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INTEGRATED RESOURCE PLANNING REPORT
TO THE
ARKANSAS PUBLIC SERVICE COMMISSION

December 1, 2015

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Executive Summary

The Integrated Resource Plan (IRP or Plan) is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore this plan is not a commitment to a specific course of action, since the future is highly uncertain, particularly in light of the economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as current and future laws environmental regulations, including proposals to control greenhouse gases. The implementation action items as 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. By Arkansas rule, Southwestern Electric Power Company (SWEPCO or Company) is required to provide an IRP at least once every three years. SWEPCO's 2015 IRP has been developed using the Company's current 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 and renewable generation resources; and
- Demand-side program costs and analysis.

To meet its customers' future energy requirements, SWEPCO has carefully considered the continued operation and the ongoing level of investment in its existing fleet of fossil-fueled assets including its efficient base-load coal plants, its newer combined cycle and combustion turbine plants, and its older gas-steam plants. Another consideration in this 2015 IRP is the increased adoption of distributed rooftop solar resources by SWEPCO's customers. While SWEPCO does not have control over how and the extent this resource is deployed, it recognizes that distributed solar will be a contributor to meeting SWEPCO's capacity and energy requirements. Keeping these considerations in mind, SWEPCO has developed a plan to provide adequate supply and demand resources to meet its peak load obligations for the next twenty years. The key components of this plan are for SWEPCO to:

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- Invest in environmental control equipment to make the Welsh Units 1 & 3 and Flint Creek solid-fuel units compliant under known or anticipated environmental regulation; Continue operation of recently installed environmental control equipment at solid-fueled Pirkey and Dolet Hills.
- Add 435MW of Natural Gas Combined Cycle generation in 2026;
- Begin the process of retiring approximately 700MW of older gas-steam units;
- Retire the solid-fuel 528MW Welsh Unit 2 in 2016;
- Acquire an optimal mix of supply-side resources in the form of additional wind resources, utility-scale solar, and natural gas-fired generation resources;
- Implement demand-side resources in the form of additional energy efficiency programs;
- Recognize that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar

Environmental Compliance Issues

This 2015 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 regulation of 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 sources which would take effect beginning in 2022. Under the Company's 'Base' pricing scenario, the cost of such CO_2 emissions is expected to stay within the $15-$20/metric ton (tonne) range over the long-term analysis period.

Arkansas IRP Stakeholder Process

The Arkansas stakeholder process is designed to allow key IRP stakeholders an opportunity to gain an understanding of SWEPCO's IRP process and key assumptions, and then prepare a "Stakeholder Report". SWEPCO can then address any issues or comments from the Stakeholder Report within the final SWEPCO IRP for Arkansas. The Stakeholder Committee is to be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the SWEPCO

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service area. The stakeholder meeting was held March 3, 2015 in Texarkana, Arkansas during which a "Draft" IRP was reviewed with the stakeholders. The stakeholders then prepared a report addressing key issues or concerns that they would like addressed in the IRP. The stakeholder report with SWEPCO's responses is included in Exhibit A of the Appendix.

Louisiana IRP Stakeholder Process

In Louisiana, various stakeholders, including Louisiana Commission staff, were presented IRP assumptions in early 2014 and provided useful feedback which has been considered and incorporated in the analysis assumptions, where warranted. For example, comments regarding renewable energy costs were used in developing pricing for future tranches of wind resources. Also, SWEPCO addressed stakeholder comments pertaining to energy efficiency by providing transparency to its assumptions and modeling energy efficiency programs on the same basis as supply resources.

Summary of SWEPCO Resource Plan

SWEPCO's total internal energy requirements are forecasted to decrease at a Compound Average Growth Rate (CAGR) of 0.3% over the IRP planning period (through 2034). Likewise, SWEPCO is expected to experience a decrease in peak demand of 0.3% per year over the planning period. The primary reductions in internal energy and peak demand are tied to the expiration of certain wholesale contracts. The net impact of load growth, plant retirements and plant deratings leaves SWEPCO with a "going-in" (i.e. *before* resource additions) capacity deficit as shown in Figure ES - 1. As can be seen from Figure ES-1, in 2022 SWEPCO is anticipated to experience a capacity shortfall, which is evident from the gap between stacked bar of available resources and the black line representing SWEPCO's load demand plus reserve requirements.

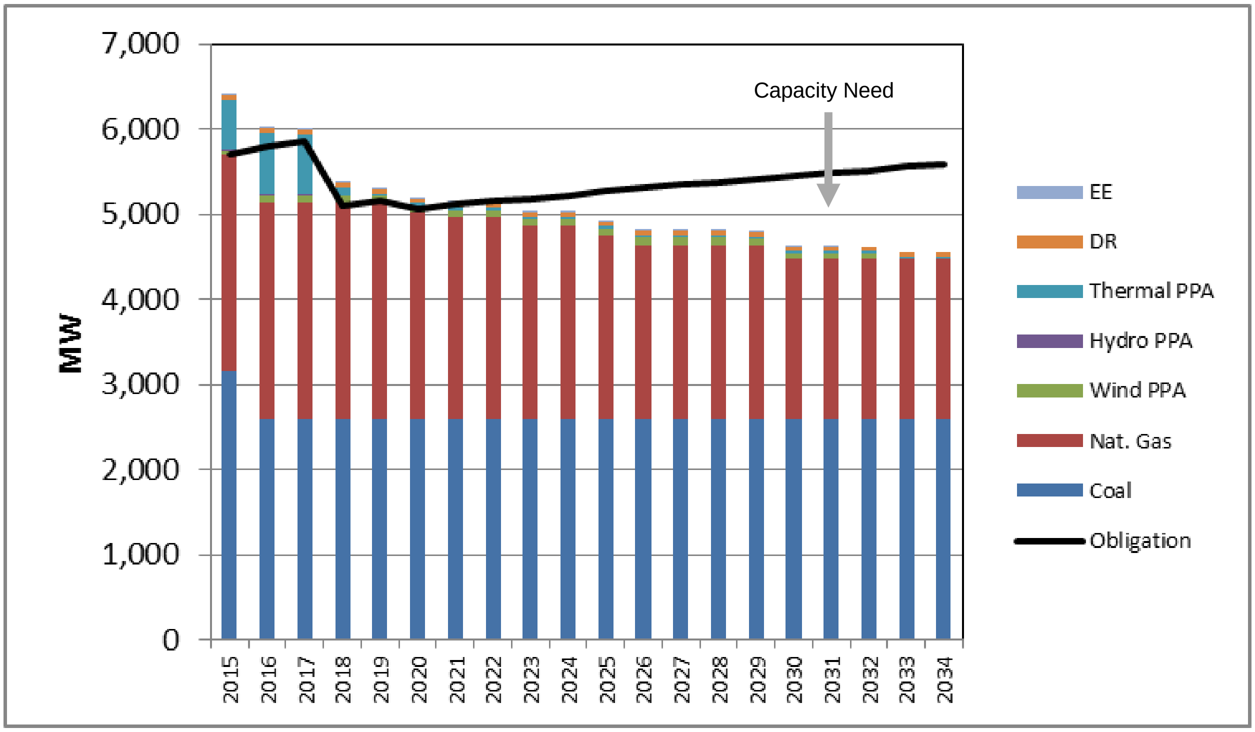

Figure ES - 1. SWEPCO 2015 "Going-In" SPP Capacity Position

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 2034), the *Plexos*® modeling was performed through the year 2045 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

SWEPCO used the results of the modeling to develop a Preferred Portfolio.

SWEPCO's Preferred Plan Portfolio

- Maintains SWEPCO's solid fuel units at Welsh Units 1 & 3, Flint Creek and Pirkey, in addition to its share of energy and capacity from the non-SWEPCO operated Dolet Hills unit
- Utilizes 390MW (nameplate) of Wind energy from existing PPA's acquired in 2012 and 2013
- Continues operation of SWEPCO's newest plant additions – the environmentally-compliant, solid-fueled Turk unit, as well as the Stall natural gas combined-cycle and Mattison natural gas combustion turbine facilities

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- Retires Welsh Unit 2 in 2016
- Retires 700MW of older gas-steam units through the end of the planning period, beginning in 2020
- Adds 435MW of Natural Gas Combined Cycle generation in 2026
- Adds 1,200MW (nameplate) of wind energy by the end of the planning period, beginning in 2017
- Implements customer and grid energy efficiency, including Volt VAR Optimization (VVO) programs so as to reduce energy requirements by 1,334GWh and capacity requirements by 221MW in 2034
- Adds 850MW (nameplate) of utility-scale solar energy by the end of the planning period, beginning in 2017
- Recognizes additional distributed solar capacity will be added by SWEPCO's customers, starting in 2016, and ramping up to 53MW (nameplate) by 2034

To arrive at the Preferred Portfolio composition, SWEPCO developed *Plexos*®-derived, "optimum" portfolios for nine separate scenarios: five commodity pricing scenarios, a high and low load forecast scenario, and two unique sensitivity scenarios. The Preferred Portfolio is intended to provide the lowest reasonable cost of incrementally-required (peak) demand and energy to SWEPCO's customers which would meet environmental and resource adequacy constraints. The following Table ES- 1 provides a summary of the Preferred Portfolio.

Table ES- 1. Preferred Plan Cumulative Capacity Resource Additions throughout Planning Period

Southwestern Electric Power Company
2015 Integrated Resource Plan
Cumulative Resource Changes

Preferred Portfolio

(LA) IRP Period	SPP Planning Year[A]	(1) (Cumulative) RETIREMENTS: Coal & Gas-Steam	(2) (Cumulative) Firm Capacity Resource ADDITIONS: New-Build (Frame) CTs	(3) New-Build (Flex) CTs	(4) New-Build NGCC	(5) (ST) PPA	(6) Energy Efficiency (EE): 'Embedded' Federal EE Regulations[B]	(7) Energy Efficiency (EE): Existing DSM Programs[C]	(8) Energy Efficiency (EE): New	(9) VVO	(10) DR: Existing DSM Programs[C]	(11) Wind[D]	(12) Solar[E]: Utility-Scale	(13) Solar[E]: Distributed	(14)=(1) to (13), ex(6) (Cumul.) NET 'RESOURCE' CHANGE[F]	(15) Resulting SWEPCO Reserves: Above SPP Minimum Rqrmnt[G]	(16) Resulting SWEPCO Reserves: Margin %	(17) (Cumulative) 'NAMEPLATE' ADDITIONS: Wind[D]	(18) Solar[E]: Utility-Scale	(19) Solar[E]: Distributed
Yr.		MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2015	(61) [F]	-	-	-	-	184	5	-	-	55	-	-	1.0	(0)	709	28.0%	-	-	9.7
2	2016	(589) [G]	-	-	-	126	198	9	-	-	55	-	-	1.1	(398)	234	18.3%	-	-	11.0
3	2017	(589)	-	-	-	86	212	12	-	26	55	30	21	1.3	(358)	234	18.2%	200	50	12.5
4	2018	(589)	-	-	-	66	225	12	22	26	55	30	21	1.4	(356)	384	22.3%	200	50	14.0
5	2019	(589)	-	-	-	-	237	12	43	26	55	30	42	1.6	(380)	291	20.1%	200	100	15.5
6	2020	(699) [H]	-	-	-	-	247	12	49	38	55	30	63	1.8	(450)	308	20.6%	200	150	17.5
7	2021	(699)	-	-	-	-	261	12	54	51	55	30	84	1.9	(410)	229	18.8%	200	198	19.0
8	2022	(699)	-	-	-	-	273	12	64	63	55	30	105	2.1	(368)	225	18.6%	200	248	21.0
9	2023	(808) [I]	-	-	-	-	284	12	75	73	55	50	126	2.3	(415)	147	16.9%	300	297	23.0
10	2024	(808)	-	-	-	-	297	12	91	83	55	70	147	2.5	(347)	165	17.3%	400	347	25.0
11	2025	(916) [J]	-	-	-	-	308	12	113	92	55	90	168	2.8	(384)	63	15.0%	500	396	27.5
12	2026	(1,026) [K]	-	-	435	-	317	12	116	92	55	110	189	3.0	(14)	381	21.9%	600	446	29.5
13	2027	(1,026)	-	-	435	-	326	12	118	92	55	130	210	3.2	30	369	21.6%	700	495	32.0
14	2028	(1,026)	-	-	435	-	335	12	121	92	55	150	231	3.5	74	376	21.7%	800	545	34.5
15	2029	(1,026)	-	-	435	-	346	12	122	92	55	170	252	3.7	115	367	21.4%	900	594	37.0
16	2030	(1,194) [L]	-	-	435	-	356	12	123	92	55	190	273	4.0	(10)	192	17.7%	1,000	644	40.0
17	2031	(1,194)	-	-	435	-	366	12	124	92	55	210	294	4.3	32	191	17.6%	1,100	693	42.5
18	2032	(1,194)	-	-	435	-	372	12	125	92	55	230	315	4.6	74	201	17.8%	1,200	743	46.0
19	2033	(1,194)	-	-	435	-	381	12	127	92	55	230	336	4.9	98	100	15.7%	1,200	792	49.0
20	2034	(1,194)	-	-	435	-	389	12	129	92	55	230	357	5.3	121	96	15.6%	1,200	842	52.5
							356	141											894	
							'TOTAL' Energy Efficiency (2015-2034)												'TOTAL' Solar (2015-2034)	

[A] SPP Planning Year is effective 6/1/XXXX.

[B] Represents estimated energy efficiency levels already 'embedded' into SWEPCO's long-term load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standareds (EPAct 2005; 2007 EISA, 2009 ARRA).

[C] Represents estimated contribution from current/known SWEPCO DSM-EE and Demand Response (interruptible, DLC/ELM) program activity also reflected in the Company's long-term load and demand forecast *(from 'Going-in' SWEPCO CDR)*.

[D] Due to the intermittency of wind resources, only 20% for Tranche A and 10% Tranche B of wind resource 'nameplate' MW rating are included for capacity resource determination purposes.

[E] Due to the intermittency of solar resources, Utility Solar receives 42.4% and Distributed Solar receives 10% of 'nameplate' MW rating are included for capacity resource determination purposes.

RETIREMENTS:
[F] Lieberman 1 retirement & Knox Lee 4 50% derate assumed 12/2014.
[G] Welsh Unit 2 retirement effective approximately June 1, 2016.
[H] Lieberman 2, Lone Star & Knox Lee 4 retirement assumed 12/2019.
[I] Lieberman 3 retirement assumed 12/2022.
[J] Lieberman 4 retirement assumed 12/2024.
[K] Arsenal Hill 5 retirement assumed 12/2025.
[L] Wilkes 1 retirement assumed 12/2029.

[F] *Excludes* cumulative annual changes in SWEPCO SPP 'Load Responsibility' (coincident peak demand) and 3rd-party resources... which also impacts relative capacity resource position.

[G] SPP minimum criterion @ 13.6% as a function of peak demand.

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Specific SWEPCO capacity and energy production changes over the 20-year planning period associated with the Preferred Portfolio are shown in Figure ES - 2 through Figure ES - 5, below.

These figures indicate that the Preferred Plan's portfolio would reduce SWEPCO's reliance on solid fuel-based and natural gas generation as part of its portfolio of resources, and increase reliance on demand-side and renewable resources, thereby enhancing fuel diversity. Specifically, over the 20-year planning horizon the Company's capacity mix attributable to solid fuel-fired assets would decline from 46% to 35%, and natural gas assets decline from 37% to 32%. Renewables (wind, utility and distributed solar, based on nameplate ratings) increase from 7% to 29%, and, similarly, demand-side and energy-efficiency measures increase from 1% to 4% over the planning period. The addition of carbon-free energy resources serve to hedge SWEPCO's exposure to natural gas price and Southwest Power Pool (SPP) energy market volatility, while producing a lower cost solution than one that includes greater reliance on new gas assets. At times renewable energy was added to the Preferred Plan portfolio when there was no need for capacity. In these instances the added resources had a positive economic effect on the overall plan due to the ability to sell low-cost energy to the SPP market.

While over the planning period SWEPCO is adding a significant amount of cost effective renewable generation, approximately 2,100MWs (nameplate) or 600MWs of firm capacity for planning purposes, these investments in intermittent renewable generating resources will be made incrementally and continually monitored and evaluated to determine if incremental additions will impact overall reliability within the SPP Regional Transmission Organization (RTO). The proposed amount of intermittent renewable resources within SWEPCO's Preferred Plan are in alignment with current SPP planning criteria. Reliability concerns due to the intermittent nature of renewable resources are mitigated by way of the Company's overall reserve margin. The reserve margin is designed to account for the unavailability of resources at times of peak demand. Should a substantial portion of renewable energy become unavailable SWEPCO would have adequate resources to meet customer needs.

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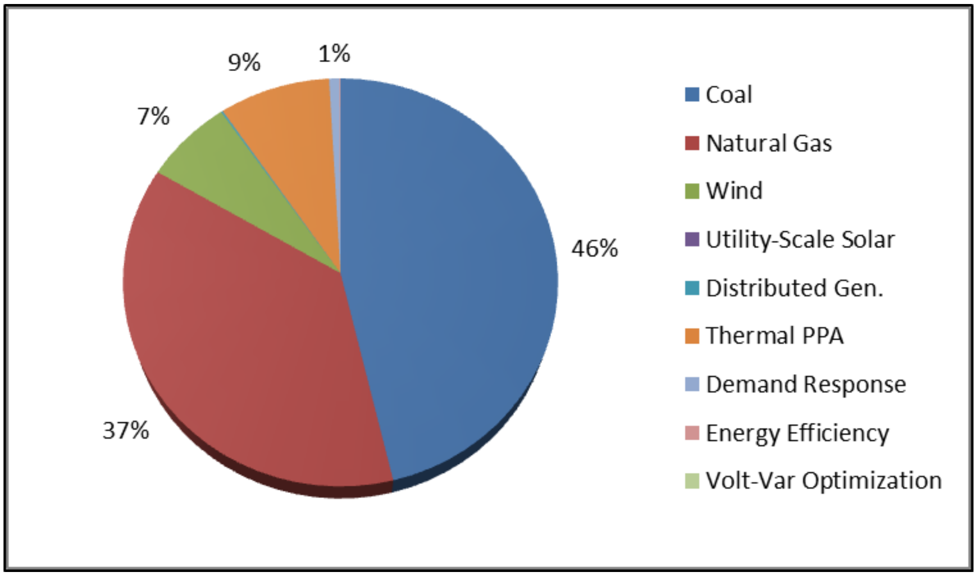

Figure ES - 2. 2015 SWEPCO Nameplate Capacity Mix

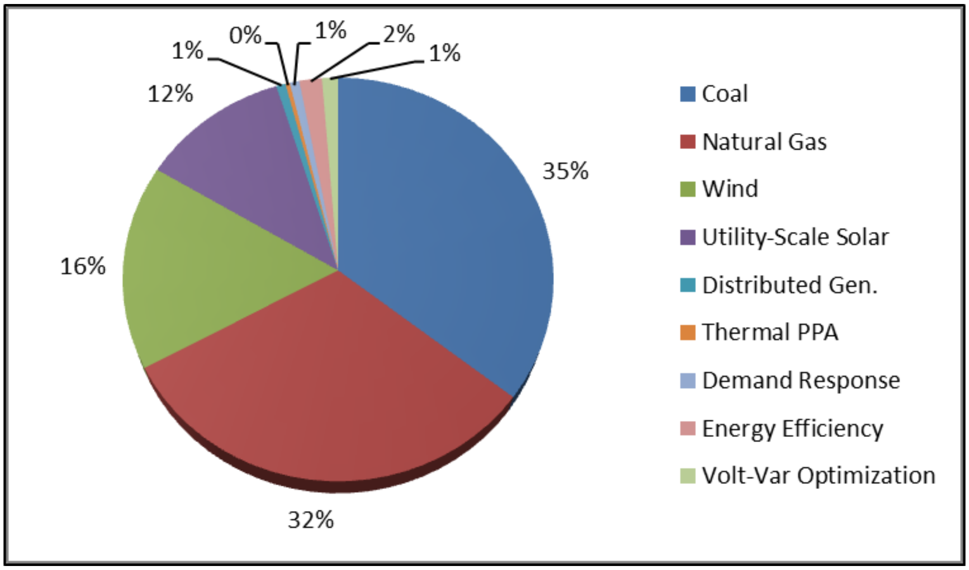

Figure ES - 3. 2034 SWEPCO Nameplate Capacity Mix

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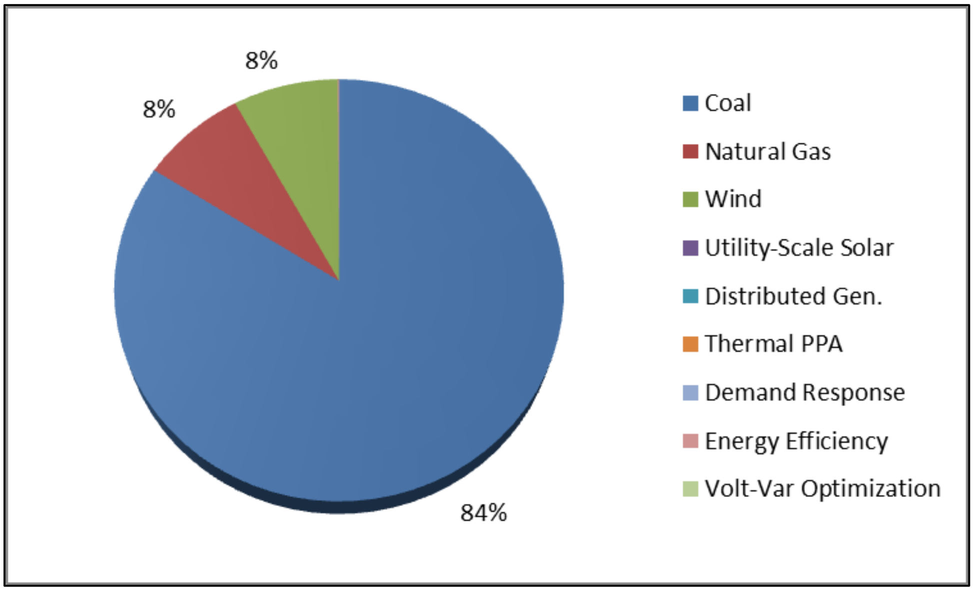

Figure ES - 4. 2015 SWEPCO Energy Mix

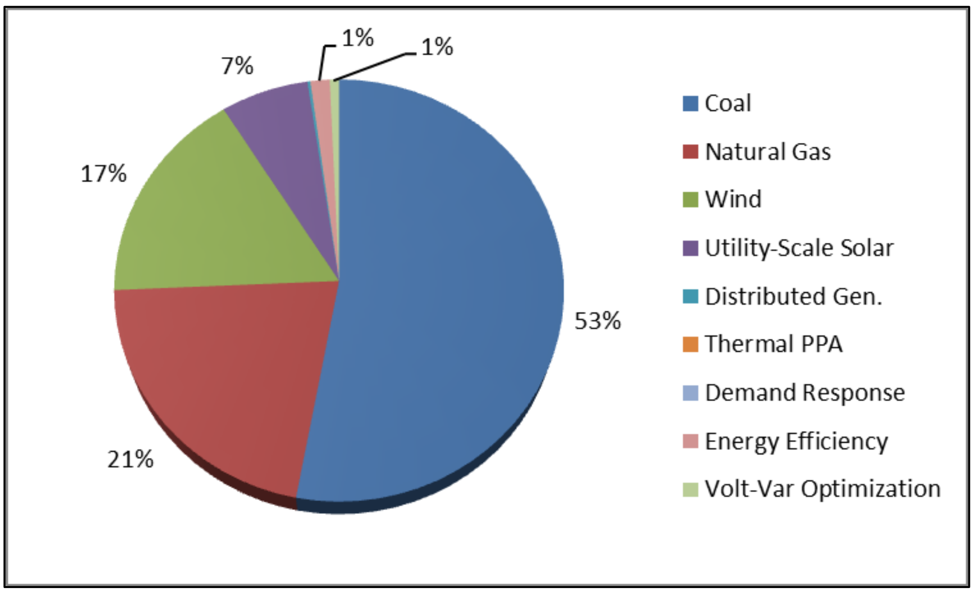

Figure ES - 5. 2034 SWEPCO Energy Mix

Figure ES - 6 illustrates SWEPCO's annual capacity position with respect to the Company's load obligation, which factors in SPP's 12% capacity margin requirement. The capacity contribution from renewable resources is fairly modest; however, those resources provide a significant volume of energy, specifically attributed to wind resources. SWEPCO's model selected those wind resources because they add more value

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(lowered SWEPCO's cost) than alternative resources.

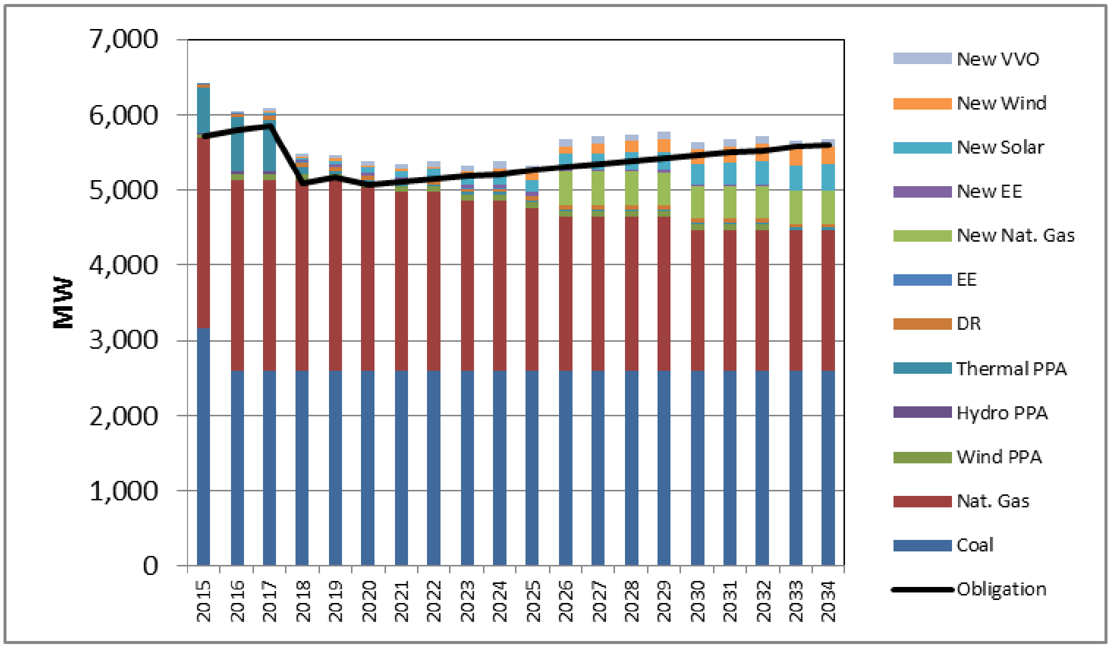

Figure ES - 6. SWEPCO Annual SPP Capacity Position throughout Planning Period (2015-2045)

The Clean Power Plan

On August 3, 2015, the EPA finalized a rule referred to as the Clean Power Plan (CPP), which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the Clean Air Act.

SWEPCO is currently in the process of reviewing these rulemakings and must undertake significant new analyses to understand the impacts of the Final CPP. SWEPCO, AEP, and other stakeholders will be working in the coming months and years to better understand the requirements of the Final CPP, and to work with state agencies on the state's response to the Final CPP.

SWEPCO Five Year Action Plan

Steps to be taken by SWEPCO in the near future to implement this plan include:

1. Begin (or continue) the planning and regulatory actions necessary to implement economic Energy Efficiency (EE) programs in each state SWEPCO serves.
    a. Arkansas – EE programs have been in place in Arkansas since 2007. For program year 2014, SWEPCO achieved 141% of its

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goal. SWEPCO has steadily grown its portfolio in Arkansas to a proposed budget of $10.3 million for 2016 with a proposed savings goal of 23,957,863 kWh. SWEPCO will file a new 3 year portfolio plan June 1, 2016.

b. Louisiana – The Quick Start Phase of energy efficiency programs began in Louisiana November 1, 2014 and is scheduled to continue through June 30, 2017. SWEPCO is in the process of completing Program Year (PY) 1 which will end October 31, 2015 with results pending. As of mid-September, we are currently at 104% of PY1 kWh goal with approximately 10% of incentive budget remaining. (PY 1 and PY2 budgets are $1.9 million each, with PY3 budget set at $1.6 million.

c. Texas – EE programs have been in place in Texas since 2000. For Program Year 2014, SWEPCO achieved 225% of its demand reduction goal and 178% of its energy goal. The proposed savings goals for Program Year 2015 are 9,282kW and 11,815,878kWh to be achieved with a budget of $3,452,748. A two-year plan is filed on May 1 of each year. This plan can be altered from the previous filing without prior commission approval.

d. The Preferred Plan illustrates that incremental EE and Volt VAR Optimization (VVO) are economical resource options. The measures selected and the amounts of VVO and EE selected will be reviewed with the state EE Managers for future inclusion into the state specific EE recommended plans/programs.

2. Conduct a Request for Proposal(s) (RFP) to explore potential near-term, tax-advantaged opportunities to add up to 200MW wind and 50MW of solar energy (via Renewable Energy Purchase Agreements (REPAs)). The modeling indicated adding these resources in this timeframe should optimize production energy costs under the assumed parameters.

Note:

- The ultimate execution and contract award of any additional renewable REPAs would be conditioned upon the prior receipt of such regulatory approvals.

- SWEPCO's ability to take advantage of the wind and solar tax incentives is complicated by the timing of the issuance of the final IRP, existing regulatory proceedings, and the regulatory requirements SWEPCO must navigate while operating in three jurisdictions. Therefore, it would be imperative to adhere to the following events to take advantage of the tax incentives:
  a. Assuming the Federal Production Tax Credits (PTCs)/Investment Tax Credits (ITCs) for wind/solar are not extended (*i.e.*, will expire by the end of 2016), an expedited review and approval process consisting of the following would need to take place:
     i. Develop and issue RFPs for PTC/ITC eligible wind/solar projects.
     ii. Evaluate RFP responses including associated transmission service and select winning projects.
     iii. Seek and obtain regulatory approval for Dec 2016 commercial operation date.
- *If*, however, federal tax incentives for wind and/or solar <u>are</u> ultimately extended by a year (or more), it would then be conceivable that this implementation plan and attendant approval requirements could be relaxed.

3. Continue to evaluate gas-steam unit ongoing operating and maintenance costs, in addition to equipment liability issues to determine most likely candidates for near term retirements.
   a. This is an ongoing activity based on observed unit performance and economic viability.
4. Complete solid fuel plant Mercury and Air Toxic Standards (MATS) and Regional Haze-required retrofit projects already underway.
   a. Pirkey Station: Install Calcium Bromide injection system (Project Complete)
   b. Welsh Units 1& 3: Complete Activated Carbon Injection (ACI) , Fabric Filter Baghouse, and Chimney installations (2016)
   c. Flint Creek: Complete Dry Fluidized Gas Desulfurization and ACI installations (2016)

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5. Continue to evaluate the Final EPA CPP guidelines and provide technical input to state regulatory bodies as to cost effective compliance options: ongoing activity.

Conclusion

This IRP provides for reliable electric utility service, at reasonable cost, through a combination of natural gas and renewable supply-side resources and demand-side programs and serves as a roadmap for SWEPCO to provide adequate capacity resources to serve its customers' peak demand and required SPP reserve margin needs throughout the forecast period.

Moreover, this IRP also recognizes SWEPCO's energy position prospectively. The highlighted Preferred Portfolio offers incremental resources that will provide—in addition to the needed SPP installed capacity to achieve mandatory SPP (summer) peak demand requirements—additional energy so as to protect the Company's customers from being overly exposed to SPP energy markets that could be influenced by many external factors, including the impact of carbon, going-forward.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. The resource planning process is becoming increasingly complex when considering pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and EE advancements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. Lastly, the ability to invest in capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on SWEPCO's customers are a primary consideration in this report.

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1.0 Introduction

1.1 Overview

This report presents the Integrated Resource Plan (IRP) for Southwestern Electric Power Company (SWEPCO, or "Company") including descriptions of assumptions, study parameters, and methodologies. The results incorporate the integration of supply-side resources and demand-side management (DSM) activity.

*The goal of the IRP process is to identify the **amount**, **timing** and **type** of resources required to ensure a reliable supply of power 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 the SPP, capacity resource planning is critical to SWEPCO due to its impact on:

- **Determining Capital Expenditure Requirements**—which represents one of the basic elements of the Company's long-term business plan.
- **Rate Case Planning**—operating in three state retail jurisdictions as well as having wholesale contracts which fall under the auspices of the Federal Energy Regulatory Commission (FERC), this planning process is a critical component of recovery filings that will reflect input based on a prudent planning process.
- **Integration with other Strategic Business Initiatives**—generation/capacity resource planning is naturally integrated with the Company's current and anticipated environmental compliance, transmission planning, and other corporate planning initiatives.

1.2 IRP Process

This IRP briefly covers the processes and assumptions required to develop the recommended Plan for SWEPCO. The IRP process consists of 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 peak load and energy which serves as the underpinning of the plan.
- Identify and evaluate demand-side options such as energy efficiency measures, demand response and distributed generation.
- Identify current supply resources, including projected changes to those resources (*e.g.*, de-rates or retirements), and transmission system integration issues.

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- Identify and evaluate supply-side resource options.
- Describe the analysis and assumptions that will be used to develop the plan such as Regional Transmission Organization (RTO) reserve margin criteria, and fundamental modeling parameters.
- Solicit input from stakeholders regarding assumptions and analyses to be performed.
- Perform resource modeling and use the results to develop portfolios.
- Perform sensitivity analyses and risk analysis and use the results to determine the Company's Preferred Plan.
- Develop an action plan to be used in implementing the IRP during the first five years of the planning horizon.
- Present the draft findings and recommendations to stakeholders, receive and consider their input, then develop the final preferred plan, and near term action plan.

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 37,600 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 4.18 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 527,000 retail customers in those states; including over 229,000 and 115,000 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 (2015) actual SWEPCO summer and winter peak demands were significant at 5,149MW and 4,708MW, occurring on August 10th and January 8th, respectively.

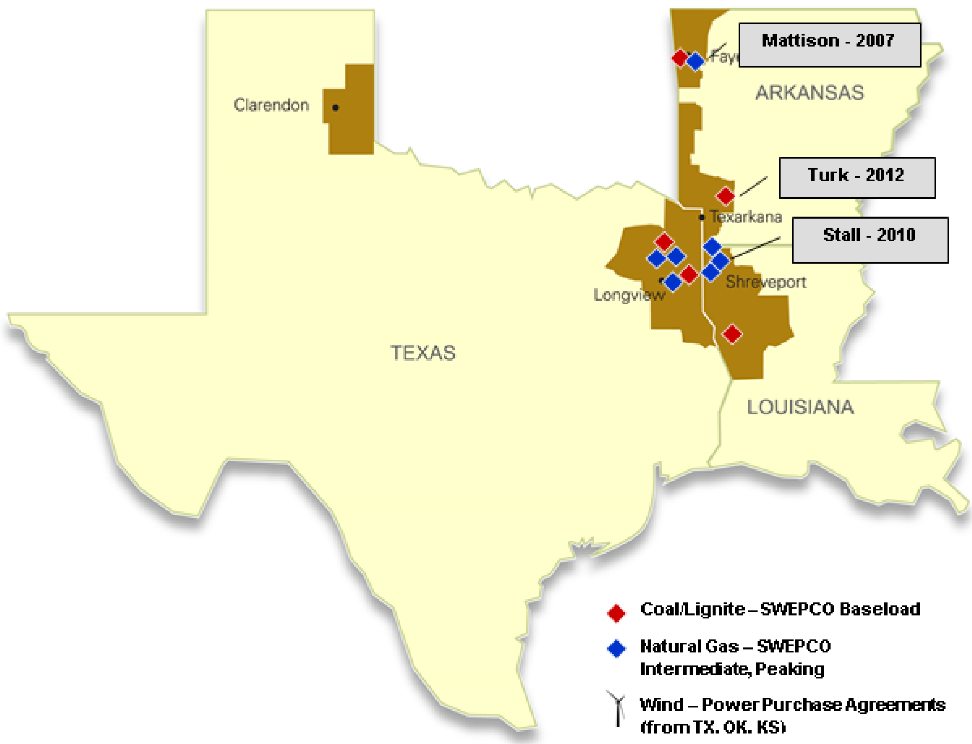

Figure 1. SWEPCO Service Territory

This IRP is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore this plan is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light 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.

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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. The load forecasting process is ongoing; however, on an annual basis the load forecasting group produces a peak demand and energy usage forecast for each operating company. This process typically begins as actual values are received and reviewed and adjusted. The annual forecast is generally available in June of each year.

The fundamental commodity forecasting process is ongoing as well and is continually monitored relative to ongoing activities that could potentially impact the existing commodity forecast values. Typically, the fundamental commodity forecast is updated when material changes are observed or expected. The most recent commodity forecast was released in June of 2015.

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

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

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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 2015.[1] 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 (2016-2035)[2], SWEPCO's service territory is expected to see population and non-farm employment to experience similar growth of 0.6% and 0.7% per year, respectively. Not surprisingly, SWEPCO is projected to see customer count growth at a similar rate of 0.5% per year. Over the same forecast period, SWEPCO's retail sales are projected to grow at 0.7% per year with stronger growth expected from the industrial class (+0.9% per year) while the residential class experiences an increase (0.5% per year) over the forecast horizon. The projected change in SWEPCO's internal energy over the next 20 years is for requirements to drop by 0.3% per year. Finally, SWEPCO's peak demand is expected to decline at an average rate of 0.2% per year through 2035. The reductions in internal energy and peak demand are tied to the expiration of certain wholesale contracts.

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 January 2015. Moody's Analytics projects moderate growth in the U.S. economy during the 2016-2035 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 2.0% per year.

[1]The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.
[2] 20 year forecast periods begin with the first full forecast year, 2016

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Industrial output, as measured by the Federal Reserve Board's (FRBs) index of industrial production, is expected to grow at 1.3% per year during the same period. Moody's projected employment growth of 0.7% per year during the forecast period and real regional income per-capita annual growth of 1.4% 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 deletions 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,

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

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

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

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

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

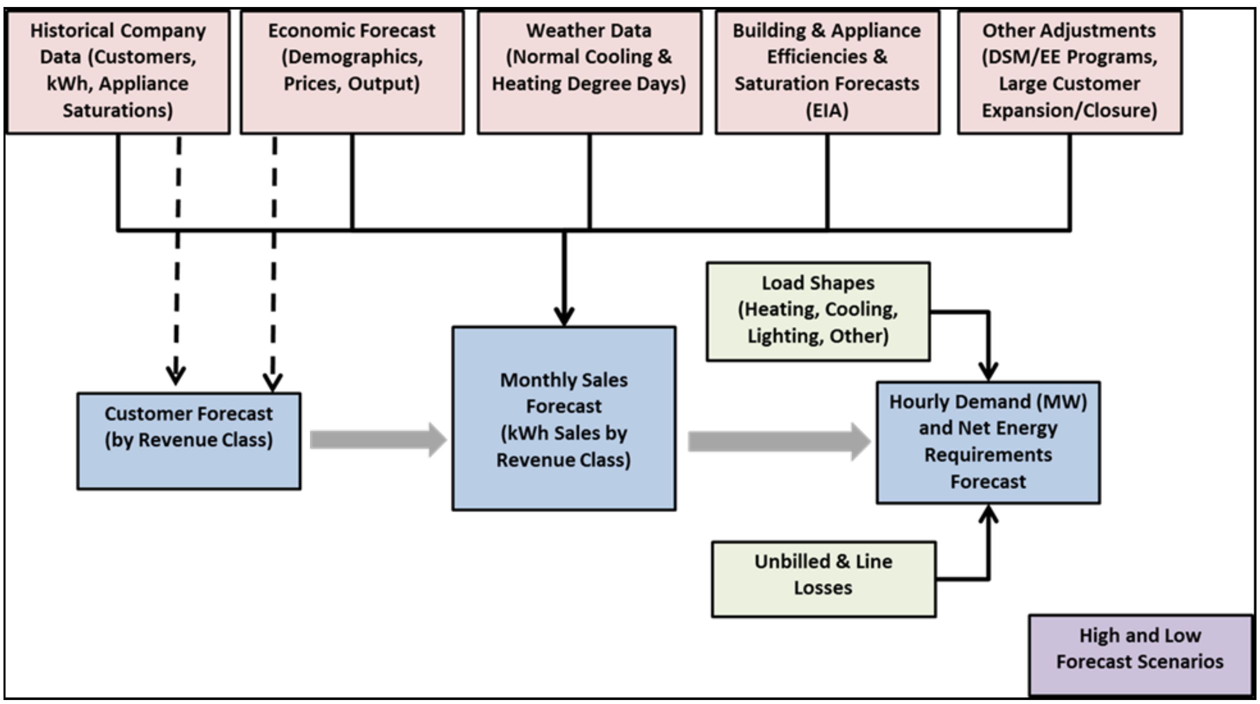

Figure 2. SWEPCO Internal Energy Requirements and Peak Demand Forecasting Method

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

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

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

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

2.4.2 Customer Forecast Models

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

The long-term residential customer forecasting models are also monthly but extend for 30 years. The explanatory economic and demographic variables include mortgage interest rates, real personal income, population and households are 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

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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 2005 through January 2015.

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 19 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 19 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. SWEPCO wholesale requirements customers include the cities of Bentonville, Hope and Prescott in Arkansas, City of Minden in Louisiana, East Texas Electric Cooperative, Northeast Texas Electric Cooperative, Rayburn County Electric Coop, and Tex-La Electric Reliability Coop. These 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 annual 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

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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 1995-2014 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 East North Central Census region's sectorial prices, with the forecast being obtained from EIA's "2015 Annual Energy Outlook." The natural gas price model is based upon 1980-2014 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.

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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 2015. 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 2014 Annual Energy Outlook. Billing days and electricity prices are developed internally. The commercial output measure is real commercial gross regional product 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 2005 through January 2015. As with the residential SAE model, the effects of EPAct, EISA, ARRA and

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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 they 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 2015.

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 three wholesale contracts being terminated by 2018 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 2015 and 2016 are taken from the short-term process. Forecast values for 2017 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 2016 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

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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 B.

2.5.1 Load Forecast

Table B-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 2005-2014, 2015 data are six months actual and six months forecast and on a forecast basis for the years 2016-2035. 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 B-2.

2.5.2 Peak Demand and Load Factor

Table B-3 provides SWEPCO’s seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2005-2014, 2015 data are six months actual and six months forecast and on a forecast basis for the year 2016-2035. The table also shows annual growth rates for both the historical and forecast periods.

2.5.3 Monthly Data

Table B-4 provides historical monthly sales data for SWEPCO by customer class (residential, commercial, industrial, other retail and wholesale) for the period January 2004 through June 2015. Table B-5 provides forecast SWEPCO monthly sales data by customer class for July 2015 through December 2035.

2.5.4 Prior Load Forecast Evaluation

Table B-6 presents a comparison of SWEPCO's energy sales and peak demand forecasts in the 2012 IRP with the actual and weather normal data for 2012, 2013 and 2014. The primary reason for the forecast differences is that the economy did not rebound as quickly as was expected when the load forecast used in the previous (2012) IRP was developed. On a national level, real GDP was expected to grow at 4.3%, 3.9% and 3.1% in 2012, 2013 and 2014, respectively. Meanwhile, real GDP grew at 2.3%, 2.2% and 2.4% in 2012, 2013 and 2014, respectively. For the SWEPCO service area real personal income per capita was projected to grow 2.6%, 2.7% and 1.3% in 2012, 2013 and 2014, respectively. However, service area real personal income actually grew at 3.1% -0.1% and 1.6% in 2012, 2013 and 2014, respectively. As the sluggish economy was seen as the primary reason for the forecast differences, there were no significant changes to the forecast model structures. But, there is a constant monitoring of the modelling process to seek improvement in forecast accuracies. Table B-7 provides the impact of demand-side management on the 2012 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 B-8 provides significant economic and demographic variables incorporated in the various residential long-term energy sales models for the Company. Table B-9 provides

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significant economic variables utilized in the various SWEPCO jurisdictional commercial energy sales models. Table B-10 presents significant economic variables that the Company employed in its jurisdictional industrial models. Table B-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 3 presents SWEPCO's historical and forecasted residential and commercial usage per customer between 1991 and 2020. During the first decade shown (1991-2000), Residential usage per customer grew at an average rate of 1.4% 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 1.0% per year. In the last decade shown (2011-2020) Residential usage is projected to decline at a rate of 0.1% per year while the Commercial usage is falls by an average of 0.7% per year.

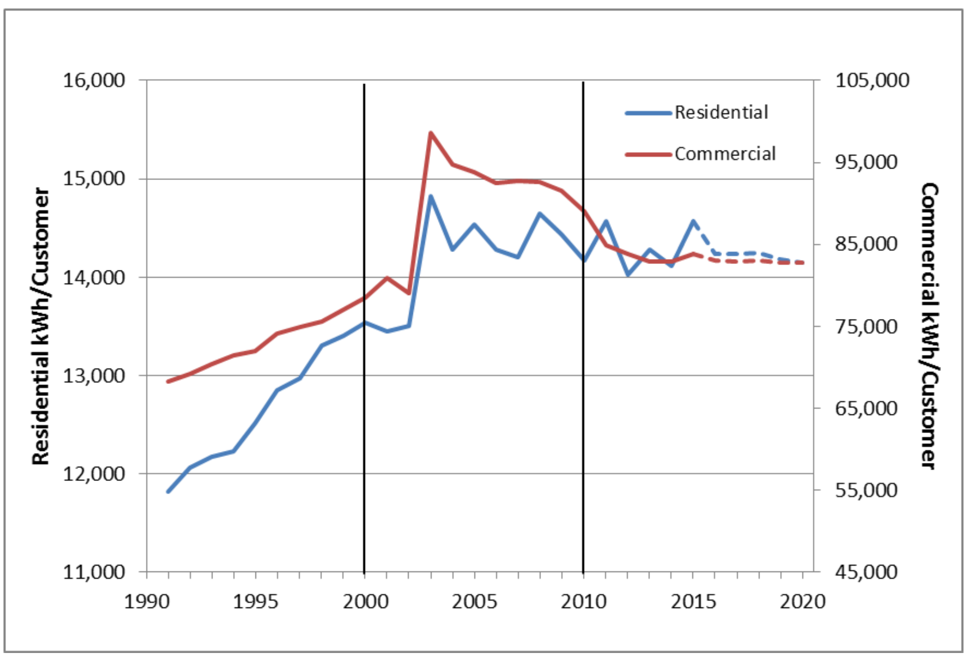

Figure 3. SWEPCO Normalized Use per Customer (kWh)

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 4 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 13.1 in 2010 to over 14.8 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units as well.

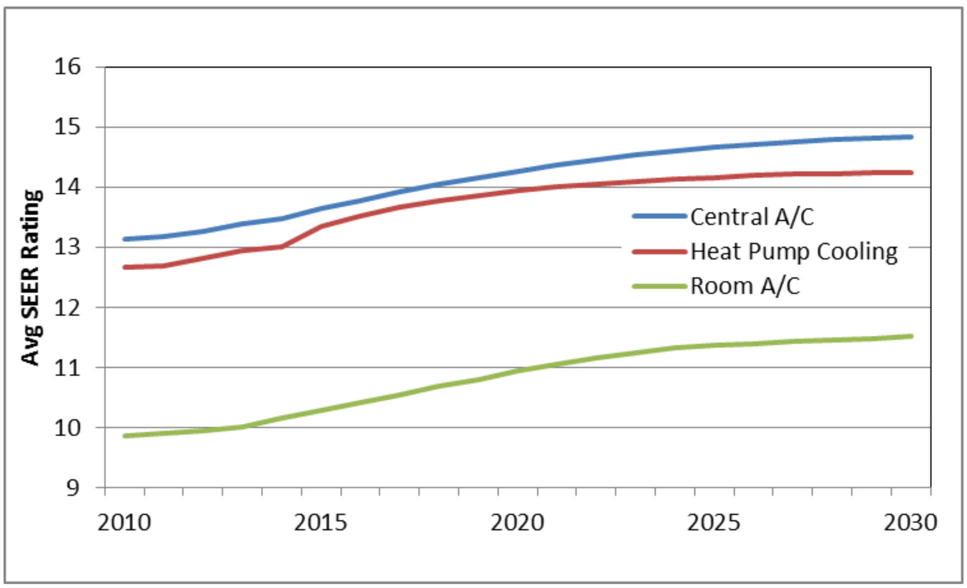

Figure 4. Projected Changes in Cooling Efficiencies, 2010-2030

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

Table B-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.

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2.6.3 Losses and Unaccounted for Energy

Actual and forecast losses and unaccounted for energy are provided in Table B-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 26 customers with interruptible provisions in their contracts. The aggregate on-peak capacity available for interruptions is 53MW. 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 B-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 2015 were typically taken from the short-term process. Forecast values for 2016 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 the end of 2016 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 5 illustrates a hypothetical example of the blending process (details of this illustration are shown in Table B-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.

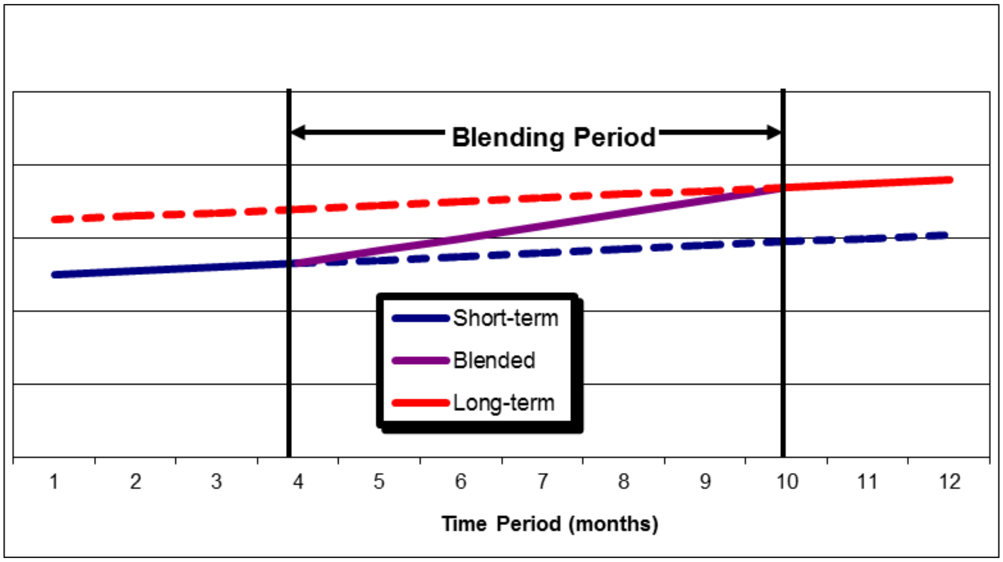

Figure 5. 2016 Load Forecast Blending Illustration

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 supplying them 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 three wholesale customers with "full requirements" load contracts that will expire by 2018 and one such customer whose

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contract expires by 2020. The load for these wholesale customers has been removed from the load forecast at the appropriate dates. 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 compact discs (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 exact quantification of outcomes, but the reality is if the all possible outcomes were known with a degree of certainty, then it 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 2015 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.

2.8.1 Low Load Sensitivity Case

The Low Load forecast reflects the impact of low economic growth for the region and consistent with the low economic growth presented by EIA.

The Low Load forecast projects firm peak load growth to average -0.7% per year on a compound basis. Total energy growth is also projected to average about -0.8% per year. The load factor is unchanged from the Base Case at about 56% to 57%. The low forecast for energy is 10.4% below the base forecast in 2035.

2.8.2 High Load Sensitivity Case

The High Load forecast represents a scenario of more sustained growth for the residential, commercial and industrial customer classes. As with the Low Load Case Load Forecast the high economic growth scenario is consistent with EIA high growth in its economic scenario.

The High Load forecast projects firm peak load growth to average 0.3% per year. Energy growth is also projected to average 0.2 % per year with a load factor of 56% to 57%. The high forecast for energy is 10.4% above the base forecast in 2035.

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3.0 Resource Evaluation

3.1 Current Resources

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

- Existing capacity resources—current levels and anticipated changes
- Anticipated changes in capability due to efficiency and/or environmental retrofit projects
- Changes resulting from decisions surrounding unit disposition evaluations
- Regional and sub-regional capacity and transmission constraints/limitations
- Load and peak demand
- Current Demand Response (DR)/EE
- 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 12 percent.[3] As a function of peak demand this converts to an equivalent "reserve margin" of 13.6 percent.[4] The reserve margin is the results of SPP's own system reliability assessment.

Exhibit C provides the Company's detailed Capacity, Demand and Reserves (CDR) report for the 20-year planning period through the year 2034 assuming no new capacity additions. In addition to identifying current projected peak demand requirements of its internal customers, this "going-in" position also identifies the MW capability of resources that are projected to be required to meet the minimum SPP reserve margin criterion. For instance, at the beginning of the first forecasted SPP planning year (2015),[5] the CDR indicates SWEPCO is expected to rely on 5,705MW of owned generating capability (seasonal ratings) to achieve this threshold. Figure 6 graphically displays each generating resource and its age, relative to the other generating resources. As depicted in the figure, the gas-steam units are the oldest units on the SWEPCO

[3] Per Section 2.1.9 of the "Southwest Power Pool Criteria" (Latest Revision: April 28, 2015).
[4] 0.12 / (1 – 0.12) = 0.136.
[5] For capacity planning/reporting purposes, SPP operates on a June (Year X) -through- May (Year X+1) fiscal year basis.

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 SPP's Day 2 market, resulting in much lower 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. With the exception of Lieberman 2, which will be retired in 2015, 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 certain of these relative older, less efficient gas-steam units will be retired over the planning period.

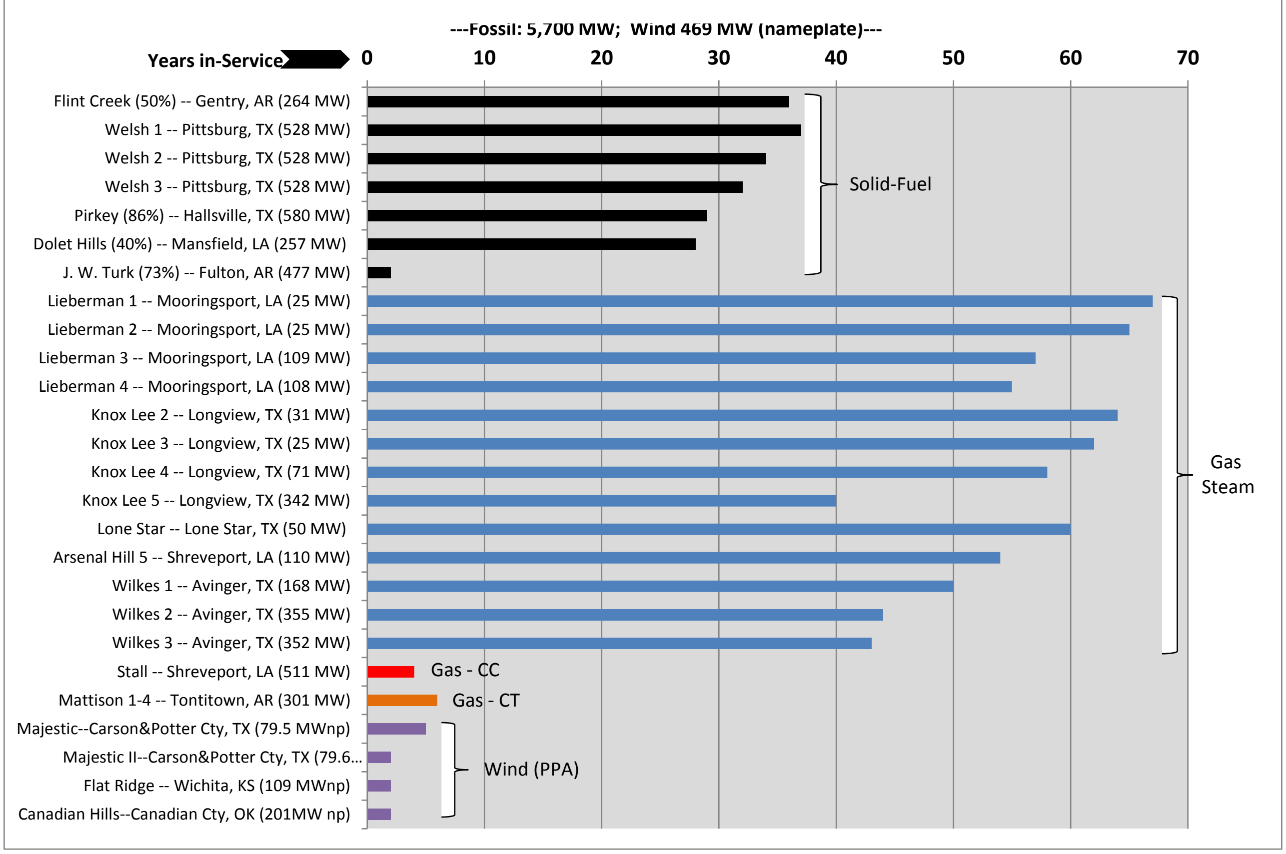

Figure 6. Current SWEPCO Fleet and Age

Table 1, below, identifies the generating resources and their key characteristics. Note, again, that the retirement dates shown for, specifically the gas units, are for planning purposes only and

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do not represent a firm commitment to retire those units on those dates. Unit retirement decisions will be made based on unit condition, ongoing unit investment requirements, and relevant market factors. In addition to Company-owned resources, SWEPCO currently utilizes several other capacity entitlements to meet the minimum SPP reserve margin requirement. As set forth in Exhibit C, SWEPCO continues to incorporate several represented purchases of capacity from non-affiliates; largely wholesale customers whom the Company has contracted to meet those customers' "full (load) requirements". Under Section 5 of the CDR, beginning in 2015, SWEPCO is expected to rely on 646MW of such "Purchases without Reserves."

Table 1. SWEPCO Owned Generation Resources

Plant	Unit	Location	Fuel Type	In Service Date	Planning Retirement Date	Winter Rating MW	Summer Rating MW
Arsenal Hill	5	Shreveport, LA	Gas Steam	1960	2025	110	110
Knox Lee	2	Longview, TX	Gas Steam	1950	2020	30	30
	3			1952	2020	26	26
	4			1956	2019	71	71
	5			1974	2039	348	342
Lieberman	1	Mooringsport. LA	Gas Steam	1947	2014	86	0
	2			1949	2019	25	25
	3			1957	2022	109	109
	4			1959	2024	108	108
Lonestar	1	Lonestar, TX	Gas Steam	1954	2019	50	50
Mattison	1	Tontitown, AR	Gas (CT)	2007	2052	78	75
	2			2007	2052	78	75
	3			2007	2052	79	76
	4			2007	2052	80	77
Wilkes	1	Avinger, TX	Gas Steam	1964	2029	171	171
	2			1970	2035	378	368
	3			1971	2036	362	354
J.L Stall	6	Shreveport, LA	Gas (CC)	2010	2045	534	511
Dolet Hills	1	Mansfield, LA	Lignite	1986	2036	257	257
Flint Creek	1	Gentry, AR	Coal	1978	2038	264	264
Pirkey	1	Hallsville, TX	Lignite	1985	2045	580	580
Turk	1	Fulton, AR	Coal	2012	2052	477	477
Welsh	1	Pittsburg, TX	Coal	1977	2037	528	528
	2			1980	2015	528	528
	3			1982	2042	528	528

3.3 Capacity Impacts of Environmental Compliance Plan

As a result of the existing and proposed environmental rules, there potentially could be significant exposures surrounding the future operations of SWEPCO's generating units. In order for SWEPCO's solid-fueled (coal and lignite) units to continue to operate in the future, they will

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be required to comply with the recently finalized Mercury Air Toxics Standards (MATS). SWEPCO's Flint Creek unit will also be required to install best available retrofit technology to comply with federal regional haze regulations

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. Therefore, the following Table 2 provides the SWEPCO unit-by-unit disposition profile for all solid-fuel and gas-steam units that were assumed for purposes of portfolio modeling.

Table 2. SWEPCO Unit Disposition Summary

Plant	Unit	Fuel Type	C.O.D. [1]	Rating MW [2]	Retire (year) or Operate	Retrofit Technology [3]
Arsenal Hill	5	Gas Steam	1960	110	2025	
Knox Lee	2	Gas Steam	1950	30	2020	See Note (4)
	3		1952	26	2020	See Note (4)
	4		1956	71	2019	See Note (4)
	5		1974	342	Operate	See Note (4)
Lieberman	1	Gas Steam	1947	0	2014	See Note (4)
	2		1949	25	2019	See Note (4)
	3		1957	109	2022	See Note (4)
	4		1959	108	2024	See Note (4)
Lonestar	1	Gas Steam	1954	50	2019	See Note (4)
Mattison	1	Gas (CT)	2007	75	Operate	
	2		2007	75	Operate	
	3		2007	76	Operate	
	4		2007	77	Operate	
Wilkes	1	Gas Steam	1964	171	2029	See Note (4)
	2		1970	368	2035	See Note (4)
	3		1971	354	Operate	See Note (4)
J.L Stall	6	Gas (CC)	2010	511	Operate	
Dolet Hills	1	Lignite	1986	257	2036	ACI/DSI/BH/DBAC/WWT
Flint Creek	1	Coal	1978	264	Retrofit	DFGD/ACI/BH/DBAC/LVWW/Note (4)
Pirkey	1	Lignite	1985	580	Retrofit	ACI/DBAC/LVWW/Note (4)
Turk	1	Coal	2012	477	Operate	
Welsh	1	Coal	1977	528	Retrofit	ACI/BH/Stack/DBAC/BAPR/Note (4)
	2		1980	528	2015	
	3		1982	528	Retrofit	ACI/BH/Stack/DBAC/BAPR/Note (4)

Notes:
(1) Commercial operation date.
(2) Peak net dependable capability (Summer) as of filing.
(3) ACI - Activated Carbon Injection, BH - Baghouse, DFGD - Dry Flue Gas Desulfurization, DSI - Dry Sorbent Injection, DBAC - Dry Bottom Ash Conversion, WWT - Waste Water Treatment, BAPR - Bottom Ash Pond Reline/DBAC, LVWW - Low Volume Waste Water
(4) A yet to be defined project to meet 316(b) standards

SWEPCO assumed that all of its coal and lignite units, with the exception of Welsh Unit 2, would continue to operate during the IRP planning period. However, with the exception of Knox Lee Unit 5 and Wilkes Unit 3, all of SWEPCO's less efficient gas-fired steam units would retire over the course of the IRP planning period. These units, while providing capacity value, contribute very little energy value. Therefore, as equipment ages and needs to be replaced, there will come a time where the cost of replacing equipment will exceed the future value of energy and capacity those units provide. However, *this in no way serves as a commitment to this course of action for these SWEPCO unit dispositions*—or the attendant timing of same. Rather, it simply serves as a basis for the modeling process for SWEPCO unit analyses. 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.

3.4 Environmental Compliance

3.4.1 Introduction

The following information provides background on both current and future environmental regulatory compliance plan issues within the SWEPCO system. The Company's goal is to develop a comprehensive plan that not only allows SWEPCO to meet the future resource needs of the Company in a reliable manner, but also to meet increasingly stringent environmental requirements in a cost-effective manner.

3.4.2 Air Emissions Compliance

There are numerous air regulations that have been promulgated or that are under development, which will apply to SWEPCO's facilities. Currently, air emissions from plants are regulated by Title V operating permits that incorporate the requirements of the Clean Air Act (CAA) and applicable State Implementation Plans (SIPs). Other applicable requirements include those related to the Clean Air Interstate Rule (CAIR), the Cross-States Air Pollution Rule

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(CSAPR), the MATS and the Regional Haze Rule (RHR). Several air regulatory programs are under development and will apply to SWEPCO plants, including those related to the regulation of GHG and revisions to the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2), oxides of nitrogen ($NO_{x)}$), fine particulate matter (PM), and ozone.

To ensure compliance, air emissions at SWEPCO's units are or will be reduced through the use of some combination of the following control practices/technologies: electrostatic precipitators (ESP), low sulfur coal, low NO_x burners, baghouses, over-fire air (OFA), activated carbon injection (ACI), wet flue gas desulfurization (FGD), dry FGD, dry sorbent injection (DSI), selective catalytic reduction (SCR), and carbon monoxide catalysts.

3.4.3 Environmental Compliance Programs

3.4.3.1 Cross-State Air Pollution Rule (CSAPR)

EPA developed the CSAPR to reduce the interstate transport of SO_2 and NOx within 28 eastern, southern and mid-western states—including Louisiana (NOx, ozone season only), Arkansas (NOx, ozone season only) and Texas (annual SO_2, and NOx, and ozone season NOx) to address associated concerns related to NAAQS for ozone and particulate matter. CSAPR was finalized in 2011 as a replacement for the CAIR. Along with other requirements, the final CSAPR established state-specific annual emission "budgets" for SO_2 and annual and seasonal budgets for NO_x. Based on this budget, each emitting unit within an affected state was allocated a specified number of NO_x and SO_2 allowances for the applicable compliance period, whether annual or ozone season. Allowance trading within and between states is allowed on a regional basis.

Phase I of the CSAPR was originally intended to go into effect in January, 2012. The program was delayed as a result of complicated and lengthy litigation. Although the D.C. Circuit issued a decision in 2014 vacating and remanding the rule to EPA, the U.S. Supreme Court found that the flaws identified by the D.C. Circuit did not justify vacating the rule. On remand, the D.C. Circuit held that the 2014 budgets for SO_2 in four states, and the seasonal NOx budgets in 11 states were more stringent than necessary to eliminate any significant contribution to any downwind non-attainment area. The CSAPR is now in effect, having been published in the Federal Register on December 3, 2014 and remains in effect while EPA evaluates what changes

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to make to the rule. Phase 1 of the program took effect on January 1, 2015, and unless modified, the CSAPR Phase 2 emission budgets will be applicable beginning in 2017.

3.4.3.2 Mercury and Air Toxics Standard (MATS) Rule

The final MATS Rule became effective on April 16, 2012, and required compliance by April 16, 2015. This rule regulates emissions of hazardous air pollutants from coal and oil-fired electric generating units. Hazardous air pollutants regulated by this rule are: 1) mercury; 2) certain non-mercury metals such as arsenic, lead, cadmium and selenium; 3) certain acid gases, including Hydrochloric Acid (HCl); and 4) certain organic hazardous air pollutants. The MATS Rule establishes stringent emission rate limits for mercury, filterable Particulate Matter as a surrogate for all non-mercury toxic metals, and HCl as a surrogate for all acid gases. Alternative emission limits were also established for the individual non-mercury metals and for SO_2 (alternate to HCl) for generating units that have operating FGD systems. The rule regulates organic hazardous air pollutants through work practice standards.

The following is a list of retrofit technologies that are being added, or have been added, to the SWEPCO fleet, including technologies to meet the requirements of the MATS Rule.

- Dolet Hills Unit 1 installed an ACI system, DSI technology, and a baghouse to mitigate mercury and PM emissions.
- Pirkey Unit 1 will be installing an ACI system.
- Welsh (Units 1 &3) will be installing an ACI system with a baghouse. These units have a one year MATS extension from the Texas Commission on Environmental Quality (TCEQ).
- Welsh Unit 2 will be retired per an unrelated settlement agreement and received an extension of the MATS requirements until the unit retires or until April 16, 2016, whichever comes first.
- Flint Creek will also have installed a dry FGD (NID™ technology), ACI system and a baghouse to meet MATS and regional haze requirements. This plant has also received a one year MATS deadline extension.

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All other SWEPCO generating units are expected to meet the MATS requirements without modification.

On November 25, 2014, the U.S. Supreme Court granted petitions to hear state and industry challenges against the EPA's MATS Rule to decide whether EPA unreasonably refused to consider costs in determining that it is appropriate to regulate hazardous air pollutants emitted by coal- and oil-fired electric generating units. The Supreme Court determined on June 29, 2015, that EPA must consider costs when deciding whether it is "appropriate and necessary" to regulate emissions under MATS. The decision did not vacate the MATS rule, but remanded the rule to the D.C. Circuit Court for further proceedings. MATS requirements remain effective unless otherwise ordered by the lower court.

3.4.3.3 Coal Combustion Residuals (CCR) Rule

EPA signed the final Coal Combustion Residuals (CCR) Rule on December 19, 2014. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and will become effective in October 2015. Preliminary review of this extensive rule indicates it is applicable to new and existing CCR landfills and CCR surface impoundments. It contains requirements for liner design criteria for new landfills, surface impoundment structural integrity requirements, CCR unit operating criteria, groundwater monitoring and corrective actions, closure and post-closure care, and recordkeeping, notification and internet posting obligations. EPA has not included a mandatory liner retrofit requirement for existing, unlined CCR surface impoundments, however operations must cease if groundwater monitoring data indicate there has been a release from the impoundment that exceeds applicable groundwater protections standards. While the final rule is still under review, initial estimates of anticipated plant modifications and capital expenditures are factored into this IRP.

3.4.3.4 Effluent Limitation Guidelines and Standards (ELG)

On September 30, 2015 EPA finalized a revision to the Effluent Limitation Guidelines and Standards (ELG Rule) for the Steam Electric Power Generating category. The ELG Rule requires more stringent controls on certain discharges from certain electric utility steam generating units or Electric Generating Units (EGUs) and sets technology-based limits for waste water discharges from power plants with a main focus on process water and wastewater from

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FGD, fly ash sluice water, bottom ash sluice water and landfill/pond leachate. Specifically, the ELG Rule will prohibit the discharge of fly ash and bottom ash transport water while also requiring the installation of physical/chemical/biological treatment for FGD wastewater.

SWEPCO's solid-fueled generating plants are well positioned to comply with the ELG Rule because they utilize dry fly ash handling systems. The Dolet Hills, Flint Creek, and Pirkey Plants may require the addition of wastewater treatment facilities in future years and initial estimates of anticipated plant modifications and capital expenditures to comply with the ELG Rule are factored into this IRP.

3.4.3.5 Clean Water Act "316(b)" Rule

A final rule under Section 316(b) of the Clean Water Act was issued by EPA on August 15, 2014, with an effective date of October 14, 2014, and affects all existing power plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems may not be required to make any technology changes. This determination would be made by the applicable state environmental agency during the plants' next National Pollutant Discharge Elimination System (NPDES) permit renewal cycle. If additional capital investment is required, the magnitude is expected to be relatively small compared to the investment that could be needed if the plants were not equipped with cooling towers.

SWEPCO's generating plants may be required to make investments to upgrade cooling water intake structures 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

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is not expected to require major capital investment, such as the addition of cooling towers, at any SWEPCO plants.

3.4.3.6 Carbon Dioxide (CO_2) Regulations, including the Clean Power Plan

On August 3, 2015, EPA finalized three rulemakings to regulate CO_2 emissions from fossil fuel-based electric generating units. EPA finalized New Source Performance Standards (NSPS) under Section 111(b) of the CAA that apply to new fossil units, as well as separate standards for modified or reconstructed existing fossil steam units. Separately, EPA finalized a rule referred to as the Clean Power Plan (CPP), which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the Clean Air Act. EPA also issued for public comment a proposed Federal Implementation Plan (FIP) to implement the CPP if states fail to submit or do not develop an approvable state plan for compliance.

EPA finalized NSPS for new sources at 1,400 pounds CO_2 per megawatt-hour gross (lb/MWh-g) for new coal units based on the agency's assumption that carbon capture and storage technology can be implemented. Reconstructed coal units have a limit of 1,800 or 2,000 lb/Gross MWh based on the size of the unit. The NSPS for modified coal units is site-specific based on historical operations. For new and reconstructed NGCC units, the NSPS was finalized at 1,000 lb/MWh-g based on the use of efficient combustion turbine designs. No limit was proposed for modified NGCC or simple cycle units.

The Final CPP establishes separate, uniform national CO_2 emission performance rates for fossil steam units (coal-,oil-, and gas-steam based units) and for stationary combustion turbines (which EPA defines as natural gas combined cycle units). The rates were established based on EPA's application of three building blocks as the Best System of Emission Reduction (BSER) for existing fossil generating units. Block 1 assumes efficiency improvements at existing coal units. Building Block 2 assumes the increased use of NGCC units that would displace coal-based generation. And block 3 entails the expansion of renewable energy sources that would displace generation from both coal and NGCC units. Excluded from the BSER process are consideration of nuclear energy, simple cycle gas turbines, and the previously proposed building block 4 related to energy efficiency measures,

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From the national emission performance rates, EPA also developed equivalent state-specific emission rate goals and equivalent state-specific mass-based goals as alternatives. The final (2030) and interim (2022-2029) state emission rate and mass based goals for Louisiana, Texas, and Arkansas are listed in the tables below.

Table 3. Clean Power Plan Interim and Final Emission Goals for SWEPCO's Affected States

	Mass-based CO2 Emission Goals (short tons)		Rate-based CO2 Emission Goals lb/net MWh)	
State	Interim Period 2022-2029	Final Goal 2030	Interim Period 2022-2029	Final Goal 2030
Arkansas	33,683,258	30,322,632	1,304	1,130
Louisiana	39,310,314	35,427,023	1,293	1,121
Texas	208,090,841	189,588,842	1,188	1,042

EPA included interim rates in the final rule, but extended the initial compliance period start from 2020 to 2022. States that decide to develop a State Plan to implement the CPP have the option of developing either an "emissions standards approach" that would apply directly to the affected units, or a "state measures approach" that would incorporate other elements into the compliance strategy. An initial draft State Plan must be submitted to EPA by September 6, 2016. A two year extensions for submitting a final State Plan is available if certain criteria are met by the state. If states do not submit an approvable plan to EPA, EPA will adopt a FIP, based on model rules that will be open for public comment when published in the Federal Register. The model rules are expected to be finalized in the summer of 2016.

SWEPCO is currently in the process of reviewing these rulemakings and must undertake significant new analyses to understand the impacts of the Final CPP. SWEPCO, AEP, and other stakeholders will be working in the coming months and years to better understand the requirements of the Final CPP, and to work with state agencies on the state's response to the final CPP.

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3.4.4 Future Environmental Rules

Several environmental regulations have been proposed that will apply to the electricity generating sector once finalized. Additionally, there are several final rules that are just now being implemented by EPA. The following is not meant to be comprehensive, but lists some of the major issues that will need to be addressed over the forecast period.

3.4.4.1 National Ambient Air Quality Standards (NAAQS)

The CAA requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. Several NAAQS have been recently revised or are under review, which could lead to more stringent SO_2 and NO_x limits as EPA proceeds with implementing these standards. This includes NAAQS for SO_2 (revised in 2010), NO_2 (revised in 2010), fine PM (revised in 2012), and ozone (proposed revision in 2014). The scope and timing of potential requirements is uncertain.

3.4.4.2 Regional Haze Rule (RHR)

The RHR requires affected states to develop Regional Haze State Implementation Plans (Regional Haze SIP) that contain enforceable measures and strategies for reducing emission of pollutants associated with visibility impairment. Each SIP must require certain eligible facilities to conduct an emission control analysis, known as Best Available Retrofit Technology (BART), including NO_X, SO_2 and particulate matter (PM) – to evaluate emission limitations necessary to improve visibility. BART is applicable to EGUs greater than 250 megawatt (MW) and that are of a certain age.

On July 6, 2005, the EPA published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations." The CAA and the RHR require certain states, including Louisiana, Arkansas and Texas, to make reasonable progress toward the "prevention of any future, and the remedying of any existing, impairment of visibility" in mandatory Class I Federal areas, both within the state and in each mandatory Class I Federal area located outside the state which may be affected by emissions from within the state. Air pollutants emitted by BART-eligible sources, which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area are: NO_X, SO_2, PM-10, and PM-2.5. EPA also provided guidance on what level of control is reasonable for certain BART-eligible sources, including EGUs, and published "presumptive BART" emission rates for SO_2 and NO_X based on the types of cost-effective controls available.

3.4.4.2.1 Arkansas Regional Haze

The State of Arkansas and the Arkansas Department of Environmental Quality (ADEQ) submitted a regional haze SIP to the EPA on April 2, 2008, to establish the emission limits necessary to meet its BART obligations. The SIP also included in its supporting documentation analysis by and correspondence from the subject-to-BART sources, outlining the pollution controls reviewed for compliance with the RHR. Pursuant to the RHR, ADEQ identified 18 potential BART-eligible sources in Arkansas in its SIP. Subsequently, ADEQ performed modeling and determined that approximately 9 units at 6 Arkansas facilities are subject-to-BART, one of which is Flint Creek.

The ADEQ utilized the presumptive NO_X and SO_2 limits provided by the EPA in the guidance document, Regional Haze Regulations and Guidelines for BART Determinations (70 Fed. Reg. 39,131). During the RHR development, these presumptive limits were determined by the EPA to sufficiently result in significant improvements in visibility and to ensure reasonable progress toward the national visibility goal.

The Regional Haze SIP developed by ADEQ was incorporated into Chapter 15 of Regulation 19 of the Arkansas Pollution Control and Ecology Commission (APC&EC), with an effective date of October 15, 2007, and a compliance deadline "as soon as practicable," but no later than October 15, 2013. However, on March 26, 2010, the APC&EC granted a variance from the October 15, 2013 deadline, instead requiring compliance with BART as expeditiously as practicable, but in no event later than five years after the EPA approval of the Arkansas Regional Haze SIP. This was done because the EPA had not yet issued its determination on whether or not it would approve the state's Regional Haze SIP and the time needed to engineer, permit and construct the necessary retrofits to comply with the presumptive limits in the SIP was not sufficient given the delay in the EPA's determination. On November 16, 2011, the EPA

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issued their proposed decision on Arkansas' Regional Haze SIP. The EPA proposed to deny approval of the Regional Haze SIP, in part, and prescribed that the ADEQ perform additional analysis then propose a revision to its SIP.

The EPA's proposed decision to deny Arkansas's Regional Haze SIP included a requirement to perform a more detailed BART analysis in which potentially more restrictive limits must be evaluated. SWEPCO coordinated with ADEQ and EPA to conduct that analysis for Flint Creek and EPA indicated they had no further comments on November 8, 2013.

Flint Creek has proposed to meet the NO_X requirements through participation in the CSAPR program. EPA has 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. As an alternative to using compliance with CSAPR to meet BART obligations, Flint Creek would install LNB/OFA and have a NO_X limit of 0.23 lb NO_X/mmBtu. The SO_2 Regional Haze requirements will be met with the installation of a dry scrubber (NID technology).

The existing PM emission limit (0.1 lb/mmBtu) was found to satisfy the BART PM requirement.

ADEQ chose to not prepare and submit a revised SIP and EPA issued a proposed FIP on April 8, 2015. EPA accepted all the controls presented in Flint Creek's BART analysis with the exception that compliance with CSAPR satisfies the NOx requirements. The EPA FIP required that the proposed alternative of Low NO_x Burners (LNB)/OFA be installed for NOx. EPA, however, did not address CSAPR at all in their FIP and comments have been submitted asking specifically that CSAPR be approved for meeting NOx obligations. Whether LNB/OFA or CSAPR will be the approved approach for meeting the NOx obligations for Regional Haze will not be known until EPA issues the final rule. EPA has set a date of August 31, 2016 to issue the FIP as final.

3.4.4.2.2 Louisiana Regional Haze

Louisiana submitted a Regional Haze SIP to 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. EPA partially approved and partially disapproved

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Louisiana's SIP in July 2012. 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 two Class I areas 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.

3.4.4.2.3 Texas Regional Haze

Texas submitted their initial Regional Haze SIP to EPA 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. EPA has reviewed the Texas SIP and issued a FIP in November 2014 for addressing Regional Haze in Texas. EPA accepted portions of the Texas SIP that relate to BART-eligible facilities, however, EPA determined that the Reasonable Progress Goals and Long Term Strategy did not adequately address visibility improvements needed in certain Class I areas. EPA conducted impact analyses to identify cost-effective controls to achieve those improvements. The FIP requires 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 EPA identified as needing to reduce emissions, and, therefore, SWEPCO units in Texas have no emission reductions resulting from Regional Haze requirements at this time.

3.4.4.3 SWEPCO Environmental Compliance

The estimated, potential impact of the previously described rules, with the exception of the CPP, may be factored into the analysis of potential resource plans by adding the incremental cost to comply with the rules, and retiring units where it is not economical to comply.

The Final CPP was issued on August 3, 2015. The Company will work in the coming months and years to develop reasonable plans toward compliance, but at this time it is not possible to determine with any certainty what the final impact will be on SWEPCO's generating fleet.

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3.5 SWEPCO Current Demand Side Programs

3.5.1 Background

Current 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 at the peak are (peak) 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 "embedded" EE programs that have been previously approved in Arkansas and Texas, as well as impacts from prospective programs that started November 1, 2014 in Louisiana. 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 smart-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.

3.5.2 Existing Demand Response (DR)/Energy Efficiency (EE) Mandates and Goals

The EISA requires, among other things, a phase-in of heightened lighting efficiency standards, appliance standards, and building codes. The increased standards will have a pronounced effect on energy consumption. Many of the standards already in place impact lighting. For instance, beginning in 2013 and 2014 common residential incandescent lighting options have begun their phase out as have common commercial lighting fixtures. Given that "lighting" options have comprised a large portion of utility-sponsored energy efficiency programs over the past decade; this pre-established transition already incorporated into the SAE long-term load forecast modeling previously describe in Section 2 may greatly affect the market potential of utility energy efficiency programs in the near and intermediate term. Table 4, illustrates the current schedule for the implementation of new EISA codes and standards.

Table 4. Forecasted View of Relevant Energy Efficiency Code Improvements

Today's Efficiency or Standard Assumption | 1st Standard (relative to today's standard) | 2nd Standard (relative to today's standard)

End Use	Technology	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Central AC	SEER 13													
	Room AC	EER 9.8		EER 11.0											
	Evaporative Central AC	Conventional													
	Evaporative Room AC	Conventional													
Cooling/Heating	Heat Pump	SEER 13.0/HSPF 7.7			SEER 14.0/HSPF 8.0										
Space Heating	Electric Resistance	Electric Resistance													
Water Heating	Water Heater (<=55 gallons)	EF 0.90			EF 0.95										
	Water Heater (>55 gallons)	EF 0.90			Heat Pump Water Heater										
Lighting	Screw-in/Pin Lamps	Incandescent		Advanced Incandescent - tier 1 (20 lumens/watt)						Advanced Incandescent - tier 2 (45 lumens/watt)					
	Linear Fluorescent	T12	T8												
Appliances	Refrigerator/2nd Refrigerator	NAECA Standard		25% more efficient											
	Freezer	NAECA Standard		25% more efficient											
	Dishwasher	Conventional (355kWh/yr)	14% more efficient (307 kWh/yr)												
	Clothes Washer	Conventional (MEF 1.26 for top loader)			MEF 1.72 for top loader			MEF 2.0 for top loader							
	Clothes Dryer	Conventional (EF 3.01)			5% more efficient (EF 3.17)										

Source: AEG-Kentucky Power Market Potential Study Kickoff

The impact of emerging codes and standards on SWEPCO's load forecast can be seen in Figure 7. Over the planning period codes and standards are forecasted to reduce retail load *by 13.5%.*

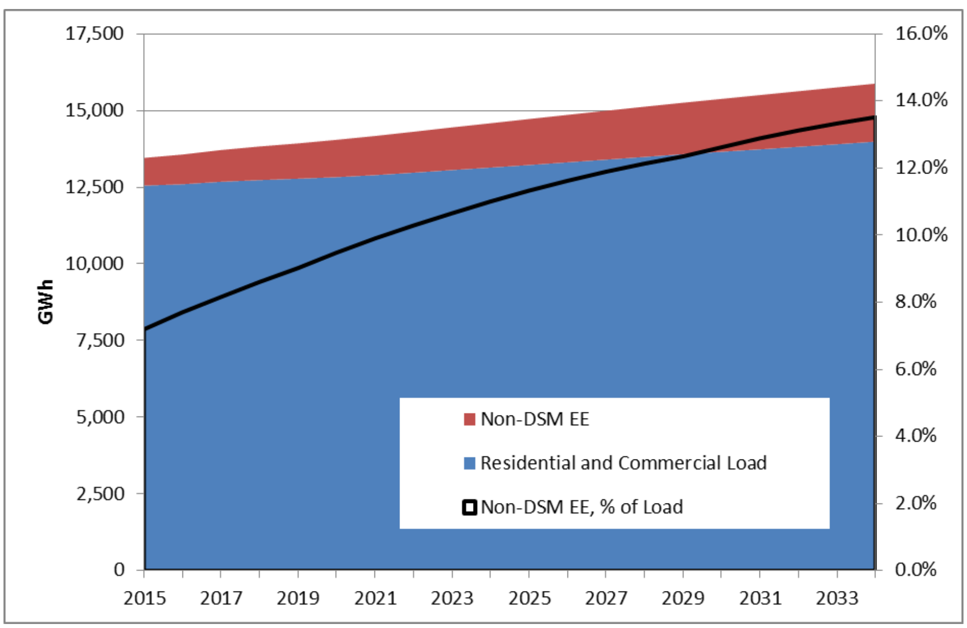

Figure 7. Impact of Non-DSM Energy Efficiency on SWEPCO Retail Load

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Louisiana has initiated an EE program and the "Quick Start Phase" began November 1, 2014. The Arkansas Public Service Commission (APSC) mandated the attainment of 0.25%, 0.50%, and 0.75% annual energy efficiency savings utilizing a 2010 retail sales basis in the years 2011, 2012 and 2013, respectively. The 0.75% attainment goal utilizing a 2013 retail sales basis was extended for 2014, and the APSC has tentatively established a 0.90% attainment goal utilizing a 2013 retail sales basis for 2015 contingent upon the outcome of a statewide energy efficiency potential study that was ordered in 2014. Texas' state energy efficiency program requires the reduction of 25% of its relative annual growth in peak demand or the previous year's requirement, whichever is greater, increasing to 30% in 2013.

This IRP considers attainment of these levels and the subsequent continuation of the program at the same level as the most likely or "base case" and again, has embedded such levels of energy efficiency savings into SWEPCO's load forecast.

3.5.3 Current Demand Response (DR)/ Energy Efficiency (EE) Programs

For the year 2015, the Company anticipates 60MW of peak demand reduction (total Company basis); consisting of 5MW and 55MW of "passive" EE and "active" DR peak demand reductions activity, respectively.[6] SWEPCO currently operates energy efficiency in all three service territories as well as load management (demand reduction) programs in its Texas and Arkansas service territories. All states have approved rate-design programs to promote energy efficiency programs.

In an effort to resolve issues related to the continued development of utility energy efficiency programs in Arkansas, the Arkansas Public Service Commission agreed with the recommendation of the Parties Working Collaboratively (PWC) that Arkansas-specific market conditions should be considered prior to the development of energy efficiency goals and targets. This was done through the implementation of a Potential Study.

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

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On July 2, 2015, the Final Potential Study (Final Study) was filed with the Arkansas Public Service Commission (APSC) in Docket No. 13-002-U. The Final Study included estimated energy savings targets, including estimated budgets, under low, medium, high, and carbon scenarios. On July 31, 2015, the Parties Working Collaboratively (PWC) filed non-consensus recommendations regarding the targets for electric utilities during 2017-2019 program cycle. While consensus could not be reached among the Parties regarding targets, there was general consensus around the use of the medium spending scenario. The recommended energy savings target varied between a flat 0.9% and 1.0% of retail sales (net of sales to Self-Direct customers) throughout the 2017-2019 program cycle. For SWEPCO Arkansas, this results in incremental net energy savings of approximately 27-30 GWh per year. As of November 30, 2015, these recommendations were still pending before the APSC.

3.5.4 Demand Reduction

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. SWEPCO's maximum (system peak) 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 and (industrial) machinery. At all 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 must 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

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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) and to as often as 15-minute increments in what is known as "real-time pricing." Accomplishing real-time pricing requires digital (smart) metering.
- *Energy Efficiency 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.
- *Line loss mitigation (Passive DR).* A line loss results during the transmission and distribution of power from the generating plant to the end user. To the extent that these losses can be reduced, less energy is required from the generator.

What may be apparent is that, with the exception of EE and Line Loss measures, the remaining "demand response" programs do not significantly reduce the amount of power consumed by customers. Less power may be consumed at the time of peak load, but that power will be consumed at some point during the day. For example, if rates encourage someone to avoid running their clothes dryer at four P.M.; they will run it at some other point in the day. This is often referred to as load shifting.

3.5.5 Energy Efficiency (EE)

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

EE measures most commonly include efficient lighting, weatherization, efficient pumps and motors, efficient Heating Ventilation and Cooling (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.

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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. According to a March 2007 DOE study such benefits include:

- Economics: Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
- Environment: Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change.
- Infrastructure: Lower demand lessens constraints and congestion on the electric transmission and distribution systems
- Security: Energy Efficiency can lessen our vulnerability to events that cut off energy supplies

However, as summarized in Table 5, market barriers to EE exist for the potential participant.

Table 5. Energy Efficiency (EE) Market Barriers

High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of energy efficiency options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for energy efficiency services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the energy efficiency measure may be different from those benefiting from the investment (e.g., rental property)
Product/Service unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings

Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

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To overcome many of the participant barriers noted above, a portfolio of 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 market transformation and measure adoption.

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP begins adding new demand-side resources in 2018 that are incremental to approved or mandated programs.

3.5.5.1 Energy Conservation

Often used interchangeably with efficiency, conservation results from foregoing the benefit of electricity either to save money or simply to reduce the impact of generating electricity. Higher rates for electricity typically result in lower consumption. Inclining block rates, or rates that increase with usage, are rates that encourage conservation.

3.5.6 Smart Grid Technologies and Opportunities

3.5.6.1 Distributed Generation (DG)

Distributed generation (DG) typically refers to small scale customer-sited generation downstream of 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 the implementation of Louisiana’s residential rooftop solar rebate program.

All three SWEPCO retail jurisdictions do have “net metering” tariffs in place which allow for the sale of power generated by customers to be purchased by the utility at the customers’ (retail) rate. Most power generated in this manner is consumed "on-site" and the net power available to be fed back into the grid for system use is negligible.

The economics of distributed generation, particularly solar, continue to improve. Figure 8 charts the fairly rapid decline of expected installed solar costs in the SWEPCO service territory, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) Installed Cost of Solar forecast. These are costs shown *without* accounting for the 30% Federal Investment Tax Credit (ITC) (reduced to a 10% credit in 2016) as well as Louisiana's rooftop solar rebate program, which would further reduce the installed cost.

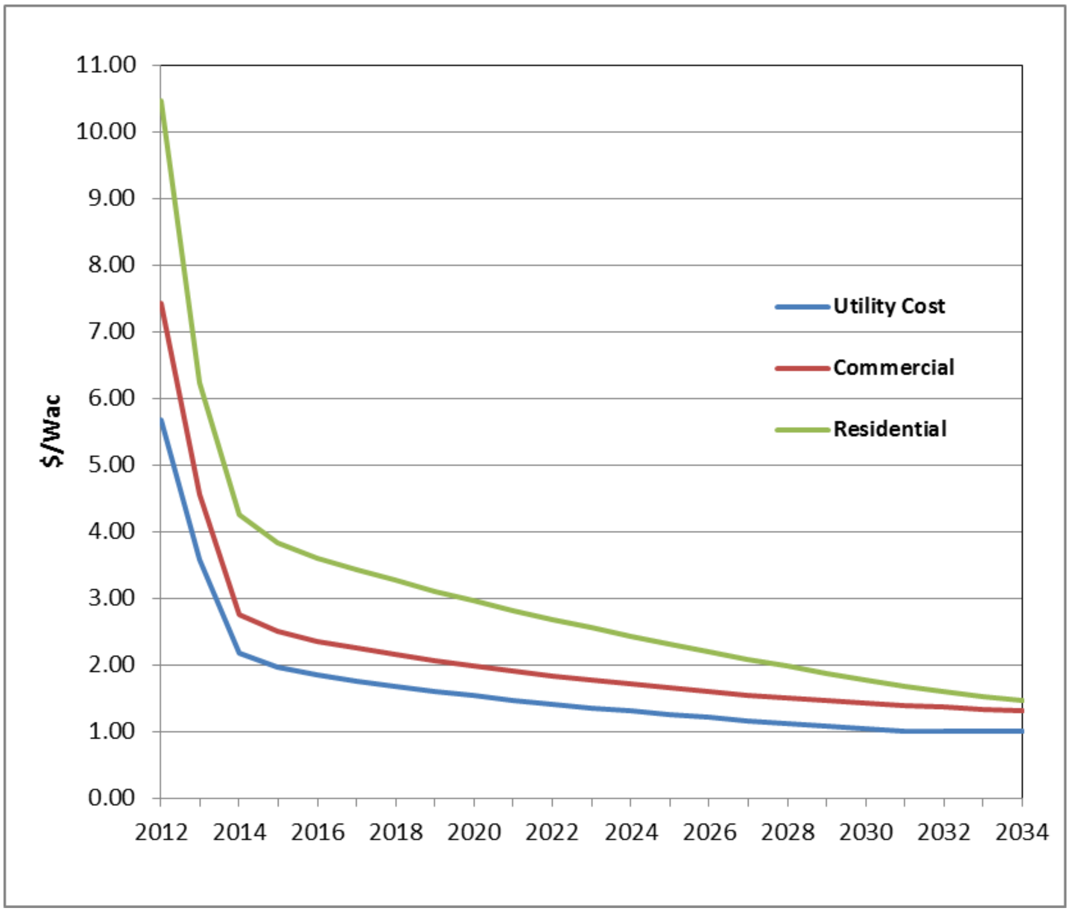

Figure 8. Forecasted Solar Installed Costs for SWEPCO Territory (Excl. Fed & State Incentives)

Not surprisingly, the declining cost of solar and the associated Louisiana residential rooftop solar rebate program has accelerated the installation of rooftop solar within Louisiana. As illustrated in Figure 9, from the residential customer perspective, upon consideration of the

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current net-metering arrangement, the estimated cost to install rooftop solar, as well as the current federal and state incentives, it may provide a Louisiana customer considerable incentive to install rooftop solar in the nearer-term. However, when the Louisiana Residential rooftop solar incentive cap is met at 7.8MWs of rooftop solar and the federal ITC is reduced, the relative value proposition will likely be reduced considerably for Louisiana retail customers. That is, the cost to install and the value (i.e. avoided costs) received are projected to become very close. Figure 9, further illustrates, by SWEPCO state jurisdictional residential sector, the equivalent value a customer would achieve on a $/Watt AC basis over the assumed 30 year life of the installed solar panels based on the customers' avoided retail rate.

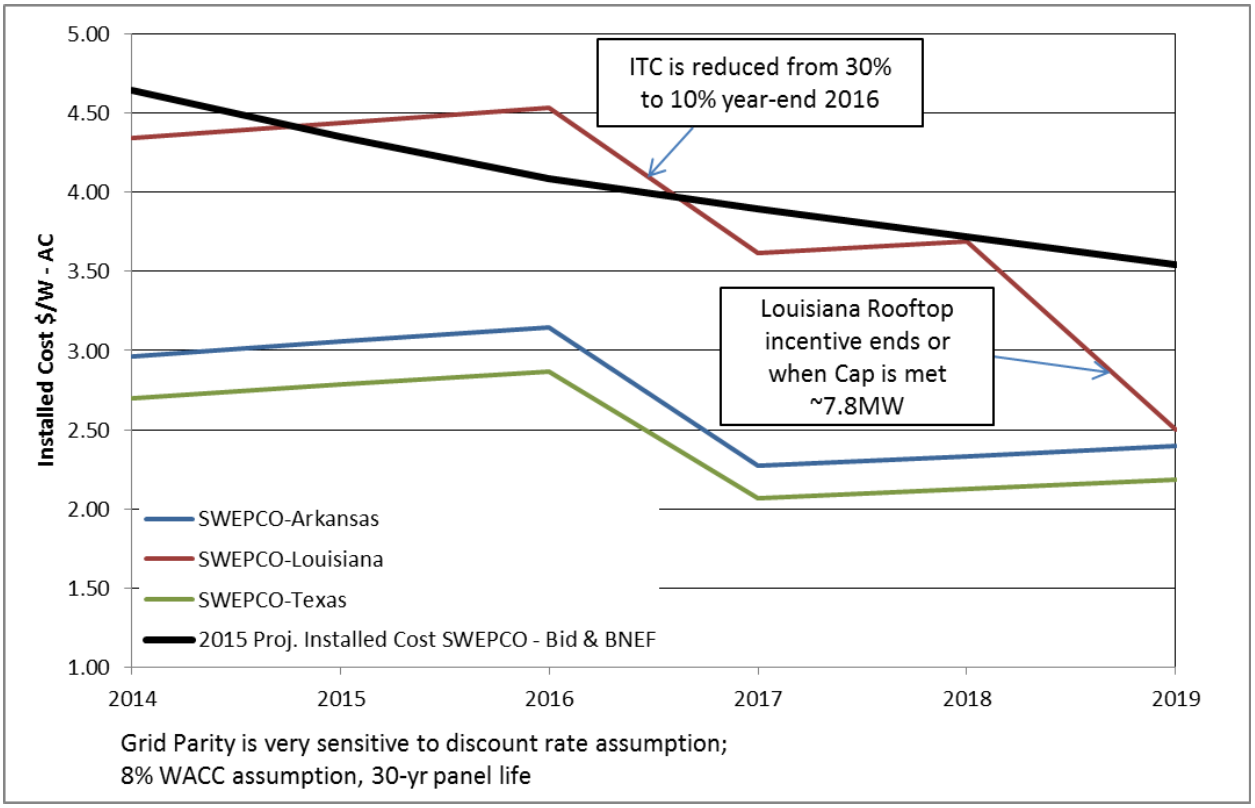

Figure 9. Distributed Generation (Rooftop Solar) Customer Breakeven Costs

Figure 10, demonstrates the historical installed rooftop solar capacity for SWEPCO by jurisdiction and the projected rooftop solar capacity additions that are included in the Preferred Plan.

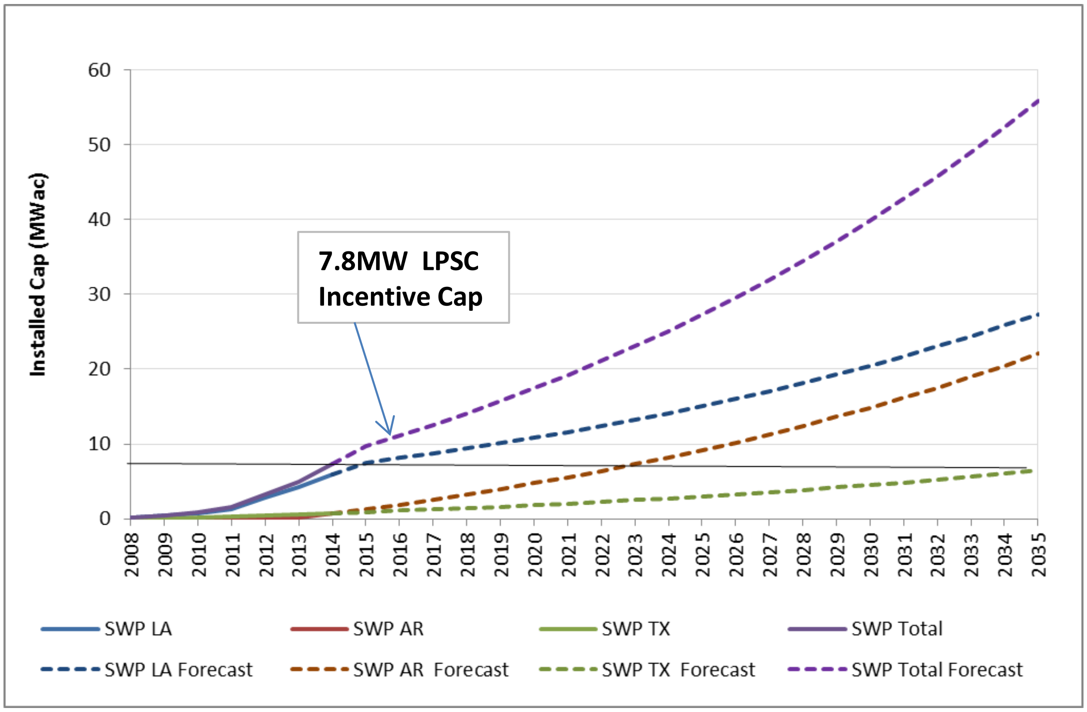

Figure 10. Cumulative Distributed Generation (Rooftop Solar) Additions/Projections for SWEPCO

The current distributed resources net metering cap for SWEPCO Louisiana is 7.8MW and based on current projections SWEPCO Louisiana will meet this cap in 2016. The assumed growth rate for rooftop solar is 5% per year after SWEPCO Louisiana reaches 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.

3.5.6.2 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 11, 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 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 a 1% voltage reduction is possible.

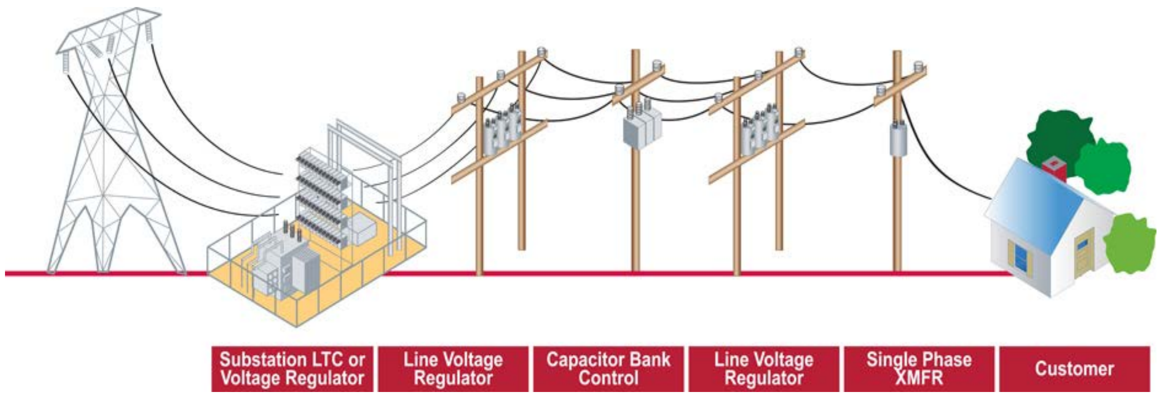

Figure 11. Voltage/VAR Optimization (VVO) Schematic

While there is no "embedded" VVO load reduction impacts implicit in the base load forecast case, VVO has been modeled as a unique EE resource. The results of which are discussed in Section 4.

3.6 AEP-SPP Transmission

3.6.1 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, and approximately 2300 miles of 69 kV. The AEP-SPP zone is also integrated with and directly connected to ten other companies at 89 interconnection points, of which 71 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.

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3.6.2 Current AEP-SPP Transmission System Issues

The limited capacity of interconnections between SPP and neighboring systems, as well as the electrical topology of the SPP footprint transmission system, influences the ability to deliver non-affiliate generation, both within and external to the SPP footprint, to AEP-SPP loads and from sources within AEP-SPP balancing authority to serve AEP-SPP loads. Moreover, a lack of seams agreements between SPP and its neighbors has significantly slowed down the process of developing new interconnections. Despite the robust nature of the AEP-SPP transmission system as originally designed, its current use is in a different manner than originally designed, in order to meet SPP 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 STEP process is a new Layfield 500-230 kV station in northwestern Louisiana (previously referred to as Messick). The Layfield project is a joint effort by SWEPCO and Cleco that may lead to improved transfer capability between SPP and MISO. The Layfield project was unanimously certified by the Louisiana Public Service Commission in an Order dated October 10, 2014 in docket U-33196, confirming that SWEPCO and Cleco fully complied with all of the requirements of the Louisiana Public Service Commission's General Order on Transmission Siting dated October 13, 2013 in docket R-26018.

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

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

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3.6.2.1 The SPP Transmission Planning Process

Currently, SPP produces an annual SPP Transmission Expansion Plan (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 2015 STEP summarizes 2014 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. Seven key topics are included in the STEP:

1) Integrated Transmission Planning (ITP)

2) Tariff Studies,

3) Sub-regional and local area planning,

4) Transmission Congestion and top Flowgates

5) Interregional coordination,

6) Project tracking; and

7) Public Policy Impacts

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:

- Balanced Portfolio – Projects identified through the Balanced Portfolio Process;
- Generation Interconnect – Projects associated with a FERC-filed Interconnection Agreement;
- Interregional – Projects developed with neighboring Transmission Providers;

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- ITP – Projects needed to meet regional reliability, economic, or policy needs in the ITP study process;
- ITP – Non-OATT – Projects to maintain reliability for SPP members not participating under the SPP OATT
- 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 2015 STEP identified 568 transmission network upgrades with a total cost of approximately $5.7 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 56% of the total cost in the 2015 STEP. The ITP process was designed to maintain reliability and provide economic benefits to the SPP region in both the near and long-term. The ITP process was conducted in three phases. The first phase recommended a long-term transmission plan for a 20-year horizon, incorporating a proposed extra-high voltage supply system. The second phase of the ITP process resulted in a recommended portfolio of transmission projects for comprehensive regional solutions, local reliability upgrades, and the expected reliability and economic needs of a 10-year horizon. Finally, the third phase of the ITP process studied the reliability of the SPP transmission system in the near-term, identifying upgrades based on a six year planning horizon.

3.6.2.2 PSO-SWEPCO Interchange Capability

Operational experience and internal assessments of company transmission capabilities indicate that, when considering a single contingency outage event, the present firm capability transfer limit from Public Service Oklahoma (PSO) to SWEPCO and from SWEPCO to PSO is about 200MW. As much as 900MW from PSO to SWEPCO and 700MW from SWEPCO to PSO may be available for economical energy transfers when no transmission facilities are out of service. However, the intra-company available transmission capability between the two companies is available to all transmission users under the provisions established by FERC Order 888 and subsequent orders. Thus, there is some question as to whether, in the future, as SPP

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grants further transmission rights, any transfer capability will in fact be available without further upgrades to the transmission system.

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 PSO and SWEPCO 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.

3.6.2.3 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.

3.6.2.4 SPP Studies that may Provide Import Capability

Within the STEP, some projects that may lead to improved transfer capability between AEP-SPP and neighboring companies and regions include:

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- A 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
- A new Layfield 500-230 kV station in northwestern Louisiana (previously referred to as Messick)
- A Sooner-Cleveland 345 kV line in northern Oklahoma, west of the Tulsa area (completed)
- A Seminole-Muskogee 345 kV line in eastern Oklahoma (completed)
- A Sunnyside-Hugo-Valliant 345 kV line across southeastern Oklahoma (completed)
- A Tuco-Woodward 345 kV line from the Texas Panhandle to northwestern Oklahoma (completed)

Besides the annual STEP process, SPP also performs other special studies or area studies on an as needed basis. One SPP study that resulted in approved projects that may lead to improved transfer capability between AEP-SPP and neighboring companies and regions is the Priority Projects study. Among the projects approved as a result of this study are:

- Double circuit Spearville-Thistle 345 kV line in southwestern Kansas (completed)
- Double circuit Thistle-Wichita 345 kV line in southern Kansas (completed)
- Double circuit Woodward-Thistle 345 kV line from northwestern Oklahoma to southwestern Kansas (completed)
- Double circuit Hitchland-Woodward 345 kV line in northwestern Oklahoma (completed)
- A Valliant-Northwest Texarkana 345 kV line from southeastern Oklahoma to northeastern Texas

3.6.3 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 1,300MW of load in the Northwest Arkansas area, about 49% 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 GRDA-Flint Creek 345 kV line, and the Clarksville-Chamber Springs 345 kV line. Wal-Mart's international

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headquarters and its supplying businesses' offices and Tyson's headquarters are all located in this area. A new 345 kV line has been completed from Flint Creek to the new Shipe Road 345/161 kV substation along with a 161 kV line connecting Shipe Road substation to East Centerton substation.

- **Port of Shreveport (Port), Louisiana—** A 138 kV loop was completed in 2012 around the Port to increase system reliability and to serve the increasing area load. This loop extends approximately 33 miles from Wallace Lake Station to the Port to Bean Station to Caplis Station to McDade Station to Haughton Station to Red Point Station. In order to serve a new industrial customer, Benteler Steel/Tube, two 138 kV lines of approximately three to four miles each, have been built from the Port to the Benteler Steel/Tube plant.
- **Turk Generation Interconnection –** In order to connect the 600MW coal-fired Turk Power Plant in southwestern Arkansas, near McNab, to the transmission system, the Turk 345/138/115 kV substation was built and several new transmission lines were built or upgraded. A 345 kV line approximately 33 miles from Turk to Northwest Texarkana substation, a 138 kV line approximately 22 miles from Turk to Sugar Hill substation, and a 138 kV line approximately 27 miles from Turk to Southeast Texarkana substation have been completed as well as a 138 kV line section and a 115 kV line section approximately 2 miles each from Turk to the Okay-Hope 115 kV line, which was opened and routed into Turk. The Patterson to Okay and Okay to Hope 115 kV lines were rebuilt to 138 kV standards, though the portion between Hope and Turk will continue to be operated at 115 kV. This expansion provides the interconnection of the Turk Power Plant, transmission service, improved reliability for the City of Hope and southwestern Arkansas, and improved reliability to Texarkana by completing a 138 kV loop around the city.
- **McAlester, Oklahoma area –** The Canadian River 345-138 kV substation has been completed northwest of McAlester, along Oklahoma Gas and Electric Company's (OG&E) Pittsburg-Muskogee 345 kV line. A 69 kV line was converted to 138 kV line for approximately 17 miles from the Canadian River substation to the McAlester City substation. This relieves 138 kV line loadings in the area and provides voltage support.
- **Cornville/Rush Springs, Oklahoma area –** The Cornville-Lindsay Water Flood radial line, approximately 33 miles, has been rebuilt and converted to 138 kV operation. A 138 kV connection, approximately 10 miles, is being built from this line to an existing radial that serves Rush Springs Natural Gas from the existing Cornville-Duncan 138 kV line. This will complete a 138 kV loop, improving reliability of the transmission system in this area.

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

3.6.4 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—** Until recently there were very few Extra High Voltage (EHV) transmission lines in this area, though that is changing due to the 345 kV projects discussed above. The area is one of the highest wind density areas within the SPP RTO footprint. The potential wind farm capacity for this area has been estimated to exceed 4,000MW. Several wind farms have already been built, and several more are in the development stages. Wind generation additions in the SPP footprint in this region will likely require significant transmission enhancements, including EHV line and station construction, to address thermal, voltage, and stability constraints.
- **PSO/SWEPCO Interface** - There is one 345 kV EHV line linking PSO's service area with the majority of SWEPCO's generation resources in its service area. An SPP approved project, mentioned above, to build a 345 kV line approximately 76 miles from Valliant substation to Northwest Texarkana substation will improve transfer capability by forming a second 345 kV path between PSO and SWEPCO's transmission system in northeastern Texas. Significant generation additions to the AEP-SPP transmission facilities (or connection to neighbor's facilities) may require significant transmission enhancements, possibly including EHV line and station construction, to address thermal, voltage, and stability constraints.
- **Tulsa Metro Area—**the Tulsa metro area load is supplied primarily by the PSO Northeastern, Riverside, and Tulsa Power Station generating plants. Additionally, OG&E has large generation plants located to the southeast and southwest of Tulsa, and there are large merchant plants just east and south of Tulsa. The Grand River Dam Authority has a large plant located to the east of Tulsa. Generation additions in the Tulsa area would likely require significant enhancements in the EHV and sub-transmission system to address thermal, voltage and stability constraints.
- **SPP Eastern Interface—**there are only five east-west EHV lines into the SPP region, which stretches from the Gulf of Mexico (east of Houston) north to Des

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> Moines, Iowa. This limitation constrains the amount of imports and exports along the eastern interface of SPP with neighboring regions. It also constrains the amount of transfers from the capacity rich western SPP region to the market hubs east and north of the SPP 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 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.

3.6.5 Summary of Transmission Overview

In the SPP region, the process of truly integrating Generation and Transmission planning is still developing. AEP continues to stand ready to engage in that process. AEP also continues supporting the SPP STEP and ITP transmission expansion processes, which include some projects which may improve import capability. Such capability improvements are more likely to be within SPP, but less so between SPP and neighboring regions, partly due to lack of seams agreements which slows the development of new interconnections as discussed above. PSO and SWEPCO 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.

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4.0 Modeling Parameters

4.1 Modeling and Planning Process – An Overview

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

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

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

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. To challenge the robustness of the ultimate Preferred Portfolio, sensitivity analyses were performed to address these factors.

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 proxy resources–both supply and demand side–and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, *Plexos*® will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the Cumulative Present Worth" (CPW), of the resulting stream of revenue requirements. The least cost option is considered the "optimum" portfolio for that unique input parameter scenario.

4.3 Fundamental Modeling Input Parameters

The AEP Fundamental Analysis group derives long-term power (energy) price forecasts from a proprietary model known as AURORA^{xmp}. Having similarities to *Plexos*®, AURORA^{xmp} is a long-term fundamental production cost-based energy and capacity price forecasting tool developed by EPIS, Inc., that is driven by comprehensive, user-defined commodity input parameters. For example, nearer-term unit-specific fuel delivery and emission allowance price forecasts, based upon actual transactions, which are established by AEP Fundamental Analysis and AEP Fuel, Emissions and Logistics, are input into AURORA^{xmp}. Estimates of longer-term natural gas and coal pricing are provided by AEP Fundamental Analysis in conjunction with input received from consultants, industry groups, trade press, governmental agencies and others. Similarly, capital costs and performance parameters for various new-build generating options, by duty-type are vetted through AEP Engineering Services and incorporated into the tool. Other information specific to the thousands of generating units being modeled is researched from Velocity Suite, an on-line information database maintained by Ventyx, an ABB Company. This

[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.

includes data such as unit capacity, heat rates, retirement dates and emission controls status. Finally, the model maintains and determines region-specific resource adequacy based on regional load estimates provided by AEP Economic Forecasting, as well as current regional reserve margin criterion. AEP uses AURORA^{xmp} to model long-term (market) energy and capacity prices for the entire U.S. eastern interconnect as well as ERCOT. The projection of a CO_2 pricing proxy is based on assumptions developed in conjunction with the AEP Strategic Policy Analysis organization. Figure 12 shows the Fundamentals process flow for solution of the long-term commodity forecast. The input assumptions are initially used to generate the output report. The output is used as feedback to change the base input assumptions. This iterative process is repeated until the output is congruent with the input assumptions (*e.g.*, level of natural gas consumption is suitable for the established price and all emission constraints are met).

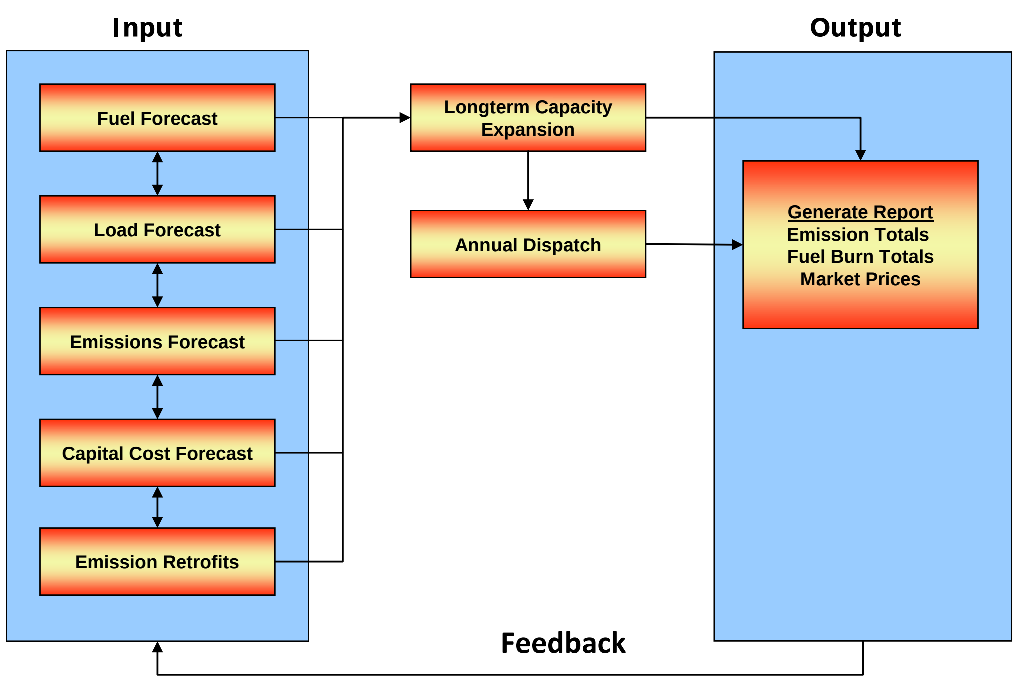

Figure 12. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Five commodity pricing scenarios were developed by AEP Fundamental Analysis for SWEPCO to enable *Plexos*® to construct resource plans under various long-term pricing conditions. In this report, the five distinct long-term commodity pricing scenarios that were

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developed for *Plexos*® are: a Base scenario view, a plausible Low Band view, a plausible High Band view; a High Carbon view; and a No Carbon view. The scenarios are described below with the results shown in Figure 13 through Figure 18.

When comparing the following pricing scenarios with others throughout the industry it should be noted that AEP's commodity pricing forecasts account for the impacts of future events, such as proposed environmental regulations. This approach differs from other popular references, such as the EIA's Annual Energy Outlook[8].

4.3.1.1 Base Scenario

This scenario recognizes the following major assumptions:

- MATS Rule effective beginning in 2015;
- Initially lower natural gas price due to the emergence of shale gas plays; and
- CO_2 emission pricing proxy begins in 2022 and was assumed to be at $15 per metric ton, growing with inflation.

Each of the pricing forecasts includes a CO_2 impact as a result of the implementation of any prospective CO_2 reduction regulation. The Base, High Band and Low Band scenarios all reflect the fundamental view that such a CO_2 pricing proxy could be modeled as a $15/tonne dispatch cost penalty, or "tax", beginning in 2022 because it results in reduction of CO_2 emissions when combined with recent EPA regulations and standards such as MATS, more-stringent Corporate Average Fuel Economy (CAFE) standards and others. Given that any plan to reduce Greenhouse Gas (GHG) emissions must be accompanied by a thorough assessment of the impact on the electric grid, allow adequate time for implementation, respect the authority of states and other federal agencies, and preserve a balanced, diverse mix of fuels for electricity generation, 2022 was considered to be the earliest reasonable projection as to when any such CO_2 reduction regulation could become effective when these pricing scenarios were established.

[8] From the Energy Information Administration's Annual Energy Outlook 2015 Preface: "The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections (for example, the proposed Clean Power Plan[3])". Available at http://www.eia.gov/forecasts/aeo/preface.cfm

The specific effects of the MATS Rule are modeled in the development of the long-term commodity forecast by retiring the smaller, older solid-fuel (i.e., coal and lignite) units which would not be economic to retrofit with emission control equipment. The retirement time frame modeled is 2015 through 2017. Those remaining solid-fuel generating units will have some combination of controls necessary to comply with the EPA's rules. Incremental regional capacity and reserve requirements will largely be addressed with new natural gas plants. One effect of the expected retirements on the emission control retrofit scenario is an over-compliance of the previous CSAPR emission limits. This will drive the emission allowance prices for SO_2 and NO_X to zero by 2018 or 2019.

4.3.1.2 Low Band Scenario

This scenario is best viewed as a plausible lower natural gas/solid-fuel/energy price profile compared to the Base view. In the near term, Low Band natural gas prices largely track the Base but, in the longer term, natural gas prices represent an even more significant infusion of shale gas. From a statistical perspective, this long-term pricing scenario is approximately one (negative) standard deviation (-1.0 SD) from the Base scenario and illustrates the effects of coal-to-gas substitution at plausibly lower gas prices. Like the Base scenario, proxied CO_2 mitigation/pricing is assumed to start in 2022 at a $15 per metric ton (real dollars).

4.3.1.3 High Band Scenario

Alternatively, this High Band scenario offers a plausible, higher natural gas/solid-fuel/energy price profile compared to the Base scenario. High Band natural gas prices reflect certain impediments to shale gas developments including stalled technological advances (drilling and completion techniques) and as yet unseen environmental costs. The pace of environmental regulation implementation is in line with the Base scenario and Low Band. Analogous to the Low Band scenario, this High Band view, from a statistical perspective, is approximately, one (positive) standard deviation (+1.0 SD) from the Base. Also, like the Base and Low Band scenarios, CO_2 pricing is assumed to begin in 2022 at the same $15 per metric ton pricing proxy.

4.3.1.4 No Carbon Scenario

This scenario does not consider the prospects of a carbon tax. While also including the necessary correlative fuel price adjustments, it serves as a baseline to understand the impact on unit dispatch and, with that, the attendant impact on energy prices associated with the Base and High Carbon scenarios.

4.3.1.5 High Carbon Scenario

Built upon the assumption of a $25 per metric ton (tonne) (66% higher than the Base scenario) CO_2 mitigation pricing proxy beginning in 2022, the High Carbon scenario includes correlative price adjustments to natural gas and solid-fuel due to changes in consumption that such heightened CO_2 pricing levels would create. This results in some additional retirements of coal-fired generating units around the implementation period. Natural gas and, to a lesser degree, renewable generation is built as replacement capacity.

The following set of figures illustrates the range of such long-term pricing projections, on a nominal dollar basis, by major commodity through the year 2030.

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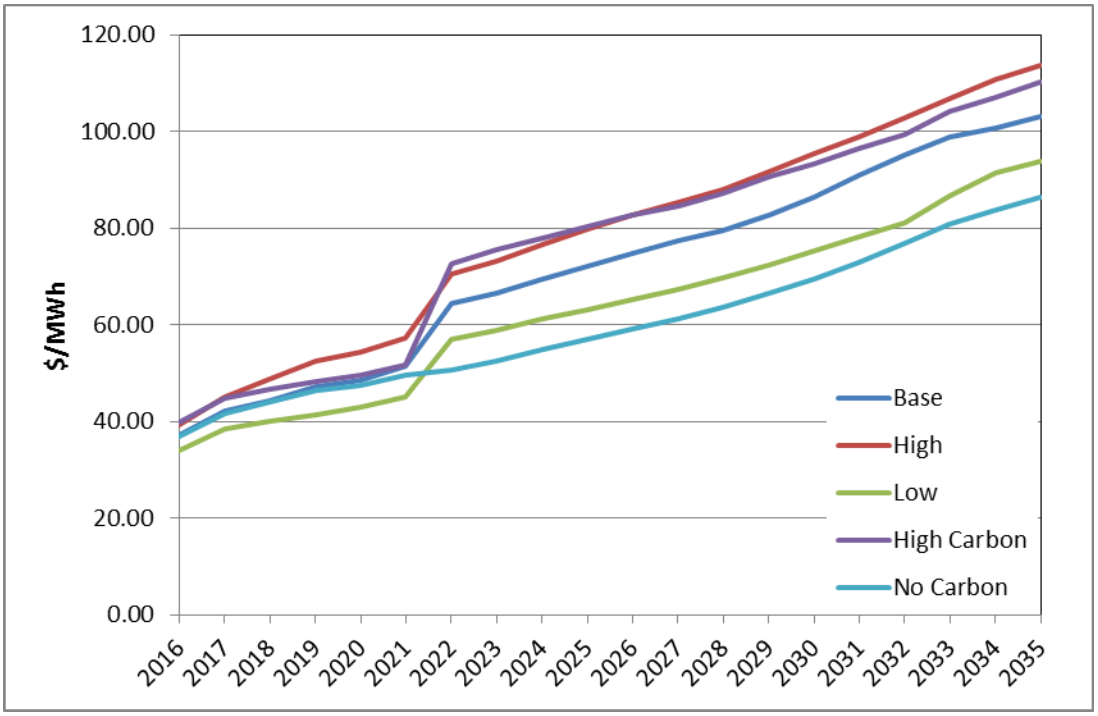

Figure 13. SPP On-Peak Energy Prices (Nominal $/MWh)

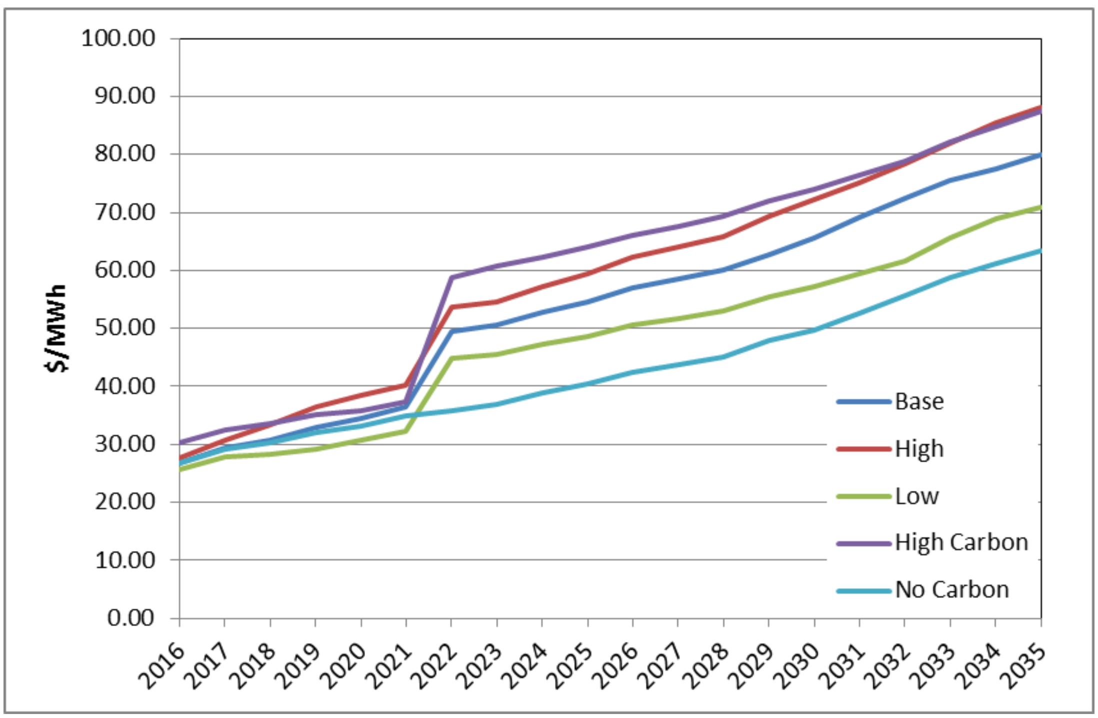

Figure 14. SPP Off-Peak Energy Prices (Nominal $/MWh)

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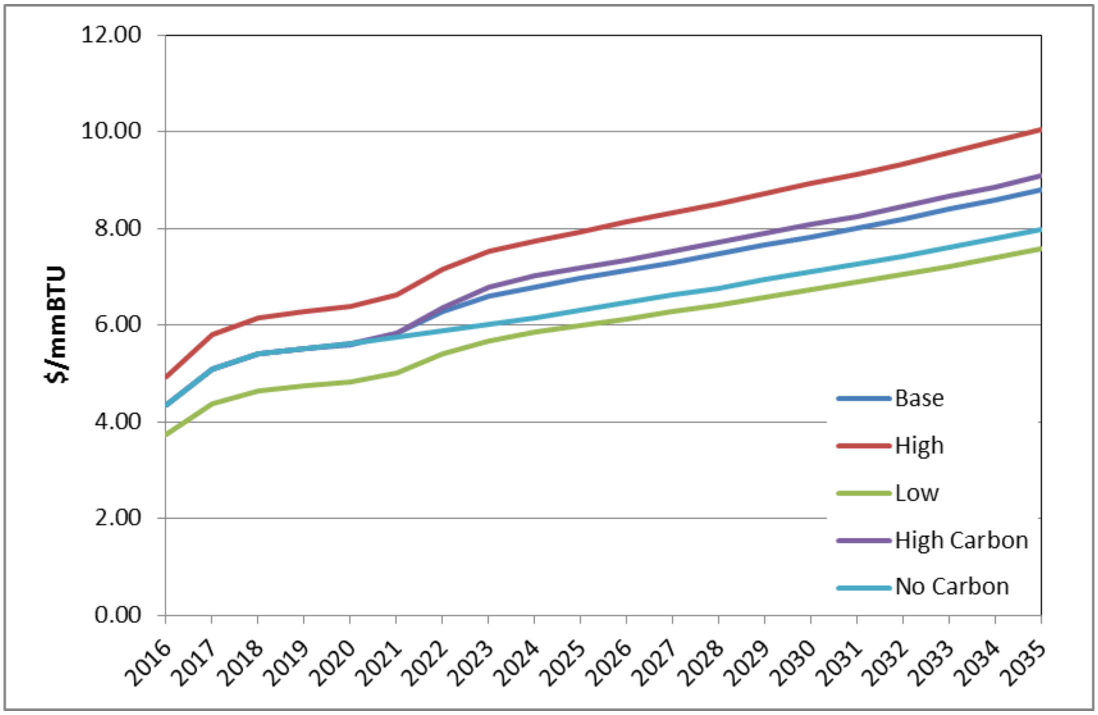

Figure 15. Henry Hub Natural Gas Prices (Nominal $/mmBTU)

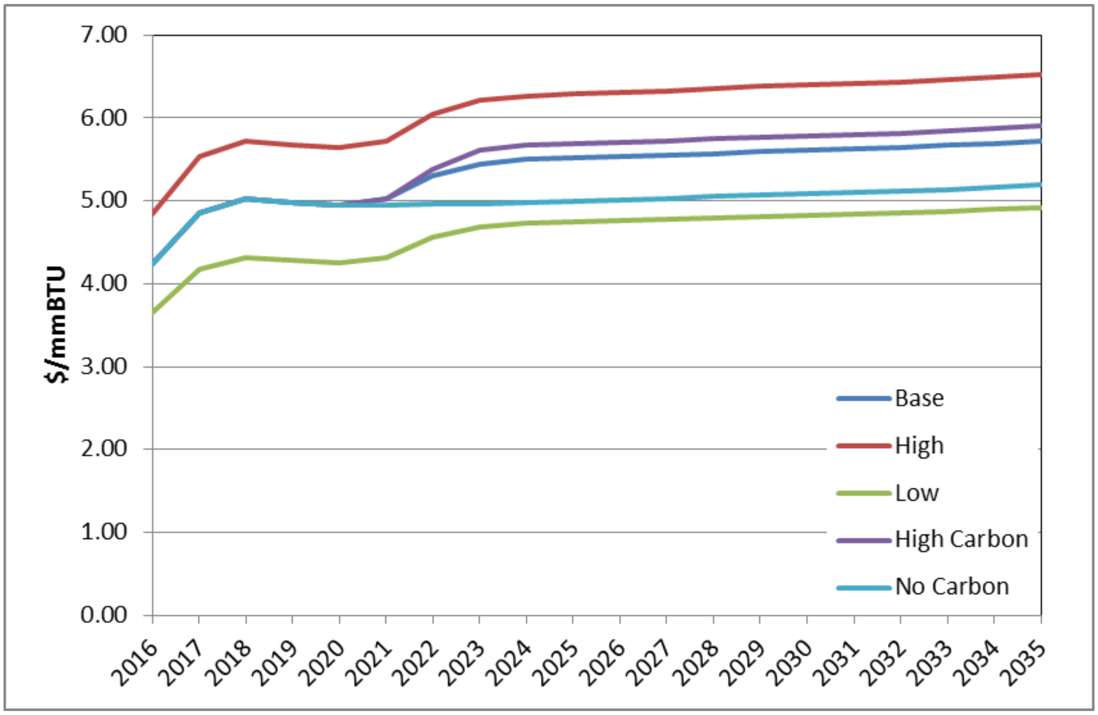

Figure 16. Henry Hub Natural Gas Prices (Real $/mmBTU)

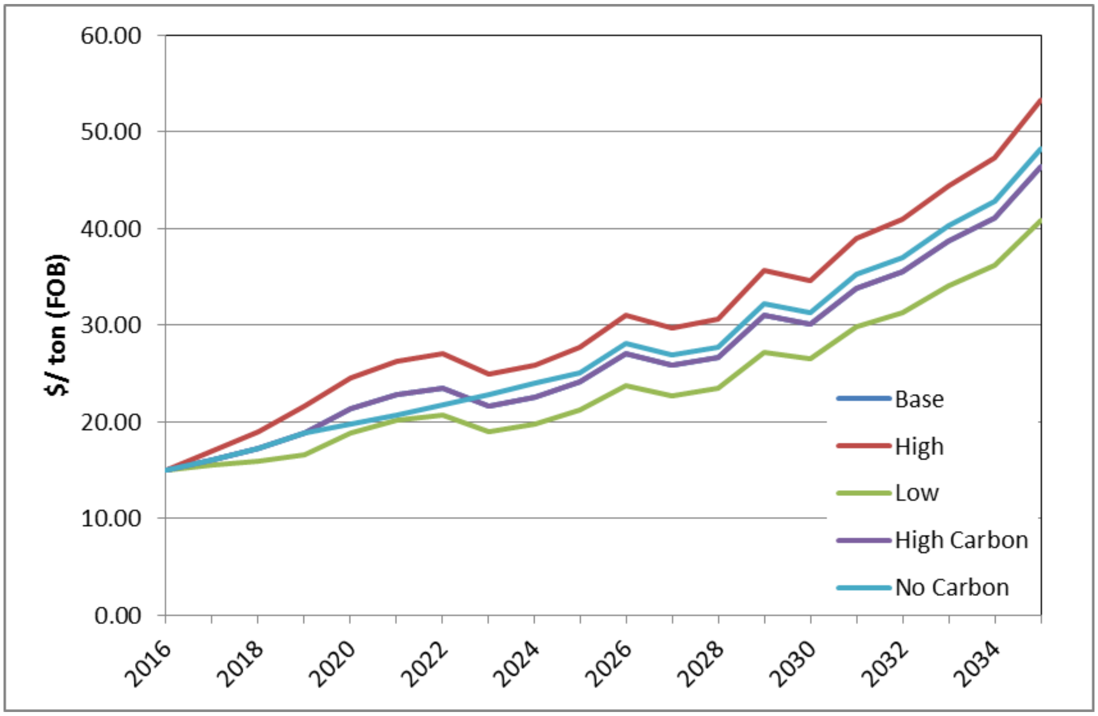

Figure 17. PRB 8,800 BTU/lb. Coal Prices (Nominal $/ton, FOB)

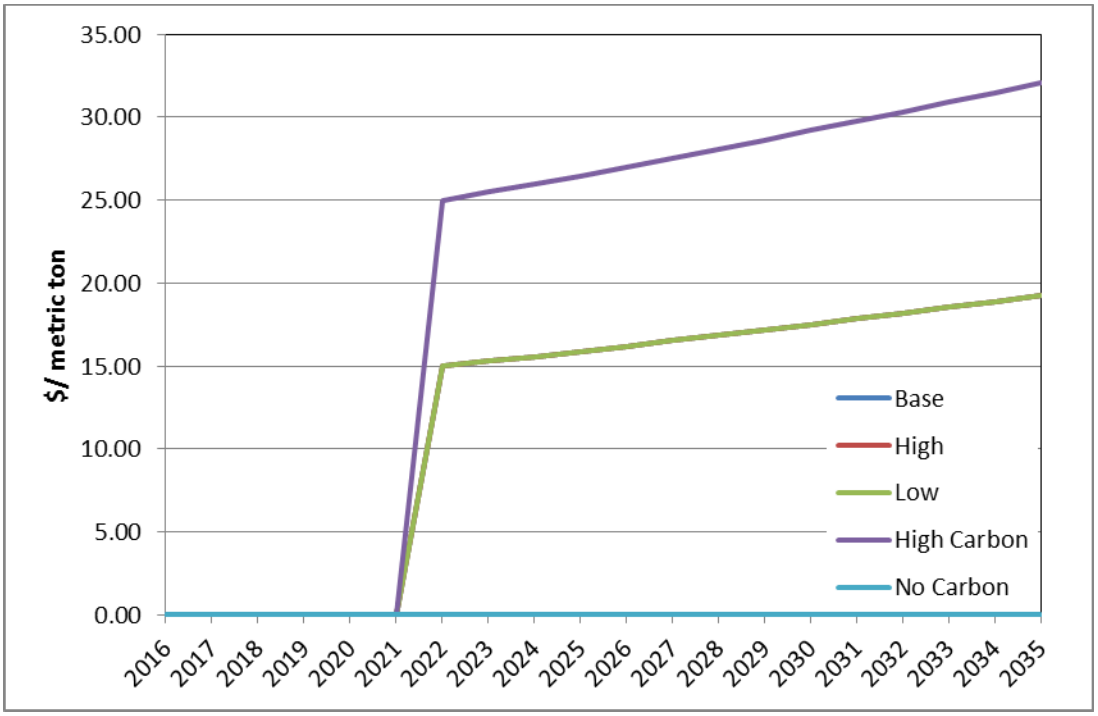

Figure 18. CO2 Prices (Nominal $/metric ton)

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

4.4.1 Overview

The process for evaluating DSM impacts for SWEPCO is practically divided into two spheres; "existing programs" and "future activity." Existing programs are those that are known or are reasonably well-defined, follow a pre-existing process for screening and determining ultimate regulatory approval. The impacts of such existing SWEPCO DSM programs are propagated throughout the long-term SWEPCO load forecast and were discussed in Section 3.5. Future 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 future DSM activity was developed and ultimately modeled based on the Electric Power Research Institute's (EPRI) "2014 U.S. Energy Efficiency Potential Through 2035" report. This comprehensive 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. Industrial programs were not developed or modeled based on the thought that industrial customers, by and large, will "self-invest" in energy efficiency measures based upon unique economic merit *irrespective* of the existence of utility-sponsored program activity.

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 higher utility cost High Achievable Potential (HAP) and an Achievable Potential (AP). Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether 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 its 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.

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As highlighted above, the HAP is the economic potential discounted for market barriers such as customer preferences and supply chain maturity; while 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 the load forecast.

4.4.3 Determining Future Demand Side Programs for the IRP

4.4.3.1 Incremental Energy Efficiency (EE)

To determine the economic demand-side EE activity to be modeled that would be over-and-above projected 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. Figure 19 and Figure 20 shows the "going-in" make-up of projected consumption in SWEPCO's Residential and Commercial sectors in the year 2018. It was assumed that the incremental programs modeled would be effective in 2018, due to the time needed to develop specific program cost and measures and receive regulatory approval to implement such programs.

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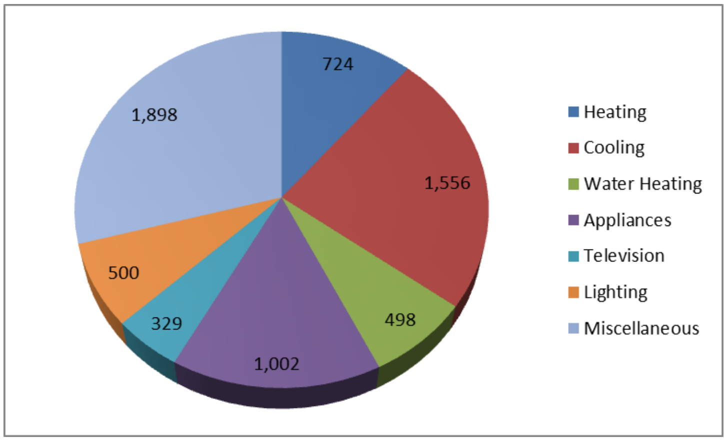

Figure 19. 2018 SWEPCO Residential End-use (GWh)

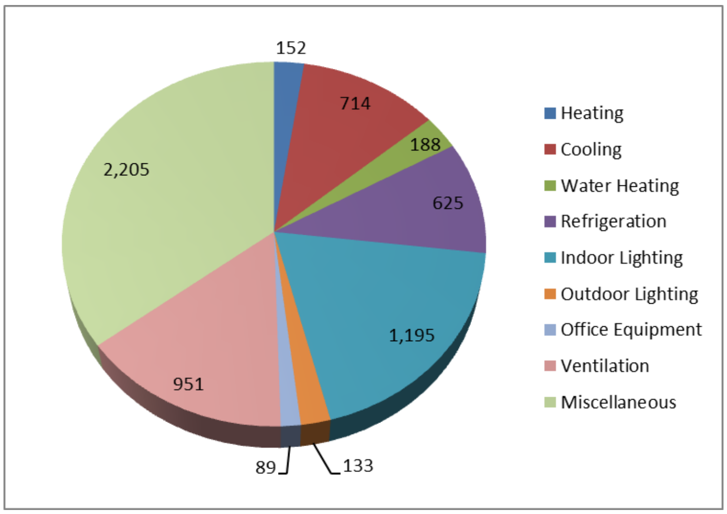

Figure 20. 2018 SWEPCO Commercial End-use (GWh)

The current programs target certain end-uses in both sectors. Future incremental EE activity can further target those areas or address other end-uses. To determine which end-uses are targeted, and in what amounts, SWEPCO looked at the previously-cited 2014 EPRI Report. This report provides comprehensive and fairly detailed 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 6 and Table 7**,** from the EPRI Report, list the individual measure categories considered for both the residential and commercial sectors.

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

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

Table 7. Commercial Sector Energy Efficiency (EE) Measure Categories

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Heat Pumps	Duct Insulation	Fans, Energy-Efficient Motors	Lighting – Screw-in
Central Air Conditioning	Water Heater	Fans, Variable Speed Control	High-Efficiency Compressor
Chiller	Water Temperature Reset	Programmable Thermostat	Anti-Sweat Heater Controls
Cool Roof	Computers	Variable Air Volume System	Floating Head Pressure Controls
Variable Speed Drive on Pump	Servers	Duct Testing and Sealing	Installation of Glass Doors
Economizer	Displays	HVAC Retro-commissioning	High-Efficiency Vending Machine
Energy Management System	Copiers Printers	Efficient Windows	Icemakers
Roof Insulation	Other Electronics	Lighting – Linear Fluorescent	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, SWEPCO has developed proxy EE bundles for both Residential and Commercial customer classes to be modeled within *Plexos*®. These bundles are based on measure characteristics identified within the EPRI report and SWEPCO customer usage, and are shown in Section 4.4.4.1.

4.4.3.2 Volt VAR Optimization (VVO)

As discussed in Section 3.5.6.2, VVO equipment is an additional resource that reduces end-use consumption. This resource is available in amounts that can be reasonably installed and tested in a given year. VVO opportunity estimates were developed and then grouped into viably-sized "tranches" to be modeled within Plexos®. The specific resources modeled are shown in Section 4.4.4.2.

4.4.3.3 Demand Response (DR)

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

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to evaluate the value of these types of programs that will meet both customer and Company needs.

4.4.3.4 Distributed Generation (DG)

DG resources were evaluated using a solar photovoltaics (PV) resource, as this is likely the primary distributed resource. Solar also has favorable characteristics in that it produces the majority of its energy at near-peak usage times. Costs were considered to be the "full" net metering (i.e. retail) rate, which is the credit required by regulation in SWEPCO's states. As previously described in Section 3, DG resources (i.e., rooftop Solar) are included in the model at an assumed growth rate based on current federal and state level incentives, future estimated costs of rooftop solar and historical rooftop solar additions.

4.4.3.5 Advanced Metering Infrastructure (AMI)

SWEPCO recognizes the potential value of Advanced Metering Infrastructure (AMI), or "smart meters", and the possible options it may provide customers with respect to managing energy consumption. As with most new advancements in technology, the initial cost of the technology is considerable and there are unforeseen complications with implementation. In an attempt to minimize any negative impact to customers, SWEPCO is currently analyzing the benefits of this new technology through the implementation programs currently being deployed by several sister companies at AEP.

4.4.4 Evaluating Incremental Demand-Side Resources

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

4.4.4.1 Incremental Energy Efficiency (EE) Modeled

Table 8 and Table 9 list the energy and cost profiles of EE resource "bundles" for the residential and commercial sectors, respectively.

Table 8. Incremental Demand-Side Residential Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Energy Savings (MWh) 2018 - 2019	Yearly Potential Energy Savings (MWh) 2020 - 2024	Yearly Potential Energy Savings (MWh) 2025 - 2029	Yearly Potential Energy Savings (MWh) 2030 - 2040	Bundle Life
Thermal Shell - AP	0.28	5,587	2,050	2,827	4,397	11
Thermal Shell - HAP	0.36	32,345	15,544	17,770	9,231	11
Cooling - AP	1.31	45,683	8,329	10,529	3,988	18
Cooling - HAP	1.62	28,514	10,035	7,196	3,467	17
Water Heating - AP	0.94	4,371	870	878	823	12
Water Heating - HAP	0.66	11,932	4,533	4,046	1,638	11
Appliances - AP	1.08	23,255	3,198	3,261	2,461	17
Appliances - HAP	1.46	28,366	8,997	6,268	5,469	17
Lighting - AP	0.15	69,589	29,847	1,252	791	30
Lighting - HAP	0.20	74,488	22,700	16,526	3,112	30

Table 9. Incremental Demand-Side Commercial Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Energy Savings (MWh) 2018 - 2019	Yearly Potential Energy Savings (MWh) 2020 - 2024	Yearly Potential Energy Savings (MWh) 2025 - 2029	Yearly Potential Energy Savings (MWh) 2030 - 2040	Bundle Life
Heating - AP	5.11	3,512	386	374	0	15
Heating - HAP	6.70	1,332	316	55	0	15
Cooling - AP	1.59	19,993	3,035	3,446	509	15
Cooling - HAP	2.08	10,275	2,987	1,326	256	15
Office Equipment - AP	1.95	3,638	653	613	486	7
Office Equipment - HAP	2.55	5,565	1,683	1,070	0	7
Indoor Lighting - AP	0.16	44,445	1,989	1,979	2,038	20
Indoor Lighting - HAP	0.20	27,589	9,388	7,720	1,782	20

As can be seen from the tables, each program has both “Achievable” Potential (AP) and “High Achievable” Potential (HAP) characteristics. The development of these characteristics is based on 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 Thermal Shell, Water Heating and Commercial Cooling—in both Achievable and High Achievable programs—include secondary measures. The MAR and PIF are utilized to develop the incremental Achievable program characteristics and the MAR only is used to develop the incremental High Achievable program characteristics. Screening tests were completed for all of the EE bundles identified in Table 8 and Table 9. The screening metrics calculated are: the Total Resources Cost (TRC), Utility Cost Test (UCT), Ratepayer Impact Measure (RIM) and Participant Cost Test (PCT). The screening was performed based on the industry standard California Public Utility Guidelines titled: “Standard Practices for Cost-Benefit

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Analysis of Conservation and Load Management Programs". Table 10, shows the resulting metric values for the EE bundles modeled.

Table 10. Energy Efficiency Bundle Cost Test Ratios

		Benefit/Cost Ratios			
Sector	**Bundle**	**PCT**	**RIM**	**TRC**	**UCT**
Residential	Thermal Shell - AP	3.8	0.9	3.7	6.0
Residential	Thermal Shell - HAP	3.0	0.8	2.4	3.0
Residential	Cooling - AP	1.2	0.7	1.1	1.8
Residential	Cooling - HAP	1.4	0.6	0.9	1.1
Residential	Water Heating - AP	1.3	0.4	0.6	1.0
Residential	Water Heating - HAP	1.9	0.4	0.7	0.9
Residential	Appliances - AP	1.3	0.5	0.1	1.2
Residential	Appliances - HAP	1.3	0.3	0.5	0.3
Residential	Lighting - AP	5.3	0.6	0.3	6.7
Residential	Lighting - HAP	4.7	0.6	3.1	0.3
Commercial	Heating - AP	0.6	0.5	0.4	0.7
Commercial	Heating - HAP	0.9	0.4	0.3	0.4
Commercial	Cooling - AP	1.0	0.4	0.5	0.9
Commercial	Cooling - HAP	1.1	0.3	0.4	0.5
Commercial	Office Equipment - AP	0.7	0.1	0.1	0.2
Commercial	Office Equipment - HAP	0.9	0.1	0.1	0.1
Commercial	Indoor Lighting - AP	4.6	1.0	5.9	9.6
Commercial	Indoor Lighting - HAP	4.4	1.0	5.1	6.3

PCT = Participant Cost Test; RIM = Ratepayer Impact Measure;
TRC = Total Resource Cost; UCT = Utility Cost Test

While many of the bundles did not provide values greater than 1.0—which indicates that the benefits of the bundle is greater than the cost—all of the bundles were offered into the *Plexos*® model. The amounts of incremental EE selected in total, and for each represented bundle, are shown in Figure 24 and Figure 25 for capacity and energy, respectively.

4.4.4.2 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 13 "tranches" based on the relative potential demand 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. Typically, a VVO tranche includes approximately 45 circuits. Table 11, below, illustrates all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in

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2014 dollars. The amount of incremental VVO selected in the model is shown in Figure 26 and Figure 27 for capacity and energy respectively.

Table 11. Volt VAR Optimization (VVO) Tranche Profiles

Tranche	State	Number of Circuits	Capital Investment	Annual O&M	kW Reduction	MWh Reduction	Total Number of Circuits	Total Capital Investment	Total Annual O&M	Total kW Reduction	Total MWh Reduction
1	Arkansas	11	$ 3,300,000	$ 99,000	4,102	16,890	48	$14,400,000	$432,000	22,534	92,778
	Louisiana	18	$ 5,400,000	$162,000	9,795	40,328					
	Texas	19	$ 5,700,000	$171,000	8,637	35,560					
2	Arkansas	10	$ 3,000,000	$ 90,000	2,989	12,307	48	$14,400,000	$432,000	12,989	53,480
	Louisiana	19	$ 5,700,000	$171,000	5,410	22,275					
	Texas	19	$ 5,700,000	$171,000	4,590	18,898					
3	Arkansas	9	$ 2,700,000	$ 81,000	2,559	10,536	46	$13,800,000	$414,000	11,084	45,634
	Louisiana	19	$ 5,700,000	$171,000	4,604	18,955					
	Texas	18	$ 5,400,000	$162,000	3,921	16,144					
4	Arkansas	10	$ 3,000,000	$ 90,000	2,574	10,599	46	$13,800,000	$414,000	10,149	41,785
	Louisiana	18	$ 5,400,000	$162,000	3,879	15,969					
	Texas	18	$ 5,400,000	$162,000	3,696	15,217					
5	Arkansas	10	$ 3,000,000	$ 90,000	2,292	9,437	48	$14,400,000	$432,000	9,534	39,252
	Louisiana	19	$ 5,700,000	$171,000	3,585	14,760					
	Texas	19	$ 5,700,000	$171,000	3,657	15,055					
6	Arkansas	9	$ 2,700,000	$ 81,000	1,721	7,087	46	$13,800,000	$414,000	8,237	33,914
	Louisiana	18	$ 5,400,000	$162,000	3,104	12,781					
	Texas	19	$ 5,700,000	$171,000	3,411	14,045					
7	Arkansas	10	$ 3,000,000	$ 90,000	1,801	7,415	47	$14,100,000	$423,000	7,605	31,310
	Louisiana	18	$ 5,400,000	$162,000	2,625	10,806					
	Texas	19	$ 5,700,000	$171,000	3,179	13,089					
8	Arkansas	9	$ 2,700,000	$ 81,000	1,454	5,986	46	$13,800,000	$414,000	6,454	26,573
	Louisiana	18	$ 5,400,000	$162,000	2,156	8,875					
	Texas	19	$ 5,700,000	$171,000	2,845	11,713					
9	Arkansas	10	$ 3,000,000	$ 90,000	1,492	6,142	47	$14,100,000	$423,000	5,844	24,062
	Louisiana	18	$ 5,400,000	$162,000	1,860	7,658					
	Texas	19	$ 5,700,000	$171,000	2,492	10,262					
10	Arkansas	9	$ 2,700,000	$ 81,000	1,109	4,564	47	$14,100,000	$423,000	4,847	19,956
	Louisiana	19	$ 5,700,000	$171,000	1,677	6,903					
	Texas	19	$ 5,700,000	$171,000	2,062	8,489					
11	Arkansas	10	$ 3,000,000	$ 90,000	1,002	4,127	47	$14,100,000	$423,000	3,905	16,079
	Louisiana	18	$ 5,400,000	$162,000	1,142	4,703					
	Texas	19	$ 5,700,000	$171,000	1,761	7,249					
12	Arkansas	10	$ 3,000,000	$ 90,000	584	2,406	48	$14,400,000	$432,000	3,003	12,363
	Louisiana	19	$ 5,700,000	$171,000	905	3,724					
	Texas	19	$ 5,700,000	$171,000	1,514	6,233					
13	Arkansas	9	$ 2,700,000	$ 81,000	380	1,566	43	$12,900,000	$387,000	1,870	7,699
	Louisiana	15	$ 4,500,000	$135,000	562	2,313					
	Texas	19	$ 5,700,000	$171,000	928	3,819					

4.4.4.3 Demand Response (DR) Modeled

As indicated in Section 4.4.3.3, additional levels of DR were not modeled as an incremental resource within this plan. However, DR associated with known and anticipated interruptible and real-time pricing initiatives have already been incorporated into SWEPCO's future "going-in" capacity position, as described in Section 2.

4.4.4.4 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

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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.

4.4.4.5 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.

4.5 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. The options assumed to be available for modeling analyses for SWEPCO are presented in Table 12.

When applicable, SWEPCO may take advantage of economical 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 utility-scale solar and wind. Further details on these technologies are available in Exhibit E. To reduce the 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 Operation 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 the *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. Utilizing 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, AEP provides current estimates to the planning process. Table 12 offers a summary of the most recent technology performance parameter data developed.

Table 12. New Generation Technology Options with Key Assumptions

Type	Capability (MW) (a)	Emission Rates SO2 (lb/mmBtu)	Emission Rates Nox (lb/mmBtu)	Emission Rates CO2 (lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load						
Nuclear	1610	0.00	0.00	0.00	90	95
Base Load (90% CO2 Capture New Unit)						
Pulv. Coal (Ultra-Supercritical) (PRB)	540	0.10	0.07	21.3	85	90
IGCC "F" Class (PRB)	490	0.06	0.06	21.3	85	88
Base / Intermediate						
Combined Cycle (1 - "F" Class)	340	0.0007	0.009	116.0	60	89
Combined Cycle (2 - "F" Class)	640	0.0007	0.009	116.0	60	89
Combined Cycle (2X1 "G" Class, w/duct firing & evap coolers)	780	0.0007	0.007	116.0	60	89
Peaking						
Combustion Turbine (2 - "E" Class)	170	0.0007	0.033	116.0	3	93
Combustion Turbine (2 - "F" Class, w/evap coolers)	430	0.0007	0.009	116.0	25	93
Aero-Derivative (1 - Small Machine)	50	0.0007	0.093	116.0	3	96
Aero-Derivative (2 - Small Machines)	90	0.0007	0.093	116.0	3	96
Recip Engine Farm (3 Engines)	50	0.0007	0.093	116.0	3	96

Notes: (a) Capability at Standard ISO Conditions at 1,000 feet above sea level.

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4.5.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by SWEPCO but were not included in the ultimate *Plexos*® resource optimization modeling analyses. The forecasted difference between SWEPCO's load forecast and existing resources are such that a large, central generating station would not be required. In addition, for coal generation resources, the proposed EPA New Source Performance Standards (NSPS) rulemaking effectively makes the construction of new coal plants environmentally/economically impractical due to the implicit requirement of carbon capture and sequestration (CCS) technology. For new nuclear construction, it is financially impractical since it would potentially require an investment of, minimally, $6,000/kW.

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 have 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' staffs have made strides to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and subcritical units are retired, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

4.5.3.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a Heat Recovery Steam Generator (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 45-60% Low 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

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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” resources 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 Natural Gas Combustion Turbines (NGCT)

In “industrial” or “frame-type” Natural Gas Combustion Turbine (NGCT) 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.

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A simple cycle combustion turbine 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% LHV), 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 7EA frame machine requires 20 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 on the order of 20% 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) 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 the aeroderivative units.

Some of the better known AD vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.[9]

[9] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG.

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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 (SI) 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. The RE generators have high efficiency, flat heat rate curves and rapid response makes 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 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 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.

The main North American suppliers for utility scale natural gas-fired RE most recently have been Caterpillar and Wartsila[10].

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 recent past, development of these resources has been

[10] Technical Assessment Guide (TAG) Power Generation and Storage Technology Options, 2012; Electric Power Research Institute.

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driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar PV and wind turbine manufacturing have reduced both installed and ongoing costs.

4.5.5.1 Utility-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 power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (typically 2kW to 20MW per installation) and can be distributed throughout the grid.

The cost of installed solar projects has declined considerably in the past decade and is expected to continue to decline, as shown in Figure 21. 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.

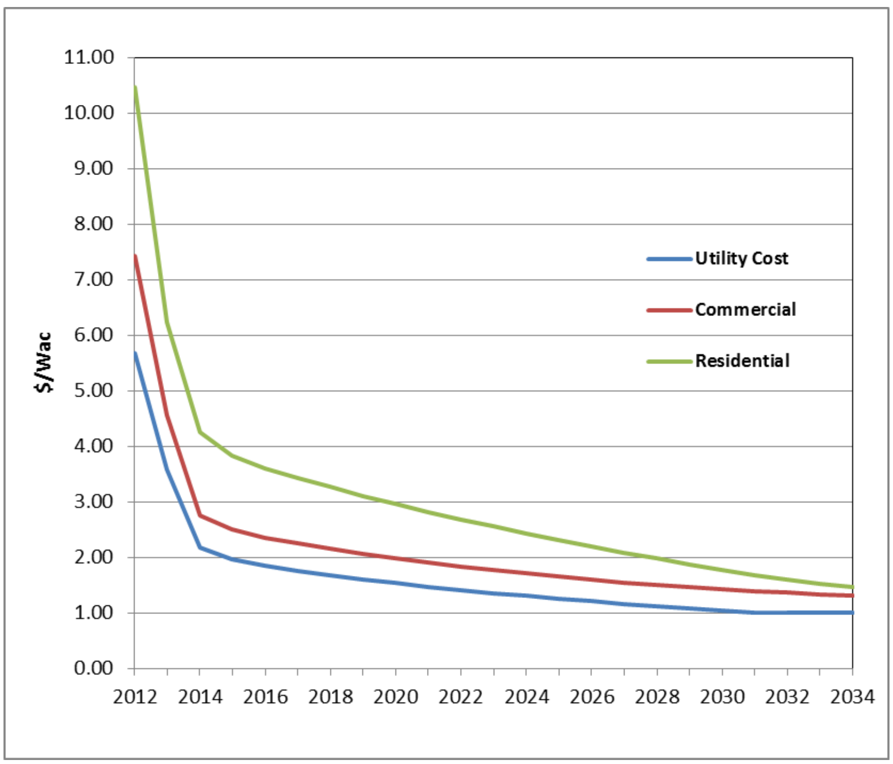

Figure 21. Forecasted Solar Installed Costs for SWEPCO Territory (Excl. Fed & State Incentives)

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Not only are utility-scale solar plants getting less expensive, the costs to install solar panels in distributed locations, often on a rooftop, are lessening as associated hardware, such as inverters, racks, and wiring bundles become standardized. If the projected cost declines materialize, both distributed and utility-scale solar projects will be economically justifiable in the future.

Utility solar plants require less lead time to build than fossil plants. There is not a defined limit to how much utility solar can be built in a given time. However, in practice, solar facilities are not added in an unlimited fashion.

Solar resources were considered available resources with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that utility-scale solar resources were available up to 50MWac[11] of nameplate capacity starting in 2016. To provide some context, a typical commercial installation is 50kW and effectively covers the surface of a typical big box retailer's roof. A 50MW utility-scale solar farm is assumed to consume nearly 350 acres, or 1,000 big box retailer roofs. 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. This 50MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted and constructed by SWEPCO in a given year. 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' useful capacity is less than its nameplate rating. This IRP assumes solar resources will have capacity valued at 42% of nameplate rating.

4.5.5.2 Wind

Utility-scale wind energy is generated by turbines ranging from 1.0 to 2.5MW, with a 1.5MW turbine being the most common size used in commercial applications today. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project

[11] 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.

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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 its proximity to a transmission system with available capacity 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 very remote locations, which forces the electricity to be transmitted long distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid.

For modeling purposes, wind was considered under various 'blocks' or 'tranches' for each year. There are three tranches of wind with different pricing. The first tranche of wind resources, Tranche A was modeled as a 100MW block with a Levelized Cost Of Energy (LCOE) with the Production Tax Credit (PTC) of $24/MWh in 2015 and a 55% capacity factor load shape. In 2017, after the expiration of the PTC, the LCOE of Tranche A increases to $47/MWh in nominal dollars with prices increasing 0.5%/year through 2035. Tranche A resources were assigned a capacity value of 20% of nameplate rating. The second tranche of wind resources, Tranche B, was modeled as a 100MW block with a LCOE with the PTC of $28/MWh in 2015$ and a 50% capacity factor load shape. In 2017, after the assumed expiration of the PTC, the LCOE of Tranche B increases to $51/MWh in nominal dollars with prices increasing 2%/year through 2035. Tranche B resources were assigned a capacity value of 10% of nameplate rating. The third tranche of wind resources, Tranche C, was modeled as a 100MW block with a LCOE with the PTC of $37/MWh in 2015$ and a 45% capacity factor load shape. In 2017, after the assumed expiration of the PTC, the LCOE of Tranche C increases to $60/MWh in nominal dollars with prices increasing 2%/year through 2035. Tranche C resources were assigned a capacity value of

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5% of nameplate rating. Wind prices were developed based on the U.S. DOE's Wind Vision Report.[12]

The expected magnitude of wind resources available per year was limited to 300MW (nameplate) with a limit of 1,200MW nameplate, incremental to that which is currently planned. This cap is based the DOE's Wind Vision Report chart on page 12 that suggest from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe. The cap for SWEPCO allows the model to select up to 30% of generation capacity resources as wind-powered by 2035. Figure 22 illustrates the three tranches of wind resources modeled and the relative LCOE pertilized for each tranche.

Figure 22. LCOE (nominal $/MWh) for Wind Resource Tranches Included in SWEPCO Model

[12] *WindVision: A New Era for Wind Power in the United States* (2015). Retrieved from http://www1.eere.energy.gov/library/default.aspx?Page=9

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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 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 through the utilization of the biomass fuel in 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.

4.5.6 Cogeneration & Combined Heat & Power (CHP)

Cogeneration is a process where electricity is generated and the waste heat by-product is used for heating or other process, raising the net thermal efficiency of the plant. 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 has five cogeneration customers, one customer in the Arkansas jurisdiction and four customers within the Texas jurisdiction. Table 13, is a summary of SWEPCO's cogeneration customers. The majority of this CHP capacity is related to the chemical and paper industries.

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Table 13. SWEPCO Cogeneration Capacity

State	Industrial Sites	Industrial Capacity (MW)	Commercial Sites	Commercial Capacity (MW)	Total Sites	Total Capacity (MW)
Arkansas	1	130	0	0	1	130
Louisiana	0	0	0	0	0	0
Texas	4	529	0	0	4	529
Total	**5**	**659**	**0**	**0**	**5**	**659**

Historically, SWEPCO's low cost of energy combined with the relatively high cost of natural gas, a primary fuel for cogeneration facilities, has made cogeneration uneconomical in SWEPCO's service territory. SWEPCO is occasionally approached by customers for help in evaluating CHP and cogeneration opportunities, but the Company's relatively low avoided costs have been a significant barrier to-date for any serious implementation consideration. Most recently SWEPCO has worked with the University of Arkansas in Fayetteville to interconnect an expected 5MW CHP project. While, SWEPCO has the flexibility to include smaller CHP offerings within its EE programs, given the unique customer/site-specific consideration of larger-scale CHP, no such incremental CHP resources were considered in this IRP.

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

4.6.1 Optimization of Expanded DSM Programs

As described in Section 4.4.4, 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 with *no* subsequent annual operating costs. Likewise, they are "retired" at the end of their useful (EE measure) lives (see Table 4-3).

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 discussed in Section 3.5.6.1. DG installation costs to SWEPCO were zero, with all costs paid by the customer.

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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 that minimize the CPW of a planning entity's generation-related variable and fixed costs over a long-term planning horizon.

Plexos® accomplishes this by 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 a 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's 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 were effectively value at the equivalent of a full-retail "net metering" credit to those customers (*i.e.*, a "utility" perspective); and
- a 'netting' of the production revenue made into 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 addition and retirement candidates (*i.e.*, maximum units built);
- Age and lifetime of generators;
- 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;

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- Emission limits on effluents such as SO_2 and NO_X; and
- Energy contract parameters such as energy and capacity.

The model inputs that compose 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 spends for transmission interconnection costs.

5.1.1 Key Input Parameters

Two of the major underpinnings in this process 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 views were created internally within AEP. The load forecast, including the SWEPCO load and demand summary offered in Exhibit B was created by the AEP Economic Forecasting organization, while the long-term commodity pricing forecast was created by the AEP Fundamental Analysis group. Exhibit F offers tables that summarize several of the key long-term fundamental commodity pricing projections utilized in these analyses. 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.

Other critical input parameters include the installed cost of replacement capacity alternative options, as well as the attendant operating costs associated with those options; data which was sourced from the AEP Engineering Services organization.

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5.2 *Plexos*® Optimization

5.2.1 Modeling Options and Constraints

The major system limitations that were modeled by use of constraints are elaborated on below. The LT Plan®, LP optimization algorithm operates modeled constraints in tandem with the objective function in order to yield the least-cost resource plan. For instance, the model required capacity additions to meet a 15% reserve margin, slightly above the SPP-required minimum reserve margin of roughly 13.6% as represented earlier in this report in the development of SWEPCO's "going-in" capacity position. This slightly higher reserve margin allows the model to select larger blocks of resources in a given year if they provide energy value relative to the SPP market while also providing a physical hedge against unanticipated SWEPCO unit retirements.

There are many variants of available supply-side and demand-side resource options and types. It is a practical limitation that 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 duty cycle "families" (base-load, intermediate, and peaking).

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 will be considered that will determine the ultimate technology type (e.g., choices for peaking technologies). The full list of screened supply options is included in Exhibit E.

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 2017 due to the anticipated period required to approve, site, engineer and construct, from:
    - NGCT units consisting of two "E" class turbines rated at 176MW at standard conditions and 179MW at summer conditions.
    - AD units (2) at 92MW at standard conditions and 87MW at summer conditions.
- *Intermediate* capacity was modeled, effective in 2019 due to anticipated period required to approve, site, engineer and construct, from:

- NGCC (2x1 "G" class turbine with duct firing and evaporative inlet air cooling) facility, rated at 779MW at standard conditions and 870MW at summer conditions. These units were offered to the model at two levels: a 50% stake (435MW summer capacity) and a 100% stake.

- Wind resources were made available up to 300MW annually consisting of three tranches of 100MW at an initial levelized cost of $47/MWh, $51/MWh, $60/MWh (without PTC). 1,200MW of incremental nameplate wind was made available.
- Utility-scale solar resources were made available up to 50MW annually of incremental nameplate capacity, consisting of two tranches. The first tranche is Louisiana based and has an installed cost of $1,970/kw. The second tranche is SPP based and has an installed cost of $2,030/kW.
- DG, in the form of distributed solar resources in 5kW sizes, was made available in amounts equal to approximately 5% of annual increases after the Louisiana incentive cap (7.8MW) is met.
- EE resources, incremental to those already incorporated into the Company's long-term load and peak demand forecast, were made available in 18 unique "bundles" of Residential and Commercial measures considering cost and performance parameters for both HAP and AP categories.
- VVO was available in 13 tranches of varying installed costs and number of circuits/sizes ranging from a low of 2MW, up to 22MW.

5.2.2 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 using the 'Base' load and demand forecast, but under five different long-term commodity pricing scenarios:

1. 'Base' pricing
2. 'High Band' pricing
3. 'Low Band' pricing
4. 'High CO_2' (or High Carbon) pricing
5. 'No CO_2' (or No Carbon) pricing

Two sensitivity portfolio evaluations were conducted under 'Base' commodity pricing, but using two different long-term load (and peak demand) forecasts:

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6. ‘High Load’ sensitivity
7. ‘Low Load’ sensitivity

Two additional “sensitivity” portfolio evaluations were created under the Base pricing *and* load forecasts assessing:

8. ‘Accelerated Gas-Steam Unit Retirement’ sensitivity
9. ‘Early Solid-Fuel Unit Retirement’ sensitivity

Finally, risk or “stochastic” analyses were then performed on select portfolios.

5.2.2.1 Optimization Modeling Results Under the Base Load Forecast

Portfolios 1 through 5 were all optimized under the base load forecast. A summary of the cumulative capacity additions is provided below in Table 14. Note that all portfolios include a diversity of resource options such as natural gas fired generation, energy efficiency, and renewable resources. The capacity values for intermittent resources (wind, utility-scale and distributed solar) represent firm capacity for reserve margin planning purposes, not nameplate values.

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Table 14. Cumulative SPP Capacity Additions (MW) for Five Commodity Pricing Scenarios

Commodity Pricing Scenarios		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1. Base	Base/Intermediate											435	435	435	435	435	435	435	435	870	870
	Peaking																				
	Solar						21	42	63	84	105	126	147	168	189	210	231	252	273	294	315
	Wind		30	30	30	30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210
	EE				22	43	48	53	58	63	68	71	74	77	80	82	85	86	87	88	89
	VVO			26	26	26	26	38	51	63	73	73	73	73	73	73	73	73	73	73	73
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5
2. High	Base/Intermediate											435	435	435	435	435	435	435	435	870	870
	Peaking																				
	Solar						21	42	63	84	105	126	147	168	189	210	231	252	273	294	315
	Wind		30	30	30	30	30	30	30	30	30	30	60	80	100	120	140	160	180	200	220
	EE				22	43	48	53	58	63	68	71	74	77	80	80	81	82	83	84	85
	VVO			26	26	26	26	38	51	63	73	73	73	73	73	73	73	73	73	73	73
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5
3. Low	Base/Intermediate											435	435	435	435	435	435	435	435	870	870
	Peaking																				
	Solar						8	29	50	1	92	113	134	155	176	197	218	239	260	281	302
	Wind		30	30	30	30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210
	EE				22	43	48	53	58	64	74	77	80	83	87	92	96	97	98	99	99
	VVO					26	38	51	63	73	83	83	83	83	83	83	83	83	83	83	58
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5
4. High Carbon	Base/Intermediate											435	435	435	435	435	435	435	435	870	870
	Peaking																				
	Solar						21	42	63	84	105	126	147	168	189	210	231	252	273	294	315
	Wind		30	30	30	30	30	30	30	30	30	30	60	80	100	120	140	160	180	200	220
	EE				22	43	48	53	58	63	68	71	74	76	79	80	81	82	83	84	85
	VVO			26	26	26	26	38	51	63	73	73	73	73	73	73	73	73	73	73	73
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5
5. No Carbon	Base/Intermediate											435	435	435	435	435	435	435	435	870	870
	Peaking																				
	Solar						8	29	50	71	92	113	134	155	176	197	218	239	260	281	302
	Wind		30	30	30	30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210
	EE				22	41	46	51	56	66	75	78	81	84	88	94	98	99	100	101	101
	VVO					26	38	51	63	73	83	83	83	83	83	83	83	83	83	83	58
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5

Base/Intermediate=NGCC; Peaking=NGCT, AD; EE=Energy Efficiency; VVO=Volt VAR Optimization; DG=Distributed Generation

Close examination of the optimized plan results provides SWEPCO with insight in developing a "preferred" resource plan. For example, no new natural gas capacity is required prior to 2025 under any pricing scenario. Also by 2018 a combination of commercial and residential incremental energy efficiency programs are added under all pricing scenarios. These programs provide additional capacity of at least 85MW by the end of the planning period in all scenarios. VVO and wind are selected in relatively comparable amounts over the planning period in all pricing scenarios, while utility-scale solar is more favored in the Base, High Band and High CO_2 pricing scenarios. Note that distributed solar must be "forced in" to the portfolios as it will generally not be selected as an optimal resource because, under the net-metering construct, the utility must pay the full retail rate for the kWh's created, which includes costs-of-service for generation, transmission and distribution, while only "avoiding" the (lower) SPP market cost of energy.

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5.2.2.1 Optimization Modeling Results of Load Scenarios

Table 15 illustrates the anticipated relationship between the forecasted load and the company's required resources. The High Load scenario calls for additional intermediate level natural gas generation, beginning in 2021, than in based load scenarios analyzed above. The Low Load scenario's portfolio does not include any new natural gas generation. Both the High and Low Load scenarios result in quantities of wind and utility-scale solar comparable to the commodity pricing scenarios above in Table 14.

Table 15. Cumulative SPP Capacity Additions (MW) for Load Scenarios

Load Scenarios		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
6. High Load	Base/Intermediate							435	435	435	435	435	870	870	870	870	870	870	1,305	1,305	1,305
	Peaking																				
	Solar						21	42	63	84	105	126	147	168	189	210	231	252	273	294	315
	Wind		30	30	30	30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210
	EE				22	43	48	53	59	65	75	83	86	89	92	96	100	104	105	106	107
	VVO			26	26	26	26	26	38	51	63	73	73	73	73	73	73	83	83	83	83
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5
7. Low Load	Base/Intermediate																				
	Peaking																				
	Solar							21	42	63	84	105	126	147	168	189	210	231	252	273	294
	Wind		30	30	30	30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210
	EE				22	43	48	53	58	60	62	65	68	71	74	76	80	81	82	84	85
	VVO			26	26	26	26	26	26	26	26	38	51	63	63	63	63	63	63	63	63
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5

Base/Intermediate=NGCC; Peaking=NGCT, AD; EE=Energy Efficiency; VVO=Volt VAR Optimization; DG=Distributed Generation

5.2.2.2 Optimization Modeling Results of Sensitivity Scenarios

Two sensitivity scenarios were analyzed in order to gain an understanding of the impacts early unit retirements can have on SWEPCO's capacity position. Table 16 shows the cumulative capacity additions for each sensitivity scenario analyzed. The first of these scenarios considered what capacity resources would be selected if SWEPCO were to retire all gas-steam units five years earlier than initially planned. The early retirement of these units would result in the need for intermediate level natural gas generation beginning in 2021, as well as an increased need for utility-scale solar resources beginning in 2016, when compared to the base commodity scenario.

The second scenario considered the impact of retiring a large coal-fired unit earlier than currently planned. In this scenario, the 580MW Pirkey Unit 1 was retired in 2026 which is 19 years earlier than currently planned. In this scenario the need for additional intermediate level natural gas resources is seen in 2026.

Both sensitivity scenarios call for 435MW more intermediate level natural gas generation than the base commodity scenario.

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Table 16. Cumulative SPP Capacity Additions (MW) for Sensitivity Scenarios

Sensitivity Scenarios		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
8. Early Gas-Steam Retire	Base/Intermediate							435	435	435	435	435	435	435	435	435	435	870	1,305	1,305	1,305
	Peaking																				
	Solar		21	25	25	46	46	67	88	109	130	151	172	193	214	235	256	277	298	319	340
	Wind		30	30	30	30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210
	EE				30	62	71	76	81	83	85	87	90	93	96	97	98	99	100	101	101
	VVO			26	38	51	63	63	63	63	63	63	63	63	63	63	63	63	63	50	37
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5
9. Early Coal (Lignite) Retire	Base/Intermediate											435	870	870	870	870	1,305	1,305	1,305	1,305	1,305
	Peaking																				
	Solar						17	38	59	80	101	122	143	164	185	206	227	248	269	290	311
	Wind		30	30	30	30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210
	EE				22	43	48	53	59	67	77	80	83	86	89	89	90	91	92	93	94
	VVO			26	26	26	26	38	51	63	73	73	73	73	73	73	73	73	73	73	73
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5

Base/Intermediate=NGCC; Peaking=NGCT, AD; EE=Energy Efficiency; VVO=Volt VAR Optimization; DG=Distributed Generation

5.2.3 Preferred Plan

Each of the nine scenarios provides insight into a potential alternative mix of resources for the future. This mix, referred to as the Preferred Plan, is shown below in Table 17. In comparison to the Base commodity scenario the Preferred Plan includes the following:

- Increased levels of renewable energy
- Earlier adoption of utility-scale solar
- One year delay in the need for intermediate level natural gas resources
- Earlier increase in the level of wind resources
- Increased amounts of EE and VVO

Table 17. Cumulative SPP Capacity Additions (MW) for Preferred Plan

Preferred Plan		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Base Commodity, Base Load	Base/Intermediate												435	435	435	435	435	435	435	435	435
	Peaking																				
	Solar			21	21	42	63	84	105	126	147	168	189	210	231	525	273	294	315	336	357
	Wind			30	30	30	30	30	30	50	70	90	110	130	150	170	190	210	230	230	230
	EE				22	43	49	54	64	75	91	113	116	118	121	122	123	124	125	127	129
	VVO			26	26	26	38	51	63	73	83	92	92	92	92	92	92	92	92	92	92
	DG		1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	5	5	5

Base/Intermediate=NGCC; Peaking=NGCT, AD; EE=Energy Efficiency; VVO=Volt VAR Optimization; DG=Distributed Generation

Incremental wind resources were added in 2017 in the Preferred Plan, as opposed to 2016 in the Base commodity pricing scenario. New wind resources will be investigated for implementation in 2016, however the length of time needed to evaluate prospective projects and obtain regulatory approval may push in-service dates back to the end of 2016. In such a scenario the SPP capacity credit for these resources would not be credited to SWEPCO until the 2017 planning year. Additional wind resources were advanced to 2023 in the Preferred Plan in order to

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position SWEPCO for compliance with any requirements resulting from the Clean Power Plan. The need for an intermediate level natural gas resource was pushed back one year in order to delay the need for a capital intensive investment. Increases in utility-scale solar, EE, and VVO were the result of these two strategic decisions.

The Preferred Portfolio offers SWEPCO significant flexibility should future conditions differ considerably from assumptions. For example, as EE programs are implemented, SWEPCO will gain insight into customer acceptance and develop hard 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. Flexibility is also achieved by the delayed need for natural gas capacity. By making small capacity additions over the next decade SWEPCO will able to adapt to changing market conditions for resources such as renewables.

5.2.3.1 Energy Efficiency (EE), Volt VAR Optimization (VVO) and Distributed Generation (DG) Results

5.2.3.1.1 Energy Efficiency (EE) Results

Figure 23, below, shows SWEPCO's total EE profile over the planning period. In the 'Base' pricing plan, incremental EE resources were selected. Overall, both Residential and Commercial programs are providing 129MW of capacity end of the planning period. The programs providing the majority of the savings are Commercial Lighting, Residential Lighting and Residential Thermal Shell programs. Figure 24 and Figure 25, illustrates the detailed annual capacity and energy savings by modeled EE program.

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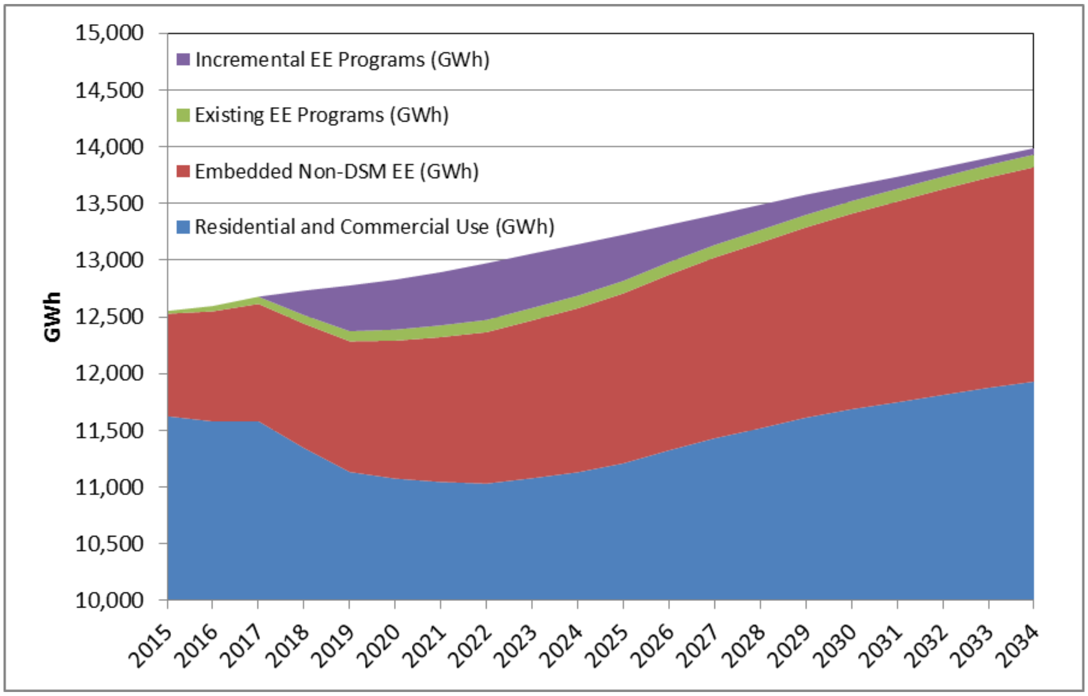

Figure 23. SWEPCO Energy Efficiency Energy Profile over Planning Period (2015-2034)

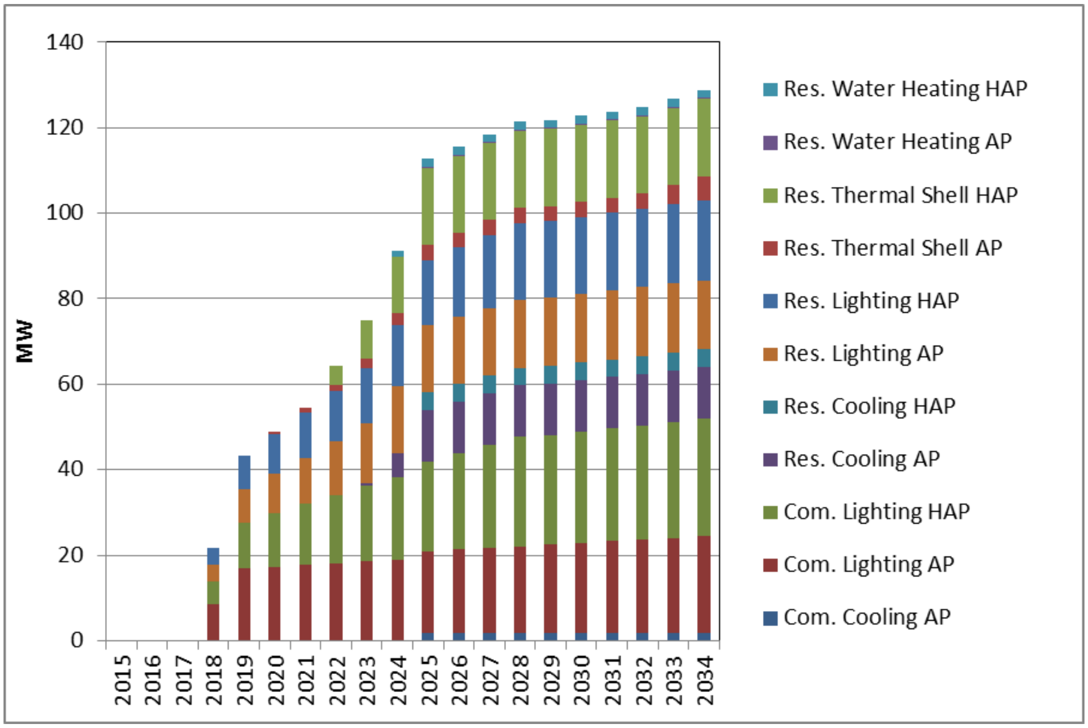

Figure 24. Preferred Plan Energy Efficiency (EE) Demand Savings (MW)

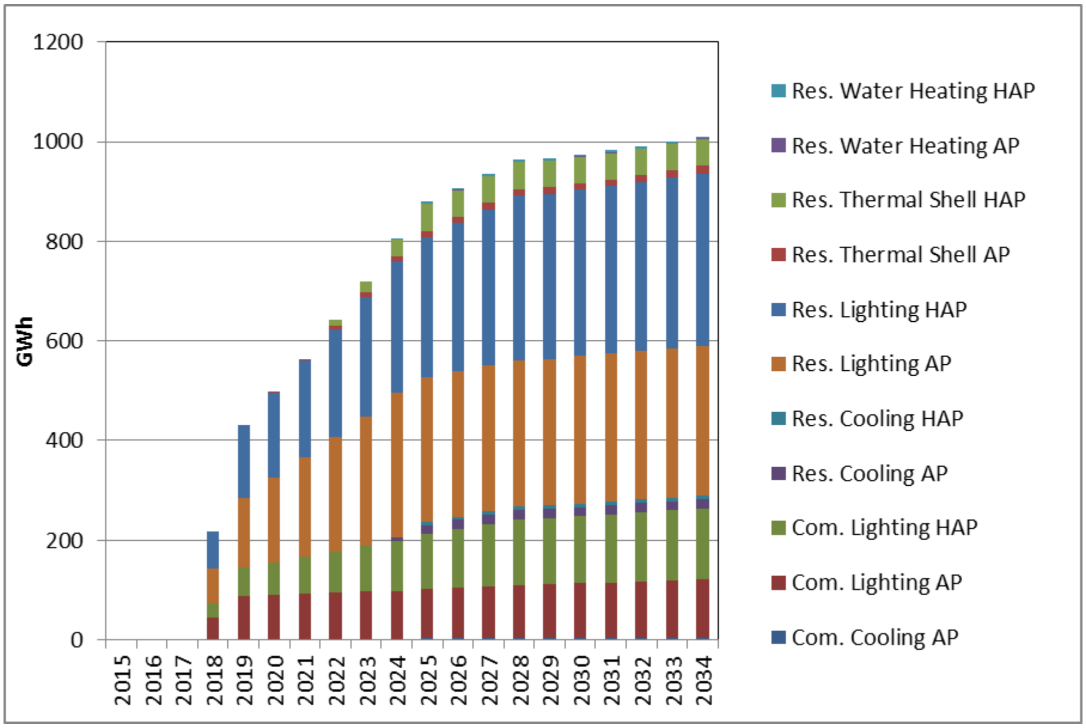

Figure 25. Preferred Plan Energy Efficiency (EE) Energy Savings (GWh)

5.2.3.1.2 Volt VAR Optimization (VVO)

In the Base pricing plan, 7 of the 13 available VVO tranches were ultimately selected by the model, with the first tranche of circuits added in 2017, and tranches 2 through 7 are added one tranche per year beginning in 2020 through 2025. The “tranches” of VVO consist of circuits that provide both summer peak demand reduction and significant annual energy reduction, as previously shown in Table 11. Figure 26 and Figure 27 illustrate the schedule when VVO resources were optimized and selected, along with the potential savings amounts per tranche for both peak demand and energy. The VVO estimates are subject to future revision as more operational information is gained from installations that are currently underway throughout the AEP system.

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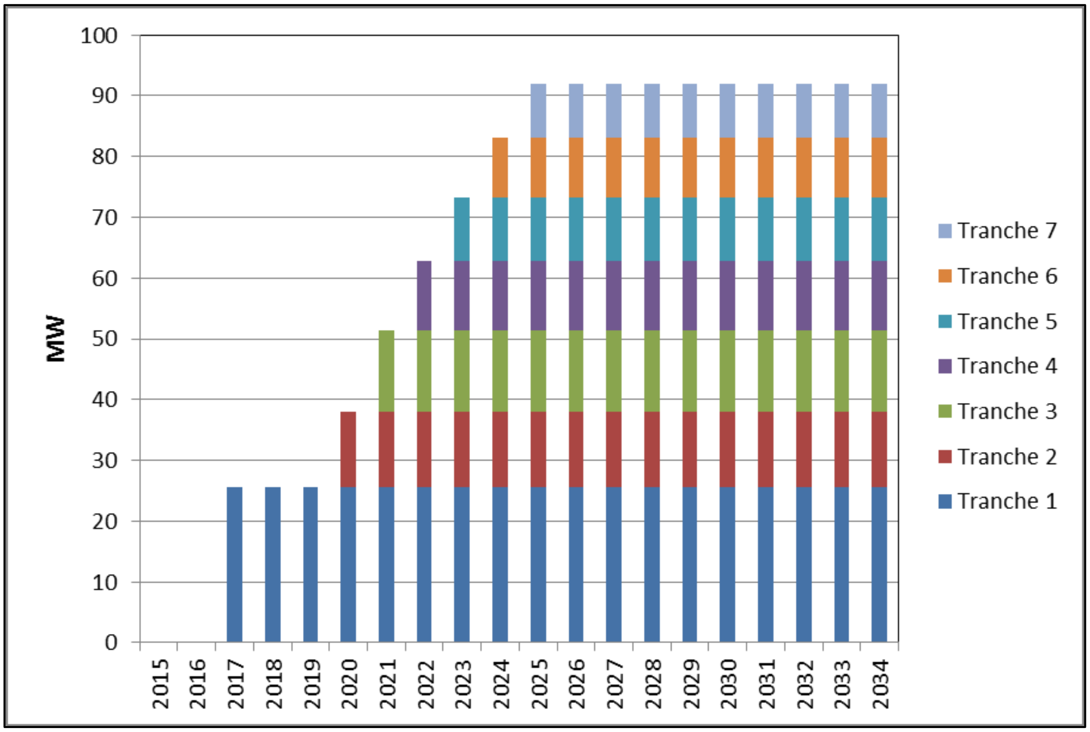

Figure 26. Preferred Plan Volt VAR Optimization (VVO) Demand Savings (MW)

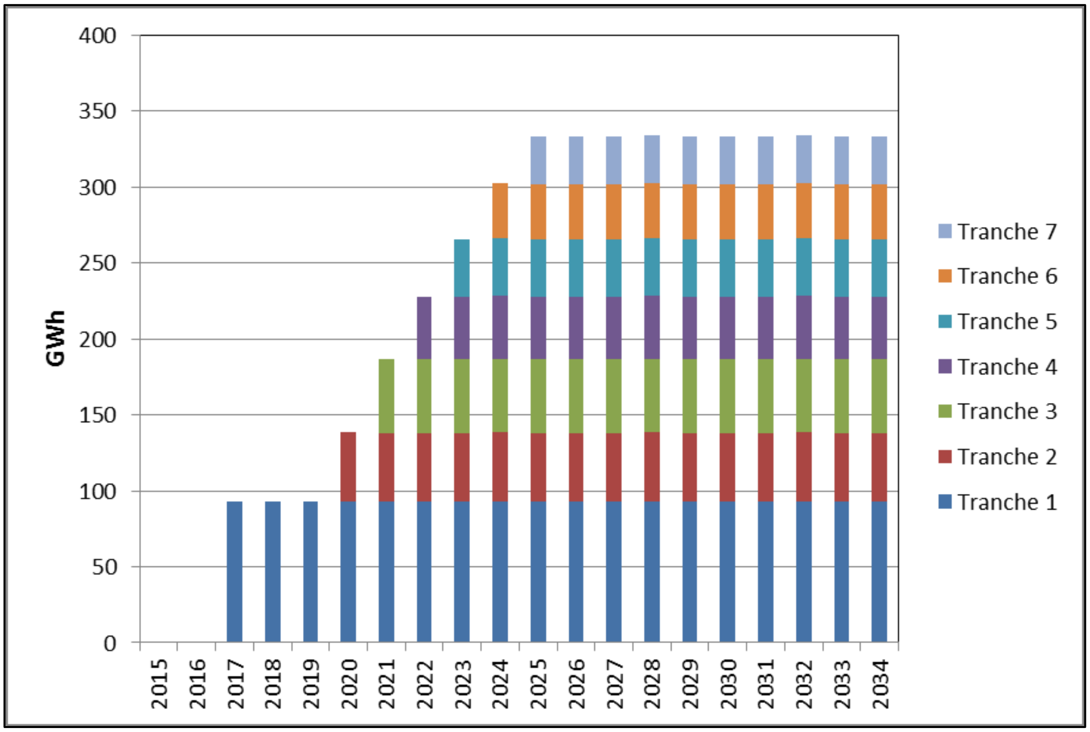

Figure 27. Preferred Plan Volt VAR Optimization (VVO) Energy Savings (GWh)

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5.2.3.1.3 Distributed Generation (DG)

DG resources were not optimized under any economic scenario during the planning period. Distributed rooftop solar was included as a resource based on historical additions for SWEPCO, the continued decline in the installed cost of solar resources and the ongoing Louisiana Residential rooftop solar incentive. Figure 28 below, illustrates the embedded rooftop solar and well as the forecasted DG solar additions that were trended from the installation history.

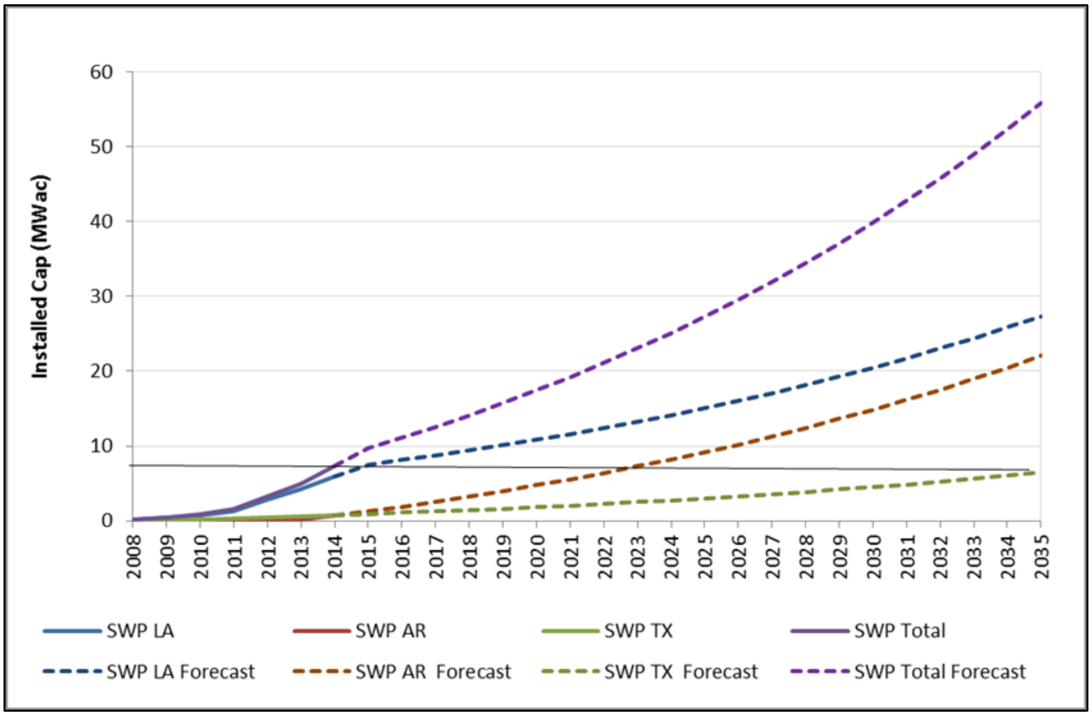

Figure 28. Cumulative Distributed Generation (DG) Rooftop Solar Additions/Projections for SWEPCO

5.2.4 Future CO_2 Emissions Trending – Preferred Plan

Figure 29 through Figure 32 offer a long-term view of the SWEPCO "total company" and state-specific projected CO_2 emissions—under both an "(intensity) rate" and "mass-based" view—for the IRP Preferred Plan portfolio. Such projected emission levels are identified as of the interim (2022 through 2029) as well as final (2030 and beyond) implementation periods set forth in the Final CPP. These charts offer a summary depiction of SWEPCO's trends—versus a 2012 (Actual) baseline—regarding CO_2 emissions that result from actions undertaken as part of this IRP process.

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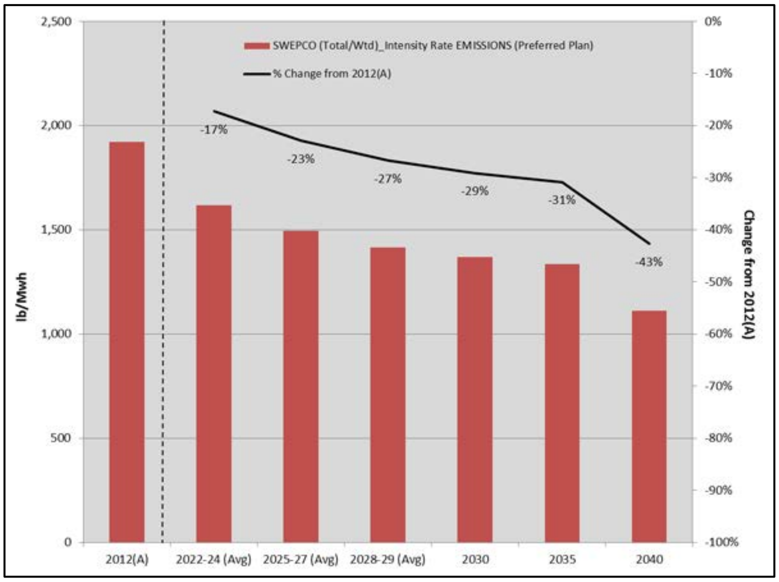

Figure 29. SWEPCO Preferred Plan Projected CO_2 Emissions Intensity Rate

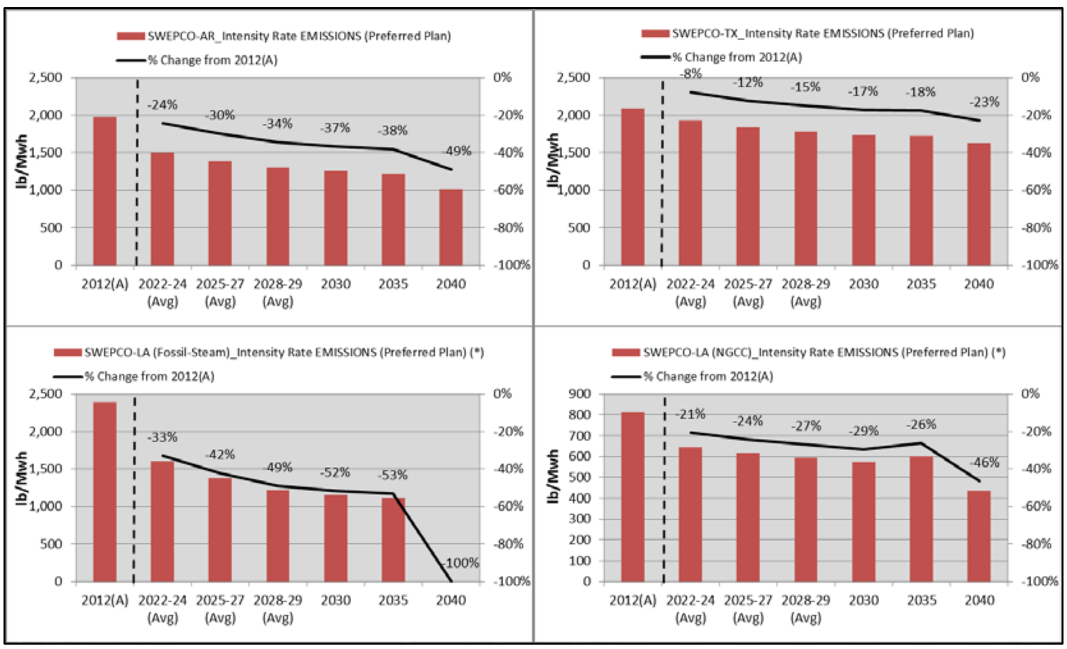

Figure 30. SWEPCO State Specific Project CO_2 Emission Intensity Rates[13]

[13] Determination of fossil category-specific SWEPCO-Louisiana "Fossil-Steam" and SWEPCO-Louisiana "NGCC" Intensity Rates reflects pro-rata allocation of both 'post-2012' and projected SWEPCO-Louisiana carbon-free (Mwh) resources in the respective calculated rate denominators.

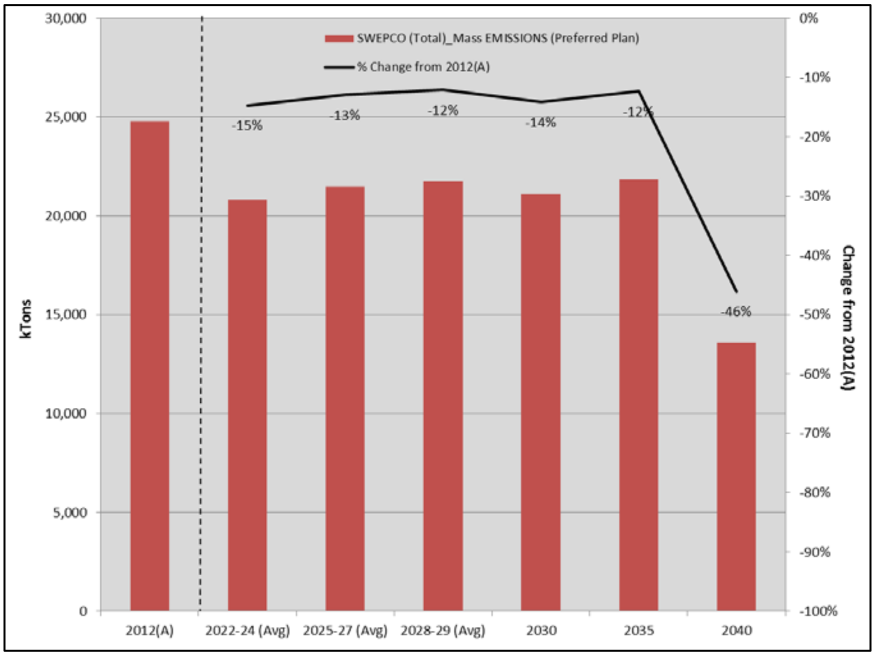

Figure 31. SWEPCO Preferred Plan Projected CO_2 Mass Emissions

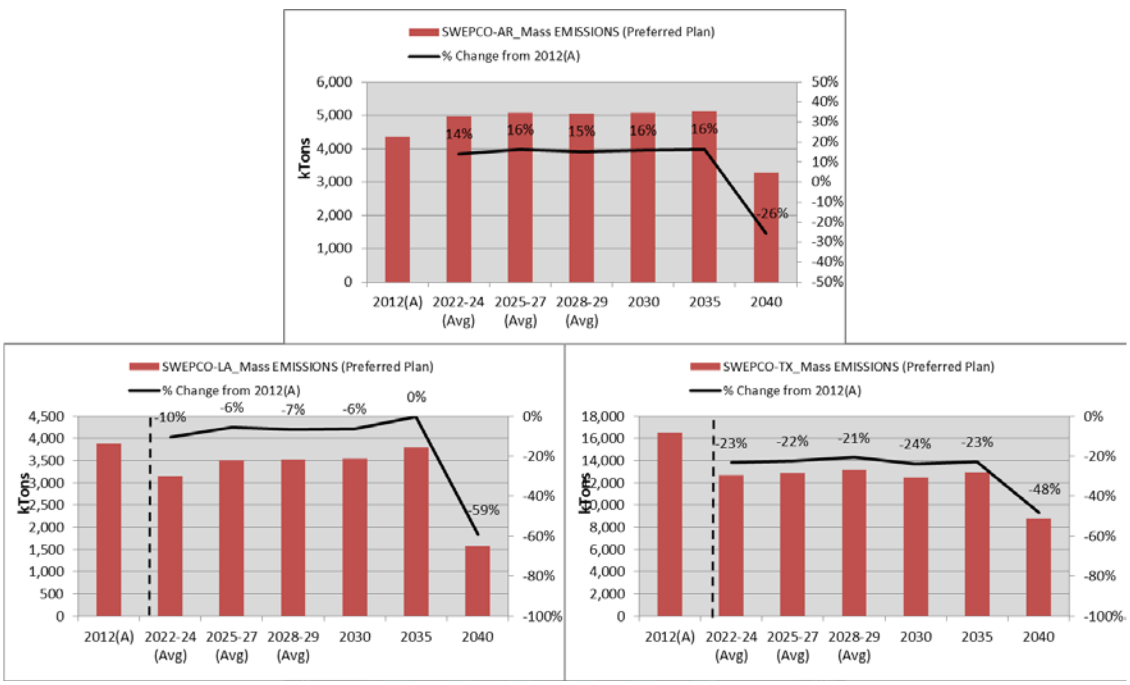

Figure 32. SWEPCO State Specific Preferred Plan Projected CO_2 Mass Emissions

5.3 Risk Analysis

In addition to developing the Preferred Portfolio based on the discrete, optimized portfolio created under Base pricing assumptions, the Preferred portfolio, Early Coal Retirement portfolio,

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and Early Gas-Steam Retirement portfolio (the "early plant retirement portfolios") were 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 four 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. Figure 33 shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other. The range of values associated with the variable inputs is shown in Figure 34.

	CO_2	Natural Gas	Power
CO_2	1	0.96	0.95
Natural Gas		1	0.47
Power			1
Standard Deviation	43.0%	19.0%	14.7%

Figure 33. Risk Analysis Factors and Relationships

The Preferred Portfolio was evaluated and compared to early plant retirement portfolios to provide a distinctly different resource profile, and therefore different revenue requirements, than those in the Preferred Portfolio.

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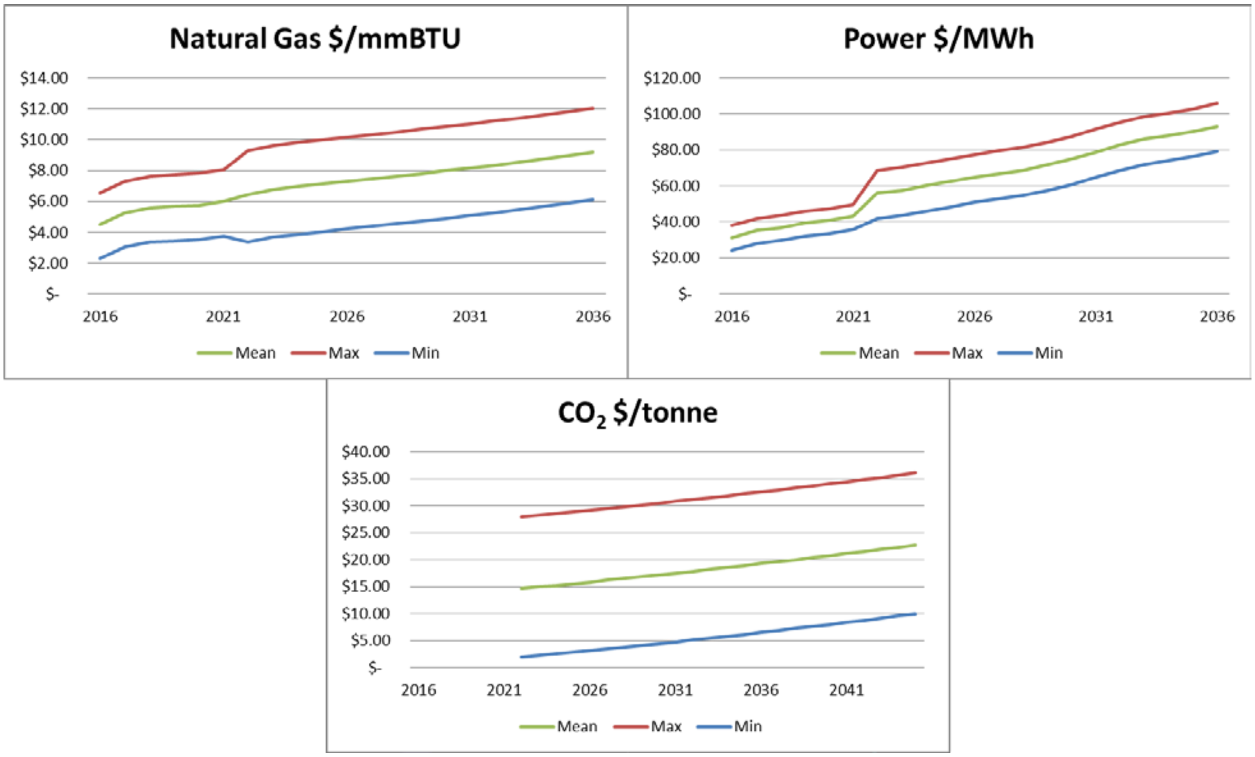

Figure 34. Range of Variable Inputs for Stochastic Analysis

5.3.1 Stochastic Modeling Process and Results

For each portfolio, the differential between the median and 95th percentile result from the multiple runs was identified as Revenue Requirement at Risk (RRaR). 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% 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 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 35 illustrates the RRaR and the expected value graphically displayed. The RRaR for the Early Coal Retirement plan is depicted specifically in the figure.

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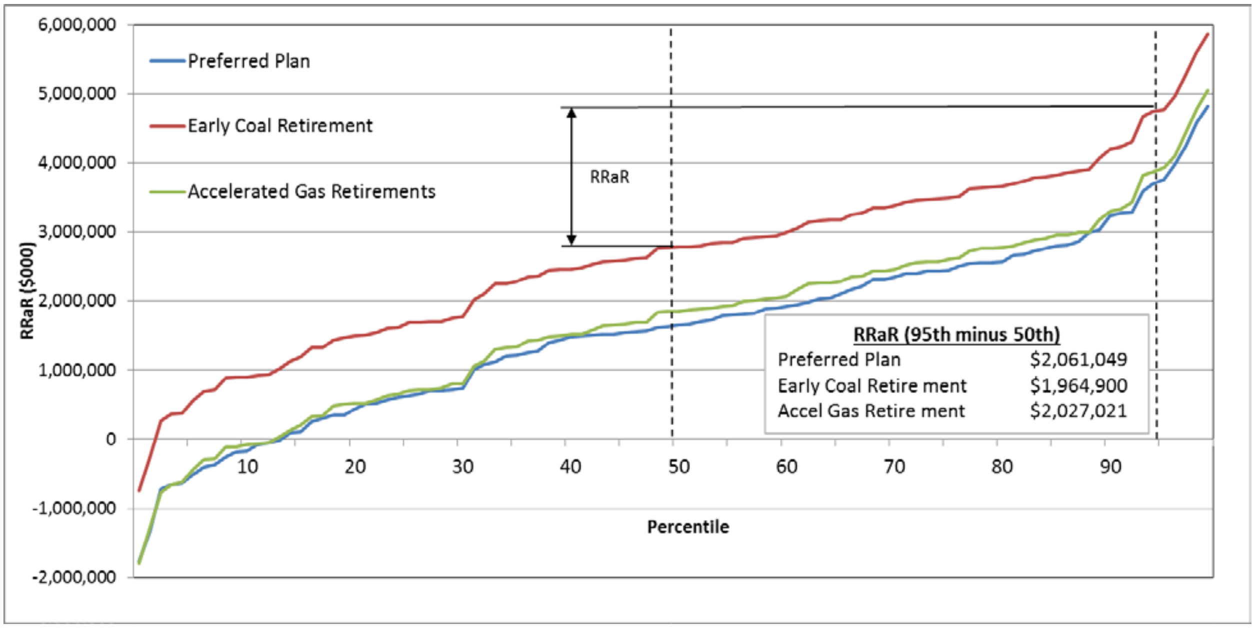

Figure 35. Revenue Requirement at Risk (RRaR) and Expected Value of Portfolios

The difference in RRaR between the portfolios is relatively small. The addition of NGCC plants, which have greater load following capability and operate at lower capacity factors than coal plants, works to slightly reduce the risk or revenue requirement volatility in the Early Coal Retirement Portfolio.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of all the portfolios are comparable and that no one portfolio is significantly advantaged. This indicates that the Preferred Portfolio represents a reasonable combination of expected costs and risk relative to the cost-risk profile of the early plant retirement portfolios.

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6.0 Conclusions and Recommendations

6.1 Plan Summary

The optimization results of this IRP demonstrate that SWEPCO, as a stand-alone entity in the SPP RTO, can serve customer needs over the planning period with additional base-load combined-cycle generation, wind and solar renewables, and DSM resources, including EE measures such as VVO. The following are summary highlights of the Selected Plan:

SWEPCO's Preferred Plan Portfolio

- Maintains SWEPCO's solid fuel units at Welsh Units 1 & 3, Flint Creek and Pirkey, in addition to its share of energy and capacity from the non-SWEPCO operated Dolet Hills unit
- Utilizes 390MW of Wind energy from existing PPA's acquired in 2012 and 2013
- Continues operation of SWEPCO's newest plant additions – the environmentally-compliant, solid-fueled Turk unit, as well as the Stall natural gas combined-cycle and Mattison natural gas combustion turbine facilities
- Retires Welsh Unit 2 in 2016
- Retires 700MW of older gas-steam units through the end of the planning period, beginning in 2020
- Adds 435MW of Natural Gas Combined Cycle generation in 2026
- Adds 1,200MW (nameplate) of wind energy by the end of the planning period, beginning in 2017
- Implements customer and grid energy efficiency, including Volt VAR Optimization (VVO) programs so as to reduce energy requirements by 1,334GWh and capacity requirements by 221MW in 2034
- Adds 850MW (nameplate) of utility-scale solar energy by the end of the planning period, beginning in 2017
- Recognizes additional distributed solar capacity will be added by SWEPCO's customers, starting in 2016, and ramping up to 53MW (nameplate) by 2034

Specific SWEPCO capacity and energy production changes over the 20-year planning period associated with the Preferred Portfolio are shown in Figure 36 through Figure 39, below.

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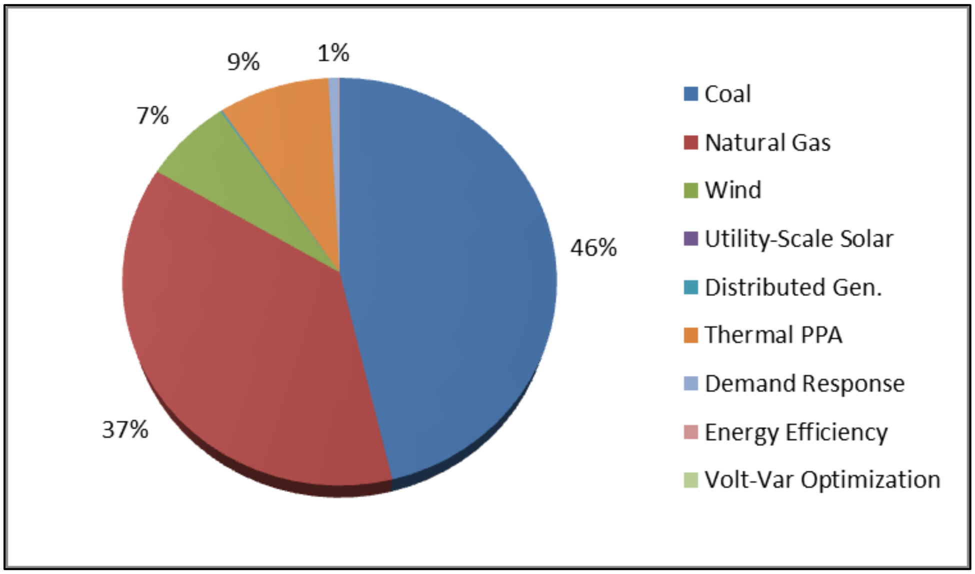

Figure 36. 2015 SWEPCO Nameplate Capacity Mix

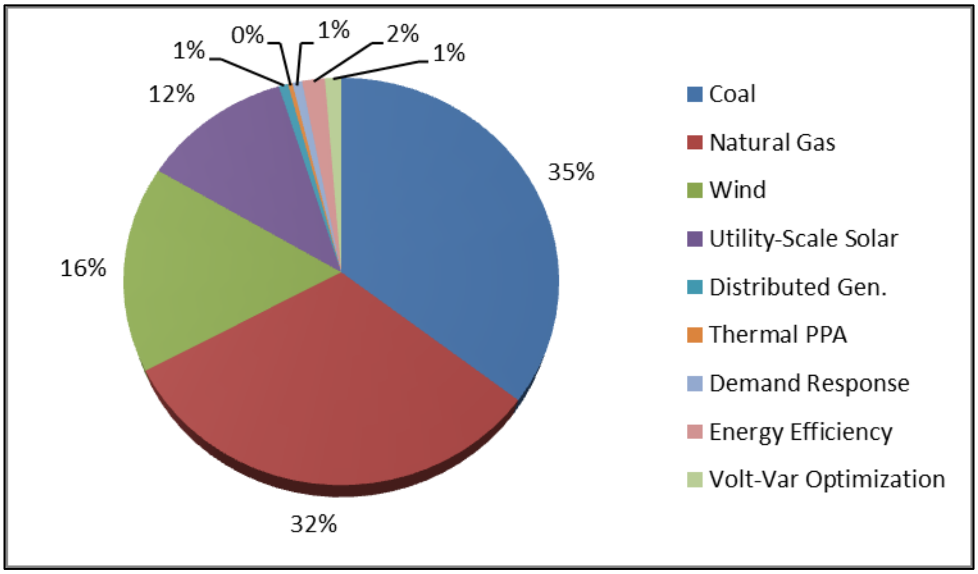

Figure 37. 2024 SWEPCO Nameplate Capacity Mix

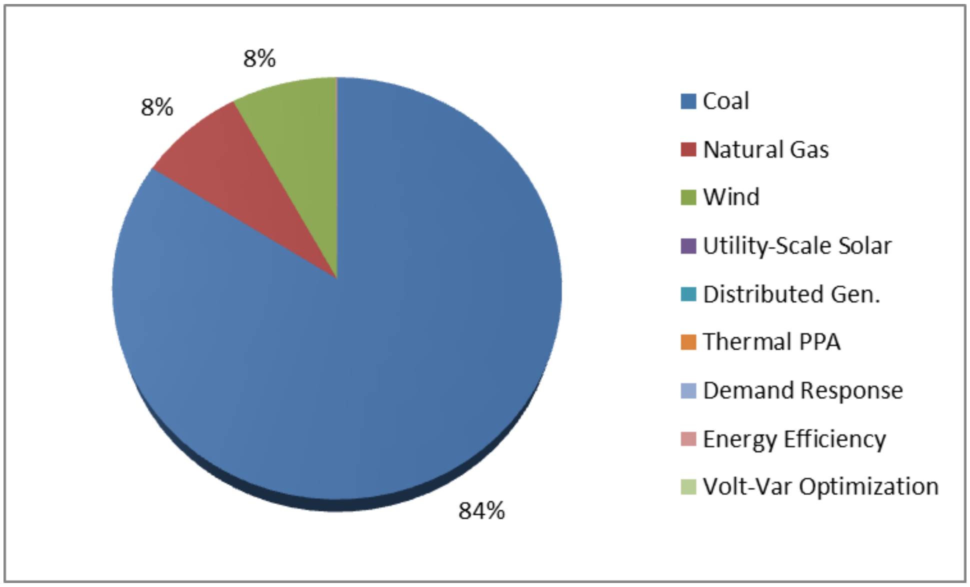

Figure 38. 2015 SWEPCO Energy Mix

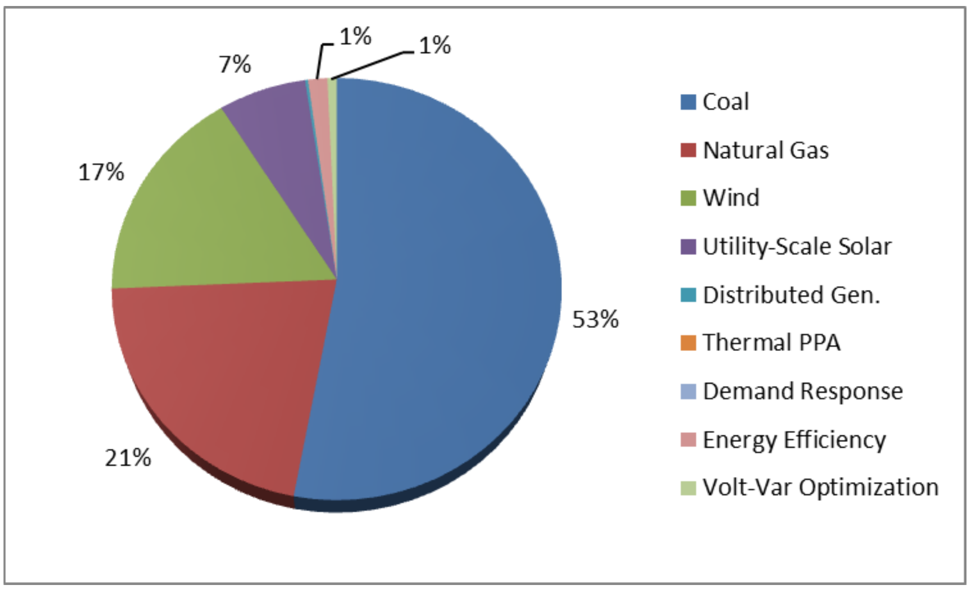

Figure 39. 2024 SWEPCO Energy Mix

Figure 36 and Figure 37 indicate that this Preferred Portfolio would reduce SWEPCO's reliance on solid fuel-based and natural gas generation as part of its portfolio of resources, and increase reliance on demand-side and renewable resources, thereby enhancing fuel diversity. Specifically, over the 20-year planning horizon the Company's capacity mix attributable to solid fuel-fired assets would decline from 46% to 35%, and natural gas assets decline from 37% to

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32%. Renewables (wind, utility and distributed solar, based on nameplate ratings) increase from 7% to 29%, and, similarly, demand-side and energy-efficiency measures increase from 1% to 4% over the planning period. Figure 38 and Figure 39 show SWEPCO's energy output attributable to solid fuel-fired generation shows a significant decrease from 84% to 53% over the period. The carbon-free energy resources being added as part of this planning process would serve to hedge SWEPCO's exposure to natural gas price and SPP energy market volatility, while producing a lower cost solution than one that includes greater reliance on new gas assets.

Figure 40 illustrates SWEPCO's annual capacity position with respect to the Company's load obligation, which factors in SPP's 12% capacity margin requirement. Figure 41 and Figure 42 show the changes in capacity and energy mix on an annual basis, respectively. Again, recognizing that renewable resources are "intermittent" in nature and, with that, are only recognized by SPP—for purposes of meeting reserve margin criterion—for a small percentage of their full nameplate ratings when determining "firm" capacity; the SPP capacity contribution from renewable resources is fairly modest. However, such renewable resources can provide a significant volume of energy, specifically when attributable to wind. SWEPCO's *Plexos*® optimization modeling selected those wind resources because they add more relative value (i.e., lowered SWEPCO's net energy cost) than alternative resources, including the purchase of energy from the SPP market. At times renewable energy was added to the Preferred Plan portfolio when there was no need for capacity. In these instances the added resources had a positive economic effect on the overall plan due to the ability to sell low-cost energy to the SPP market.

While over the planning period SWEPCO is adding a significant amount of cost effective renewable generation, approximately 2,100MWs (nameplate) or 600MWs of firm capacity for planning purposes, these amounts of incremental intermittent renewable generating resources will be continually monitored and evaluated to determine if incremental additions will impact overall reliability within the SPP RTO. The amount of intermittent renewable resources within SWEPCO's Preferred Plan are in alignment with current SPP planning criteria. Reliability concerns due to the intermittent nature of renewable resources are mitigated by way of the Company's overall reserve margin. The reserve margin is designed to account for the unavailability of resources at times of peak demand. Should a substantial portion of renewable energy become unavailable SWEPCO would have adequate resources to meet customer needs.

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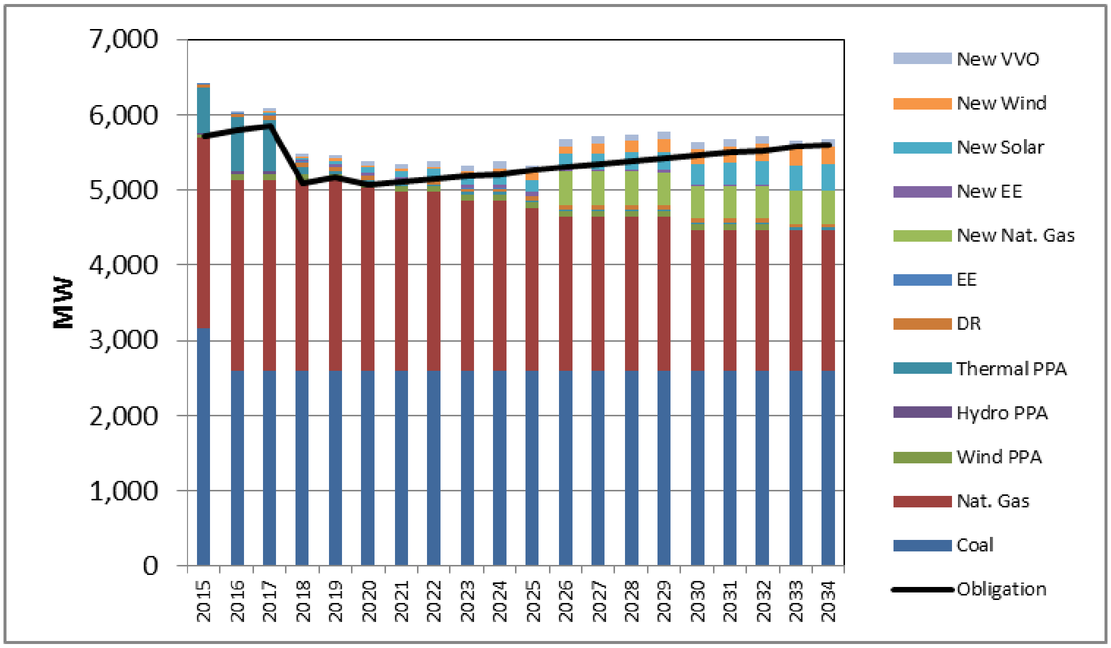
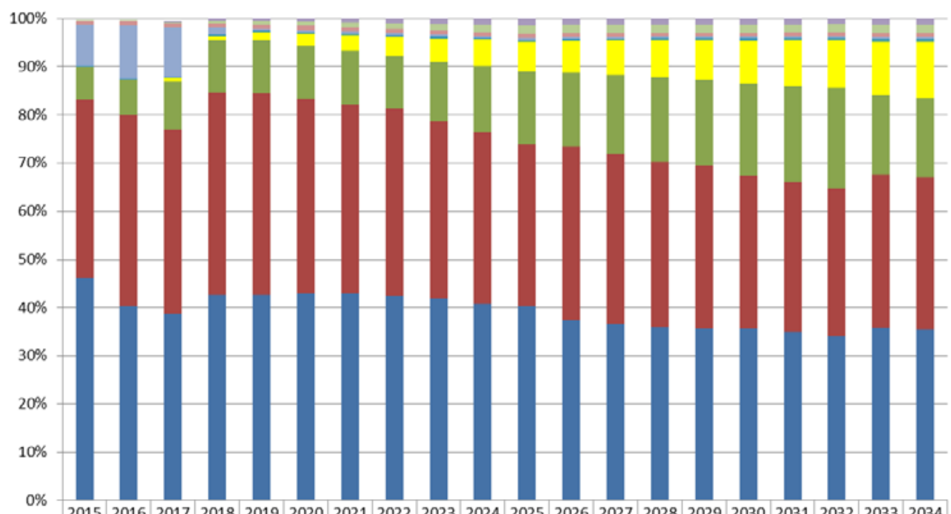
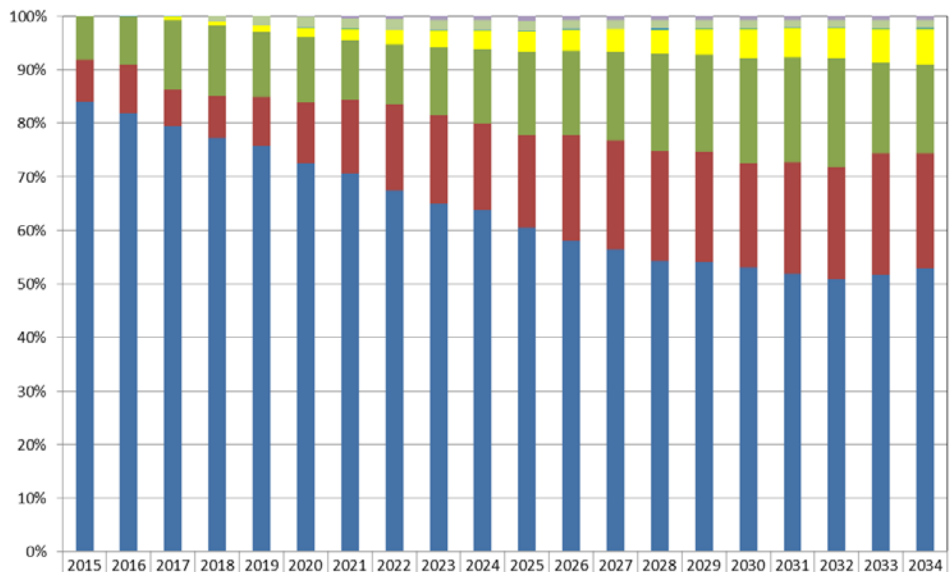


Figure 40. SWEPCO Annual SPP Capacity Position throughout Planning Period (2015-2034)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Volt-Var Optimization	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Energy Efficiency	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Demand Response	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Thermal PPA	9%	11%	10%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Distributed Gen.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%
Utility-Scale Solar	0%	0%	1%	1%	2%	2%	3%	4%	5%	6%	6%	7%	7%	8%	8%	9%	9%	10%	11%	12%
Wind	7%	7%	10%	11%	11%	11%	11%	11%	12%	14%	15%	15%	17%	18%	18%	19%	20%	21%	17%	16%
Natural Gas	37%	40%	38%	42%	42%	40%	39%	39%	37%	36%	34%	36%	35%	34%	34%	32%	31%	30%	32%	32%
Coal	46%	40%	39%	43%	43%	43%	43%	42%	42%	41%	40%	38%	37%	36%	36%	36%	35%	34%	36%	35%

Figure 41. SWEPCO Annual Nameplate Capacity Position throughout Planning Period (2015-2034)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Volt-Var Optimization	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Energy Efficiency	0%	0%	0%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%
Distributed Solar	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Utility-Scale Solar	0%	0%	1%	1%	1%	2%	2%	3%	3%	3%	4%	4%	4%	5%	5%	5%	5%	6%	6%	7%
Wind	8%	9%	13%	13%	12%	12%	11%	11%	13%	14%	16%	16%	17%	18%	18%	20%	20%	20%	17%	17%
Natural Gas	8%	9%	7%	8%	9%	11%	14%	16%	16%	16%	17%	20%	20%	21%	21%	19%	21%	21%	23%	21%
Coal	84%	82%	79%	77%	76%	73%	71%	67%	65%	64%	60%	58%	56%	54%	54%	53%	52%	51%	52%	53%

Figure 42. SWEPCO Annual Energy Production Position throughout Planning Period (2015-2034)

Table 18 provides a summary of the Preferred Portfolio which resulted from resource optimization modeling under the Base case commodity pricing scenario with the modifications noted in Section 5.2.3.

Table 18. Preferred Plan Cumulative Capacity Resource Additions throughout Planning Period

Southwestern Electric Power Company
2015 Integrated Resource Plan
Cumulative Resource Changes

Preferred Portfolio

MW		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)=(1)to(13), ex(6)	(15)	(16)	(17)	(18)	(19)
		(Cumulative) RETIREMENTS	*(Cumulative) Firm Capacity Resource ADDITIONS*												*(Cumul.) NET 'RESOURCE' CHANGE*[P]	*Resulting* SWEPCO Reserves		*(Cumulative) 'NAMEPLATE' ADDITIONS*		
			New-Build			(ST) PPA	Energy Efficiency (EE)			VVO	DR	Wind[D]	Solar[E]					Wind[D]	Solar[E]	
(LA) IRP Period	SPP Planning Year[A]	Coal & Gas-Steam	(Frame) CTs	(Flex) CTs	NGCC		*'Embedded' Federal EE Regulations*[B]	Existing DSM Programs[C]	New		Existing DSM Programs[C]		Utility-Scale	Distributed		Above SPP Minimum Rqrmnt[Q]	*Margin %*		Utility-Scale	Distributed
Yr.		MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2015	(61) [F]	-	-	-	-	*184*	5	-	-	55	-	-	1.0	*(0)*	709	*28.0%*	-	-	*9.7*
2	2016	(589) [G]	-	-	-	126	*198*	9	-	-	55	-	-	1.1	*(398)*	234	*18.3%*	-	-	*11.0*
3	2017	(589)	-	-	-	86	*212*	12	-	26	55	30	21	1.3	*(358)*	234	*18.2%*	200	50	*12.5*
4	2018	(589)	-	-	-	66	*225*	12	22	26	55	30	21	1.4	*(356)*	384	*22.3%*	200	50	*14.0*
5	2019	(589)	-	-	-	-	*237*	12	43	26	55	30	42	1.6	*(380)*	291	*20.1%*	200	100	*15.5*
6	2020	(699) [H]	-	-	-	-	*247*	12	49	38	55	30	63	1.8	*(450)*	308	*20.6%*	200	150	*17.5*
7	2021	(699)	-	-	-	-	*261*	12	54	51	55	30	84	1.9	*(410)*	229	*18.8%*	200	198	*19.0*
8	2022	(699)	-	-	-	-	*273*	12	64	63	55	30	105	2.1	*(368)*	225	*18.6%*	200	248	*21.0*
9	2023	(808) [I]	-	-	-	-	*284*	12	75	73	55	50	126	2.3	*(415)*	147	*16.9%*	300	297	*23.0*
10	2024	(808)	-	-	-	-	*297*	12	91	83	55	70	147	2.5	*(347)*	165	*17.3%*	400	347	*25.0*
11	2025	(916) [J]	-	-	-	-	*308*	12	113	92	55	90	168	2.8	*(384)*	63	*15.0%*	500	396	*27.5*
12	2026	(1,026) [K]	-	-	435	-	*317*	12	116	92	55	110	189	3.0	*(14)*	381	*21.9%*	600	446	*29.5*
13	2027	(1,026)	-	-	435	-	*326*	12	118	92	55	130	210	3.2	*30*	369	*21.6%*	700	495	*32.0*
14	2028	(1,026)	-	-	435	-	*335*	12	121	92	55	150	231	3.5	*74*	376	*21.7%*	800	545	*34.5*
15	2029	(1,026)	-	-	435	-	*346*	12	122	92	55	170	252	3.7	*115*	367	*21.4%*	900	594	*37.0*
16	2030	(1,194) [L]	-	-	435	-	*356*	12	123	92	55	190	273	4.0	*(10)*	192	*17.7%*	1,000	644	*40.0*
17	2031	(1,194)	-	-	435	-	*366*	12	124	92	55	210	294	4.3	*32*	191	*17.6%*	1,100	693	*42.5*
18	2032	(1,194)	-	-	435	-	*372*	12	125	92	55	230	315	4.6	*74*	201	*17.8%*	1,200	743	*46.0*
19	2033	(1,194)	-	-	435	-	*381*	12	127	92	55	230	336	4.9	*98*	100	*15.7%*	1,200	792	*49.0*
20	2034	(1,194)	-	-	435	-	*389*	12	129	92	55	230	357	5.3	*121*	96	*15.6%*	1,200	842	*52.5*
							356	***141***											***894***	
							'TOTAL' Energy Efficiency (2015-3034)												*'TOTAL' Solar (2015-2034)*	

[A] SPP Planning Year is effective 6/1/XXXX.
[B] Represents estimated energy efficiency levels already 'embedded' into SWEPCO's long-term load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standareds (EPAct 2005; 2007 EISA, 2009 ARRA).
[C] Represents estimated contribution from current/known SWEPCO DSM-EE and Demand Response (Interruptible, DLC/ELM) program activity also reflected in the Company's long-term load and demand forecast *(from 'Going-In' SWEPCO CDR)*.
[D] Due to the intermittency of wind resources, only 20% for Tranche A and 10% Tranche B of wind resource 'nameplate' MW rating are included for capacity resource determination purposes.
[E] Due to the intermittency of solar resources, Utility Solar receives 42.4% and Distributed Solar receives 10% of 'nameplate' MW rating are included for capacity resource determination purposes.

RETIREMENTS:
[F] Lieberman 1 retirement & Knox Lee 4 50% derate assumed 12/2014.
[G] Welsh Unit 2 retirement effective approximately June 1, 2016.
[H] Lieberman 2, Lone Star & Knox Lee 4 retirement assumed 12/2019.
[I] Lieberman 3 retirement assumed 12/2022.
[J] Lieberman 4 retirement assumed 12/2024.
[K] Arsenal Hill 5 retirement assumed 12/2025.
[L] Wilkes 1 retirement assumed 12/2029.

[P] ___Excludes___ cumulative annual changes in SWEPCO SPP 'Load Responsibility' (coincident peak demand) and 3rd-party resources... which also impacts relative capacity resource position.
[Q] SPP minimum criterion @ 13.6% as a function of peak demand.

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6.1.1 SWEPCO Five Year Action Plan

Steps to be taken by SWEPCO in the near future to implement this plan include:

1. Begin (or continue) the planning and regulatory actions necessary to implement economic EE programs in each state SWEPCO serves.
    a. Arkansas – EE programs have been in place in Arkansas since 2007. For program year 2014, SWEPCO achieved 141% of its goal. SWEPCO has steadily grown its portfolio in Arkansas to a proposed budget of $10.3 million for 2016 with a proposed savings goal of 23,957,863 kWh. SWEPCO will file a new 3 year portfolio plan June 1, 2016.
    b. Louisiana – The Quick Start Phase of energy efficiency programs began in Louisiana November 1, 2014 and is scheduled to continue through June 30, 2017. SWEPCO is in the process of completing Program Year (PY) 1 which will end October 31, 2015 with results pending. As of mid-September, we are currently at 104% of PY1 kWh goal with approximately 10% of incentive budget remaining. (PY 1 and PY2 budgets are $1.9 million each, with PY3 budget set at $1.6 million.
    c. Texas – EE programs have been in place in Texas since 2000. For Program Year 2014, SWEPCO achieved 225% of its demand reduction goal and 178% of its energy goal. The proposed savings goals for Program Year 2015 are 9,282kW and 11,815,878kWh to be achieved with a budget of $3,452,748. A two-year plan is filed on May 1 of each year. This plan can be altered from the previous filing without prior commission approval.
    d. The Preferred Plan illustrates that incremental EE and VVO are economical resource options. The measures selected and the amounts of VVO and EE selected will be reviewed with the state EE Managers for future inclusion into the state specific EE recommended plans/programs.
2. Conduct a Request for Proposal(s) (RFPs) to explore potential near-term, tax-advantaged opportunities to add up to 200MW wind and 50MW of solar energy (via Renewable Energy Purchase Agreements (REPAs)). The modeling indicated adding these resources in this timeframe should optimize production energy costs under the assumed parameters.

Note:

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- The ultimate execution and contract award of any additional renewable REPAs would be conditioned upon the prior receipt of such regulatory approvals.
- SWEPCO's ability to take advantage of the wind and solar tax incentives is complicated by the timing of the issuance of the final IRP, existing regulatory proceedings, and the regulatory requirements SWEPCO must navigate while operating in three jurisdictions. Therefore, it would be imperative to adhere to the following events to take advantage of the tax incentives:
  a. Assuming the Federal Production Tax Credits (PTCs)/Investment Tax Credits (ITCs) for wind/solar are not extended (*i.e.*, will expire by the end of 2016), an expedited review and approval process consisting of the following would need to take place:
     i. Develop and issue RFPs for PTC/ITC eligible wind/solar projects.
     ii. Evaluate RFP responses including associated transmission service and select winning projects.
     iii. Seek and obtain regulatory approval for Dec 2016 commercial operation date.
- *If*, however, federal tax incentives for wind and/or solar <u>are</u> ultimately extended by a year (or more), it would then be conceivable that this implementation plan and attendant approval requirements could be relaxed.

3. Continue to evaluate gas-steam unit ongoing operating and maintenance costs, in addition to equipment liability issues to determine most likely candidates for near term retirements.
   a. This is an ongoing activity based on observed unit performance and economic viability.
4. Complete solid fuel plant Mercury and Air Toxic Standards (MATS) and Regional Haze-required retrofit projects already underway.
   a. Pirkey Station: Install Calcium Bromide injection system (Project Complete)
   b. Welsh Units 1& 3: Complete Activated Carbon Injection (ACI) , Fabric Filter Baghouse, and Chimney installations (2016)

c. Flint Creek: Complete Dry Fluidized Gas Desulfurization and ACI installations (2016)

5. Continue to evaluate the Final EPA CPP guidelines and provide technical input to state regulatory bodies as to cost effective compliance options: ongoing activity.

6.2 Conclusion

Exhibit C represents the "Going-in" capacity position before the ultimate determination of how capacity deficiencies would be met. SWEPCO has set forth a Plan that meets the requirements of its customers in a *least reasonable cost* fashion as reflected in Exhibit D.

The pursuit of renewable resources has significant economic advantages, particularly after considering the relative impacts associated with three of the more critical "driving" economic risk parameters, the potential future cost of natural gas, the timing of CO_2/carbon pricing, and the future costs to construct the available options. In addition, the Company continues to operate demand-side programs in its Arkansas and Texas jurisdictions. SWEPCO will continue to evaluate supply and demand-side options to meet the long-term needs of its customers in a cost-effective and reliable manner.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in modifications in the resource plan reflected for SWEPCO. The resource 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. As such, changes and assumptions are recognized, updated, and refined, with input information reevaluated and resource plans modified as appropriate.

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This 2015 SWEPCO IRP provides for reliable electric utility service, at reasonable cost, through a combination of existing resources, renewable energy and demand-side programs. SWEPCO will provide for adequate capacity and energy resources to serve its customers' peak demand, energy requirement and required SPP reserve margin needs throughout the forecast period.

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APPENDIX

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Exhibit A: Stakeholder Committee Report with Company Responses

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AEP/Southwestern Electric Power Company
Integrated Resource Plan
Stakeholder Committee Report
With Company Responses – November 2015

May 15, 2015

Meeting Held March 3, 2015
Texarkana, Arkansas

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I. Executive Summary

On March 3, 2015, AEP hosted an Integrated Resource Plan (IRP) Stakeholder Committee Meeting. The meeting was attended by retail and wholesale customers, and members of regional power providers, environmental groups, Southwest Power Pool, low-income advocates, and others. The meeting consisted of presentations by AEP on the objectives and goals of the Integrated Stakeholder Committee Meeting, Resource Planning Guidelines, and a description of the Draft IRP and IRP assumptions.

Prior to the beginning of the meeting, stakeholders were provided a draft copy of the Integrated Resource Planning Report, which will be filed with the Arkansas Public Service Company. This Stakeholder Committee Report represents discussions and recommendations regarding renewables, demand side management and energy efficiency, ratepayer impacts, environmental mandates, and supply resources.

II. IRP Presentation Attendees

The following were present during the AEP/Southwestern Electric Power Company IRP Stakeholder Meeting.

Name	Representing	Email
Tracy Altenbaumer	Domtar	tracy.altenbaumer@domtar.com
Clark Cotten	Arkansas Public Service Commission	clark_cotten@psc.state.ar.us
John DiDonato	NextEra Energy Resources, LLC	john.didonato@nexteraenergy.com
Juliano Freitas	Southwest Power Pool	jfreitas@spp.org
David Fincher	Hope Water & Light Commission	dfincher@hope-wl.com
Bob Grygotis	Domtar	bob.grygotis@domtar.com
Tammara Harrelson	Arkansas Department of Environmental Quality	Harrelson@adeq.state.ar.us
Glen Hooks	Sierra ClubArkansas	glen.hooks@sierraclub.org
Forest Kessinger	Arkansas Electric Cooperative Corp.	fkessinger@aecc.com
Lud Kozlowski	ACAAA	lkozlowski@acaaa.org
Gerry Larsen	Smith-Blair	Gerry.Larsen@smith-blair.com
Kenneth Leary	Cooper Tire	kfleary@coopertire.com
Mak Nagle	Apex Clean Energy, Inc.	mak.nagle@apexcleanenergy.com
Kevin Lemley	Attorney General	kevin.lemley@arkansasag.gov
Gary Moody	Audubon	gmoody@audubon.org

Wally Nixon	Arkansas Public Service Commission	WNixon@psc.state.ar.us
Nick Paxton	Smith-Blair	Nick.Paxton@smith-blair.com
Aaron Pupa	LS Power Development, LLC	apupa@lspower.com
Ken Smith	Arkansas Advanced Energy Foundation	ken@klsmithconsulting.com

III. Stakeholder Feedback

THE IRP DRAFT REPORT

It is suggested that a section be added to the report to address what SWEPCO sees as challenges or hurdles to achieving the preferred plan. For example, the IRP does not address possible electric transmission requirements associated with the addition of 1,700 MW of wind resources or concerns with competition for wind resources nationally; achieving 410 MW of incremental energy efficiency and the programs needed to promote this growth; and other items. This added section should also present the challenges or obstructions that AEP foresees that exist in either state or federal legislation or regulation to achieving its preferred plan. The presentation of this information would assist the reader to understand that based on the assumptions for the planning horizon, the preferred plan is the economic choice, but the plan may rely on extrinsic factors beyond AEP's control to achieve.

The Stakeholders did not see anything that reflects the percentage of capacity at which the assets are operated.

Company Response:

The Five Year Action Plan now includes potential challenges and obstructions that could occur during the implementation period.

The magnitudes of additional wind and energy efficiency (EE) were both reduced in the Preferred Portfolio versus the Draft Report. This was driven by updates to the: EE inputs, Wind capacity credit value, Load Forecast and Fundamental Commodity prices. Additional detail is included in the Final Report, as well as summarized in each section below.

Capacity factors are not explicitly reported, however actual generation by resource type can be found in Exhibit H: Modeled Scenario Results.

RENEWABLES

A stakeholder was impressed with incorporation of renewables into the plan. However, he did not have a sense as to what that is compared.

The inclusion of renewables provides a balanced generation portfolio.

A stakeholder asked what the possible for alternatives are if we do not get competitive prices for solar or wind. Also, where would SWEPCO go from there? Are they looking at life cycle costs? What is the fall back position?

A stakeholder suggested adding incremental steps between current the pie chart and projected pie chart for 2035. (e.g. add additional pie charts showing visual changes over five year periods).

Additional renewables are expected to be brought online post-2020/2021 – we would like to see it stepped up accordingly. A stakeholder questions the waiting until 2021 to add renewables until demand catches up. It is recommended that an explanation be given for waiting until 2021. It may be prudent to secure PPAs now for renewables (particularly wind) to take advantage of federal production tax credit (PTC) qualified pricing rather than wait until 2021 when PTC is expected to expire or phase out. SWEPCO can always lock in the most competitive price while pushing the start date of the PPA contracts two to three years from now. The developer can sell the power to third party or into SPP market.

A stakeholder suggests an analysis to show an early acquisition of wind resources (economic analysis) to displace thermal.

Current PTC guidance would allow wind resources to be acquired by 2016 which will allow the Federal PTC of 2.3 cents per Kilowatt hour. (Benefits)

Regarding capacity value, an explanation of how they arrived at the 10% for their capacity outreach should be given. Is 10% the right number? Should it be 12.5%? Should it be 8%?

Company Response:

The Five Year Action Plan describes the Company's potential next steps regarding the acquisition of renewable resources. The IRP process considers all resource costs over the life of each resource alternative that is included in the model. Figures 41 (p. 124) and 42 (p. 125) provide the annual portfolio changes. Securing renewable resources were accelerated to potentially include 200MW of wind and 50MW of solar to be available by 2017, taking advantage of existing tax benefits.

The capacity value of Wind resources was updated to reflect the expected performance of each resource modeled. As discussed in Section 4.5.5.2 of the report, wind resource Tranche A's load shape supports a 20% capacity value, Tranche B's load shape supports a 10% capacity value and Tranche C's load shape supports a 5% capacity value, based on SPP planning criteria.

Levelized Cost of Electricity for Solar Resources

A stakeholder suggested that SWEPCO has done an outstanding job of addressing renewable resources in its draft IRP. However, these technologies are evolving quickly, particularly utility scale solar, and it is easy to inadvertently use outdated information. That may be the case with the Levelized Cost of Electricity (LCOE) for utility scale solar. The current draft IRP assumes LCOE for utility scale solar of between $120/MWh and $140/MWh, depending on whether you assume a future federal investment tax credit (ITC) for solar (and at what rate – i.e., 30%, 10% or zero). Currently, in Texas, utility scale solar PPAs are being signed for $55/MWh levelized for 20 years. It is unclear how to convert this to LCOE for a rate-based asset, but it seems to be significantly lower than what has been modeled. This price appears more indicative of ERCOT pricing; therefore, companies in the western area of the Southwest Power Pool grid would likely obtain more competitive pricing. If the LOCE for utility scale solar is remodeled and is, in fact, lower, then perhaps the model would conclude that more solar should be built, less of something else (probably wind) and the overall cost of the preferred portfolio may be lowered.

Company Response:

The Company maintained its estimate for the installed cost of solar for modeling purposes. The Five Year Action Plan describes the Company's next steps regarding the potential acquisition of renewable resources. Should the timeline provide sufficient opportunity for the Company to issue an RFP for renewable resources, proposals are expected to address the pricing issues mentioned above by the Stakeholders.

Timing of Purchased Power Agreements for Wind

A stakeholder suggested that SWEPCO has done an outstanding job of explaining the timing of its capacity needs. However, as it relates to the timing of procuring wind, it would be beneficial to see what the overall cost of the preferred portfolio would be if SWEPCO purchased wind before the federal production tax credit (PTC) expires, instead of after. The Present Value of the PTC (pre-tax) over 25 years to a developer is approximately $23.50/MWH. It may be more economical to purchase wind in 2016 with this $23.50/MWh incentive and sell it back to the market until 2021 than wait until 2021 and lose the $23.50/MWh incentive. The model should be able to tell us. As an alternative, maybe a developer would sign a PPA that begins in 2021 now and build before 2016 to claim the PTC. The benefit this approach is that it would likely lower the cost of the preferred portfolio.

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Company Response:

Based on the assumptions included in the IRP report, the Company's Five Year Action Plan addresses this concern by, to the extent possible, accelerating 200MW of wind and 50MW of solar resources to take advantage of the current tax incentives associated with renewable resources.

Too Much Dependency on Renewables

It appears the leverage of renewables does not feasibly meet demand at cost competitive levels. Short-term loss of demand in 2017 & 2018 – how does that impact cost over the short term? Does it impact rates from fewer base customers?

Rate increases will hinder any future industrial and manufacturing competitiveness. How do our proposed rate increases compare to other sections of the country, region, state? The benefit of addressing this is to ensure stabilized rates in order to be competitive.

Company Response:

The Company's Preferred Portfolio will diversify the generation portfolio over the planning period which will assist the Company in providing stable rates over the planning period. Additionally, the plan may assist the Company in meeting future compliance requirements associated with the Clean Power Plan.

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY

Demand side management (DSM) and energy efficiency (EE) provides a value to the ratepayer, a balanced portfolio, and reduced risk.

SWEPCO did a good job of hitting energy efficiency savings. When you throw in the Volt var with the demand response you are looking at 410 megawatts of savings there. Another Arkansas electric utility target was 700 Megawatts over a 10-year period of time during their last IRP. On the Energy Efficiency (EE) side, it's an aggressive target.

An Arkansas Energy Efficiency Potential Study is being developed which will provide needed information regarding Arkansas-specific market conditions prior to the development of energy efficiency goals and targets by the Arkansas Public Service Commission. It is recommended that a summary of this Potential Study be incorporated into the IRP and the resulting Potential Study data should be incorporated into AEP's level of what needs to be done in terms of meeting EE savings.

IRPs specifically are important when looking at power purchase agreements, energy efficiency and see if what they do is consistent or different from the IRP that was filed.

Under the Volt Var piece with EE, (table 4-5 on page 83), it is suggested that a column be added for geographic region besides number of circuits. It would helpful to have that breakdown to better understand things.

SWEPCO is encouraged to seek out Combined Heat and Power (CHP) candidates over to planning.

Company Response:

The Company has included a summary of the status of the Arkansas Potential Study within Section 3.5.3 of the IRP report. Additionally, the Volt VAR Table 11 (p. 89), in Section 4.4.4.2 was updated to show the impacted circuits by state. The report also includes the Company's discussion on CHP, within Section 4.5.6.

RATEPAYER IMPACTS

There are concerns for all consumer categories (response to low and moderate income comment) and the economic result higher rates might bring.

The short-term loss of two large customers does not reflect:

1) Plan to remove high operating cost units
2) Impact to remaining customer base

What are the options to reduce costs to lessen the impact of price increases going forward? Is there a short-term plan to address drop in demand with higher cost power being mothballed? The IRP should reflect the impacts of decisions outside the region. For example:

Solar – Demand for units to drive cost up and availability down
Wind – Demand for units to drive cost up and availability down

This would give a more balanced view of the likely outcome that reflects markets outside the region, but adjoining or relevant asset comparisons.

The resources SWEPCO uses for its plan need to be efficient and cost-effective so that the rate impact from the plan does not cause a heavy burden of low to moderate income SWEPCO customers.

Company Response:

The two large customers that are referred to also provide generation to meet the majority of their load requirements, resulting in a moderate net change in SWEPCO's capacity position. SWEPCO has included staggered retirements of its older less efficient gas-steam units (Section 3, Table 2 (p. 41)). The Company's Preferred Portfolio was developed to manage future risk and provide a cost-effective path forward.

ENVIRONMENTAL MANDATES

Environmental mandates are in process or in effect. Another Arkansas electric utility stressed this impact on their system. Does SWEPCO have that impact laid out like the other utility? That could be helpful. Another stakeholder was satisfied that it is addressed.

It is suggested that AEP be aware of the regulations regarding 111.d and addressing them in order to keep resources adequate, while costs to customers low. The possible impact of EPA Rule 111.d. and the uncertainties as to what the fuel mix may result when these are finally finalized is important, particularly the economic and environmental impact it may have on U.S. energy supply and related costs in energy bills and how they might impact low to moderate income. The IRP addresses this as much as is able on what is known; therefore, no changes are recommended at this time. The final regulations will drive consistent adjustments and trying to plan around that can be complicated. Making sure the resources SWEPCO uses are the most efficient and cost-effective so that they won't impact customer rates to where low to moderate income rate payers are unreasonably burdened.

Addressing the impacts of Rule 111.d places SWEPCO in a better position in responding to the development of state plans.

Company Response:

The IRP report addresses these concerns within the Executive Summary, Section 3.4 and Section 6.

SUPPLY

It is suggested that a criterion for a siting plan or a preferred siting plan be integrated as part of the IRP. Among those criteria would be available transmission to deliver the resources.

There are concerns for natural gas delivery. If we don't have gas here, will the plan be feasible? Pressures are being developed on natural gas. Can supply keep up with that?

Company Response:

The Company agrees that the available transmission capacity related to any generation resource can impact that resource's effectiveness. This analysis is considered in the implementation phase when specific resource locations have been determined. The IRP does not identify specific resource locations, only the types of resources that provide the best solution for the Company.

When the Company analyzes RFP responses for proposed resource additions many factors will be considered in the analyses including for example: siting issues, fuel supply, technology reliability/performance and transmission interconnection issues, etc.

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IV. CONCLUSION

The stakeholders wish to thank AEP/SWEPCO for the opportunity to meet with the company to discuss its generation and transmission needs and its opportunities through an integrated resource planning process. We believe the company generally has been on the right track to diversify its generation portfolio by modernizing the base load generation, by shutting down Welsh 2 in 2016, and by incorporating more renewable energy. The stakeholders endorse the company's continued progress and improvements in energy efficiency programs even in light of the restrictions on commercial and industrial programs that the Arkansas Legislature has imposed. We believe SWEPCO's EE programs are exceptional working models of how utilities should operate EE programs.

We caution AEP/SWEPCO regarding future investments to Welsh Units 1 and 3 in light of MATS, regional haze rules, and pending carbon emission reductions. The stakeholders are wary of environmental retrofits of existing fossil fuel plants that could lead to significant rate increases. In considering the future of these plants, we call attention to generation options including natural gas, wind, and solar. The Arkansas Legislature recently passed House Bill 1633 that allows electric utilities to enter into long-term "power purchase agreements and to recover an additional sum as determined by the public service commission…. a commensurate return on the power purchase agreement as would be allowed for an equivalent investment in a power plant….an equitable sharing of any savings between the utility and the retail customers of the utility….."

Elevating the status of PPAs for generation, current abundance of natural gas, declining costs of wind and solar, and improvements in demand side management programs offer generation and management tools not readily available in past years. These concluding statements bring the stakeholders to perhaps their most important recommendation summarized on pages four and five. We encourage AEP/SWEPCO to take advantage of Renewable Energy Production Tax Credits qualified pricing sooner than to wait until 2021 to bring on additional renewable energy. The Renewable Energy PTC is set to expire at the end of 2016. We believe the company now could lock into competitive prices while extending the start of PPA contracts to a later date. We applaud the company's inclusion of a distributed generation target as part of its draft preferred plan. We encourage AEP/SWEPCO to work with its customers, regional advanced energy associations, and state public service commissions to work through any barriers that currently prevent or impede individuals and companies from generating more of their own energy.

A second important recommendation is for AEP/SWEPCO to include the results of the Arkansas DSM and EE potential study into the company's IRP. How will the study impact the company's target of 410 megawatts over the 20-year horizon? What would be the rate impact in the preferred plan?

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The stakeholders appreciate AEP/SWEPCO's consideration of the pending carbon emission reduction rule under Section 111(d) of the Clean Air Act. The final rule is due in mid-summer 2015. After the rule is released, we recommend that the company conduct a new analysis of how close the company's preferred plan achieve its share of state carbon reduction targets and an analysis of cost-effective options for doing so.

Finally, the placement of generation and transmission facilities always is controversial be it transmission lines across the Ozarks or new generation. So a final recommendation is for AEP/SWEPCO to include an informed discussion about the transmission of electricity to the SPP or a natural gas line to a generation plant as part of a final IRP.

Company Response:

The Company would like to thank all of the Stakeholders for both participating in the Stakeholder meeting held in Texarkana, Arkansas on March 3, 2015 and for developing very constructive comments and feedback on the Company's DRAFT IRP.

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Exhibit B: Load Forecast Tables

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Southwestern Electric Power Company
Actual and Forecast Internal Energy Requirements (GWh)
By Customer Class After DSM/EE Effects
Table B-1

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other** Energy Requirements	Growth Rate	Internal Energy Requirements	Growth Rate
Actual										
2005	5,644	---	5,791	---	5,555	---	6,607	---	23,596	---
2006	5,539	-1.9	5,732	-1.0	5,643	1.6	6,951	5.2	23,865	1.1
2007	5,628	1.6	5,971	4.2	5,607	-0.6	6,663	-4.2	23,868	0.0
2008	5,694	1.2	5,994	0.4	5,402	-3.7	6,677	0.2	23,767	-0.4
2009	5,587	-1.9	5,957	-0.6	4,460	-17.4	6,945	4.0	22,949	-3.4
2010	6,361	13.9	6,141	3.1	5,230	17.2	7,495	7.9	25,227	9.9
2011	6,908	8.6	6,280	2.3	5,408	3.4	7,480	-0.2	26,077	3.4
2012	6,301	-8.8	6,103	-2.8	5,661	4.7	7,123	-4.8	25,188	-3.4
2013	6,431	2.1	6,011	-1.5	5,612	-0.9	7,430	4.3	25,484	1.2
2014	6,311	-1.9	5,996	-0.2	5,901	5.1	7,308	-1.6	25,516	0.1
Forecast										
2015*	6,483	2.7	6,151	2.6	5,676	-3.8	7,416	1.5	25,726	0.8
2016	6,421	-0.9	6,141	-0.2	5,979	5.3	7,500	1.1	26,041	1.2
2017	6,452	0.5	6,173	0.5	5,983	0.1	7,637	1.8	26,245	0.8
2018	6,491	0.6	6,211	0.6	6,008	0.4	3,936	-48.5	22,646	-13.7
2019	6,498	0.1	6,220	0.1	6,187	3.0	3,989	1.3	22,895	1.1
2020	6,518	0.3	6,241	0.3	6,349	2.6	3,447	-13.6	22,555	-1.5
2021	6,546	0.4	6,274	0.5	6,421	1.1	3,465	0.5	22,706	0.7
2022	6,575	0.4	6,311	0.6	6,482	0.9	3,502	1.0	22,869	0.7
2023	6,611	0.6	6,354	0.7	6,541	0.9	3,529	0.8	23,035	0.7
2024	6,653	0.6	6,400	0.7	6,599	0.9	3,541	0.4	23,193	0.7
2025	6,699	0.7	6,446	0.7	6,651	0.8	3,548	0.2	23,345	0.7
2026	6,738	0.6	6,487	0.6	6,695	0.7	3,579	0.9	23,498	0.7
2027	6,782	0.7	6,533	0.7	6,741	0.7	3,595	0.5	23,651	0.6
2028	6,816	0.5	6,570	0.6	6,783	0.6	3,642	1.3	23,812	0.7
2029	6,869	0.8	6,627	0.9	6,833	0.7	3,631	-0.3	23,960	0.6
2030	6,911	0.6	6,662	0.5	6,876	0.6	3,649	0.5	24,098	0.6
2031	6,952	0.6	6,699	0.6	6,919	0.6	3,662	0.4	24,232	0.6
2032	6,991	0.6	6,738	0.6	6,963	0.6	3,686	0.7	24,377	0.6
2033	7,035	0.6	6,782	0.6	7,008	0.7	3,696	0.3	24,521	0.6
2034	7,074	0.6	6,819	0.5	7,052	0.6	3,721	0.7	24,666	0.6
2035	7,121	0.7	6,864	0.7	7,103	0.7	3,723	0.1	24,810	0.6

Note: *2015 data are six months acutal and six months forecast.
**Other energy requirements include other retail sales, wholesale sales and losses.

Compound Annual Growth Rate 2005-2014

	Residential	Commercial	Industrial	Other** Energy Requirements	Internal Energy Requirements
Compound Annual Growth Rate 2005-2014	1.2	0.4	0.7	1.1	0.9

Compound Annual Growth Rate 2016-2035

	Residential	Commercial	Industrial	Other** Energy Requirements	Internal Energy Requirements
Compound Annual Growth Rate 2016-2035	0.5	0.6	0.9	-3.6	-0.3

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Southwestern Electric Power Company-Arkansas
Actual and Forecast Retail Sales (GWh)
By Customer Class After DSM/EE Effects
Table B-2 (page 1)

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2005	1,127	---	1,339	---	1,741	---	11	---	4,218	---
2006	1,097	-2.7	1,313	-2.0	1,737	-0.2	11	-0.4	4,158	-1.4
2007	1,122	2.3	1,378	5.0	1,740	0.2	12	3.2	4,252	2.3
2008	1,113	-0.8	1,367	-0.8	1,646	-5.4	12	0.9	4,138	-2.7
2009	1,069	-4.0	1,313	-4.0	1,511	-8.2	12	-1.5	3,904	-5.7
2010	1,194	11.7	1,372	4.5	1,593	5.5	12	-1.5	4,170	6.8
2011	1,198	0.4	1,390	1.3	1,575	-1.1	12	2.3	4,175	0.1
2012	1,132	-5.5	1,356	-2.4	1,562	-0.8	12	-0.2	4,062	-2.7
2013	1,135	0.2	1,332	-1.8	1,540	-1.4	12	-1.1	4,018	-1.1
2014	1,121	-1.2	1,343	0.8	1,543	0.2	12	-0.5	4,019	0.0
Forecast										
2015*	1,156	3.1	1,370	2.0	1,403	-9.1	12	2.0	3,941	-1.9
2016	1,138	-1.6	1,358	-0.9	1,366	-2.7	12	-0.4	3,874	-1.7
2017	1,139	0.1	1,356	-0.1	1,326	-2.9	12	0.2	3,833	-1.0
2018	1,144	0.4	1,359	0.2	1,316	-0.7	12	0.7	3,832	0.0
2019	1,139	-0.4	1,354	-0.4	1,325	0.6	12	0.0	3,830	-0.1
2020	1,140	0.1	1,354	0.0	1,333	0.6	12	0.3	3,839	0.2
2021	1,142	0.2	1,357	0.2	1,342	0.6	12	0.3	3,853	0.4
2022	1,146	0.3	1,362	0.3	1,351	0.7	12	0.2	3,870	0.4
2023	1,152	0.5	1,367	0.4	1,360	0.7	12	0.2	3,891	0.5
2024	1,159	0.6	1,374	0.5	1,369	0.6	12	0.3	3,913	0.6
2025	1,167	0.7	1,381	0.5	1,376	0.6	12	0.3	3,936	0.6
2026	1,172	0.5	1,388	0.5	1,384	0.6	12	0.1	3,957	0.5
2027	1,180	0.6	1,395	0.6	1,393	0.6	12	0.3	3,980	0.6
2028	1,184	0.4	1,401	0.4	1,401	0.6	12	0.0	3,999	0.5
2029	1,194	0.8	1,411	0.7	1,410	0.6	12	0.4	4,028	0.7
2030	1,200	0.5	1,418	0.4	1,418	0.6	12	0.2	4,048	0.5
2031	1,206	0.5	1,425	0.5	1,426	0.6	12	0.2	4,069	0.5
2032	1,211	0.4	1,432	0.5	1,435	0.6	12	0.1	4,090	0.5
2033	1,217	0.5	1,440	0.6	1,444	0.6	12	0.2	4,114	0.6
2034	1,223	0.4	1,448	0.5	1,452	0.6	12	0.0	4,135	0.5
2035	1,229	0.5	1,456	0.6	1,462	0.7	12	0.2	4,160	0.6

Note: *2015 data are six months acutal and six months forecast.

Compound Annual Growth Rate 2005-2014

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	-0.1	0.0	-1.3	0.1	-0.5

Compound Annual Growth Rate 2016-2035

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.4	0.4	0.4	0.2	0.4

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Southwestern Electric Power Company-Louisiana
Actual and Forecast Retail Sales (GWh)
By Customer Class After DSM/EE Effects
Table B-2 (page 2)

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2005	2,384	---	2,277	---	931	---	39	---	5,630	---
2006	2,368	-0.7	2,275	-0.1	899	-3.4	39	0.3	5,581	-0.9
2007	2,383	0.6	2,345	3.0	911	1.3	39	1.1	5,677	1.7
2008	2,405	0.9	2,344	0.0	853	-6.3	39	0.7	5,641	-0.6
2009	2,382	-0.9	2,417	3.1	791	-7.3	39	-0.5	5,630	-0.2
2010	2,804	17.7	2,439	0.9	967	22.2	39	-0.2	6,249	11.0
2011	3,291	17.3	2,525	3.5	1,103	14.1	40	1.8	6,959	11.4
2012	2,990	-9.1	2,453	-2.9	1,080	-2.1	40	0.5	6,563	-5.7
2013	3,041	1.7	2,428	-1.0	1,020	-5.6	40	-0.9	6,528	-0.5
2014	2,991	-1.6	2,406	-0.9	1,034	1.4	40	0.3	6,472	-0.9
Forecast										
2015*	3,067	2.5	2,483	3.2	1,166	12.8	40	1.5	6,756	4.4
2016	3,032	-1.1	2,484	0.0	1,324	13.6	40	-1.1	6,881	1.8
2017	3,047	0.5	2,502	0.7	1,337	1.0	40	0.0	6,926	0.7
2018	3,066	0.6	2,517	0.6	1,347	0.8	40	0.2	6,971	0.6
2019	3,077	0.3	2,521	0.2	1,477	9.6	40	0.0	7,115	2.1
2020	3,088	0.3	2,525	0.2	1,573	6.5	40	-0.1	7,226	1.5
2021	3,104	0.5	2,537	0.5	1,581	0.5	40	0.0	7,263	0.5
2022	3,122	0.6	2,551	0.6	1,588	0.4	40	0.0	7,302	0.5
2023	3,143	0.7	2,568	0.7	1,595	0.5	40	0.0	7,347	0.6
2024	3,167	0.7	2,585	0.7	1,603	0.5	40	0.1	7,395	0.7
2025	3,191	0.8	2,604	0.7	1,610	0.4	40	0.1	7,446	0.7
2026	3,212	0.7	2,621	0.6	1,615	0.3	40	0.0	7,489	0.6
2027	3,235	0.7	2,639	0.7	1,621	0.3	40	0.0	7,536	0.6
2028	3,254	0.6	2,654	0.6	1,625	0.3	40	-0.1	7,574	0.5
2029	3,281	0.8	2,677	0.9	1,632	0.4	40	0.1	7,629	0.7
2030	3,303	0.7	2,690	0.5	1,637	0.3	40	0.0	7,670	0.5
2031	3,324	0.6	2,704	0.5	1,641	0.3	40	0.0	7,710	0.5
2032	3,345	0.6	2,719	0.5	1,646	0.3	40	0.0	7,749	0.5
2033	3,367	0.7	2,736	0.6	1,652	0.3	40	0.0	7,795	0.6
2034	3,388	0.6	2,750	0.5	1,658	0.4	40	0.0	7,836	0.5
2035	3,412	0.7	2,766	0.6	1,665	0.5	40	0.1	7,883	0.6

Note: *2015 data are six months acutal and six months forecast.

	Residential	Commercial	Industrial	Other Retail	Retail Sales
Compound Annual Growth Rate 2005-2014					
	2.6	0.6	1.2	0.4	1.6
Compound Annual Growth Rate 2016-2035					
	0.6	0.6	1.2	0.0	0.7

Southwestern Electric Power Company-Texas
Actual and Forecast Retail Sales (GWh)
By Customer Class After DSM/EE Effects
Table B-2 (page 3)

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2005	2,133	---	2,175	---	2,884	---	30	---	7,221	---
2006	2,074	-2.8	2,144	-1.4	3,008	4.3	29	-2.3	7,254	0.5
2007	2,124	2.4	2,248	4.8	2,956	-1.7	31	6.8	7,358	1.4
2008	2,176	2.5	2,283	1.6	2,903	-1.8	31	1.1	7,393	0.5
2009	2,136	-1.8	2,228	-2.4	2,158	-25.6	31	-1.3	6,553	-11.4
2010	2,363	10.6	2,330	4.6	2,670	23.7	30	-1.1	7,394	12.8
2011	2,419	2.3	2,365	1.5	2,730	2.3	31	0.7	7,544	2.0
2012	2,179	-9.9	2,294	-3.0	3,018	10.6	30	-3.5	7,521	-0.3
2013	2,256	3.5	2,251	-1.9	3,053	1.1	29	-1.4	7,588	0.9
2014	2,198	-2.5	2,247	-0.2	3,324	8.9	29	-0.6	7,798	2.8
Forecast										
2015*	2,260	2.8	2,298	2.2	3,107	-6.5	29	0.9	7,694	-1.3
2016	2,250	-0.4	2,299	0.1	3,289	5.9	29	0.2	7,868	2.3
2017	2,265	0.7	2,315	0.7	3,319	0.9	29	0.2	7,929	0.8
2018	2,281	0.7	2,335	0.8	3,344	0.7	29	0.3	7,989	0.7
2019	2,282	0.1	2,345	0.5	3,385	1.2	29	-0.1	8,042	0.7
2020	2,290	0.4	2,362	0.7	3,443	1.7	29	0.0	8,125	1.0
2021	2,299	0.4	2,379	0.7	3,498	1.6	29	0.1	8,206	1.0
2022	2,307	0.3	2,398	0.8	3,543	1.3	29	0.0	8,277	0.9
2023	2,316	0.4	2,419	0.9	3,585	1.2	29	0.1	8,349	0.9
2024	2,328	0.5	2,440	0.9	3,627	1.2	29	0.1	8,425	0.9
2025	2,342	0.6	2,461	0.8	3,665	1.0	30	0.1	8,497	0.9
2026	2,353	0.5	2,478	0.7	3,695	0.8	29	-0.1	8,556	0.7
2027	2,367	0.6	2,498	0.8	3,728	0.9	30	0.1	8,622	0.8
2028	2,377	0.4	2,515	0.7	3,757	0.8	29	-0.1	8,679	0.7
2029	2,394	0.7	2,538	0.9	3,791	0.9	30	0.1	8,754	0.9
2030	2,408	0.6	2,554	0.6	3,821	0.8	30	0.0	8,812	0.7
2031	2,422	0.6	2,570	0.6	3,851	0.8	30	0.1	8,873	0.7
2032	2,435	0.5	2,587	0.7	3,882	0.8	30	0.1	8,934	0.7
2033	2,450	0.6	2,606	0.7	3,913	0.8	30	0.1	8,998	0.7
2034	2,463	0.5	2,621	0.6	3,942	0.7	30	0.0	9,056	0.6
2035	2,480	0.7	2,641	0.8	3,975	0.8	30	0.2	9,126	0.8

Note: *2015 data are six months acutal and six months forecast.

Compound Annual Growth Rate 2005-2014

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.3	0.4	1.6	-0.2	0.9

Compound Annual Growth Rate 2016-2035

	Residential	Commercial	Industrial	Other Retail	Retail Sales
	0.5	0.7	1.0	0.1	0.8

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Southwestern Electric Power Company
Winter, Summer and Annual Peak Demand (MW)
Internal Energy Requirements (GWh) and Load Factor (%)
After DSM/EE Effects
Table B-3

Year	Summer Peak Demand	Preceding Winter Peak Demand	Annual Peak Demand	Internal Energy Requirements	Load Factor
Actual					
2005	4,725	3,635	4,725	23,596	57.0
2006	4,912	3,895	4,912	23,865	55.5
2007	4,924	4,186	4,924	23,868	55.3
2008	4,950	3,992	4,950	23,767	54.7
2009	4,750	3,909	4,750	22,949	55.2
2010	4,994	4,539	4,994	25,227	57.7
2011	5,554	4,823	5,554	26,077	53.6
2012	5,205	4,080	5,205	25,188	55.1
2013	5,048	4,178	5,048	25,484	57.6
2014	4,836	4,919	4,919	25,516	59.2
Forecast					
2015*	5,146	4,708	5,146	25,726	57.1
2016	5,223	4,619	5,223	26,041	56.8
2017	5,272	4,682	5,272	26,245	56.8
2018	4,554	4,044	4,554	22,646	56.8
2019	4,610	3,960	4,610	22,895	56.7
2020	4,528	3,924	4,528	22,555	56.7
2021	4,572	3,963	4,572	22,706	56.7
2022	4,607	3,995	4,607	22,869	56.7
2023	4,635	4,012	4,635	23,035	56.7
2024	4,661	4,016	4,661	23,193	56.6
2025	4,708	4,056	4,708	23,345	56.6
2026	4,744	4,078	4,744	23,498	56.5
2027	4,778	4,100	4,778	23,651	56.5
2028	4,806	4,109	4,806	23,812	56.4
2029	4,839	4,146	4,839	23,960	56.5
2030	4,872	4,165	4,872	24,098	56.5
2031	4,906	4,184	4,906	24,232	56.4
2032	4,929	4,186	4,929	24,377	56.3
2033	4,974	4,223	4,974	24,521	56.3
2034	4,997	4,250	4,997	24,666	56.3
2035	5,031	4,269	5,031	24,810	56.3

Note: *2015 data are six months acutal and six months forecast.

Compound Annual Growth Rate 2004-2013					
	0.3	3.4	0.4	0.9	0.4
Compound Annual Growth Rate 2016-2035					
	-0.2	-0.4	-0.2	-0.3	0.0

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Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class
Table B-4

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2004	1	479.3	409.5	391.3	546.5	1,826.7
2004	2	429.6	410.1	398.6	534.0	1,772.2
2004	3	319.6	400.0	422.3	421.7	1,563.7
2004	4	285.8	439.4	443.7	408.7	1,577.7
2004	5	412.2	553.8	479.5	399.2	1,844.8
2004	6	531.6	513.7	427.2	505.3	1,977.9
2004	7	625.2	573.7	452.6	602.1	2,253.7
2004	8	601.7	558.3	500.8	529.6	2,190.4
2004	9	474.9	529.5	403.4	566.0	1,973.7
2004	10	395.0	487.0	476.2	454.9	1,813.0
2004	11	287.3	401.7	432.4	479.9	1,601.3
2004	12	416.1	417.6	458.9	585.6	1,878.2
2005	1	489.5	427.2	402.3	544.9	1,863.9
2005	2	365.5	380.4	411.2	464.6	1,621.7
2005	3	348.4	422.2	471.8	443.4	1,685.9
2005	4	296.1	425.4	435.2	420.4	1,577.1
2005	5	390.7	527.1	499.4	474.7	1,891.9
2005	6	616.8	567.6	486.9	604.7	2,276.1
2005	7	722.8	580.8	455.9	654.0	2,413.5
2005	8	718.1	619.5	523.0	688.2	2,548.8
2005	9	558.0	517.1	463.8	724.4	2,263.3
2005	10	407.1	476.6	451.1	484.8	1,819.6
2005	11	272.5	430.5	493.8	496.4	1,693.1
2005	12	458.2	416.6	460.9	606.0	1,941.6
2006	1	420.4	390.7	415.8	551.5	1,778.4
2006	2	381.7	414.4	443.3	523.4	1,762.8
2006	3	386.0	422.1	450.8	460.0	1,718.8
2006	4	346.7	461.8	473.1	465.9	1,747.5
2006	5	393.0	488.0	509.6	638.6	2,029.2
2006	6	534.4	515.1	472.9	691.9	2,214.3
2006	7	700.1	587.8	480.2	734.4	2,502.5
2006	8	788.5	640.1	504.4	709.2	2,642.2
2006	9	468.2	479.8	430.4	626.4	2,004.8
2006	10	349.2	476.4	509.3	474.0	1,808.9
2006	11	322.4	442.5	490.7	480.6	1,736.2
2006	12	448.2	412.9	462.9	595.2	1,919.2
2007	1	519.6	458.9	472.3	643.6	2,094.4
2007	2	453.0	390.0	391.4	576.2	1,810.6
2007	3	353.8	434.6	471.4	463.8	1,723.6
2007	4	301.4	447.9	471.8	446.0	1,667.1
2007	5	421.0	518.9	524.2	467.8	1,932.0
2007	6	516.5	542.8	494.9	601.0	2,155.2
2007	7	595.9	560.0	484.7	608.5	2,249.1
2007	8	719.3	650.0	521.3	729.1	2,619.8
2007	9	565.1	538.1	432.5	594.7	2,130.5
2007	10	415.3	511.4	459.4	502.4	1,888.5
2007	11	312.3	453.7	448.2	475.9	1,690.1

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Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class
Table B-4

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2007	12	455.1	464.1	434.6	553.5	1,907.4
2008	1	563.7	458.7	408.8	671.7	2,102.9
2008	2	436.2	420.2	409.2	504.5	1,770.1
2008	3	390.7	455.1	409.4	496.4	1,751.6
2008	4	297.0	433.9	481.9	448.7	1,661.5
2008	5	386.4	524.3	490.0	531.3	1,931.9
2008	6	608.1	578.2	474.5	605.1	2,265.9
2008	7	704.2	625.0	482.6	715.3	2,527.1
2008	8	658.6	563.2	450.2	722.4	2,394.4
2008	9	446.7	508.8	456.7	508.2	1,920.4
2008	10	333.9	491.7	470.5	468.2	1,764.2
2008	11	317.7	442.1	450.5	475.2	1,685.5
2008	12	550.7	492.3	417.6	530.3	1,990.9
2009	1	517.8	419.7	321.1	729.1	1,987.7
2009	2	388.3	376.2	322.8	508.7	1,596.0
2009	3	377.0	467.0	376.2	515.6	1,735.8
2009	4	332.1	446.1	364.1	460.9	1,603.2
2009	5	389.5	517.2	403.3	501.8	1,811.8
2009	6	577.2	610.5	421.4	650.7	2,259.8
2009	7	748.2	589.8	346.5	702.5	2,387.1
2009	8	630.4	601.0	411.4	680.7	2,323.5
2009	9	464.9	523.1	371.5	545.0	1,904.5
2009	10	328.0	475.4	378.1	463.0	1,644.4
2009	11	295.1	433.7	369.4	485.0	1,583.2
2009	12	538.6	497.6	374.6	701.8	2,112.6
2010	1	650.6	453.3	346.8	725.4	2,176.2
2010	2	505.4	466.7	371.3	629.8	1,973.2
2010	3	443.0	418.5	403.9	537.2	1,802.5
2010	4	294.3	442.6	439.8	461.1	1,637.8
2010	5	405.6	534.2	470.6	660.0	2,070.5
2010	6	690.5	621.4	472.6	634.5	2,419.0
2010	7	752.2	622.4	407.1	710.8	2,492.5
2010	8	767.1	655.1	510.6	782.7	2,715.5
2010	9	586.8	552.7	429.5	625.0	2,194.0
2010	10	422.6	507.9	446.4	498.5	1,875.3
2010	11	299.7	410.5	517.7	547.6	1,775.4
2010	12	543.4	455.9	413.3	682.6	2,095.2
2011	1	656.7	458.9	404.6	727.1	2,247.3
2011	2	575.3	440.2	380.1	546.4	1,942.0
2011	3	372.0	466.5	466.8	501.7	1,806.9
2011	4	405.2	483.7	460.8	468.2	1,818.0
2011	5	479.0	533.4	473.7	550.1	2,036.2
2011	6	761.2	646.6	490.4	705.2	2,603.3
2011	7	904.1	649.1	468.0	828.5	2,849.8
2011	8	931.2	691.4	500.6	830.9	2,954.0
2011	9	536.2	490.9	403.9	697.8	2,128.8
2011	10	384.9	500.1	472.8	491.4	1,849.2

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Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class
Table B-4

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2011	11	356.0	464.7	464.4	478.3	1,763.4
2011	12	545.8	454.8	422.4	655.0	2,078.0
2012	1	567.8	429.1	402.9	597.0	1,996.7
2012	2	417.4	422.7	420.6	563.5	1,824.2
2012	3	396.9	458.8	494.2	473.0	1,822.9
2012	4	368.8	484.4	474.1	455.8	1,783.2
2012	5	514.8	574.7	526.7	568.5	2,184.8
2012	6	686.5	584.1	512.5	660.1	2,443.2
2012	7	784.0	610.6	484.8	769.7	2,649.1
2012	8	790.3	632.2	486.7	700.1	2,609.3
2012	9	545.3	521.3	476.4	649.2	2,192.2
2012	10	378.2	484.9	473.6	525.5	1,862.1
2012	11	353.4	442.1	455.6	545.2	1,796.3
2012	12	497.7	458.3	452.5	615.2	2,023.7
2013	1	630.1	442.5	409.2	646.6	2,128.4
2013	2	390.8	393.1	398.2	625.7	1,807.7
2013	3	472.8	443.7	451.3	526.9	1,894.7
2013	4	390.3	453.6	465.4	479.5	1,788.9
2013	5	429.8	519.0	501.3	561.6	2,011.6
2013	6	626.6	582.6	498.6	657.2	2,365.0
2013	7	695.3	548.7	467.2	757.5	2,468.6
2013	8	750.2	635.5	513.5	736.1	2,635.3
2013	9	635.5	561.1	461.9	655.7	2,314.3
2013	10	414.8	482.6	456.0	519.8	1,873.2
2013	11	357.0	478.0	525.1	565.2	1,925.3
2013	12	638.2	470.3	464.5	697.9	2,270.8
2014	1	711.6	488.7	454.8	723.7	2,378.8
2014	2	550.0	434.6	437.0	610.9	2,032.5
2014	3	485.4	470.0	485.6	622.3	2,063.3
2014	4	312.2	407.0	563.0	517.2	1,799.5
2014	5	389.6	470.6	502.9	602.7	1,965.7
2014	6	576.0	567.8	498.7	618.5	2,261.0
2014	7	640.8	556.2	477.3	722.4	2,396.7
2014	8	750.8	690.1	590.8	505.5	2,537.2
2014	9	557.6	498.4	442.6	705.1	2,203.8
2014	10	408.3	497.7	487.3	504.6	1,897.9
2014	11	387.2	470.8	505.7	564.2	1,928.0
2014	12	541.6	444.4	455.0	610.7	2,051.8
2015	1	674.7	491.3	433.6	696.3	2,295.8
2015	2	495.4	425.4	403.4	714.5	2,038.7
2015	3	536.1	448.9	408.5	533.5	1,927.1
2015	4	316.0	456.1	455.0	476.2	1,703.3
2015	5	428.9	528.0	491.2	477.0	1,925.2
2015	6	597.1	573.0	468.4	661.8	2,300.3

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

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table B-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2015	7	745.4	594.8	488.8	813.0	2,642.0
2015	8	769.9	634.5	528.6	751.3	2,684.3
2015	9	555.0	516.9	473.8	672.8	2,218.5
2015	10	431.0	524.7	526.3	465.5	1,947.6
2015	11	378.3	488.1	527.0	467.4	1,860.7
2015	12	554.8	468.9	471.8	687.0	2,182.5
2016	1	593.1	427.7	437.1	747.6	2,205.5
2016	2	485.3	433.1	447.3	659.8	2,025.4
2016	3	417.4	443.9	480.1	577.7	1,919.1
2016	4	339.0	429.4	485.6	559.6	1,813.7
2016	5	479.4	567.5	549.1	456.0	2,052.0
2016	6	650.6	586.7	527.5	602.7	2,367.4
2016	7	744.3	593.7	505.1	829.0	2,672.1
2016	8	788.9	650.5	551.4	745.2	2,735.9
2016	9	555.3	517.5	472.1	689.8	2,234.7
2016	10	424.6	519.5	521.7	490.8	1,956.6
2016	11	390.2	504.6	532.5	440.1	1,867.3
2016	12	553.1	467.0	469.8	701.3	2,191.1
2017	1	602.7	436.1	442.7	763.8	2,245.4
2017	2	466.5	417.4	442.7	647.0	1,973.7
2017	3	430.1	456.5	487.2	566.8	1,940.5
2017	4	339.3	431.0	484.3	572.7	1,827.3
2017	5	476.8	564.9	545.6	491.8	2,079.1
2017	6	657.5	595.3	530.0	607.2	2,390.0
2017	7	753.0	600.8	506.6	838.2	2,698.7
2017	8	788.1	648.3	548.8	778.9	2,764.1
2017	9	559.5	519.6	471.6	700.4	2,251.1
2017	10	437.1	532.5	525.3	487.3	1,982.2
2017	11	385.1	500.0	528.3	474.1	1,887.5
2017	12	555.9	470.8	469.5	709.3	2,205.5
2018	1	623.0	453.7	446.2	368.9	1,891.7
2018	2	473.7	425.7	442.0	329.5	1,670.9
2018	3	413.2	443.2	478.3	334.8	1,669.5
2018	4	346.0	441.7	489.8	320.6	1,598.2
2018	5	477.1	566.6	547.3	215.9	1,806.9
2018	6	653.8	588.4	527.7	308.2	2,078.1
2018	7	780.4	623.0	517.4	431.1	2,351.9
2018	8	778.4	636.6	546.9	437.6	2,399.4
2018	9	574.8	532.4	478.9	372.0	1,958.1
2018	10	411.8	509.4	519.4	248.0	1,688.7
2018	11	385.5	501.6	532.0	203.5	1,622.6
2018	12	573.2	489.0	482.0	365.9	1,910.0
2019	1	626.9	454.5	449.1	371.2	1,901.7
2019	2	473.9	427.5	445.9	331.8	1,679.2
2019	3	410.0	442.9	482.5	336.7	1,672.0
2019	4	346.3	446.5	496.4	323.4	1,612.6

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Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table B-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2019	5	461.1	547.8	542.2	265.1	1,816.2
2019	6	662.3	597.4	553.5	290.6	2,103.8
2019	7	786.0	626.2	541.2	435.4	2,388.7
2019	8	779.5	635.4	569.2	441.1	2,425.1
2019	9	578.8	535.1	502.8	376.1	1,992.9
2019	10	410.5	509.6	542.2	254.6	1,716.9
2019	11	387.9	507.1	557.3	193.2	1,645.5
2019	12	575.0	490.5	505.1	369.6	1,940.2
2020	1	628.4	454.5	471.7	316.7	1,871.4
2020	2	498.0	450.0	477.6	291.2	1,716.8
2020	3	411.3	448.2	508.4	297.1	1,665.0
2020	4	344.2	451.2	522.4	289.4	1,607.2
2020	5	439.9	522.6	552.6	240.2	1,755.3
2020	6	660.8	594.5	558.3	266.0	2,079.6
2020	7	790.5	629.2	548.2	378.3	2,346.2
2020	8	781.7	636.2	575.4	383.7	2,377.0
2020	9	585.1	540.0	510.4	330.6	1,966.1
2020	10	411.2	511.5	548.7	176.6	1,648.0
2020	11	386.4	506.7	562.4	160.4	1,616.0
2020	12	580.3	496.2	513.0	316.5	1,906.1
2021	1	629.1	454.5	476.5	318.4	1,878.5
2021	2	477.0	431.7	474.8	289.1	1,672.6
2021	3	419.6	455.4	515.8	300.2	1,691.0
2021	4	347.7	454.0	528.0	291.6	1,621.3
2021	5	455.1	542.2	567.0	208.1	1,772.4
2021	6	663.0	596.2	563.9	276.4	2,099.5
2021	7	795.1	632.5	554.4	380.7	2,362.6
2021	8	791.1	643.7	583.6	386.9	2,405.3
2021	9	590.1	544.7	516.8	333.1	1,984.7
2021	10	404.3	506.5	551.6	195.9	1,658.4
2021	11	387.8	510.0	568.5	165.7	1,632.0
2021	12	586.0	502.5	520.3	319.3	1,928.1
2022	1	634.7	459.0	482.2	320.8	1,896.7
2022	2	478.5	434.2	479.6	291.0	1,683.3
2022	3	420.4	458.1	521.1	302.1	1,701.8
2022	4	346.2	454.8	532.3	293.1	1,626.4
2022	5	454.4	542.4	570.8	223.9	1,791.5
2022	6	667.7	601.3	569.9	276.1	2,115.0
2022	7	797.9	634.9	559.0	382.6	2,374.3
2022	8	799.0	650.5	590.1	389.8	2,429.4
2022	9	593.4	548.1	521.7	335.2	1,998.4
2022	10	406.0	509.7	556.7	198.7	1,671.1
2022	11	389.7	513.8	573.9	167.4	1,644.8
2022	12	586.9	504.0	524.3	321.0	1,936.2
2023	1	640.1	464.1	487.8	323.3	1,915.4
2023	2	480.7	437.0	484.1	292.9	1,694.8

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Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table B-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2023	3	421.6	460.7	525.6	303.9	1,711.8
2023	4	346.3	456.2	536.3	294.7	1,633.4
2023	5	458.7	548.6	577.1	227.5	1,811.8
2023	6	672.0	605.8	575.2	277.6	2,130.6
2023	7	803.8	639.9	564.3	385.1	2,393.0
2023	8	805.1	655.7	595.7	392.3	2,448.8
2023	9	595.3	550.1	525.8	336.9	2,008.2
2023	10	409.4	514.6	562.1	203.4	1,689.5
2023	11	391.5	517.6	579.0	169.0	1,657.1
2023	12	586.6	504.3	527.4	322.3	1,940.6
2024	1	639.9	464.7	491.6	324.8	1,920.9
2024	2	507.5	461.5	497.6	299.3	1,765.8
2024	3	415.1	457.3	528.0	304.5	1,704.8
2024	4	348.9	463.1	543.1	297.1	1,652.2
2024	5	451.1	540.2	576.1	252.3	1,819.7
2024	6	676.4	609.9	580.2	264.3	2,130.9
2024	7	812.3	646.4	570.3	387.8	2,416.9
2024	8	805.6	654.9	598.9	393.6	2,453.0
2024	9	597.8	551.7	529.7	338.7	2,018.0
2024	10	415.3	521.1	568.0	197.8	1,702.2
2024	11	393.9	521.9	584.1	157.0	1,656.8
2024	12	589.1	507.1	531.4	324.2	1,951.8
2025	1	645.9	469.7	496.6	327.1	1,939.4
2025	2	485.4	442.1	492.3	296.6	1,716.4
2025	3	420.9	461.7	531.9	306.6	1,721.1
2025	4	354.7	467.3	546.9	299.3	1,668.2
2025	5	468.9	562.6	589.6	208.9	1,830.0
2025	6	680.9	613.7	584.6	276.5	2,155.7
2025	7	820.8	652.7	575.5	390.5	2,439.6
2025	8	811.7	658.7	603.4	395.8	2,469.7
2025	9	606.8	559.1	535.2	341.5	2,042.7
2025	10	410.8	518.0	569.6	219.2	1,717.5
2025	11	396.0	525.7	588.3	159.0	1,669.1
2025	12	596.5	515.0	537.4	326.9	1,975.9
2026	1	647.5	470.5	498.8	328.5	1,945.3
2026	2	487.7	445.0	495.6	298.3	1,726.8
2026	3	424.5	466.8	536.4	308.8	1,736.4
2026	4	356.0	471.0	550.9	301.1	1,678.9
2026	5	469.1	563.5	592.0	211.0	1,835.6
2026	6	685.3	617.5	588.4	284.9	2,176.0
2026	7	826.6	656.6	579.4	392.6	2,455.3
2026	8	818.5	663.3	607.7	398.1	2,487.6
2026	9	611.8	562.9	539.0	343.5	2,057.2
2026	10	413.1	521.3	573.3	215.6	1,723.3
2026	11	397.9	529.3	592.1	167.7	1,687.0
2026	12	599.8	519.0	541.1	328.8	1,988.7

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table B-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2027	1	648.3	471.4	501.2	329.9	1,950.8
2027	2	490.1	447.7	498.9	300.0	1,736.8
2027	3	430.6	473.8	541.6	311.2	1,757.2
2027	4	357.0	473.9	554.3	302.7	1,687.9
2027	5	471.9	567.6	596.0	212.7	1,848.2
2027	6	690.0	621.7	592.4	286.9	2,190.9
2027	7	830.6	658.8	582.6	394.3	2,466.3
2027	8	827.4	669.8	612.9	400.7	2,510.8
2027	9	616.5	566.4	542.7	345.4	2,070.9
2027	10	415.2	524.4	577.1	212.1	1,728.8
2027	11	399.9	533.2	596.2	168.2	1,697.5
2027	12	604.2	524.0	545.5	330.9	2,004.6
2028	1	652.1	474.8	504.7	331.7	1,963.3
2028	2	518.0	473.9	511.9	306.4	1,810.1
2028	3	428.1	475.5	545.4	312.5	1,761.5
2028	4	351.3	473.1	556.7	303.3	1,684.4
2028	5	460.1	553.8	591.2	265.7	1,870.8
2028	6	695.1	626.5	596.7	282.6	2,201.0
2028	7	832.7	659.6	585.2	395.7	2,473.2
2028	8	834.5	675.0	617.4	402.9	2,529.8
2028	9	616.4	565.5	544.8	346.4	2,073.1
2028	10	425.5	535.1	583.7	198.3	1,742.6
2028	11	402.2	537.5	600.4	165.4	1,705.4
2028	12	599.9	520.3	545.3	331.1	1,996.6
2029	1	659.8	482.9	510.7	334.3	1,987.7
2029	2	495.3	454.0	505.8	303.3	1,758.4
2029	3	431.7	477.4	547.3	313.9	1,770.3
2029	4	359.7	479.1	560.5	305.6	1,705.0
2029	5	483.5	583.2	607.6	213.4	1,887.7
2029	6	700.0	631.0	600.8	282.3	2,214.1
2029	7	843.4	668.1	590.7	398.5	2,500.6
2029	8	842.5	680.6	622.2	405.2	2,550.5
2029	9	620.7	569.1	548.2	348.1	2,086.1
2029	10	421.9	533.0	585.2	223.9	1,763.9
2029	11	404.6	541.7	604.3	169.6	1,720.2
2029	12	605.6	526.7	550.1	333.3	2,015.7
2030	1	663.6	485.2	513.8	335.9	1,998.6
2030	2	497.5	456.3	508.9	304.7	1,767.4
2030	3	430.9	477.3	549.6	314.8	1,772.6
2030	4	363.7	484.4	565.2	307.5	1,720.8
2030	5	484.8	584.6	610.4	217.6	1,897.5
2030	6	704.9	634.5	604.6	278.7	2,222.7
2030	7	852.2	673.9	595.4	400.8	2,522.2
2030	8	846.3	681.8	625.2	406.6	2,559.9
2030	9	628.0	574.1	552.5	350.2	2,104.8
2030	10	421.6	533.0	587.7	232.5	1,774.8

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Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table B-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2030	11	407.0	545.1	608.1	164.5	1,724.8
2030	12	610.6	531.5	554.4	335.2	2,031.7
2031	1	666.5	487.3	516.7	337.2	2,007.6
2031	2	499.6	458.7	512.0	306.1	1,776.3
2031	3	432.4	479.9	552.9	316.1	1,781.4
2031	4	365.2	487.5	568.8	308.9	1,730.4
2031	5	486.7	587.1	613.7	214.2	1,901.6
2031	6	709.2	637.7	608.2	286.5	2,241.6
2031	7	858.6	677.8	599.3	402.6	2,538.3
2031	8	850.1	683.2	628.3	408.0	2,569.5
2031	9	635.3	579.4	557.0	352.2	2,123.8
2031	10	423.6	535.5	591.2	233.6	1,783.9
2031	11	409.1	548.7	612.1	159.9	1,729.9
2031	12	615.3	536.6	559.0	336.9	2,047.8
2032	1	664.3	485.2	517.8	337.6	2,004.8
2032	2	525.7	482.7	524.2	311.7	1,844.4
2032	3	436.8	487.4	559.3	318.2	1,801.7
2032	4	362.2	489.7	572.8	309.8	1,734.5
2032	5	472.3	569.7	607.2	253.2	1,902.3
2032	6	713.6	641.4	612.0	289.8	2,256.8
2032	7	859.4	677.1	601.4	403.3	2,541.2
2032	8	856.6	687.7	632.5	409.7	2,586.5
2032	9	637.8	580.5	559.9	353.3	2,131.5
2032	10	433.6	545.6	597.7	199.9	1,776.8
2032	11	410.9	551.9	615.9	161.6	1,740.2
2032	12	617.3	539.0	562.0	338.1	2,056.4
2033	1	670.8	490.9	522.4	339.5	2,023.6
2033	2	504.4	464.1	518.6	308.6	1,795.6
2033	3	442.5	491.9	562.6	319.8	1,816.9
2033	4	365.9	491.2	574.9	310.9	1,742.8
2033	5	491.6	593.6	621.0	219.2	1,925.5
2033	6	718.5	645.5	616.0	295.7	2,275.8
2033	7	865.4	681.1	605.2	404.9	2,556.6
2033	8	868.1	696.4	638.6	412.3	2,615.4
2033	9	644.0	585.5	564.0	355.0	2,148.5
2033	10	429.5	542.6	599.0	222.1	1,793.2
2033	11	413.2	555.5	619.8	168.7	1,757.2
2033	12	621.2	543.2	566.0	339.6	2,069.9
2034	1	677.0	496.0	526.8	341.2	2,041.1
2034	2	506.8	467.0	521.9	309.8	1,805.6
2034	3	443.7	494.3	566.1	320.9	1,825.0
2034	4	366.0	492.7	577.8	311.7	1,748.2
2034	5	494.1	596.9	624.7	228.9	1,944.6
2034	6	723.5	649.7	620.1	295.8	2,289.0
2034	7	871.7	685.3	609.3	406.6	2,572.9
2034	8	874.7	700.7	643.0	414.0	2,632.4

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Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table B-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2034	9	646.2	586.7	566.9	356.0	2,155.8
2034	10	433.5	547.0	603.4	226.6	1,810.4
2034	11	415.7	559.4	624.0	169.5	1,768.7
2034	12	620.9	543.0	568.0	340.1	2,072.0
2035	1	680.1	499.3	530.8	342.5	2,052.6
2035	2	509.3	469.5	525.4	310.9	1,815.2
2035	3	443.4	494.4	568.4	321.5	1,827.7
2035	4	370.7	497.8	582.3	313.3	1,764.1
2035	5	501.3	605.7	631.5	218.1	1,956.7
2035	6	728.4	653.7	624.5	290.1	2,296.7
2035	7	880.5	691.8	614.6	408.6	2,595.5
2035	8	880.3	704.1	647.3	415.5	2,647.3
2035	9	648.6	588.0	570.1	357.0	2,163.7
2035	10	435.4	549.4	607.2	235.7	1,827.6
2035	11	418.4	563.3	628.4	168.4	1,778.4
2035	12	624.4	546.6	572.0	341.4	2,084.4

Southwestern Electric Power Company
Actual and Weather Normal Energy Sales (GWh)
And Peak Demand (MW) vs. 2012 IRP Forecast
Table B-6

	2012 IRP Forecast			Actual			Difference			% Difference		
	2012	2013	2014	2012	2013	2014	2012	2013	2014	2012	2013	2014
Residential	6,502	6,495	6,508	6,301	6,431	6,311	200	63	197	3.2%	1.0%	3.1%
Commercial	6,207	6,265	6,308	6,103	6,011	5,996	103	254	311	1.7%	4.2%	5.2%
Industrial	5,713	5,799	5,870	5,661	5,612	5,901	52	187	-31	0.9%	3.3%	-0.5%
Other Retail	82	83	83	81	81	80	1	2	3	1.3%	2.6%	3.2%
Wholesale	6,488	6,602	6,719	6,117	6,299	6,218	371	303	501	6.1%	4.8%	8.1%
Total Sales	24,992	25,244	25,488	24,264	24,434	24,506	728	810	981	3.0%	3.3%	4.0%

	2012 IRP Forecast			Normal			Difference			% Difference		
	2012	2013	2014	2012	2013	2014	2012	2013	2014	2012	2013	2014
Residential	6,502	6,495	6,508	6,221	6,360	6,308	280	135	200	4.5%	2.1%	3.2%
Commercial	6,207	6,265	6,308	6,044	5,999	6,032	163	266	275	2.7%	4.4%	4.6%
Industrial	5,713	5,799	5,870	5,661	5,612	5,901	52	187	-31	0.9%	3.3%	-0.5%
Other Retail	82	83	83	81	81	80	1	2	3	1.3%	2.6%	3.2%
Wholesale	6,488	6,602	6,719	6,168	6,241	6,161	321	361	558	5.2%	5.8%	9.0%
Total Sales	24,992	25,244	25,488	24,175	24,292	24,483	817	952	1,005	3.4%	3.9%	4.1%

	2012 IRP Forecast			Actual			Difference			% Difference		
	2012	2013	2014	2012	2013	2014	2012	2013	2014	2012	2013	2014
Winter Peak	4,370	4,452	4,501	4,021	4,178	4,919	349	274	-418	8.7%	6.6%	-8.5%
Summer Peak	5,286	5,358	5,396	5,205	5,048	4,836	81	310	560	1.6%	6.1%	11.6%

	2012 IRP Forecast			Normal			Difference			% Difference		
	2012	2013	2014	2012	2013	2014	2012	2013	2014	2012	2013	2014
Winter Peak	4,370	4,452	4,501	4,305	4,326	4,509	65	126	-8	1.5%	2.9%	-0.2%
Summer Peak	5,286	5,358	5,396	5,034	5,054	5,080	252	304	316	5.0%	6.0%	6.2%

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in 2012 IRP Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)
Table B-7

	SWEPCO DSM/EE			SWEPCO - Arkansas DSM/EE			SWEPCO - Louisana DSM/EE			SWEPCO - Texas DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2012	98.7	15.7	13.7	41.4	7.8	5.6	0.0	0.0	0.0	57.3	7.9	8.1
2013	151.4	24.2	21.2	66.4	12.4	8.8	9.2	1.0	1.5	75.8	10.8	10.9
2014	222.8	37.8	32.9	97.2	18.9	13.1	32.4	4.6	6.0	93.2	14.2	13.8
2015	288.4	50.6	43.7	125.2	24.9	17.2	55.5	8.3	10.2	107.8	17.4	16.3
2016	348.3	62.2	53.6	150.3	30.4	20.8	78.1	11.8	14.5	119.8	20.1	18.4
2017	403.6	73.5	63.2	168.7	34.3	23.5	95.6	14.3	17.7	139.2	24.8	21.9
2018	453.8	83.6	72.0	183.9	37.6	25.8	111.8	16.7	20.7	158.0	29.4	25.5
2019	500.5	93.1	80.4	197.0	40.5	27.7	127.9	19.0	23.7	175.6	33.7	28.9
2020	544.3	101.9	88.0	208.2	43.0	29.4	143.8	21.2	26.6	192.4	37.7	32.0
2021	556.8	104.2	90.6	213.1	44.1	30.2	151.6	22.0	28.1	192.1	38.1	32.3
2022	567.1	105.9	92.5	216.5	44.9	30.8	159.3	22.7	29.4	191.3	38.2	32.4
2023	575.4	107.2	93.9	218.6	45.3	31.2	166.8	23.5	30.6	190.0	38.3	32.1
2024	582.1	107.9	94.9	219.5	45.5	31.3	174.2	24.2	31.8	188.3	38.2	31.8
2025	587.5	108.7	96.4	219.5	45.7	31.5	181.5	24.9	33.1	186.4	38.1	31.8
2026	586.2	108.6	96.4	219.3	45.7	31.5	181.5	24.9	33.1	185.4	37.9	31.7
2027	586.2	108.5	96.4	219.3	45.7	31.5	181.5	24.8	33.2	185.4	37.9	31.8
2028	586.2	108.3	96.1	219.3	45.7	31.4	181.5	24.8	33.1	185.4	37.8	31.7
2029	586.2	108.4	96.3	219.3	45.7	31.5	181.5	24.8	33.1	185.4	37.9	31.7
2030	586.2	108.3	96.3	219.3	45.7	31.5	181.5	24.7	33.2	185.4	37.9	31.7
2031	586.2	108.3	96.4	219.3	45.7	31.5	181.5	24.7	33.2	185.4	37.9	31.7

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

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Residential Customer and Energy Usage Models
Table B-8

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Arkansas Gross Regional Product	SWEPCO Arkansas Employment	SWEPCO Louisiana Population	SWEPCO Louisiana Real Personal Income	SWEPCO Louisiana Households	SWEPCO Louisana Employment	SWEPCO Texas Population	SWEPCO Texas Real Personal Income	SWEPCO Texas Employment
1995	566.0	14,272.4	18,256.8	273.4	572.4	14,395.8	212.1	209.5	784.8	19,469.9	291.5
1996	582.1	14,898.0	19,022.3	278.7	573.6	14,578.7	213.6	212.8	796.2	20,354.0	299.2
1997	593.8	15,472.9	19,678.3	283.3	574.1	14,904.5	214.9	214.5	804.8	21,537.3	310.9
1998	602.5	16,419.1	19,997.0	288.2	573.0	15,297.2	215.5	220.2	813.4	22,632.1	315.7
1999	613.6	17,131.2	21,556.4	296.8	575.5	15,600.8	217.5	222.9	819.5	23,154.4	319.8
2000	627.3	17,812.8	22,128.0	304.0	577.2	16,014.8	219.2	225.6	825.4	24,331.5	326.0
2001	636.3	18,660.2	22,859.3	309.8	576.6	16,812.1	219.5	223.7	830.1	24,747.7	328.7
2002	647.0	18,904.6	24,014.1	313.3	576.7	17,036.8	220.1	219.6	837.4	24,798.1	328.6
2003	659.7	19,592.6	25,800.5	315.5	575.9	17,457.0	220.4	220.1	845.2	25,455.1	331.1
2004	672.9	20,845.6	27,480.3	321.6	579.9	18,151.9	222.5	225.6	853.1	26,039.7	341.2
2005	690.0	21,610.2	29,224.8	332.2	583.4	18,931.2	224.4	232.1	861.1	27,065.3	348.7
2006	708.5	22,622.9	30,350.6	340.5	589.7	19,822.3	227.6	235.2	873.9	28,113.6	356.9
2007	722.3	23,541.3	29,792.5	342.7	589.7	19,899.9	228.3	237.1	882.2	29,286.4	368.4
2008	733.4	24,029.3	29,682.6	340.7	590.3	21,982.5	229.2	237.2	890.2	32,320.0	376.4
2009	743.7	23,351.8	28,464.2	327.0	596.1	20,990.8	232.1	232.0	900.5	30,405.1	361.8
2010	756.0	23,721.9	29,748.4	327.3	603.4	21,796.2	235.7	233.0	907.8	31,470.6	363.5
2011	765.5	25,158.6	29,850.3	329.4	606.6	22,717.4	236.4	235.0	913.8	33,122.5	366.8
2012	773.8	26,727.1	30,639.5	334.5	611.2	23,086.3	238.0	232.8	916.6	34,272.3	371.6
2013	783.0	27,070.4	31,660.6	336.8	607.4	22,722.2	238.1	228.0	918.0	34,438.0	381.0
2014	790.6	27,490.2	32,651.2	340.4	608.0	23,000.9	238.2	227.6	925.6	35,672.1	393.1
2015	798.3	28,243.4	33,648.6	347.2	608.7	23,807.2	238.5	229.8	933.7	37,370.5	406.3
2016	806.3	29,189.9	34,668.5	356.6	609.3	24,688.9	240.9	231.4	942.2	39,345.1	419.9
2017	814.9	30,044.9	35,397.9	363.9	610.2	25,509.2	243.2	233.2	950.9	40,804.3	427.3
2018	823.4	30,707.1	35,943.9	369.1	611.3	26,128.0	245.1	234.6	959.6	41,888.0	428.7
2019	831.8	31,067.8	36,498.8	373.4	612.5	26,566.1	246.2	235.5	968.1	42,432.3	429.4
2020	840.2	31,560.9	37,057.2	377.9	613.9	27,024.8	247.1	236.4	976.4	43,014.2	430.0

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Residential Customer and Energy Usage Models
Table B-8

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Arkansas Gross Regional Product	SWEPCO Arkansas Employment	SWEPCO Louisiana Population	SWEPCO Louisiana Real Personal Income	SWEPCO Louisiana Households	SWEPCO Louisana Employment	SWEPCO Texas Population	SWEPCO Texas Real Personal Income	SWEPCO Texas Employment
2021	848.5	32,183.8	37,664.2	382.8	615.1	27,547.3	247.9	237.3	984.8	43,748.2	432.2
2022	856.6	32,862.8	38,345.5	387.7	616.3	28,072.2	248.7	238.2	993.0	44,499.1	434.8
2023	864.6	33,556.4	39,063.2	392.3	617.6	28,612.0	249.5	238.9	1,001.2	45,290.9	437.9
2024	872.3	34,312.7	39,752.1	396.6	618.9	29,213.3	250.2	239.3	1,009.5	46,157.5	440.8
2025	879.8	35,105.3	40,402.0	400.7	620.0	29,840.1	250.8	239.7	1,017.5	47,003.4	442.1
2026	887.2	35,950.6	41,055.1	404.7	620.8	30,487.7	251.3	239.9	1,025.7	47,891.7	442.5
2027	894.4	36,843.7	41,737.1	408.6	621.5	31,151.3	251.7	240.0	1,034.0	48,860.0	443.5
2028	901.2	37,759.9	42,465.1	412.4	622.2	31,801.6	252.0	240.2	1,042.4	49,840.8	444.8
2029	907.5	38,655.5	43,207.0	416.1	622.9	32,435.2	252.4	240.5	1,050.9	50,756.8	445.5
2030	913.3	39,546.4	43,925.6	419.4	623.6	33,070.9	252.7	240.9	1,059.4	51,661.4	446.2
2031	918.6	40,496.7	44,665.0	422.9	624.1	33,728.3	253.1	241.5	1,068.2	52,671.7	448.3
2032	923.4	41,502.2	45,456.4	426.6	624.5	34,398.3	253.4	242.2	1,076.9	53,779.8	451.8
2033	927.7	42,525.7	46,301.0	430.5	625.1	35,060.9	253.8	243.2	1,085.7	54,836.0	454.7
2034	931.6	43,576.5	47,177.7	434.7	625.8	35,721.0	254.3	244.5	1,094.7	55,894.7	458.1
2035	935.1	44,608.9	48,069.5	439.2	626.7	36,330.9	254.8	246.0	1,103.7	56,961.5	462.3
2036	938.4	45,667.6	48,909.1	443.6	627.7	36,930.8	255.4	247.8	1,112.9	58,036.9	465.7
2037	941.9	46,786.7	49,734.5	448.0	628.8	37,575.8	256.0	249.8	1,122.0	59,213.9	469.6
2038	945.4	47,925.2	50,534.7	452.3	629.9	38,232.1	256.6	251.8	1,131.1	60,403.1	473.1
2039	948.8	49,098.0	51,348.4	456.4	631.0	38,905.5	257.1	253.8	1,140.3	61,672.1	477.0
2040	951.9	50,361.4	52,236.8	460.4	632.1	39,632.4	257.7	255.9	1,149.6	63,098.7	481.7
2041	955.0	51,673.5	53,133.5	464.3	633.2	40,394.1	258.2	257.9	1,159.0	64,487.4	485.4
2042	958.0	52,963.4	54,003.0	468.1	634.3	41,145.9	258.7	260.0	1,168.5	65,771.9	488.1
2043	961.1	54,309.7	54,843.6	471.9	635.4	41,935.9	259.2	262.1	1,178.1	67,102.5	490.5
2044	964.1	55,670.7	55,543.5	475.7	636.5	42,740.7	259.6	264.2	1,187.8	68,385.6	492.1
Units	**Thousands**	**Millions**	**Millions**	**Thousands**	**Thousands**	**Millions**	**Thousands**	**Thousands**	**Thousands**	**Millions**	**Thousands**

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Residential Customer and Energy Usage Models
Table B-8

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income (2009 $)	SWEPCO Arkansas Gross Regional Product (2009 $)	SWEPCO Arkansas Employment	SWEPCO Louisiana Population	SWEPCO Louisiana Real Personal Income (2009 $)	SWEPCO Louisiana Households	SWEPCO Louisana Employment	SWEPCO Texas Population	SWEPCO Texas Real Personal Income (2009 $)	SWEPCO Texas Employment

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Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Commercial Energy Sales Models
Table B-9

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Louisana Real Personal Income	SWEPCO Texas SWEPCO Louisana Employment	SWEPCO Texas Gross Regional Product	SWEPCO Texas Gross Regional Product - Commercial	SWEPCO Texas Population
1995	566.0	14,272.4	14,395.8	209.5	26,474.9	17,231.3	784.8
1996	582.1	14,898.0	14,578.7	212.8	27,776.1	18,103.7	796.2
1997	593.8	15,472.9	14,904.5	214.5	29,421.4	19,157.5	804.8
1998	602.5	16,419.1	15,297.2	220.2	30,489.3	19,822.1	813.4
1999	613.6	17,131.2	15,600.8	222.9	31,381.3	20,762.5	819.5
2000	627.3	17,812.8	16,014.8	225.6	32,206.8	21,286.4	825.4
2001	636.3	18,660.2	16,812.1	223.7	32,494.1	21,327.0	830.1
2002	647.0	18,904.6	17,036.8	219.6	33,331.4	21,776.3	837.4
2003	659.7	19,592.6	17,457.0	220.1	33,964.5	22,193.5	845.2
2004	672.9	20,845.6	18,151.9	225.6	36,785.9	23,129.7	853.1
2005	690.0	21,610.2	18,931.2	232.1	36,631.1	23,966.7	861.1
2006	708.5	22,622.9	19,822.3	235.2	38,661.8	24,897.7	873.9
2007	722.3	23,541.3	19,899.9	237.1	40,225.4	25,439.4	882.2
2008	733.4	24,029.3	21,982.5	237.2	40,483.4	26,198.6	890.2
2009	743.7	23,351.8	20,990.8	232.0	39,001.8	25,590.8	900.5
2010	756.0	23,721.9	21,796.2	233.0	40,612.2	26,416.5	907.8
2011	765.5	25,158.6	22,717.4	235.0	41,628.8	26,846.6	913.8
2012	773.8	26,727.1	23,086.3	232.8	44,745.3	29,154.4	916.6
2013	783.0	27,070.4	22,722.2	228.0	45,809.1	29,548.5	918.0
2014	790.6	27,490.2	23,000.9	227.6	47,041.7	30,050.9	925.6
2015	798.3	28,243.4	23,807.2	229.8	49,063.2	31,097.4	933.7
2016	806.3	29,189.9	24,688.9	231.4	51,253.1	32,107.6	942.2
2017	814.9	30,044.9	25,509.2	233.2	52,838.1	32,725.8	950.9
2018	823.4	30,707.1	26,128.0	234.6	54,021.3	33,170.1	959.6
2019	831.8	31,067.8	26,566.1	235.5	55,319.8	33,643.7	968.1
2020	840.2	31,560.9	27,024.8	236.4	56,393.9	34,061.4	976.4
2021	848.5	32,183.8	27,547.3	237.3	57,251.2	34,476.8	984.8
2022	856.6	32,862.8	28,072.2	238.2	58,105.5	34,928.4	993.0
2023	864.6	33,556.4	28,612.0	238.9	59,142.0	35,457.7	1,001.2
2024	872.3	34,312.7	29,213.3	239.3	60,224.5	36,022.0	1,009.5
2025	879.8	35,105.3	29,840.1	239.7	61,109.1	36,491.0	1,017.5
2026	887.2	35,950.6	30,487.7	239.9	61,840.1	36,890.5	1,025.7
2027	894.4	36,843.7	31,151.3	240.0	62,649.1	37,343.7	1,034.0
2028	901.2	37,759.9	31,801.6	240.2	63,476.3	37,805.3	1,042.4
2029	907.5	38,655.5	32,435.2	240.5	64,183.0	38,201.7	1,050.9

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Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Commercial Energy Sales Models
Table B-9

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Louisana Real Personal Income	SWEPCO Texas SWEPCO Louisana Employment	SWEPCO Texas Gross Regional Product	SWEPCO Texas Gross Regional Product - Commercial	SWEPCO Texas Population
2030	913.3	39,546.4	33,070.9	240.9	64,803.1	38,553.0	1,059.4
2031	918.6	40,496.7	33,728.3	241.5	65,603.3	38,977.0	1,068.2
2032	923.4	41,502.2	34,398.3	242.2	66,585.1	39,480.8	1,076.9
2033	927.7	42,525.7	35,060.9	243.2	67,377.9	39,910.5	1,085.7
2034	931.6	43,576.5	35,721.0	244.5	68,176.4	40,352.6	1,094.7
2035	935.1	44,608.9	36,330.9	246.0	69,217.4	40,947.4	1,103.7
2036	938.4	45,667.6	36,930.8	247.8	70,180.6	41,494.9	1,112.9
2037	941.9	46,786.7	37,575.8	249.8	71,262.8	42,112.1	1,122.0
2038	945.4	47,925.2	38,232.1	251.8	72,278.9	42,703.2	1,131.1
2039	948.8	49,098.0	38,905.5	253.8	73,339.4	43,361.4	1,140.3
2040	951.9	50,361.4	39,632.4	255.9	74,562.9	44,171.3	1,149.6
2041	955.0	51,673.5	40,394.1	257.9	75,520.8	44,766.9	1,159.0
2042	958.0	52,963.4	41,145.9	260.0	76,288.2	45,222.1	1,168.5
2043	961.1	54,309.7	41,935.9	262.1	77,069.5	45,691.3	1,178.1
2044	964.1	55,670.7	42,740.7	264.2	77,487.0	45,910.6	1,187.8
Units	**Thousands**	**Millions (2009 $)**	**Millions (2009 $)**	**Thousands**	**Millions (2009 $)**	**Millions (2009 $)**	**Thousands**

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Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Manufacturing Energy Sales Models
Table B-10

Year	SWEPCO Arkansas Gross Regional Product - Manufacturing	SWEPCO Louisana Gross Regional Product - Manufacturing	SWEPCO Louisana Manufacturing Employment	SWEPCO Texas Manufacturing Employment	FRB Industrial Production Index Primary Metals
1995	5,031.9	2,950.2	28.0	5,936.1	95.6
1996	5,015.4	2,966.9	27.2	6,202.1	97.9
1997	5,211.0	2,972.4	25.7	6,239.0	102.0
1998	5,054.6	2,934.2	25.4	6,165.3	103.8
1999	5,573.8	3,193.0	25.6	5,929.1	103.7
2000	5,513.0	2,633.1	25.4	5,945.3	100.3
2001	5,411.2	2,342.9	23.6	5,810.5	91.3
2002	5,864.7	2,695.0	21.4	6,127.9	91.3
2003	6,409.0	3,813.8	21.4	6,379.5	89.8
2004	6,873.7	3,942.8	21.9	8,290.8	97.7
2005	6,961.5	4,298.8	22.3	7,211.0	95.2
2006	7,039.5	3,929.0	22.2	7,922.7	98.0
2007	5,927.9	3,599.1	21.8	8,348.0	100.0
2008	5,209.0	3,180.6	19.4	7,574.2	100.0
2009	4,804.7	3,017.2	16.9	6,564.7	74.0
2010	5,240.9	3,614.1	16.9	7,069.2	91.1
2011	5,028.5	3,598.5	17.0	7,247.9	97.4
2012	4,795.9	3,463.6	16.7	7,218.1	99.6
2013	4,756.0	3,754.8	16.1	7,695.6	100.8
2014	5,047.6	3,263.1	15.8	8,098.2	106.4
2015	5,302.0	3,460.2	15.9	8,661.9	111.0
2016	5,533.0	3,602.8	15.9	9,132.8	112.4
2017	5,707.5	3,754.0	15.9	9,382.6	113.6
2018	5,819.4	3,894.0	15.9	9,438.4	115.1
2019	5,938.5	4,055.8	15.8	9,568.9	117.3
2020	6,063.9	4,234.5	15.6	9,743.0	120.4
2021	6,193.6	4,409.6	15.5	9,928.0	123.3
2022	6,338.6	4,580.3	15.3	10,121.8	125.5
2023	6,490.3	4,761.6	15.1	10,359.5	127.5
2024	6,615.8	4,940.5	15.0	10,573.6	129.4
2025	6,722.3	5,114.9	14.8	10,719.2	131.2
2026	6,840.0	5,285.8	14.6	10,814.0	132.7
2027	6,967.2	5,456.3	14.4	10,914.0	134.3
2028	7,103.4	5,630.9	14.3	11,014.9	135.9
2029	7,240.3	5,808.0	14.1	11,090.0	137.4

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Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Manufacturing Energy Sales Models
Table B-10

Year	SWEPCO Arkansas Gross Regional Product - Manufacturing	SWEPCO Louisana Gross Regional Product - Manufacturing	SWEPCO Louisana Manufacturing Employment	SWEPCO Texas Manufacturing Employment	FRB Industrial Production Index Primary Metals
2030	7,361.5	5,987.3	14.0	11,147.7	138.9
2031	7,483.6	6,158.8	13.8	11,241.7	140.4
2032	7,619.4	6,337.0	13.7	11,369.1	141.9
2033	7,766.0	6,518.1	13.6	11,458.8	143.3
2034	7,918.5	6,715.7	13.6	11,549.7	144.8
2035	8,082.0	6,924.2	13.6	11,676.5	146.3
2036	8,248.1	7,162.7	13.6	11,769.7	147.8
2037	8,417.7	7,427.5	13.7	11,877.3	149.3
2038	8,584.3	7,712.8	13.8	11,976.7	150.8
2039	8,747.8	8,044.6	13.9	12,091.0	152.2
2040	8,918.7	8,432.0	14.0	12,243.6	153.8
2041	9,107.8	8,841.1	14.2	12,365.5	155.3
2042	9,296.7	9,276.9	14.3	12,448.9	156.9
2043	9,465.5	9,748.6	14.5	12,519.1	158.5
2044	9,615.1	10,250.0	14.7	12,550.4	160.1
Units	**Millions (2009 $)**	**Millions (2009 $)**	**Thousands**	**Thousands**	**Index (2007=100)**

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Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Other Retail and Wholesale Energy Sales Models
Table B-11

Year	SWEPCO Arkansas Population	SWEPCO Louisiana Population	SWEPCO Texas Employment	SWEPCO Texas Population	SWEPCO Texas Gross Regional Product - Commercial	SWEPCO Texas Gross Regional Product
1995	566.0	572.4	291.5	784.8	17,231.3	26,474.9
1996	582.1	573.6	299.2	796.2	18,103.7	27,776.1
1997	593.8	574.1	310.9	804.8	19,157.5	29,421.4
1998	602.5	573.0	315.7	813.4	19,822.1	30,489.3
1999	613.6	575.5	319.8	819.5	20,762.5	31,381.3
2000	627.3	577.2	326.0	825.4	21,286.4	32,206.8
2001	636.3	576.6	328.7	830.1	21,327.0	32,494.1
2002	647.0	576.7	328.6	837.4	21,776.3	33,331.4
2003	659.7	575.9	331.1	845.2	22,193.5	33,964.5
2004	672.9	579.9	341.2	853.1	23,129.7	36,785.9
2005	690.0	583.4	348.7	861.1	23,966.7	36,631.1
2006	708.5	589.7	356.9	873.9	24,897.7	38,661.8
2007	722.3	589.7	368.4	882.2	25,439.4	40,225.4
2008	733.4	590.3	376.4	890.2	26,198.6	40,483.4
2009	743.7	596.1	361.8	900.5	25,590.8	39,001.8
2010	756.0	603.4	363.5	907.8	26,416.5	40,612.2
2011	765.5	606.6	366.8	913.8	26,846.6	41,628.8
2012	773.8	611.2	371.6	916.6	29,154.4	44,745.3
2013	783.0	607.4	381.0	918.0	29,548.5	45,809.1
2014	790.6	608.0	393.1	925.6	30,050.9	47,041.7
2015	798.3	608.7	406.3	933.7	31,097.4	49,063.2
2016	806.3	609.3	419.9	942.2	32,107.6	51,253.1
2017	814.9	610.2	427.3	950.9	32,725.8	52,838.1
2018	823.4	611.3	428.7	959.6	33,170.1	54,021.3
2019	831.8	612.5	429.4	968.1	33,643.7	55,319.8
2020	840.2	613.9	430.0	976.4	34,061.4	56,393.9
2021	848.5	615.1	432.2	984.8	34,476.8	57,251.2
2022	856.6	616.3	434.8	993.0	34,928.4	58,105.5
2023	864.6	617.6	437.9	1,001.2	35,457.7	59,142.0
2024	872.3	618.9	440.8	1,009.5	36,022.0	60,224.5
2025	879.8	620.0	442.1	1,017.5	36,491.0	61,109.1
2026	887.2	620.8	442.5	1,025.7	36,890.5	61,840.1
2027	894.4	621.5	443.5	1,034.0	37,343.7	62,649.1
2028	901.2	622.2	444.8	1,042.4	37,805.3	63,476.3
2029	907.5	622.9	445.5	1,050.9	38,201.7	64,183.0

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Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Other Retail and Wholesale Energy Sales Models
Table B-11

Year	SWEPCO Arkansas Population	SWEPCO Louisiana Population	SWEPCO Texas Employment	SWEPCO Texas Population	SWEPCO Texas Gross Regional Product - Commercial	SWEPCO Texas Gross Regional Product
2030	913.3	623.6	446.2	1,059.4	38,553.0	64,803.1
2031	918.6	624.1	448.3	1,068.2	38,977.0	65,603.3
2032	923.4	624.5	451.8	1,076.9	39,480.8	66,585.1
2033	927.7	625.1	454.7	1,085.7	39,910.5	67,377.9
2034	931.6	625.8	458.1	1,094.7	40,352.6	68,176.4
2035	935.1	626.7	462.3	1,103.7	40,947.4	69,217.4
2036	938.4	627.7	465.7	1,112.9	41,494.9	70,180.6
2037	941.9	628.8	469.6	1,122.0	42,112.1	71,262.8
2038	945.4	629.9	473.1	1,131.1	42,703.2	72,278.9
2039	948.8	631.0	477.0	1,140.3	43,361.4	73,339.4
2040	951.9	632.1	481.7	1,149.6	44,171.3	74,562.9
2041	955.0	633.2	485.4	1,159.0	44,766.9	75,520.8
2042	958.0	634.3	488.1	1,168.5	45,222.1	76,288.2
2043	961.1	635.4	490.5	1,178.1	45,691.3	77,069.5
2044	964.1	636.5	492.1	1,187.8	45,910.6	77,487.0
Units	**Thousands**	**Thousands**	**Thousands**	**Thousands**	**Millions (2009 $)**	**Millions (2009 $)**

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)
Table B-12

	SWEPCO DSM/EE			SWEPCO - Arkansas DSM/EE			SWEPCO - Louisana DSM/EE			SWEPCO - Texas DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2015	24.5	4.9	3.9	19.6	3.7	3.2	3.3	0.7	0.5	1.5	0.5	0.2
2016	46.7	9.0	7.4	36.2	6.7	5.8	9.9	2.0	1.6	0.6	0.3	0.0
2017	63.5	12.3	9.9	47.9	9.1	7.4	15.3	3.1	2.5	0.3	0.1	0.0
2018	76.6	14.8	10.5	57.4	10.9	7.3	19.2	3.9	3.1	0.0	0.0	0.0
2019	88.4	16.9	12.1	66.1	12.4	8.4	22.2	4.6	3.7	0.0	0.0	0.0
2020	97.5	18.5	13.2	72.8	13.4	9.2	24.8	5.1	4.1	0.0	0.0	0.0
2021	103.9	19.6	14.2	77.2	14.1	9.7	26.8	5.5	4.4	0.0	0.0	0.0
2022	107.8	20.2	14.5	79.5	14.4	9.8	28.3	5.9	4.8	0.0	0.0	0.0
2023	109.8	20.5	14.9	80.5	14.4	10.0	29.3	6.1	4.9	0.0	0.0	0.0
2024	110.9	20.5	15.0	81.3	14.4	10.1	29.6	6.1	4.9	0.0	0.0	0.0
2025	111.0	20.6	15.0	81.5	14.5	10.1	29.5	6.1	4.9	0.0	0.0	0.0
2026	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2027	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2028	110.9	20.5	14.3	81.5	14.4	9.4	29.4	6.1	4.9	0.0	0.0	0.0
2029	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2030	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2031	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2032	110.9	20.5	14.9	81.5	14.4	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2033	110.9	20.6	14.3	81.5	14.5	9.4	29.4	6.1	4.9	0.0	0.0	0.0
2034	110.9	20.6	14.7	81.5	14.5	9.8	29.4	6.1	4.8	0.0	0.0	0.0
2035	110.9	20.6	14.7	81.5	14.5	9.8	29.4	6.1	4.8	0.0	0.0	0.0

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

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Southwestern Electric Power Company
Actual and Forecast Losses (GWh)
Table B-13

Year	Losses
2004	784.6
2005	972.6
2006	1,203.3
2007	808.5
2008	751.5
2009	965.9
2010	1,020.6
2011	902.2
2012	924.0
2013	1,049.7
2014	1,009.6
2015*	971.4
2016	876.4
2017	885.8
2018	1,052.9
2019	1,084.8
2020	1,095.3
2021	1,099.1
2022	1,121.2
2023	1,134.5
2024	1,133.5
2025	1,127.1
2026	1,145.5
2027	1,149.7
2028	1,185.4
2029	1,164.5
2030	1,172.6
2031	1,177.4
2032	1,194.1
2033	1,197.8
2034	1,216.3
2035	1,212.7

Note: *2015 data are six months actual
six months forecast

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Southwestern Electric Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results
Table B-14

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

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Blending Illustration
Table B-15

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

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

SOUTHWESTERN ELECTRIC POWER COMPANY
CAPABILITY,DEMAND AND RESERVES FORECAST
GOING-IN (2014-2045)
(MW)

AEP SOUTHWESTERN ELECTRIC POWER

CAPABILITY

	Plant Capabilities	14 ACT	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	12 ARSENAL HILL # 5	110	110	110	110	110	110	110	110	110	110	110	110	0	0	0	0	0	0	0	0	0
	11 J.L. STALL (ARSENAL HILL) CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
	10 DOLET HILLS #1	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	9 FLINT CREEK # 1	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264
	8 TURK (HEMPSTEAD) PC	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
	7 KNOX LEE # 2, 3, 4, 5	469	469	469	469	469	469	398	342	342	342	342	342	342	342	342	342	342	342	342	342	342
	6 LIEBERMAN # 1, 2, 3, 4	267	242	242	242	242	242	217	217	217	108	108	0	0	0	0	0	0	0	0	0	0
	5 LONE STAR # 1	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4 PIRKEY #1	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
	3 MATTISON (TONTITOWN) CTs	301	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303
	2 WELSH # 1, 2, 3	1,584	1,584	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056
	1 WILKES # 1, 2, 3	875	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	722	722	722	722	722
1	**TOTAL**	**5,745**	**5,740**	**5,212**	**5,212**	**5,212**	**5,212**	**5,066**	**5,010**	**5,010**	**4,901**	**4,901**	**4,793**	**4,683**	**4,683**	**4,683**	**4,683**	**4,512**	**4,512**	**4,512**	**4,512**	**4,512**
	Adjustments to Plant Capability																					
	Knox Lee 4		-36	-36	-36	-36	-36															
	Welsh 1 ACI, 2.08%, 2016			-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11
	Welsh 3 ACI, 2.08%, 2016			-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11
	Pirkey ACI 2.07%, 2016			-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12
	Flint Creek FGD, ACI, 2.08%, 2016			-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
2	**TOTAL**	**0**	**-36**	**-75**	**-75**	**-75**	**-75**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**
3	**Net Plant Capability (1 + 2)**	**5,745**	**5,705**	**5,137**	**5,137**	**5,137**	**5,137**	**5,027**	**4,971**	**4,971**	**4,862**	**4,862**	**4,754**	**4,644**	**4,644**	**4,644**	**4,644**	**4,473**	**4,473**	**4,473**	**4,473**	**4,473**
	Sales Without Reserves																					
	Backup contracts (Eastman, Domtar, & Internat'l Paper)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
	SALE TO PSO																					
4	**TOTAL**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**
	Purchases Without Reserves																					
	NTEC - HCPP	165	286	287	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC GENERATION - PIRKEY/DOLET HILLS/TURK	171	171	171	171	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	scrubber adjustments to above	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC - ENTERGY ISES	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC - SPA NARROWS	27	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TEX-LA - HCPP	50	77	77	77	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	MAJESTIC WIND PROJECT	5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	5	5	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	0	0
	ETEC - HCPP	28	31	31	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CUSTOMER GENERATION - MINDEN	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	EXELON GREEN COUNTRY (2)			126	86	66	0	0														
	CANADIAN HILLS WIND PROJECT	10	10	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	0	0
	HIGH MAJESTIC WIND PROJECT	4	4	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	0	0
	WHOLESALE PURCHASE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
5	**TOTAL**	**520**	**646**	**824**	**797**	**171**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**95**	**95**	**95**	**95**	**25**	**25**
6	**Total Capability (3 - 4 + 5)**	**6,247**	**6,333**	**5,943**	**5,916**	**5,290**	**5,224**	**5,114**	**5,058**	**5,058**	**4,949**	**4,949**	**4,841**	**4,731**	**4,731**	**4,731**	**4,721**	**4,550**	**4,550**	**4,550**	**4,480**	**4,480**

DEMAND	14 ACT	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Original Forecast	3,686	3,912	3,966	3,984	3,965	4,023	4,057	4,099	4,133	4,158	4,184	4,226	4,260	4,292	4,319	4,348	4,379	4,412	4,435	4,477	4,498
Bentonville, City of	146	150	154	159	163	165	167	170	173	175	177	179	182	184	185	187	189	190	191	193	194
East Texas EC	79	90	90	93	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hope, City of	55	60	60	60	60	61	61	61	61	61	61	62	62	62	62	62	62	62	62	62	62
Minden, City of	37	39	39	39	40	40	40	40	40	41	41	41	41	41	42	42	42	42	42	42	42
NTEC	622	671	684	699	200	200	199	200	200	200	199	200	200	200	199	200	200	200	199	200	200
Rayburn Country EC	96	105	108	111	113	114	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
City of Prescott	15	16	16	17	17	18	18	18	19	19	19	20	20	20	20	21	21	21	21	21	21
TEX-LA EC - ERCOT	45	45	46	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEX-LA EC - SPP	100	103	106	109	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less TEX-LA ERCOT Demand included above	-45	-45	-46	-48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A Peak Demand Before Passive DSM	**4,836**	**5,151**	**5,232**	**5,285**	**4,569**	**4,627**	**4,546**	**4,591**	**4,628**	**4,655**	**4,682**	**4,728**	**4,764**	**4,799**	**4,826**	**4,859**	**4,893**	**4,927**	**4,950**	**4,995**	**5,018**
NTEC		0	0	0	-200	-200	-199	-200	-200	-200	-199	-200	-200	-200	-199	-200	-200	-200	-199	-200	-200
A Peak Demand Before Passive DSM Adjusted	**4,836**	**5,151**	**5,232**	**5,285**	**4,369**	**4,427**	**4,347**	**4,392**	**4,428**	**4,455**	**4,483**	**4,528**	**4,564**	**4,599**	**4,628**	**4,659**	**4,693**	**4,727**	**4,751**	**4,795**	**4,818**
B Passive DSM																					
Approved Passive DSM	0	5	9	12	11	7	4	3	2	1	1	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**5**	**9**	**12**	**11**	**7**	**4**	**3**	**2**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
C Peak Demand (A - B)	**4,836**	**5,146**	**5,223**	**5,272**	**4,358**	**4,421**	**4,343**	**4,389**	**4,426**	**4,454**	**4,482**	**4,528**	**4,564**	**4,599**	**4,628**	**4,659**	**4,693**	**4,727**	**4,751**	**4,795**	**4,818**
D Active DSM																					
INTERRUPTIBLE	29	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
DLC/ELM	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**46**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**
E Firm Demand (C - D)	**4,791**	**5,091**	**5,168**	**5,217**	**4,302**	**4,366**	**4,288**	**4,333**	**4,371**	**4,399**	**4,427**	**4,473**	**4,509**	**4,544**	**4,572**	**4,604**	**4,638**	**4,672**	**4,696**	**4,740**	**4,762**
F Other Demand Adjustments																					
DIVERSITY	22	21	22	24	26	29	32	33	34	36	36	36	36	36	37	38	38	39	38	38	41
TOTAL	**22**	**21**	**22**	**24**	**26**	**29**	**32**	**33**	**34**	**36**	**36**	**36**	**36**	**36**	**37**	**38**	**38**	**39**	**38**	**38**	**41**
7 Native Load Responsibility (E - F)	**4,768**	**5,070**	**5,146**	**5,193**	**4,276**	**4,337**	**4,256**	**4,300**	**4,337**	**4,363**	**4,391**	**4,437**	**4,473**	**4,508**	**4,536**	**4,566**	**4,600**	**4,633**	**4,657**	**4,702**	**4,721**
Sales With Reserves																					
TEX-LA ERCOT	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NTEC		0	0	0	200	200	199	200	200	200	199	200	200	200	199	200	200	200	199	200	200
8 TOTAL	**54**	**54**	**54**	**54**	**200**	**200**	**199**	**200**	**200**	**200**	**199**	**200**	**200**	**200**	**199**	**200**	**200**	**200**	**199**	**200**	**200**
Purchases With Reserves																					
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CLECO PPA (VEMCO LOAD)	177																				
NTEC SPA HYDRO PEAKING	102	102	102	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOUISIANA GENERATION (FORMERLY CAJUN)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	23	23	23	23	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
9 TOTAL	**352**	**175**	**175**	**175**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**
10 Load Responsibility (7 + 8 - 9)	**4,470**	**4,949**	**5,025**	**5,072**	**4,404**	**4,465**	**4,383**	**4,428**	**4,464**	**4,491**	**4,518**	**4,565**	**4,601**	**4,635**	**4,663**	**4,694**	**4,728**	**4,761**	**4,784**	**4,829**	**4,849**

RESERVES	14 ACT	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
11 Reserve Capacity (6 - 10)	**1,777**	**1,384**	**918**	**844**	**886**	**760**	**731**	**630**	**593**	**458**	**431**	**276**	**130**	**95**	**68**	**27**	**-178**	**-212**	**-235**	**-350**	**-370**
12 % Reserve Margin ((11/10) * *100*)	**39.7**	**28.0**	**18.3**	**16.6**	**20.1**	**17.0**	**16.7**	**14.2**	**13.3**	**10.2**	**9.5**	**6.0**	**2.8**	**2.1**	**1.5**	**0.6**	**-3.8**	**-4.4**	**-4.9**	**-7.2**	**-7.6**
13 % Capacity Margin (11/(6) * *100*)	**28.4**	**21.8**	**15.4**	**14.3**	**16.7**	**14.5**	**14.3**	**12.5**	**11.7**	**9.3**	**8.7**	**5.7**	**2.7**	**2.0**	**1.4**	**0.6**	**-3.9**	**-4.6**	**-5.2**	**-7.8**	**-8.3**
14 Reserves Above Minimum 12% Capacity Margin	**1167**	**709**	**233**	**152**	**285**	**151**	**133**	**26**	**-15**	**-154**	**-185**	**-347**	**-498**	**-537**	**-568**	**-613**	**-823**	**-861**	**-887**	**-1008**	**-1,031**

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Exhibit D: Capability, Demand and Reserve (CDR) - Preferred Plan

SOUTHWESTERN ELECTRIC POWER COMPANY
CAPABILITY,DEMAND AND RESERVES FORECAST
PREFERRED PLAN 2014-2045
(MW)

AEP SOUTHWESTERN ELECTRIC POWER

CAPABILITY

	Plant Capabilities	14 ACT	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	12 ARSENAL HILL # 5	110	110	110	110	110	110	110	110	110	110	110	110	0	0	0	0	0	0	0	0	0
	11 J.L. STALL (ARSENAL HILL) CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
	10 DOLET HILLS #1	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	9 FLINT CREEK # 1	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264
	8 TURK (HEMPSTEAD) PC	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
	7 KNOX LEE # 2, 3, 4, 5	469	469	469	469	469	469	398	342	342	342	342	342	342	342	342	342	342	342	342	342	342
	6 LIEBERMAN # 1, 2, 3, 4	267	242	242	242	242	242	217	217	217	108	108	0	0	0	0	0	0	0	0	0	0
	5 LONE STAR # 1	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4 PIRKEY #1	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
	3 MATTISON (TONTITOWN) CTs	301	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303	303
	2 WELSH # 1, 2, 3	1,584	1,584	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056
	1 WILKES # 1, 2, 3	875	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	722	722	722	722	722
	New Intermediate/Base Load Gas Resources			0	0	0	0	0	0	0	0	0	0	435	435	435	435	435	435	435	435	435
	New Utility Solar Resources			21	21	21	42	63	84	105	126	147	168	189	210	231	252	273	294	315	336	357
	New Wind Resources			30	30	30	30	30	30	30	50	70	90	110	130	150	170	190	210	230	230	230
1	**TOTAL**	**5,745**	**5,740**	**5,263**	**5,263**	**5,263**	**5,284**	**5,159**	**5,124**	**5,145**	**5,077**	**5,118**	**5,051**	**5,417**	**5,458**	**5,499**	**5,540**	**5,410**	**5,451**	**5,492**	**5,513**	**5,534**
	Adjustments to Plant Capability																					
	Knox Lee 4		-36	-36	-36	-36	-36															
	Welsh 1 ACI, 2.08%, 2016			-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11
	Welsh 3 ACI, 2.08%, 2016			-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11
	Pirkey ACI 2.07%, 2016			-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12
	Flint Creek FGD, ACI, 2.08%, 2016			-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
2	**TOTAL**	**0**	**-36**	**-75**	**-75**	**-75**	**-75**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**	**-40**
3	**Net Plant Capability (1 + 2)**	**5,745**	**5,705**	**5,188**	**5,188**	**5,188**	**5,209**	**5,120**	**5,085**	**5,106**	**5,038**	**5,079**	**5,012**	**5,378**	**5,419**	**5,460**	**5,501**	**5,371**	**5,412**	**5,453**	**5,474**	**5,495**
	Sales Without Reserves																					
	Backup contracts (Eastman, Domtar, & Internat'l Paper)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
	SALE TO PSO																					
4	**TOTAL**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**
	Purchases Without Reserves																					
	NTEC - HCPP	165	286	287	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC GENERATION - PIRKEY/DOLET HILLS/TURK	171	171	171	171	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	scrubber adjustments to above	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC - ENTERGY ISES	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC - SPA NARROWS	27	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TEX-LA - HCPP	50	77	77	77	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	MAJESTIC WIND PROJECT	5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	5	5	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	0	0
	ETEC - HCPP	28	31	31	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CUSTOMER GENERATION - MINDEN	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	EXELON GREEN COUNTRY (2)			126	86	66	0	0														
	CANADIAN HILLS WIND PROJECT	10	10	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	0	0
	HIGH MAJESTIC WIND PROJECT	4	4	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	0	0
	WHOLESALE PURCHASE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
5	**TOTAL**	**520**	**646**	**824**	**797**	**171**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**95**	**95**	**95**	**95**	**25**	**25**
6	**Total Capability (3 - 4 + 5)**	**6,247**	**6,333**	**5,994**	**5,967**	**5,341**	**5,296**	**5,207**	**5,172**	**5,193**	**5,125**	**5,166**	**5,099**	**5,465**	**5,506**	**5,547**	**5,578**	**5,448**	**5,489**	**5,530**	**5,481**	**5,502**

DEMAND	14 ACT	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Original Forecast	3,686	3,912	3,966	3,984	3,965	4,023	4,057	4,099	4,133	4,158	4,184	4,226	4,260	4,292	4,319	4,348	4,379	4,412	4,435	4,477	4,498
Bentonville, City of	146	150	154	159	163	165	167	170	173	175	177	179	182	184	185	187	189	190	191	193	194
East Texas EC	79	90	90	93	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hope, City of	55	60	60	60	60	61	61	61	61	61	61	62	62	62	62	62	62	62	62	62	62
Minden, City of	37	39	39	39	40	40	40	40	40	41	41	41	41	41	42	42	42	42	42	42	42
NTEC	622	671	684	699	200	200	199	200	200	200	199	200	200	200	199	200	200	200	199	200	200
Rayburn Country EC	96	105	108	111	113	114	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
City of Prescott	15	16	16	17	17	18	18	18	19	19	19	20	20	20	20	21	21	21	21	21	21
TEX-LA EC - ERCOT	45	45	46	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEX-LA EC - SPP	100	103	106	109	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less TEX-LA ERCOT Demand included above	-45	-45	-46	-48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A Peak Demand Before Passive DSM	**4,836**	**5,151**	**5,232**	**5,285**	**4,569**	**4,627**	**4,546**	**4,591**	**4,628**	**4,655**	**4,682**	**4,728**	**4,764**	**4,799**	**4,826**	**4,859**	**4,893**	**4,927**	**4,950**	**4,995**	**5,018**
NTEC		0	0	0	-200	-200	-199	-200	-200	-200	-199	-200	-200	-200	-199	-200	-200	-200	-199	-200	-200
A Peak Demand Before Passive DSM Adjusted	**4,836**	**5,151**	**5,232**	**5,285**	**4,369**	**4,427**	**4,347**	**4,392**	**4,428**	**4,455**	**4,483**	**4,528**	**4,564**	**4,599**	**4,628**	**4,659**	**4,693**	**4,727**	**4,751**	**4,795**	**4,818**
B Passive DSM																					
Approved Passive DSM	0	5	9	12	11	7	4	3	2	1	1	0	0	0	0	0	0	0	0	0	0
Incremental Energy Efficency			0	0	19	35	38	31	34	40	42	50	42	31	29	25	18	14	9	7	7
VVO			0	23	23	23	33	45	55	64	73	81	81	81	81	81	81	81	81	81	81
Residential Rooftop Solar			1	1	1	1	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
TOTAL	**0**	**5**	**10**	**36**	**54**	**66**	**77**	**81**	**93**	**108**	**118**	**133**	**126**	**115**	**113**	**109**	**103**	**99**	**94**	**93**	**93**
C Peak Demand (A - B)	**4,836**	**5,146**	**5,222**	**5,249**	**4,315**	**4,361**	**4,270**	**4,310**	**4,335**	**4,347**	**4,365**	**4,395**	**4,438**	**4,484**	**4,515**	**4,551**	**4,590**	**4,628**	**4,656**	**4,703**	**4,725**
D Active DSM																					
INTERRUPTIBLE	29	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
DLC/ELM	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**46**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**	**55**
E Firm Demand (C - D)	**4,791**	**5,091**	**5,167**	**5,194**	**4,260**	**4,306**	**4,215**	**4,255**	**4,280**	**4,292**	**4,310**	**4,340**	**4,383**	**4,429**	**4,460**	**4,495**	**4,535**	**4,573**	**4,601**	**4,647**	**4,670**
F Other Demand Adjustments																					
DIVERSITY	22	21	22	24	26	29	32	33	34	36	36	36	36	36	37	38	38	39	38	38	41
TOTAL	**22**	**21**	**22**	**24**	**26**	**29**	**32**	**33**	**34**	**36**	**36**	**36**	**36**	**36**	**37**	**38**	**38**	**39**	**38**	**38**	**41**
7 Native Load Responsibility (E - F)	**4,768**	**5,070**	**5,145**	**5,170**	**4,233**	**4,277**	**4,183**	**4,222**	**4,245**	**4,256**	**4,274**	**4,304**	**4,347**	**4,392**	**4,423**	**4,457**	**4,497**	**4,534**	**4,563**	**4,609**	**4,629**
Sales With Reserves																					
TEX-LA ERCOT	54	54	54	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NTEC		0	0	0	200	200	199	200	200	200	199	200	200	200	199	200	200	200	199	200	200
8 TOTAL	**54**	**54**	**54**	**54**	**200**	**200**	**199**	**200**	**200**	**200**	**199**	**200**	**200**	**200**	**199**	**200**	**200**	**200**	**199**	**200**	**200**
Purchases With Reserves																					
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CLECO PPA (VEMCO LOAD)	177																				
NTEC SPA HYDRO PEAKING	102	102	102	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOUISIANA GENERATION (FORMERLY CAJUN)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	23	23	23	23	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
9 TOTAL	**352**	**175**	**175**	**175**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**
10 Load Responsibility (7 + 8 - 9)	**4,470**	**4,949**	**5,024**	**5,049**	**4,361**	**4,405**	**4,310**	**4,350**	**4,373**	**4,384**	**4,401**	**4,432**	**4,475**	**4,520**	**4,550**	**4,585**	**4,625**	**4,662**	**4,690**	**4,737**	**4,757**

RESERVES	14 ACT	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
11 Reserve Capacity (6 - 10)	**1,777**	**1,384**	**970**	**918**	**980**	**891**	**897**	**822**	**820**	**741**	**765**	**667**	**990**	**986**	**997**	**993**	**823**	**827**	**840**	**744**	**745**
12 % Reserve Margin ((11/10) * *100*)	**39.7**	**28.0**	**19.3**	**18.2**	**22.5**	**20.2**	**20.8**	**18.9**	**18.8**	**16.9**	**17.4**	**15.0**	**22.1**	**21.8**	**21.9**	**21.6**	**17.8**	**17.7**	**17.9**	**15.7**	**15.7**
13 % Capacity Margin (11/(6) * *100*)	**28.4**	**21.8**	**16.2**	**15.4**	**18.3**	**16.8**	**17.2**	**15.9**	**15.8**	**14.5**	**14.8**	**13.1**	**18.1**	**17.9**	**18.0**	**17.8**	**15.1**	**15.1**	**15.2**	**13.6**	**13.5**
14 Reserves Above Minimum 12% Capacity Margin	**1167**	**709**	**285**	**230**	**385**	**290**	**309**	**229**	**224**	**143**	**165**	**62**	**380**	**369**	**376**	**367**	**192**	**191**	**200**	**98**	**96**

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Exhibit E: New Generation Technology Options

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

Type	Capability (MW) (f) Std. ISO	Capability (MW) (f) Winter	Capability (MW) (f) Summer	Installed Cost (d) ($/kW)	Trans. Cost ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost (e) ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	Emission Rates NOx (Lb/mmBtu)	Emission Rates CO2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)	LCOE ($/MWh)(g)
Base Load															
Nuclear	1,610	1,620	1,540	6,300	64	10,500	1.1	5.6	109.5	0.0000	0.000	0.00	90	95	142
Base Load (90% CO2 Capture New Unit)															
Pulv. Coal (Ultra-Supercritical) (PRB)	540	550	530	8,100	28	12,500	3.6	9.5	71.1	0.1000	0.070	21.3	85	90	219
IGCC "F" Class (PRB)	490	490	480	7,400	28	10,300	3.6	9.2	80.4	0.0638	0.062	21.3	85	88	206
Base / Intermediate															
Combined Cycle (1 - "F" Class)	340	360	400	1,500	60	6,700	7.5	3.6	18.4	0.0007	0.009	116.0	60	89	106
Combined Cycle (2 - "F" Class)	640	770	670	1,300	60	6,600	7.5	2.9	12.5	0.0007	0.009	116.0	60	89	96
Combined Cycle (2X1 "G" Class, w/duct firing & evap coolers)	780	820	870	1,200	60	6,800	7.5	2.8	11.1	0.0007	0.007	116.0	60	89	94
Peaking															
Combustion Turbine (2 - "E" Class)	170	180	170	700	60	11,700	7.5	8.3	12.2	0.0007	0.033	116.0	3	93	563
Combustion Turbine (2 - "F" Class, w/evap coolers)	430	450	440	600	60	10,100	7.5	1.4	8.2	0.0007	0.009	116.0	25	93	132
Aero-Derivative (1 - Small Machine)	50	50	40	1,100	60	9,600	7.5	3.3	20.6	0.0007	0.093	116.0	3	96	772
Aero-Derivative (2 - Small Machines)	90	90	90	1,000	60	9,600	7.5	3.3	11.7	0.0007	0.093	116.0	3	96	660
Recip Engine Farm (3 Engines)	50	50	50	1,200	60	8,200	7.5	4.5	18.4	0.0007	0.018	116.0	3	96	798

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2015 dollars. Assume 1.78% escalation rate for 2015 and beyond.
(c) $/kW costs are based on nominal capability.
(d) Total Plant & Interconnection Cost w/AFUDC (AEP-West rate of 7.61%,site rating $/kW).
(e) Levelized Fuel Cost (40-Yr. Period 2016-2055)
(f) All Capabilities are at 1,000 feet above sea level
(g) Levelized cost of energy based on assumed capacity factors shown in table.

Exhibit F: 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 $/tonne				
	Base	Low Band	High Band	No Carbon	High Carbon	Base	Low Band	High Band	No Carbon	High Carbon	Base	Low Band	High Band	No Carbon	High Carbon
2016	4.34	3.73	4.94	4.34	3.73	15.05	15.05	15.05	15.05	15.05	0	0	0	0	0
2017	5.09	4.38	5.80	5.09	4.38	16.11	15.47	16.92	16.11	16.11	0.00	0.00	0.00	0.00	0.00
2018	5.40	4.64	6.16	5.40	4.64	17.28	15.90	19.01	17.28	17.28	0.00	0.00	0.00	0.00	0.00
2019	5.50	4.73	6.27	5.51	4.73	18.81	16.56	21.64	18.81	18.81	0.00	0.00	0.00	0.00	0.00
2020	5.60	4.82	6.39	5.61	4.82	21.38	18.81	24.59	19.74	21.38	0.00	0.00	0.00	0.00	0.00
2021	5.82	5.01	6.64	5.83	5.01	22.86	20.12	26.29	20.71	22.86	0.00	0.00	0.00	0.00	0.00
2022	6.28	5.40	7.16	6.37	5.40	23.49	20.68	27.02	21.73	23.49	15.00	15.00	15.00	0.00	25.00
2023	6.60	5.68	7.52	6.79	5.68	21.62	19.03	24.86	22.80	21.62	15.29	15.29	15.29	0.00	25.47
2024	6.80	5.85	7.75	7.01	5.85	22.51	19.80	25.88	23.93	22.51	15.58	15.58	15.58	0.00	25.96
2025	6.96	5.99	7.94	7.18	5.99	24.10	21.21	27.72	25.11	24.10	15.88	15.88	15.88	0.00	26.47
2026	7.13	6.13	8.13	7.35	6.13	26.99	23.75	31.04	28.11	26.99	16.19	16.19	16.19	0.00	27.00
2027	7.30	6.28	8.32	7.53	6.28	25.82	22.72	29.69	26.89	25.82	16.51	16.51	16.51	0.00	27.52
2028	7.47	6.43	8.52	7.71	6.43	26.60	23.41	30.59	27.71	26.60	16.84	16.84	16.84	0.00	28.08
2029	7.65	6.58	8.73	7.90	6.58	30.95	27.23	35.59	32.23	30.95	17.17	17.17	17.17	0.00	28.62
2030	7.83	6.73	8.92	8.07	6.73	30.05	26.44	34.56	31.30	30.05	17.50	17.50	17.50	0.00	29.18
2031	8.00	6.88	9.12	8.25	6.88	33.82	29.76	38.89	35.23	33.82	17.85	17.85	17.85	0.00	29.74
2032	8.19	7.04	9.34	8.45	7.04	35.56	31.29	40.89	37.04	35.56	18.19	18.19	18.19	0.00	30.31
2033	8.39	7.22	9.57	8.66	7.22	38.63	33.99	44.42	40.23	38.63	18.54	18.54	18.54	0.00	30.90
2034	8.59	7.39	9.79	8.86	7.39	41.10	36.17	47.27	42.81	41.10	18.88	18.88	18.88	0.00	31.48

	Power On-Peak (SPP) $/MWh					Power Off-Peak (SPP) $/MWh				
	Base	Low Band	High Band	No Carbon	High Carbon	Base	Low Band	High Band	No Carbon	High Carbon
2016	37.04	34.06	39.24	36.96	39.74	26.84	25.55	27.64	26.76	30.21
2017	42.20	38.56	45.19	41.76	44.68	29.41	27.79	30.74	29.09	32.45
2018	44.33	40.17	48.80	43.95	46.71	30.73	28.35	33.26	30.35	33.58
2019	47.10	41.44	52.45	46.29	48.37	32.84	29.08	36.40	32.13	35.06
2020	48.64	42.86	54.29	47.46	49.51	34.53	30.62	38.46	33.12	35.84
2021	51.41	45.06	57.15	49.64	51.67	36.41	32.15	40.16	34.81	37.42
2022	64.33	56.98	70.61	50.63	72.59	49.56	44.94	53.66	35.69	58.66
2023	66.59	58.78	73.05	52.55	75.64	50.57	45.53	54.54	36.98	60.75
2024	69.56	61.22	76.69	54.94	77.99	52.70	47.20	57.30	38.83	62.25
2025	72.19	63.21	79.69	57.08	80.39	54.65	48.66	59.52	40.39	64.11
2026	74.83	65.18	82.57	59.06	82.66	56.98	50.49	62.19	42.36	66.10
2027	77.35	67.34	85.35	61.25	84.67	58.44	51.64	64.02	43.64	67.59
2028	79.55	69.63	87.96	63.55	87.21	60.11	53.04	65.88	45.17	69.24
2029	82.76	72.37	91.68	66.42	90.70	62.81	55.49	69.26	47.83	71.98
2030	86.48	75.18	95.43	69.39	93.22	65.60	57.27	72.12	49.73	73.93
2031	90.82	78.17	98.89	72.96	96.37	69.13	59.51	75.10	52.49	76.35
2032	95.25	81.17	102.87	76.87	99.35	72.48	61.67	78.39	55.57	78.91
2033	98.87	86.59	106.88	80.94	104.20	75.55	65.57	82.01	58.81	82.19
2034	100.67	91.30	110.71	83.83	106.94	77.56	68.94	85.37	61.08	84.73

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Exhibit G: Cost of Capital

Southwestern Power
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2014

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16
Depreciation (2)	48.95	31.72	23.10	17.95	7.80	4.58	3.07	2.22	1.70	1.48	1.12	0.81
FIT (3) (4)	2.41	1.76	1.88	1.58	1.51	1.81	1.88	1.66	1.52	1.46	1.35	1.26
Property Taxes, General & Admin Expenses	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47
	60.99	43.11	34.61	29.15	18.94	16.02	14.58	13.51	12.85	12.57	12.10	11.70

(1) Based on a 100% (as of 12/31/2014) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 35% Federal Income Tax Rate

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Exhibit H: Modeled Scenario Results

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

Utility Costs (Nominal$)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var 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
2016	$747,681	$541,906	$24,028	$264,331	$27,434	$32,754	$8,458	$695,055	$951,537
2017	$845,540	$554,763	$24,896	$307,308	$27,102	$35,229	$1,976	$759,992	$1,036,823
2018	$884,153	$581,739	$24,106	$325,724	$27,289	$75,429	($765)	$788,668	$1,129,006
2019	$953,586	$639,877	$37,679	$341,425	$30,653	$83,573	($4,902)	$911,634	$1,170,256
2020	$976,922	$639,587	$36,256	$379,343	$32,682	$70,178	($7,714)	$946,796	$1,180,459
2021	$1,039,877	$743,451	$40,914	$387,812	$37,630	$81,508	($11,542)	$1,090,039	$1,229,612
2022	$1,350,140	$773,929	$326,778	$400,497	$40,392	$97,223	($36,292)	$1,422,160	$1,530,507
2023	$1,401,002	$764,809	$330,713	$401,474	$43,041	$131,177	($38,700)	$1,492,625	$1,540,892
2024	$1,475,033	$813,678	$350,222	$391,969	$46,898	$173,735	($43,103)	$1,653,265	$1,555,165
2025	$1,541,808	$833,704	$343,820	$412,918	$49,154	$240,176	($46,703)	$1,726,615	$1,648,261
2026	$1,613,445	$963,373	$377,508	$417,538	$63,664	$318,641	($50,905)	$1,994,926	$1,708,336
2027	$1,675,648	$985,291	$390,547	$424,528	$67,593	$350,433	($53,958)	$2,135,026	$1,705,056
2028	$1,734,037	$995,543	$387,253	$433,503	$70,089	$382,042	($57,058)	$2,200,030	$1,745,379
2029	$1,821,484	$1,088,624	$406,945	$441,440	$74,385	$408,622	($63,604)	$2,395,523	$1,782,373
2030	$1,915,689	$1,032,667	$400,636	$451,458	$75,152	$441,895	($68,848)	$2,476,053	$1,772,594
2031	$2,028,075	$1,180,667	$432,562	$459,098	$82,085	$473,465	($74,958)	$2,787,875	$1,793,121
2032	$2,143,176	$1,225,509	$445,513	$467,711	$86,647	$506,068	($79,232)	$3,010,467	$1,784,924
2033	$2,242,538	$1,241,187	$439,413	$476,529	$89,371	$513,682	$0	$3,082,765	$1,919,956
2034	$2,302,690	$1,305,251	$460,037	$477,996	$93,501	$520,116	$0	$3,195,129	$1,964,463
2035	$2,380,181	$1,329,108	$450,186	$464,242	$95,677	$524,406	$0	$3,260,373	$1,983,427
2036	$2,468,111	$1,552,847	$496,201	$348,961	$117,557	$625,917	$0	$3,610,316	$1,999,276
2037	$2,530,899	$1,902,187	$540,352	$329,813	$155,147	$881,668	$0	$4,185,157	$2,154,910
2038	$2,621,363	$2,052,801	$551,179	$305,152	$175,377	$1,014,697	$0	$4,482,491	$2,238,078
2039	$2,668,425	$2,310,437	$597,067	$259,778	$199,399	$1,150,854	$0	$4,893,471	$2,292,488
2040	$2,752,236	$2,494,502	$607,006	$231,748	$221,908	$1,290,414	$0	$5,233,160	$2,364,654
2041	$2,819,461	$2,585,829	$636,173	$226,942	$227,565	$1,288,139	$0	$5,379,459	$2,404,650
2042	$2,906,019	$2,622,624	$647,367	$225,359	$233,696	$1,294,899	$0	$5,499,774	$2,430,190
2043	$2,988,400	$2,860,720	$666,085	$208,973	$260,938	$1,424,646	$0	$5,849,494	$2,560,267
2044	$3,066,275	$2,968,723	$699,764	$194,201	$268,515	$1,397,717	$0	$6,003,597	$2,591,596
2045	$3,170,349	$3,014,523	$703,142	$179,968	$272,794	$1,371,102	$0	$6,084,181	$2,627,696

Resource (Capacity) Additions

	(10) Supply-Side (Thermal) + (Current) Purchased Installed	(11)	(12) (Increm) Energy Efficiency+ VVO	(13)	(14) Distributed Solar	(15)	(16) Generic Wind	(17)	(18) Utility Solar	(19)
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	21.0	21.0
2017	(27)	5,916	25.6	25.6	0.2	1.8	0	30	0.0	21.0
2018	(626)	5,290	21.7	47.3	0.2	2.0	0	30	0.0	21.0
2019	(66)	5,224	18.6	65.9	0.2	2.2	0	30	21.0	42.0
2020	(111)	5,114	15.1	81.0	0.3	2.5	0	30	21.0	63.0
2021	(56)	5,058	5.8	86.8	0.2	2.7	0	30	21.0	84.0
2022	0	5,058	15.1	101.9	0.3	2.9	0	30	21.0	105.0
2023	(109)	4,949	16.9	118.8	0.3	3.2	20	50	21.0	126.0
2024	0	4,949	11.6	130.4	0.3	3.5	20	70	21.0	147.0
2025	(108)	4,841	17.9	148.3	0.4	3.9	20	90	21.0	168.0
2026	325	5,166	-8.1	140.2	0.3	4.1	20	110	21.0	189.0
2027	0	5,166	-12.6	127.6	0.4	4.5	20	130	21.0	210.0
2028	0	5,166	-3.1	124.4	0.4	4.8	20	150	21.0	231.0
2029	(10)	5,156	-4.6	119.8	0.4	5.2	20	170	21.0	252.0
2030	(171)	4,985	-6.9	112.9	0.4	5.6	20	190	21.0	273.0
2031	0	4,985	-4.6	108.3	0.4	6.0	20	210	21.0	294.0
2032	0	4,985	-5.6	102.7	0.5	6.4	20	230	21.0	315.0
2033	(70)	4,915	-2.4	100.4	0.4	6.9	0	230	21.0	336.0
2034	0	4,915	-0.5	99.9	0.5	7.4	0	230	21.0	357.0
2035	0	4,915	-13.8	86.1	0.5	7.8	0	230	21.0	378.0
2036	67	4,982	-15.1	71.0	0.5	8.3	-30	200	21.0	399.0
2037	259	5,241	-12.9	58.1	0.6	8.9	0	200	21.0	420.0
2038	(82)	5,159	-11.8	46.4	0.6	9.5	0	200	21.0	441.0
2039	177	5,335	-10.6	35.7	0.6	10.1	0	200	21.0	462.0
2040	93	5,428	-9.6	26.2	0.6	10.7	0	200	21.0	483.0
2041	0	5,428	-0.2	26.0	0.6	11.3	0	200	0.0	483.0
2042	0	5,428	-0.1	25.9	0.7	12.0	0	200	21.0	504.0
2043	(82)	5,346	-0.1	25.8	0.8	12.8	-20	180	21.0	525.0
2044	0	5,346	-0.1	25.7	0.7	13.5	-20	160	0.0	525.0
2045	0	5,346	-0.1	25.6	0.8	14.4	-20	140	0.0	525.0

Energy & Capacity Positions

	(20) Thermal Generation	(21) (Current) Purchased Energy	(22) (New) Generic Wind + Utility Solar	(23)=(20)+(21)+(22) = Market Sales	(24) Load (Net of Embedded EE)	(25) *Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	(26)=(24)-(25) = Net Load Require- ments	(27)=(23)-(26) ENERGY Surplus	(28) Capacity	(29) Peak + Reserves	(30)=(28)-(29) CAPACITY Surplus	(31) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,877	1,942	1,054	22,872	22,988	16	22,972	-99	5,996	5,710	286	19.3
2017	19,094	1,937	1,051	22,082	23,144	111	23,033	-950	5,994	5,760	234	18.2
2018	18,524	1,937	1,051	21,513	22,618	329	22,289	-776	5,390	5,006	385	22.3
2019	19,894	1,937	1,185	23,017	22,906	518	22,388	629	5,364	5,073	291	20.1
2020	19,634	1,942	1,323	22,898	22,588	604	21,984	914	5,290	4,981	309	20.7
2021	21,303	1,937	1,454	24,693	22,752	683	22,070	2,623	5,261	5,032	230	18.8
2022	21,399	1,937	1,588	24,924	22,924	758	22,166	2,758	5,297	5,071	226	18.7
2023	21,238	1,937	2,209	25,384	23,094	778	22,316	3,067	5,247	5,099	148	16.9
2024	22,103	1,942	2,838	26,882	23,255	792	22,463	4,419	5,300	5,133	166	17.3
2025	21,657	1,937	3,452	27,045	23,409	779	22,630	4,415	5,251	5,187	64	15.0
2026	23,900	1,937	4,073	29,909	23,563	706	22,858	7,051	5,609	5,227	382	21.9
2027	24,464	1,937	4,694	31,094	23,717	645	23,072	8,022	5,638	5,267	370	21.6
2028	23,949	1,942	5,329	31,219	23,877	607	23,270	7,949	5,676	5,298	377	21.7
2029	24,719	1,648	5,936	32,304	24,026	565	23,461	8,842	5,703	5,334	368	21.4
2030	23,821	1,620	6,558	31,999	24,164	527	23,636	8,362	5,566	5,373	193	17.7
2031	25,525	1,620	7,179	34,324	24,298	502	23,797	10,527	5,603	5,410	193	17.7
2032	25,923	1,581	7,820	35,325	24,443	483	23,961	11,365	5,639	5,436	203	17.8
2033	25,300	0	7,934	33,234	24,587	468	24,119	9,115	5,588	5,486	102	15.7
2034	25,705	0	8,069	33,774	24,732	466	24,266	9,508	5,609	5,511	98	15.6
2035	25,239	0	8,203	33,442	24,876	412	24,464	8,978	5,616	5,548	68	15.0
2036	28,581	0	7,440	36,021	25,019	359	24,660	11,361	5,660	5,572	88	15.4
2037	33,438	0	7,555	40,993	25,174	313	24,861	16,132	5,928	5,628	300	19.6
2038	34,974	0	7,689	42,663	25,337	274	25,063	17,600	5,855	5,668	188	17.4
2039	38,322	0	7,823	46,145	25,508	240	25,268	20,877	6,043	5,709	334	20.2
2040	40,082	0	7,978	48,060	25,682	210	25,472	22,588	6,148	5,727	421	22.0
2041	40,804	0	7,958	48,762	25,852	214	25,638	23,123	6,148	5,781	367	20.8
2042	40,573	0	8,092	48,665	26,019	128	25,892	22,773	6,170	5,827	343	20.3
2043	42,969	0	7,739	50,708	26,189	135	26,054	24,654	6,090	5,868	221	17.9
2044	43,862	0	7,271	51,133	26,359	142	26,217	24,916	6,070	5,896	174	17.0
2045	43,528	0	6,765	50,293	26,529	150	26,380	23,914	6,051	5,931	120	15.9

Cumulative Present Worth $000 (2016$)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Utility CPW 2016-2045	$16,756,595	$11,040,728	$2,923,233	$4,064,481	$746,439	$3,459,424	-$239,106	$21,760,056	$16,991,737
CPW of End Effects beyond 2045									$3,061,150
TOTAL Utility Cost, Net CPW (2016$)									$20,052,888

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Base' Commodity Pricing

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var 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
2016	$747,681	$541,906	$24,028	$264,331	$26,354	$23,719	$8,458	$690,356	$946,121
2017	$845,540	$554,763	$24,896	$307,308	$25,999	$26,194	$1,976	$754,702	$1,031,973
2018	$884,153	$581,739	$24,106	$325,724	$26,158	$66,393	($765)	$782,804	$1,124,703
2019	$953,586	$639,877	$37,679	$341,425	$28,334	$64,438	($4,902)	$899,159	$1,161,278
2020	$976,922	$639,587	$36,256	$379,343	$29,931	$48,313	($7,714)	$931,763	$1,170,875
2021	$1,039,877	$743,451	$40,914	$387,812	$34,713	$59,126	($11,542)	$1,073,947	$1,220,405
2022	$1,350,140	$773,929	$326,778	$400,497	$37,429	$70,190	($36,292)	$1,401,389	$1,521,281
2023	$1,401,002	$764,809	$330,713	$401,474	$40,001	$80,792	($38,700)	$1,443,376	$1,536,717
2024	$1,475,033	$813,678	$350,222	$391,969	$43,753	$88,764	($43,103)	$1,571,577	$1,548,739
2025	$1,541,808	$911,250	$352,910	$412,918	$56,129	$188,873	($46,703)	$1,724,753	$1,692,432
2026	$1,613,445	$963,373	$377,508	$417,538	$59,847	$220,822	($50,905)	$1,872,051	$1,729,577
2027	$1,675,648	$985,291	$390,547	$424,528	$63,686	$252,614	($53,958)	$2,009,356	$1,729,000
2028	$1,734,037	$995,543	$387,253	$433,503	$66,073	$284,223	($57,058)	$2,071,319	$1,772,255
2029	$1,821,484	$1,088,624	$406,945	$441,440	$70,274	$312,626	($63,604)	$2,262,787	$1,815,003
2030	$1,915,689	$1,032,667	$400,636	$451,458	$70,944	$347,521	($68,848)	$2,338,920	$1,811,146
2031	$2,028,075	$1,180,667	$432,562	$459,098	$77,769	$375,647	($74,958)	$2,644,042	$1,834,819
2032	$2,143,176	$1,225,509	$445,513	$467,711	$82,213	$408,250	($79,232)	$2,859,437	$1,833,701
2033	$2,242,538	$1,369,476	$453,951	$476,529	$99,715	$553,479	$0	$3,176,195	$2,019,492
2034	$2,302,690	$1,440,023	$475,219	$477,996	$104,253	$583,840	$0	$3,335,097	$2,048,925
2035	$2,380,181	$1,469,017	$465,876	$464,242	$107,296	$615,425	$0	$3,454,705	$2,047,332
2036	$2,468,111	$1,701,643	$512,784	$348,961	$129,896	$718,959	$0	$3,818,232	$2,062,123
2037	$2,530,899	$1,902,187	$540,352	$329,813	$150,826	$848,707	$0	$4,152,625	$2,150,160
2038	$2,621,363	$2,052,801	$551,179	$305,152	$170,950	$981,736	$0	$4,448,690	$2,234,491
2039	$2,668,425	$2,310,437	$597,067	$259,778	$194,884	$1,118,016	$0	$4,859,332	$2,289,273
2040	$2,752,236	$2,494,502	$607,006	$231,748	$218,002	$1,260,464	$0	$5,201,760	$2,362,197
2041	$2,819,461	$2,585,829	$636,173	$226,942	$225,569	$1,267,224	$0	$5,363,559	$2,397,639
2042	$2,906,019	$2,622,624	$647,367	$225,359	$231,650	$1,273,985	$0	$5,483,504	$2,423,499
2043	$2,988,400	$2,860,720	$666,085	$208,973	$258,840	$1,427,200	$0	$5,884,474	$2,525,744
2044	$3,066,275	$2,968,723	$699,764	$194,201	$268,515	$1,433,960	$0	$6,109,262	$2,522,175
2045	$3,170,349	$3,014,523	$703,142	$179,968	$272,794	$1,431,046	$0	$6,246,604	$2,525,218
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$16,756,595	$11,195,537	$2,940,805	$4,064,481	$733,138	$3,101,007	-$239,106	$21,463,134	$17,089,324
CPW of End Effects beyond 2045									$2,941,768
TOTAL Utility Cost, Net CPW (2016$)									$20,031,092

	Resource (Capacity) Additions									
	(10) Supply-Side (Thermal) + (Current) Purchased Installed	(11)	(12) (Increm) Energy Efficiency+ VVO	(13)	(14) Distributed Solar	(15)	(16) Generic Wind	(17)	(18) Utility Solar	(19)
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	25.6	25.6	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	47.3	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	18.6	65.9	0.2	2.2	0	30	0.0	0.0
2020	(111)	5,114	2.1	68.0	0.3	2.5	0	30	21.0	21.0
2021	(56)	5,058	4.5	72.6	0.2	2.7	0	30	21.0	42.0
2022	0	5,058	14.0	86.6	0.3	2.9	0	30	21.0	63.0
2023	(109)	4,949	17.1	103.7	0.3	3.2	0	30	21.0	84.0
2024	0	4,949	5.9	109.6	0.3	3.5	0	30	21.0	105.0
2025	327	5,276	-7.1	102.5	0.4	3.9	0	30	21.0	126.0
2026	(110)	5,166	-5.4	97.2	0.3	4.1	20	50	21.0	147.0
2027	0	5,166	-8.4	88.7	0.4	4.5	20	70	21.0	168.0
2028	0	5,166	1.6	90.3	0.4	4.8	20	90	21.0	189.0
2029	(10)	5,156	-1.8	88.6	0.4	5.2	20	110	21.0	210.0
2030	(171)	4,985	-0.8	87.7	0.4	5.6	20	130	21.0	231.0
2031	0	4,985	-2.6	85.1	0.4	6.0	20	150	21.0	252.0
2032	0	4,985	-4.3	80.8	0.5	6.4	20	170	21.0	273.0
2033	365	5,350	-1.7	79.1	0.4	6.9	20	190	21.0	294.0
2034	0	5,350	-0.1	79.0	0.5	7.4	20	210	21.0	315.0
2035	0	5,350	-1.4	77.7	0.5	7.8	20	230	21.0	336.0
2036	67	5,417	-13.5	64.1	0.5	8.3	-30	200	21.0	357.0
2037	(176)	5,241	-14.4	49.8	0.6	8.9	0	200	21.0	378.0
2038	(82)	5,159	-12.6	37.2	0.6	9.5	0	200	21.0	399.0
2039	177	5,335	-10.7	26.5	0.6	10.1	0	200	21.0	420.0
2040	93	5,428	-0.4	26.1	0.6	10.7	0	200	21.0	441.0
2041	0	5,428	-0.2	25.9	0.6	11.3	0	200	21.0	462.0
2042	0	5,428	-0.1	25.8	0.7	12.0	0	200	21.0	483.0
2043	(82)	5,346	-0.1	25.7	0.8	12.8	0	200	21.0	504.0
2044	0	5,346	-0.1	25.7	0.7	13.5	0	200	21.0	525.0
2045	0	5,346	-0.1	25.6	0.8	14.4	0	200	0.0	525.0

	Energy & Capacity Positions											
	(20) Thermal Generation	(21) (Current) Purchased Energy	(22) (New) Generic Wind + Utility Solar	(23)=(20)+(21)+(22) = Market Sales	(24) Load (Net of Embedded EE)	(25) *Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	(26)=(24)-(25) = Net Load Require- ments	(27)=(23)-(26) ENERGY Surplus	(28) Capacity	(29) Peak + Reserves	(30)=(28)-(29) CAPACITY Surplus	(31) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,877	1,942	919	22,738	22,988	16	22,972	-234	5,975	5,710	265	18.9
2017	19,094	1,937	917	21,948	23,144	111	23,033	-1,085	5,973	5,760	213	17.8
2018	18,524	1,937	917	21,378	22,618	329	22,289	-911	5,369	5,006	364	21.9
2019	19,894	1,937	917	22,749	22,906	518	22,388	361	5,322	5,073	249	19.2
2020	19,634	1,942	1,054	22,629	22,588	557	22,031	598	5,235	4,981	254	19.4
2021	21,303	1,937	1,185	24,424	22,752	631	22,122	2,303	5,205	5,032	173	17.5
2022	21,399	1,937	1,319	24,655	22,924	700	22,224	2,432	5,240	5,071	169	17.4
2023	21,238	1,937	1,454	24,628	23,094	718	22,376	2,252	5,170	5,099	71	15.2
2024	22,103	1,942	1,592	25,636	23,255	714	22,541	3,095	5,197	5,133	63	15.0
2025	23,265	1,937	1,722	26,924	23,409	634	22,775	4,149	5,538	5,187	351	21.3
2026	23,900	1,937	2,343	28,180	23,563	573	22,990	5,189	5,464	5,227	237	18.7
2027	24,464	1,937	2,965	29,365	23,717	524	23,192	6,173	5,497	5,267	230	18.6
2028	23,949	1,942	3,595	29,486	23,877	498	23,380	6,106	5,540	5,298	241	18.8
2029	24,719	1,648	4,207	30,574	24,026	470	23,556	7,018	5,569	5,334	235	18.6
2030	23,821	1,620	4,828	30,269	24,164	451	23,713	6,557	5,439	5,373	66	15.0
2031	25,525	1,620	5,449	32,595	24,298	429	23,869	8,725	5,478	5,410	68	15.0
2032	25,923	1,581	6,087	33,591	24,443	412	24,031	9,560	5,515	5,436	79	15.3
2033	27,503	0	6,692	34,195	24,587	397	24,190	10,005	5,919	5,486	433	22.6
2034	27,964	0	7,313	35,277	24,732	390	24,342	10,936	5,961	5,511	450	22.9
2035	27,531	0	7,934	35,465	24,876	381	24,495	10,971	6,001	5,548	453	22.9
2036	30,959	0	7,171	38,129	25,019	334	24,685	13,444	6,046	5,572	474	23.3
2037	33,438	0	7,286	40,724	25,174	282	24,892	15,833	5,877	5,628	249	18.6
2038	34,974	0	7,421	42,394	25,337	241	25,096	17,298	5,804	5,668	137	16.3
2039	38,322	0	7,555	45,877	25,508	207	25,302	20,575	5,992	5,709	283	19.2
2040	40,082	0	7,709	47,791	25,682	209	25,473	22,319	6,106	5,727	379	21.1
2041	40,804	0	7,823	48,627	25,852	214	25,639	22,989	6,127	5,781	346	20.4
2042	40,573	0	7,958	48,531	26,019	127	25,892	22,639	6,149	5,827	322	19.9
2043	42,969	0	8,092	51,061	26,189	135	26,055	25,006	6,089	5,868	220	17.9
2044	43,862	0	8,247	52,110	26,359	142	26,217	25,892	6,110	5,896	214	17.7
2045	43,528	0	8,226	51,754	26,529	150	26,380	25,374	6,111	5,931	180	17.0

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'High Band' Commodity Pricing

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var 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
2016	$784,976	$551,128	$23,828	$264,331	$25,559	$23,719	$5,908	$708,121	$971,328
2017	$898,925	$575,071	$24,746	$307,308	$25,581	$26,194	($1,777)	$793,308	$1,062,739
2018	$968,099	$605,586	$24,339	$325,724	$26,208	$66,393	($7,086)	$859,621	$1,149,643
2019	$1,060,317	$666,792	$38,208	$341,425	$28,170	$64,438	($13,148)	$996,087	$1,190,115
2020	$1,089,442	$661,187	$36,853	$379,343	$29,423	$48,313	($16,651)	$1,024,496	$1,203,414
2021	$1,152,844	$769,328	$41,455	$387,812	$34,145	$59,126	($20,301)	$1,171,448	$1,252,961
2022	$1,473,708	$828,990	$331,660	$400,497	$37,649	$70,190	($45,908)	$1,539,025	$1,557,761
2023	$1,526,899	$810,538	$333,843	$401,474	$39,973	$80,792	($48,277)	$1,572,027	$1,573,216
2024	$1,618,056	$867,396	$353,614	$391,969	$43,844	$88,764	($53,936)	$1,726,660	$1,583,049
2025	$1,693,471	$981,877	$357,023	$412,918	$56,167	$188,873	($58,093)	$1,900,406	$1,731,829
2026	$1,772,897	$1,039,212	$382,155	$417,538	$59,827	$246,499	($62,912)	$2,095,264	$1,759,952
2027	$1,843,586	$1,062,685	$395,488	$424,528	$63,660	$278,291	($66,552)	$2,248,278	$1,753,409
2028	$1,910,796	$1,073,534	$391,355	$433,503	$65,921	$309,900	($70,227)	$2,317,903	$1,796,879
2029	$2,013,412	$1,181,860	$413,221	$441,440	$70,389	$336,480	($75,823)	$2,547,138	$1,833,840
2030	$2,109,777	$1,113,245	$404,980	$451,458	$70,876	$369,754	($80,935)	$2,611,512	$1,827,643
2031	$2,203,794	$1,251,129	$433,331	$459,098	$76,740	$401,324	($86,007)	$2,881,588	$1,857,820
2032	$2,312,745	$1,307,164	$446,561	$467,711	$81,281	$433,927	($89,661)	$3,101,352	$1,858,375
2033	$2,424,193	$1,457,750	$454,226	$476,529	$97,944	$579,156	$0	$3,434,235	$2,055,562
2034	$2,530,143	$1,557,327	$479,313	$477,996	$103,348	$610,595	$0	$3,696,977	$2,061,745
2035	$2,622,422	$1,608,845	$471,460	$464,242	$106,947	$616,185	$0	$3,807,682	$2,082,419
2036	$2,713,314	$1,868,473	$519,428	$348,961	$129,424	$719,718	$0	$4,199,922	$2,099,395
2037	$2,786,068	$2,077,156	$544,147	$329,813	$149,502	$849,467	$0	$4,551,325	$2,184,828
2038	$2,882,101	$2,264,480	$557,057	$305,152	$170,258	$982,496	$0	$4,888,708	$2,272,835
2039	$2,953,804	$2,554,853	$603,812	$259,778	$194,115	$1,118,775	$0	$5,377,394	$2,307,743
2040	$3,019,658	$2,742,387	$610,498	$231,748	$216,358	$1,261,284	$0	$5,677,538	$2,404,395
2041	$3,116,711	$2,880,769	$646,191	$226,942	$225,687	$1,268,025	$0	$5,951,049	$2,413,276
2042	$3,197,599	$2,919,210	$655,771	$225,359	$231,790	$1,274,744	$0	$6,049,715	$2,454,759
2043	$3,295,386	$3,172,133	$673,414	$208,973	$258,084	$1,427,959	$0	$6,484,448	$2,551,500
2044	$3,357,587	$3,253,465	$702,441	$194,201	$265,621	$1,434,719	$0	$6,637,245	$2,570,789
2045	$3,454,254	$3,293,728	$703,587	$179,968	$269,768	$1,431,806	$0	$6,737,976	$2,595,136
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$18,348,606	$12,005,279	$2,969,180	$4,064,481	$728,714	$3,173,526	-$316,842	$23,552,100	$17,420,845
CPW of End Effects beyond 2045									$3,023,219
TOTAL Utility Cost, Net CPW (2016$)									$20,444,064

	Resource (Capacity) Additions									
	(10) Supply-Side (Thermal) + (Current) Purchased Installed	(11)	(12) (Increm) Energy Efficiency+ VVO	(13)	(14) Distributed Solar	(15)	(16) Generic Wind	(17)	(18) Utility Solar	(19)
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	25.6	25.6	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	47.3	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	18.6	65.9	0.2	2.2	0	30	0.0	0.0
2020	(111)	5,114	2.1	68.0	0.3	2.5	0	30	21.0	21.0
2021	(56)	5,058	4.5	72.6	0.2	2.7	0	30	21.0	42.0
2022	0	5,058	14.0	86.6	0.3	2.9	0	30	21.0	63.0
2023	(109)	4,949	17.1	103.7	0.3	3.2	0	30	21.0	84.0
2024	0	4,949	5.9	109.6	0.3	3.5	0	30	21.0	105.0
2025	327	5,276	-7.1	102.5	0.4	3.9	0	30	21.0	126.0
2026	(110)	5,166	-5.4	97.2	0.3	4.1	30	60	21.0	147.0
2027	0	5,166	-8.4	88.7	0.4	4.5	20	80	21.0	168.0
2028	0	5,166	1.6	90.3	0.4	4.8	20	100	21.0	189.0
2029	(10)	5,156	-3.1	87.3	0.4	5.2	20	120	21.0	210.0
2030	(171)	4,985	-2.6	84.6	0.4	5.6	20	140	21.0	231.0
2031	0	4,985	-2.1	82.5	0.4	6.0	20	160	21.0	252.0
2032	0	4,985	-3.5	79.0	0.5	6.4	20	180	21.0	273.0
2033	365	5,350	-1.2	77.8	0.4	6.9	20	200	21.0	294.0
2034	0	5,350	0.8	78.6	0.5	7.4	20	220	21.0	315.0
2035	0	5,350	-1.3	77.3	0.5	7.8	0	220	21.0	336.0
2036	67	5,417	-13.4	63.9	0.5	8.3	-30	190	21.0	357.0
2037	(176)	5,241	-14.3	49.6	0.6	8.9	0	190	21.0	378.0
2038	(82)	5,159	-12.5	37.1	0.6	9.5	0	190	21.0	399.0
2039	177	5,335	-10.7	26.4	0.6	10.1	0	190	21.0	420.0
2040	93	5,428	-0.2	26.2	0.6	10.7	0	190	21.0	441.0
2041	0	5,428	-0.2	26.0	0.6	11.3	0	190	21.0	462.0
2042	0	5,428	-0.1	25.9	0.7	12.0	0	190	21.0	483.0
2043	(82)	5,346	-0.1	25.8	0.8	12.8	0	190	21.0	504.0
2044	0	5,346	-0.1	25.7	0.7	13.5	0	190	21.0	525.0
2045	0	5,346	-0.1	25.6	0.8	14.4	0	190	0.0	525.0

	Energy & Capacity Positions											
	(20) Thermal Generation	(21) (Current) Purchased Energy	(22) (New) Generic Wind + Utility Solar	(23)=(20)+(21)+(22) = Market Sales	(24) Load (Net of Embedded EE)	(25) *Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	(26)=(24)-(25) = Net Load Require- ments	(27)=(23)-(26) ENERGY Surplus	(28) Capacity	(29) Peak + Reserves	(30)=(28)-(29) CAPACITY Surplus	(31) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,298	1,942	919	22,159	22,988	16	22,972	-813	5,975	5,710	265	18.9
2017	18,800	1,937	917	21,654	23,144	111	23,033	-1,379	5,973	5,760	213	17.8
2018	18,623	1,937	917	21,477	22,618	329	22,289	-812	5,369	5,006	364	21.9
2019	19,908	1,937	917	22,762	22,906	518	22,388	374	5,322	5,073	249	19.2
2020	19,426	1,942	1,054	22,421	22,588	557	22,031	390	5,235	4,981	254	19.4
2021	21,003	1,937	1,185	24,125	22,752	631	22,122	2,003	5,205	5,032	173	17.5
2022	21,592	1,937	1,319	24,848	22,924	700	22,224	2,625	5,240	5,071	169	17.4
2023	21,265	1,937	1,454	24,655	23,094	718	22,376	2,279	5,170	5,099	71	15.2
2024	22,158	1,942	1,592	25,692	23,255	714	22,541	3,151	5,197	5,133	63	15.0
2025	23,353	1,937	1,722	27,012	23,409	634	22,775	4,237	5,538	5,187	351	21.3
2026	24,048	1,937	2,773	28,758	23,563	573	22,990	5,768	5,474	5,227	247	19.0
2027	24,613	1,937	3,394	29,944	23,717	524	23,192	6,752	5,507	5,267	240	18.8
2028	24,044	1,942	4,026	30,012	23,877	498	23,380	6,632	5,550	5,298	251	19.0
2029	24,951	1,648	4,637	31,235	24,026	464	23,562	7,673	5,578	5,334	244	18.8
2030	23,920	1,620	5,258	30,798	24,164	438	23,726	7,073	5,446	5,373	73	15.1
2031	25,284	1,620	5,879	32,784	24,298	418	23,880	8,904	5,485	5,410	75	15.2
2032	25,719	1,581	6,517	33,818	24,443	404	24,039	9,779	5,523	5,436	88	15.4
2033	27,138	0	7,122	34,259	24,587	391	24,196	10,063	5,928	5,486	442	22.8
2034	27,934	0	7,743	35,677	24,732	390	24,342	11,334	5,970	5,511	460	23.1
2035	27,615	0	7,877	35,492	24,876	381	24,495	10,997	5,991	5,548	443	22.7
2036	31,054	0	7,113	38,168	25,019	334	24,685	13,482	6,036	5,572	464	23.1
2037	33,311	0	7,229	40,540	25,174	282	24,892	15,648	5,867	5,628	239	18.4
2038	35,013	0	7,363	42,376	25,337	241	25,096	17,280	5,794	5,668	126	16.1
2039	38,379	0	7,498	45,877	25,508	206	25,302	20,575	5,981	5,709	273	19.0
2040	39,879	0	7,651	47,530	25,682	210	25,472	22,058	6,096	5,727	369	20.9
2041	41,085	0	7,766	48,851	25,852	214	25,638	23,213	6,117	5,781	336	20.2
2042	40,812	0	7,900	48,713	26,019	128	25,892	22,821	6,139	5,827	312	19.7
2043	43,035	0	8,035	51,070	26,189	135	26,054	25,015	6,079	5,868	210	17.7
2044	43,467	0	8,190	51,657	26,359	142	26,217	25,440	6,100	5,896	204	17.5
2045	43,029	0	8,169	51,198	26,529	150	26,380	24,818	6,101	5,931	170	16.8

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
"Low Band" Commodity Pricing

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var 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
2016	$697,631	$511,403	$19,727	$264,331	$26,757	$23,719	$12,302	$582,759	$973,110
2017	$782,256	$488,199	$20,547	$307,308	$24,287	$23,719	$6,631	$590,432	$1,062,514
2018	$804,951	$507,218	$19,832	$325,724	$24,847	$63,918	$5,155	$618,645	$1,133,000
2019	$840,318	$528,683	$31,754	$341,425	$26,540	$64,565	$3,778	$670,294	$1,166,770
2020	$862,066	$520,418	$30,114	$379,343	$27,868	$44,746	$1,260	$695,414	$1,170,402
2021	$912,636	$594,820	$34,618	$387,812	$31,994	$56,127	($1,787)	$792,208	$1,224,013
2022	$1,206,399	$542,511	$228,829	$400,497	$31,706	$67,547	($25,325)	$941,689	$1,510,474
2023	$1,244,837	$576,735	$256,291	$401,474	$35,734	$78,031	($26,904)	$1,033,505	$1,532,693
2024	$1,305,080	$627,485	$278,867	$391,969	$39,944	$90,951	($30,356)	$1,143,346	$1,560,593
2025	$1,356,953	$699,715	$278,012	$412,918	$51,922	$185,881	($32,949)	$1,255,545	$1,696,907
2026	$1,412,371	$706,485	$282,556	$417,538	$54,155	$217,829	($36,098)	$1,313,877	$1,740,959
2027	$1,465,502	$749,736	$309,588	$424,528	$58,803	$249,621	($38,464)	$1,464,290	$1,755,024
2028	$1,520,242	$766,249	$310,790	$433,503	$61,292	$281,815	($41,368)	$1,533,870	$1,798,653
2029	$1,596,941	$828,908	$321,188	$441,440	$65,130	$313,861	($49,668)	$1,667,010	$1,850,788
2030	$1,666,041	$793,355	$324,717	$451,458	$66,479	$346,951	($53,605)	$1,734,985	$1,860,411
2031	$1,743,058	$889,511	$343,413	$459,098	$72,025	$372,654	($57,668)	$1,924,551	$1,897,541
2032	$1,821,994	$913,188	$352,192	$467,711	$75,879	$404,149	($60,303)	$2,058,889	$1,915,920
2033	$1,954,735	$1,068,951	$374,532	$476,529	$94,615	$548,692	$0	$2,434,873	$2,083,180
2034	$2,073,549	$1,149,892	$397,218	$477,996	$99,954	$577,138	$0	$2,665,512	$2,110,234
2035	$2,145,177	$1,137,401	$378,352	$464,242	$101,522	$606,612	$0	$2,732,756	$2,100,549
2036	$2,206,697	$1,328,685	$420,998	$348,961	$123,313	$709,275	$0	$3,012,478	$2,125,451
2037	$2,286,338	$1,502,066	$445,471	$329,813	$144,629	$839,239	$0	$3,342,374	$2,205,183
2038	$2,360,312	$1,642,399	$462,066	$305,152	$164,851	$972,335	$0	$3,611,842	$2,295,273
2039	$2,420,355	$1,850,456	$501,242	$259,778	$188,323	$1,108,537	$0	$3,984,686	$2,344,004
2040	$2,492,177	$2,024,359	$515,541	$231,748	$212,136	$1,251,076	$0	$4,305,630	$2,421,408
2041	$2,556,276	$2,096,368	$537,819	$226,942	$220,128	$1,257,836	$0	$4,441,562	$2,453,806
2042	$2,598,928	$2,102,965	$540,952	$225,359	$224,851	$1,264,597	$0	$4,458,234	$2,499,417
2043	$2,677,775	$2,310,762	$563,444	$208,973	$251,786	$1,417,812	$0	$4,833,381	$2,597,170
2044	$2,752,922	$2,376,343	$587,923	$194,201	$260,004	$1,424,572	$0	$4,993,096	$2,602,868
2045	$2,833,146	$2,412,665	$591,998	$179,968	$265,220	$1,427,463	$0	$5,091,692	$2,618,767
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$14,905,573	$8,905,843	$2,359,456	$4,064,481	$692,280	$3,067,387	-$145,981	$16,474,853	$17,374,186
CPW of End Effects beyond 2045									$3,050,748
TOTAL Utility Cost, Net CPW (2016$)									$20,424,934

	Resource (Capacity) Additions									
	(10) Supply-Side (Thermal) + (Current) Purchased Installed	(11)	(12) (Increm) Energy Efficiency+ VVO	(13)	(14) Distributed Solar	(15)	(16) Generic Wind	(17)	(18) Utility Solar	(19)
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	0.0	0.0	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	21.7	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	44.2	65.9	0.2	2.2	0	30	0.0	0.0
2020	(111)	5,114	14.6	80.5	0.3	2.5	0	30	8.4	8.4
2021	(56)	5,058	5.5	86.0	0.2	2.7	0	30	21.0	29.4
2022	0	5,058	12.5	98.4	0.3	2.9	0	30	21.0	50.4
2023	(109)	4,949	16.0	114.4	0.3	3.2	0	30	21.0	71.4
2024	0	4,949	7.8	122.2	0.3	3.5	0	30	21.0	92.4
2025	327	5,276	-7.7	114.5	0.4	3.9	0	30	21.0	113.4
2026	(110)	5,166	-5.8	108.7	0.3	4.1	20	50	21.0	134.4
2027	0	5,166	-9.0	99.7	0.4	4.5	20	70	21.0	155.4
2028	0	5,166	1.7	101.4	0.4	4.8	20	90	21.0	176.4
2029	(10)	5,156	-0.7	100.7	0.4	5.2	20	110	21.0	197.4
2030	(171)	4,985	-0.4	100.3	0.4	5.6	20	130	21.0	218.4
2031	0	4,985	-3.1	97.2	0.4	6.0	20	150	21.0	239.4
2032	0	4,985	-5.0	92.2	0.5	6.4	20	170	21.0	260.4
2033	365	5,350	-2.2	90.0	0.4	6.9	20	190	21.0	281.4
2034	0	5,350	-26.0	64.0	0.5	7.4	20	210	21.0	302.4
2035	0	5,350	-14.0	50.0	0.5	7.8	20	230	21.0	323.4
2036	67	5,417	-14.7	35.3	0.5	8.3	-30	200	21.0	344.4
2037	(176)	5,241	-12.6	22.7	0.6	8.9	0	200	21.0	365.4
2038	(82)	5,159	-11.4	11.3	0.6	9.5	0	200	21.0	386.4
2039	177	5,335	-10.4	0.9	0.6	10.1	0	200	21.0	407.4
2040	93	5,428	-0.5	0.4	0.6	10.7	0	200	21.0	428.4
2041	0	5,428	-0.1	0.2	0.6	11.3	0	200	21.0	449.4
2042	0	5,428	-0.1	0.2	0.7	12.0	0	200	21.0	470.4
2043	(82)	5,346	-0.1	0.1	0.8	12.8	0	200	21.0	491.4
2044	0	5,346	-0.1	0.1	0.7	13.5	0	200	21.0	512.4
2045	0	5,346	-0.1	0.0	0.8	14.4	0	200	12.6	525.0

	Energy & Capacity Positions											
	(20) Thermal Generation	(21) (Current) Purchased Energy	(22) (New) Generic Wind + Utility Solar	(23)=(20)+(21)+(22) = Market Sales	(24) Load (Net of Embedded EE)	(25) *Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	(26)=(24)-(25) = Net Load Require- ments	(27)=(23)-(26) ENERGY Surplus	(28) Capacity	(29) Peak + Reserves	(30)=(28)-(29) CAPACITY Surplus	(31) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	17,748	1,942	919	20,608	22,988	16	22,972	-2,363	5,975	5,710	265	18.9
2017	15,900	1,937	917	18,754	23,144	18	23,125	-4,372	5,948	5,760	188	17.3
2018	15,917	1,937	917	18,772	22,618	236	22,382	-3,610	5,344	5,006	338	21.3
2019	16,467	1,937	917	19,322	22,906	518	22,388	-3,066	5,322	5,073	249	19.2
2020	16,294	1,942	973	19,208	22,588	602	21,986	-2,777	5,235	4,981	254	19.4
2021	17,573	1,937	1,105	20,614	22,752	679	22,073	-1,459	5,206	5,032	174	17.5
2022	15,410	1,937	1,239	18,585	22,924	743	22,181	-3,596	5,239	5,071	168	17.4
2023	16,587	1,937	1,373	19,897	23,094	758	22,337	-2,440	5,168	5,099	69	15.1
2024	17,593	1,942	1,511	21,045	23,255	768	22,487	-1,441	5,197	5,133	63	15.0
2025	18,634	1,937	1,642	22,213	23,409	685	22,724	-512	5,537	5,187	351	21.3
2026	18,365	1,937	2,263	22,565	23,563	620	22,944	-379	5,463	5,227	236	18.7
2027	19,595	1,937	2,884	24,416	23,717	568	23,149	1,267	5,495	5,267	228	18.5
2028	19,434	1,942	3,514	24,890	23,877	540	23,337	1,553	5,538	5,298	240	18.7
2029	19,821	1,648	4,127	25,595	24,026	525	23,501	2,094	5,569	5,334	235	18.6
2030	19,344	1,620	4,748	25,712	24,164	506	23,658	2,054	5,439	5,373	66	15.0
2031	20,418	1,620	5,369	27,408	24,298	479	23,819	3,589	5,477	5,410	67	15.0
2032	20,624	1,581	6,006	28,212	24,443	459	23,985	4,227	5,514	5,436	78	15.2
2033	23,101	0	6,611	29,712	24,587	438	24,149	5,563	5,918	5,486	432	22.5
2034	23,843	0	7,233	31,076	24,732	337	24,396	6,680	5,933	5,511	423	22.3
2035	23,009	0	7,854	30,863	24,876	281	24,595	6,267	5,961	5,548	413	22.1
2036	26,226	0	7,090	33,316	25,019	228	24,791	8,524	6,004	5,572	433	22.4
2037	28,786	0	7,206	35,992	25,174	183	24,991	11,001	5,837	5,628	210	17.8
2038	30,659	0	7,340	37,999	25,337	146	25,191	12,808	5,766	5,668	98	15.6
2039	33,723	0	7,474	41,198	25,508	113	25,396	15,802	5,953	5,709	245	18.5
2040	35,799	0	7,628	43,427	25,682	115	25,567	17,860	6,067	5,727	341	20.4
2041	36,440	0	7,743	44,183	25,852	120	25,732	18,450	6,089	5,781	308	19.7
2042	35,838	0	7,877	43,715	26,019	127	25,892	17,823	6,111	5,827	284	19.1
2043	38,465	0	8,011	46,477	26,189	134	26,055	20,422	6,050	5,868	182	17.1
2044	38,869	0	8,166	47,035	26,359	142	26,217	20,818	6,072	5,896	176	17.0
2045	38,557	0	8,226	46,784	26,529	150	26,380	20,404	6,085	5,931	154	16.5

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'High Carbon' Commodity Pricing

	Utility Costs (Nominal$)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM and OGC	(Incremental) Fixed & (All) Var Costs	(Incremental) Capital + Renewable + EE + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2016	$817,536	$614,698	$24,748	$264,331	$29,989	$23,719	$2,456	$836,320	$941,156
2017	$909,258	$594,248	$25,473	$307,308	$27,768	$26,194	($3,467)	$854,030	$1,032,752
2018	$942,465	$630,667	$24,638	$325,724	$28,224	$66,393	($5,947)	$887,413	$1,124,751
2019	$992,319	$691,728	$38,358	$341,425	$30,455	$64,438	($8,487)	$991,760	$1,158,477
2020	$1,000,766	$666,968	$36,698	$379,343	$31,059	$48,313	($9,945)	$983,779	$1,169,425
2021	$1,052,641	$752,115	$41,249	$387,812	$35,097	$59,126	($12,951)	$1,096,425	$1,218,664
2022	$1,550,949	$805,998	$520,405	$400,497	$38,683	$70,190	($53,281)	$1,643,484	$1,689,956
2023	$1,624,474	$808,909	$529,728	$401,474	$41,471	$80,792	($57,579)	$1,718,265	$1,711,005
2024	$1,684,327	$838,351	$554,158	$391,969	$44,534	$89,553	($60,887)	$1,811,837	$1,730,169
2025	$1,748,683	$942,812	$559,992	$412,918	$57,340	$188,873	($64,163)	$1,980,377	$1,866,079
2026	$1,811,699	$994,585	$598,507	$417,538	$61,111	$246,499	($67,738)	$2,158,233	$1,903,966
2027	$1,869,202	$1,010,817	$616,248	$424,528	$64,628	$278,291	($70,356)	$2,287,660	$1,905,698
2028	$1,932,615	$1,013,903	$609,978	$433,503	$66,566	$309,900	($73,830)	$2,344,569	$1,948,065
2029	$2,024,947	$1,125,245	$645,018	$441,440	$71,636	$336,480	($78,054)	$2,576,770	$1,989,943
2030	$2,093,402	$1,043,888	$627,027	$451,458	$71,279	$369,754	($81,519)	$2,583,530	$1,991,759
2031	$2,178,338	$1,171,219	$670,422	$459,098	$77,281	$401,324	($85,831)	$2,841,222	$2,030,629
2032	$2,263,816	$1,200,154	$687,045	$467,711	$81,056	$433,927	($88,134)	$3,003,036	$2,042,539
2033	$2,384,170	$1,352,779	$703,203	$476,529	$98,919	$579,156	$0	$3,366,031	$2,228,726
2034	$2,466,530	$1,422,403	$734,857	$477,996	$103,443	$610,595	$0	$3,561,478	$2,254,344
2035	$2,564,406	$1,463,644	$722,426	$464,242	$106,849	$616,185	$0	$3,676,637	$2,261,115
2036	$2,629,650	$1,672,984	$787,073	$348,961	$128,144	$719,718	$0	$3,983,521	$2,303,009
2037	$2,701,660	$1,863,114	$828,162	$329,813	$148,347	$849,467	$0	$4,326,150	$2,394,413
2038	$2,772,391	$2,008,612	$841,295	$305,152	$167,845	$982,496	$0	$4,579,871	$2,497,920
2039	$2,837,990	$2,229,005	$898,261	$259,778	$190,300	$1,118,775	$0	$4,983,044	$2,551,064
2040	$2,913,817	$2,426,142	$918,653	$231,748	$213,580	$1,261,284	$0	$5,329,278	$2,635,945
2041	$2,986,468	$2,502,380	$954,325	$226,942	$220,389	$1,267,984	$0	$5,481,890	$2,676,598
2042	$3,032,028	$2,508,438	$958,810	$225,359	$225,271	$1,274,744	$0	$5,475,688	$2,748,962
2043	$3,135,273	$2,739,768	$992,346	$208,973	$251,438	$1,427,959	$0	$5,911,395	$2,844,362
2044	$3,202,300	$2,787,299	$1,026,141	$194,201	$258,180	$1,434,719	$0	$6,036,205	$2,866,635
2045	$3,299,000	$2,834,289	$1,037,366	$179,968	$262,241	$1,431,806	$0	$6,158,527	$2,886,143
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$18,159,323	$11,377,003	$4,493,568	$4,064,481	$738,427	$3,173,910	-$328,768	$23,272,544	$18,405,398
CPW of End Effects beyond 2045									$3,362,229
TOTAL Utility Cost, Net CPW (2016$)									$21,767,627

	Resource (Capacity) Additions									
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	Supply-Side (Thermal) + (Current) Purchased Installed		(Increm) Energy Efficiency+ VVO		Distributed Solar		Generic Wind		Utility Solar	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	25.6	25.6	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	47.3	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	18.6	65.9	0.2	2.2	0	30	0.0	0.0
2020	(111)	5,114	2.1	68.0	0.3	2.5	0	30	21.0	21.0
2021	(56)	5,058	4.5	72.6	0.2	2.7	0	30	21.0	42.0
2022	0	5,058	14.0	86.6	0.3	2.9	0	30	21.0	63.0
2023	(109)	4,949	17.1	103.7	0.3	3.2	0	30	21.0	84.0
2024	0	4,949	5.9	109.6	0.3	3.5	0	30	21.0	105.0
2025	327	5,276	-7.1	102.6	0.4	3.9	0	30	21.0	126.0
2026	(110)	5,166	-5.4	97.2	0.3	4.1	30	60	21.0	147.0
2027	0	5,166	-8.5	88.8	0.4	4.5	20	80	21.0	168.0
2028	0	5,166	1.6	90.4	0.4	4.8	20	100	21.0	189.0
2029	(10)	5,156	-3.1	87.2	0.4	5.2	20	120	21.0	210.0
2030	(171)	4,985	-2.6	84.6	0.4	5.6	20	140	21.0	231.0
2031	0	4,985	-2.1	82.5	0.4	6.0	20	160	21.0	252.0
2032	0	4,985	-3.5	79.0	0.5	6.4	20	180	21.0	273.0
2033	365	5,350	-1.2	77.8	0.4	6.9	20	200	21.0	294.0
2034	0	5,350	0.8	78.6	0.5	7.4	20	220	21.0	315.0
2035	0	5,350	-1.3	77.3	0.5	7.8	0	220	21.0	336.0
2036	67	5,417	-13.4	63.9	0.5	8.3	-30	190	21.0	357.0
2037	(176)	5,241	-14.3	49.6	0.6	8.9	0	190	21.0	378.0
2038	(82)	5,159	-12.5	37.1	0.6	9.5	0	190	21.0	399.0
2039	177	5,335	-10.7	26.4	0.6	10.1	0	190	21.0	420.0
2040	93	5,428	-0.2	26.2	0.6	10.7	0	190	21.0	441.0
2041	0	5,428	-0.2	26.0	0.6	11.3	0	190	21.0	462.0
2042	0	5,428	-0.1	25.9	0.7	12.0	0	190	21.0	483.0
2043	(82)	5,346	-0.1	25.8	0.8	12.8	0	190	21.0	504.0
2044	0	5,346	-0.1	25.7	0.7	13.5	0	190	21.0	525.0
2045	0	5,346	-0.1	25.6	0.8	14.4	0	190	0.0	525.0

	Energy & Capacity Positions											
	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)
	Thermal Generation	(Current) Purchased Energy	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Require- ments	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	22,359	1,942	919	25,220	22,988	16	22,972	2,248	5,975	5,710	265	18.9
2017	20,289	1,937	917	23,143	23,144	111	23,033	110	5,973	5,760	213	17.8
2018	19,910	1,937	917	22,764	22,618	329	22,289	475	5,369	5,006	364	21.9
2019	21,320	1,937	917	24,174	22,906	518	22,388	1,787	5,322	5,073	249	19.2
2020	20,387	1,942	1,054	23,383	22,588	557	22,031	1,351	5,235	4,981	254	19.4
2021	21,638	1,937	1,185	24,760	22,752	631	22,122	2,638	5,205	5,032	173	17.5
2022	21,898	1,937	1,319	25,154	22,924	700	22,224	2,930	5,240	5,071	169	17.4
2023	21,954	1,937	1,454	25,344	23,094	718	22,376	2,968	5,170	5,099	71	15.2
2024	22,398	1,942	1,592	25,932	23,255	717	22,538	3,394	5,197	5,133	63	15.0
2025	23,701	1,937	1,722	27,360	23,409	637	22,772	4,588	5,538	5,187	351	21.3
2026	24,301	1,937	2,773	29,011	23,563	575	22,988	6,022	5,474	5,227	247	19.0
2027	24,733	1,937	3,394	30,064	23,717	526	23,191	6,873	5,507	5,267	240	18.8
2028	24,094	1,942	4,026	30,062	23,877	499	23,379	6,683	5,550	5,298	251	19.0
2029	25,120	1,648	4,637	31,404	24,026	464	23,562	7,842	5,578	5,334	244	18.8
2030	23,785	1,620	5,258	30,663	24,164	439	23,725	6,938	5,446	5,373	73	15.1
2031	25,108	1,620	5,879	32,608	24,298	418	23,880	8,728	5,485	5,410	75	15.2
2032	25,267	1,581	6,517	33,366	24,443	404	24,039	9,327	5,523	5,436	88	15.4
2033	26,969	0	7,122	34,091	24,587	391	24,196	9,895	5,928	5,486	442	22.8
2034	27,383	0	7,743	35,126	24,732	390	24,342	10,784	5,970	5,511	460	23.1
2035	27,082	0	7,877	34,959	24,876	381	24,495	10,465	5,991	5,548	443	22.7
2036	30,073	0	7,113	37,186	25,019	334	24,685	12,500	6,036	5,572	464	23.1
2037	32,373	0	7,229	39,602	25,174	282	24,892	14,710	5,867	5,628	239	18.4
2038	33,699	0	7,363	41,062	25,337	241	25,096	15,966	5,794	5,668	126	16.1
2039	36,505	0	7,498	44,003	25,508	206	25,302	18,701	5,981	5,709	273	19.0
2040	38,370	0	7,651	46,021	25,682	210	25,472	20,549	6,096	5,727	369	20.9
2041	38,824	0	7,766	46,590	25,852	214	25,638	20,952	6,117	5,781	336	20.2
2042	38,201	0	7,900	46,102	26,019	128	25,892	20,210	6,139	5,827	312	19.7
2043	40,499	0	8,035	48,534	26,189	135	26,054	22,479	6,079	5,868	210	17.7
2044	40,651	0	8,190	48,841	26,359	142	26,217	22,624	6,100	5,896	204	17.5
2045	40,422	0	8,169	48,591	26,529	150	26,380	22,211	6,101	5,931	170	16.8

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'No Carbon' Commodity Pricing

	Utility Costs (Nominal$)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM and OGC	(Incremental) Fixed & (All) Var Costs	(Incremental) Capital + Renewable + EE + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2016	$745,935	$547,892	$23,668	$264,331	$25,879	$23,719	$8,618	$678,429	$961,613
2017	$836,982	$562,275	$24,541	$307,308	$25,194	$23,719	$2,692	$734,736	$1,047,974
2018	$875,435	$581,154	$24,029	$325,724	$25,617	$63,918	($19)	$769,558	$1,126,300
2019	$935,489	$618,338	$37,459	$341,425	$27,449	$54,879	($3,486)	$857,540	$1,154,011
2020	$947,443	$601,600	$36,039	$379,343	$28,440	$44,746	($5,166)	$871,444	$1,161,002
2021	$999,578	$686,981	$40,754	$387,812	$33,008	$56,127	($8,380)	$989,086	$1,206,794
2022	$1,028,211	$694,485	$41,222	$400,497	$34,969	$67,547	($9,644)	$1,014,531	$1,242,757
2023	$1,075,095	$702,114	$42,103	$401,474	$37,893	$81,669	($12,089)	$1,060,484	$1,267,775
2024	$1,135,397	$763,061	$44,982	$391,969	$42,136	$88,494	($15,705)	$1,173,137	$1,277,196
2025	$1,188,702	$840,808	$43,993	$412,918	$53,408	$185,881	($18,574)	$1,285,381	$1,421,755
2026	$1,244,510	$903,464	$47,569	$417,538	$57,459	$217,829	($21,896)	$1,407,005	$1,459,467
2027	$1,297,536	$923,068	$48,770	$424,528	$61,277	$249,621	($24,454)	$1,519,707	$1,460,640
2028	$1,354,108	$929,049	$47,884	$433,503	$63,504	$281,608	($27,393)	$1,578,727	$1,503,536
2029	$1,433,313	$1,027,989	$50,451	$441,440	$67,891	$312,455	($38,181)	$1,747,407	$1,547,952
2030	$1,503,973	$964,607	$49,981	$451,458	$68,325	$346,951	($42,542)	$1,792,176	$1,550,576
2031	$1,595,769	$1,095,081	$52,926	$459,098	$74,745	$372,654	($47,391)	$2,023,638	$1,579,243
2032	$1,697,075	$1,156,352	$54,391	$467,711	$79,931	$404,149	($51,701)	$2,225,736	$1,582,172
2033	$1,803,754	$1,274,276	$53,131	$476,529	$96,299	$548,225	$0	$2,501,321	$1,750,894
2034	$1,879,983	$1,352,993	$56,357	$477,996	$100,318	$577,138	$0	$2,667,900	$1,776,884
2035	$1,958,323	$1,391,365	$54,599	$464,242	$103,453	$606,211	$0	$2,798,013	$1,780,180
2036	$2,044,139	$1,598,961	$58,389	$348,961	$124,957	$709,275	$0	$3,106,763	$1,777,919
2037	$2,125,088	$1,778,424	$59,639	$329,813	$145,367	$839,239	$0	$3,425,936	$1,851,635
2038	$2,217,499	$1,926,600	$58,667	$305,152	$166,146	$972,335	$0	$3,719,644	$1,926,754
2039	$2,283,459	$2,182,512	$62,478	$259,778	$190,854	$1,108,537	$0	$4,130,981	$1,956,636
2040	$2,386,664	$2,407,116	$61,356	$231,748	$217,002	$1,251,076	$0	$4,552,547	$2,002,416
2041	$2,468,866	$2,519,030	$65,195	$226,942	$226,628	$1,257,836	$0	$4,766,773	$1,997,725
2042	$2,536,116	$2,564,652	$66,268	$225,359	$233,197	$1,264,597	$0	$4,873,479	$2,016,710
2043	$2,635,834	$2,796,208	$65,096	$208,973	$261,130	$1,417,812	$0	$5,300,516	$2,084,536
2044	$2,725,194	$2,933,794	$69,562	$194,201	$271,678	$1,424,572	$0	$5,572,061	$2,046,940
2045	$2,794,594	$2,962,849	$69,777	$179,968	$276,300	$1,427,463	$0	$5,643,120	$2,067,830

Cumulative Present Worth $000 (2016$)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Utility CPW 2016-2045	$14,235,814	$10,651,840	$469,769	$4,064,481	$713,590	$3,060,298	-$110,914	$17,857,443	$15,227,435
CPW of End Effects beyond 2045									$2,408,931
TOTAL Utility Cost, Net CPW (2016$)									$17,636,366

	Resource (Capacity) Additions									
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	Supply-Side (Thermal) + (Current) Purchased Installed		(Increm) Energy Efficiency+ VVO		Distributed Solar		Generic Wind		Utility Solar	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	0.0	0.0	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	21.7	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	41.8	63.5	0.2	2.2	0	30	0.0	0.0
2020	(111)	5,114	14.8	78.2	0.3	2.5	0	30	8.4	8.4
2021	(56)	5,058	6.0	84.2	0.2	2.7	0	30	21.0	29.4
2022	0	5,058	12.6	96.8	0.3	2.9	0	30	21.0	50.4
2023	(109)	4,949	17.9	114.7	0.3	3.2	0	30	21.0	71.4
2024	0	4,949	7.5	122.2	0.3	3.5	0	30	21.0	92.4
2025	327	5,276	-7.7	114.5	0.4	3.9	0	30	21.0	113.4
2026	(110)	5,166	-5.7	108.8	0.3	4.1	20	50	21.0	134.4
2027	0	5,166	-9.0	99.8	0.4	4.5	20	70	21.0	155.4
2028	0	5,166	1.6	101.4	0.4	4.8	20	90	21.0	176.4
2029	(10)	5,156	-0.4	101.1	0.4	5.2	20	110	21.0	197.4
2030	(171)	4,985	-0.8	100.3	0.4	5.6	20	130	21.0	218.4
2031	0	4,985	-3.1	97.2	0.4	6.0	20	150	21.0	239.4
2032	0	4,985	-5.0	92.3	0.5	6.4	20	170	21.0	260.4
2033	365	5,350	-2.4	89.9	0.4	6.9	20	190	21.0	281.4
2034	0	5,350	-26.1	63.7	0.5	7.4	20	210	21.0	302.4
2035	0	5,350	-14.3	49.4	0.5	7.8	20	230	21.0	323.4
2036	67	5,417	-14.6	34.8	0.5	8.3	-30	200	21.0	344.4
2037	(176)	5,241	-12.4	22.4	0.6	8.9	0	200	21.0	365.4
2038	(82)	5,159	-11.3	11.1	0.6	9.5	0	200	21.0	386.4
2039	177	5,335	-10.4	0.8	0.6	10.1	0	200	21.0	407.4
2040	93	5,428	-0.5	0.3	0.6	10.7	0	200	21.0	428.4
2041	0	5,428	-0.1	0.2	0.6	11.3	0	200	21.0	449.4
2042	0	5,428	-0.1	0.1	0.7	12.0	0	200	21.0	470.4
2043	(82)	5,346	0.0	0.1	0.8	12.8	0	200	21.0	491.4
2044	0	5,346	0.0	0.0	0.7	13.5	0	200	21.0	512.4
2045	0	5,346	0.0	0.0	0.8	14.4	0	200	12.6	525.0

	Energy & Capacity Positions											
	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)
	Thermal Generation	(Current) Purchased Energy	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Require- ments	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,449	1,942	919	22,309	22,988	16	22,972	-662	5,975	5,710	265	18.9
2017	18,758	1,937	917	21,612	23,144	18	23,125	-1,514	5,948	5,760	188	17.3
2018	18,445	1,937	917	21,299	22,618	236	22,382	-1,082	5,344	5,006	338	21.3
2019	19,371	1,937	917	22,225	22,906	474	22,433	-208	5,320	5,073	247	19.1
2020	18,968	1,942	973	21,882	22,588	561	22,027	-145	5,233	4,981	252	19.3
2021	20,479	1,937	1,105	23,520	22,752	641	22,112	1,408	5,204	5,032	172	17.5
2022	20,320	1,937	1,239	23,495	22,924	708	22,216	1,279	5,238	5,071	166	17.3
2023	20,264	1,937	1,373	23,574	23,094	738	22,356	1,218	5,168	5,099	69	15.1
2024	21,311	1,942	1,511	24,764	23,255	743	22,511	2,252	5,197	5,133	63	15.0
2025	22,324	1,937	1,642	25,902	23,409	668	22,742	3,160	5,537	5,187	351	21.3
2026	23,184	1,937	2,263	27,383	23,563	608	22,955	4,428	5,463	5,227	236	18.7
2027	23,767	1,937	2,884	28,588	23,717	560	23,156	5,431	5,495	5,267	228	18.5
2028	23,255	1,942	3,514	28,711	23,877	535	23,342	5,368	5,538	5,298	240	18.7
2029	24,146	1,648	4,127	29,921	24,026	514	23,513	6,408	5,569	5,334	235	18.6
2030	23,107	1,620	4,748	29,475	24,164	496	23,668	5,807	5,439	5,373	66	15.0
2031	24,592	1,620	5,369	31,581	24,298	472	23,826	7,755	5,477	5,410	67	15.0
2032	25,291	1,581	6,006	32,878	24,443	454	23,989	8,889	5,514	5,436	78	15.2
2033	26,675	0	6,611	33,286	24,587	434	24,153	9,133	5,918	5,486	432	22.5
2034	27,258	0	7,233	34,490	24,732	334	24,399	10,092	5,933	5,511	422	22.3
2035	27,003	0	7,854	34,856	24,876	276	24,599	10,257	5,960	5,548	412	22.0
2036	30,289	0	7,090	37,379	25,019	225	24,794	12,585	6,004	5,572	432	22.4
2037	32,689	0	7,206	39,895	25,174	181	24,993	14,902	5,837	5,628	209	17.8
2038	34,458	0	7,340	41,798	25,337	145	25,193	16,605	5,765	5,668	98	15.6
2039	38,061	0	7,474	45,535	25,508	112	25,397	20,139	5,953	5,709	245	18.5
2040	40,616	0	7,628	48,244	25,682	115	25,567	22,677	6,067	5,727	341	20.4
2041	41,812	0	7,743	49,555	25,852	120	25,733	23,822	6,089	5,781	308	19.7
2042	41,657	0	7,877	49,534	26,019	127	25,893	23,642	6,111	5,827	284	19.1
2043	44,287	0	8,011	52,299	26,189	134	26,055	26,244	6,050	5,868	182	17.1
2044	45,467	0	8,166	53,634	26,359	142	26,217	27,416	6,072	5,896	176	17.0
2045	44,918	0	8,226	53,144	26,529	150	26,380	26,765	6,085	5,931	154	16.5

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Base' Commodity Pricing - High Load

	Utility Costs (Nominal$)								
	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var 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
2016	$757,684	$541,906	$24,028	$264,331	$26,354	$23,719	$8,458	$690,356	$956,124
2017	$856,033	$554,763	$24,896	$307,308	$25,999	$26,194	$1,976	$754,702	$1,042,466
2018	$899,999	$581,739	$24,106	$325,724	$26,158	$66,393	($765)	$782,804	$1,140,550
2019	$975,688	$639,877	$37,679	$341,425	$28,334	$64,438	($4,902)	$899,159	$1,183,380
2020	$1,005,877	$639,587	$36,256	$379,343	$29,931	$48,313	($7,714)	$931,763	$1,199,830
2021	$1,077,951	$782,337	$40,914	$387,812	$42,262	$141,029	($11,542)	$1,126,277	$1,334,486
2022	$1,407,763	$845,389	$335,528	$400,497	$47,112	$151,984	($36,292)	$1,505,035	$1,646,946
2023	$1,468,318	$835,616	$339,137	$401,474	$49,602	$162,813	($38,700)	$1,545,765	$1,672,495
2024	$1,552,384	$888,686	$359,062	$391,969	$53,711	$175,557	($43,103)	$1,682,624	$1,695,642
2025	$1,628,412	$911,250	$352,910	$412,918	$56,129	$189,109	($46,703)	$1,727,082	$1,776,944
2026	$1,711,718	$1,046,183	$387,172	$417,538	$70,990	$307,502	($50,905)	$2,000,334	$1,889,863
2027	$1,786,603	$1,069,597	$400,342	$424,528	$75,013	$339,294	($53,958)	$2,140,518	$1,900,900
2028	$1,856,621	$1,084,939	$397,604	$433,503	$77,859	$371,097	($57,058)	$2,209,933	$1,954,633
2029	$1,958,078	$1,184,771	$418,040	$441,440	$82,603	$402,403	($63,604)	$2,413,547	$2,010,184
2030	$2,066,226	$1,132,730	$412,145	$451,458	$83,640	$436,623	($68,848)	$2,497,916	$2,016,057
2031	$2,195,582	$1,291,085	$445,217	$459,098	$91,882	$471,209	($74,958)	$2,826,208	$2,052,907
2032	$2,330,659	$1,468,047	$473,133	$467,711	$111,505	$609,395	($79,232)	$3,256,196	$2,125,021
2033	$2,448,693	$1,497,764	$468,488	$476,529	$115,235	$640,816	$0	$3,390,029	$2,257,496
2034	$2,526,592	$1,574,796	$490,401	$477,996	$120,314	$671,177	$0	$3,556,064	$2,305,212
2035	$2,626,984	$1,608,926	$481,565	$464,242	$123,813	$702,762	$0	$3,684,230	$2,324,061
2036	$2,742,308	$1,850,440	$529,368	$348,961	$147,677	$808,459	$0	$4,066,312	$2,360,900
2037	$2,833,703	$2,207,599	$574,189	$329,813	$186,544	$1,067,888	$0	$4,653,847	$2,545,889
2038	$2,957,239	$2,368,783	$586,076	$305,152	$207,617	$1,200,799	$0	$4,968,340	$2,657,325
2039	$3,032,620	$2,631,702	$632,417	$259,778	$232,187	$1,337,079	$0	$5,383,415	$2,742,368
2040	$3,152,644	$2,827,347	$643,493	$231,748	$255,674	$1,476,638	$0	$5,741,067	$2,846,477
2041	$3,256,409	$2,923,617	$673,102	$226,942	$263,816	$1,483,398	$0	$5,905,920	$2,921,363
2042	$3,384,745	$2,967,130	$685,002	$225,359	$270,651	$1,490,158	$0	$6,031,785	$2,991,260
2043	$3,511,041	$3,217,985	$705,037	$208,973	$298,976	$1,643,373	$0	$6,451,666	$3,133,719
2044	$3,633,423	$3,357,911	$742,236	$194,201	$314,320	$1,700,761	$0	$6,720,290	$3,222,561
2045	$3,788,954	$3,411,023	$746,433	$179,968	$319,464	$1,697,848	$0	$6,875,531	$3,268,158
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$18,027,371	$12,118,670	$3,042,339	$4,064,481	$847,542	$3,871,715	-$239,106	$22,927,397	$18,805,615
CPW of End Effects beyond 2045									$3,807,260
TOTAL Utility Cost, Net CPW (2016$)									$22,612,875

	Resource (Capacity) Additions									
	(10) Supply-Side (Thermal) + (Current) Purchased Installed	(11)	(12) (Increm) Energy Efficiency+ VVO	(13)	(14) Distributed Solar	(15)	(16) Generic Wind	(17)	(18) Utility Solar	(19)
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	25.6	25.6	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	47.3	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	18.6	65.9	0.2	2.2	0	30	0.0	0.0
2020	(111)	5,114	2.1	68.0	0.3	2.5	0	30	21.0	21.0
2021	379	5,493	-7.9	60.1	0.2	2.7	0	30	21.0	42.0
2022	0	5,493	13.5	73.6	0.3	2.9	0	30	21.0	63.0
2023	(109)	5,384	19.2	92.8	0.3	3.2	0	30	21.0	84.0
2024	0	5,384	9.3	102.1	0.3	3.5	0	30	21.0	105.0
2025	(108)	5,276	8.1	110.1	0.4	3.9	0	30	21.0	126.0
2026	325	5,601	-6.1	104.0	0.3	4.1	20	50	21.0	147.0
2027	0	5,601	-10.6	93.4	0.4	4.5	20	70	21.0	168.0
2028	0	5,601	0.4	93.8	0.4	4.8	20	90	21.0	189.0
2029	(10)	5,591	-1.7	92.1	0.4	5.2	20	110	21.0	210.0
2030	(171)	5,420	-0.8	91.4	0.4	5.6	20	130	21.0	231.0
2031	0	5,420	9.7	101.1	0.4	6.0	20	150	21.0	252.0
2032	435	5,855	-6.1	95.0	0.5	6.4	20	170	21.0	273.0
2033	(70)	5,785	-2.9	92.1	0.4	6.9	20	190	21.0	294.0
2034	0	5,785	-1.2	91.0	0.5	7.4	20	210	21.0	315.0
2035	0	5,785	-1.9	89.1	0.5	7.8	20	230	21.0	336.0
2036	67	5,852	-1.5	87.6	0.5	8.3	-30	200	21.0	357.0
2037	259	6,111	-1.2	86.4	0.6	8.9	0	200	21.0	378.0
2038	(82)	6,029	-14.8	71.7	0.6	9.5	0	200	21.0	399.0
2039	177	6,205	-12.0	59.6	0.6	10.1	0	200	21.0	420.0
2040	93	6,298	-11.1	48.6	0.6	10.7	0	200	21.0	441.0
2041	0	6,298	-0.2	48.4	0.6	11.3	0	200	21.0	462.0
2042	0	6,298	-0.1	48.3	0.7	12.0	0	200	21.0	483.0
2043	(82)	6,216	-0.1	48.2	0.8	12.8	0	200	21.0	504.0
2044	179	6,395	-0.1	48.1	0.7	13.5	0	200	21.0	525.0
2045	0	6,395	-0.1	48.0	0.8	14.4	0	200	0.0	525.0

	Energy & Capacity Positions											
	(20) Thermal Generation	(21) (Current) Purchased Energy	(22) (New) Generic Wind + Utility Solar	(23)=(20)+(21)+(22) = Market Sales	(24) Load (Net of Embedded EE)	(25) *Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	(26)=(24)-(25) = Net Load Require- ments	(27)=(23)-(26) ENERGY Surplus	(28) Capacity	(29) Peak + Reserves	(30)=(28)-(29) CAPACITY Surplus	(31) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,877	1,942	919	22,738	23,295	16	23,279	-541	5,975	5,786	188	17.3
2017	19,094	1,937	917	21,948	23,431	111	23,320	-1,372	5,973	5,832	142	16.4
2018	18,524	1,937	917	21,378	23,024	329	22,694	-1,316	5,369	5,095	274	19.7
2019	19,894	1,937	917	22,749	23,437	518	22,919	-170	5,322	5,190	132	16.5
2020	19,634	1,942	1,054	22,629	23,258	557	22,701	-72	5,235	5,129	107	16.0
2021	22,284	1,937	1,185	25,406	23,585	586	23,000	2,406	5,627	5,216	412	22.6
2022	23,038	1,937	1,319	26,294	23,902	653	23,249	3,045	5,662	5,288	374	21.6
2023	22,786	1,937	1,454	26,176	24,204	679	23,525	2,652	5,594	5,344	249	18.9
2024	23,698	1,942	1,592	27,231	24,474	695	23,779	3,452	5,624	5,403	222	18.3
2025	23,265	1,937	1,722	26,924	24,724	670	24,054	2,870	5,546	5,478	68	15.0
2026	25,577	1,937	2,343	29,857	24,999	603	24,396	5,461	5,906	5,545	360	21.0
2027	26,131	1,937	2,965	31,032	25,287	547	24,740	6,292	5,937	5,616	321	20.1
2028	25,676	1,942	3,595	31,212	25,565	515	25,051	6,162	5,978	5,673	305	19.7
2029	26,535	1,648	4,207	32,390	25,828	494	25,334	7,056	6,008	5,734	274	19.0
2030	25,668	1,620	4,828	32,117	26,063	473	25,589	6,527	5,878	5,795	83	15.2
2031	27,518	1,620	5,449	34,587	26,305	494	25,811	8,776	5,929	5,856	72	15.0
2032	30,190	1,581	6,087	37,858	26,582	470	26,111	11,747	6,399	5,911	488	23.0
2033	29,706	0	6,692	36,398	26,847	449	26,399	9,999	6,368	5,990	377	20.8
2034	30,223	0	7,313	37,536	27,137	438	26,699	10,837	6,408	6,046	362	20.4
2035	29,823	0	7,934	37,757	27,455	424	27,031	10,726	6,447	6,123	324	19.6
2036	33,336	0	7,171	40,507	27,799	420	27,379	13,128	6,504	6,191	313	19.4
2037	38,203	0	7,286	45,489	28,186	416	27,770	17,719	6,784	6,301	483	22.3
2038	39,797	0	7,421	47,218	28,584	366	28,217	19,001	6,709	6,394	315	19.2
2039	43,122	0	7,555	50,677	28,990	327	28,663	22,014	6,895	6,488	407	20.7
2040	44,946	0	7,709	52,655	29,418	291	29,128	23,528	6,998	6,559	439	21.2
2041	45,638	0	7,823	53,461	29,859	295	29,564	23,898	7,020	6,677	343	19.4
2042	45,410	0	7,958	53,368	30,306	127	30,178	23,190	7,041	6,786	255	17.9
2043	47,886	0	8,092	55,978	30,770	135	30,635	25,343	6,981	6,894	87	15.0
2044	48,990	0	8,247	57,237	31,235	142	31,093	26,145	7,182	6,987	195	16.8
2045	48,661	0	8,226	56,887	31,706	150	31,556	25,331	7,182	7,088	94	15.1

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Base' Commodity Pricing - Low Load

Utility Costs (Nominal$)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var 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
2016	$739,824	$541,906	$24,028	$264,331	$26,354	$23,719	$8,458	$690,356	$938,264
2017	$830,653	$554,763	$24,896	$307,308	$25,999	$26,194	$1,976	$754,702	$1,017,086
2018	$861,250	$581,739	$24,106	$325,724	$26,158	$66,393	($765)	$782,804	$1,101,801
2019	$922,919	$639,877	$37,679	$341,425	$28,334	$64,438	($4,902)	$899,159	$1,130,610
2020	$939,556	$639,587	$36,256	$379,343	$28,739	$38,640	($7,714)	$925,283	$1,129,123
2021	$994,864	$743,451	$40,914	$387,812	$33,121	$47,289	($11,542)	$1,065,012	$1,170,897
2022	$1,285,167	$773,929	$326,778	$400,497	$35,303	$55,553	($36,292)	$1,387,130	$1,453,806
2023	$1,326,110	$764,809	$330,713	$401,474	$37,342	$57,357	($38,700)	$1,424,602	$1,454,502
2024	$1,388,898	$813,678	$350,222	$391,969	$40,533	$65,274	($43,103)	$1,548,798	$1,458,671
2025	$1,444,624	$833,704	$343,820	$412,918	$42,556	$78,042	($46,703)	$1,587,457	$1,521,503
2026	$1,504,447	$880,563	$367,844	$417,538	$46,291	$113,081	($50,905)	$1,728,765	$1,550,093
2027	$1,555,504	$900,986	$380,753	$424,528	$50,417	$147,909	($53,958)	$1,865,697	$1,540,441
2028	$1,601,789	$906,146	$376,902	$433,503	$52,292	$179,517	($57,058)	$1,919,744	$1,573,349
2029	$1,673,874	$992,477	$395,851	$441,440	$55,902	$207,973	($63,604)	$2,099,293	$1,604,620
2030	$1,751,344	$932,603	$389,127	$451,458	$56,157	$243,300	($68,848)	$2,166,703	$1,588,437
2031	$1,845,831	$1,070,250	$419,907	$459,098	$62,125	$270,941	($74,958)	$2,451,707	$1,601,488
2032	$1,943,781	$1,104,240	$431,703	$467,711	$65,673	$304,119	($79,232)	$2,647,361	$1,590,635
2033	$2,026,625	$1,112,899	$424,876	$476,529	$67,705	$335,825	$0	$2,741,381	$1,703,079
2034	$2,072,313	$1,170,479	$444,855	$477,996	$71,139	$365,327	$0	$2,885,037	$1,717,071
2035	$2,133,135	$1,189,199	$434,496	$464,242	$73,241	$396,912	$0	$2,986,472	$1,704,752
2036	$2,203,097	$1,404,050	$479,617	$348,961	$94,937	$502,609	$0	$3,325,846	$1,707,424
2037	$2,249,386	$1,749,481	$523,433	$329,813	$132,731	$761,044	$0	$3,899,996	$1,845,892
2038	$2,319,011	$1,894,811	$533,730	$305,152	$153,050	$896,824	$0	$4,190,738	$1,911,839
2039	$2,350,182	$1,989,171	$561,718	$259,778	$159,760	$903,539	$0	$4,347,314	$1,876,834
2040	$2,411,398	$2,161,657	$570,518	$231,748	$181,243	$1,043,600	$0	$4,665,558	$1,934,606
2041	$2,458,234	$2,248,042	$599,243	$226,942	$187,473	$1,047,270	$0	$4,819,021	$1,948,183
2042	$2,521,301	$2,278,118	$609,732	$225,359	$192,000	$1,050,994	$0	$4,918,980	$1,958,524
2043	$2,579,813	$2,503,455	$627,133	$208,973	$218,005	$1,204,210	$0	$5,300,705	$2,040,883
2044	$2,634,498	$2,602,959	$659,913	$194,201	$226,692	$1,210,970	$0	$5,513,479	$2,015,754
2045	$2,711,010	$2,641,703	$662,500	$179,968	$232,337	$1,217,730	$0	$5,650,551	$1,994,696
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$15,503,342	$10,347,796	$2,845,658	$4,064,481	$618,685	$2,349,912	-$239,106	$20,009,407	$15,481,362
CPW of End Effects beyond 2045									$2,323,733
TOTAL Utility Cost, Net CPW (2016$)									$17,805,096

Resource (Capacity) Additions

	(10) Supply-Side (Thermal) + (Current) Purchased Installed	(11)	(12) (Increm) Energy Efficiency+ VVO	(13)	(14) Distributed Solar	(15)	(16) Generic Wind	(17)	(18) Utility Solar	(19)
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	25.6	25.6	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	47.3	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	18.6	65.9	0.2	2.2	0	30	0.0	0.0
2020	(111)	5,114	2.1	68.0	0.3	2.5	0	30	0.0	0.0
2021	(56)	5,058	-7.9	60.1	0.2	2.7	0	30	21.0	21.0
2022	0	5,058	0.7	60.8	0.3	2.9	0	30	21.0	42.0
2023	(109)	4,949	3.2	64.0	0.3	3.2	0	30	21.0	63.0
2024	0	4,949	-6.0	58.1	0.3	3.5	0	30	21.0	84.0
2025	(108)	4,841	6.2	64.3	0.4	3.9	0	30	21.0	105.0
2026	(110)	4,731	8.8	73.1	0.3	4.1	20	50	21.0	126.0
2027	0	4,731	4.1	77.2	0.4	4.5	20	70	21.0	147.0
2028	0	4,731	1.8	79.0	0.4	4.8	20	90	21.0	168.0
2029	(10)	4,721	-1.4	77.6	0.4	5.2	20	110	21.0	189.0
2030	(171)	4,550	-0.3	77.3	0.4	5.6	20	130	21.0	210.0
2031	0	4,550	-2.5	74.8	0.4	6.0	20	150	21.0	231.0
2032	0	4,550	-3.9	70.9	0.5	6.4	20	170	21.0	252.0
2033	(70)	4,480	-1.3	69.6	0.4	6.9	20	190	21.0	273.0
2034	0	4,480	-0.4	69.2	0.5	7.4	20	210	21.0	294.0
2035	0	4,480	-1.3	67.9	0.5	7.8	20	230	21.0	315.0
2036	67	4,547	-1.2	66.7	0.5	8.3	-30	200	21.0	336.0
2037	259	4,806	-1.1	65.6	0.6	8.9	0	200	21.0	357.0
2038	(82)	4,724	-1.2	64.4	0.6	9.5	0	200	21.0	378.0
2039	(259)	4,465	-0.5	63.9	0.6	10.1	0	200	21.0	399.0
2040	93	4,558	-13.0	51.0	0.6	10.7	0	200	21.0	420.0
2041	0	4,558	-13.5	37.4	0.6	11.3	0	200	21.0	441.0
2042	0	4,558	-11.6	25.8	0.7	12.0	0	200	21.0	462.0
2043	(82)	4,476	-0.1	25.7	0.8	12.8	0	200	21.0	483.0
2044	0	4,476	-0.1	25.7	0.7	13.5	0	200	21.0	504.0
2045	0	4,476	-0.1	25.6	0.8	14.4	0	200	21.0	525.0

Energy & Capacity Positions

	(20) Thermal Generation	(21) (Current) Purchased Energy	(22) (New) Generic Wind + Utility Solar	(23)=(20)+(21)+(22) = Market Sales	(24) Load (Net of Embedded EE)	(25) *Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	(26)=(24)-(25) = Net Load Require- ments	(27)=(23)-(26) ENERGY Surplus	(28) Capacity	(29) Peak + Reserves	(30)=(28)-(29) CAPACITY Surplus	(31) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,877	1,942	919	22,738	22,746	16	22,730	8	5,975	5,650	325	20.1
2017	19,094	1,937	917	21,948	22,736	111	22,625	-677	5,973	5,659	315	19.9
2018	18,524	1,937	917	21,378	22,032	329	21,703	-325	5,369	4,876	493	25.1
2019	19,894	1,937	917	22,749	22,170	518	21,651	1,097	5,322	4,910	413	23.1
2020	19,634	1,942	919	22,494	21,724	557	21,167	1,327	5,214	4,791	424	23.6
2021	21,303	1,937	1,051	24,290	21,768	586	21,182	3,108	5,171	4,814	358	22.0
2022	21,399	1,937	1,185	24,521	21,821	607	21,214	3,307	5,193	4,827	366	22.2
2023	21,238	1,937	1,319	24,494	21,860	557	21,302	3,192	5,109	4,826	283	20.3
2024	22,103	1,942	1,457	25,502	21,897	504	21,393	4,109	5,124	4,834	290	20.4
2025	21,657	1,937	1,588	25,182	21,934	478	21,456	3,726	5,044	4,860	184	17.9
2026	22,223	1,937	2,209	26,368	21,972	473	21,499	4,869	4,984	4,874	110	16.2
2027	22,797	1,937	2,830	27,564	22,016	473	21,543	6,021	5,029	4,890	140	16.8
2028	22,222	1,942	3,461	27,624	22,056	451	21,606	6,019	5,072	4,894	178	17.7
2029	22,904	1,648	4,073	28,625	22,079	427	21,652	6,973	5,102	4,902	200	18.2
2030	21,973	1,620	4,694	28,288	22,091	411	21,680	6,608	4,973	4,912	61	15.0
2031	23,532	1,620	5,315	30,468	22,115	390	21,725	8,743	5,011	4,924	88	15.6
2032	23,790	1,581	5,952	31,323	22,169	375	21,794	9,529	5,049	4,930	119	16.3
2033	23,097	0	6,558	29,654	22,220	362	21,858	7,797	5,019	4,958	61	15.0
2034	23,446	0	7,179	30,625	22,258	355	21,903	8,722	5,060	4,959	101	15.9
2035	22,947	0	7,800	30,747	22,294	346	21,948	8,799	5,100	4,972	128	16.5
2036	26,204	0	7,036	33,240	22,333	343	21,990	11,250	5,158	4,973	184	17.8
2037	31,056	0	7,152	38,208	22,374	340	22,034	16,174	5,437	5,002	435	23.5
2038	32,562	0	7,286	39,848	22,415	340	22,075	17,773	5,375	5,014	361	21.8
2039	33,522	0	7,421	40,942	22,466	342	22,124	18,818	5,138	5,028	110	16.1
2040	35,219	0	7,574	42,793	22,501	299	22,202	20,591	5,240	5,017	222	18.6
2041	35,970	0	7,689	43,659	22,540	255	22,285	21,374	5,248	5,040	208	18.3
2042	35,736	0	7,823	43,559	22,575	127	22,447	21,112	5,258	5,056	202	18.1
2043	38,051	0	7,958	46,009	22,609	135	22,474	23,535	5,198	5,066	132	16.6
2044	38,922	0	8,113	47,035	22,648	142	22,505	24,529	5,219	5,065	154	17.0
2045	38,581	0	8,226	46,807	22,686	150	22,536	24,271	5,241	5,072	169	17.4

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Base' Commodity Pricing - Accelerated Gas Retirement

	Utility Costs (Nominal$)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM and OGC	(Incremental) Fixed & (All) Var Costs	(Incremental) Capital + Renewable + EE + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2016	$747,681	$541,906	$24,028	$261,604	$27,434	$32,754	$8,458	$695,055	$948,810
2017	$845,540	$554,763	$24,896	$301,566	$27,323	$37,443	$1,976	$761,050	$1,032,458
2018	$884,153	$581,739	$24,106	$313,073	$27,867	$91,364	($765)	$792,882	$1,128,655
2019	$953,586	$639,877	$37,679	$331,469	$31,701	$103,250	($4,902)	$919,465	$1,173,194
2020	$976,922	$639,587	$36,256	$367,706	$32,641	$72,153	($7,714)	$948,269	$1,169,281
2021	$1,039,877	$782,337	$40,914	$374,823	$45,037	$159,868	($11,542)	$1,143,016	$1,288,297
2022	$1,350,140	$845,389	$335,528	$388,032	$49,565	$168,132	($36,292)	$1,522,916	$1,577,578
2023	$1,401,002	$835,616	$339,137	$390,022	$51,618	$169,935	($38,700)	$1,559,063	$1,589,567
2024	$1,475,033	$888,686	$359,062	$381,586	$55,290	$177,852	($43,103)	$1,691,718	$1,602,688
2025	$1,541,808	$876,947	$348,744	$400,962	$55,629	$188,232	($46,703)	$1,697,710	$1,667,910
2026	$1,613,445	$929,156	$373,374	$407,768	$59,463	$220,181	($50,905)	$1,845,371	$1,707,110
2027	$1,675,648	$949,195	$386,199	$414,245	$63,248	$251,973	($53,958)	$1,980,454	$1,706,097
2028	$1,734,037	$958,969	$382,866	$422,697	$65,654	$283,582	($57,058)	$2,041,872	$1,748,874
2029	$1,821,484	$1,049,938	$402,321	$430,304	$69,787	$310,162	($63,604)	$2,230,334	$1,790,059
2030	$1,915,689	$1,032,667	$400,636	$436,867	$72,199	$343,436	($68,848)	$2,348,615	$1,784,030
2031	$2,028,075	$1,258,362	$441,241	$445,824	$91,097	$483,198	($74,958)	$2,783,794	$1,889,046
2032	$2,143,176	$1,388,509	$463,524	$451,206	$108,846	$626,769	($79,232)	$3,145,754	$1,957,044
2033	$2,242,538	$1,418,440	$458,943	$459,941	$112,099	$656,181	$0	$3,276,109	$2,072,034
2034	$2,302,690	$1,491,146	$480,391	$461,416	$116,359	$683,943	$0	$3,433,399	$2,102,545
2035	$2,380,181	$1,608,050	$480,637	$447,046	$133,745	$832,658	$0	$3,704,778	$2,177,537
2036	$2,468,111	$1,707,578	$512,607	$334,317	$141,724	$815,601	$0	$3,858,253	$2,121,684
2037	$2,530,899	$1,906,872	$539,992	$318,986	$163,502	$948,149	$0	$4,196,012	$2,212,387
2038	$2,621,363	$2,062,151	$551,348	$294,340	$184,887	$1,083,929	$0	$4,504,140	$2,293,879
2039	$2,668,425	$2,321,300	$597,407	$248,241	$209,801	$1,223,028	$0	$4,921,599	$2,346,603
2040	$2,752,236	$2,352,562	$590,625	$221,206	$215,631	$1,229,698	$0	$5,019,637	$2,342,319
2041	$2,819,461	$2,424,318	$617,596	$203,764	$220,617	$1,227,423	$0	$5,138,184	$2,374,994
2042	$2,906,019	$2,454,919	$628,120	$202,365	$226,161	$1,231,969	$0	$5,248,030	$2,401,522
2043	$2,988,400	$2,692,224	$646,782	$199,355	$253,324	$1,385,184	$0	$5,647,823	$2,517,445
2044	$3,066,275	$2,802,704	$680,771	$185,423	$260,937	$1,381,845	$0	$5,861,619	$2,516,337
2045	$3,170,349	$2,842,708	$683,509	$171,944	$267,258	$1,388,605	$0	$6,005,621	$2,518,753
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$16,756,595	$11,275,041	$2,945,908	$3,941,892	$793,392	$3,612,670	-$239,106	$21,777,875	$17,308,517
CPW of End Effects beyond 2045									$2,934,236
TOTAL Utility Cost, Net CPW (2016$)									$20,242,753

	Resource (Capacity) Additions									
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	Supply-Side (Thermal) + (Current) Purchased Installed		(Increm) Energy Efficiency+ VVO		Distributed Solar		Generic Wind		Utility Solar	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,777	0.0	0.0	1.5	1.5	30	30	21.0	21.0
2017	(27)	5,750	25.6	25.6	0.2	1.8	0	30	4.2	25.2
2018	(735)	5,015	42.7	68.3	0.2	2.0	0	30	0.0	25.2
2019	(66)	4,949	40.0	108.3	0.2	2.2	0	30	21.0	46.2
2020	(108)	4,841	14.8	123.1	0.3	2.5	0	30	0.0	46.2
2021	325	5,166	-13.8	109.3	0.2	2.7	0	30	21.0	67.2
2022	0	5,166	-2.4	106.9	0.3	2.9	0	30	21.0	88.2
2023	0	5,166	0.0	106.9	0.3	3.2	0	30	21.0	109.2
2024	0	5,166	-6.3	100.6	0.3	3.5	0	30	21.0	130.2
2025	(171)	4,995	-7.6	93.0	0.4	3.9	0	30	21.0	151.2
2026	0	4,995	-5.4	87.5	0.3	4.1	20	50	21.0	172.2
2027	0	4,995	-8.4	79.1	0.4	4.5	20	70	21.0	193.2
2028	0	4,995	0.3	79.4	0.4	4.8	20	90	21.0	214.2
2029	(10)	4,985	-2.8	76.6	0.4	5.2	20	110	21.0	235.2
2030	0	4,985	-2.7	73.9	0.4	5.6	20	130	21.0	256.2
2031	67	5,052	-2.0	71.9	0.4	6.0	20	150	21.0	277.2
2032	81	5,133	-3.4	68.5	0.5	6.4	20	170	21.0	298.2
2033	(70)	5,063	-13.6	54.9	0.4	6.9	20	190	21.0	319.2
2034	0	5,063	-13.0	42.0	0.5	7.4	20	210	21.0	340.2
2035	93	5,156	-12.6	29.4	0.5	7.8	20	230	21.0	361.2
2036	0	5,156	-0.9	28.5	0.5	8.3	-30	200	21.0	382.2
2037	178	5,334	-0.9	27.6	0.6	8.9	0	200	21.0	403.2
2038	(82)	5,252	-1.0	26.7	0.6	9.5	0	200	21.0	424.2
2039	177	5,428	-0.3	26.3	0.6	10.1	0	200	21.0	445.2
2040	0	5,428	-0.2	26.1	0.6	10.7	0	200	21.0	466.2
2041	0	5,428	-0.2	25.9	0.6	11.3	0	200	0.0	466.2
2042	0	5,428	-0.1	25.8	0.7	12.0	0	200	16.8	483.0
2043	(82)	5,346	-0.1	25.7	0.8	12.8	0	200	21.0	504.0
2044	0	5,346	-0.1	25.7	0.7	13.5	0	200	0.0	504.0
2045	0	5,346	-0.1	25.6	0.8	14.4	0	200	21.0	525.0

	Energy & Capacity Positions											
	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)
	Thermal Generation	(Current) Purchased Energy	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Require- ments	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,877	1,942	1,054	22,872	22,988	16	22,972	-99	5,829	5,710	119	16.0
2017	19,094	1,937	1,078	22,109	23,144	111	23,033	-924	5,832	5,760	72	15.0
2018	18,524	1,937	1,078	21,540	22,618	406	22,212	-672	5,140	5,006	134	16.6
2019	19,894	1,937	1,212	23,044	22,906	675	22,231	813	5,135	5,073	63	15.0
2020	19,634	1,942	1,215	22,790	22,588	757	21,831	959	5,042	4,981	61	15.0
2021	22,284	1,937	1,346	25,567	22,752	770	21,982	3,585	5,375	5,032	343	21.3
2022	23,038	1,937	1,481	26,456	22,924	779	22,145	4,311	5,394	5,071	322	20.8
2023	22,786	1,937	1,615	26,337	23,094	720	22,374	3,963	5,415	5,099	316	20.6
2024	23,698	1,942	1,753	27,393	23,255	659	22,595	4,797	5,430	5,133	296	20.2
2025	22,801	1,937	1,883	26,621	23,409	583	22,826	3,794	5,273	5,187	86	15.5
2026	23,444	1,937	2,505	27,885	23,563	525	23,039	4,846	5,308	5,227	81	15.4
2027	23,992	1,937	3,126	29,054	23,717	481	23,236	5,818	5,341	5,267	74	15.2
2028	23,481	1,942	3,757	29,180	23,877	452	23,425	5,754	5,383	5,298	85	15.4
2029	24,235	1,648	4,368	30,251	24,026	421	23,605	6,646	5,412	5,334	77	15.2
2030	23,821	1,620	4,989	30,431	24,164	397	23,767	6,664	5,450	5,373	78	15.2
2031	27,092	1,620	5,611	34,323	24,298	378	23,920	10,403	5,557	5,410	147	16.7
2032	29,202	1,581	6,248	37,031	24,443	365	24,079	12,953	5,676	5,436	240	18.6
2033	28,741	0	6,853	35,594	24,587	307	24,280	11,315	5,634	5,486	148	16.7
2034	29,231	0	7,474	36,705	24,732	255	24,478	12,227	5,662	5,511	151	16.7
2035	30,547	0	8,095	38,643	24,876	206	24,670	13,973	5,784	5,548	236	18.4
2036	31,786	0	7,332	39,118	25,019	204	24,815	14,303	5,775	5,572	203	17.7
2037	34,249	0	7,447	41,697	25,174	202	24,972	16,725	5,973	5,628	345	20.6
2038	35,847	0	7,582	43,429	25,337	203	25,134	18,294	5,912	5,668	244	18.5
2039	39,204	0	7,716	46,920	25,508	206	25,303	21,618	6,110	5,709	401	21.6
2040	38,675	0	7,870	46,545	25,682	209	25,473	21,073	6,131	5,727	405	21.6
2041	39,232	0	7,850	47,083	25,852	214	25,639	21,444	6,131	5,781	351	20.5
2042	38,977	0	7,958	46,935	26,019	127	25,892	21,043	6,149	5,827	322	19.9
2043	41,396	0	8,092	49,488	26,189	135	26,055	23,434	6,089	5,868	220	17.9
2044	42,345	0	8,113	50,458	26,359	142	26,217	24,240	6,089	5,896	193	17.3
2045	41,989	0	8,226	50,215	26,529	150	26,380	23,835	6,111	5,931	180	17.0

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Base' Commodity Pricing - Early Coal Retirement

Utility Costs (Nominal$)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var 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
2016	$747,681	$541,906	$24,028	$264,331	$26,354	$23,719	$8,458	$690,356	$946,121
2017	$845,540	$554,763	$24,896	$307,308	$25,999	$26,194	$1,976	$754,702	$1,031,974
2018	$884,153	$581,739	$24,106	$325,724	$26,158	$66,393	($765)	$782,804	$1,124,703
2019	$953,586	$639,877	$37,679	$341,425	$28,334	$64,438	($4,902)	$899,159	$1,161,278
2020	$976,922	$639,587	$36,256	$379,343	$29,692	$46,379	($7,714)	$930,467	$1,169,997
2021	$1,039,877	$743,451	$40,914	$387,812	$34,469	$57,191	($11,542)	$1,072,579	$1,219,594
2022	$1,350,140	$773,929	$326,778	$400,497	$37,179	$68,728	($36,292)	$1,399,742	$1,521,217
2023	$1,401,002	$764,809	$330,713	$401,474	$39,745	$81,712	($38,700)	$1,442,074	$1,538,682
2024	$1,475,033	$813,678	$350,222	$391,713	$43,490	$92,184	($43,103)	$1,571,138	$1,552,079
2025	$1,541,808	$911,250	$352,910	$412,410	$55,860	$186,939	($46,703)	$1,723,944	$1,690,529
2026	$1,613,445	$912,439	$304,085	$396,619	$62,504	$314,249	($50,905)	$1,708,437	$1,843,998
2027	$1,675,648	$955,053	$315,829	$404,446	$66,386	$346,041	($53,958)	$1,839,855	$1,869,589
2028	$1,734,037	$964,912	$311,266	$411,521	$69,050	$377,650	($57,058)	$1,900,685	$1,910,694
2029	$1,821,484	$1,050,161	$330,155	$419,443	$73,643	$404,231	($63,604)	$2,090,331	$1,945,181
2030	$1,915,689	$1,126,033	$341,313	$429,077	$87,916	$543,020	($68,848)	$2,343,157	$2,031,042
2031	$2,028,075	$1,264,299	$366,823	$435,927	$95,493	$574,590	($74,958)	$2,645,389	$2,044,861
2032	$2,143,176	$1,335,990	$379,643	$444,134	$101,361	$607,193	($79,232)	$2,876,728	$2,055,536
2033	$2,242,538	$1,365,912	$373,394	$452,416	$104,918	$638,614	$0	$2,998,655	$2,179,137
2034	$2,302,690	$1,427,905	$393,414	$453,293	$109,789	$668,976	$0	$3,154,297	$2,201,770
2035	$2,380,181	$1,486,798	$391,276	$439,052	$113,930	$700,560	$0	$3,306,609	$2,205,188
2036	$2,468,111	$1,714,072	$428,494	$323,244	$136,735	$807,228	$0	$3,643,527	$2,234,356
2037	$2,530,899	$1,916,068	$454,936	$303,563	$157,858	$936,977	$0	$3,973,511	$2,326,789
2038	$2,621,363	$2,228,025	$482,254	$278,376	$195,654	$1,199,092	$0	$4,521,277	$2,483,487
2039	$2,668,425	$2,326,982	$508,719	$232,465	$202,339	$1,202,987	$0	$4,674,405	$2,467,513
2040	$2,752,236	$2,526,038	$526,189	$203,896	$226,677	$1,345,436	$0	$5,048,428	$2,532,043
2041	$2,819,461	$2,605,013	$544,856	$198,547	$233,483	$1,352,196	$0	$5,174,720	$2,578,836
2042	$2,906,019	$2,641,964	$554,182	$196,416	$239,726	$1,358,956	$0	$5,282,529	$2,614,734
2043	$2,988,400	$2,883,599	$571,954	$179,799	$267,327	$1,512,172	$0	$5,684,466	$2,718,784
2044	$3,066,275	$2,992,669	$603,823	$165,373	$277,954	$1,522,942	$0	$5,901,615	$2,727,421
2045	$3,170,349	$3,052,381	$615,440	$151,475	$284,610	$1,526,439	$0	$6,078,197	$2,722,497
Cumulative Present Worth $000 (2016$)									
Utility CPW 2016-2045	$16,756,595	$11,274,315	$2,600,310	$3,957,589	$769,921	$3,608,460	-$239,106	$20,884,712	$17,843,371
CPW of End Effects beyond 2045									$3,171,589
TOTAL Utility Cost, Net CPW (2016$)									$21,014,960

Resource (Capacity) Additions

	(10) Supply-Side (Thermal) + (Current) Purchased Installed	(11)	(12) (Increm) Energy Efficiency+ VVO	(13)	(14) Distributed Solar	(15)	(16) Generic Wind	(17)	(18) Utility Solar	(19)
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2016	0	5,943	0.0	0.0	1.5	1.5	30	30	0.0	0.0
2017	(27)	5,916	25.6	25.6	0.2	1.8	0	30	0.0	0.0
2018	(626)	5,290	21.7	47.3	0.2	2.0	0	30	0.0	0.0
2019	(66)	5,224	18.6	65.9	0.2	2.2	0	30	0.0	0.0
2020	(110)	5,114	2.1	68.0	0.3	2.5	0	30	16.8	16.8
2021	(56)	5,058	4.5	72.6	0.2	2.7	0	30	21.0	37.8
2022	0	5,058	14.4	87.0	0.3	2.9	0	30	21.0	58.8
2023	(109)	4,949	18.4	105.3	0.3	3.2	0	30	21.0	79.8
2024	0	4,949	8.1	113.4	0.3	3.5	0	30	21.0	100.8
2025	327	5,276	-8.0	105.4	0.4	3.9	0	30	21.0	121.8
2026	(243)	5,033	-6.0	99.4	0.3	4.1	20	50	21.0	142.8
2027	0	5,033	-9.3	90.1	0.4	4.5	20	70	21.0	163.8
2028	0	5,033	1.2	91.3	0.4	4.8	20	90	21.0	184.8
2029	(10)	5,023	-3.3	88.0	0.4	5.2	20	110	21.0	205.8
2030	264	5,287	-3.4	84.7	0.4	5.6	20	130	21.0	226.8
2031	0	5,287	-2.1	82.5	0.4	6.0	20	150	21.0	247.8
2032	0	5,287	-3.5	79.0	0.5	6.4	20	170	21.0	268.8
2033	(70)	5,217	-1.2	77.8	0.4	6.9	20	190	21.0	289.8
2034	0	5,217	0.4	78.2	0.5	7.4	20	210	21.0	310.8
2035	0	5,217	-1.2	76.9	0.5	7.8	20	230	21.0	331.8
2036	67	5,284	-0.9	76.1	0.5	8.3	-30	200	21.0	352.8
2037	(176)	5,108	-14.2	61.9	0.6	8.9	0	200	21.0	373.8
2038	353	5,461	-12.4	49.4	0.6	9.5	0	200	21.0	394.8
2039	(259)	5,202	-10.6	38.8	0.6	10.1	0	200	21.0	415.8
2040	93	5,295	-0.2	38.6	0.6	10.7	0	200	21.0	436.8
2041	0	5,295	-0.2	38.4	0.6	11.3	0	200	21.0	457.8
2042	0	5,295	-0.1	38.3	0.7	12.0	0	200	21.0	478.8
2043	(82)	5,213	-0.1	38.2	0.8	12.8	0	200	21.0	499.8
2044	0	5,213	2.0	40.2	0.7	13.5	0	200	21.0	520.8
2045	0	5,213	13.3	53.5	0.8	14.4	0	200	4.2	525.0

Energy & Capacity Positions

	(20) Thermal Generation	(21) (Current) Purchased Energy	(22) (New) Generic Wind + Utility Solar	(23)=(20)+(21)+(22) = Market Sales	(24) Load (Net of Embedded EE)	(25) *Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	(26)=(24)-(25) = Net Load Require- ments	(27)=(23)-(26) ENERGY Surplus	(28) Capacity	(29) Peak + Reserves	(30)=(28)-(29) CAPACITY Surplus	(31) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2016	19,877	1,942	919	22,738	22,988	16	22,972	-234	5,975	5,710	264	18.9
2017	19,094	1,937	917	21,948	23,144	111	23,033	-1,085	5,973	5,760	213	17.8
2018	18,524	1,937	917	21,378	22,618	329	22,289	-911	5,369	5,006	364	21.9
2019	19,894	1,937	917	22,749	22,906	518	22,388	361	5,322	5,073	249	19.2
2020	19,634	1,942	1,027	22,602	22,588	557	22,031	571	5,231	4,981	250	19.3
2021	21,303	1,937	1,158	24,397	22,752	631	22,122	2,276	5,201	5,032	169	17.4
2022	21,399	1,937	1,293	24,629	22,924	702	22,222	2,406	5,237	5,071	165	17.3
2023	21,238	1,937	1,427	24,601	23,094	726	22,368	2,233	5,167	5,099	68	15.1
2024	22,103	1,942	1,565	25,609	23,255	737	22,518	3,091	5,197	5,133	63	15.0
2025	23,265	1,937	1,695	26,897	23,409	652	22,757	4,140	5,537	5,187	350	21.3
2026	21,177	1,937	2,317	25,430	23,563	586	22,977	2,453	5,329	5,227	102	15.8
2027	21,741	1,937	2,938	26,615	23,717	534	23,183	3,432	5,361	5,267	94	15.6
2028	21,278	1,942	3,568	26,788	23,877	504	23,373	3,414	5,404	5,298	106	15.9
2029	22,144	1,648	4,180	27,972	24,026	468	23,558	4,414	5,432	5,334	98	15.7
2030	23,479	1,620	4,801	29,900	24,164	439	23,724	6,176	5,734	5,373	361	21.2
2031	25,130	1,620	5,423	32,174	24,298	419	23,879	8,294	5,773	5,410	364	21.2
2032	25,777	1,581	6,060	33,418	24,443	405	24,039	9,379	5,811	5,436	376	21.5
2033	25,301	0	6,665	31,966	24,587	391	24,196	7,770	5,781	5,486	295	19.7
2034	25,811	0	7,286	33,097	24,732	386	24,346	8,752	5,823	5,511	313	20.0
2035	25,790	0	7,907	33,698	24,876	378	24,497	9,200	5,864	5,548	316	20.1
2036	28,914	0	7,144	36,057	25,019	377	24,642	11,415	5,921	5,572	349	20.7
2037	31,412	0	7,259	38,672	25,174	326	24,848	13,824	5,753	5,628	125	16.1
2038	35,406	0	7,394	42,800	25,337	285	25,052	17,748	6,115	5,668	447	22.6
2039	36,316	0	7,528	43,844	25,508	251	25,257	18,587	5,867	5,709	158	16.7
2040	38,473	0	7,682	46,155	25,682	254	25,428	20,727	5,981	5,727	255	18.6
2041	38,821	0	7,797	46,618	25,852	259	25,594	21,024	6,003	5,781	222	18.0
2042	38,583	0	7,931	46,514	26,019	127	25,892	20,622	6,024	5,827	197	17.4
2043	41,035	0	8,065	49,100	26,189	135	26,055	23,045	5,964	5,868	96	15.5
2044	41,932	0	8,220	50,153	26,359	142	26,217	23,936	5,988	5,896	92	15.4
2045	41,973	0	8,226	50,199	26,529	150	26,380	23,819	6,006	5,931	74	15.0

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Exhibit I: IRP Changes from February Draft

IRP Changes from February Draft to Final Report

	DRAFT	FINAL
LOAD/DEMAND	2014 Load Forecast	2015 Load Forecast - 50MW Demand Reduction (1.0%) - 350 GWh Energy Reduction (1.5%)
COMMODITY PRICING	August 2013 Long-Term Forecast	May 2015 Long-Term Forecast - ~$0.80/mmBtu *reduction* in Natural Gas - Maintain $15/tonne CO_2 proxy effective '22
RETIREMENTS	667MW (8 Smaller, older gas-steam units) thru '34	No Change
NEW BUILDS	Peaking capacity added in 2023, 2025	NGCC capacity added in 2026
WIND	No additional early (PTC-advantaged wind resources; 1,700MW (nameplate) beginning 2021 thru 2031 (w/o PTC) at 100-200MW/year	200MW (nameplate) in 2017 (w/PTC) 1,000MW (nameplate) beginning 2023 thru 2032 (w/o PTC) at 100MW/yr
SOLAR (Utility-Scale)	No additional early (30% ITC-advantaged) solar resources; 750MW (namplate) beginning 2020 thru 2034 (w/10% ITC at 50MW/year	50MW (nameplate) in 2016 (w/30% ITC) 800MW (nameplate) beginning 2019 thru 2034 (w/ 10% ITC) at 50MW/yr
SOLAR (Distributed)	5% annual increments from historical levels (~50MW by '34)	No Change
ENERGY EFFICIENCY **(Incremental Post '17)**	~18MW per year (~85GWh/yr, or 0.7%)	~8MW per year (~40GWh/yr; or 0.33%)
VOLT VAR OPTIMIZATION	1st tranche (26MW, 46 circuits) in 2017; Subsequent tranches in '18, '22, '26-30 (100MW total)	No Change Subsequent tranches in '20-25 (92MW total)

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Exhibit J: Acronyms

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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

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ACRONYM	DEFINITION
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

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ACRONYM	DEFINITION
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 CAR Optimization