUTHWESTERN ELECTRIC POWER COMPANY
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'Low' Commodity Pricing - Optimal Plan

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	$451,032	$340,469	$6,383	$152,104	$24,301	$0	$28,960	$299,143	$704,106
2020	$442,339	$344,294	$6,805	$180,379	$26,316	$2,867	$29,143	$317,743	$714,401
2021	$446,376	$331,796	$6,904	$213,911	$25,546	$20,433	$29,038	$315,497	$758,507
2022	$458,579	$339,048	$7,474	$238,949	$25,609	$79,015	$28,839	$366,088	$811,425
2023	$474,415	$360,325	$7,941	$255,023	$27,196	$149,030	$28,141	$435,884	$866,188
2024	$490,787	$379,280	$8,465	$280,110	$28,367	$149,080	$27,414	$459,187	$904,316
2025	$512,071	$366,818	$17,442	$304,653	$27,292	$148,488	$26,119	$452,464	$950,419
2026	$527,197	$393,646	$18,755	$356,929	$29,839	$148,462	$25,354	$483,887	$1,016,294
2027	$544,984	$400,809	$19,679	$373,595	$31,437	$148,288	$24,195	$510,399	$1,032,588
2028	$752,903	$360,726	$181,220	$377,475	$29,812	$148,263	$6,773	$649,429	$1,207,744
2029	$759,341	$391,806	$187,400	$388,914	$29,945	$153,958	($4,528)	$650,688	$1,256,148
2030	$779,401	$358,192	$183,467	$425,090	$28,252	$171,586	($6,656)	$654,936	$1,284,396
2031	$802,203	$382,795	$199,746	$451,667	$30,589	$188,751	($8,011)	$707,734	$1,340,005
2032	$825,682	$390,484	$206,734	$474,306	$32,096	$208,041	($9,258)	$744,927	$1,383,157
2033	$846,173	$383,673	$205,585	$495,091	$31,827	$225,488	$0	$755,861	$1,431,977
2034	$886,620	$409,368	$220,152	$516,523	$33,548	$243,143	$0	$819,933	$1,489,422
2035	$922,665	$409,914	$220,766	$538,205	$33,954	$262,307	$0	$859,718	$1,528,094
2036	$944,232	$434,541	$238,054	$557,235	$36,083	$280,581	$0	$911,491	$1,579,235
2037	$976,473	$439,765	$245,243	$572,259	$38,648	$299,111	$0	$951,287	$1,620,212
2038	$1,007,991	$390,594	$207,582	$583,773	$42,382	$409,479	$0	$967,697	$1,674,104
2039	$1,037,473	$400,299	$199,577	$559,682	$47,037	$464,244	$0	$984,400	$1,723,913
2040	$1,083,299	$426,135	$206,531	$539,893	$53,681	$520,257	$0	$1,062,903	$1,766,893
2041	$1,131,017	$451,408	$222,518	$528,798	$55,583	$627,548	$0	$1,235,376	$1,781,496
2042	$1,157,671	$453,502	$228,864	$526,739	$56,481	$627,548	$0	$1,246,281	$1,804,524
2043	$1,177,665	$395,198	$179,183	$520,934	$61,321	$690,947	$0	$1,185,543	$1,839,706
2044	$1,215,350	$434,598	$196,951	$466,218	$68,078	$752,571	$0	$1,261,597	$1,872,169
2045	$1,270,400	$452,743	$206,151	$454,707	$70,180	$752,639	$0	$1,325,747	$1,881,074
2046	$1,319,914	$347,185	$118,228	$440,394	$72,604	$816,331	$0	$1,195,616	$1,919,040
2047	$1,347,805	$332,851	$108,512	$387,750	$77,940	$877,954	$0	$1,206,732	$1,926,080
2048	$1,392,331	$353,635	$114,788	$400,905	$81,516	$877,954	$0	$1,262,857	$1,958,272
Cumulative Present Worth $000 (2019$)									
Utility CPW 2019-	$8,747,069	$4,684,345	$1,242,558	$4,467,637	$423,167	$2,681,237	$172,288	$7,840,478	$14,577,824
CPW of End Effects beyond 2045									$3,706,294
TOTAL Utility Cost, Net CPW (2018$)									$18,284,118

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	Resource (Capacity) Additions										Energy & Capacity Positions										Carbon Intensities	
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(12)	(13)	(14)	(15)=(12)+(13)+(14)	(16)	(17)=(16)-(15)	(17)	(18)	(19)=(17)-(18)	(20)	(21)	(22)
	Supply-Side (Thermal)		(Increm) Energy Efficiency + VVO		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation	(Current) Purchased Energy	(New) Wind, EE, Solar, IVV	= Market Sales	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2 Emissions
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	13,068	1,874	19	14,962	20,971	(6,010)	5,642	5,092	550	24.1	13,051,130	13,051,130
2020	0	0	26.8	**26.8**	0.0	3.30	0.0	0	0	0	13,664	1,880	145	15,688	20,438	(4,750)	5,543	4,971	572	24.9	13,661,008	13,661,008
2021	0	0	2.3	**29.1**	0.3	3.63	30.6	31	0	0	12,785	1,874	939	15,598	20,534	(4,936)	5,577	5,001	576	24.9	12,893,620	12,893,620
2022	0	0	1.8	**30.9**	0.0	3.63	91.8	122	0	0	12,601	1,874	3,269	17,745	20,664	(2,920)	5,671	5,031	640	26.2	12,735,417	12,735,417
2023	0	0	0.7	**31.6**	0.3	3.96	91.8	214	0	0	12,912	1,874	5,598	20,384	20,706	(322)	5,623	5,029	594	25.2	13,040,010	13,040,010
2024	0	0	1.2	**32.8**	0.0	3.96	0.0	214	0	0	13,256	1,880	5,622	20,759	20,756	3	5,624	5,045	579	24.9	13,398,485	13,398,485
2025	0	0	(0.4)	**32.3**	0.3	4.29	0.0	214	0	0	12,250	1,874	5,601	19,726	20,787	(1,061)	5,517	5,057	460	22.2	12,377,324	12,377,324
2026	0	0	(0.8)	**31.5**	0.3	4.62	0.0	214	0	0	13,116	1,874	5,593	20,583	20,804	(222)	5,406	5,065	341	19.5	13,316,638	13,316,638
2027	0	0	(1.2)	**30.3**	0.0	4.62	0.0	214	0	0	13,583	1,874	5,581	21,038	20,836	202	5,404	5,134	271	17.9	13,787,047	13,787,047
2028	0	0	(1.2)	**29.1**	0.3	4.95	0.0	214	0	0	12,088	1,880	5,585	19,553	20,888	(1,335)	5,403	5,137	266	17.8	12,043,506	12,043,506
2029	0	0	(1.0)	**28.1**	0.0	4.95	0.0	214	25	25	11,951	1,591	5,683	19,225	20,962	(1,737)	5,389	5,157	233	17.1	12,035,363	12,035,363
2030	0	0	(0.3)	**27.7**	0.3	5.28	0.0	214	75	100	11,219	1,569	6,047	18,836	21,016	(2,181)	5,225	5,175	50	13.1	11,376,321	11,376,321
2031	0	0	0.2	**28.0**	0.3	5.61	0.0	214	75	175	11,836	1,569	6,411	19,816	21,073	(1,257)	5,301	5,197	104	14.2	11,988,553	11,988,553
2032	0	0	10.5	**38.5**	0.3	5.94	0.0	214	75	250	11,828	1,528	6,834	20,190	21,126	(936)	5,375	5,217	159	15.4	12,001,397	12,001,397
2033	0	0	(0.4)	**38.1**	0.0	5.94	0.0	214	75	325	11,378	0	7,182	18,560	21,193	(2,633)	5,391	5,236	154	15.3	11,550,275	11,550,275
2034	0	0	(1.0)	**37.1**	0.3	6.27	0.0	214	75	400	11,716	0	7,548	19,264	21,265	(2,001)	5,465	5,244	221	16.7	11,959,393	11,959,393
2035	0	0	(0.3)	**36.9**	0.3	6.60	0.0	214	75	475	11,444	0	7,915	19,359	21,339	(1,980)	5,540	5,267	273	17.8	11,596,789	11,596,789
2036	0	0	(0.4)	**36.5**	0.3	6.93	0.0	214	75	550	11,916	0	8,297	20,214	21,403	(1,189)	5,310	5,291	19	12.4	12,100,210	12,100,210
2037	0	0	(0.3)	**36.2**	0.3	7.26	0.0	214	75	625	11,807	0	8,650	20,457	21,477	(1,020)	5,320	5,313	7	12.1	12,054,561	12,054,561
2038	373	373	12.7	**48.9**	0.3	7.59	30.6	245	75	700	9,840	0	9,843	19,682	21,543	(1,861)	5,366	5,335	31	12.7	9,809,591	10,004,722
2039	373	746	(0.3)	**48.6**	0.3	7.92	0.0	245	0	700	9,044	0	9,843	18,887	21,621	(2,734)	5,383	5,357	26	12.5	8,890,941	9,287,434
2040	373	1,119	(0.2)	**48.3**	0.3	8.25	0.0	245	0	700	8,894	0	9,862	18,756	21,687	(2,931)	5,368	5,366	2	12.0	8,699,865	9,303,009
2041	0	1,119	(0.2)	**48.1**	0.3	8.58	91.8	337	0	700	9,227	0	12,157	21,383	21,752	(368)	5,418	5,388	30	12.6	9,077,126	9,694,302
2042	0	1,119	(0.1)	**48.0**	0.3	8.91	0.0	337	0	700	9,152	0	12,158	21,310	21,821	(511)	5,418	5,414	5	12.1	9,065,756	9,640,321
2043	373	1,492	10.0	**58.0**	0.3	9.24	0.0	337	0	700	7,092	0	12,201	19,293	21,887	(2,594)	5,437	5,435	2	12.0	6,696,512	7,442,963
2044	373	1,865	0.9	**58.9**	0.3	9.57	0.0	337	0	700	7,449	0	12,229	19,678	21,955	(2,277)	5,479	5,458	20	12.4	7,052,461	7,913,216
2045	0	1,865	0.0	**58.9**	0.3	9.90	0.0	337	0	700	7,517	0	12,207	19,724	22,031	(2,307)	5,511	5,466	46	12.9	7,116,032	8,009,188
2046	373	2,238	(0.5)	**58.4**	0.7	10.56	0.0	337	0	700	3,953	0	12,209	16,163	22,101	(5,939)	5,590	5,489	101	14.1	3,408,485	4,471,661
2047	373	2,611	(11.6)	**46.7**	0.3	10.89	0.0	337	0	700	3,425	0	12,164	15,589	22,165	(6,576)	5,533	5,511	22	12.5	2,796,073	3,981,733
2048	0	2,611	0.0	**46.7**	0.3	11.22	0.0	337	0	700	3,430	0	12,189	15,619	22,214	(6,595)	5,534	5,531	2	12.0	2,811,117	4,077,381

SOUTHWESTERN ELECTRIC POWER COMPANY
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No Carbon' Commodity Pricing - Optimal Plan

Utility Costs (Nominal$)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	$489,076	$364,782	$6,917	$152,104	$25,414	$0	$25,769	$342,733	$721,329
2020	$487,259	$370,298	$7,395	$180,379	$27,721	$3,591	$25,295	$370,422	$731,516
2021	$503,128	$367,915	$7,659	$213,911	$27,844	$20,673	$24,149	$388,015	$777,264
2022	$524,944	$381,356	$8,145	$238,949	$27,456	$79,072	$23,190	$445,206	$837,906
2023	$546,936	$405,134	$8,622	$255,023	$29,018	$149,079	$21,949	$527,829	$887,931
2024	$570,904	$429,200	$9,219	$280,110	$30,489	$149,080	$20,587	$563,607	$925,982
2025	$593,630	$413,020	$19,107	$304,653	$29,152	$148,970	$19,219	$551,439	$976,312
2026	$617,246	$444,058	$20,601	$356,929	$32,013	$148,462	$17,759	$598,889	$1,038,179
2027	$642,690	$454,845	$21,737	$373,595	$33,903	$148,288	$15,999	$638,834	$1,052,224
2028	$663,751	$427,367	$20,728	$377,475	$33,398	$148,149	$14,962	$632,732	$1,053,099
2029	$693,466	$483,461	$21,959	$388,914	$34,950	$148,132	$791	$672,816	$1,098,858
2030	$723,666	$447,078	$21,782	$425,090	$33,273	$165,760	($1,934)	$689,082	$1,125,633
2031	$757,186	$487,791	$23,515	$451,667	$36,624	$182,925	($4,020)	$763,661	$1,172,028
2032	$794,504	$508,655	$24,447	$474,306	$39,101	$202,215	($6,160)	$829,425	$1,207,643
2033	$828,657	$510,840	$24,183	$495,091	$39,530	$219,662	$0	$864,494	$1,253,468
2034	$861,352	$538,251	$25,839	$516,523	$41,368	$243,555	$0	$932,425	$1,294,463
2035	$903,014	$541,870	$25,873	$538,205	$41,910	$262,719	$0	$980,789	$1,332,802
2036	$914,484	$568,622	$27,317	$557,235	$44,153	$280,993	$0	$1,022,499	$1,370,305
2037	$958,952	$584,314	$28,352	$572,259	$47,420	$299,523	$0	$1,088,803	$1,402,017
2038	$1,003,314	$511,728	$20,083	$583,773	$50,257	$409,890	$0	$1,089,332	$1,489,714
2039	$1,022,847	$508,428	$19,128	$559,682	$53,658	$464,656	$0	$1,075,329	$1,553,070
2040	$1,058,274	$532,198	$19,500	$539,893	$59,385	$556,079	$0	$1,171,008	$1,594,321
2041	$1,087,416	$561,324	$20,506	$528,798	$62,376	$591,843	$0	$1,249,346	$1,602,916
2042	$1,118,422	$571,204	$21,168	$526,739	$64,319	$627,960	$0	$1,312,487	$1,617,325
2043	$1,152,146	$484,917	$11,171	$520,934	$71,860	$691,359	$0	$1,229,881	$1,702,506
2044	$1,193,362	$532,506	$12,009	$466,218	$72,386	$752,507	$0	$1,313,826	$1,715,162
2045	$1,264,394	$567,409	$12,354	$454,707	$75,183	$753,051	$0	$1,411,515	$1,715,584
2046	$1,311,492	$451,825	$6,569	$440,394	$86,392	$817,161	$0	$1,261,435	$1,852,399
2047	$1,359,394	$451,897	$5,386	$388,097	$91,031	$878,366	$0	$1,308,970	$1,865,202
2048	$1,382,118	$465,952	$5,444	$245,645	$95,238	$878,366	$0	$1,333,146	$1,739,618
Cumulative Present Worth $000 (2019$)									
Utility CPW 2019-	$8,975,451	$5,590,944	$196,643	$4,447,175	$476,885	$2,671,936	$147,136	$8,800,473	$13,705,697
CPW of End Effects beyond 2045									$3,292,461
TOTAL Utility Cost, Net CPW (2018$)									$16,998,158

SOUTHWESTERN ELECTRIC POWER COMPANY
2019 INTEGRATED RESOURCE PLAN
No Carbon' Commodity Pricing - Optimal Plan

	Resource (Capacity) Additions										Energy & Capacity Positions										Carbon Intensities	
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(12)	(13)	(14)	(15)=(12)+(13)+(14)	(16)	(17)=(16)-(15)	(17)	(18)	(19)=(17)-(18)	(20)	(21)	(22)
	Supply-Side (Thermal)		(Increm) Energy Efficiency + VVO		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation	(Current) Purchased Energy	(New) Wind, EE, Solar, IVV	= Market Sales	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2 Emissions
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	13,897	1,874	19	15,790	20,971	(5,181)	5,642	5,092	550	24.1	13,976,876	13,976,876
2020	0	0	29.0	**29.0**	0.0	3.30	0.0	0	0	0	14,598	1,880	150	16,628	20,438	(3,810)	5,543	4,971	572	24.9	14,708,477	14,708,477
2021	0	0	2.6	**31.5**	0.3	3.63	30.6	31	0	0	14,159	1,874	945	16,979	20,534	(3,556)	5,577	5,001	576	24.9	14,312,329	14,312,329
2022	0	0	2.0	**33.5**	0.0	3.63	91.8	122	0	0	13,640	1,874	3,276	18,790	20,664	(1,874)	5,671	5,031	640	26.2	13,758,400	13,758,400
2023	0	0	(0.2)	**33.3**	0.3	3.96	91.8	214	0	0	13,899	1,874	5,605	21,378	20,706	672	5,623	5,029	594	25.2	14,017,323	14,017,323
2024	0	0	1.4	**34.7**	0.0	3.96	0.0	214	0	0	14,376	1,880	5,628	21,885	20,756	1,129	5,624	5,045	579	24.9	14,493,900	14,493,900
2025	0	0	0.4	**35.1**	0.3	4.29	0.0	214	0	0	13,213	1,874	5,610	20,698	20,787	(89)	5,517	5,057	460	22.2	13,326,846	13,326,846
2026	0	0	(1.3)	**33.8**	0.3	4.62	0.0	214	0	0	14,209	1,874	5,600	21,683	20,804	879	5,406	5,065	341	19.5	14,372,144	14,372,144
2027	0	0	(1.6)	**32.2**	0.0	4.62	0.0	214	0	0	14,796	1,874	5,587	22,257	20,836	1,422	5,404	5,134	271	17.9	14,947,113	14,947,113
2028	0	0	(1.9)	**30.3**	0.3	4.95	0.0	214	0	0	13,977	1,880	5,589	21,446	20,888	557	5,403	5,137	266	17.8	14,065,442	14,065,442
2029	0	0	(1.3)	**28.9**	0.0	4.95	0.0	214	0	0	14,410	1,591	5,563	21,564	20,962	602	5,389	5,157	233	17.1	14,509,083	14,509,083
2030	0	0	(0.6)	**28.4**	0.3	5.28	0.0	214	75	75	13,635	1,569	5,926	21,130	21,016	114	5,225	5,175	50	13.1	13,785,212	13,785,212
2031	0	0	(0.0)	**28.3**	0.3	5.61	0.0	214	75	150	14,591	1,569	6,289	22,450	21,073	1,377	5,301	5,197	104	14.2	14,695,026	14,695,026
2032	0	0	10.3	**38.7**	0.3	5.94	0.0	214	75	225	14,871	1,528	6,711	23,111	21,126	1,985	5,375	5,217	159	15.4	14,948,209	14,948,209
2033	0	0	(0.5)	**38.2**	0.0	5.94	0.0	214	75	300	14,561	0	7,060	21,621	21,193	428	5,391	5,236	154	15.3	14,581,697	14,581,697
2034	0	0	(1.0)	**37.1**	0.3	6.27	0.0	214	100	400	15,010	0	7,548	22,558	21,265	1,293	5,465	5,244	221	16.7	15,107,899	15,107,899
2035	0	0	(0.3)	**36.8**	0.3	6.60	0.0	214	75	475	14,713	0	7,914	22,628	21,339	1,289	5,540	5,267	273	17.8	14,726,656	14,726,656
2036	0	0	(0.4)	**36.5**	0.3	6.93	0.0	214	75	550	15,220	0	8,297	23,517	21,403	2,114	5,310	5,291	19	12.4	15,279,260	15,279,260
2037	0	0	(0.3)	**36.1**	0.3	7.26	0.0	214	75	625	15,346	0	8,650	23,996	21,477	2,519	5,320	5,313	7	12.1	15,433,701	15,433,701
2038	373	373	12.7	**48.9**	0.3	7.59	30.6	245	75	700	12,637	0	9,843	22,479	21,543	936	5,366	5,335	31	12.7	12,447,017	12,664,417
2039	373	746	(0.3)	**48.6**	0.3	7.92	0.0	245	0	700	11,245	0	9,843	21,088	21,621	(533)	5,383	5,357	26	12.5	10,907,679	11,333,384
2040	373	1,119	(0.2)	**48.3**	0.3	8.25	30.6	275	0	700	11,090	0	10,634	21,724	21,687	37	5,368	5,366	2	12.0	10,708,840	11,286,479
2041	0	1,119	(0.2)	**48.1**	0.3	8.58	30.6	306	0	700	11,364	0	11,386	22,750	21,752	999	5,418	5,388	30	12.6	11,053,614	11,678,981
2042	0	1,119	(0.1)	**48.0**	0.3	8.91	30.6	337	0	700	11,405	0	12,158	23,563	21,821	1,742	5,418	5,414	5	12.1	11,139,681	11,731,912
2043	373	1,492	10.0	**58.0**	0.3	9.24	0.0	337	0	700	8,451	0	12,201	20,652	21,887	(1,235)	5,437	5,435	2	12.0	7,885,271	8,688,058
2044	373	1,865	0.3	**58.3**	0.3	9.57	0.0	337	0	700	8,860	0	12,227	21,087	21,955	(868)	5,479	5,458	20	12.4	8,291,262	9,216,261
2045	0	1,865	0.3	**58.6**	0.3	9.90	0.0	337	0	700	8,973	0	12,206	21,180	22,031	(851)	5,511	5,466	46	12.9	8,366,051	9,385,995
2046	373	2,238	(0.3)	**58.4**	0.7	10.56	0.0	337	0	700	5,088	0	12,209	17,297	22,101	(4,804)	5,590	5,489	101	14.1	4,355,311	5,504,651
2047	373	2,611	(11.6)	**46.7**	0.3	10.89	0.0	337	0	700	4,404	0	12,164	16,568	22,165	(5,597)	5,533	5,511	22	12.5	3,527,551	4,930,133
2048	0	2,611	0.0	**46.7**	0.3	11.22	0.0	337	0	700	4,384	0	12,189	16,574	22,214	(5,640)	5,534	5,531	2	12.0	3,536,545	4,962,761

SOUTHWESTERN ELECTRIC POWER COMPANY
2019 INTEGRATED RESOURCE PLAN
Low No Carbon' Commodity Pricing - Optimal Plan

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) *Less:* Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	$451,179	$340,609	$6,383	$152,104	$24,319	$0	$28,958	$299,511	$704,041
2020	$442,485	$344,259	$6,804	$180,379	$26,315	$2,740	$29,137	$317,623	$714,498
2021	$446,274	$331,605	$6,901	$213,911	$25,532	$20,433	$29,044	$315,192	$758,508
2022	$458,406	$339,209	$7,476	$238,949	$25,628	$79,015	$28,856	$366,117	$811,422
2023	$477,094	$362,678	$7,972	$255,023	$27,399	$79,033	$27,883	$389,557	$847,527
2024	$494,775	$381,699	$8,512	$280,110	$28,562	$79,082	$27,070	$412,307	$887,504
2025	$513,763	$367,453	$17,471	$304,653	$27,332	$78,331	$25,928	$399,638	$935,293
2026	$535,885	$398,415	$18,957	$356,929	$30,225	$78,180	$24,524	$439,109	$1,004,006
2027	$553,655	$406,341	$19,899	$373,595	$31,918	$78,167	$23,366	$465,473	$1,021,467
2028	$569,151	$379,131	$18,898	$377,475	$31,349	$78,152	$22,774	$454,951	$1,021,979
2029	$589,093	$424,122	$19,808	$388,914	$32,268	$78,135	$8,073	$474,254	$1,066,160
2030	$609,497	$390,108	$19,617	$425,090	$31,031	$78,175	$5,783	$467,856	$1,091,446
2031	$637,852	$427,460	$21,217	$451,667	$33,788	$95,230	$4,073	$526,925	$1,144,363
2032	$664,558	$441,826	$21,930	$474,306	$35,207	$112,537	$2,281	$566,476	$1,186,169
2033	$691,626	$442,639	$21,663	$495,091	$35,544	$129,984	$0	$591,076	$1,225,471
2034	$724,515	$468,904	$23,133	$516,523	$37,515	$147,592	$0	$644,928	$1,273,254
2035	$768,120	$476,269	$23,283	$538,205	$38,475	$166,803	$0	$695,624	$1,315,533
2036	$784,592	$503,926	$24,721	$557,235	$42,002	$201,021	$0	$750,530	$1,362,966
2037	$817,961	$514,409	$25,544	$572,259	$45,582	$242,159	$0	$810,208	$1,407,705
2038	$846,094	$471,208	$18,170	$583,773	$51,032	$362,106	$0	$797,787	$1,534,596
2039	$880,518	$454,063	$17,420	$559,682	$51,629	$397,163	$0	$812,360	$1,548,117
2040	$901,200	$465,275	$17,535	$539,893	$57,599	$453,176	$0	$842,389	$1,592,290
2041	$945,243	$501,765	$18,748	$528,798	$60,662	$453,176	$0	$903,485	$1,604,907
2042	$969,943	$507,917	$19,185	$526,739	$61,798	$489,293	$0	$947,990	$1,626,884
2043	$998,726	$456,743	$10,579	$520,934	$68,345	$608,633	$0	$915,611	$1,748,349
2044	$1,022,876	$474,529	$11,398	$466,218	$71,679	$608,633	$0	$936,291	$1,719,041
2045	$1,077,048	$501,909	$11,716	$454,707	$75,491	$608,633	$0	$999,749	$1,729,755
2046	$1,125,345	$417,796	$5,927	$440,394	$76,992	$810,943	$0	$994,291	$1,883,107
2047	$1,164,574	$381,098	$4,919	$387,750	$82,806	$848,898	$0	$1,028,890	$1,841,155
2048	$1,202,318	$395,811	$4,996	$400,905	$86,289	$848,898	$0	$1,068,944	$1,870,274
Cumulative Present Worth $000 (2019$)									
Utility CPW 2019-	$7,753,598	$4,989,024	$178,861	$4,467,637	$448,593	$1,954,947	$200,027	$6,518,020	$13,474,666
CPW of End Effects beyond 2045									$3,539,745
TOTAL Utility Cost, Net CPW (2018$)									$17,014,411

SOUTHWESTERN ELECTRIC POWER COMPANY
2019 INTEGRATED RESOURCE PLAN
Low No Carbon' Commodity Pricing - Optimal Plan

	Resource (Capacity) Additions										Energy & Capacity Positions										Carbon Intensities	
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(12)	(13)	(14)	(15)=(12)+(13)+(14)	(16)	(17)=(16)-(15)	(17)	(18)	(19)=(17)-(18)	(20)	(21)	(22)
	Supply-Side (Thermal)		(Increm) Energy Efficiency + VVO		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation	(Current) Purchased Energy	(New) Wind, EE, Solar, IVV	= Market Sales	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2 Emissions
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	13,073	1,874	19	14,966	20,971	(6,005)	5,642	5,092	550	24.1	13,054,953	13,054,953
2020	0	0	26.6	26.6	0.0	3.30	0.0	0	0	0	13,660	1,880	144	15,683	20,438	(4,755)	5,541	4,971	570	24.8	13,657,912	13,657,912
2021	0	0	2.3	28.9	0.3	3.63	30.6	31	0	0	12,777	1,874	938	15,589	20,534	(4,945)	5,574	5,001	573	24.8	12,884,524	12,884,524
2022	0	0	1.8	30.7	0.0	3.63	91.8	122	0	0	12,610	1,874	3,268	17,752	20,664	(2,912)	5,668	5,031	637	26.2	12,737,917	12,737,917
2023	0	0	0.7	31.4	0.3	3.96	0.0	122	0	0	13,012	1,874	3,286	18,172	20,706	(2,534)	5,560	5,029	530	23.8	13,113,574	13,113,574
2024	0	0	1.2	32.6	0.0	3.96	0.0	122	0	0	13,355	1,880	3,305	18,540	20,756	(2,216)	5,561	5,045	516	23.4	13,486,674	13,486,674
2025	0	0	(0.9)	31.8	0.3	4.29	0.0	122	0	0	12,271	1,874	3,288	17,433	20,787	(3,354)	5,452	5,057	396	20.8	12,397,155	12,397,155
2026	0	0	(1.4)	30.4	0.3	4.62	0.0	122	0	0	13,297	1,874	3,278	18,449	20,804	(2,356)	5,341	5,065	276	18.1	13,473,998	13,473,998
2027	0	0	(1.3)	29.1	0.0	4.62	0.0	122	0	0	13,795	1,874	3,266	18,935	20,836	(1,901)	5,340	5,134	206	16.5	13,957,492	13,957,492
2028	0	0	(1.0)	28.0	0.3	4.95	0.0	122	0	0	12,980	1,880	3,264	18,123	20,888	(2,765)	5,339	5,137	203	16.4	13,095,728	13,095,728
2029	0	0	(1.0)	27.0	0.0	4.95	0.0	122	0	0	13,168	1,591	3,245	18,005	20,962	(2,958)	5,326	5,157	170	15.7	13,340,459	13,340,459
2030	0	0	(0.4)	26.6	0.3	5.28	0.0	122	0	0	12,404	1,569	3,241	17,214	21,016	(3,802)	5,212	5,175	37	12.8	12,652,390	12,652,390
2031	0	0	(0.1)	26.5	0.3	5.61	0.0	122	75	75	13,348	1,569	3,604	18,521	21,073	(2,552)	5,212	5,197	16	12.3	13,521,547	13,521,547
2032	0	0	(0.3)	26.2	0.3	5.94	0.0	122	75	150	13,504	1,528	3,976	19,008	21,126	(2,118)	5,263	5,217	46	13.0	13,672,491	13,672,491
2033	0	0	(0.2)	26.0	0.0	5.94	0.0	122	75	225	13,223	0	4,331	17,554	21,193	(3,640)	5,278	5,236	42	12.9	13,328,914	13,328,914
2034	0	0	(0.7)	25.3	0.3	6.27	0.0	122	75	300	13,652	0	4,697	18,350	21,265	(2,915)	5,253	5,244	9	12.2	13,831,738	13,831,738
2035	0	0	(0.1)	25.2	0.3	6.60	0.0	122	75	375	13,509	0	5,065	18,574	21,339	(2,765)	5,328	5,267	61	13.3	13,574,744	13,574,744
2036	0	0	12.8	38.1	0.3	6.93	0.0	122	125	500	14,052	0	5,742	19,794	21,403	(1,609)	5,298	5,291	7	12.1	14,162,066	14,162,066
2037	0	0	10.7	48.8	0.3	7.26	0.0	122	150	650	14,074	0	6,513	20,588	21,477	(889)	5,344	5,313	30	12.6	14,223,468	14,223,468
2038	746	746	(0.3)	48.5	0.3	7.59	0.0	122	50	700	11,658	0	6,759	18,417	21,543	(3,127)	5,342	5,335	7	12.1	11,544,261	11,935,134
2039	0	746	(0.2)	48.3	0.3	7.92	30.6	153	0	700	10,541	0	7,530	18,072	21,621	(3,550)	5,395	5,357	38	12.8	10,263,201	10,669,445
2040	373	1,119	(0.2)	48.2	0.3	8.25	0.0	153	0	700	10,257	0	7,544	17,801	21,687	(3,886)	5,368	5,366	1	12.0	9,959,051	10,492,458
2041	0	1,119	(0.1)	48.0	0.3	8.58	0.0	153	0	700	10,676	0	7,533	18,209	21,752	(3,543)	5,399	5,388	10	12.2	10,421,932	11,035,423
2042	0	1,119	(0.1)	48.0	0.3	8.91	30.6	184	0	700	10,649	0	8,305	18,954	21,821	(2,867)	5,430	5,414	16	12.3	10,441,408	11,016,885
2043	746	1,865	(0.1)	47.9	0.3	9.24	0.0	184	0	700	8,126	0	8,307	16,433	21,887	(5,454)	5,448	5,435	13	12.3	7,603,998	8,541,157
2044	0	1,865	(0.0)	47.9	0.3	9.57	0.0	184	0	700	8,475	0	8,323	16,798	21,955	(5,157)	5,498	5,458	40	12.8	7,979,035	8,862,348
2045	0	1,865	(0.0)	47.9	0.3	9.90	0.0	184	0	700	8,586	0	8,310	16,897	22,031	(5,134)	5,469	5,466	4	12.1	8,045,132	9,003,794
2046	746	2,611	0.0	47.9	0.7	10.56	61.2	245	0	700	4,769	0	9,855	14,624	22,101	(7,477)	5,498	5,489	9	12.2	4,065,169	5,400,819
2047	0	2,611	0.0	47.9	0.3	10.89	30.6	275	0	700	4,178	0	10,628	14,806	22,165	(7,360)	5,533	5,511	22	12.4	3,354,224	4,684,389
2048	0	2,611	0.0	47.9	0.3	11.22	0.0	275	0	700	4,197	0	10,649	14,847	22,214	(7,367)	5,533	5,531	2	12.0	3,384,869	4,743,703

Exhibit I Stakeholder Comments

STAKEHOLDER COMMENTS:	SWEPCO Response
SREA encouraged company to develop framework to fairly evaluate energy storage options associated with wind and solar energy proposals	The Company refers the Stakeholders to Exhibit K for an analysis of energy storage prepared for the SWEPCO Arkansas stakeholders. At this time, the Company observations suggest that the addition of energy storage to either wind or solar resources will raise the combined resources cost.
SREA requested SWEPCO to publish all cost and performance assumptions for all generation technologies in a single chart and conduct a narrative comparison w/ the NREL ATB highlighting the areas that are higher or lower.	See Exhibit B for the table and Exhibit J for the narrative comparison.
SREA requested SWEPCO to increase its cap on wind energy to beyond 60%, increase solar cap to beyond 25% and consider increasing its annual limit for those sources to 1000 MW/year or higher as an additional sensitivity run.	Section 4.5.5 describes the basis for our cap on these resources. For this IRP, SWEPCO's resource additions caps for both wind and solar are reasonable.
SREA requested the company to explain the details of its existing renewable energy PPAs and how transmission service is handled.	See Section 3.2. Also note: The Buyer receives the Locational Marginal Price (LMP) at the point of interconnection, which is net of congestion and line loss costs and then pays the Seller the contracted rate for the energy. The Buyer also pays the Seller for deemed generation and lost Production Tax Credits anytime Buyer Economically Curtails (dispatches down) generation from the wind facility. However, if the Transmission Operator curtails generation due to a "Reliability Problem or event" then the Buyer does not pay or reimburse the Seller for any deemed or lost generation. The Seller is also required to transmit real-time SCADA data (output, wind speed, availability, etc.) from the turbines and the substation for use by the Buyer in developing its offer into the SPP market. So long as the Seller is reliably transmitting this real-time data, the Buyer is responsible for the schedule imbalance costs incurred for its account. If the Seller is not reliably transmitting real-time data to the Buyer, following a notice period and chance to cure, the Seller then would absorb or reimburse imbalance costs billed by SPP.
SREA requested the Company's energy storage assumptions be reduced	See Section 4.5.5.4.4

SREA encouraged company to explain the implications of a model's perfect knowledge and for company to make recommendations on how to work around this problem.	The Company does not see the model's ability to have "perfect knowledge" as an issue with it's the Plexos resource planning tool. The model's "perfect knowledge" of future conditions allows the Company to make near-term resource decisions with the understanding of how changes in future conditions will impact the economics of those resource decisions, thereby, providing the best resource plan for SWEPCO's customers.
AAE expressed its belief that the company may have further opportunity to reduce risks and secure low cost resources by modeling and implementing additional DR Programs for all customer classes.	See Section 4.4.3.
AAE urged SWEPCO to expand its DR projections and provide a qualitative discussion of how DR capacity that could be provided under new programs would deliver value to SWEPCO and reduce need for supply side alternatives..	See Section 4.4.3.
AAE disappointed to see energy storage not modeled with renewables.	The Company refers the Stakeholders to Exhibit J for an analysis of energy storage prepared for the SWEPCO Arkansas stakeholders. At this time, the Company observations suggest that the addition of energy storage to either wind or solar resources will raise the combined resources cost.
Sierra Club stated SWEPCO should improve its model structure and assumptions to expedite renewable resources and increase DSM.	Sections 4 and 5 describe our model structure and basis for assumptions.
Sierra Club recommended company ensure its model is allowed to pick partial blocks of resources where in block size is not a barrier (solar and wind) and pick reasonable partial blocks of other resources where capacity can be shared between utilities.	See Sections 4 and 5. The model balances block size with economies of scale for solar, wind, NGCC and energy efficiency.
Sierra Club recommended that SWEPCO not overly constrain the model by ensuring that it minimizes manual portfolio decisions and prescreening	See Sections 4 and 5.
Sierra Club stated SWEPCO should ensure that it captures avoided costs that are provided by certain resources that occur outside of traditional energy planning	See Section 4.3.

Sierra Club state the company should ensure that the Aurora model has ability to fully optimize the SWEPCO portfolio, including retirements and demand side resources.	SWEPCO believes this comment is actually referring to our PLEXOS model in which, the retirements and demand side resources are included in the optimizations.

Exhibit J – Energy Storage Analysis

Energy Storage Analysis

SWEPCO should provide an estimate at what value and/or what cost energy storage would begin to be selected in the current model.

Response: Below is a simulation of the breakeven cost needed for the battery storage resource that the Company has included in this IRP. The Company has assumed for the purposes of this calculation that Ancillary Services revenue may range from zero to 50% of the energy revenue earned, ultimately the Ancillary Services revenue will be dependent on the storage design as well as the market. For Scenarios 1, 2 & 3, the Company modified the installed cost to get a breakeven NPV for each Scenario. In Scenarios 2 & 3, the value of Ancillary Services was changed to gain a relative understanding of Ancillary Services revenue on breakeven installed cost. In conclusion, based on current conditions the storage resource installed cost would need to be reduced by approximately 80%.

Summary

		Break-Even Cost		
	Today's Cost	Scenario 1	Scenario 2	Scenario 3
Intalled Cost ($/kWh)	457	85	100	70
Capacity (kWh)	40,000	40,000	40,000	40,000
Installed Cost ($)	18,280,000	***3,410,002***	***4,011,965***	***2,808,038***
Fixed O&M ($/kW-yr.)	39	39	39	39
Ancillary Svs Rev. as % of Energy	25%	25%	***50%***	***0%***
Fixed Charge Rate (FCR) for 20 Yr. Asset (%)	13%	13%	13%	13%
Discount to Today's Cost(%)		***-81%***	***-78%***	***-85%***
NPV ($)	(22,104,995)	0	0	0