2018
Integrated Resource Plan
Filed in Compliance with 17.7.3 NMAC

Southwestern Public Service Company

July 16, 2018

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond Southwestern Public Service Company's, a New Mexico corporation ("SPS") control, and many of which could have a significant impact on SPS's operations, results of operations, and financial condition, and could cause actual results to differ materially from those anticipated. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.xcelenergy.com.

The information in this document is based on the best available information at the time of preparation. SPS undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, except to the extent the events or circumstances constitute material changes in the Integrated Resource Plan ("IRP") that are required to be reported to the New Mexico Public Regulation Commission ("Commission") pursuant to 17.7.3.10 NMAC.

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Glossary of Acronyms and Defined Terms

Acronym/Defined Term	Meaning
2018 IRP	Integrated Resource Plan, filed July 16, 2018
Action Plan	IRP Implementation During the First Four Years of the IRP
Action Plan Period	2018 IRP implementation from 2019-2022
ANPR	Advance Notice of Proposed Rulemaking
BA	Balancing Authority
BART	Best Available Retrofit Technology
BAU	Business as Usual
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbine
CCR	Coal Combustion Residuals
CCR Rule	Coal Combustion Residual Rule
CER	Capital Expenditure Recovery
CERA	Cambridge Energy Research Associates
CO_2	Carbon dioxide
Commission	New Mexico Public Regulation Commission
CPP	Clean Power Plan

Acronym/Defined Term	Meaning
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
CWA	Clean Water Act
DG	Distributed Generation
DSM	Demand-Side Management
ECC	Economic Carrying Charge
EE	Energy Efficiency
EGU	Electric Generating Unit
ELG	Effluent Limitation Guidelines
EOY	End of Year
EPA	Environmental Protection Agency
EUEA	Efficiency Use of Energy Act
FOM	Fixed Operations and Maintenance
GAF	Generations and Fuel
GHG	Green House Gas
Global Insight	IHS Global Insight, Inc.
GPM	Gallons per Minute
GSP	Gross State Product
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
ICO	Interruptible Credit Option

Acronym/Defined Term	Meaning
IM	Integrated Marketplace
IRP	Integrated Resource Plan
IRP Rule	17.7.3 NMAC
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-hour
L&R	Loads and Resources
LED	Light Emitting Diode
LFA	Load Forecast Adjustment
LM	Load Management
MATS	Mercury and Air Toxics Rule
MMBtu	Million British Thermal Unit
MMBtu/hr	Million British Thermal Unit per hour
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
New Mexico Cooperatives	Farmers Electric Cooperative, Inc., Central Valley Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc.
NO_2	Nitrogen Dioxide

Acronym/Defined Term	**Meaning**
NOx	Nitrous Oxide
NPDES	National Pollutant Discharge Elimination System
O&M	Operations and Maintenance
PIRA	Petroleum Industry Research Associates
Planning Period	2019-2038 Planning Period
PM	Particulate Matter
PPA	Purchased Power Agreement
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value of Revenue Requirement
QF	Qualifying Facility
RCRA	Resource Conservation and Recovery Act
RCT	Reasonable Cost Threshold
RFP	Request for Proposal
RHR	Regional Haze Rule
RPS	Renewable Portfolio Standard
RPSA	Replacement Power Sales Agreement
SIP	State Implementation Plan
SO_2	sulfur dioxide
SPP	Southwest Power Pool

Acronym/Defined Term	**Meaning**
SPS	Southwestern Public Service Company, a New Mexico corporation
Staff	Utility Division Staff of the Commission
T1	Tolk Unit 1
T2	Tolk Unit 2
TCEQ	Texas Commission on Environmental Quality
TOU	Time of Use
VOM	Variable Operations and Maintenance
WACC	Weighted-Average Cost of Capital
WTMPA	West Texas Municipal Power Agency
Xcel Energy	Xcel Energy Inc.

Section 1. EXECUTIVE SUMMARY

SPS, a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), presents its 2018 integrated resource plan ("2018 IRP") in accordance with the Efficient Use of Energy Act (NMSA 1978, § 62-17-1, *et seq.*, "EUEA") and 17.7.3 NMAC (the "IRP Rule"). SPS's 2018 IRP: (i) identifies the most reasonable cost-effective resource portfolio to meet all applicable regulatory requirements and to supply the energy needs of New Mexico customers during the 2019-2038 Planning Period ("Planning Period"); and (ii) provides an Action Plan discussing 2018 IRP implementation from 2019-2022 ("Action Plan Period").

SPS's 2018 IRP was developed by considering studies, forecasts, regulatory predictions, and information exchanged through a public advisory process, combined with historical data, existing and potential resource capabilities, and costs associated with alternative generation resource expansion plans. SPS's analysis considered both short- and long-term cost impacts to its customers, while balancing the ability to deliver the expected level of service to those customers while meeting applicable regulatory and operational obligations. The ultimate goal of SPS's 2018 IRP was to develop a reliable, robust, cost-effective, and environmentally-focused generation expansion plan.

With respect to the Planning Period, the age of the SPS generation fleet and the proposed early retirement of Tolk Station, are both the most significant drivers impacting the need for new generation. SPS's loads and resources ("L&R") base forecast indicates that it will have a surplus capacity of 382 megawatts ("MW") in 2028, but will need approximately 2,896 MW in 2038. Thus, SPS's planning process indicates that SPS's optimal resource plan for the Planning Period would be to add wind, simple cycle combustion turbine ("CT") generation, and combined cycle ("CC") energy, and to enter into favorable purchased power agreements ("PPA"), in order to lower total system costs relative to other available options.

Many factors that may impact this IRP and could potentially require updates to the Action Plan and will be the subject of future IRPs, including the 2021 and 2024 plans. These factors include: (i) new and revised environmental regulations (more stringent than existing requirements); (ii) the impacts of the Southwest Power Pool ("SPP") Integrated Marketplace ("IM") on costs, generation cycling, planned generation retirement dates, and reserve margins; (iii) customer expectations; (iv) technological advances; (v) groundwater aquifer depletion at SPS's Tolk Station; (vi) an aging generation fleet; (vii) load growth variability; (viii) changes to tax credits and incentives; (ix) gas price forecast variability; and (x) Commission Rule 572 renewable portfolio standard ("RPS") acquisitions. Each of these factors is discussed in more detail in the 2018 IRP.

Accordingly, and as mentioned earlier, it is very likely that SPS will need to modify its Action Plan and there may be significant changes between the 2018 IRP and future IRPs. Most importantly, the resource plan is presented based on the best information available at the time, and with recognition that SPS will have to be flexible in resource plan execution over the Action Plan and Planning Periods to: (1) address expected short-term resource needs; and (2) respond to the uncertainties associated with the expected long-term needs in the outer years of the Planning Period. SPS will continue to actively monitor developments in these areas. However, as presented, SPS's 2018 IRP provides a well-rounded resource portfolio that addresses customer cost impacts, environmental impacts, and operational issues, and complies with applicable regulatory requirements. Finally, SPS is not requesting approval of any new resource actuations in this proceeding.

The remainder of the IRP is organized as follows: (i) Section 2 provides a background; (ii) Section 3 discusses existing supply- and demand-side resources, including a discussion of pending and proposed environmental regulations, reserve margin/reliability requirements, the impact of an aging generation fleet, load variability, and critical facilities; (iii) Section 4 provides SPS's load forecast; (iv) Section 5 presents SPS's L&R table for the Planning Period; (v) Section 6 identifies the resource options; (vi) Section 7 presents a determination of the most cost-effective resource portfolio and alternative portfolios; (vii) Section 8 discusses the public advisory process; and (viii) Section 9 presents SPS's Action Plan.

Section 2. BACKGROUND

New Mexico adopted the requirement for a formal IRP process in 2005 with the passage of the EUEA[1], and, in 2007, the Commission promulgated the IRP Rule. The objective of the IRP is to identify the most cost-effective portfolio of resources to supply the energy needs of customers while giving preference to resources that minimize environmental impacts whose costs and service quality are equivalent (17.7.3.6 NMAC).

Specifically, the IRP Rule requires that affected utilities provide the following details (17.7.3.9(B) NMAC):

(1) description of existing electric supply-side and demand-side resources;
(2) current load forecasts;
(3) load and resource ("L&R") tables;
(4) identification of resource options;
(5) description of the resource and fuel diversity;
(6) identification of critical facilities susceptible to supply-source or other failures;
(7) determination of the most cost-effective resource portfolio and alternative portfolios;
(8) description of the public advisory process;
(9) Action Plan; and
(10) other information that the utility finds may aid the Commission in reviewing the utility's planning process.

Please refer to Appendix L for a table indicating where each of the rule requirements is met in this filing.

SPS filed its initial New Mexico IRP on July 16, 2009 (Case No. 09-00285-UT), its second IRP on July 16, 2012 (Case No. 12-00298-UT), and its third IRP on July 16, 2015 (Case No. 15-00217-UT); all three IRPs were accepted by the Commission without modification. SPS's

[1] The EUEA was most recently amended in 2017.

present filing, the 2018 IRP, includes all of the required components of the IRP Rule. In addition to the required components, SPS has provided additional information, particularly in relation to proposed modifications to existing environmental standards and proposed new environmental regulations (17.7.3.9(B)(10) NMAC).

Section 3. EXISTING SUPPLY-SIDE & DEMAND-SIDE RESOURCES

3.01 - SPS-Owned Resources

SPS owns a number of supply-side generation resources, located in both New Mexico and Texas, which serve its entire system. These supply-side resources had a 2017 summer generation capacity of 4,485 MW and were comprised of a mix of coal-fired, gas steam, and simple-cycle CT units. Of the 4,485 MW of 2017 summer peak capacity, the Harrington and Tolk Station coal-fired generation units totaled approximately 2,107 MW; gas steam units totaled 1,750 MW; and simple-cycle CT units totaled 628 MW.

Historical cost information, location, net dependable capacity (MW), capital costs (gross plant balance), fixed and variable operation and maintenance costs ("FOM" and "VOM"), fuel costs, and purchased power costs for calendar year 2017 are provided in Table 3-1 (next page).

Table 3-1: Location, Net Dependable Capacity, Retirement, & Cost Data for all Generating Units - Calendar Year 2017

Southwestern Public Service Company
Location, Net Dependable Capacity, Retirement, & Cost Data for all Generating Units
Year Ended December 31, 2017

Unit Name	Location	Dependable Capacity (MW)	Depreciation Retirement Date	Capital $ (Gross plant)	O&M $ Note (1)	Fuel $ Note (2)	Net Unit Heat Rate (Btu/kWh)	Annual Capacity Factor
Steam Production - Gas/Oil								
Jones Unit 1	Lubbock Co., TX	243	2031	56,505,515	7,781,168	27,525,230	11,725	15%
Jones Unit 2	Lubbock Co., TX	243	2034	42,974,162			11,653	21%
Plant X Unit 1	Lamb Co., TX	41	2019	12,936,222	5,177,841	19,237,688		0%
Plant X Unit 2	Lamb Co., TX	90	2020	24,622,309			13,209	8%
Plant X Unit 3	Lamb Co., TX	93	2024	18,855,781			10,325	10%
Plant X Unit 4	Lamb Co., TX	191	2027	35,719,494			11,502	19%
Steam Production - Gas								
Cunningham Unit 1	Lea Co., NM	73	2019	17,959,658	6,368,910	24,723,641	11,926	21%
Cunningham Unit 2	Lea Co., NM	183	2025	35,112,060			10,826	32%
Maddox Unit 1	Lea Co., NM	112	2028	26,215,290	2,758,834	13,598,149	11,192	38%
Nichols Unit 1	Potter Co., TX	112	2022	25,135,111	6,564,463	18,615,269	12,162	13%
Nichols Unit 2	Potter Co., TX	112	2023	26,429,204			12,349	9%
Nichols Unit 3	Potter Co., TX	250	2030	43,879,171			12,639	9%
Steam Production - Coal								
Harrington Unit 1	Potter Co., TX	342	2036	164,388,476	20,746,232	82,992,794	10,897	43%
Harrington Unit 2	Potter Co., TX	357	2038	176,463,752			10,737	53%
Harrington Unit 3	Potter Co., TX	346	2040	182,861,633			10,519	55%
Tolk Unit 1	Bailey Co., TX	537	2042	318,411,848	18,533,025	97,553,785	10,441	56%
Tolk Unit 2	Bailey Co., TX	541	2045	356,579,357			10,156	53%
Turbine - Gas								
Cunningham Unit 3	Lea Co., NM	106	2040	39,770,605		8,914,831	11,854	10%
Cunningham Unit 4	Lea Co., NM	106	2040	32,503,867			11,149	15%
Maddox Unit 2	Lea Co., NM	61	2025	14,652,207		765,907	13,498	2%
Jones Unit 3	Lubbock Co., TX	168	2056	83,000,136		8,027,899	10,708	7%
Jones Unit 4	Lubbock Co., TX	168	2058	83,299,451			9,312	7%
Turbine - Fuel Oil								
Quay	Hutchinson Co, TX	17	2034	26,534,227	245,846	78,346	20,970	0%

Note (1) The O&M $ are reported by plant
Note (2) Fuel $ is measured at the plant level
Note (3) Retirement dates are reflective of the book depreciation life

3.02 - SPS-Purchased Power

In addition to SPS's owned generation, SPS currently has long-term PPAs totaling 1,200 MW of firm generation capacity, and purchases the energy output from renewable intermittent generation consisting of 1,220 MW of wind and 190 MW_{AC} of solar. In December of 2018 SPS will add an additional 230 MW of wind generation. This additional wind generation consists of two purchased power wind facilities, 80 MW of Bonita Phase I and 150 MW of Bonita Phase II located in Crosby County, Texas and Cochran County, Texas, respectively. These resources serve SPS's entire system. Table 3-2 lists the capacity and expiration dates for each long-term PPA under which SPS currently purchases capacity and/or energy.

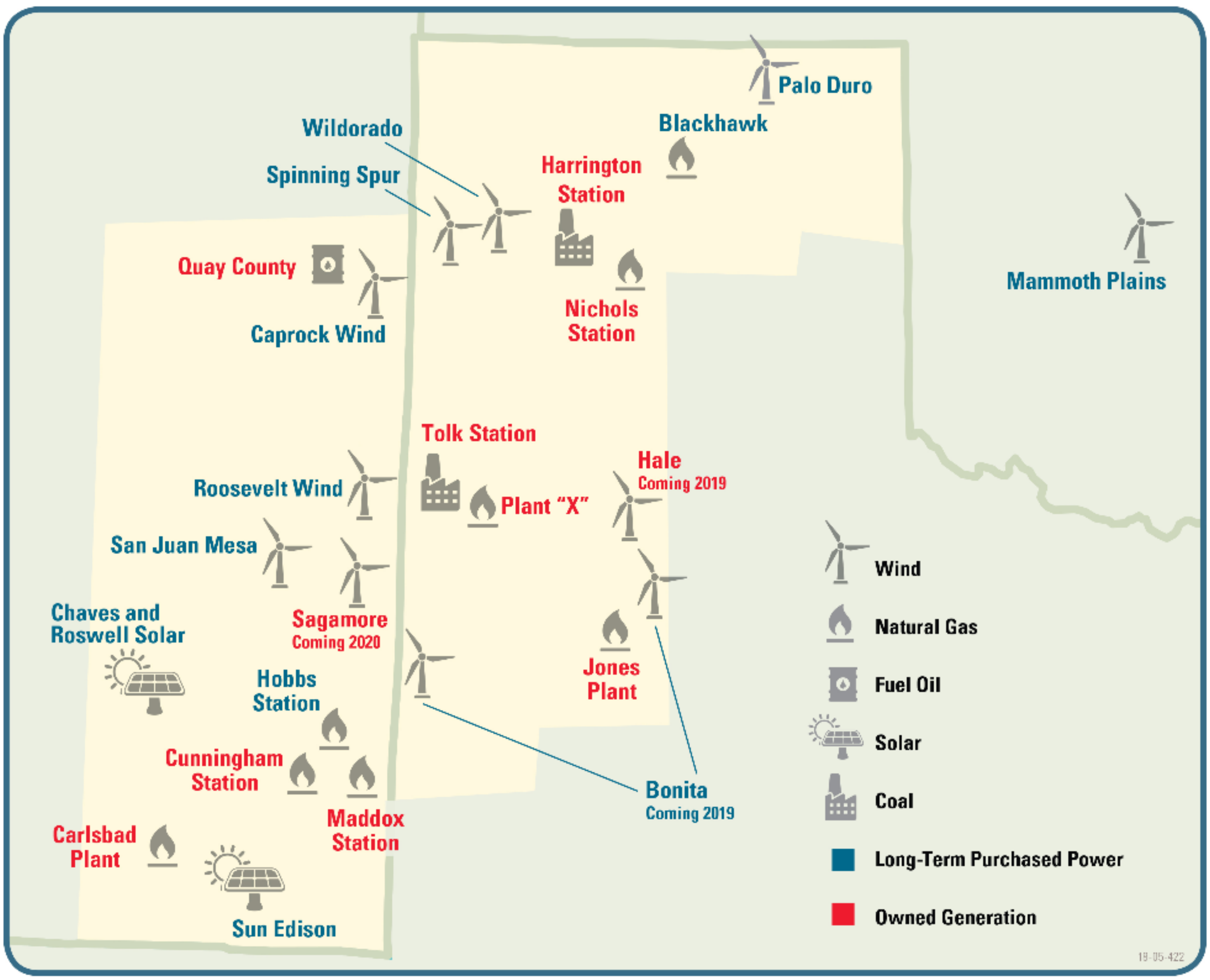
Table 3-2: PPA Capacity and Expiration Dates

Purchased Power Agreement	Capacity (MW)	Expiration Date
Calpine 1 (Oneta)-Gas	200	2018
Calpine 2 (Oneta)-Gas	200	2019
City of Lubbock (Cooke)-Gas	16	2019
Sid Richardson-Steam	8	2021
Blackhawk Plant (Borger, TX)-Gas	219	2023
Lea Power Partners (Hobbs, NM)-Gas	557	2033
Caprock Wind	80	2024
San Juan (Padoma) Wind	120	2025
Wildorado Wind	161	2027
Spinning Spur Wind	161	2027
Mammoth Plains Wind	199	2034
Palo Duro Wind	249	2034
Roosevelt Wind	250	2035
Sun Edison Solar	50	2031
Chaves Solar	70	2041
Roswell Solar	70	2041

In addition, SPS historic cost (calendar year 2017) information regarding each of the PPAs is provided in Appendix A.

Figure 3F.1 below provides a regional map of the SPS generation fleet (owned and purchased).

Figure 3F.1: SPS Existing Capacity



3.03 - Additional SPS Owned Generation Approved but not In-Service

In NMPRC Case No. 17-00044-UT, SPS received approval for a certificate of public convenience and necessity ("CCN") to acquire, develop, and own an additional 522 MW wind generating facility. Sagamore Wind, located near Portales, New Mexico has a planned in-service date of May of 2020.

In NMPRC Case No. 17-00044-UT, SPS received approval for a CCN to install, acquire, develop, and own an additional 478 MW wind generating facility. Hale Wind, located near Plainview, Texas has a planned in-service date of June of 2019.

3.04 - Wheeling Agreements

SPS does not purchase any capacity or energy under wheeling agreements with other utilities.

3.05 - Demand-Side Resources

The IRP Rule specifically requests that the utilities detail their existing demand-side management ("DSM") resources in their IRP filing and defines those resources as "energy efficiency and load management." Energy efficiency ("EE") is defined in the IRP Rule as "*measures, including energy conservation measures, or programs that target consumer behavior, equipment or devices to result in a decrease in consumption of electricity without reducing the amount or quality of energy services*." Load management ("LM") is defined as "*measures or programs that target equipment or devices to decrease peak electricity demand or shift demand from peak to off-peak periods.*" SPS offers DSM resources in both New Mexico and Texas in accordance with state-specific rules and laws.[2]

[2] DSM costs are directly assigned by jurisdiction.

New Mexico DSM

Under the EUEA, SPS is required to acquire cost-effective and achievable DSM to achieve no less than an 8% reduction in 2005 sales in 2020. SPS's 2005 New Mexico retail sales were 3,750,469 megawatt-hour ("MWh"). To meet the EUEA requirements, SPS needs to achieve savings of 300,037,520 kilowatt-hour ("kWh") by 2020.

SPS must annually report its achieved levels for the previous calendar year and receive approval of its going-forward plans every three years to continue towards its statutory goals. SPS's 2018 EE and LM Plan was approved in Case No. 17-00159-UT on December 13, 2017.[3] SPS will continue its approved 2017 EE and LM Plan through the Plan Year 2019.[4] SPS will file its first triennial filing under revised rule 17.7.2 NMAC on May 15, 2019 for the Plan Year 2020, 2021, and 2022. Previous plans were approved for calendar years 2011 – 2017 in Case Nos. 11-00400-UT, 13-00286-UT, 15-00119-UT, 16-00110-UT, respectively. Table 3-3 below describes SPS's EE achievements under the EUEA.

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[3] *In the Matter of Southwestern Public Service Company's Energy Efficiency Compliance Application that Requests Authorization to: (1) Per Approved Variance, Continue Its: (A) 2017 Energy Efficiency and Load Management Programs for Plan Year 2018; (B) 2017 Energy Savings Goal for Plan Year 2018; (C) Energy Efficiency Tariff Rider to Recover the Three Percent Funding Level for Plan Year 2018 and Reconciliation of 2016 Expenditures and Collections; and (D) 2017 Financial Incentive for Plan Year 2018 and Recover the Incentive Through Its Energy Efficiency Tariff Rider; and (2) Recover the 2016 Reconciled Financial Incentive Through the Energy Efficiency Tariff Rider,* Case No. 17-00159-UT, Final Order Approving Certification of Stipulation (Dec 13, 2017).

[4] *In the Matter of Southwestern Public Service Company's Petition Seeking Commission Determination of an Appropriate Energy Efficiency and Load Management Filing,* Case No. 18-00139-UT, Final Order (Jun. 20, 2018).

Table 3-3: EE Achievements for Plan Years 2011-2017

Year	Customer kW Saved	Customer kWh Saved
2011	7,838	35,641,535
2012	7,406	33,336,151
2013	8,056	37.674.221
2014	8,873	30,492,802
2015	10,716	35,225,196
2016	8,486	34,384,659
2017	8,476	33,191,039

At the time of this IRP filing, SPS is offering the following approved DSM programs to its New Mexico customers (designated by "EE" for energy efficiency and "LM" for load management). All of the EE and LM programs offered in 2018 are programs that continued from 2017.

Residential Segment:

- Residential Energy Feedback (EE) – provides participating customers with different forms of feedback regarding their energy consumption. The feedback communication strategies and associated tips and tools result in a decrease in energy usage by encouraging changes in the behavior of participating customers.

- Residential Cooling (EE) – provides a cash rebate to electric customers who purchase and permanently install high-efficiency evaporative cooling, high efficiency air conditioners, air source heat pumps, mini-split heat pumps or electronically commutated motors in air conditioning equipment for residential use in New Mexico.

- Home Energy Services (EE) – includes residential and low-income measures as well as a kit for low-income customers. This program provides incentives for the installation of a wide range of measures that reduce customer energy costs and reduce peak demand and/or save energy for existing single- and multi-family residential customers. Incentives are paid to third-party EE service providers on the basis of deemed savings, which are standardized savings values or formulas for a wide range of measures in representative building types. The program includes attic insulation, air infiltration reduction, duct leakage repairs, and high efficiency central air conditioners. The kit includes the following measures:
    - four 10-watt light emitting diode ("LED") bulbs;
    - high efficiency showerhead;
    - kitchen aerator (1.5 gallons per minute ("gpm"); and

- bathroom aerator (1.0 gpm).

- Home Lighting (EE) – helps customers save energy and money by offering energy efficient LED bulbs at discounted prices at participating retailers. SPS works with retailers and manufacturers to buy down the prices of bulbs.

- Residential Saver's Switch® (LM) – offers bill credits as an incentive for residential customers to allow SPS to control operation of their central air conditioners and electric water heaters on days when the electricity system is approaching its peak.

- School Education Kits (EE) – is a package of EE classroom activities combined with projects for the home. Each participant receives an activity kit containing:
  - two LEDs (9 Watt – 60 Watt Equivalent);
  - two LEDs (11 Watt – 75 Watt Equivalent);
  - energy efficient showerhead (1.5 gpm);
  - kitchen aerator (1.5 gpm);
  - bathroom aerator (1.0 gpm);
  - furnace air filter whistle;
  - LED nightlight;
  - digital water/air thermometer;
  - toilet leak detector tablets; and
  - parent evaluation card.

- Smart Thermostat Pilot – (EE/LM) the Smart Thermostat Pilot is designed to evaluate if Wi-Fi connected communicating, smart thermostats can save residential customers energy by installing a smart thermostat device and connecting it to the manufacturer's cloud service. In addition to EE benefits, the Pilot also plans to evaluate demand response capacity from smart thermostats in the residential market. SPS offers customers smart thermostats and installation at no cost.

<u>Business Segment</u>:

- Business Comprehensive Program, which is made up of the following components:
  - Computer Efficiency (EE) – offers upstream incentives to encourage manufacturers to build and sell higher efficiency computers and provides downstream rebates to

customers who install desktop personal computer virtualization, which reduces energy usage by hosting multiple users on a single computer;

  - Cooling Efficiency (EE) – SPS's Cooling Efficiency Program provides financial incentives for customers to purchase energy-efficient electric cooling equipment;

  - Custom Efficiency (EE) – offers rebates to reduce incremental project costs for customers who install energy efficient measures. Since energy applications and building systems can vary greatly by customer type, this program provides rebates for business projects or process changes that are not covered by SPS's prescriptive programs;

  - Large Customer Self-Direct (EE) – provides the opportunity for qualifying large customers to either self-direct their own EE projects or opt-out of the EE tariff rider if they can prove they have completed all cost-effective conservation. Self-direct participants of this program are also eligible for the other Business Segment programs;

  - Lighting Efficiency (EE) – offers rebates for customers to install more efficient lighting, or de-lamp, as needed;

  - Motor & Drive Efficiency (EE) – offers rebates to customers who install motors exceeding the National Electrical Manufacturers Association Premium Efficiency® motors standards and variable frequency drives in existing and new construction facilities; and

  - Building Tune-up (EE) – is a study/implementation option designed to assist smaller business customers to improve the efficiency of existing building operations by identifying existing functional systems that can be "tuned up" to run as efficiently as possible through low- or no-cost improvements.

- Interruptible Credit Option ("ICO") (LM) – offers significant savings opportunities for New Mexico business customers who will grant SPS the right to interrupt their electric demand at any time throughout the year, and accept an interruption, when called, with either one hour or no notice before the interruption.

Table 3-4 below shows the remaining life of DSM achievements made since EUEA program inception in 2008, using the Portfolio Effective Useful Lifetime method (energy savings provided in gigawatt-hours ("GWh")).[5]

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[5] This calculation method is consistent with the methodology proposed by the Commission's Utility Division Staff in Case No. 09-00352-UT (*see Staff Compliance Affidavit Regarding Decretal Paragraph "L" of the Certification of Stipulation Adopted by the Commission in its March 11, 2010 Final Order in this Proceeding,* Oct. 19, 2010).

Table 3-4: Remaining Savings Provided by the 2008-2017 EE Programs

Year	Annual Net Customer Achievement (MW)	Cumulative Net Customer Achievement (MW)	Annual Net Customer Achievement (GWh)	Cumulative Net Customer Achievement (GWh)	Cumulative % of 2005 Retail Sales
2008	0.256	0.256	3.355	3.355	0.09%
2009	2.684	2.942	14.136	17.491	0.47%
2010	5.717	8.644	23.231	40.722	1.09%
2011	6.532	15.317	35.642	76.363	2.04%
2012	6.353	21.528	31.534	107.897	2.88%
2013	6.379	27.942	34.452	142.349	3.80%
2014	5.223	33.165	30.493	172.841	4.61%
2015	5.170	38.128	32.805	202.962	5.41%
2016	3.981	42.058	31.966	234.257	6.25%
2017	4.572	46.401	29.429	263.686	7.03%
2018 (forecast)	5.072	51.577	26.444	290.130	7.74%
2019 (forecast)	4.534	76.474	23.637	295.489	7.88%
2020 (forecast)	4.534	100.683	23.637	300.038	8.00%
2021 (forecast)	5.068	112.189	26.424	326.461	8.70%
2022 (forecast)	5.068	121.769	26.424	342.604	9.13%
2023 (forecast)	5.068	120.489	26.424	301.799	8.05%
2024 (forecast)	5.068	123.380	26.424	279.712	7.46%
2025 (forecast)	5.068	133.845	26.424	300.038	8.00%
2026 (forecast)	4.019	145.349	20.955	320.993	8.56%
2027 (forecast)	4.019	151.700	20.955	309.143	8.24%
2028 (forecast)	4.019	161.220	20.955	314.116	8.38%
2029 (forecast)	4.019	170.741	20.955	319.089	8.51%
2030 (forecast)	4.019	177.467	20.955	311.809	8.31%

EE Goals through 2038

The following goals were developed in accordance with the EUEA to allow SPS to attain a reduction in its 2005 retail sales of 8% in 2020, and further, to maintain the 8% reduction beyond 2020. Note that the EUEA neither requires nor establishes annual goals. Thus, the goals in Table 3-5 below are preliminary and subject to change in SPS's annual EE and LM Plans.

Table 3-5: Proposed New Mexico DSM Goals at the Customer for the Planning Period

Year	Demand Savings (MW)	Energy Savings (GWh)
2018	5.07	26.444
2019	4.53	23.637
2020-2038	4.51	23.533

Texas DSM Requirements

SPS offers DSM programs in its Texas service territory pursuant to the Public Utility Regulatory Act and 16 Tex. Admin. Code § 25.181. These programs include standard offer and market-transformation programs for commercial and industrial, LM, residential, and low-income customers limited to customers receiving service at 69 kilovolts ("kV") or less and all government customers. The following table shows SPS's historic demand savings (in MW) and energy savings (in GWh) in its Texas service territory.

Table 3-6: SPS's EE and LM Achievements - 2011 to 2017 in Texas

Year	Customer Demand Savings (MW)	Customer Energy Savings (GWh)
2011	3.88	13.821
2012	5.30	9.077
2013	5.10	7.950
2014	5.02	11.900
2015	8.17	14.537
2016	8.19	14.451
2017	7.80	16.871

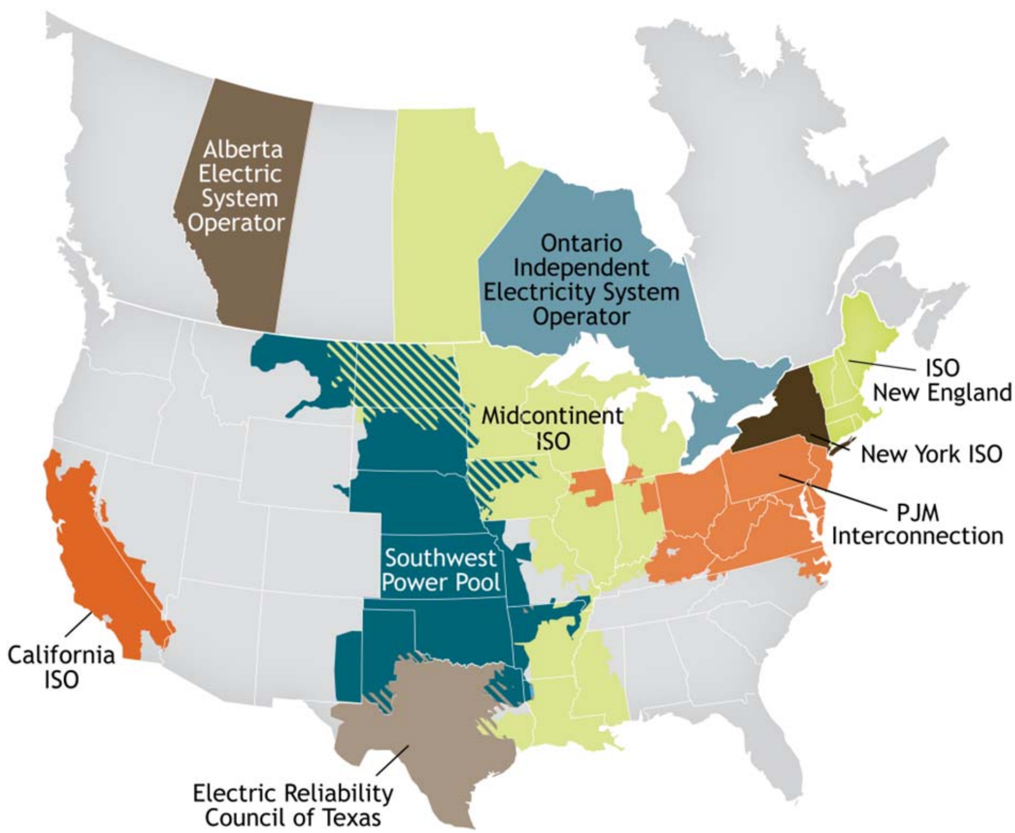
In addition, SPS offers residential and business Saver's Switch and ICO LM programs (the savings are not included in the table above).

3.06 - Reserve Margin and Reserve Reliability Requirements

Electric System Reliability Councils

The reliability of the electrical system of North America is coordinated by the North American Electric Reliability Corporation ("NERC"). NERC is comprised of nine separate regional councils (*see* Figure 3F.2 below). Each council is responsible for defining specific reliability criteria for use by the member electric systems. SPS is a member of the SPP, which is one of the nine NERC regional councils established to promote the reliable operation of the interconnected bulk power system.

Figure 3F.2: NERC Map



SPP Integrated Market

The SPP IM was launched on March 1, 2014. SPP is now responsible for generation unit commitment and dispatch across the SPP footprint, consolidating the 16 balancing authorities ("BA") into one BA. Additionally, SPP administers the day-ahead and real-time balancing market, including incorporation of a price-based operating reserve market (i.e., regulation up/down and spin/supplemental reserves). Instead of each load serving entity (e.g., SPS) committing and dispatching its own generation resources to meet its own load requirements, reliability unit commitment and economic dispatch are now performed by the SPP. The SPP IM has been in operation for just over four years and SPS has noticed a change in the commitment of its generation fleet for reliability needs. In particular, SPS's gas units are committed less often for reliability purposes.

Current expectations and future requirements regarding market operations, locational generation dispatch, congestion, and losses will impact future transmission and generation planning/siting activities.

Reserves - Generally

Electric system owners work to maintain service at all times to their firm customers. As a result, each system must maintain an adequate supply of electric generation that not only will meet the maximum demand of its customers (i.e., the "peak" demand) but also provide for unforeseen events (e.g., transmission line outages, power plant outages, etc.). To accomplish these objectives, electric systems acquire (through direct ownership or PPAs) and operate more generation capacity than is needed to meet peak demand. The additional generation, above what is needed to meet peak customer demand, is called reserve margin or reserves. Generally, there are two basic types of reserves: (i) Planning Reserves, which are the amount of installed capacity required in excess of annual peak firm demand, and (ii) Operating Reserves, which are the amount of generation capacity required in real-time, either with units carrying regulation and/or spinning reserves; or units offline but in warm reserve and capable of providing additional electric supply in order to meet real-time changes in load/demand and any unforeseen contingencies (e.g., transmission outage, generator forced outage, gas supply disruptions, etc.).

From a long-term planning standpoint, SPS is currently required by the SPP to plan for a 10.7% capacity margin (or 12.0% planning reserves) (discussed in more detail in the next subsection). SPP resource adequacy is constantly under review. In fact, the current resource adequacy policies are in a proposed state of revision and are awaiting approval by the Federal Energy Regulatory Commission (Docket No. ER18-1268-000).

SPP Capacity Reserve Requirements

Under the current SPP Planning Criteria, SPP has adopted a "Capacity Margin" criterion to ensure reliable electric service is provided to firm load customers. SPP requires that each load-serving member maintain a "Capacity Margin" of at least 10.7%[6] (equivalent to a 12% reserve margin). The Percent Capacity Margin formula, as well as its relationship to the more commonly referred to "reserve margin," is provided below:

$$\textbf{Capacity Margin \%} = \frac{\textbf{Capacity Margin (MW)}}{\textbf{System Capacity (MW)}} \times 100 = 10.7\%$$

$$\begin{aligned} \textbf{Reserve Margin \%} &= (1 / (1-\text{Capacity Margin \%})) - 1 \\ &= (1/(1-.107))-1 \\ &= .1198 = 12.0\% \end{aligned}$$

$$\textbf{Capacity Margin (MW)} = \textbf{Reserve Margin \%} \times \textbf{Firm Load}$$

6 Load serving members comprised of at least 75% hydro-based generation have a minimum required capacity margin of 9%.

SPS Capacity Reserves

The future resource needs of the SPS system are estimated by performing a comparison of SPS's (base) peak demand forecast with the system capacity (i.e., "capacity balance"). Once these needs are identified, SPS develops a resource acquisition plan to acquire the necessary electrical generating capacity to meet its customers' peak demand plus the 10.7% capacity margin (this equates to a planning reserve margin of 12% multiplied by peak demand). Based upon the actual Capacity Margin in any one year, additional generating capacity might be acquired through various methods, including construction of SPS-owned facilities and/or PPAs via competitive resource solicitations.

3.07 - Existing Transmission Capabilities

SPS, as a member of SPP, participates in several technical groups and committees. SPS is also a member of the North American Transmission Forum, a group that promotes sharing of technical solutions among members.

An analysis of the SPS transmission system is contained in the SPP 2017 Integrated Transmission Planning Near-Term Assessment, which is provided as Appendix B. This report discusses the performance of the SPS network and recommends new projects to improve the network performance.

A list of current projects SPS is constructing based on notifications to construct is provided as Appendix C. This list also includes the generator interconnection projects.

Transmission Import Rights

SPS has a total of 1,655 MW of transmission flow capability between the SPP transmission system and SPS. SPS's use of these rights on a firm basis is more fully described below.

400 MW Import Path from the Tulsa, Oklahoma Area

SPS has two, 200 MW, network resources delivered from the LS Power Oneta CC facility; one for the term of January 1, 2012 - December 31, 2018, the other for the term of June 1, 2014 - May 31, 2019.

50 MW Import from Western Farmers Electric Cooperative

As agent for the Farmers Electric Cooperative, Inc., Central Valley Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc. (collectively, "New Mexico Cooperatives"), SPS holds firm network transmission rights to import up to 50 MW from Western Farmers Electric Cooperative, a generation and transmission cooperative located in Oklahoma. This resource represents part of the New Mexico Cooperatives' Phase 1 load reduction under their Replacement Power Sales Agreements ("RPSA") with SPS. The term of this service began June 1, 2012 and continues for 30 years.

Additional 80 MW Import from Western Farmers Electric Cooperative

This resource represents the New Mexico Cooperatives' Phase 2 load reduction under their RPSA with SPS. The term of this service begins June 1, 2017 and continues for 30 years.

249 MW Palo Duro Wind

SPS has firm transmission service for this wind farm beginning January 1, 2018 and continuing for the term of the PPA through December 31, 2034.

199 MW Mammoth Plains Wind

SPS will have firm transmission service for this wind farm beginning November 16, 2018 and continuing for the term of the PPA through December 31, 2034.

101 MW Import from Elk City 2 Wind

As agent for the cities of Brownfield, Floydada, Tulia, and Lubbock, Texas served under the West Texas Municipal Power Agency (collectively, "WTMPA"), SPS holds the firm network transmission rights to import up to 101 MW from Elk City 2 Wind, located in Oklahoma. This resource represents part of the replacement power required to serve the WTMPA members upon termination of their full requirements contracts with SPS. The term of this service begins June 1, 2019 and continues for 13 years.

3.08 - Environmental Impacts of Existing Supply-Side Resources

17.7.3.9(C)(12) NMAC requires utilities to provide environmental impacts of existing supply-side resources, including the following information: (1) the percentage of kWh generated by each fuel type; (2) where feasible, the emission rates (critical pollutants and carbon dioxide and mercury) of each supply side-resource; and (3) to the extent feasible, the current water consumption rate of its supply-side resources. These requirements are addressed below.

Environmental leadership is fundamental to Xcel Energy's operations. For more than a decade, Xcel Energy has strived to serve its customers with a cleaner mix of resources and with an energy grid that is more reliable and secure — all while keeping customer energy bills low. Xcel Energy is committed to leading the way and creating a cleaner, more affordable, and sustainable energy future for all of us. In 2017, carbon emissions were reduced by 34% in the SPS territory compared with 2005 levels. Corporate-wide, Xcel Energy has reduced emissions 35% since 2005 and has set one of the most ambitious emission-reduction targets in the industry—Xcel Energy's goal is to reduce carbon emissions 60% from 2005 levels by 2030. To achieve these goals, Xcel Energy's clean energy strategy is a comprehensive balanced approach that includes adding renewable energy to the system, increasing the size of its EE programs, and reducing emissions at its plants. Xcel Energy's plans in the southwest are focused on keeping customer energy bills low, powering economic development, and using the region's natural resources in the most efficient way to serve customers.

As a national leader in wind energy, Xcel Energy operates about 7% of the nation's wind capacity, and has plans for more. SPS has 1,220 MW of wind under long-term PPAs and 283.2 MW of qualifying facilities ("QF") wind[7], which have served to reduce customer rates in addition to meeting state-specific renewable requirements (see Tables 3-7 and 3-8). Over the next three years SPS will acquire 1,230 MW of owned generation and long-term PPA wind in Texas and New Mexico.

Additionally, SPS has a demonstration of four separate community solar projects installed on community partner sites in eastern and southeastern New Mexico. In 2011, SPS began purchasing power from five 10 MW solar farms in Lea and Eddy Counties in New Mexico. And, in 2016, SPS began purchasing power from two 70 MW solar farms located in Roswell and Chaves Counties, New Mexico (see Table 3-9 below). Through its New Mexico Solar Rewards program, SPS currently provides incentives to customers that have installed solar systems on homes and businesses; currently, there are approximately 150 customers receiving incentive payments.

[7] The 283.2 MW of QF wind will increase to 290.7 MW on September 1, 2018 when Lubbock Wind Ranch begins commercial operation. Then, the QF wind will decrease down to 123.2 MW starting August 1, 2018 when Frisco, Novus and Pringle expire.

Table 3-7: Long-term PPA Wind

PPA Wind	Nameplate Capacity (MW)	Commercial Operation Date	Termination Date
Mammoth Wind	199	12/31/2014	12/31/2034
Caprock Wind	80	12/31/2004	12/30/2024
Palo Duro Wind	249	12/15/2014	12/31/2034
Roosevelt Wind	250	12/31/2015	12/31/2035
San Juan Wind	120	12/22/2015	12/22/2025
Spinning Spur Wind	161	12/13/2012	12/31/2027
Wildorado Wind	161	04/27/2007	04/27/2027

Table 3-8: QF Wind

QF Wind	Nameplate Capacity (MW)	Commercial Operation Date	Termination Date
Cirrus Wind	61.2	12/10/2012	
Frisco Wind	20	02/01/2012	08/1/2018*
Novus Wind	120	10/01/2012	08/1/2018*
Pantex Wind	11.5	06/30/2014	
Pleasant Hills Wind	19.8	06/30/2014	
Pringle Wind	20	08/20/2010	08/1/2018*
Ralls Wind	10	07/15/2011	
Sunray 2 Wind	9	08/11/2009	
Suzlon 8 Wind	4.2	11/10/2011	
Lubbock Wind Ranch	7.5	09/01/2018 *	
** Note: see footnote 7 on the previous page*			

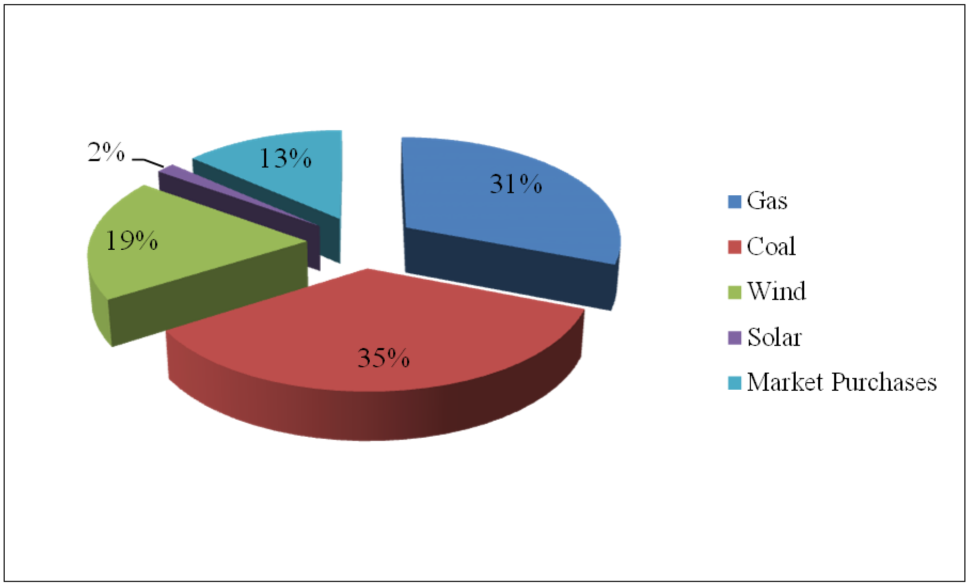
Table 3-9: Long-term PPA Solar

PPA Solar	Nameplate Capacity (MW)	Commercial Operation Date	Termination Date
Chaves Solar	70	10/26/2016	10/25/2041
Roswell Solar	70	09/01/2016	08/31/2041
Sun Edison Solar	50	Fall of 2011	Fall of 2031

Percentage of MWh Generated

The percentages of MWh generated by each fuel type used by SPS for Calendar Year 2017 are provided in Figure 3F.3 below.

Figure 3F.3: Percentage in 2017 by Fuel Type



SPS Emissions Information

The emission rates for SPS-owned generation resources are shown in Table 3-10 below. All emission rates are expressed in pounds per kWh.

Water Consumption Rates

Average water consumption rates, by plant, and expressed in gallons per kWh (H_2O Consumption) are also shown in Table 3-10 below.

Table 3-10: Emission and Water Consumption Rates

2017 SPS Emission Rates of Criteria Pollutants plus Mercury and Carbon Dioxide Expressed in Pounds per Kilowatt-Hour (lb/KWh) and Water Consumption Expressed in Gallons per KWh										
Plant	Unit	SO2	NOx	PM	CO2	Hg	CO	Pb	VOC	H2O Consumption (Plant Average)
Cunningham	1	7.142E-06	1.926E-03	9.098E-05	1.47	3.086E-09	2.605E-04	5.989E-09	1.675E-05	0.550
Cunningham	2	6.518E-06	1.651E-03	8.042E-05	1.30	2.758E-09	2.193E-04	5.289E-09	1.481E-05	
Cunningham	3	6.571E-06	5.980E-04	7.480E-05	1.35	2.841E-09	2.266E-05	0.000E+00	2.380E-05	
Cunningham	4	6.909E-06	6.569E-04	7.753E-05	1.40	2.950E-09	2.349E-05	0.000E+00	2.466E-05	
Harrington	1	5.463E-03	1.465E-03	5.023E-04	2.23	9.330E-09	1.088E-03	6.266E-08	3.685E-05	0.619
Harrington	2	5.735E-03	1.607E-03	1.214E-04	2.27	5.899E-09	1.135E-03	2.011E-08	3.636E-05	
Harrington	3	5.557E-03	1.539E-03	1.427E-04	2.21	6.155E-09	1.112E-03	2.293E-08	3.560E-05	
Jones	1	6.918E-06	1.243E-03	8.598E-05	1.38	2.942E-09	2.715E-04	5.658E-09	3.111E-08	0.504
Jones	2	7.013E-06	9.882E-04	8.539E-05	1.40	2.930E-09	2.695E-04	5.647E-09	3.087E-08	
Jones	3	6.013E-06	2.935E-04	1.328E-05	1.19	0.000E+00	2.802E-04	0.000E+00	1.692E-09	
Jones	4	5.202E-06	2.490E-04	9.312E-06	1.03	0.000E+00	2.641E-04	0.000E+00	2.328E-09	
Maddox	1	6.546E-06	1.504E-03	8.050E-05	1.30	2.754E-09	5.500E-06	5.298E-09	5.829E-05	1.370
Maddox	2	1.112E-05	4.248E-03	9.081E-05	1.60	3.391E-09	7.413E-06	6.486E-09	2.965E-05	
Maddox	3	1.237E-05	3.918E-03	1.031E-04	2.48	4.021E-09	3.505E-04	7.629E-09	3.299E-05	
Nichols	1	6.810E-06	1.093E-03	8.404E-05	1.36	2.875E-09	2.654E-04	5.529E-09	6.082E-05	0.917
Nichols	2	8.235E-06	1.402E-03	9.779E-05	1.58	3.345E-09	3.088E-04	6.434E-09	7.077E-05	
Nichols	3	7.561E-06	1.691E-03	9.389E-05	1.52	3.212E-09	2.965E-04	6.177E-09	6.795E-05	
Plant X	1	2.795E-05	2.018E-02	3.693E-04	6.00	1.258E-08	4.083E-03	2.427E-08	2.673E-04	0.590
Plant X	2	7.733E-06	9.800E-04	9.517E-05	1.55	3.297E-09	2.998E-04	6.402E-09	6.859E-05	
Plant X	3	5.968E-06	1.523E-03	7.475E-05	1.21	2.558E-09	2.361E-04	4.918E-09	5.410E-05	
Plant X	4	6.981E-06	1.157E-03	8.602E-05	1.40	2.945E-09	2.716E-04	5.665E-09	6.224E-05	
Quay County	1	3.063E-05	1.440E-02	2.348E-04	3.38	3.267E-05	4.901E-05	2.553E-08	7.147E-06	0.000
Tolk	1	5.086E-03	1.227E-03	6.540E-05	2.01	7.418E-09	2.830E-03	1.173E-08	3.288E-05	0.501
Tolk	2	5.491E-03	1.373E-03	1.009E-04	2.18	7.950E-09	2.660E-03	1.622E-08	3.094E-05	

3.09 - New and Future Environmental Regulations

The discussion below summarizes the complex array of existing and pending environmental mandates SPS must comply with. As will be seen, the discussion serves to highlight areas of uncertainty regarding rule promulgation or changes and long-term planning changes that exist where SPS must make decisions with incomplete information regarding the evolution of future environmental regulations.

Status of Each Regulation

This section summarizes the current status and remaining unknowns about each regulation (identified earlier), along with the potential impacts on SPS's generation resources.

A. Greenhouse Gas ("GHG") Emissions from New and Existing Power Plants

The landscape for Federal carbon dioxide ("CO_2") regulation is highly uncertain at this time. The major greenhouse gas regulations that were put into place under the Obama administration, including the Clean Power Plan and the emission standards for new power plants, are in the process of being repealed and potentially replaced under the Trump administration. At this time, it is unclear what regulatory structure will replace these major regulations. Given this uncertainty, this IRP will continue to consider carbon regulation risk through carbon price sensitivity analysis.

The following section summarizes the most recent events surrounding Federal greenhouse gas regulations.

GHG Emissions Standards for Existing Power Plants

- The Environmental Protection Agency's ("EPA") Clean Power Plan ("CPP"), finalized in October 2015, was stayed by the U.S. Supreme Court in February 2016, and remains stayed pending the ongoing legal challenge at the D.C. Circuit Court.

The latter court has held this litigation in abeyance pending EPA's review of the rule.[8]

- In October 2017, the EPA, acting under an Executive Order requiring federal agencies to review existing regulations that potentially burden the development or use of domestically-produced energy resources[9], issued a proposed rule to repeal the CPP in its entirety.[10] EPA has completed the comment period on this proposal, and held four public hearings.[11] It is unknown how or when EPA will act on the final repeal.

- EPA in December 2017 issued an Advance Notice of Proposed Rulemaking ("ANPR') requesting comment on whether it should issue a replacement to the CPP and if so, what form a replacement rule should take.[12] EPA received over 260,000 comments on the ANPR, during the comment period. It is unknown whether EPA will ultimately replace the CPP, what form a replacement rule may take, and what options it will give states for flexibility in designing compliance plans – all of which will affect regulatory compliance costs for utilities and their customers.

GHG Emissions Standards for New, Modified, and Reconstructed Power Plants

- In October 2015, the EPA promulgated a final rule to establish emissions standards of CO_2 for newly constructed, modified, and reconstructed electric units.[13]

- EPA received and denied several requests for administrative reconsideration of the standard. The denial of reconsideration was subsequently challenged and cases were consolidated under *North Dakota v. EPA* by the D.C. Circuit Court.

- In April 2017, the EPA, acting under an Executive Order requiring federal agencies to review existing regulations that potentially burden the development or use of

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[8] *West Virginia v. EPA*, No. 15-1363 (D.C. Cir.).

[9] Executive Order, "Promoting Energy Independence and Economic Growth," § 1(c), 82 Fed. Reg. 16,093(Mar. 28, 2017).

[8] Proposed Rule, Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; 82 *Fed. Reg.* 48,035.

[11] Notice of three public listening sessions and that the public comment period will be reopened. Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; 83 Fed. Reg. 4,620.

[12] Advance Notice of Proposed Rulemaking: State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units. 82 Fed. Reg. 61,507.

[13] Final Rule, Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Generating Units; 80 Fed. Reg. 64509.

domestically-produced energy resources,[14] issued an announcement to review and, if appropriate, suspend, revise, or rescind the standards for new, modified, and reconstructed sources.[15] It is unknown how or when EPA will act on this review.

- Pursuant to an EPA motion, in April 2017, the D.C. Circuit Court ordered the challenges to the standard in abeyance for 60 days.[16] Subsequently, in August 2017, the Court held the cases in abeyance until further court order, requiring reports from EPA to be filed every 90 days.[17]

The significant uncertainty in Federal climate policy as outlined above makes decades long resource planning a challenge. SPS will continue to monitor these developments, maintain its leadership on clean energy, and keep bills low for its customers.

B. Particulate Matter, Nitrogen Oxides, Sulfur Dioxide, and Mercury Emissions

Particulate matter ("PM") (including "fine" PM under 2.5 micrometers in diameter ($PM_{2.5}$)), nitrogen dioxide ("NO_2"), and sulfur dioxide ("SO_2") are three of the primary pollutants regulated by the EPA under the Clean Air Act ("CAA"). These pollutants are regulated under three main programs: National Ambient Air Quality Standards ("NAAQS"), CAA programs that address interstate transport of air pollution, and the Regional Haze program, which addresses visibility impairment in national parks and wilderness areas. Mercury emissions from coal-fired power plants are regulated under the Mercury and Air Toxics Rule ("MATS"). Each of these requirements is addressed in this section.

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[14] Executive Order, "Promoting Energy Independence and Economic Growth," § 1(c), 82 Fed. Reg. 16,093 (Mar. 28, 2017).

[15] Proposed Rule, Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Generating Units; 82 *Fed. Reg.* 16330.

[16] *State of North Dakota, et al. v. United States Environmental Protection Agency*, No. 15-1381 (D.C. Cir. Apr. 28, 2017) (order holding cases in abeyance and directing parties to brief whether the cases should be remanded to the agency).

[17] *State of North Dakota, et al. v. United States Environmental Protection Agency*, No. 15-1381 (D.C. Cir. Aug. 10, 2017) (order holding cases in abeyance).

National Ambient Air Quality Standards

The CAA requires the EPA to set NAAQS to protect public health and the environment. NAAQS include both: (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children, and the elderly; and (2) secondary standards to protect public welfare, including protection against damages to animals, crops, and buildings. The EPA has established NAAQS for six criteria pollutants: PM, NO_2, SO_2, ozone, carbon monoxide, and lead. The NAAQS program has been in place since the early 1970s.

Once the EPA adopts or revises a NAAQS, states have two years to monitor their air, analyze the data, and submit to the EPA their classification of the state into Attainment Areas (areas having monitored ambient air quality concentrations below the NAAQS), Nonattainment Areas (areas having monitored ambient air quality concentrations above the NAAQS), and unclassifiable areas. The EPA reviews the state's submittal and determines the final area designations a year later.

When the EPA designates an area as Nonattainment, the state is generally given three years to develop a new State Implementation Plan ("SIP") which identifies actions to be taken to bring the area back into Attainment. A nonattainment SIP must include emission reduction requirements needed to demonstrate that air quality will attain the NAAQS in the timelines required by the CAA – usually within two to seven years after the SIP is submitted to the EPA for approval.

The NAAQS are periodically reviewed and, if appropriate, individually revised for each pollutant. Since the 2015 IRP filing, EPA has completed designations under the most recent NAAQS for all areas in SPS's service territory. The following table shows Texas' and New Mexico's status under the current NAAQS in areas where SPS operates power plants:

Table 3-11: NAAQS for New Mexico and Texas

NAAQS	Precursor Emissions Regulated*	Last Revised or Reviewed	New Mexico Status at SPS Plant Locations	Texas Status at SPS Plant Locations
Particles	NOx, SO_2, PM	2012	Attainment	Attainment
Ozone	NOx	2008	Attainment	Attainment
Ozone	NOx	2015	Attainment	Attainment
Sulfur Dioxide		2010	Attainment	Attainment, except Potter County is Unclassifiable
Nitrogen Dioxide		2010	Attainment	Attainment
Carbon Monoxide		2011	Attainment	Attainment
Lead		2016	Attainment	Attainment

* Precursor emissions contribute to formation of the NAAQS-regulated pollutants ozone and particles after being released to the atmosphere from a source.

In June 2016, the EPA issued final SO_2 designations which found the area near the Harrington Plant in Potter County, Texas was "unclassifiable." The area near the Harrington Plant is to be monitored for three years and a final designation is expected to be made by December 2020. If the area near the Harrington Plant is designated nonattainment in 2020, the Texas Commission on Environmental Quality ("TCEQ") will need to develop a SIP, which would be due by 2022, designed to achieve the SO_2 NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan.

If an area attains a NAAQS, no further emission reduction plan is required. Every five years, the EPA reviews the scientific data on health effects and decides whether any revision to the NAAQS is needed. If areas were to be designated as nonattainment at some point in the future under a revised NAAQS, this could require emission reductions from SPS's thermal generation units. It is not known what adjustments to the NAAQS, if any, the EPA may make in future reviews.

Interstate Transport of Air Pollution

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[18] The EPA has developed programs for the Eastern United States that would reduce interstate transport of pollutants that are precursors to ozone and fine particles. Nitrous Oxide ("NO_X") is a precursor to ozone and fine particle formation, and SO_2 is a precursor to fine particle formation. For the utility industry, the current program is the Cross-State Air Pollution Rule ("CSAPR"). CSAPR was adopted to address upwind states' emissions that impact downwind states' attainment of the ozone and particulate NAAQS. As the EPA revises NAAQS in the future, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program.

CSAPR was designed as a "cap-and-trade" program that reduces overall emissions from electric generating units ("EGUs"). This means that total emissions from EGUs in a state or region are limited (the cap), and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount, but provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both. Depending on the EPA's analysis of an upwind state's

[18] CAA, 42 U.S.C. section 7410(a)(2)(D)(i)(I).

contribution to nonattainment in downwind states, CSAPR imposes one or both of the following emission limitations: (1) summer season NOx emissions (to address ozone), and/or (2) annual NOx and SO_2 emissions (to address fine particles).

In September 2017, the EPA adopted a final rule that withdrew Texas from the CSAPR particle program and determined that further emission reductions in Texas are not needed to address interstate particle transport. Texas is no longer subject to the annual SO_2 and NOx emission budgets under CSAPR. Texas remains subject to the summertime NOx emission budgets under the CSAPR ozone program. In November 2017, the National Parks Conservation Association and Sierra Club appealed this rule to the D.C. Circuit Court. The litigation is being held in abeyance pending EPA's decision whether to administratively reconsider the rule.

SPS currently forecasts compliance with the current CSAPR emission limits, without installation of additional controls, through the purchase of NOx allowances as needed.

Visibility Impairment in National Parks and Wilderness Areas (Regional Haze)

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. The CAA established a national goal of remedying existing and preventing future visibility impairment from man-made air pollution in specified "Class I" areas – national parks and wilderness areas throughout the United States, including New Mexico and Texas.

In 1999, the EPA adopted the current Regional Haze Rule ("RHR") to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. The Best Available Retrofit Technology ("BART") requirements of the EPA's RHR require emission controls to be determined in the first planning period for industrial facilities put into operation between 1962 and 1977 that emit air pollutants that cause or contribute to visibility impairment in national parks and wilderness areas. Under BART, regional haze plans identify facilities that will have to reduce SO_2, NO_X, and PM emissions and set emission limits for those facilities. BART requirements can also be met through participation in interstate emission trading programs such as the Clean Air Interstate Rule ("CAIR") and its successor, CSAPR. SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no man-made visibility impairment in Class I areas by 2064.

The New Mexico Regional Haze SIP for the first planning period does not affect any SPS New Mexico facilities. That plan covers reductions for the 2008-2018 planning period.

The Texas Regional Haze SIP for the first planning period was subject to a lengthy EPA review. Texas developed a SIP in 2009 that found the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would have been required. In 2014, the EPA proposed to approve the BART portion of the SIP, with substitution of CSAPR compliance for Texas' reliance on CAIR. In January 2016, the EPA adopted a final rule that deferred its approval of CSAPR compliance as BART until the EPA considered further adjustments to CSAPR emission budgets under the D.C. Circuit Court's remand of the Texas SO_2 emission budgets.

The EPA then published a proposed rule in January 2017 that, if adopted as proposed, would have required the installation of dry scrubbers to reduce SO_2 emissions at Harrington Units 1 and 2. Investment costs associated with dry scrubbers for Harrington Units 1 and 2 are approximately $400 million. In October 2017, the EPA issued a final rule adopting a Texas only SO_2 trading program as a BART alternative. The program allocated SO_2 allowances to EGUs in

Texas, including all three Harrington units and both Tolk units, consistent with their allocation under CSAPR, resulting in an emissions budget for Texas that is consistent with the EPA's 2012 rule that found CSAPR emission reductions approvable under the RHR as "Better than BART." SPS expects the allowance allocations to be sufficient for SO_2 emissions from Harrington and Tolk units in 2019 and future years. Similarly, EPA found that the CSAPR ozone program that regulates summertime NO_X emissions satisfies BART for NO_X for EGUs.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's October 2017 final BART rule to the Fifth Circuit, and filed a petition for administrative reconsideration of the final rule with the EPA. In January 2018, the court granted SPS's motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The litigation is being held in abeyance pending EPA's decision whether to administratively reconsider the rule.[19]

In addition to making BART determinations, the RHR requires states to consider whether further emission reductions need to be imposed to achieve reasonable progress toward the long-term national visibility goal. The Texas SIP evaluated this issue and did not impose additional emission reduction requirements for reasonable progress in the first planning period. In January 2016, the EPA disapproved the Texas SIP on this issue and adopted a final rule establishing a federal implementation plan for the state of Texas, which imposed SO_2 emission limitations that require the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be approximately $600

[19] Several parties have also challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree lodged with the United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The litigation is being held in abeyance pending EPA's decision whether to administratively reconsider the rule.

million. SPS appealed the EPA's decision and requested a stay of the final rule, which the Fifth Circuit granted.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, while leaving the stay in effect. The Fifth Circuit is now holding the case in abeyance until the EPA completes its reconsideration of the rule. In the final BART rule that affects Tolk and Harrington described above, the EPA noted that it will address the remanded rule in a future action. Such a rule will address whether further SO_2 emission reductions are needed at Tolk to address the reasonable progress requirements of the RHR. The risk of these controls being imposed along with the risk of investments to provide additional cooling water to Tolk have caused SPS to seek to decrease the remaining depreciable life of the Tolk units. The EPA has not announced a schedule for acting on the remanded rule.

The next planning cycle for the regional haze program requires the states to evaluate progress in their Class I areas and design emission reduction programs to continue reasonable progress toward the national visibility goal. The SIPs, including those for New Mexico and Texas, are due in 2021 and will then be subject to EPA review. Since the planning efforts are not yet underway, SPS cannot predict what the requirements of these plans may be. These plans may require additional control equipment for SO_2 or NO_X or both at SPS's power plants, particularly the coal-fired Harrington and Tolk plants. Assuming a SIP is adopted in 2021 by a state and reviewed by EPA by 2023, any control equipment that may be required in the RHR's second planning period would need to be installed by approximately 2028.

Mercury and Air Toxics Rule

EPA adopted the MATS in 2012 to reduce emissions of mercury, acid gases, and other non-mercury metals from coal-fired power plants. SPS has installed the activated carbon injection control systems needed to meet the mercury limits and complies with the acid gas and non-mercury metals emission limits imposed by the MATS using existing controls installed at Harrington and Tolk.

C. Regulation of Coal Combustion Residuals (Ash)

Coal Combustion Residuals ("CCR"), often referred to as coal ash, are regulated as non-hazardous wastes under the federal Resource Conservation and Recovery Act ("RCRA") and are also regulated under state regulatory programs. Coal ash is residue from the combustion of coal in power plants. Generally, CCRs are captured by pollution control equipment and either recycled for beneficial reuse or disposed of appropriately. Environmental issues involving coal ash derive primarily from concerns regarding structural failure of large surface impoundments (e.g., the 2008 Tennessee Valley Authority Kingston ash pond failure, and more recent incidents at Duke Energy power plants in the southeast U.S.), and the potential for releases from unlined ash impoundments and landfills to impact groundwater.

Currently, the CCRs that result from the combustion of coal at SPS units are 100% beneficially used in dry form and marketed by an onsite marketing facility for use. There are no wet operations for ash management in SPS.

SPS's operations are subject to federal and state laws that impose requirements for handling, storage, treatment, and disposal of wastes. On December 19, 2014, the EPA signed a final rule establishing national standards for the management and disposal of CCRs ("CCR Rule").[20] Litigation challenging the rule, brought by industry and non-governmental organizations, is currently pending in the D.C. Circuit. EPA is also considering proposed rules to further modify the CCR Rule. The rule regulates this material as a non-hazardous waste under Subtitle D of the RCRA. The rule establishes minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to SPS's current requirements under State enforceable, site-specific permits, and operating plans. SPS has evaluated the rule and proposed modifications to the rule, and determined the rule will have minimal direct impact on SPS's current operations or costs. As long as ash remains viable to the industry and control technologies that may be required under other air regulations do not chemically or physically change the ash, 100% beneficial use of ash will be maintained. In the event the installation of controls through other regulations renders the ash unusable for market purposes, SPS will be required to follow the CCR Rule for disposal, potentially requiring the installation, maintenance, and monitoring of ash landfills.

D. Water Quality Regulation

Cooling Water Intake Structures

Section 316(b) of the federal Clean Water Act ("CWA") requires the EPA to develop regulations governing the design, maintenance, and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to aquatic species. The regulations must address both impingement (the trapping of aquatic biota

[20] *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*. Final Rule, December 19, 2014. See http://www2.epa.gov/coalash/coal-ash-rule.

against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems).

SPS's New Mexico and Texas facilities are not affected by this rule because no SPS facilities withdraw surface water for cooling purposes. In addition, SPS does not operate any cooling ponds.

Thermal Discharge

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. SPS facilities are not subject to this rule because they do not discharge any heated cooling water from power plants to surface waters.

Effluent Limitation Guidelines

As part of the National Pollutant Discharge Elimination System ("NPDES") process, the EPA identifies technology-based contaminant reduction requirements called Effluent Limitation Guidelines ("ELG"). The ELGs are used by permit writers as the maximum amount of a pollutant that may be discharged to a water body. ELGs are periodically updated to reflect improvements in pollution control and reduction technologies.

In 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil, or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. In 2017, the EPA postponed the rule's compliance date pending judicial review and agency reconsideration of the rule.

States that implement the federal NPDES have the authority to implement more restrictive requirements than are currently in place and it is possible that states will utilize the extensive docket of information published in the draft ELG rule to justify more stringent discharge limits.

3.10 - Impacts Due to an Aging SPS Generation Fleet

Aging fossil fuel generating units are becoming a critical issue facing SPS, as replacement of existing generation generally places upward pressure on rates when incremental costs are higher than average (embedded) costs. Average generation age of the SPS fleet is approximately 45 years old. Several of SPS-owned generation units are at the end of their useful life and either must be retired or totally refurbished/rebuilt. Retirement of certain generation could create transmission reliability problems, depending on the location, resulting in increased transmission expenditures. The cost and operational advantage of new technology could outweigh the benefits and cost of maintaining existing or rebuilt generation. SPS must weigh the costs and benefits of acquiring new capacity either through self-build or purchased power compared to the cost of maintaining an aging generation fleet.

3.11 - Impacts Due to High Variability in SPS Forecasted Loads

Over the last several years, SPS has experienced an increased variability in system load growth. Much of the variability in load growth is being driven by the volatility in oil and natural gas prices. Increased variability in loads creates additional risk that does not exist in a system that is characterized by stable growth in system loads. Providing reliable service for a system containing significant load variability will cost more than a system without such load variability. An example of the volatility in oil and natural gas prices occurred in the period 2013 to 2015. Oil prices were high reaching upwards of $95 per barrel. Oil companies were investing significant capital dollars in oil production in the southeast New Mexico region which significantly increased the load obligation to SPS. In mid-2016, oil prices began slowly decreasing to the point the load growth slowed close to zero growth in southeast New Mexico.

As oil prices decrease, oil-related capital expansions also decrease, ultimately impacting SPS in terms of reductions to the forecasted obligation load. More recently, SPS has experienced a slight increase in system load growth due to substantial oil production in southeastern New Mexico.

These "on-again off-again" plans for capital expansion in the oil sector directly impact SPS's resource planning. A conservative approach (to generation resource planning) is to design a system capable of serving the expected oil-related load growth, but no more than the expected load growth, which could result in SPS's inability to provide service to some new loads (including non-oil loads). Another approach is to design a generation resource plan capable of covering the expected load growth plus some level of load growth uncertainty.

The choice between a conservative and flexible approach to generation resource planning depends upon many competing factors including the risks created due to the size of the potential variability in new load growth, the rate and timing of this new load growth, and the cost of the ability to reliably serve this additional new load growth variability.

3.12 - Identification of Critical Facilities Susceptible to Supply-Source or Other Failures and Summary of Back-up Fuel Capabilities and Options

SPS takes system reliability very seriously and devotes significant resources to protecting the system from multiple types of risks. The SPS transmission system is designed for single contingency or N-1 standards and therefore has the ability to sustain service in the face of various types of generator and transmission contingencies. In addition, SPS is compliant with the NERC reliability standards which require that assets critical to operation of the bulk electric system be identified and special protections for those facilities implemented. For safety and reliability, any lists or descriptions of these critical assets are considered highly confidential and not available to the public domain. Further, all of SPS's owned generation units have redundant fuel supplies, mitigating the risk of supply-source failures. With the move from SPS as the BA to SPP as the BA, the entire generation market is operated differently. Other SPP market generation would address any deficiencies in SPS resources.

Section 4. CURRENT LOAD FORECAST

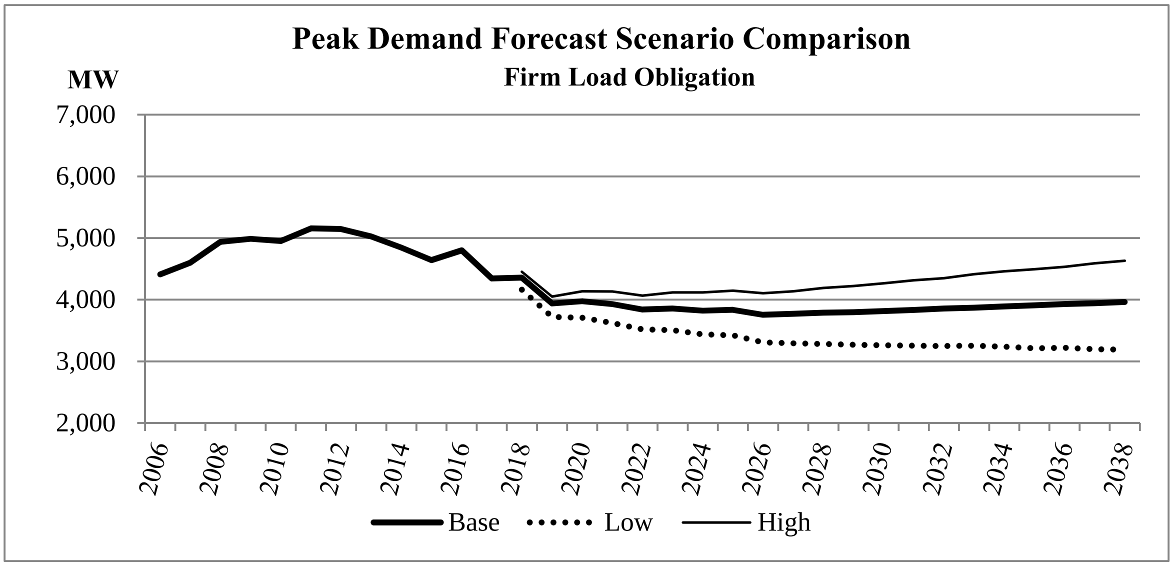
4.01 - Forecast Overview

Projections of future energy sales and coincident peak demand are fundamental inputs into SPS's resource need assessment. As required by the IRP Rule, SPS has prepared base, high, and low case scenario forecasts (17.7.3.9(D)(2) NMAC).

SPS projects its base or median electric firm obligation load (firm retail and firm wholesale requirements customers) to decrease at a compounded annual growth rate of -0.5% or an average of -18 MW per year through the Planning Period (2019-2038). The primary driver in the average MW decline is the expiration of the WTMPA contract in May 2019. SPS's base or median energy sales are forecasted to decrease at a compounded annual growth rate of -0.1% or an average growth rate of -25 GWh during the same period. The load decrease over the Planning Period contrasts to the historical annual average load decline of -0.6% over the last 10 years (ending 2017). The historical annual average energy decline over the ten years ending 2017 is -0.9%. Load and energy decreases were driven by the decline of wholesale load due to expiration of the New Mexico Cooperatives' wholesale contracts and contractual changes within existing wholesale contracts. In addition, the decline in oil prices that started in the third quarter of 2015 slowed the oil and gas expansion in southeastern New Mexico. Also, over the last several years SPS has seen a decline in potash mining.

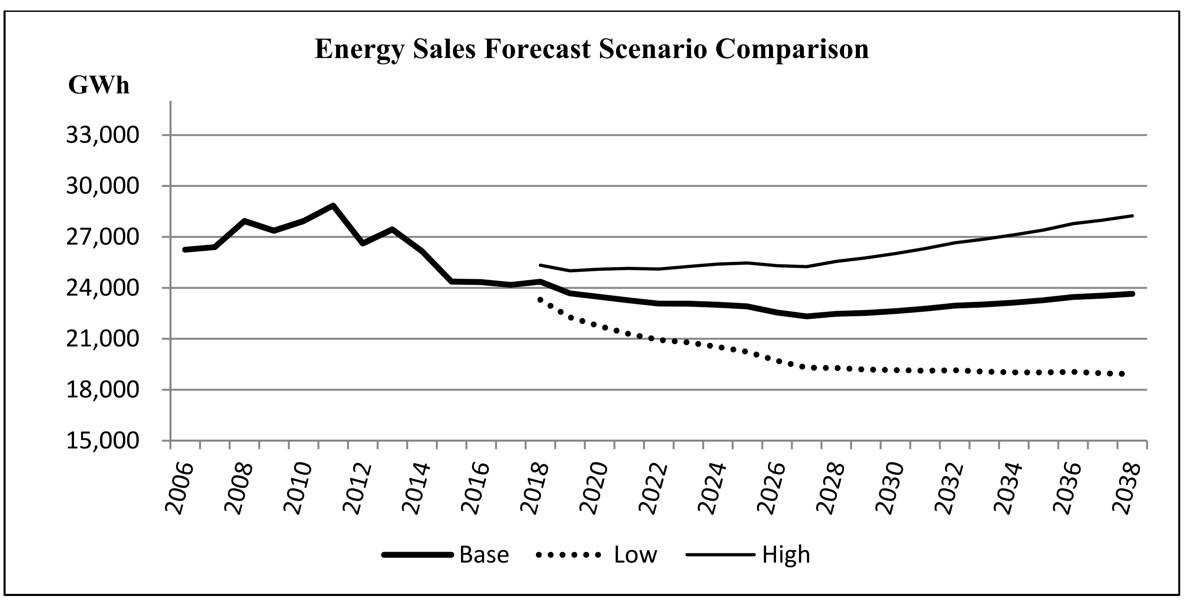
The SPS low forecast scenario of coincident peak demand decreases at a compounded annual growth rate of -1.3% through the Planning Period, and the high forecast scenario of coincident peak demand increases at a compounded annual growth rate of 0.2% per year. Figure 4F.1 below contains a graphical representation of the low and high forecast scenarios of coincident peak demand.

Figure 4F.1: Coincident Peak Demand Forecasts



SPS's annual energy sales low forecast scenario decreases at a compounded annual growth rate of -1.0% through 2038, and the annual energy sales high forecast scenario increases at a compounded annual growth rate of 0.5% per year. Figure 4F.2 below contains a graphical representation of the low and high scenario forecasts of annual energy sales.

Figure 4F.2: Energy Sales Forecasts



Figures 4F.1 and 4F.2 (above) show the base, high, and low forecasts for firm coincident peak demand and annual energy sales graphically. Appendix D (Tables D-10 and D-11) provides the data supporting the charts. Appendix D (Table D-11) also shows the SPS forecast for its total annual energy sales with eighteen years of history starting in 2000, and it shows annual growth and compounded growth to/from 2017. The bold line across the table delineates historical from projected information.

The base peak demand forecast assumes economic growth based on projections from IHS Global Insight, Inc. ("Global Insight") and normal summer peak weather conditions. SPS estimates a 70% probability that the actual peak demands and energy sales will fall between the high and the low forecast scenarios.

4.02 - Peak Demand Discussion

Firm peak demand in the SPS service territory has declined over the last 10 years (through 2017). SPS's firm peak demand decreased by -595 MW or -12.0%, from 2008 to 2017. Load growth was dampened as a result of decreased demand from wholesale customers due to changes in contracted load and the settlement agreement with the New Mexico Cooperatives. In the 10-year period ending 2017, the population in the SPS service territory grew by an annual average rate of 0.6% per year. Combined New Mexico and Texas Gross State Product ("GSP") averaged annual gains of 2.6% from 2008 through 2017. During this same period, SPS lost 2.1% of its residential customers due to the loss of approximately 18,000 residential customers when the City of Lubbock assets were sold to Lubbock Power & Light. When the loss of residential customers from the Lubbock sale was netted out, SPS's residential customer base increased by approximately 12,800 customers (or 4.4%) from 2008 to 2017.

The peak demand forecast compounded annual growth rate for the Planning Period through 2038 is a 0.5% loss. This is slightly lower than the ten-year period ending in 2017 with a compounded annual growth rate of a 0.6% loss. Retail peak demand for the Planning Period increases at a compounded annual growth rate of 0.5%, compared to the ten-year period ending 2017 compounded annual growth rate of 1.1%. Since 2004, the historical growth in SPS's retail sector has been fueled by oil drilling and gas extraction in southeastern New Mexico; however, the growth has been dampened by slow growth in the New Mexico and Texas residential and Texas commercial sectors. SPS has identified potential growth in the New Mexico retail sector due to additional increases in oil and gas load during the resource Planning Period; however, this potential load has been excluded from the forecast (see Table 1 below). SPS does not include new load in the forecast until the load has materialized and is reporting in SPS's customer billing system. Wholesale peak demand for the Planning Period decreases at a compounded annual growth rate of -7.2%, compared to the ten-year period ending 2017 compounded annual growth rate of 4.7%. The decline of wholesale load is due to the settlement agreement with the New Mexico Cooperatives, wholesale contracts ending, and contractual changes within existing wholesale load. SPS assumes that these wholesale contracts will not be renewed after their known expiration dates.

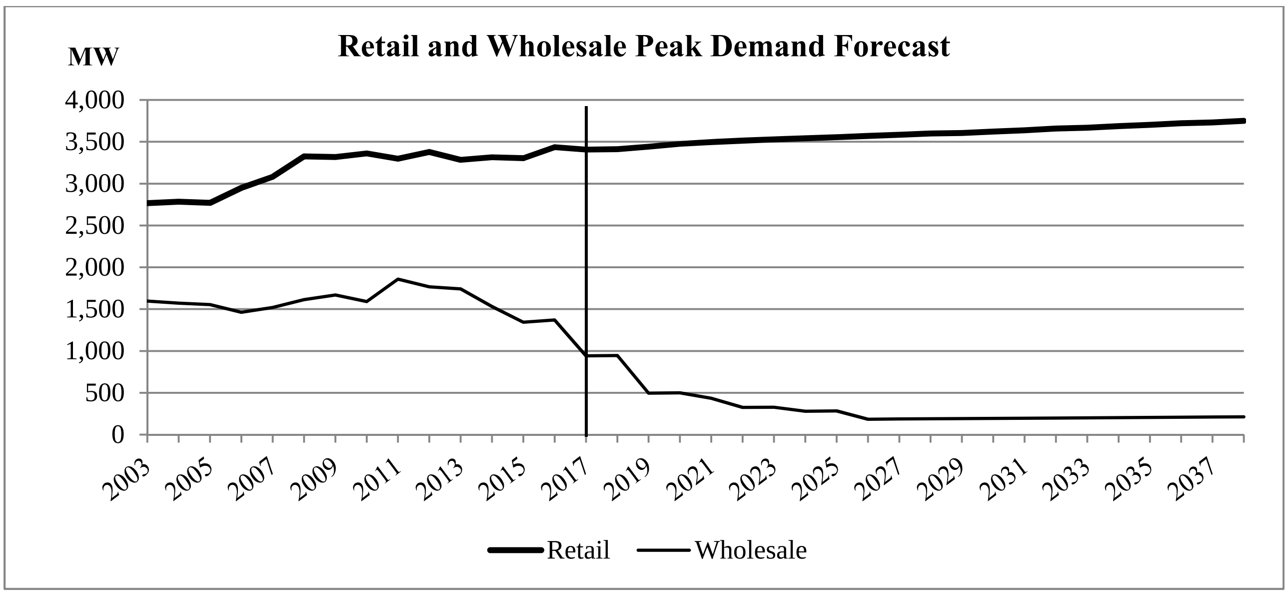
Table 4-1: Potential Load Not in Forecast (in MW)

Year	Q1	Q2	Q3	Q4	Total
2018	27	105	24	78	234
2019	15	53	27	49	144
2020	45	45	0	11	101
2021	20	70	0	40	130

Combined growth in Texas and New Mexico GSP is calculated at 2.6% in 2017, followed by an average annual growth rate of 2.7% during the Planning Period. Population growth is similar to the recent past, with annual gains averaging 0.5% through the Planning Period. SPS projects residential customer growth will average annual increases of 0.5% per year through 2038.

Table D-4 in Appendix D (Electric Energy and Demand Forecast) shows the SPS coincident peak demand by retail and wholesale customer categories. Figure 4F.3 shows the SPS coincident peak demand by retail and wholesale customers graphically.

Figure 4F.3: Retail and Wholesale Peak Demand Forecasts

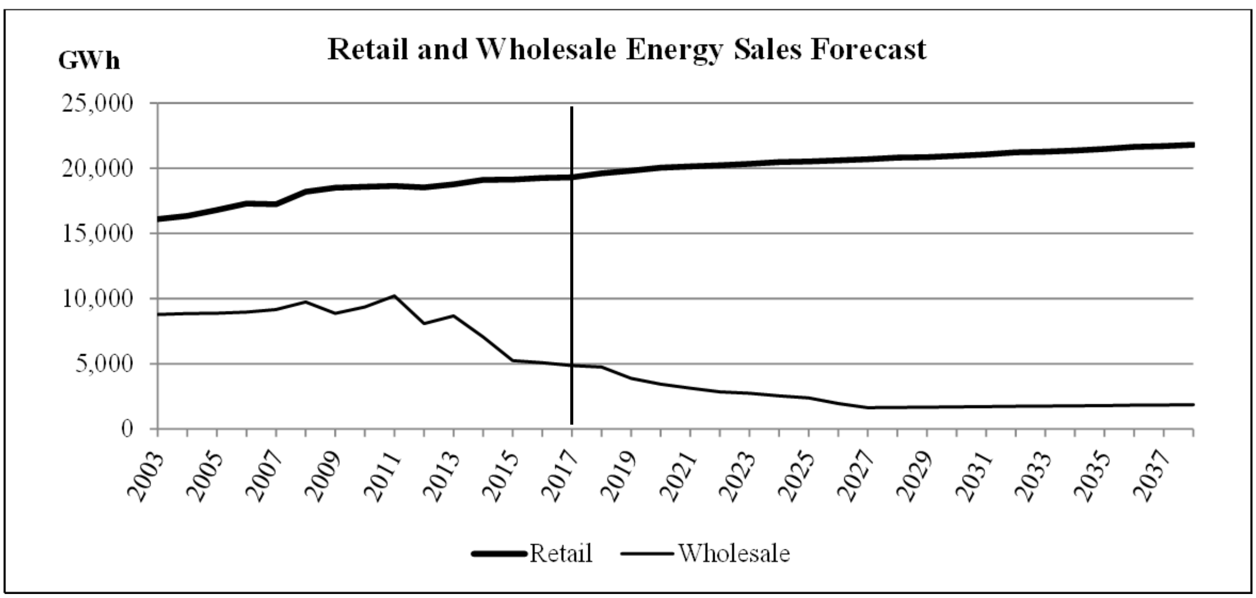


4.03 - Annual Energy Discussion

SPS is calling for energy sales in the base case forecast to experience flat growth over the Planning Period. The expected declines in wholesale energy sales corresponding to the termination or reduction of sales to specific wholesale customers will offset growth in the retail sector.

During the past ten years SPS has experienced declines in energy sales. Energy sales decreased by 3,759 GWh, or 13.5%, from 2008 to 2017. From 2019 to 2038, SPS estimates its annual energy sales will decrease by -28 GWh or -0.1%. The energy sales forecast's compounded annual growth rate for the Planning Period through 2038 is -0.1%. This is less negative than the compounded annual growth rate of -0.9% for the 10-year period ending 2017. Retail energy sales for the Planning Period increase at a compounded annual growth rate of 0.5%, compared to the 10-year period ending 2017 compounded annual growth rate of 1.1%. Retail energy sales will benefit from strong growth in the New Mexico commercial and industrial sector, which is heavily dependent on the oil and natural gas industries. Base case wholesale energy sales are forecasted to decrease at a compounded annual growth rate of -4.6% for the Planning Period. This pace is less negative than the historical annual rate of 6.1% loss from 2007 to 2017. Again, the decline of wholesale load is due to the settlement agreement with the New Mexico Cooperatives, wholesale contracts ending, and contractual changes within existing wholesale load. Figure 4F.4 shows SPS's energy sales by retail and wholesale customer class graphically.

Figure 4F.4: Retail and Wholesale Energy Sales Forecasts



4.04 - High and Low Case Forecasts

Development and use of different energy sales and demand forecasts for planning future resources is an important aspect of the planning process. Alternative high and low forecast scenarios to the base case were developed for the 2018 IRP. The high and low forecast scenarios are based on a Monte Carlo simulation for energy sales and peak demand forecasts with probabilistic inputs for the economic, energy, and weather drivers of the forecast models and for model error. The high forecast scenario is the forecast level from the Monte Carlo simulation that represents a plus one standard deviation confidence band from the base case forecast. The low forecast scenario is the forecast level from the Monte Carlo simulation that represents a minus one standard deviation confidence band from the base case forecast. There is a 70% probability that actual energy sales and coincident peak demand will fall within the high and low forecast scenarios.

Appendix D (Table D-10 and Table D-11) provides a summary of the base, high, and low peak demand and energy sales forecasts.

Typical Historic Day Load Patterns

Please refer to Appendix E for the typical day load patterns on a system-wide basis for each customer class provided for: peak day, average day, and representative off-peak days for each calendar month.

4.05 - Forecasting Methodologies

The following discussion describes the methods used to forecast energy sales and coincident peak demand for each of its various customer classes in SPS.

SPS forecasts retail energy sales and customers by class for each jurisdiction. Retail coincident peak demand is forecasted in aggregate at the total SPS level. The wholesale energy sales and coincident peak demand forecasts are developed at the individual customer level of detail. SPS models its forecasts at a monthly frequency and uses monthly historical data to develop the customers, energy sales, and coincident peak demand forecasts. Annual energy sales are an aggregation of the monthly energy sales estimates. Energy sales are forecasted at the delivery point and peak demand is forecasted at the generating source. The annual coincident peak demand occurs in July throughout the Planning Period 2019-2038.

Global Insight, a trusted data source for forecasting professionals, provides economic and demographic data and forecasts. SPS assumes normal weather for the forecast period. Normal weather is based on a 30-year rolling average of historical weather data for the energy sales and retail coincident peak forecasts.

4.06 - Energy Sales Forecasts

SPS's retail customer counts, retail energy sales, and full requirement wholesale energy sales forecasts are developed using econometric models and trend models. An econometric model is a widely accepted modeling approach involving linear regression analysis. Linear regression analysis is a statistical technique that attempts to understand the movement of the dependent variable, for example, energy sales, as a function of movements in a set of independent variables, such as economic and demographic concepts, customers, price, trend, and weather, through the quantification of a single equation. Other variables used in the econometric models may include autoregressive correction terms and binary variables. Binary variables are used in models to account for non-weather-related seasonal factors and unusual billing activity. The autoregressive correction term is used to aid in eliminating bias found in time-series models. After developing and testing the econometric models to identify the relationship between the dependent and independent variables, forecasts of the independent variables are used to predict future energy sales and customer counts.

SPS's econometric models are evaluated through examining the model statistics output and tests results. Each variable coefficient in the models is checked for the correct theoretical signs and statistical significance. The coefficient of determination (R-squared) test statistic is a measure to verify the quality of the model's fit to the historical data. The models are also tested for correlation of errors from one period to the next. The absence of correlation between the residual errors is an important indicator that the model is performing adequately. Graphical inspection of a model's error term helps identify if a model suffers from auto-correlation (i.e., error terms are not random and are correlated between periods) or heteroscedasticity (i.e., inconstant variance of errors over the sample period). A model with auto-correlation may indicate model misspecification.

The output from the econometric models for the retail energy sales is adjusted to reflect the expected incremental impact of DSM programs. The model output is also adjusted for electric vehicle impacts. SPS developed a base, low, and high scenario of estimated sales due to electric vehicles. The forecast assumes the base sales scenario. The model output may also be adjusted with information from SPS's Managed Account Sales group regarding SPS's largest commercial and industrial customers. The Managed Account Sales group provides information about known events that can impact energy sales that would not be captured in the historical data. Such events might include a scheduled increase or decrease in load for a specific customer due to a plant expansion, or a reduction in load stemming from a plant shutdown. The final adjusted output from the econometric models becomes part of the base case energy sales forecast.

Energy sales forecasts for SPS's partial requirement wholesale customers are developed based on historical consumption patterns or econometric models as described above, subject to contractual agreement.

4.07 - Peak Demand Forecasts

SPS develops an econometric model, as described above, to forecast the monthly retail coincident peak demand. Total retail coincident peak demand is forecasted in aggregate at the source for the total SPS company level. The exogenous variables in the retail coincident peak demand model include weather, binary and trend variables, and retail energy sales. Retail energy sales are not adjusted for DSM savings, electric vehicle increases or load increases or decreases as identified by the Managed Account Sales group prior to being used in the model. Instead, these adjustments are made to the output from the retail peak demand model.

The full requirements wholesale coincident peak demand is developed on an individual customer basis. SPS uses a load factor methodology to calculate the coincident peak demand associated with the energy sales for each full requirement wholesale customer. For each customer, SPS calculates a monthly load factor based on historical energy sales and coincident peak demand data as recorded at the delivery point. Monthly load factors are calculated as:

Load Factor = Energy Sales/(Peak Demand * Hours Per Month)

The monthly load factors are then applied to each full requirement wholesale customer's respective energy sales forecast to derive the monthly peak demand forecasts.

Peak Demand = Energy Sales/(Load Factor * Hours Per Month)

The peak demand forecasts are then adjusted for line losses to derive the peak demand forecast at the source.

The partial requirement wholesale customer coincident peak demand forecasts are determined by individual customer contractual agreement.

4.08 - Modeling for Uncertainty

SPS has developed high and low forecast scenarios to the base case forecast. These alternative forecasts are derived from Monte Carlo simulations of energy sales and coincident peak demand.

Monte Carlo simulation is a modeling technique that ascribes probabilistic characteristics to selected inputs and the output of a model. The Monte Carlo simulations are based on econometric models used to forecast energy sales and coincident peak demand. In particular, energy sales and coincident peak demand are modeled at the combined retail and full requirement wholesale sales level of aggregation, excluding the wholesale customer WTMPA. WTMPA is modeled separately because of how that load is handled in the generation modeling process.

In these models, probability distributions are defined for exogenous variables with inherent uncertainty associated with their forecast values. Probability distributions are a realistic way of describing uncertainty in variables. An example of a variable with inherent uncertainty is the maximum peak day temperature in the coincident peak demand model. While SPS assumes the value will be 101.7 degrees Fahrenheit for each July during the forecast period, it is unlikely that each year the actual peak day maximum temperature will be 101.7 degrees Fahrenheit. The probability distributions contain the possible values for variables with inherent uncertainty over the forecast period, based on characteristics of the data set for each variable. The weather, economic and energy variables, and the model error are assumed to have inherent uncertainty in the models used to develop the high and low energy sales and coincident peak demand forecast scenarios.

For each simulation run of these forecasting models, the values for the exogenous variables with inherent uncertainty are randomly selected from respective probability distribution. By using probability distributions, variables can have different probabilities of different outcomes occurring. Monte Carlo simulation calculates the model results over and over, each time using a different set of random values from the probability functions. The output from the Monte Carlo simulation models is then calibrated so that the 50% probability forecast is equal to the respective energy sales and coincident peak demand base case forecast.

4.09 - Weather Adjustments

SPS incorporates several different weather variables in its forecasting models. For the energy sales models, SPS may include monthly heating degree days, cooling degree days, and precipitation. The heating degree days and the cooling degree days are calculated on a base of 65 degrees Fahrenheit for each day and then totaled by month.

Heating Degree Days = Max (65 - Average Daily Temperature, 0)

Cooling Degree Days = Max (Average Daily Temperature - 65, 0)

The coincident peak demand models include a maximum peak day temperature variable and a rolling one-week summation of the days prior to the monthly peak day with a maximum daily temperature of 95 degrees Fahrenheit or greater variable.

Weather during the forecast period is assumed to be normal. Normal weather is defined as a rolling 30-year average for heating degree days, cooling degree days, precipitation, maximum temperature, minimum temperature, average temperature, and days with maximum temperature 95 degrees Fahrenheit or greater. The energy sales and coincident peak demand forecasts do not have any other weather normalization adjustments.

For historical periods, SPS weather normalizes historical energy sales and coincident peak demand data for variance analysis purposes. This weather normalization process involves subtracting weather-impacted energy sales or peak demand from actual sales or peak demand. Weather-impacted sales or peak demand is calculated by multiplying the forecast model weather variable coefficients by the variance of actual weather from normal weather.

Weather-Impacted Energy Sales =

Weather Coefficient * (Actual Weather-Normal Weather)

Weather Impacted Peak Demand =

Weather Coefficient * (Actual Weather-Normal Weather)

4.10 - Demand-Side Management

SPS promotes DSM programs that help its customers reduce energy sales and peak demand through energy efficiency and education. Xcel Energy's DSM Regulatory Strategy and Planning group develops the projections of future and embedded DSM program savings.

SPS adjusts its retail energy sales and coincident peak demand forecasts with projected incremental DSM program savings. The incremental DSM program savings are calculated by subtracting embedded DSM savings from future DSM savings.

Incremental DSM Savings = Future DSM Savings – Embedded DSM Savings

SPS does not directly adjust its forecast models or model output for naturally occurring DSM savings that could be attributed to actions other than those of SPS. Naturally occurring DSM energy and peak demand savings are unquantifiable. However, theoretically the historical energy sales and coincident peak demand data used in SPS's forecast modeling process does have embedded in it any naturally occurring DSM savings. Therefore, the forecast models and model output do account indirectly, through the historical data, for naturally occurring DSM savings. Naturally occurring DSM energy and peak demand savings do not impact SPS's sponsored DSM resources.

4.11 - Demand Response, Energy Efficiency, and Behind-the-Meter Generation

The historical energy sales data used in SPS's forecast modeling process is net of behind-the-meter generation and demand response energy sales. Therefore, the forecast models and model output indirectly account, through the historical data, for behind-the-meter and demand response energy sales. The historical peak demand data used in the forecasting process has been adjusted to add back behind-the-meter generation and demand response to represent the total demand on the system.

4.12 - Forecast Accuracy

SPS reviews its demand and energy forecasts for accuracy annually. Overall, forecast accuracy is better in the short term than in the long term.

Appendix D (Table D-12 through Table D-17) provides a comparison of the actual energy sales and firm load obligation demand forecasts to the forecasted sales and firm load obligation demands, as required by the IRP Rule. Firm load obligation equals actual load less available interruptible load. *See* Figures 4F.5 and 4F.6 (next page).

Figure 4F.5: Forecast Comparison with Actual Energy Sales

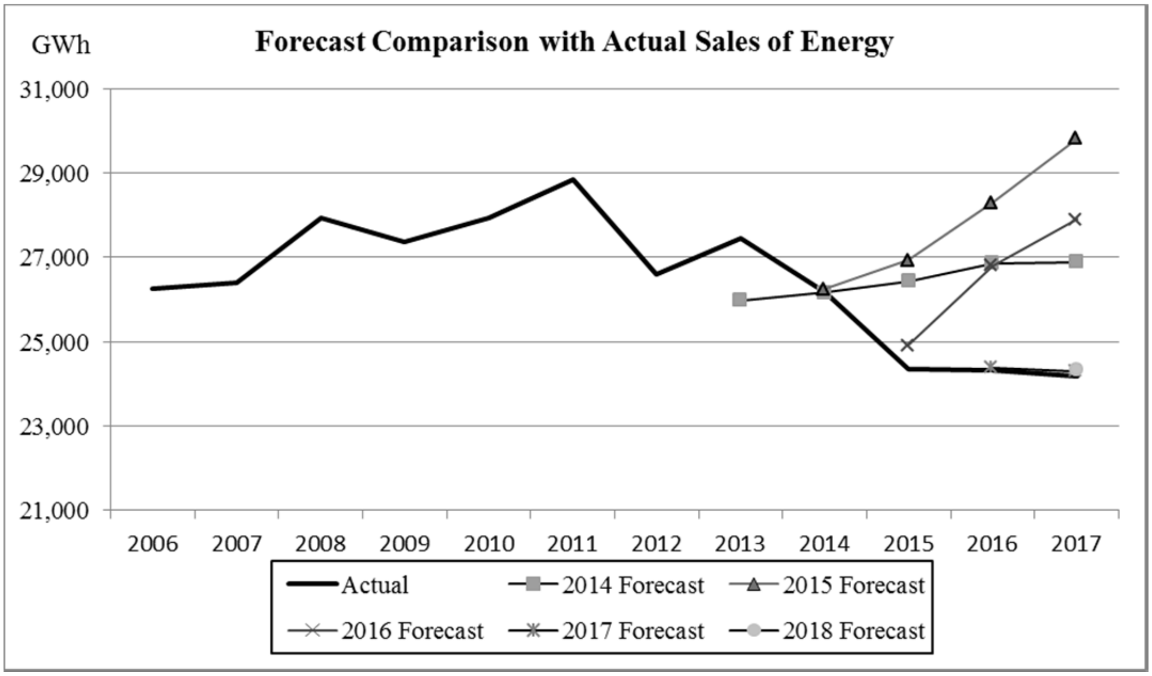
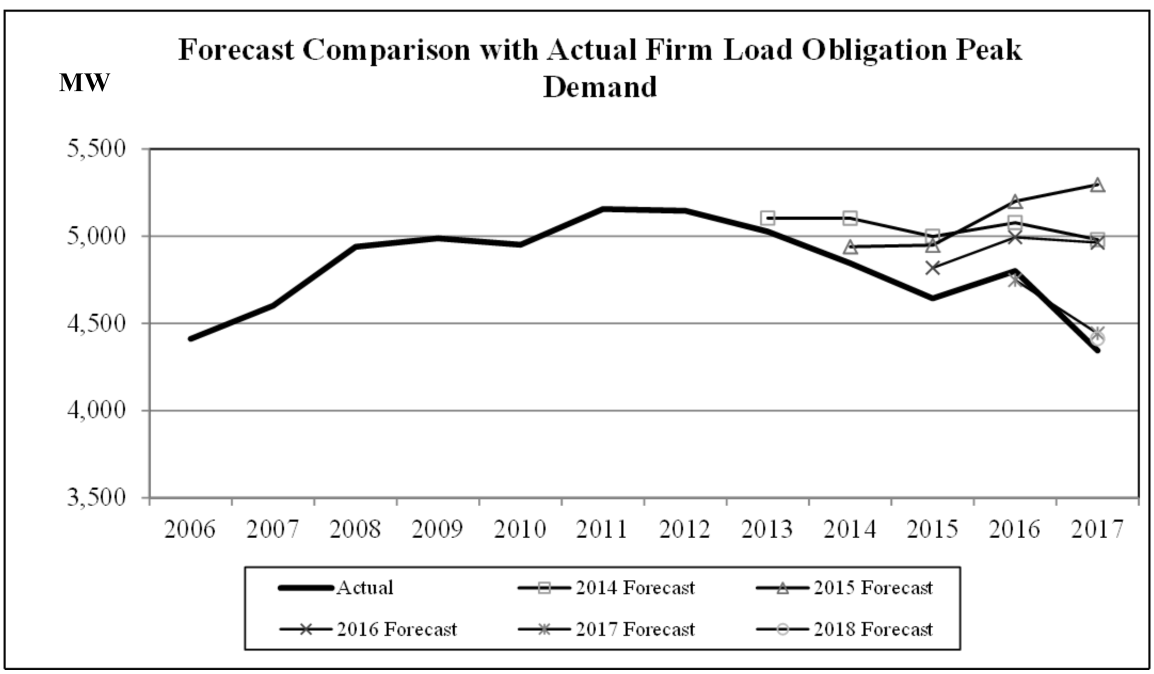


Figure 4F.6: Forecast Comparison with Actual Firm Load Obligation Peak



4.13 - Econometric Model Parameters

Please refer to Appendix F, which provides the parameters associated with SPS's econometric forecasting models.

Section 5. L&R TABLE

The IRP Rule requires that utilities provide an L&R table of existing loads and resources at the time of its IRP filing, specifically including: (1) utility-owned generation; (2) energy storage resources; (3) existing and future contracted-for purchased power including QF purchases, (4) purchases through net metering programs, as appropriate, (5) demand-side resources, as appropriate, and (6) any other resources relied upon by the utility.

Resource planners use a range of approaches to help identify the amounts, timing, and types of generation resources that should be added to meet increasing customer demand for electric power. One basic and straightforward tool is the L&R table. The function of an L&R table is to provide a comparison between the amount of electric generating supply and the peak load of a system. In years when load (plus some added margin[21]) exceeds generation supply, additional generation is needed. Table 5-1 provides a summarized L&R table for the SPS electric system.

Table 5-1: Summarized L&R Table

		2019 (MW)	**2020 (MW)**	**2021 (MW)**
(a)	Owned Generation Capacity	4,492	4,492	4,492
(b)	Purchased Generation Capacity	1,089	1,089	1,089
(c)	Total Generation Capacity	5,581	5,581	5,581
(d)	Load Requirements	3,938	3,976	3,929
(e)	Capacity Margin (12%)	473	477	472
(f)	Total Load + Reserves	4,410	4,453	4,401
(g)	Resources Long / (Short)	782	629	992

[21] Reserve margin is additional generation capacity that can be used during any contingency including: higher than expected energy demand, unplanned generation outages, and inoperable transmission infrastructure.

The L&R table above provides a number of insights into the amounts and timing of future generation resource needs. SPS has more than sufficient capacity in 2019, 2020, and 2021, largely due to the reduction in the load forecast over the past three years, in particular the reduction in the oil and gas growth.

SPS's L&R preferred base case, low load case, and high load case tables for the Planning Period (2019-2038) are based on the March 2018 forecast and have been provided in Tables 5.2, 5.3, and 5.4 below. The L&R case tables show SPS will have more than sufficient capacity to meet its firm load obligations for the Action Plan Period (2019-2022). For a more detailed discussion of the base case load and resources, along with the low and high-load forecast sensitivities, please refer to Section 7.

Table 5-2: Summary of Preferred SPS Base Case L&R

SPS Loads & Resources Balance Summer 2019-2038 - BASE FORECAST
Based on March 2018 Load Forecast

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1.0 Existing Generation:	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492
2.0 Existing Energy Storage Resources:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.0 Purchased Power:	1,089	1,089	1,089	1,084	1,084	860	849	841	820	780	780	780	780	746	746	189	166	117	117	117
4.0 Expansion Plan:	11	15	16	16	17	21	21	22	43	84	84	85	85	120	120	121	121	171	172	173
5.0 Retirements:	0	(114)	(204)	(204)	(316)	(428)	(521)	(765)	(765)	(956)	(1,068)	(1,068)	(1,318)	(1,561)	(2,639)	(2,639)	(2,899)	(2,899)	(3,241)	(3,241)
6.0 Contract Extensions	0	0	0	0	0	224	224	224	224	224	224	224	224	224	224	0	0	0	0	0
A) Net Dependable Capacity	**5,592**	**5,482**	**5,392**	**5,388**	**5,277**	**5,168**	**5,065**	**4,813**	**4,814**	**4,624**	**4,512**	**4,513**	**4,263**	**4,021**	**2,943**	**2,163**	**1,881**	**1,882**	**1,540**	**1,541**
7.0 Retail:	3,479	3,518	3,540	3,565	3,584	3,603	3,619	3,641	3,659	3,679	3,690	3,712	3,734	3,758	3,772	3,795	3,815	3,839	3,853	3,877
8.0 Firm Wholesale:	326	327	261	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.0 DSM Impact:	(6)	(10)	(15)	(19)	(24)	(29)	(34)	(39)	(44)	(50)	(55)	(61)	(67)	(71)	(76)	(81)	(86)	(91)	(96)	(101)
10.0 Interruptibles:	(31)	(31)	(31)	(31)	(32)	(32)	(32)	(32)	(31)	(31)	(30)	(30)	(30)	(29)	(29)	(28)	(28)	(28)	(27)	(27)
11.0 Firm PR Load:	170	172	174	326	328	280	283	185	187	189	192	194	196	199	201	203	206	208	211	213
B) Firm Load Obligation	**3,938**	**3,976**	**3,929**	**3,840**	**3,856**	**3,823**	**3,835**	**3,755**	**3,770**	**3,788**	**3,795**	**3,815**	**3,833**	**3,856**	**3,868**	**3,889**	**3,907**	**3,929**	**3,941**	**3,962**
12.0 Planning Reserve Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
13.0 Required Reserves	473	477	472	461	463	459	460	451	452	455	455	458	460	463	464	467	469	471	473	475
14.0 Actual Existing Excess Capacity	1,654	1,506	1,463	1,548	1,421	1,345	1,230	1,058	1,044	836	717	697	430	165	(925)	(1,726)	(2,027)	(2,047)	(2,401)	(2,421)
15.0 Capacity Position: Long *(Short)*	1,182	1,029	992	1,087	958	886	769	608	591	382	261	240	(30)	(298)	(1,389)	(2,193)	(2,496)	(2,519)	(2,873)	(2,896)
16.0 Lubbock Firm Capacity Sale	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C) Net Capacity Position: Long *(Short)*	782	629	992	1,087	958	886	769	608	591	382	261	240	(30)	(298)	(1,389)	(2,193)	(2,496)	(2,519)	(2,873)	(2,896)

Table 5-3: Summary of SPS High Load Case L&R

SPS Loads & Resources Balance Summer 2019-2038 - HIGH Forecast

Based on March 2018 Load Forecast

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1.0	Existing Generation:	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492
2.0	Existing Energy Storage Resources:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.0	Purchased Power:	1,089	1,089	1,089	1,084	1,084	860	849	841	820	780	780	780	780	746	746	189	166	117	117	117
4.0	Expansion Plan:	11	15	16	16	17	21	21	22	43	84	84	85	85	120	120	121	121	171	172	173
5.0	Retirements:	0	(114)	(204)	(204)	(316)	(428)	(521)	(765)	(765)	(956)	(1,068)	(1,068)	(1,318)	(1,561)	(2,639)	(2,639)	(2,899)	(2,899)	(3,241)	(3,241)
6.0	Contract Extensions	0	0	0	0	0	224	224	224	224	224	224	224	224	224	224	0	0	0	0	0
A)	**Net Dependable Capacity**	**5,592**	**5,482**	**5,392**	**5,388**	**5,277**	**5,168**	**5,065**	**4,813**	**4,814**	**4,624**	**4,512**	**4,513**	**4,263**	**4,021**	**2,943**	**2,163**	**1,881**	**1,882**	**1,540**	**1,541**
7.0	Retail:	3,592	3,679	3,745	3,790	3,844	3,897	3,931	3,991	4,024	4,081	4,115	4,164	4,215	4,250	4,318	4,366	4,402	4,407	4,449	4,547
8.0	Firm Wholesale:	326	327	261	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.0	DSM Impact:	(6)	(10)	(15)	(19)	(24)	(29)	(34)	(39)	(44)	(50)	(55)	(61)	(67)	(71)	(76)	(81)	(86)	(91)	(96)	(101)
10.0	Interruptibles:	(31)	(31)	(31)	(31)	(32)	(32)	(32)	(32)	(31)	(31)	(30)	(30)	(30)	(29)	(29)	(28)	(28)	(28)	(27)	(27)
11.0	Firm PR Load:	170	172	174	326	328	280	283	185	187	189	192	194	196	199	201	203	206	208	211	213
B)	**Firm Load Obligation**	**4,051**	**4,137**	**4,134**	**4,065**	**4,117**	**4,117**	**4,148**	**4,105**	**4,136**	**4,190**	**4,221**	**4,267**	**4,314**	**4,348**	**4,414**	**4,460**	**4,494**	**4,497**	**4,537**	**4,633**
12.0	Planning Reserve Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
13.0	Required Reserves	486	496	496	488	494	494	498	493	496	503	507	512	518	522	530	535	539	540	544	556
14.0	Actual Existing Excess Capacity	1,541	1,345	1,258	1,323	1,160	1,051	917	708	678	434	291	246	(51)	(327)	(1,471)	(2,298)	(2,614)	(2,615)	(2,996)	(3,092)
15.0	Capacity Position: Long (Short)	1,055	849	762	835	666	557	420	216	182	(69)	(216)	(266)	(569)	(849)	(2,000)	(2,833)	(3,153)	(3,155)	(3,541)	(3,648)
16.0	Lubbock Firm Capacity Sale	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C)	Net Capacity Position: Long (Short)	655	449	762	835	666	557	420	216	182	(69)	(216)	(266)	(569)	(849)	(2,000)	(2,833)	(3,153)	(3,155)	(3,541)	(3,648)

Table 5-4: Summary of SPS Low Load Case L&R

SPS Loads & Resources Balance Summer 2019-2038 - LOW FORECAST

Based on March 2018 Load Forecast

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1.0	Existing Generation:	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492
2.0	Existing Energy Storage Resources:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.0	Purchased Power:	1,089	1,089	1,089	1,084	1,084	860	849	841	820	780	780	780	780	746	746	189	166	117	117	117
3.0	Expansion Plan:	11	15	16	16	17	21	21	22	43	84	84	85	85	120	120	121	121	171	172	173
5.0	Retirements:	0	(114)	(204)	(204)	(316)	(428)	(521)	(765)	(765)	(956)	(1,068)	(1,068)	(1,318)	(1,561)	(2,639)	(2,639)	(2,899)	(2,899)	(3,241)	(3,241)
6.0	Contract Extensions	0	0	0	0	0	224	224	224	224	224	224	224	224	224	224	0	0	0	0	0
A)	**Net Dependable Capacity**	**5,592**	**5,482**	**5,392**	**5,388**	**5,277**	**5,168**	**5,065**	**4,813**	**4,814**	**4,624**	**4,512**	**4,513**	**4,263**	**4,021**	**2,943**	**2,163**	**1,881**	**1,882**	**1,540**	**1,541**
7.0	Retail:	3,261	3,252	3,234	3,243	3,233	3,219	3,205	3,194	3,181	3,175	3,164	3,159	3,154	3,150	3,157	3,146	3,120	3,125	3,135	3,106
8.0	Firm Wholesale:	326	327	261	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.0	DSM Impact:	(6)	(10)	(15)	(19)	(24)	(29)	(34)	(39)	(44)	(50)	(55)	(61)	(67)	(71)	(76)	(81)	(86)	(91)	(96)	(101)
10.0	Interruptibles:	(31)	(31)	(31)	(31)	(32)	(32)	(32)	(32)	(31)	(31)	(30)	(30)	(30)	(29)	(29)	(28)	(28)	(28)	(27)	(27)
11.0	Firm PR Load:	170	172	174	326	328	280	283	185	187	189	192	194	196	199	201	203	206	208	211	213
B)	**Firm Load Obligation**	**3,720**	**3,709**	**3,623**	**3,519**	**3,506**	**3,439**	**3,422**	**3,308**	**3,293**	**3,283**	**3,269**	**3,261**	**3,254**	**3,248**	**3,253**	**3,240**	**3,212**	**3,214**	**3,222**	**3,191**
12.0	Planning Reserve Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
13.0	Required Reserves	446	445	435	422	421	413	411	397	395	394	392	391	390	390	390	389	385	386	387	383
14.0	Actual Existing Excess Capacity	1,872	1,773	1,769	1,869	1,771	1,730	1,643	1,505	1,521	1,340	1,243	1,251	1,010	773	(310)	(1,077)	(1,331)	(1,333)	(1,682)	(1,650)
15.0	Capacity Position: Long (Short)	1,426	1,328	1,334	1,447	1,351	1,317	1,232	1,108	1,126	946	850	860	619	383	(701)	(1,466)	(1,716)	(1,718)	(2,069)	(2,033)
16.0	Lubbock Firm Capacity Sale	400	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C)	Net Capacity Position: Long (Short)	1,026	928	1,334	1,447	1,351	1,317	1,232	1,108	1,126	946	850	860	619	383	(701)	(1,466)	(1,716)	(1,718)	(2,069)	(2,033)

Section 6. IDENTIFICATION OF RESOURCE OPTIONS

The basic types of resources that are available for matching electricity supply and demand are discussed below. These resources play different roles in meeting a utility's demand and energy requirements. Supply-side resources provide generation capacity to serve load, whereas demand-side resources act to reduce the level of customer demand for electric power so fewer supply side-resources are required. Supply-side resources generally fall into three categories: traditional (or thermal), renewable, and energy storage. Traditional supply-side resources are typically fossil fuel based generation resources with physical fuel supplies that can be dispatched as the demand (or need) for power changes (increases or decreases) throughout the day. Renewable resources, on the other hand, are intermittent supply-side "as available" generation resources, effectively the energy produced is a function of the timing and force created by the wind blowing or the solar radiation intensity and conversion of photons of light to electrical voltage (e.g., photovoltaic "PV"). Renewable resources are typically must-take resources, which at times can create operational issues related to their integration into the electrical power grid. Energy storage supply-side resources can occur as potential, kinetic, chemical, or thermal energy and are capable of storing previously generated electric energy and releasing it at a later time.

Examples of Thermal Supply-Side Resources

1. <u>CT (Combustion Turbine)</u> – These simple-cycle, natural gas fired units are available in a wide range of sizes (25 MW to over 200 MW) and are often considered "peaking" units. CTs are very similar to a jet engine with an electrical generator connected to the turbine shaft. CTs are typically inexpensive to build but are relatively inefficient sources of generation. The ideal role for CTs is to be run during times of high electric demand.

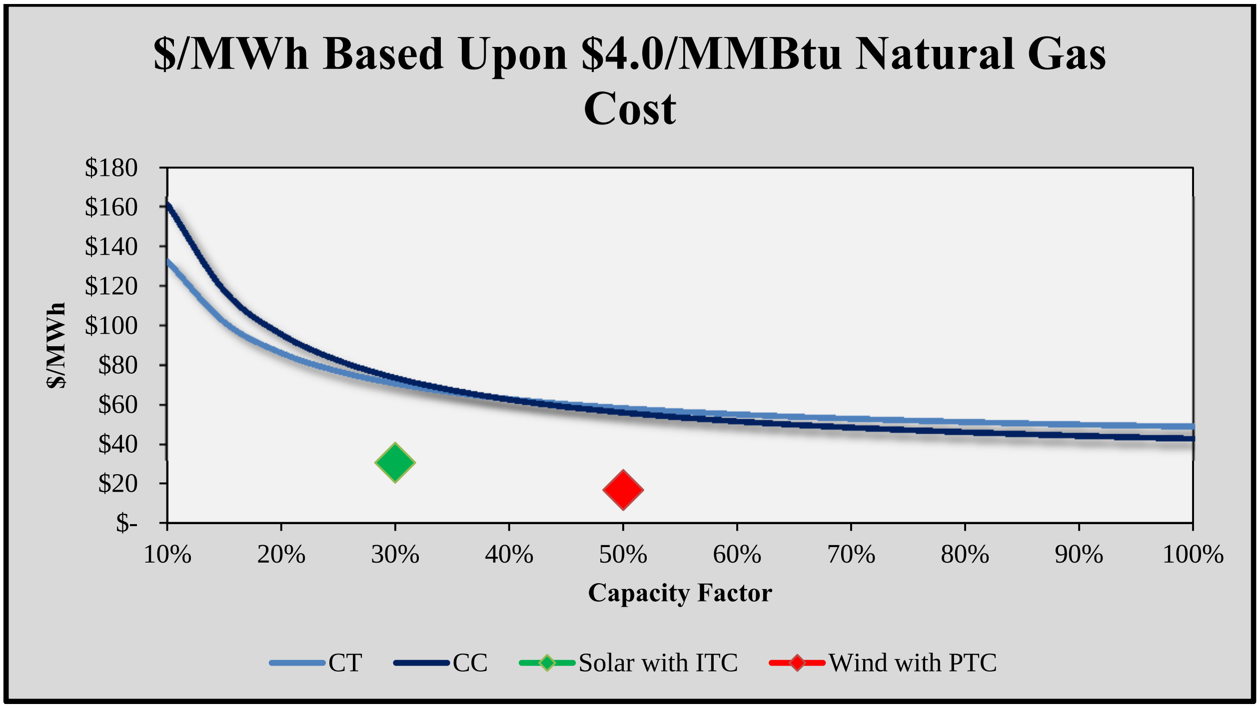
2. CC (Combined Cycle) – These high-efficiency, natural gas fired facilities use single or multiple CTs in conjunction with Heat Recovery Steam Generators ("HRSG") and they are often times considered "intermediate" units. The waste heat from a CT's exhaust gas is used to generate steam to run a steam turbine, which in turn produces additional electric power. CC units come in a variety of sizes near 100 MW to over 700 MW depending on the specific configuration of the facility. CC units have higher installed costs than CT units, but lower operating costs.

Resources are categorized by how they are used: (i) peaking, (ii) intermediate, (iii) baseload, or (iv) intermittent. Different generation technologies have distinctly different capital and operating cost characteristics. These characteristics dictate how various technologies are dispatched or used to serve load requirements of the system.

Figure 6F.1 (below) provides an illustration of how the general cost characteristics of gas CTs, gas CCs, renewable, and storage resources might compare with one another based on how they are utilized (i.e., peaking, intermediate, baseload, or intermittent) on the system. The figure shows that the overall cost (i.e., "all-in" cost) of electric energy per MWh depends highly on the number of hours a unit is operated, that is, the unit's capacity factor. The "all-in" cost curves decline as the annual fixed costs are distributed over more hours of operation.

Wind and solar resources have significantly decreased in costs over the past three years such that the all-in costs of these resources have become the most cost-effective when including tax credits. As discussed in Section 7, determining the most cost-effective generating portfolio must include consideration of the operational needs of the generating and transmission system.

Figure 6F.1: General Cost by Resource Type and Capacity Factor



Examples of Renewable Supply-Side Resources

1. Biomass – Biomass energy is derived from diverse energy sources such as wood and other organic matter, animal wastes, human refuse, and alcohol derived fuels. Landfill gas is a type of biomass generation using the methane gas produced by a solid waste landfill for combustion and power production. Biomass facilities are often base loaded energy sources with capacity factors of 80% or better.
2. Geothermal – Geothermal resources convert hot underground geothermal steam/fluids into electricity and are generally run as baseload facilities and have capacity factors in the 80-90% range.
3. Hydroelectric – Flowing water is used in hydro plants to rotate a turbine and generate electric power. Run-of-river units offer continuous energy contributions, while dammed or

pumped storage units offer the ability to use the facility as a peak-shaving unit thereby providing additional value to the resource. Capacity factors for hydroelectric resources vary widely dependent on river flow and size of storage.

4. Solar – Solar generation resources convert the sun's energy (photons of light) into electricity (voltage). Solar generation can take several forms, such as PV, concentrating PV, or concentrating solar power. Like the wind, solar generation is intermittent. Solar generation is only available during the daytime and its output is coincident with the time of the day (i.e., as the sun rises and falls, so does the solar generation output). Maximum solar output (without storage) occurs prior to the time when electric demand reaches its highest level. Therefore, something less than the full nameplate generating capability of solar generation is counted toward meeting electric system peak demands. Solar generation capacity factors typically range from 20-35% depending upon whether the resource is PV (fixed– 20%, 1 axis tracking – 33%) or whether the project is PV with storage (30%).
5. Wind – These are typically large, three-bladed turbines mounted atop high towers over 200 feet tall. Wind projects can consist of a single turbine or multiple turbines with aggregated capacities up to hundreds of MW. Because the wind drives the turbines, the generation from a wind turbine is considered intermittent and can be difficult to predict. Consequently, the electric generation capacity that is attributed to wind turbines is less than the full design output rating. Wind generation units in New Mexico and Texas typically have an annual capacity factor in the 45-55% range.

The basic cost characteristics of generation resource technologies are illustrated in the following table.

Table 6-1: Cost Structure of Generic Resources

Costs	Gas CT	Gas CC	Wind	Solar
Installed Cost	Low	Mid	High	Mid/High
Operating Costs	High	Mid/High	Low	Low
Capacity Factor %	0-25%	25-80%	45-55%	30%
CO_2	Medium	Low	None	None
Fuel Price Risk	High	Mid/High	N/A	N/A

Examples of Energy Storage Resources

Energy Storage – Lithium ion battery storage has become increasingly popular due to declining costs. These battery storage devices typically range in size from 10 – 200 MW and vary in duration from 1-4 hours. Battery storage is beneficial because it allows for high efficiency and a long lifespan without regular maintenance. For short duration requirements, battery storage can bring about frequency control and stability and for longer duration requirements they can bring about energy management or reserves.

DSM Resources

DSM resources act to reduce the demand for electric power and include a variety of measures such as EE, energy conservation, LM, and demand response. There are two basic types of demand-side resources: peak shavers and energy savers. Peak shavers are used to reduce a customer's demand and energy requirements during periods of high demand. Examples of peak shaver DSM options include SPS's Commission-approved ICO (available to the business segment), and the Saver's Switch (available to residential customers) programs. Energy savers are used to reduce energy over all periods of the year. An example of an energy saver would be replacement of incandescent light bulbs with more energy efficient LED bulbs to reduce energy consumption throughout the year.

Transmission Upgrades

Investments in transmission can be used as substitutes for investments in new generating facilities or demand-side resources, where transmission upgrades are used to access existing generation (or excess generation) within other transmission-constrained areas.

6.01 - Resource Options Considered

DSM Resources

Cost-effective DSM (both New Mexico and Texas) is included as an offset to the corresponding base, low, and high-load forecasts.

Supply-Side Thermal Resources

1. Gas-fired CT - Natural gas-fired CTs are available in a range of sizes (25 MW to over 200 MW). CTs typically have low capital costs, but are relatively inefficient sources of generation and thus have high operating costs ($/MWh). The typical role for CTs is to be run at times of the highest load demand or during unanticipated outages of lower cost generators (i.e., "peaking" capacity).

2. Gas-fired CC - Natural gas-fired CC units incorporate single or multiple CTs used in conjunction with a HRSG. The waste heat from a CT's high temperature exhaust gas is captured and used to create steam to run a steam turbine for additional power and significantly higher efficiency (i.e., a lower heat rate) than a CT operating in simple cycle mode. CC units range in generation sizes from 100 MW to over 700 MW, and have higher capital costs than CT peaking units. A CC's ideal role is to be operated in more of an "intermediate" role, which means less often than base load resources but more often than peaking resources. The lower heat rate of CCs results in reduced fuel burn when compared

to CTs for a given amount of generation, and, as a result, CCs have a significantly lower emission rate of CO_2 compared to CTs (approximately 35% lower).

Standalone Energy Storage Resource

Energy Storage – Lithium ion batteries are highly efficient and low-maintenance. They can both dispatch and store energy, making them ideal for emergency services (e.g., voltage and frequency control) and for energy management and ancillary services. Battery storage is proving to be very flexible and can meet the demands of a more variable generation mix (e.g., renewables). Battery storage is typically charged from the grid during hours of low demand where electricity is at a lower energy cost. The battery can then be discharged during times of high demand and cost.

Energy Storage with Solar

Energy Storage with Solar – When integrated with renewables, in this case solar, solar energy is produced, and the battery stores the energy and returns it to the grid in times of low or no renewable production or when production falls below consumption.

6.02 - Resource Option Cost and Performance Estimates

In developing the 2018 IRP, estimates were developed for the various costs, performance, and operational characteristics for the resource options discussed above. The resource options were then applied in SPS's computer modeling to represent how these various technologies would integrate with the existing SPS electric system to serve future customer load projections. Table 6-2 contains a summary of the information used to represent the various generic generation technologies that were considered in the 2018 IRP. Detailed cost and performance information related to the generic resource types is presented in Appendix G.

Table 6-2: Generic Resource Summary Cost and Performance - 2018[22]

Resource	Capacity MW	Capacity Cost $/kw	Fixed O&M $000/yr	On-Going Capital $000/yr	VOM $/MWh	Heat Rate MMBTu/MWh	Capacity Factor	CO_2 Emissions Lbs/MMBTu
Generic 2x1	771	$795	$3,931	$2,558	$1.15	7,319	9%	118
Generic CT	201	$629	$212	$812	$0.76	10,009	60%	118

6.03 - Existing Rates and Tariffs

SPS's current mix of seasonal rate design, service curtailment programs, and EE programs provide a fair balance between the interest in meeting, delaying, or avoiding the need for new capacity, balanced with cost containment and minimizing adverse rate impacts resulting from significant changes in rate structures.[23] A list of each tariff is provided below.

- General Service rates
- TOU rates
- ICO
    - Summer Only ICO
    - Voluntary Load Reduction Purchase Option
- Commercial and Industrial Controlled Air Conditioning Rider
- Residential Controlled Air Conditioning and Water Heater Rider

General Service Rates

All general service rates have some form of seasonality in the kWh consumption charge or the kW demand charge. Summer rates are higher than winter (non-summer) rates, which requires the customer to pay more for electricity used in higher demand, peak periods in the summer

[22] Table 6-2 reflects 2018 costs escalating at 2%.

[23] SPS's current rates were set in Case No. 16-00296-UT. The rates are subject to revision in Case No. 17-00255-UT.

compared to the same levels of usage in winter billing months. A higher bill can serve to discourage excessive usage in summer months, and where possible for the customer, serve as an incentive to shift usage to lower demand winter billing periods.

TOU Rates

Available as an option for all general service customers, except Large General Service – Transmission, limited to a total of 190 customers. TOU rates provide a lower rate compared to general service rates for off-peak demand or energy consumption, with a higher charge based upon avoided capacity cost during peak hours. Peak hours are 12 noon through 6 p.m., Mondays through Fridays, during the summer billing months of June through September. Lower rates during off-peak hours, and all hours for eight off-peak months, can encourage customers to take electric service during periods in which capacity is not strained. Higher rates during peak hours can encourage customers to minimize or avoid taking electric service when capacity can potentially be strained, minimizing the requirement to expand capacity and related costs, as a result of requirements during peak hours.

ICO

Available as an option for customers who receive electric service under SPS's Primary General Service, Secondary General Service, or Large General Service Transmission rate schedules who are willing to have their service interrupted with one hour or no notice, thereby relieving SPS of the obligation to serve those customers as circumstances warrant.

Summer Only ICO

Available as an interruptible service option, at the discretion of SPS, when: (1) SPS determines that it has need for additional resources; and (2) SPS is interested in receiving offers from customers for interruptible load. Customer(s) must meet each of the following conditions: (1)

customer receives electric service under SPS's Primary General Service, Secondary General Service, or Large General Service Transmission rate schedules; (2) customer's contract interruptible load is 300 kW or greater; (3) customer achieved (or SPS estimates that customer will achieve) an interruptible demand of at least 300 kW during each of the most recent four summer peak season months of June, July, August, and September; and (4) customer and SPS have executed a Summer Only ICO Agreement that specifies the contract firm demand and monthly credit rate, as well as the customer specific data necessary for SPS to calculate the customer's monthly credit.

Voluntary Load Reduction Purchase Option

Applicable to customers with at least 500 kW of peak load during each of the four summer months, June through September, which can be made available for interruption under this tariff and is not committed for interruption under another interruptible program or tariff.

Residential Controlled Air Conditioning and Water Heater Rider

Voluntary program in which SPS can control customer's air conditioners and electric water heating normally LM designed to achieve a 50% reduction in the building air conditioning requirements during a LM period.

Commercial and Industrial Controlled Air Conditioning Rider

Voluntary program in which SPS can control customer's air conditioners normally designed to achieve a 50% reduction in the building air conditioning requirements during a LM period.

Section 7. DETERMINATION OF THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO AND ALTERNATIVE PORTFOLIOS

7.01 - Resource Planning Fundamentals

In its simplest form, electric resource planning is the process of taking forecasts of customer electric demand and energy use and determining the appropriate diversification of generation sources, including but not limited to, thermal generation, renewable resources, energy storage, DSM and LM, that should be developed to meet customer requirements in a cost-effective and reliable fashion. Engineering, permitting, and constructing electric generating facilities takes a significant amount of time and therefore the resource planning process must be completed with adequate lead-time to allow the development of new resources that are needed to meet customer energy requirements.

The following words and terms are used in the resource planning process.

Definitions

1. Annual Capacity Factor is the ratio of the net energy produced by a generating facility over a year, to the amount of energy that could have been produced if the facility operated continuously at full capacity over the year.

2. Capacity is the instantaneous capability of an electrical system to provide electricity or energy to meet demand and is usually measured in MW.

3. Demand or load is the level of power consumed at an instantaneous point in time.

4. Dispatchable Resource is a generation resource that provides the ability to physically control the generation output of that facility. Generally, thermal or storage type of units that can be "switched" on or off when requested, to a specified output.

5. Energy is the rate of electrical power delivered over a quantity of time and is usually measured in MWh.

6. Generation Resource Stack is a representation of the supply-side Dispatchable Resources sorted by operating cost, with the lowest cost generators such as coal and nuclear being at the bottom of the stack, intermediate cost generators such as CC gas units being in the

middle of the stack, and the generators with the highest operating costs (i.e., peaking facilities) being at the top of the stack.

7. Heat Rate defines the efficiency of the generation unit. Generally, heat rate is measured by units of fuel burned to create one MWh of energy.

8. Non-Dispatchable Resource is a resource without the ability to physically control the generation output of that facility. Generally, renewable type resources that only produce electricity when fuel (e.g., wind or sunshine) is available.

Computer Models

After developing forecasts of customer demand, L&R tables, and load duration curves of the system, computer modeling of the electric system is often the next step in the planning process. Computer models allow the resource planner to examine how different resource technologies will integrate with the existing fleet to meet the system needs under a range of assumptions from key inputs such as fuel costs. A utility expansion-planning model is specifically designed to construct combinations or portfolios of resources that would meet the capacity and energy needs of the system. The model simulates operation of each of these combinations of resources together with existing generation resources, while keeping track of all associated fixed and variable costs of the entire system.

The computer is needed because it can keep track of the thousands of calculations on costs, emissions, operational data, and various other metrics for each of the possible resource portfolios. Models typically have the capability to rank the various portfolios according to user-established objective functions (e.g., minimization of average rates to customers, or minimization of net present value of revenue requirements).

While this model is a powerful tool that can be used to generate and evaluate thousands of possible resource portfolios, the sheer complexity of these resource evaluations of this magnitude would quickly overwhelm the model's data storage and computational capabilities unless steps are taken to limit the size of the optimization problem presented to the model at any one time. The number of resource combinations that can be generated each year grows exponentially depending on the number of resources made available to the model.

7.011 - Strategist Model Description

Strategist[24] is a resource planning model specifically designed to determine the least-cost resource mix for a utility system from a prescribed set of resource technologies under given sets of constraints and assumptions. *Strategist* incorporates a wide variety of expansion planning parameters including alternative generation technologies available to meet future needs, unit capacity sizes, heat rates, fuel costs, LM, conservation programs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan that best suits the utility system being analyzed. *Strategist* contains four basic modules (load forecast adjustment ("LFA"), generation and fuel ("GAF"), capital expenditure recovery ("CER"), and PROVIEW that work in concert to simulate the operation of the existing utility system as well as the new resource additions needed to meet future demand growth on the utility system and calculates the costs of serving the system capacity energy needs over the defined study period.

The LFA module is used to represent the utility's demand and energy forecast. The GAF module represents the operating characteristics of the electric supply system (e.g., generating capacity, heat rate, operations and maintenance, maintenance, equivalent forced outage rate) and works in concert with the LFA to simulate operation of the utility power system. The CER module is used to calculate the revenue requirements for capital expenditures. The PROVIEW module pulls

[24] Strategist is one model in a portfolio of modeling tools owned by ABB in Atlanta, Georgia. Xcel Energy has a licensing agreement with ABB for use of the model.

information from all three modules to determine the least-cost balanced demand and supply plan for the utility system under prescribed sets of constraints and assumptions.

7.012 - Costs Included in Strategist

The *Strategist* model used to develop long-range expansion plans for the SPS electric system includes only a portion of the total electric system cost SPS incurs to provide electric service to its customers. A summary of the costs typically included and those not included in the model are as follows:

Costs Included in Strategist

1. Fuel costs for all electric power supply resources (owned and purchased);
2. Purchased energy costs for all electric power supply resources;
3. Capacity costs of purchased power;
4. VOM costs of purchased power;
5. Capital costs for new electric generation facilities added to meet future load;
6. Electric transmission interconnection and network upgrade cost for new generation;
7. Emissions and emission costs for CO_2, SO_2, and NOx;
8. FOM costs for existing and new generation facilities;
9. VOM costs for existing and new generation facilities; and
10. Remaining book value of SPS-owned generating units.

Costs Not Included in Strategist

1. Remaining book value of existing electric transmission or distribution facilities;
2. Capital costs for planned electric transmission upgrades or distribution facilities;
3. Capital costs for emission control systems; and
4. Administrative and general costs.

7.013 - SPS Unit Retirements

Strategist modeling assumed specific dates for the retirement of SPS generation consistent with Table 3-1 (*see* Section 3, above) with the exception of the Tolk generating units. Section 7.07 discusses the retirement dates of the Tolk units for each scenario analyzed in the optimization analysis.

7.014 - Representation of Capital Costs

The CER module within the *Strategist* model is used to calculate the revenue requirements for capital expenditures. The revenue requirements over the book life of the alternative resource options is then discounted to the base year for use in the Proview module. This base year revenue requirement allows the full costs of assets to be represented in the developing and ranking electric resource expansion plans.

7.015 - Other Key Modeling Assumptions

Impacts Due to Change in SPP Regional Fundamentals

SPP power prices are exogenous and treated as inputs to *Strategist*. Regional impacts due to either surplus and/or shortage of generation capacity including any impacts due to the introduction of the SPP IM (which began March 2014) are reflected in the long-term fundamentally-based forecasts from IHS Energy and Petroleum Industry Research Associates ("PIRA").

Natural Gas Modeling Methodology

Gas prices are developed using a blend of the latest market information (NYMEX futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, IHS Energy, and PIRA forecasts for Henry Hub. The four sources are combined as a simple average to develop the composite forecast. In the later years, the various sources no longer provide data (i.e., NYMEX goes through June of 2030 currently). As the source data ends, the latest value is escalated at a gross domestic product/inflation proxy rate to extend the forecast through the end of the modeling period.

For the basis differentials to Henry Hub of the various regional gas hubs needed for the analysis, the settlement price for the ICE-traded basis swap for the relevant hub is used. The last reported year's profile is extended through the modeling period.

Detailed information regarding the three consultants can be found on their respective websites:

- PIRA: www.pira.com;
- IHS Energy: www.ihsmarkit.com; and
- Wood MacKenzie: www.woodmac.com.

High and Low Natural Gas Sensitivity Cases

For the low and high price cases, the base gas forecast for Henry Hub was adjusted down by 50% of the growth (escalation) in the base gas case to represent the low gas case, and adjusted up by 150% of the growth in the base gas to represent the high gas case. The basis differentials were left unchanged from the base case.

Electric Power Price Modeling Methodology

Power prices are developed from the latest fundamental analyses from Wood Mackenzie and IHS Energy. From their studies, we extract their implied heat rates for the required locations (i.e., back out the gas price to "normalize" the data), and average the heat rates from the two sources to arrive at a composite forecast. Then, the heat rates are multiplied by the composite natural gas price forecast (as explained in the previous section) to determine the electric prices. This methodology results in power and gas forecasts that are consistent with each other.

High and Low Power Sensitivity Cases

The heat rates are kept the same as in the base case, but are then multiplied by the high and low natural gas price forecasts to determine the sensitivity case power prices.

Carbon Price Sensitivity

Emissions of CO_2 were modeled at $8, $20, and $40 per metric ton base year of 2011, escalated at 2.5%/year consistent with the final order in NMPRC Case No. 06-00448-UT (*Order Approving Recommended Decision and Adopting Standardized Carbon Emission Costs for Integrated Resource Plans*).

RPS Requirements

All modeling assumed SPS's compliance with respect to the RPS and SPS's compliance requirements related to meeting the diversity requirements required in 17.9.572.7.G NMAC.

Escalation

The general escalation rate assumed for the base analysis is 2%.

Discount Rate

In evaluating the economics of resource planning decisions and competing resource options, SPS discounts future utility revenue requirement cash flows to determine the lowest cost option, which is normally expressed on a present value of revenue requirement ("PVRR") basis. These revenue requirements include avoided energy, generation build, capacity purchases, and the tax deductibility of debt interest. In IRP analyses, revenue requirements normally include the tax deductibility of debt interest expense and therefore it is appropriate to use the after-tax weighted-average cost of capital ("WACC") that incorporates the impact of the deductibility of debt interest expense.

The discount rate used in developing the 2018 IRP is SPS's combined jurisdictional weighted after-tax cost of capital of 7.34%, with a tax rate of 21%.[25]

Table 7-1: Discount Rate Calculation

SPS System Weighted	Cost	Capitalization	Pre-Tax WACC	After-Tax WACC
LT Debt	4.39%	42.00%	1.84%	1.42%
Common Equity	10.20%	58.00%	5.92%	5.92%
Total		**100.00%**	**7.76%**	**7.34%**

Transmission Costs

Transmission costs were reflected in the modeling by assigning cost estimates for transmission interconnection and transmission delivery upgrades (i.e., infrastructure) to the generic thermal resources.

7.02 - A Changing Planning & Regulatory Landscape

SPS is approaching the time period (2019-2038) where it will need to respond to significant changes in regulatory policy and environmental regulations that could result in: (1) the need to make large capital investments, which will shape the selection of new generation resources; and (2) retirement of existing generation resources, ultimately impacting system costs and customer rates. Some of the key developments and challenges SPS expects to face over the Planning Period will impact future resource needs and operations, as well as impact the resulting cost of service and rates. Specifically, SPS addresses the:

[25] SPS used a weighted average of its proposed WACC and Return on Equity *requested* in SPS's Texas rate case (Public Utility Commission of Texas Docket No. 47527 and SPS's pending New Mexico rate case New Mexico Public Regulation Commission Case No. 17-00255-UT), which reflects the impacts of the Tax Cuts and Job Act.

- Evolving environmental regulations (Section 7.021);
- Evolving SPP IM (Section 7.022);
- Changing customer expectations (Section 7.023);
- Technology advancements that will impact the future of the grid (Section 7.024);
- Tolk Station aquifer depletion (Section 7.025);
- Impacts to the IRP due to an aging generation fleet (Section 3.09); and
- Impacts to the IRP due to high variability system load growth (Section 3.10).

In addition, other variables are also discussed, including tax credits and incentives; gas price forecasts; and RPS-resources acquisition.

This long-term planning landscape addressed in this section foreshadows certain key issues to be addressed in subsequent IRP filings (particularly the 2021 and 2024 IRPs). The planning landscape is also presented so that recommendations and conclusion reached in this 2018 IRP are consistent with the expected future direction of resource planning.

A detailed discussion of the planning landscape is provided below to promote awareness of the major policy issues that will need to be addressed in subsequent IRPs. As mentioned earlier, as a result of the significant uncertainty existing today, SPS was unable to accurately capture the impacts of these key policy issues. The 2018 IRP addresses SPS's near-term resource needs and identifies key policy issues that will shape subsequent IRP content and recommendations and may necessitate changes to the Action Plan in the interim.

7.021 - Impacts Due to Evolving Environmental Regulations

Since the development and filing of SPS's last resource plan filing (2015 IRP), multiple new air, water, and waste regulations have been updated and adopted by the EPA. Moreover, regulations for oxides of nitrogen, SO_2, particulate matter, CO_2, and ozone continue to be updated periodically. As discussed in detail in Section 3.09, these regulations impose significant uncertainty in Federal climate policy.

Uncertainty in the environmental regulation arena and the associated range of potential outcomes necessitates a resource plan capable of meeting current rules/regulations yet flexible enough to respond to any significant changes in environmental policy.

7.022 - Impacts Due to the SPP IM

As discussed earlier (*see* Section 3.06) the SPP IM has been in operation just over four years, and SPS has noticed a change in the commitment of its generation fleet for reliability needs. In particular, SPS's gas units are committed less often for reliability purposes. At the same time, resource adequacy is constantly under review by the SPP and it is plausible that the current capacity margin could be reduced below 12% in the future.

7.023 - Impacts Due to Shifting Customer Expectations and Preferences

SPS's large customers have historically been very active in the regulatory process, particularly in their desire for SPS to maintain a competitive rate structure due to the energy-intensive nature of their operations and the significant impact of electric rates on their overall cost of production. These customers are extremely price sensitive and are most likely to take advantage of new products and services which enable them to reduce their electricity costs. SPS is also hearing from some of its small/medium commercial accounts and even its residential customers regarding their preference for environmentally clean energy, energy conservation programs, and innovative rate design to encourage shifting of demand/energy usage to off-peak periods. Self-generation (PV) and storage technologies (batteries) could enable customers to bypass their local utility provider. Cost-based alignment of utility-based services and rate design will be crucial (even more than it is today), to ensure that all customers pay for services from which they depend upon and to prevent cost shifting from one customer or customer segment to another customer or group of customers**.**

<u>7.024 - Impacts Due to Emerging Technologies</u>

The advancement of distributed energy resources such as distributed generation ("DG"), energy storage, and other decentralized devices that supply power to the grid, but are not necessarily energy generators, are contributing to the evolution of the utility industry. SPS continues to see small increases in DG, which is broadly defined as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, with a total capacity of no more than 10 MW. With the cost of solar continuing to decrease further relative to SPS rates, at some point reaching parity with SPS system rates, DG penetration could increase as compared to where it is today. Generally, customers are increasingly interested in various types of self-generation – specifically solar PV. Growth in solar across all market segments is driven by several forces. Namely, its economics are improving through state and federal incentives and manufacturing advancements. Customers are increasingly interested in new energy choices, including the option to install solar on their homes and businesses to produce their own energy; and state and federal policies are promoting solar as a way to reduce GHG emissions and support local economic development**.**

<u>7.025 - Impacts Due to Aquifer Reductions</u>

Tolk Station consists of two coal-powered steam turbine units in Texas with a total net capacity of 1,067 MW. Tolk Unit 1 ("T1") has a net capacity of 532 MW and Tolk Unit 2 ("T2") has a net capacity of 535 MW. Tolk Station currently relies exclusively on groundwater for generation cooling. At the time Tolk Station was built, the groundwater in the aquifer was believed to be sufficient to accommodate the water needs of the plant for the forecasted depreciable life of the facility. The depletion of the aquifer has been accelerated by significant regional drought since 2010 and thus by heavy agricultural irrigation in the region. And, although SPS has implemented water conservation measures by bringing previously used water from nearby Plant X, this is not a long-term solution. Because groundwater production is far in excess of the aquifer recharge rate, the aquifer has been consistently depleted through widespread development. Biannual testing in the area has confirmed that it has become increasingly critical to add additional wells to offset the annual productivity loss and maintain peak flows to support generation at Tolk Station. SPS continues to add new wells nearly every year to maintain the water flows necessary to operate the Tolk units. This effort is becoming increasingly expensive with diminishing returns and is not sustainable long-term. The level of generation at Tolk Station is directly related to the amount of water required to operate the facility. By reducing the Tolk unit operations to shorter periods (e.g., operation in the summer only), SPS can mitigate these water flow issues by reducing the amount of water needed per year to support Tolk operations. The impact to the generation at Tolk due to the decline in the Tolk wellfield area are discussed in greater detail in Section 7.07.

7.03 - Additional Planning Uncertainties

The following subsection details areas of additional planning uncertainty during the Planning Period for this IRP. These sections are provided for educational purposes and to further emphasize the complexities of the generation resource planning process.

Tax Credits and Incentives

The federal renewable electricity production tax credit ("PTC") is an inflation-adjusted per-kWh tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The current PTC for wind resources applies to wind facilities commencing construction by December 31, 2019 and all other QF facilities commencing construction by January 1, 2018. The PTC, which was $24/MWh in 2017, is escalated each year at an inflation factor published by the Internal Revenue Service in April of each year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities placed in service after August 8, 2005. The value of the credit for wind steps down in 2017, 2018, and 2019. For wind facilities commencing construction in 2017, the PTC amount is reduced by 20%. For wind facilities commencing construction in 2018, the PTC amount is reduced by 40%. For wind facilities commencing construction in 2019, the PTC amount is reduced by 60%. While the PTC has seen several extensions in the past, the current climate in the U.S. Congress makes another extension uncertain.

The federal investment tax credit ("ITC") for solar resources is currently 30% for invested property which have commenced construction through 2019. The ITC then steps down to 26% for projects that begin construction in 2020 and down to 22% for projects that begin construction in 2021. After 2021, the utility credit will drop to a permanent 10%.[26]

Natural Gas

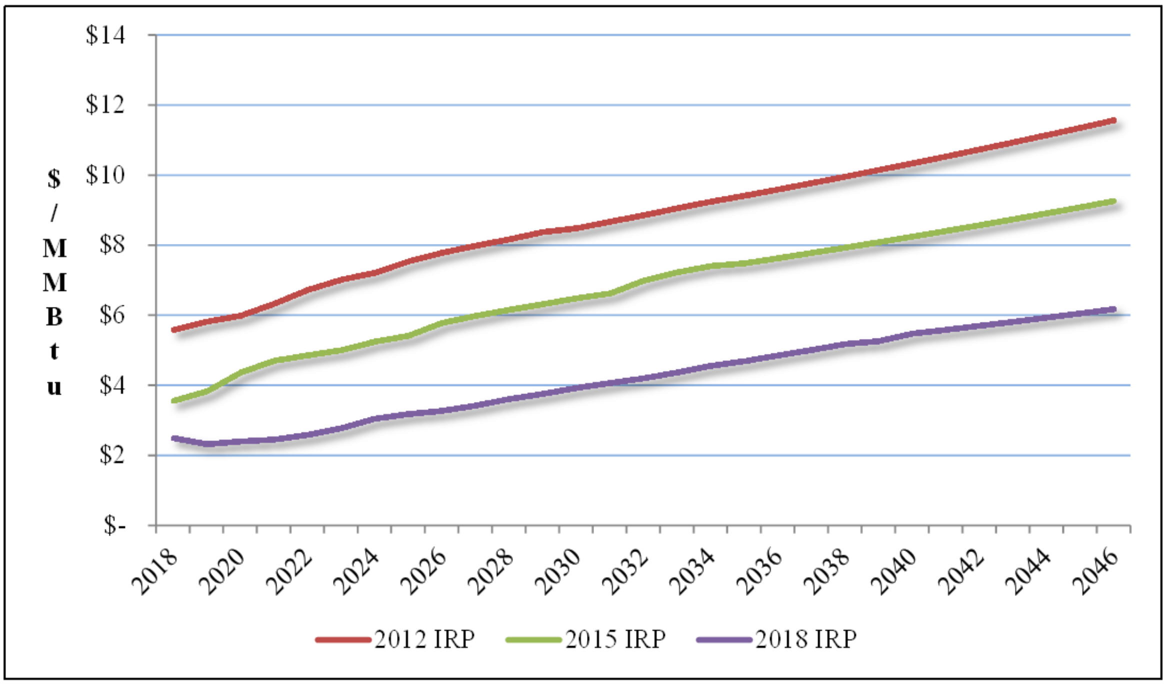
The price of natural gas is a key driver in determining the cost-effectiveness of renewable resources such as wind and solar relative to gas-fired resources. Low gas prices make wind and

[26] Developers can take 30% of a project's total development and construction cost as a tax credit.

solar less competitive with gas-fired resources while higher gas prices make them more competitive. Current projections indicate lower forecasted natural gas prices (as compared to the 2012 IRP and 2015 IRP forecasts) (*see* Figure 7F.1 below); however, these are still forecasts and as such are not guaranteed prices. Factors that could alter the current price outlook include:

- Resistance to local drilling impacts (e.g., noise, air quality, land access, etc.);
- Water issues, including fears over contamination of groundwater and fears of pollution associated with the disposal of "produced water" from fracking that could lead to greater regulation; and
- Increased natural gas demand due to faster-than-expected economic growth.

Figure 7F.1: SPS Natural Gas Price Forecasts



7.04 - Renewable Resource Additions

In the 2018 IRP, SPS has assumed full compliance with the RPS requirements of the Renewable Energy Act and the Commission's Rule 572. However, based on the Reasonable Cost Threshold ("RCT") presented by SPS in its 2018 RPS filing (2019 RPS Plan), the results (under varying scenarios) indicate that SPS has exceeded the RCT and therefore no new RPS-related resources can be acquired at this time. However: (i) the Commission has not made a determination regarding SPS's 2019 RPS plan; and (ii) the RCT is very dependent on natural gas prices, which could change future RCT analysis results. Moreover, to the extent renewable energy can be acquired as a cost-effective resource addition, SPS will pursue such additions under a buy-over-time acquisition strategy.

7.05 - Additional Generation Resources

As mentioned previously in Sections 3.02 and 3.03, SPS entered into a PPA with NextEra to purchase 230 MW of wind energy from the Bonita Wind facilities (150 MW located in Cochran County, Texas and 80 MW located in Crosby County, Texas) beginning January 2019 for a term of 25 years. SPS is also constructing two wind facilities: (1) 478 MW Hale Wind to be in-service July 2019, located in Hale County, Texas, and (2) 522 MW Sagamore Wind to be in-service May 2020, located in Roosevelt County, New Mexico.

SPS filed a wind CCN for approval of these wind projects at the NMPRC in Case No. 17-00044-UT. A final order approving the acquisition of the 1230 MW of wind energy was issued on March 21, 2018.

7.06 - Summary of Analysis

Strategist was used to simulate system dispatch of the SPS electrical system and economically optimize the resource additions, subject to the constraints and assumptions identified above, with emphasis on the impact of aquifer reductions at Tolk Station that are discussed in Section 7.025. *Strategist* was relied upon to capture the incremental impact of various resource additions, removals, or replacements. Following is a discussion of low, base, and high load forecasts, optimized model runs, and delta case scenarios.

7.07 - Strategist Optimized Model Results

As discussed in Section 7.025, the depletion of the groundwater at Tolk Station has been accelerated by significant regional drought since 2010 and thus by heavy agricultural irrigation in the region. Due to the decline in the aquifer within the area of the Tolk/Plant X Station wellfield and the impacts to the Tolk generation, SPS developed a spreadsheet model to evaluate Tolk's long-term water supply under various operating scenarios and sensitivities. The model allowed for variation of key input variables to produce an estimate of the longevity of the Tolk/Plant X wellfield. There are several key variables that are utilized in the model. The variables are estimates that can be modified as needed to give ranges of future potential operations of the plants. Some of the variables are:

- Generating unit capacity (Tolk, Plant X, and Jones Stations);
- Generating unit capacity factors and monthly/seasonal variability;
- Generating unit retirement dates;
- Auxiliary water demand;
- Available reservoir storage;
- Wellfield capacity, outage rate, rate of productivity decline, and starting capacity of new wells;
- Water demand for potential environmental controls;
- Variables to account for other variation in water use by each unit; and
- Estimate of starting recoverable groundwater volume (derived from MODFLOW modeling).

SPS's water model results yield a depletion window, which provides the estimated years in which the retirement of the Tolk units would be required due to the prediction of insufficient groundwater for Tolk's generation cooling needs. The specification of the depletion window was consistent across all model runs. The start of the depletion window began when the model indicated 50,000 acre-feet of recoverable water remaining in storage, and ended when the model indicated less than 20,000 acre-feet of recoverable water. These thresholds relate to a saturated thickness change of between three and five feet, which is reasonable when compared to the 30- and 40-foot well draw-down lengths necessary to produce groundwater from the Tolk/Plant X wellfield.

Under the business-as-usual ("BAU") assumption, the economic depletion range (expressed in years of service) was determined to be 2022 – 2024 for Tolk. Based on the BAU economic depletion range, scenarios were developed that incorporate various ranges of reduced operations at Tolk in an attempt to extend the economic depletion range of the groundwater supply. Each scenario also includes sensitivities that reflect different start dates for the scenario. The scenarios/sensitivities were run through the water model to determine a new economic depletion range for each scenario/sensitivity. Cost estimates were developed for each scenario/sensitivity, on-going capital cost for Tolk, FOM costs, and VOM costs.

The development of alternative operating scenarios for the Tolk units was an iterative process. Multiple operational scenarios for Tolk with various sensitivities were determined that would help give a more detailed analysis of potential costs or savings under the different operating scenarios. The water model considered the operating assumptions in each scenario (e.g., generation, retirement date, variable load conditions) and developed a result of when the aquifer could no longer support that particular option. Appendix H shows all operating scenarios/sensitivities developed. The operating scenarios were narrowed down by choosing scenarios that would allow SPS to keep the Tolk units online as long as possible and maximize the amount of energy available from those resources. The resulting scenarios/sensitivities used in the *Strategist* analysis are:

- Scenario 8: Tolk operations BAU to current retirement dates (T1 End of Year ("EOY") 2042, T2 EOY 2045), and installation of a water pipeline and hybrid cooling towers.

- Scenario 4: Operation of both T1 and T2 as Summer Peaking (June-September), T1 and T2 minimum load only in off-peak months (October-May), retire T1 and T2 EOY 2026.

- Scenario 6: Managed decline (i.e., operation of T1 and T2 as Summer Peaking + operation in off-peak months at minimum load (starting in 2018), and operation at minimum load for all months (starting 2022), followed by operation as Summer Peaking only (starting 2025), installation of one synchronous condenser in 2026, T1 retirement (EOY 2026), T2 retirement (EOY 2029).

- Sensitivity 7D: Tolk operations BAU, installation of one synchronous condenser in 2021, retire T1 EOY 2020, retire T2 EOY 2025

- Sensitivity 9C: Tolk operations BAU, with installation of water pipeline, retire T1 and T2 EOY 2032.

- Scenario 10: Operation of T1 and T2 Summer peaking (June-September), with T1 operating during off-peak months at minimum load and T2 operating off-line in off-peak months, installation of one synchronous condenser in 2019, retire both T1 and T2 EOY 2029.

- Scenario 11: Operation of T1 and T2 BAU January-September (2018) and minimum load from October-December. Beginning 2019, T1 and T2 minimum load January-May, summer peaking June-September, and one unit at minimum load October-December, with second unit off-line. Beginning 2020, T1 and T2 would be off-line in off-peak months (October-May) and T1 and T2 summer peaking (June-September). T1 and T2 retire EOY 2032.

A reference case (Scenario 8) that assumed existing PPAs and thermal resources (including the Tolk generating units) expire at their PPA termination date, or at the currently approved retirement date in the case of SPS-owned resources. As shown above, water pipeline and hybrid cooling towers would be required in order for both Tolk generating units to be available up to their approved retirement dates. The reference case includes the costs for the water pipeline build and hybrid tower installation.

Each scenario/sensitivity (i.e., Scenarios 4, 6, 8, and 10-11 plus Sensitivity 7D and 9C) were modeled taking into account the cost estimates. Each scenario/sensitivity was allowed to economically optimize resource additions, based upon the base load forecast. The resulting costs of each scenario/sensitivity were compared to the reference case (Scenario 8) and ranked from lowest to highest cost. Table 7-2 shows the PVRR and ranking results of the base load analysis.

Table 7-2: Base Load Analysis

ID	Scenario/Sensitivity Description	PVRR Total ($M)	Δ	Rank
8	Coal Book Life + Water Pipeline & Hybrid Cooling + Normal Operations	15,514	0	5
4	Retire Tolk EOY 2026 + Summer Peak (230 MW Off Peak)	15,506	(8)	4
6	Retire Tolk EOY 2026/2029 + Manage Decline	15,529	15	6
7d	Retire Tolk EOY 2020/2025 + Normal Operations	15,426	(88)	2
9c	Retire Tolk EOY 2032 + Water Pipeline + Normal Operations	15,566	52	7
10	Retire Tolk EOY 2029 + Summer Peak (230 MW/0MW Off peak)	15,487	(27)	3
11	Retire Tolk EOY 2032 + Summer Peak (0 MW Off Peak beginning 2020)	15,358	(156)	1

Appendix I shows the optimized expansion plan in the base load analysis for each scenario/sensitivity.

Risk and Uncertainties

The operating scenarios/sensitivities were run including high and low fuel/power price assumptions, high and low load forecast and varying carbon price assumptions. Specifically, *Strategist* was allowed to re-dispatch under these varying assumptions (for the price of natural gas low & high), carbon prices and allowed to re-optimize under the low load forecast and under the high load forecast). Table 7-3 shows the PVRR and ranking results of the risk and uncertainties analyses. The optimized expansion plan for the risk and uncertainties analyses are included in Appendix I.

Table 7-3: Risk and Uncertainties Analyses

PVRR Total ($M)

ID	Scenario / Sensitivity Description	Base	Low Gas	High Gas	Low Load	High Load	Low CO2	Med CO2	High CO2
8	Coal Book Life + Water Pipeline & Hybrid Cooling + Normal Operations	15,514	14,743	16,614	13,345	17,714	17,910	21,223	26,468
4	Retire Tolk EOY 2026 + Summer Peak (230 MW Off Peak)	15,506	14,435	17,053	13,206	17,736	17,556	20,488	25,172
6	Retire Tolk EOY 2026/2029 + Manage Decline	15,529	14,442	17,084	13,217	17,742	17,581	20,530	25,249
7d	Retire Tolk EOY 2020/2025 + Normal Operations	15,426	14,338	16,993	13,100	17,679	17,456	20,338	24,929
9c	Retire Tolk EOY 2032 + Water Pipeline + Normal Operations	15,566	14,602	16,987	13,374	17,739	17,764	20,855	25,763
10	Retire Tolk EOY 2029 + Summer Peak (230 MW/0MW Off peak)	15,487	14,423	17,019	13,214	17,697	17,557	20,521	25,251
11	Retire Tolk EOY 2032 + Summer Peak (0 MW Off Peak beginning 2020)	15,358	14,302	16,875	13,098	17,588	17,420	20,360	25,052

PVRR Δ

ID	Scenario / Sensitivity Description	Base	Low Gas	High Gas	Low Load	High Load	Low CO2	Med CO2	High CO2
8	Coal Book Life + Water Pipeline & Hybrid Cooling + Normal Operations	0	0	0	0	0	0	0	0
4	Retire Tolk EOY 2026 + Summer Peak (230 MW Off Peak)	(8)	(308)	439	(139)	22	(354)	(735)	(1,295)
6	Retire Tolk EOY 2026/2029 + Manage Decline	15	(301)	471	(128)	28	(328)	(693)	(1,219)
7d	Retire Tolk EOY 2020/2025 + Normal Operations	(88)	(405)	379	(245)	(35)	(454)	(885)	(1,538)
9c	Retire Tolk EOY 2032 + Water Pipeline + Normal Operations	52	(141)	373	29	24	(146)	(368)	(704)
10	Retire Tolk EOY 2029 + Summer Peak (230 MW/0MW Off peak)	(27)	(320)	405	(131)	(18)	(353)	(702)	(1,216)
11	Retire Tolk EOY 2032 + Summer Peak (0 MW Off Peak beginning 2020)	(156)	(441)	261	(247)	(127)	(490)	(863)	(1,415)

PVRR Rank

ID	Scenario / Sensitivity Description	Base	Low Gas	High Gas	Low Load	High Load	Low CO2	Med CO2	High CO2
8	Coal Book Life + Water Pipeline & Hybrid Cooling + Normal Operations	5	7	1	6	4	7	7	7
4	Retire Tolk EOY 2026 + Summer Peak (230 MW Off Peak)	4	4	6	3	5	3	3	3
6	Retire Tolk EOY 2026/2029 + Manage Decline	6	5	7	5	7	5	5	4
7d	Retire Tolk EOY 2020/2025 + Normal Operations	2	2	4	2	2	2	1	1
9c	Retire Tolk EOY 2032 + Water Pipeline + Normal Operations	7	6	3	7	6	6	6	6
10	Retire Tolk EOY 2029 + Summer Peak (230 MW/0MW Off peak)	3	3	5	4	3	4	4	5
11	Retire Tolk EOY 2032 + Summer Peak (0 MW Off Peak beginning 2020)	1	1	2	1	1	1	2	2

Energy Storage Analysis

Energy storage, specifically standalone battery storage and solar with battery storage, was not included as a resource option in the Strategist optimization. Due to the complex operations of storage, the optimization logic in the Strategist model is less effective in a regional dispatch. Therefore, the energy storage options were evaluated after the preferred plan was developed. SPS modeled a 100 MW, 4-hour battery with an accredited capacity of 75 MW and modeled a 100 MW, 4-hour battery (75 MW accreditation) integrated with a 200 MW solar PV facility (136 MW accreditation) for a combined accreditation of 211 MW. The storage resources were included as inputs into the model the year the capacity was needed and Strategist was run to re-optimize the remaining capacity additions. In this case, the energy storage was included in year 2032. The cost of the energy storage options were taken from bids received on November 29, 2017 by SPS's affiliate, Public Service Company of Colorado, in its All-Source Solicitation. As shown in Table 7-4 including a solar plus storage option in the resource mix is an economic solution.

Table 7-4: Energy Storage Analysis Results

Scenario / Sensitivity Description	PVRR Total ($M)	Δ	Rank
Scenario 11	15,358	0	2
Scenario 11 + Battery 2032	15,389	30	3
Scenario 11 + Solar Plus Storage 2032	15,267	(91)	1

Appendix I shows the optimized expansion plan for each energy storage scenario.

Generic Solar and Wind Costs

SPS frequently evaluates the costs associated with acquiring new solar or wind resources, either through long term PPA's or company ownership. In the event such analyses demonstrated potential economic savings to ratepayers, SPS would potentially re-evaluate its future expansion plan to include these economic resources instead of the generic resources detailed above. This process was recently successfully demonstrated with approval of SPS's proposal of 1,230 MW of new wind generation (Bonita Wind, Hale Wind, and Sagamore Wind) to be in-service in 2019 and 2020.

7.08 - Conclusion

Table 7-2 shows the cost results of the base load analysis for each of the Tolk operating scenarios/sensitivities that were analyzed. The resulting costs are compared to the reference case (Scenario 8) and ranked from lowest to highest cost. Table 7-3 shows the cost results of the Risk and Uncertainties analyses. Scenario 11 is the most cost-effective scenario in five of the eight analyses. It is only when gas and CO_2 prices are high that Scenario 11 becomes the second most cost-effective scenario. Scenario 11 is the preferred plan.

Under the base assumptions for electric sales and natural gas prices, and the *expected* (emphasis added) level of operation, maintenance, and capital expense for such units, Scenario 11 is the most cost-effective alternative. This scenario assumes beginning 2018 T1 and T2 operate a minimum load in the off-peak months and are available for full load operation in the summer months. Beginning 2020 and through 2032 T1 and T2 will be off-line in the off-peak months and available for full load operation in the summer months.

The remaining scenarios/sensitivities assume even earlier shutdown dates of the Tolk generating units with Scenario 8 being the only exception. With that said, Scenario 8 depends on the installation of a water pipeline and hybrid cooling towers to get the Tolk units to the end of their currently approved retirement dates. Both of those investments would pose significant costs and, in the case of the hybrid cooling tower, are developing technologies. Additionally, keeping the Tolk units online and operating until their currently approved retirement dates would impose real, present day O&M and fuel costs on SPS's customers.

Table 7-4 shows the cost results of including energy storage in the analysis. Including a 100 MW battery only and assuming a 75% capacity accreditation (75 MW) results in an increased cost to the base load case. When the battery is coupled with a 200 MW solar facility and assuming a 68% capacity accreditation for the solar (136 MW) for a total of 211 MW, there is a reduction in cost to the base load case. The results indicate that there is potential opportunity to consider renewable energy plus battery storage. SPS will continue to evaluate the opportunities for energy storage including enhancing utility operations, provide grid support, optimizing the power system and enhancing the customer experience.

Section 8. PUBLIC ADVISORY PROCESS

Pursuant to the IRP Rule (17.7.3.9.H NMAC), SPS was required to begin planning for the 2018 IRP filing a minimum of one year prior to the filing date; therefore, consistent with the IRP Rule, invitations and notices for the initial meeting, held on June 15, 2017, were sent and published a minimum of 30 days prior to the first meeting. A repeat of the initial meeting was held on July 17, 2017. To ensure broad public input, SPS invited the Utility Division Staff of the Commission ("Staff"), as well as the interveners in its most recent general rate case, renewable energy, EE, and IRP proceedings. The invited parties cover multiple interest areas (e.g., residential, environmental, industrial and consumer advocacy) to ensure varied opinions and perspectives.

On May 3, 2017, SPS published notice of the first Public Advisory meeting in the Carlsbad Current-Argus, Eastern New Mexico News, Hobbs News-Sun, Quay County Sun, and Roswell Daily Record newspapers. These newspapers cover the general circulation of every county in New Mexico that SPS serves. SPS also provided notice with a one-time bill insert to all New Mexico retail customers during the May 2017 billing period. Copies of the invitation, public notice, and bill insert are included in Appendix J.

SPS provided adequate notice and an agenda of topics to be discussed before each meeting. SPS experienced low public participation at all public advisory meetings. Commonly, attendance included one or two members from Staff, one or two renewable energy developers, one environmental agency representative, and other energy industry representatives (i.e., oil and gas producers, renewable energy service providers). Very few questions were fielded by SPS representatives throughout the Public Advisory Process.

All Public Advisory Process meetings, held over an approximately 12 month time frame, were held using a webinar and an external conference bridge. A complete timeline of the Public Advisory meetings and summary of subject matters that were discussed at each of these meetings is presented in Table 8-1. A complete record showing the content presented at each of these meetings is included in Appendix K.

Table 8-1: Public Advisory Process Timeline and Subject Areas

Meeting Date	Topics Discussed
June 15, 2017	SPS System Overview SPS Landscape & Updates Since 2015 IRP 2017 RPS Filing Update
July 17, 2017	SPS System Overview SPS Landscape & Updates Since 2015 IRP 2017 RPS Filing Update
November 9, 2017	Tolk Water Situation
January 30, 2018	Gas and Power Market Price Forecasting Emerging Environmental Impacts for SPS New Mexico IRP
March 27, 2018	SPS Sales and Load Forecasting
May 31, 2018	SPS Coal Supply Energy Storage Overview

Section 9. ACTION PLAN

9.01 – SPS Action Plan for 2019-2022

Table 5-2, which is SPS's base load forecast, indicates that SPS has adequate generating capacity for the period 2019-2022. Beginning in EOY 2019, Plant X Unit 1, and Cunningham Unit 1 are currently scheduled for retirement. Plant X Unit 2 is currently scheduled for retirement beginning EOY 2020. Because the L&R indicates adequate generating capacity with excess capacity ranging between 629 MW up to 1,087 MW, SPS believes it might be possible to accelerate the retirement of one or more of the gas units that are schedule for retirement over the next four to eight years. There are many factors that will need to be taken into consideration in order to determine if it is feasible to accelerate any generating unit retirements including the value of the resource in relation to its capacity and energy to the system, cost recovery contingency and the variability of the load growth in the SPS service area.

During the Action Plan Period the new wind facilities described in Section 7.05 are planned to be in-service (i.e., the 478 MW Hale Wind to be in-service July 2019, the 522 MW Sagamore Wind to be in-service May 2020, and the 230 MW Bonita Wind is projected to be in-service January 2019).

9.02 – Status Report

When SPS filed the 2015 IRP, SPS was experiencing significant load growth in southeast New Mexico, driven primarily from an increase in oil and natural gas production. The increased load growth was occurring in the most isolated area of SPS, as well as the SPP footprint. This resulted in the need for location-specific generation and transmission planning solutions. Because of the increasing load in southeast New Mexico, SPS issued a Request for Proposal ("RFP") in

September 2014 seeking up to 200 MW of PV solar energy. The RFP resulted in SPS successfully negotiating two 70 MW PPAs, located in Chaves County and Roosevelt County, New Mexico. The Commission ultimately approved the solar acquisition in Case No. 15-00083-UT on September 21, 2015.

In SPS's most recent RPS filing (Case No. 18-00201-UT), SPS determined that its 2019 RPS revenue requirement will significantly exceed the RCT and SPS will not procure any additional renewable resources to satisfy requirements under 17.9.572 NMAC.